DRAFT

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
(CE) - Capacity Expansion
(CCS) - Carbon Caputure and Sequestration
(CNPPID) - Central Nebraska Public Power & Irrigation District
(CC) - Combined Cycle
(CT) - Combustion Turbine
(CNS) - Cooper Nuclear Station
(DA) - Day-Ahead
(DR) - Demand Response
(DRR) - Demand Response Resource
(ELCC) - Effective Load Carrying Capacity
(EPRI) - Electric Power Research Institute
(EE) - Energy Efficiency
(EIA)- Energy Information Administration
(GI) - Generation Interconnection
(GGS) - Gerald Gentleman Station
(IRA) - Inflation Reduction Act
(IRP) - Integrated Resource Plan
(MMU) - Market Monitoring Unit
(MEAN) - Municipal Energy Agency of Nebraska
(NC2) - Nebraska City Unit 2
(NPV) - Net Present Value
(NPPD) - Nebraska Public Power District
(NRC) - Nuclear Regulatory Commission
(OPPD) - Omaha Public Power District
(PBA) - Performance Based Accreditation
(PRM) - Planning Reserve Margin
(QLG) - Qualifying Local Generation
(RT) - Real-Time
(RICE) - Reciprocating Internal Combustion Engines
(RAR) - Resource Adequacy Requirement
(SMR) - Small Modular Reactor
(SPP) - Southwest Power Pool
(SD) - Strategic Directive
(SAWG) - Supply Adequacy Working Group
(TEA) - The Energy Authority
(WAPA) - Western Area Power Administration

EXECUTIVE SUMMARY

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 Contract.

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 enough 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 also intended to support, and not replace, the judgment of NPPD's decision makers.

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.

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). 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 that were used to help focus the IRP analysis process are:

- Resource expansion plans evaluated and selected in the IRP must meet future native load 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.

Interface with the Public

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

Refer to the presentation provided to the Board of Directors at their November 3, 2021 retreat for more information. It can be found in Appendix D.

Add 2023 IRP public interfaces in final report. .

Existing System & Committed Resources

Generation

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. For 2021 approximately 43% of NPPD's energy generation was from coal, 36% nuclear, 5% hydro, 3% gas & oil, and 6% wind and solar. The remaining 7% of NPPD's energy was supplied through purchases with over one half (½) of the purchases coming from WAPA. Non-carbon resources generated energy equal to 62.9% of native load energy in 2021. Appendix B lists all of NPPD's existing generation resources, including in-state hydro purchases and capacity purchases.

Transmission

NPPD's transmission system includes more than 4,600 miles of transmission lines in the state of Nebraska. This is composed of 1,122 miles of 345 kV, 671 miles of 230 kV and 2,850 miles of 115 kV facilities. NPPD is a member of the Southwest Power Pool (SPP), a regional transmission organization based in Little Rock, Arkansas. Membership in SPP provides the District reliability coordination service, generation reserve sharing, regional tariff administration, including generation interconnection service, network, point-to-point transmission service, and regional transmission expansion planning. SPP also offers an Integrated Market that provides Day-Ahead, Ancillary Services, and Real-Time Balancing Market.

Location is one of many inputs required by Transmission Planning when reviewing transmission system reliability for a new unit. Since this IRP did not go into detail regarding location for most of the new resources, a well-defined scope of what is needed for transmission is not available. However, to evaluate supply side resources, all costs, including transmission should be included. Transmission capital costs are usually an order of magnitude less than the capital costs of the generating unit, thus the impact of transmission cost uncertainty on the IRP results is not deemed to be as great as other variables.

Load Forecast

NPPD employs both top-down and bottom-up forecasting methods. Top-down econometric forecast uses service area socioeconomic "drivers" to project loads based on overall service area economic and demographic trends. The econometric forecast includes models for NPPD system level demand and energy at the busbar, or system inlet. Top-down econometric forecast also develops customer class energy forecasts at the end-use meter level. 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[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

[1] Corresponding winter season demand requirements are forecast to grow at an average rate of 1.3% between 2013/14 and 2018/19, and 1.3% annually between 2019/20 and 2032/33.

average rate of 0.26% annually between 2025 and 2052. 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.

Major Planning Assumptions

Environmental

NPPD presently meets all existing environmental regulations at all of our facilities.. There is a large degree of uncertainty surrounding potential carbon emissions and emissions regulation are a significant business risk for NPPD and its customers. The NPPD Board of Directors approved Strategic Directive BP-SD-05 (SD-05) on December 9, 2021 to help address this business risk. SD-05 adopts the goal of achieving "net zero" carbon emissions from NPPD's generation resources by 2050. The Board recognized and stated the importance of balancing affordability, reliability/resilience, and sustainability when addressing the business risks related to carbon emissions and emissions regulations. In addition to a CO2 reduction scenario modeled on the requirements of SD-05, NPPD also included two other CO2 reduction scenarios that modeled more aggressive CO2 reductions.

Fuel and Market Prices

In general, fuel prices are based on assumptions from NPPD's 2021 Rate Outlook version, which extends to 2027. For fuel prices beyond this period, assumptions from EIA's long-term escalation forecasts were generally used. Natural gas forecasts through 2034 were provided by NPPD's Fuel Department, with EIA escalation used for later years.

Major IRP assumptions for fuel costs (compounded annual growth rates 2023-2052) are:

- Coal costs are expected to escalate approximately 2.2% over the next 30 years
- Nuclear fuel costs are expected to escalate approximately 2.1% over the next 30 years
- Natural Gas costs are expected to escalate approximately 2.2% over the next 30 years

These growth rates are slightly higher than the 2% general inflation rate assumed in the study.

Major IRP assumptions for the 7x24 electricity energy market (compounded annual growth rates) are:

- Base market escalates at 0.2% annually
- Low market scenario escalates at -0.3% annually
- High market scenario escalates at 1% annually
- NPPD also considered a higher market sensitivity in which the price was approximately $10/MWh higher than the high market scenario.

Although not specifically evaluated in the IRP, resource plans could include small year-to-year adjustments to reflect the potential for short-term capacity purchases and sales. Long-term capacity purchases were not considered in the resource plans, based on NPPD's historical preference to own assets and uncertainty surrounding the availability of surplus capacity in the surrounding region.

Resources Studied

Energy Efficiency, Conservation, and Demand Response

An alternative to building additional supply-side (generation and delivery) resources to meet higher demands is to effect end-use customer behavior changes that result in reductions in their specific energy-related requirements. These reductions can be achieved through improved energy efficiency, energy conservation, and reduced demand for energy.

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 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℠ Energy Efficiency (EE) 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℠ umbrella. The IRP also examined a high EE scenario, with increased funding for the EnergyWise℠ program.

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.

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. 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. A scenario with increased use of demand response was considered, as part of the IRP analysis.

Renewable

Renewable resources include projects such as wind, solar, biomass, landfill gas, and new or incremental hydro facilities. The amount of additional generation available to NPPD from biomass, landfill gas, or new hydro facilities is limited. For this reason, the IRP did not concentrate on these types of resources, but it should not be construed that NPPD is eliminating them from consideration. Any resource will be considered by NPPD if it is determined to be cost effective.

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 2021 Report, wind nameplate capacity of over 30 GW was registered in the region. Average wind generation as a percent of load was 34% in 2021, and the maximum value for any five-minute interval reached a value of just over 77% in 2021. There is 25.1 GW of wind in the SPP's Generation Interconnection (GI) queue[2].

Solar facilities have not yet been as fully developed as wind in SPP. There is only approximately 235 MW of solar installed, but there is 42.5 GW in the SPP's GI queue.

NPPD included utility size wind and solar facilities as potential new resources. Refer to the New Resource Alternatives Section of the report for details concerning the assumptions.

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 eight (8) percent of all hours in the Day-Ahead (DA) Market were negative in 2021. The percent of negative pricing hours has been trending up. In 2019, two (2) percent of the DA hours were negative with five (5) percent in 2020. 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.

Energy Storage (ES)

NPPD estimated ES characteristics and costs based on four (4) hour lithium-ion batteries. SPP requires a minimum operation time of four (4) hours to accredit generation resources.

Conventional Resources

NPPD included new dual-fuel combustion turbines, Reciprocating Internal Combustion Engines (RICE), Combined Cycles (CC)[3], and also Small Modular Reactors (SMR). In addition to

[2] Per SPP GI Queue Dashboard (https://www.sppp.org/engineering/generator-interconnection/GI_Queue_Dashboard), as of 11/2/2022
[3] NPPD modeled a small and large CC, along with a CC with carbon capture equipment.

existing units operating as they do today, carbon capture and sequestration (CCS) was included as an option for GGS Unit 2, a second relicense option for CNS, and restoring natural gas as the primary fuel at Sheldon.

IRP Model

NPPD used Hitachi Energy's Enterprise Software Capacity Expansion model to develop this IRP. Capacity Expansion (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 their Rate Outlook and budgeting processes.

NPPD modeled scenarios and combinations of scenarios to produce more than 50 different expansion plans. Some of the uncertainties modeled were carbon reduction paths, market prices, load forecasts, as well as differing levels of energy efficiency and demand response.

Results

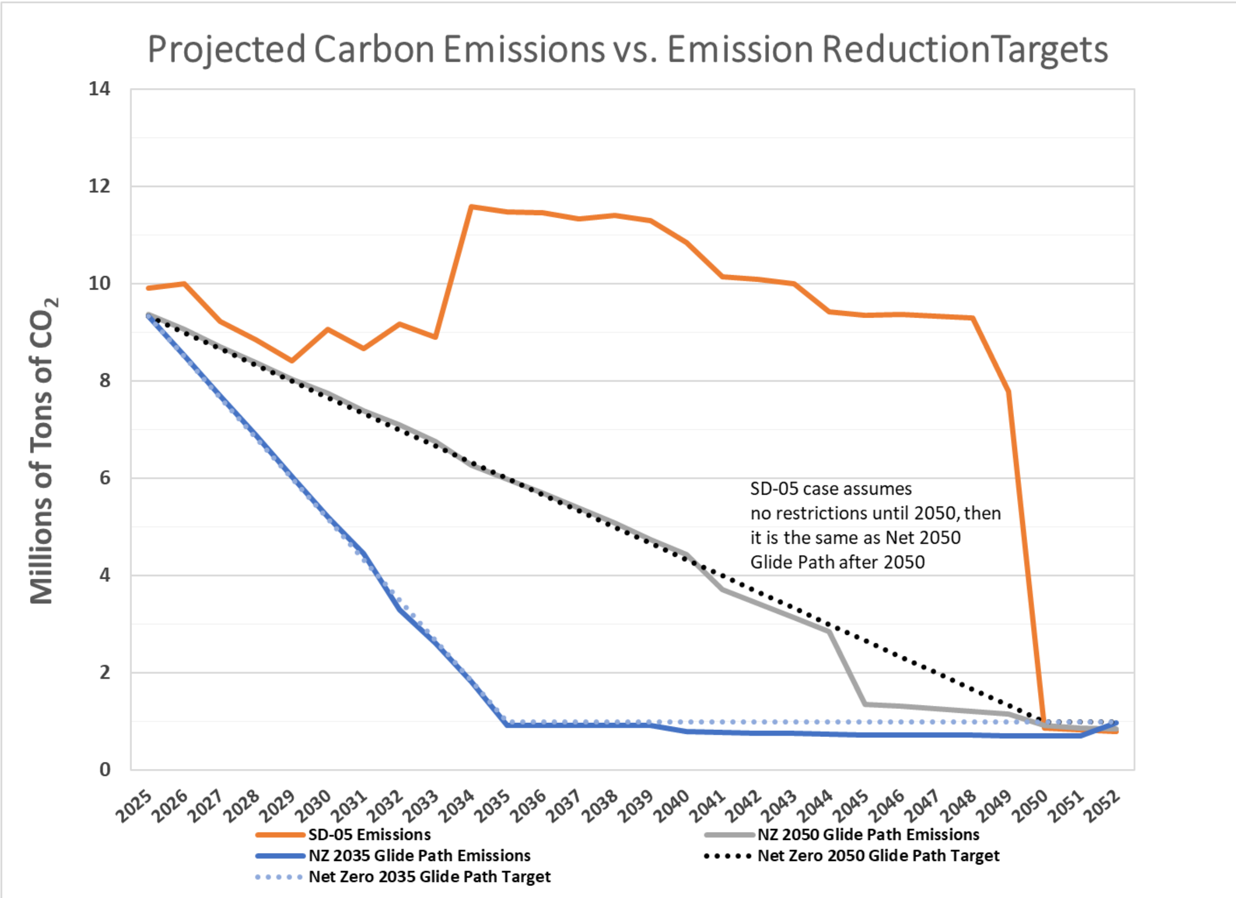
NPPD ran 54 cases using the Capacity Expansion software. The NPV of 30-year Wholesale Revenue Requirements for all of the runs are shown in Exhibit 3.1.1-1. The first 27 cases examined combinations of low, base, and high scenarios for CO2 restrictions, load, and market. After reviewing these results, 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. The values below are in Net Present Value (NPV) dollars.

- Operation of CNS from 2024 to 2032 could provide $0 to 700 million of credits depending on clarification of prevailing wages and gross receipts definitions.
- Carbon capture at a GGS unit could develop $2.6 billion in credits at high reliability and capacity factor.
- SMR could develop credits in the $700 million range.
- Renewables could generate IRA credits on the order of $850 million in high load and the most restrictive CO2 scenario modeled. In the early installation of renewable sensitivity, the credit is in the range of $200 million.

A graph showing annual projected emissions using a representative case for each CO2 restriction scenario is provided below in Exhibit ES-1. All of the resulting resource plans were generally able to meet the modeled CO2 reduction scenarios.

Exhibit ES-1 – Annual CO2 Emissions for selected Resource Plans



Although load was the greatest uncertainty as measured by NPV and shown in Exhibit 3.1.1-2 in the Results Section, the CO2 restriction variable had a greater impact on the types of resource selected. Coal plants without CO2 controls operated longer with the least restricted CO2 restriction sceanario, while NPPD's nuclear facility fared better under the most restricted CO2 restriction 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 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.

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.

The two exhibits below are summarized from the Results Section and illustrate how a second relicense at CNS or CCS at GGS maintains fuel diversity.

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

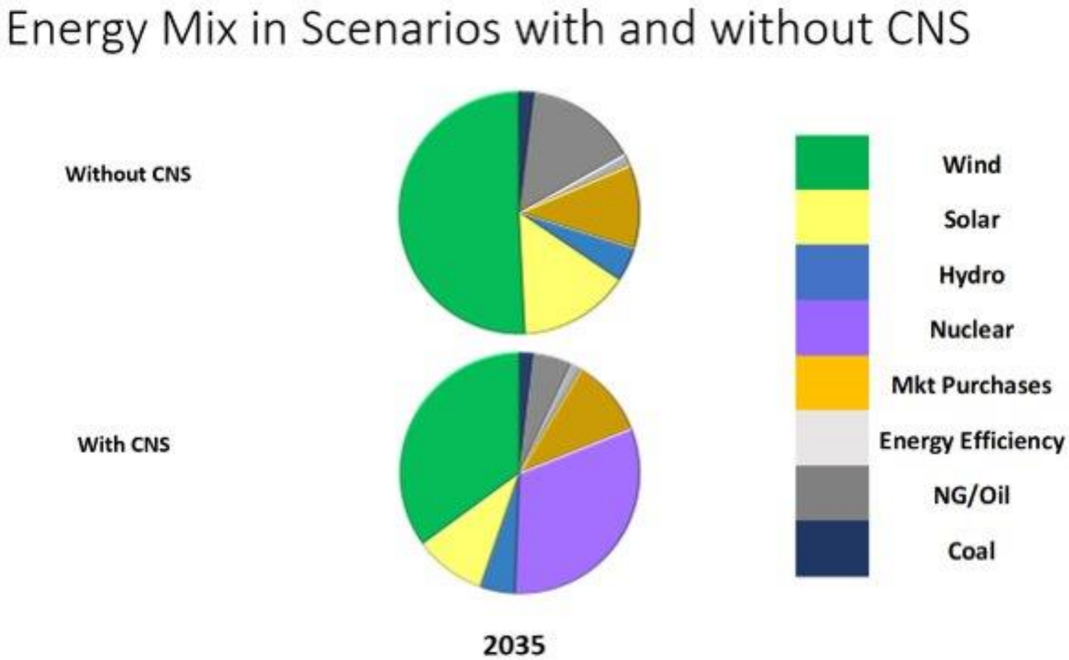
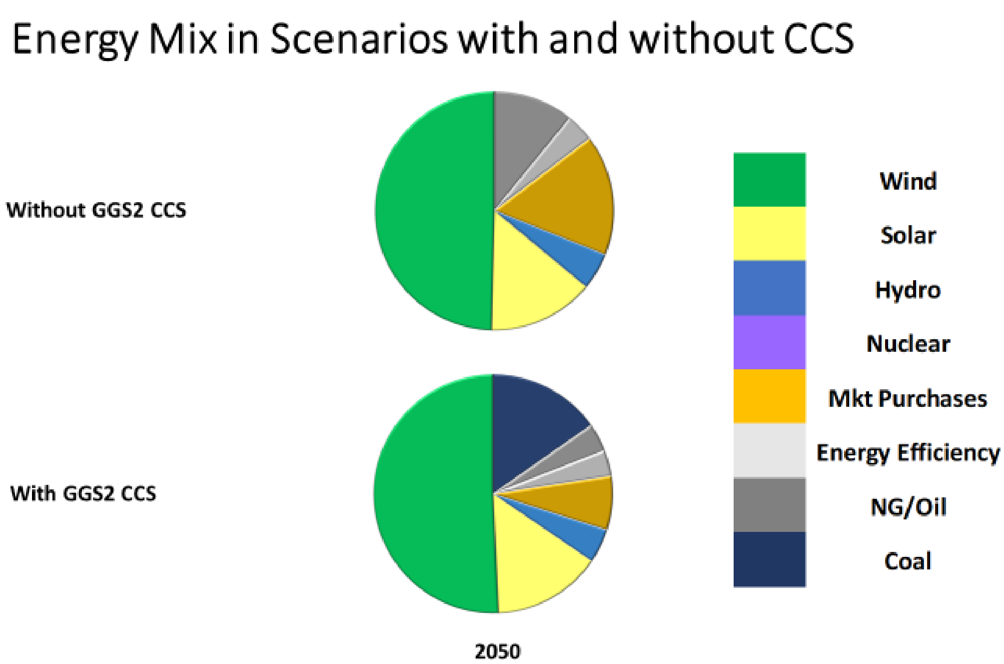


Exhibit ES-3 – Energy Mix with and without GGS2 CCS



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 customer's best interest. It is recommended to continue to pursue required modifications at Sheldon for compliance with Effluent Limitation Guideline (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.

Energy efficiency and demand response can also provide value to our customers. 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. 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.

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 program.

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 CO2 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.

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 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.

Exhibit ES-4 –Capital Requirements for selected Cases

CO2 Scenario	Load Scenario	Other	Capital Requirements (Billions of Dollars)[4]	
			Through 2035	Through 2052
SD-05	Base		$0.9	$7.4
2050 Glide Path	Base		$3.5	$6.2
2035 Glide Path	Base		$6.4	$6.9
2050 Glide Path	High		$4.5	$8.8
2050 Glide Path	Low		$2.8	$3.7
2050 Glide Path	Base	2nd Relicense at CNS	$0.2	$4.1
2050 Glide Path	Base	CCS at GGS 2	$4.8	$9.9

[4] 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.

For comparisons that relate to the achievement of measurement goals, 2023 shall be used as the base reference year.

Action Plan

The 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 on a regular basis 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 4 and summarized below are expected to be completed by the next IRP report.

> Action Item 4.1 – 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 4.2 - 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 4.3 - 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 4.4 – Continue to monitor SMR progress and complete preliminary siting studies.
>
> Action Item 4.5 - 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 4.6 - 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 4.7 - 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.

1. EXISTING SYSTEM & COMMITTED RESOURCES

1.1 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. Non-carbon resources generated energy equal to 62.9% of native load energy in 2021. Appendix B lists all of NPPD's existing generation resources, including in-state hydro purchases and capacity purchases. Exhibit 1.1-1 shows NPPD's share of Energy Resources in 2021, where Exhibit 1.1-2 presents the capacity breakdown.

Exhibit 1.1-1 – NPPD's Share of 2021 Actual Energy Resources

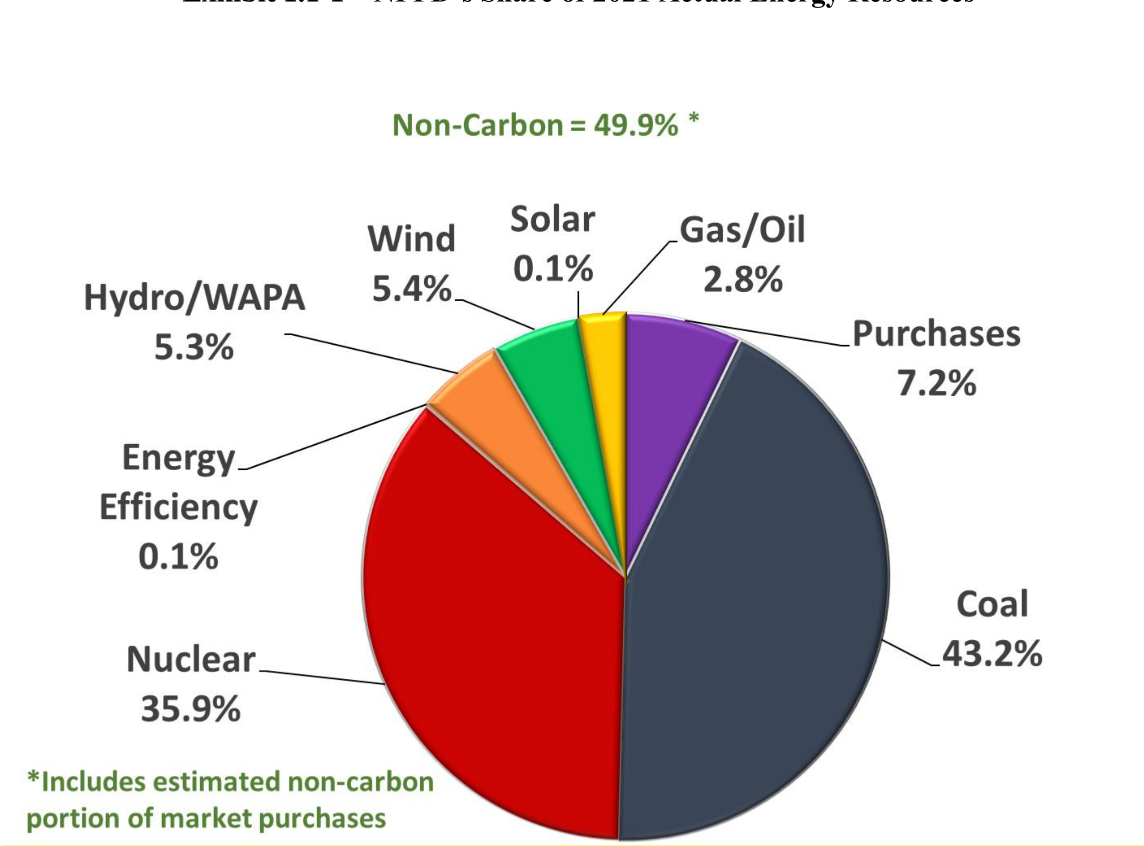
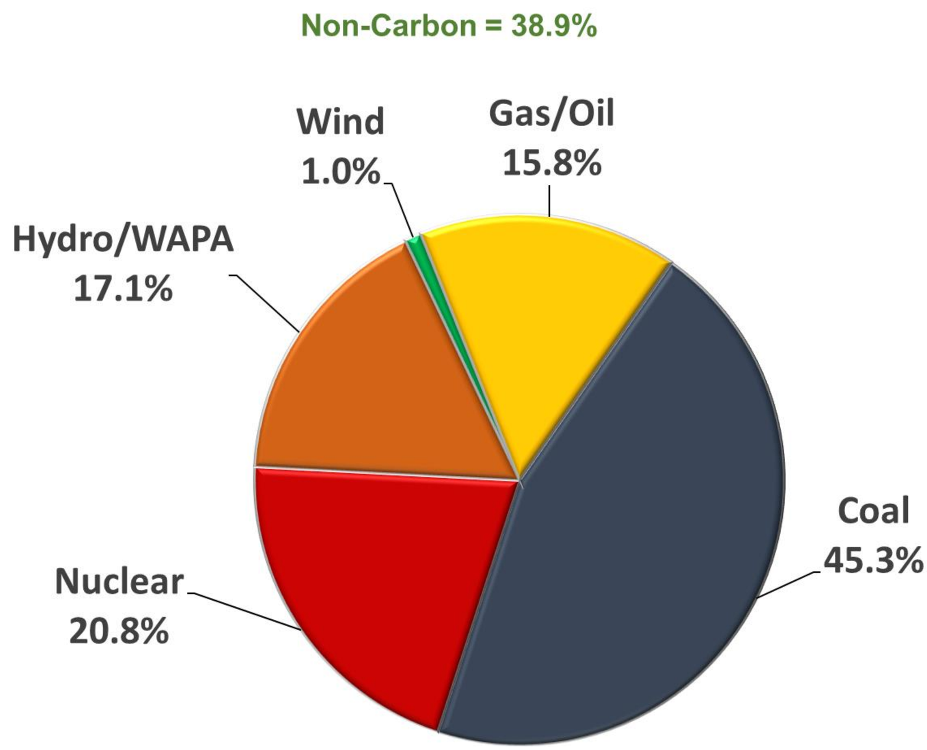


Exhibit 1.1-2 – NPPD’s Share of 2021 Actual Capacity Resources



In 2021, 43% 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, CNS accounted for approximately 36% 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 the 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 thirty-six 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 the 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.

1.2 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 that 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.

2. MAJOR ASSUMPTIONS

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

2.1 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 2.1-1). 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 2.1-2). 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 2.1-1 and 2.1-2 compare the annual peak demand and energy, respectively for the three scenarios.

Exhibit 2.1-1 – Peak Demand Forecast

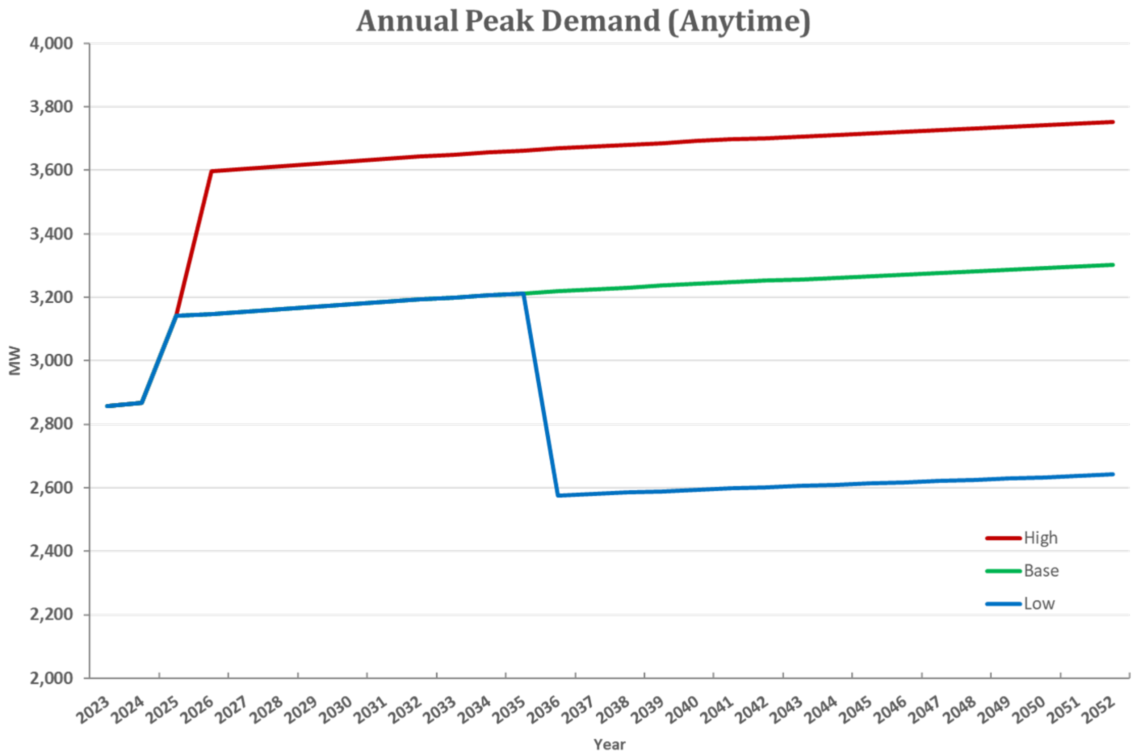
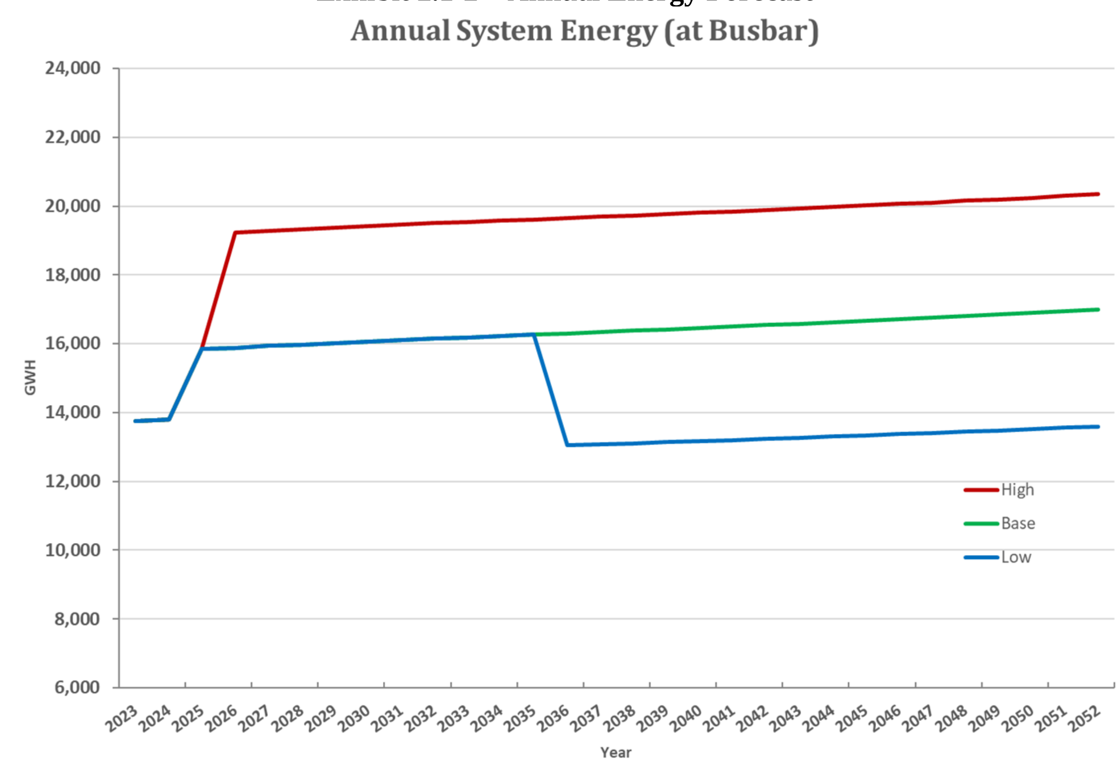


Exhibit 2.1-2 – Annual Energy Forecast



2.2 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, the NPPD Board of Directors approved Strategic Directive BP-SD-05 (SD-05) on December 9, 2021. SD-05 adopts the goal of achieving "net zero" carbon emissions from NPPD's generation resources by 2050.

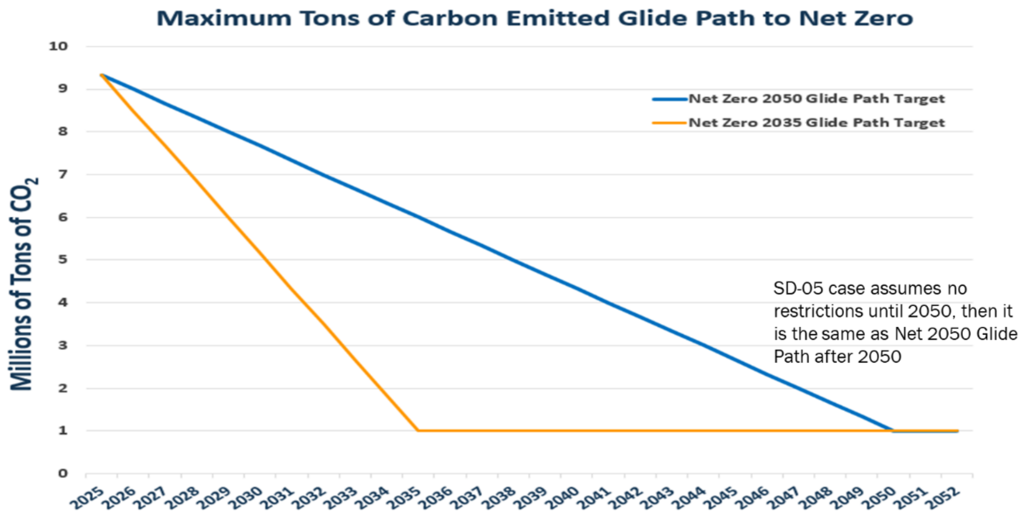
Three different scenarios were modeled.

- SD-05 – This scenario, which incorporates the requirements of BP-SD-05, assumes a limit on CO2 emissions of 1 million ton maximum[5] starting in 2050. No limits were assumed before 2050 since no intermidiate goals are listed in 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 CO2 emission limit in 2050, but with a linear reduction beginning from a starting point of 9.3 million tons[6] 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
- 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.

[5] 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.
[6] This is approximately equal to NPPD's actual 2021emissions for Native Load plus Non-firm Sales.

The three emission reduction scenarios are shown graphically in Exhibit 2.2-1

Exhibit 2.2-1 – Emission Reduction Scenarios



- 2025 value based on 2021 actual emissions

2.3 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

2.4 Resources Studied

2.4.1 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℠ 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℠ umbrella.

The Base EE assumption for the IRP assumed continued funding of the EnergyWise℠ 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[7].

An alternate High EE scenario was also examined, as part of the IRP analysis. NPPD's Energy Efficiency Group provided estimated impacts for an increase in budgeted spending of $1.3 million annually, beginning in 2025, and assuming the energy saving could continue to be delivered at a cost of about 1¢/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.

[7] These Base EE savings are reflected in the load forecast scenarios, discussed in Section 2.1.

Exhibits 2.4.1-1 and 2.4.1-2 summarize the projected Demand & Energy EE savings assumptions, respectively.

Exhibit 2.4.1-1 – EE Demand Reduction Assumptions

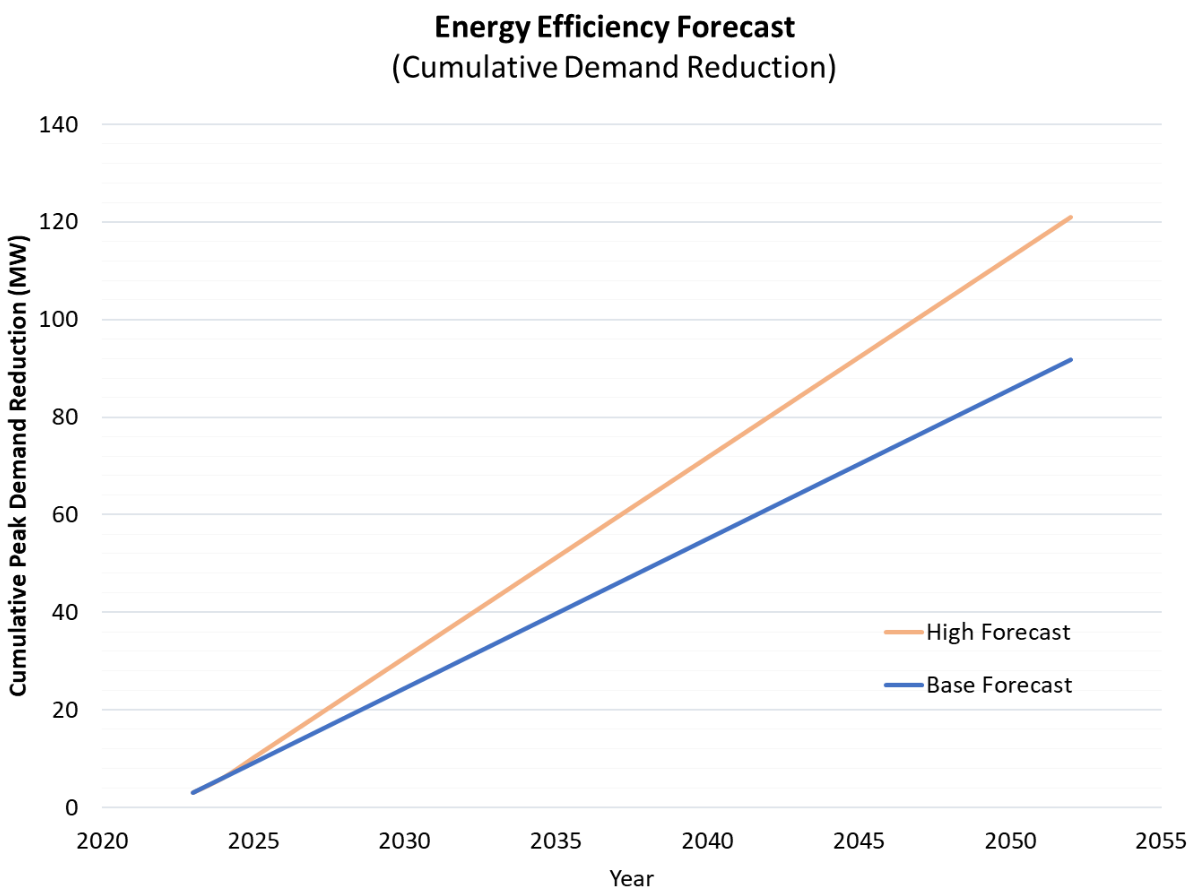
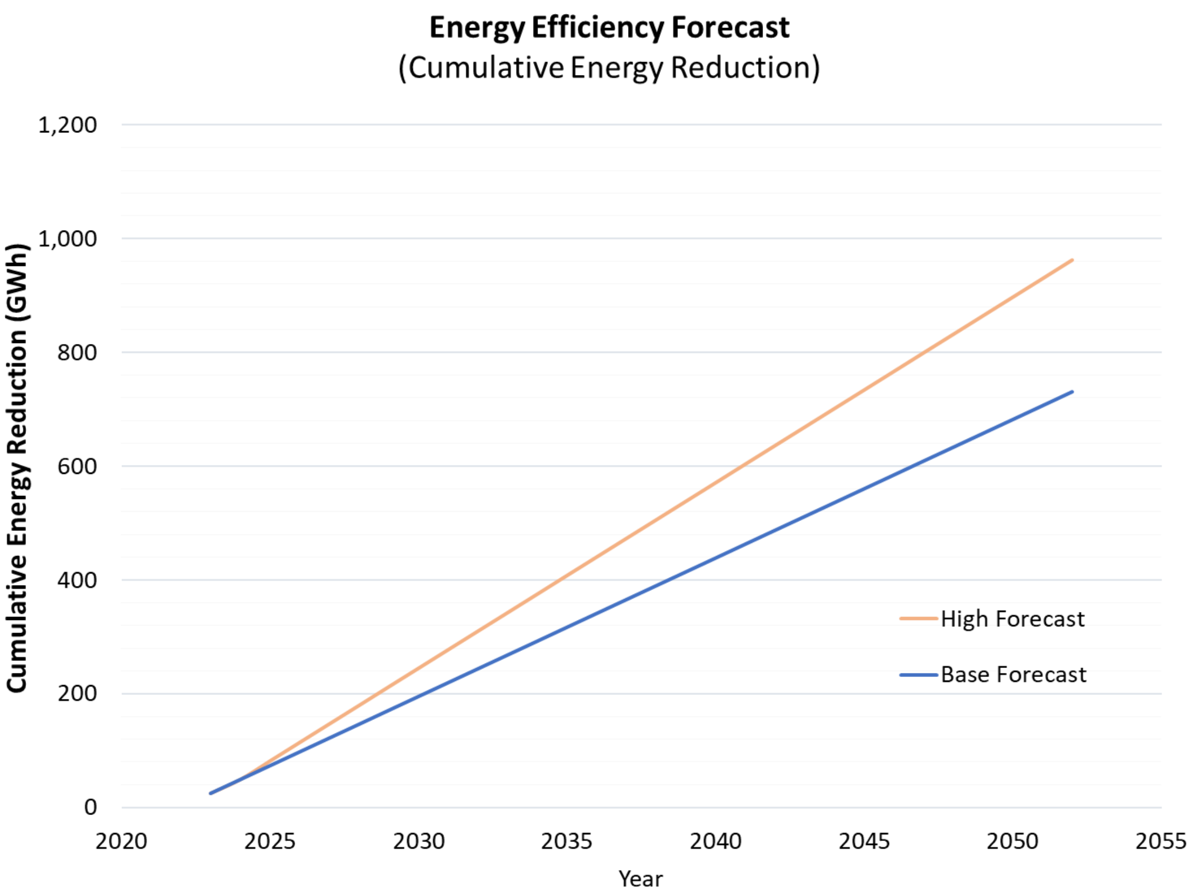


Exhibit 2.4.1-2 – EE Energy Reduction Assumptions

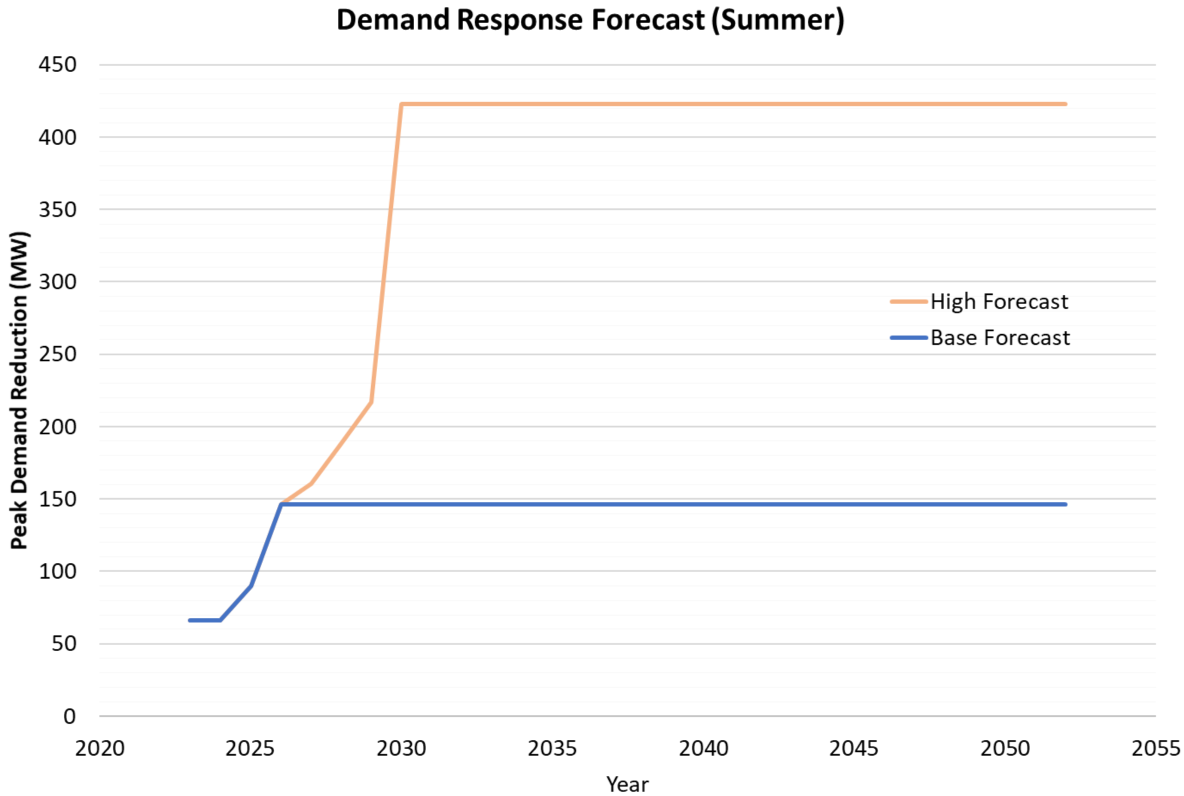


In 2018, NPPD implemented a Large Customer Interruptible Rate Schedule (Special Power Product No. 8), which is available to eligible wholesale customers, as well as an Interruptible Service Rider Rate Schedule (INT Rider), which is available to retail customers. Under these rate schedules, NPPD may call 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 it's 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 also 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 2.4.1-3 – Demand Response Forecast Assumptions



2.4.2 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.[8] The final assumptions for the nine new resources in the IRP model are summarized in Exhibit 2.4.2-1.

Exhibit 2.4.2-1 – New Resource Alternative Assumptions

Resource	Capacity (MW)	Economic Life (years)	Capital ($/kW)	Capital Escalation	1st Year $/MWh	Assumed C.F.
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 C.F. is based on the typical capacity factor for existing resources most like the new resources and is used for the first year cost calculations.[9] The battery resource was assumed to only charge and discharge three hours of its capacity daily to preserve its economic life.

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

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.

2.4.2.1 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. 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.

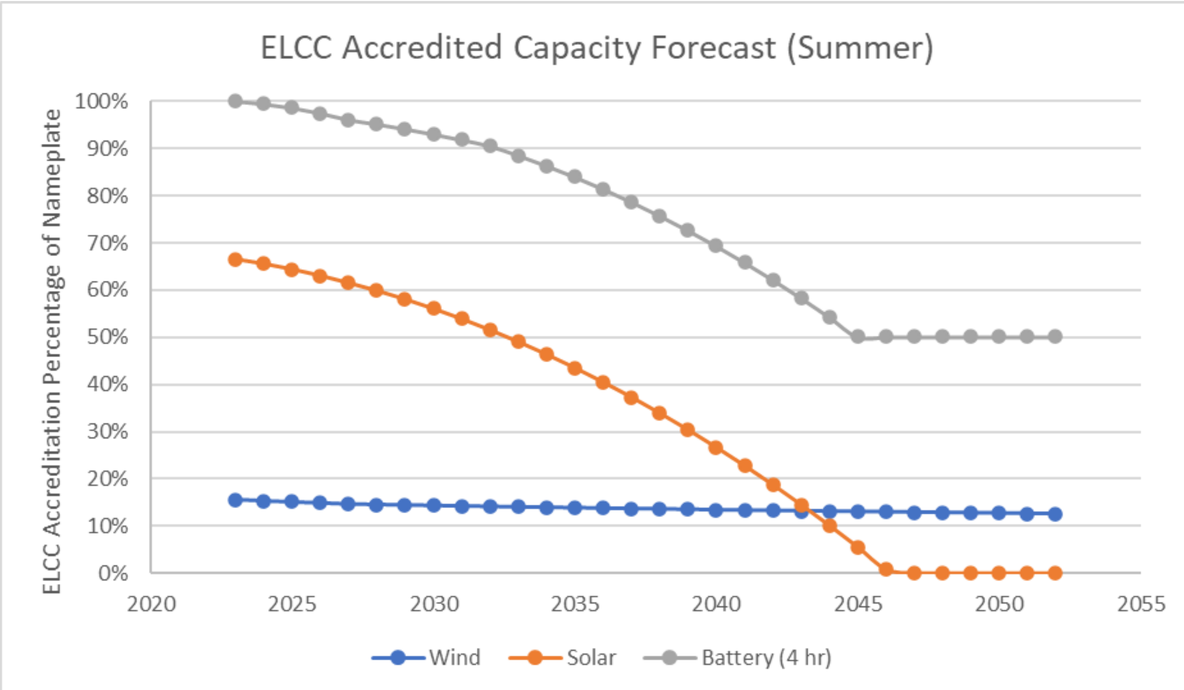
Although the exact accreditation adjustments, resulting from the application of SPP's ELCC methodology couldn't be determined, it was important to try and estimate those adjustments in the IRP in order to account for the accredited capability which could be claimed for new wind, solar, and ESR alternatives.

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[10]. These study results were in the form three separate graphs displaying the ELCC accreditation percentage of nameplate capacity verses the resource penetration.[11] 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 2.4.2.1-1.

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.

[10] 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.
[11] Penetration was displayed as installed namplate as a percentage of SPP peak load.

Exhibit 2.4.2.1-1 – Accredited Capacity for new Wind, Solar, and Battery Alternatives



2.4.3 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 Finance and Cost Group, while assumptions associated with CCS were provided by the Generation Strategies Group and include capital and incremental Operation and Maintenance (O&M) costs. It is important to note, no additional emission control equipment was assumed to be required for continued operation on coal over the study period.

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 finance cost group. 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 Group. 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 1.1, 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.[12] 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 1.1, are assumed to continue operation through the thirty year study period, for purposes of the IRP.

2.4.4 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 (SAWG). 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 2.4.2.1, the IRP did apply estimated ELCC accredited capacity values for new wind, solar, and storage alternatives.[13]

The SPP Board of Directors, also approved the implementation of Performance-Based Accreditation (PBA) for conventional resources during their July 2022 meeting. 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

[12] 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.

[13] 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.

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.

2.4.5 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.

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 NPV of these resiliency impacts to the NPV of selected sensitivity cases.

3. RESULTS

3.1.1 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 3.1.1-1. The first 27 cases examined combinations of low, base, and high scenarios for CO2 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 3.1.1-1 –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 still 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 us with a range of estimated benefits to NPPD and its customers.

- Existing Nuclear Credits – CNS may be eligible for existing nuclear credits from 2024 to 2032. NPPD is still 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 2030's, the NPV could be above $2.6 billion assuming high availability and capacity factor.

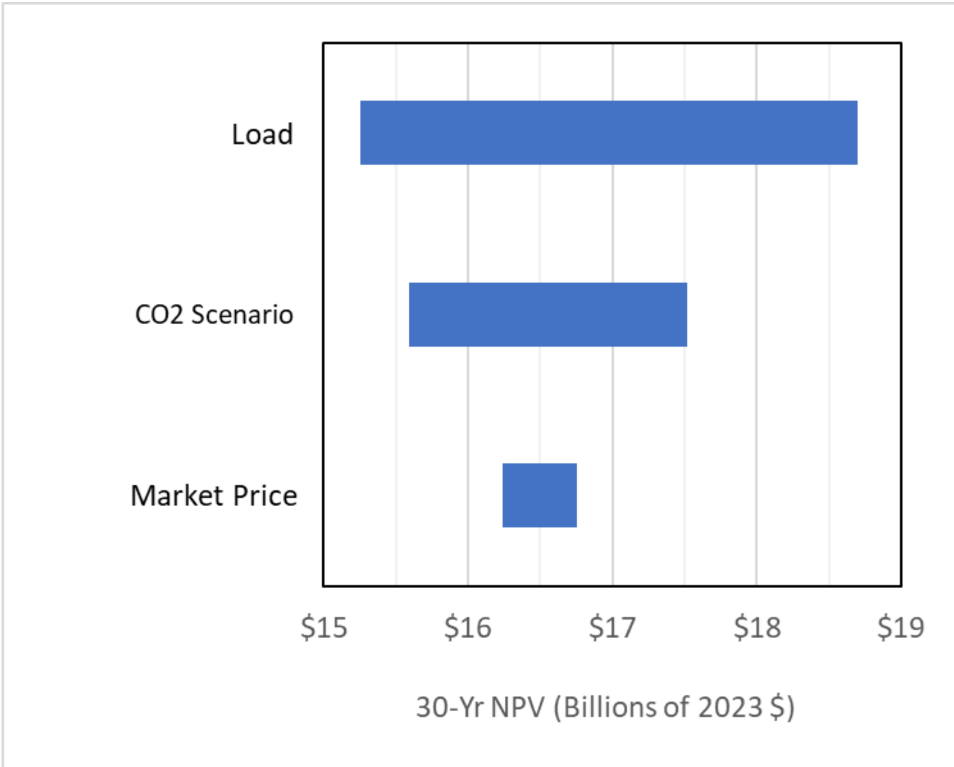
- Small Module Reactor – The IRA PTC is similar to the PTC for renewables, around $26/MWh in today's dollars and escalated for inflation in future years, for a period of 10 years. A 600 MW SMR installed by the early 2030's and operating with high capacity factors could have a NPV around $700 million.

- 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 CO2 scenario of net zero by 2035 with a glide path. In these cases, the NPV is on the order of $850 million.

Exhibit 3.1.1-2 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 CO2 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 CO2. The IRP analysis assumed a cost of $15/tonne for carbon storage. Recent estimates range from $20-$30/tonne.

Exhibit 3.1.1-2 –NPV Variation by Load, CO2 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 1/6 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 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 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.

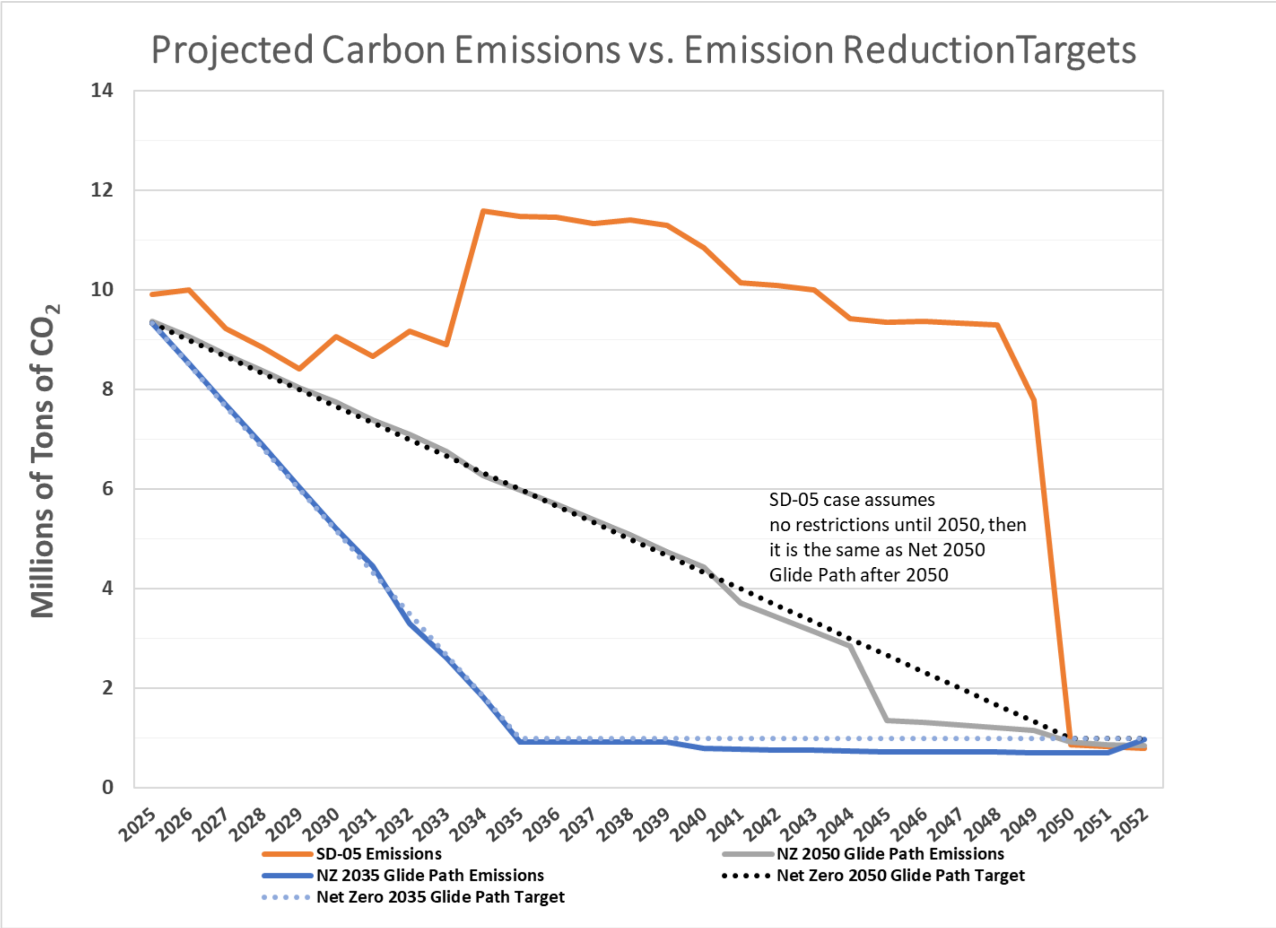
Exhibit 3.1.1-3 –Capital Requirements for selected Cases

Case	CO2 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 CO2 reduction scenarios. Exhibit 3.1.1-4 graphically compares projected annual CO2 emissions to the CO2 reduction targets, for three representative resource plans. Under the SD-05 scenario, CO2 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 3.1.1-4 –Annual CO2 Emissions for selected Resource Plans

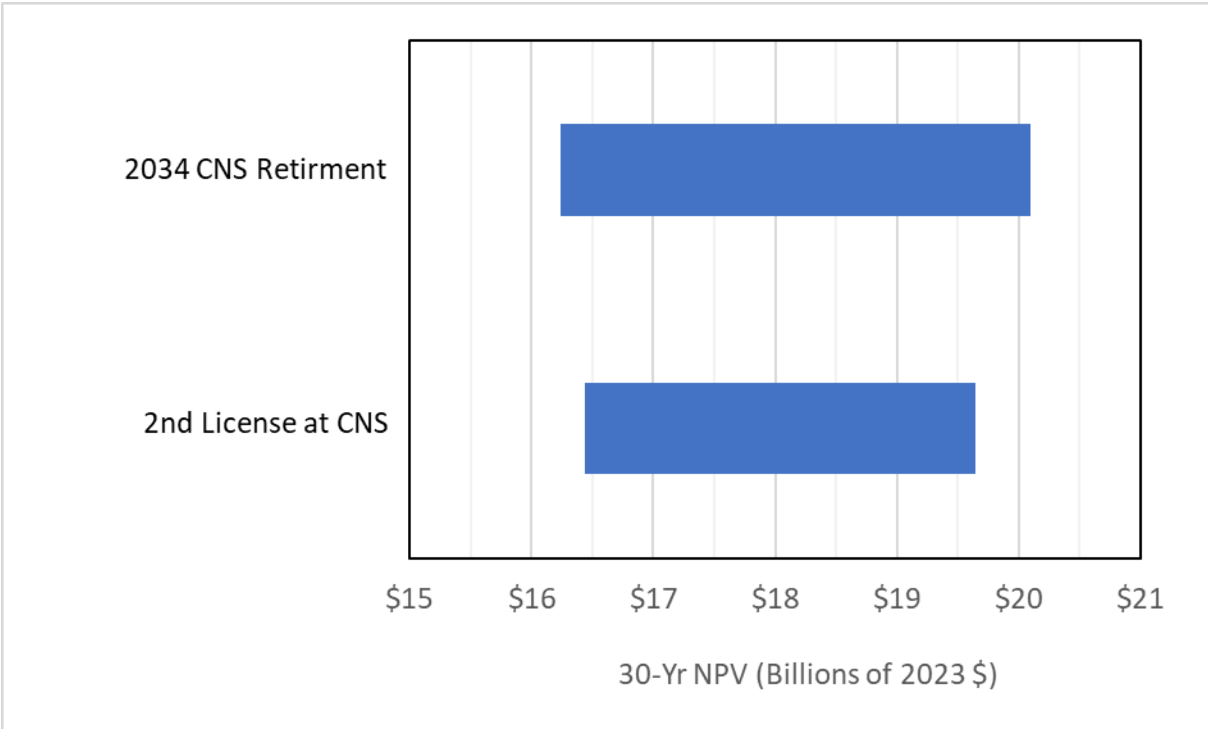


3.1.2 Cooper Nuclear Station (CNS) Sensitivity

When comparing a second relicense at CNS vs. the next lowest cost resource plan, the second relicense was more economical for the more restrictive CO2 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 CO2 restrictions, Exhibit 3.1.2-1 shows the NPV cost with and without the second relicense of CNS, under the 2050 glide path and 2035 glide path CO2 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 3.1.2-1 –NPV variation with and without CNS License Extension

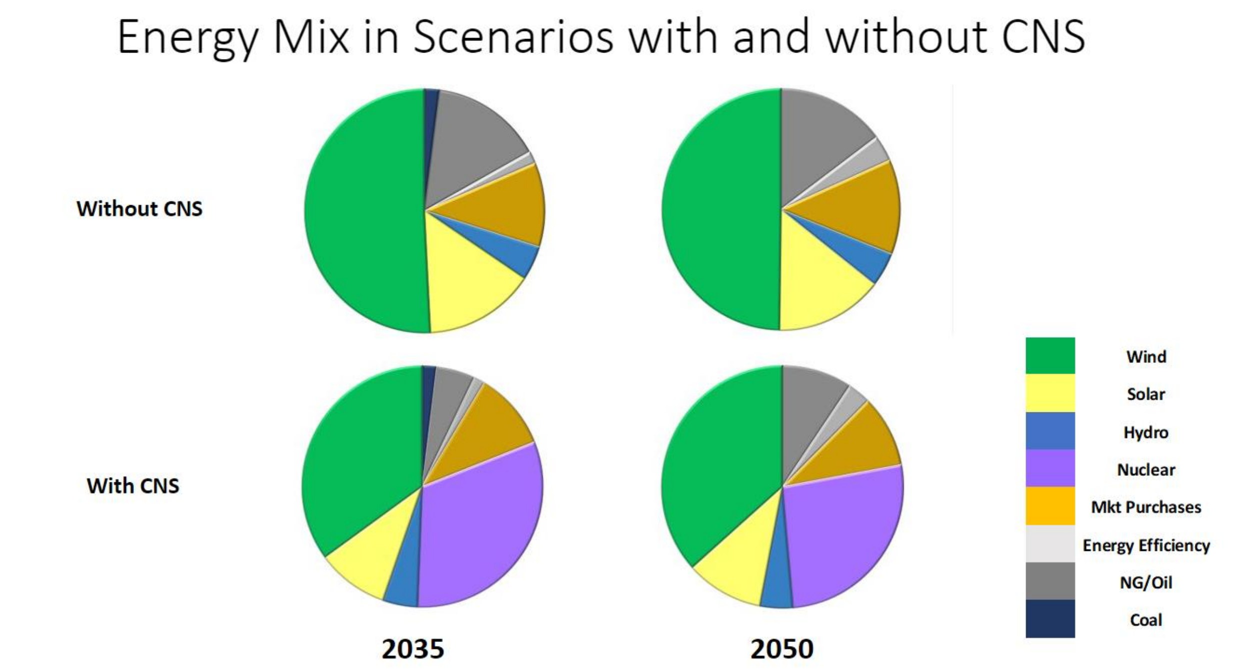


A second license extension at CNS was not shown as economical for a scenario with no CO2 restrictions before 2050 and when projected load is reduced in 2036 (i.e., low load scenario).

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 3.1.2-2 is a graph showing the resource mix with and without CNS under the 2035 glide path CO2 restriction scenario. Fuel diversity is more robust with the second license at CNS.

Exhibit 3.1.2-2 –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.

3.1.3 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 CO2 restriction scenarios studied. Under the SD-05 scenario, GGS continues to operate on coal until carbon constraints begin in 2050.

With the increasing CO2 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 reirement, 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 CO2 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.

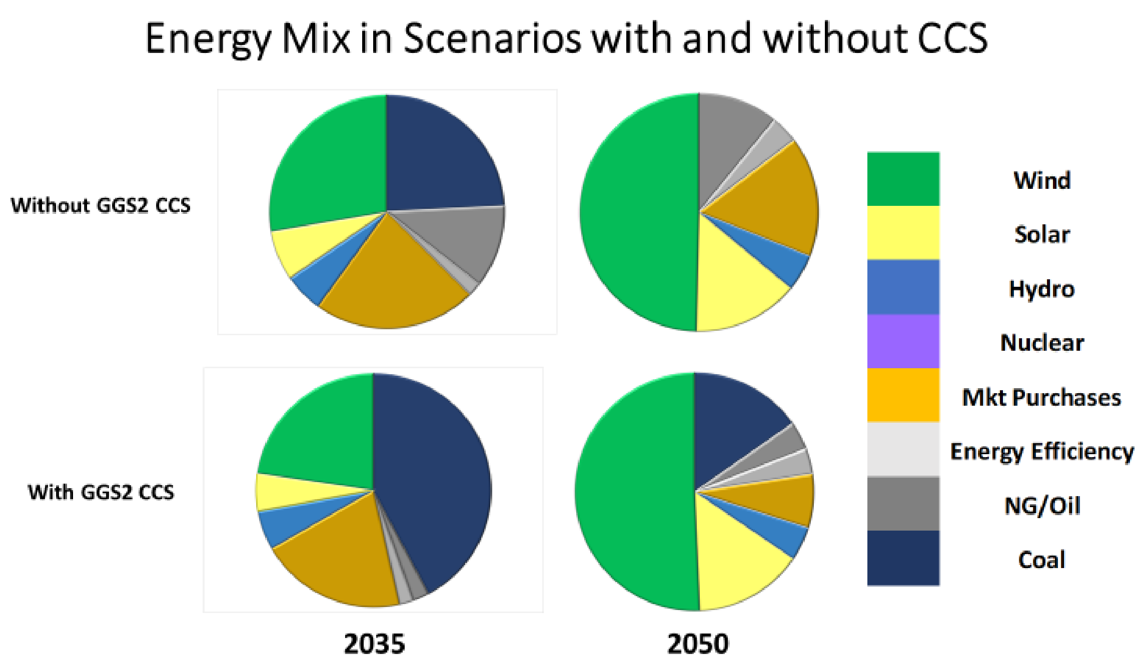
As discussed in the previous section on CNS, increasing CO2 reduction constraints will impact the fuel diversty of NPPD's resource mix.

The installation of Carbon Capture & Sequestration (CCS) equipment on GGS2 was not selected in the initial 27 runs varying CO2 restrictions, load, or market. Three (3) sensitivity cases were modeled to capture a range of costs and situations: 1) SD-05 CO2 restriction, low load and market, 2) 2050 net zero with glide path CO2 restriction, base load and market, and 3) 2035 net zero with glide path CO2 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 CO2 sequestered, these 45Q credits could be enough to eliminate the gap or show a small benefit.

Exhibit 3.1.3-1 shows the resource mix with and without GGS2 CCS under the 2050 glide path CO2 restriction scenario. Fuel diversity is more robust with the CCS.

Exhibit 3.1.3-1 –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 CO2 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.

3.1.4 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 CO2 restrictions, load, or market. Three (3) sensitivity cases were modeled to compare retirement to natural gas operation 1) SD-05 CO2 restriction, low load and market, 2) 2050 net zero with glide path CO2 restriction, base load and market, and 3) 2035 net zero with glide path CO2 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 CO2 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 recommend 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. 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.

3.1.5 Small Modular Reactor (SMR) Sensitivity

A SMR facility was not chosen as a resource in the initial 27 runs varying CO2 restrictions, load, or market. Three (3) sensitivity cases were modeled to capture a range of costs and situations: 1) SD-05 CO2 restriction, low load and market, 2) 2050 net zero with glide path CO2 restriction, base load and market, and 3) 2035 net zero with glide path CO2 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 themselves 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 utilize the IRA credits.

3.1.6 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 2.4.1, to capture the range of impacts: 1) SD-05 CO2 restriction, low load and market, 2) 2050 net zero with glide path CO2 restriction, base load and market, and 3) 2035 net zero with glide path CO2 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 CO2 case and least beneficial in the low load/least restrictive CO2 case.

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.

3.1.7 High Demand Response Sensitivity

The base assumption for Demand Response (DR), as discussed in section 2.4.1, was utilized for the initial 27 CE runs. Two (2) sensitivity cases were run with the high DR assumption: 1) SD-05 CO2 restriction, low load and market, 2) 2050 net zero with glide path CO2 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.

3.1.8 Early Renewable Sensitivity

The earliest renewable generation was installed in the initial 27 runs was 2030 in the 2035 glide path CO2 restriction scenario, and 2034 in the SD-05 and 2050 glide path CO2 restriction scenarios. To understand the additional costs of early installation of renewables, NPPD modeled adding 125 MW solar and 200 MW of wind in 2026 under the following three (3) cases: 1) SD-05 CO2 restriction, low load and market, 2) 2050 net zero with glide path CO2 restriction, base load and market, and 3) 2035 net zero with glide path CO2 restriction, high load and market.

The additional NPV costs for the early renewable sensitivity ranged from $0-0.6 billion higher. Earlier installation was most beneficial in the most restrictive CO2 case, and least beneficial in the least restrictive CO2 case. For the "middle" CO2 case, the additional cost was $0.17 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.

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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.

These results did not include IRA credits. It appears if NPPD is able to fully utilize the IRA credits, early installation can make economic sense in the CO2 glide path cases. Early installation will have a higher NPV cost even with IRA credits in the SD-05 CO2 Restriction case. The cost to install renewable units have lately taken a jump 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.

3.1.9 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 CO2 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 $0.0 to 0.2 billion 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.

3.2 Summary

Although load was the greatest uncertainty as measured by NPV, the CO2 restriction variable had a greater impact on the types of resource selected. Coal plants without CO2 controls operated longer with the least restricted CO2 restriction sceanario, while NPPD’s nuclear facility fared better under the most restricted CO2 restriction 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 allows them to reliabily 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, and reaffirms the need to maintain fuel diversity in our resources.

CNS is presently the least risky nuclear or coal with CCS option under a restrictive CO2 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 CO2 scenario if retrofitted with CCS equipment. This technology is 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 customer's 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 from 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 CO2 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.

4. 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.

4.1 CNS

Action Item 4.1 – 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.

4.2 GGS

Action Item 4.2 - Continue to operate GGS on coal, while monitoring potential risks to continued GGS operationpotential 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.

4.3 Sheldon

Action Item 4.3 - 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.

4.4 Small Modular Reactors

Action Item 4.4 - Continue to monitor SMR progress and complete preliminary siting studies.

4.5 Energy Efficiency

Action Item 4.5 - 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.

4.6 Demand Response Resources

Action Item 4.6 - 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.

4.7 Early Installation of Renewables

Action Item 4.7 - 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.

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 Valleys RPPD	Ord, NE	Yes
McCook PPD	McCook, NE	Yes
Niobrara Valley EMC	O'Neill, NE	Yes
North Central PPD	Creighton, NE	Yes
Perennial PPD	York, NE	Yes
Polk County RPPD	Stromsburg, NE	Yes
South Central PPD	Nelson, NE	Yes
Southwest PPD	Palisade, NE	Yes
Stanton County PPD	Stanton, NE	Yes
Twin Valleys PPD	Cambridge, NE	Yes
Loup Power District	Columbus, NE	No
Norris PPD	Beatrice, NE	No
Southern PD	Grand Island, NE	No

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	Direct WAPA Allocation
Bartley, NE	
Belleville, KS	
Cambridge, NE	Yes
Campbell, NE	
Clarkson, NE	
Decatur, NE	
Edgar, NE	
Filley, NE	
Franklin, NE	Yes
Giltner, NE	
Hebron, NE	
Hickman, NE	
Holbrook, NE	
Hubbell, NE	
Indianola, NE	Yes
Laurel, NE	Yes
Leigh, NE	
Mullen, NE	
Polk, NE	
Sargent, NE	Yes
Schuyler, NE	Yes
Spalding, NE	Yes
St. Paul, NE	
Stanton, NE	
Stratton, NE	
Stromsburg, NE	
Weston, NE	
Wilber, NE	Yes
Santee Sioux Tribe	Yes
Omaha Tribe	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) Agreements

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	

Other Entities

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

RETAIL CUSTOMERS OF NPPD'S WHOLESALE CUSTOMERS					
Abie	Center	Farwell	Lawrence	Ohiowa	Springranch
Adams	Chambers	Firth	Lebanon	Ong	Springview
Agnew	Chapman	Flats	Liberty	Orchard	St. Bernard
Akron	Clarks	Fordyce	Lindsay	Orleans	St. Edward
Albion	Clatonia	Fullerton	Linwood	Osceola	St. Helena
Alda	Clay Center	Funk	Litchfield	Overton	St. James
Alexandria	Clearwater	Gandy	Loma	Page	St. Libory
Almeria	Closter	Garland	Loomis	Palisade	St. Stephens
Aloys	Cody	Garrison	Loretto	Palmer	Stamford
Altona	Coleridge	Gates	Lowell	Panama	Staplehurst
Amelia	Columbus	Genoa	Lushton	Parks	Stapleton
Amherst	Comstock	Glenvil	Macon	Pauline	Stockham
Angus	Cordova	Goehner	Macy	Petersburg	Stockville
Anselmo	Cornlea	Grafton	Magnet	Phillips	Strang
Arcadia	Cortland	Greeley	Malcolm	Pickrell	Sumner
Archer	Cotesfield	Gresham	Malmo	Pilger	Surprise
Assumption	Cowles	Gross	Marion	Platte Center	Swan Lake
Aten	Creston	Guide Rock	Marquette	Pleasant Dale	Swanton
Atlanta	Crofton	Hadar	Martell	Pleasant Hill	Swedehome
Axtell	Crookston	Haigler	Mascot	Pleasanton	Sweetwater
Ayr	Crowell	Hallam	Mason City	Plymouth	Tamora
Bancroft	Culbertson	Halsey	Max	Poole	Tarnov
Barneston	Cummingsville	Hamlet	Maxwell	Powell	Taylor
Bartlett	Cushing	Hansen	McCool Junction	Primrose	Thayer
Bazile Mills	Danbury	Hardy	Merna	Princeton	Thedford
Beaver Crossing	Dannebrog	Harvard	Midway	Prosser	Tobias
Bee	Darr	Havens	Milburn	Purdum	Toughy
Beemer	Davey	Hayes Center	Miller	Raeville	Trumbull
Belden	Daykin	Hayland	Milligan	Ragan	Tryon
Belgrade	Denman	Hazard	Mills	Raymond	Uehling
Bellwood	Denton	Heartwell	Monowi	Republican City	Ulysses
Belvidere	Deweese	Henderson	Monroe	Richland	Upland
Benedict	Diller	Hendley	Monterey	Rising City	Utica
Bertrand	Dodge	Hershey	Moorefield	Riverdale	Valparaiso
Berwyn	Doniphan	Holland	Mt. Clare	Riverton	Verdel
Beverly	Duncan	Hollinger	Murphy	Roca	Verdigre
Bladen	Dunning	Holmesville	Naper	Rockford	Verona
Bloomington	Dwight	Holstein	Naponee	Rockville	Virginia
Blue Springs	Eddyville	Hordville	Nemaha	Rokeby	Walton
Boelus	Edison	Howe	Nenzel	Rosalie	Waco
Boone	Elba	Howells	Newark	Rose	Wausa
Bostwick	Eldorado	Humphrey	Newman Grove	Roseland	Webster
Bow Valley	Elgin	Huntley	Newport	Rosemont	Weissert
Brady	Elsmere	Inavale	Niobrara	Rosenburg	Wellfleet
Brewster	Elwood	Inland	Nora	Royal	Western
Brownlee	Elyria	Jamison	Norden	Ruby	Westerville
Brownville	Emerald	Johnson	Norman	Ruskin	Willis
Bruning	Enders	Johnston	North Loup	Santee	Willow Island
Bruno	Enola	Johnstown	North Star	Saronville	Wilsonville
Brunswick	Ericson	Keene	Nysted	Scotia	Winnetoon
Burton	Eustis	Kenesaw	Oak	Seneca	Wolbach
Byron	Ewing	Kennedy	Oconto	Shelby	Wood Lake
Cairo	Exeter	Kilgore	Octavia	Silver Creek	Wood River
Carleton	Fairfield	Kramer	Odell	Smithfield	Woodland Park
Cedar Rapids	Farnam	Kronberg	Odessa	Sprague	Wynot

Appendix B – Existing Generating Unit Data

Nebraska Public Power District

Generating Capability Data
2021 Existing Megawatts

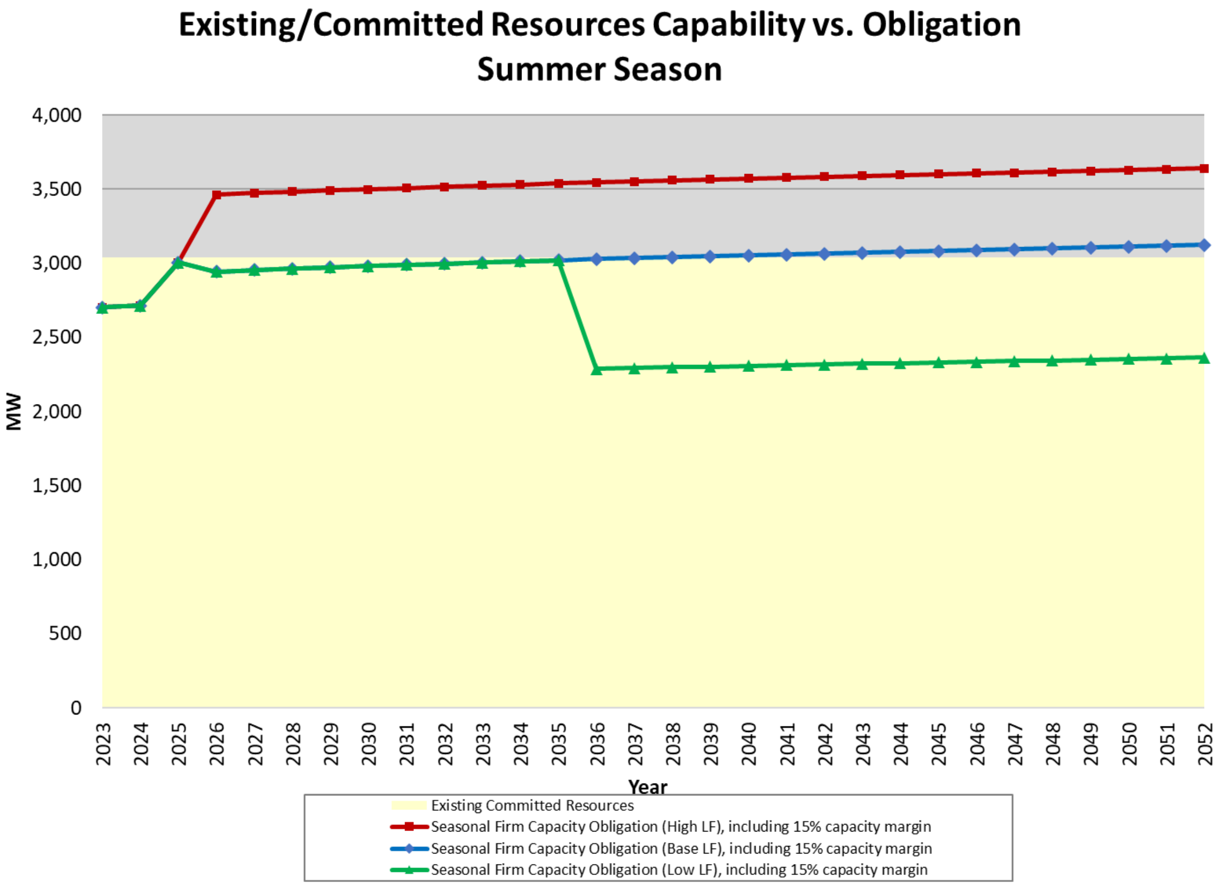
Unit Name	Location	Unit Type	Fuel Type	Summer Rating	Winter Rating	Commercial Start Date
Auburn 1	Auburn, NE	IC	NG,FO2	2.00	2.00	1982
Auburn 2	Auburn, NE	IC	NG,FO2	1.00	1.00	1949
Auburn 4	Auburn, NE	IC	NG,FO2	3.00	3.00	1993
Auburn 5	Auburn, NE	IC	NG,FO2	3.00	3.00	1973
Auburn 6	Auburn, NE	IC	NG,FO2	2.00	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 4	Belleville, KS	IC	NG,FO2	0.00	0.00	1955
Belleville 5	Belleville, KS	IC	NG,FO2	1.40	1.40	1961
Belleville 6	Belleville, KS	IC	NG,FO2	2.50	2.50	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	770.00	770.00	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	1.33	1.33	1996
David City 7	David City, NE	IC	FO2	1.34	1.34	1996
Franklin 1	Franklin, NE	IC	NG, FO2	0.65	0.65	1963
Franklin 2	Franklin, NE	IC	NG, FO2	1.35	1.35	1974
Franklin 3	Franklin, NE	IC	NG, FO2	1.05	1.05	1968
Franklin 4	Franklin, NE	IC	NG, FO2	0.70	0.70	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	41.95	41.95	1973
Hebron	Hebron, NE	GT	FO2	41.95	41.95	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	1.70	1.70	1969
Madison 2	Madison, NE	IC	NG, FO2	0.95	0.95	1959
Madison 3	Madison, NE	IC	NG, FO2	0.85	0.85	1953
Madison 4	Madison, NE	IC	FO2	0.50	0.50	1946
McCook	McCook, NE	GT	FO2	39.70	39.70	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	113.00	113.00	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	2.9	2.9	1949
Total				2977.3	2977.3	
				Nameplate Rating [1]		
Ainsworth Wind	Ainsworth, NE	WD	WD	59.40		2005
Elkhorn Ridge Wind	Bloomfield, NE	WD	WD	80.00		2009
Laredo Ridge Wind	Petersburg, NE	WD	WD	80.00		2011
Springview Wind	Springview, NE	WD	WD	3.00		2011
Crofton Hills Wind	Crofton, NE	WD	WD	42.00		2012
Broken Bow Wind	Broken Bow, NE	WD	WD	80.00		2012
Steele Flats	Diller, NE	WD	WD	75.00		2013
Broken Bow Wind II	Broken Bow, NE	WD	WD	73.00		2014

[1] Based on current SPP Criteria for establishing the summer ratings capability of variable capacity resources, such as wind, the resulting ratings were estimated to be zero (0) for practical purposes.

Appendix C – Projected Load & Capability Graphs

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



Public/Customer Outreach

NPPD Board of Directors Retreat
November 3, 2021

Conrad Saltzgaber
Chief Audit and Ethics Officer

Nebraska Public Power District
Always there when you need us

Outreach Objective

- Obtain customer and public feedback around these three questions:
  - Do our constituents see carbon emissions as a business risk to NPPD?
  - What is the best structure for NPPD's carbon reduction goal?
  - What principles of electric service are most important to maintain or achieve as we reduce carbon emissions?
    - Reliability
    - Resiliency
    - Affordability
    - Environmental Impact

3

Public Informational Forums

- Public Meetings Complete (attendance)
  - Norfolk – 125 (16 *Public Comments*)
  - Seward – 85 (17)
  - North Platte – 145 (16)
  - Scottsbluff – 45 (8)
  - Kearney – 145 (23)
- Customer Meeting on August 20
- Posted on NPPD.com
  - Educational Material
  - SD-05 Discussion Draft
  - Meeting Polling Results
- MSR summary and transcript report received (provided September 29)
  - Report includes emails and letters sent to Board member as of September 22
  - Additional letters and emails received after this date have been sent to the Board

4

Online Survey

- Survey live from August 11th to September 1st
- Final Survey Count (post data cleansing)
  - End-users– 1,914
  - Wholesale Muni – 18
  - Wholesale Rural – 92
  - Retail – 7
  - Other – 2,210
    - Non-NPPD Customers – 1,144
    - Unvalidated Responses – 1,067
- EPRI analysis presentation received (provided October 5)
  - Technical briefing forthcoming

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Summary Results/Themes

Nebraska Public Power District

Carbon Emissions Risks to NPPD

- MSR Report/Themes
  - 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

- EPRI Analysis
  - Decarbonization is a polarizing issue among End-users
  - Wholesale customers likely to see decarbonization as expensive and politics-driven
  - Wholesale rural most likely to see addressing decarbonization as unimportant
  - Retail leaders had split negative and positive impressions of decarbonization

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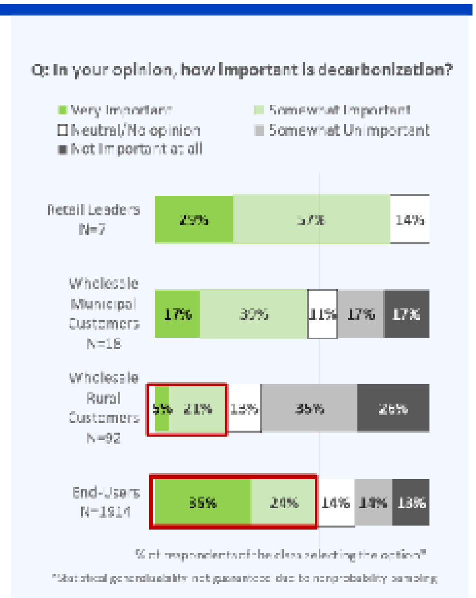
Carbon Emissions Risks to NPPD

Executive Summary (cont'd)

1. Do constituents view carbon emissions from generation as a business risk for NPPD?

- Attitudes towards decarbonization differ among NPPD's constituents. 59% of End-Users (retail customers) consider decarbonization very or somewhat important, compared to only 26% of Wholesale Rural Customers.
- However, constituents also perceive risks in pursuing decarbonization
  - Respondents in all four customer classes associate decarbonization as "expensive"

    Wholesale rural customers are most likely to consider decarbonization as "unreliable" and leading to "more outages"



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NPPD's Carbon Reduction Goal

- MSR Report/Themes
  - Climate change is an urgent matter for NPPD to address
  - Participants expect NPPD to take the lead in energy policy
  - Support for the need to re-evaluate power generation mix
  - Meeting polling showed that at least 30% (30-87%) of those who participated in polling think a 2050 net-zero goal is too ambitious

- EPRI Analysis
  - Most preferred goal among all customer segments was "net-zero"
  - Wholesale rural customers most likely to prefer neither a "net-zero" or "carbon-free" goal
  - Over half of customers across all classes state that they care very much about NPPD's decarbonization goals

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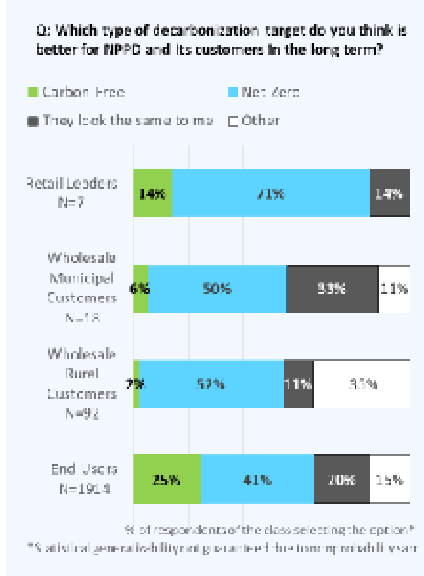
NPPD’s Carbon Reduction Goal

Executive Summary (cont’d)

3. What type of carbon goal do constituents think is right for NPPD?

- Over half of customers (across all classes) care very much about NPPD’s decarbonization goals
- This “caring” generally polarizes as support largely from retail customers and resistance from wholesale customers; very few are indifferent
- All customer classes prefer that NPPD frame its long-term decarbonization goal as “Net-Zero” rather than “Carbon-Free”
- But 25% of End-users (retail customers) prefer “Carbon-Free”, the highest among the four classes
- Cost and feasibility are the two leading factors in deciding the type of decarbonization target (across all classes)
- Support for nuclear power appears decoupled from support for decarbonization
  - 73% of Wholesale Rural Customers support more nuclear power while only 21% of them consider decarbonization important
  - Only 43% of End-users (retail customers) support more nuclear power while 59% of them consider decarbonization important



Priority Principles of Electric Service

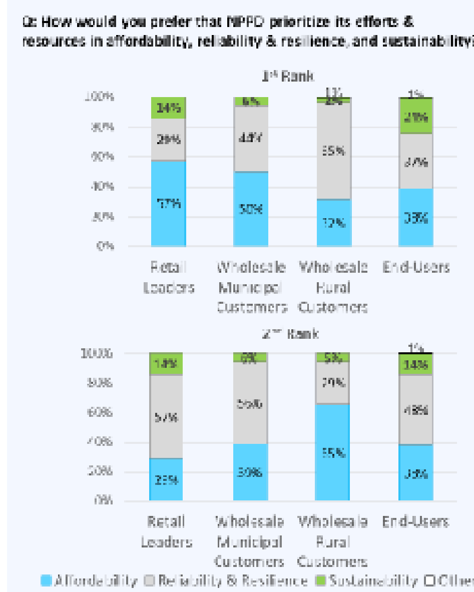
- MSR Report/Themes
  - Ensuring reliability/resilience is paramount
  - Importance of affordability
  - Climate change is an urgent matter for NPPD to address
  - Reliability/Resiliency polled the highest at all public meetings, cost was 2nd at five of the six meetings, and environmental impact was 3rd at all but one meeting (Scottsbluff)
- EPRI Analysis
  - End-users equally rank affordability or reliability & resiliency as their top two priorities, but have the highest likelihood of ranking sustainability first among the customer classes
  - Wholesale municipal and retail leaders rank affordability first, reliability & resiliency second, and sustainability last
  - Wholesale rural rank reliability & resiliency first, affordability second, and sustainability last
    - 92% rank sustainability as 3rd or lower

Priority Principles of Electric Service

Executive Summary (cont'd)

2. How do constituents prioritize the core principles of electricity service as NPPD pursues a carbon goal?

- Affordability is the most important priority for Retail Leaders and Wholesale Municipal Customers, while Reliability is most important to Wholesale Rural Customers
- Sustainability is a distant 3rd priority for wholesale customers and Retail Leaders
- Among End-users (retail customers) the spread is much less, with 24% ranking Sustainability as the highest priority
- End-users are nearly equally divided between Affordability and Reliability/Resilience as their highest priority



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Questions?

Stay connected with us.

Nebraska Public Power District

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Added after public comment period.

Summary of public comments

NPPD Response

Appendix E – Resource Plan Summary

	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)										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	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		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		413			800	500		2,713		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		826			2,000	1,250		5,076		1,000		1,240			2,000	1,250		5,490
4	CE22001d	NZ 2050	High	Base	R 2050/50	R 2034	NG 2028	386			413			400	250		1,449	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		826			1,000	625		3,451		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		207			1,400	875		3,482		1,000		413			2,200	1,375		4,988
7	CE22001g	NZ 2050	Low	Base	R 2048/50	R 2034	NG 2028				620					100	720		1,000		620			1,000	625	100	3,345
8	CE22001h	NZ 2050 GP	Low	Base	R 2037/45	R 2034	NG 2028				826			800	500		2,126				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		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		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		413			1,000	625		3,038		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			2,000	1,250		5,049	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		207			200	125		1,532		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		413			1,600	1,000		4,013		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			1,400	875		3,688		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						1,207		1,000		207			1,200	750		3,157
17	CE22002h	NZ 2050 GP	Low	High	R 2036/48	R 2034	NG 2028	386			207			800	500		1,893	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		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		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		207			600	375		2,182		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			2,000	1,250		5,076		1,000		826			2,400	1,500		5,726
22	CE22003d	NZ 2050	High	Low	R 2050/50	R 2034	R 2028		1,000		207			200	125		1,532		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		413			1,200	750		3,363		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				1,000	625	50	3,023		1,000	348				1,200	750	100	3,398
25	CE22003g	NZ 2050	Low	Low	R 2050/50	R 2034	NG 2028				620					100	720		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			600	375		2,182		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		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		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		413			800	500		2,713		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			1,400	875		3,688		1,000		413			2,400	1,500		5,313
31	CE22004d	NZ 2050	Low	Low	R 2050/50	R 2034	NG 2028				413						413	386	1,000		413			1,000	625		3,424
32	CE22004e	NZ 2050 GP	Base	Base	R 2038/45	R 2034	NG 2028				207			1,000	625		1,832				1,446			2,400	1,500		5,346
33	CE22005a	NZ 2050	Low	Low	R 2036/50	LE 2034	NG 2028										0		1,000		413			200	125		1,738
34	CE22005b	NZ 2050 GP	Base	Base	R 2038/47	LE 2034	NG 2028										0		1,000		207			1,000	625		2,832
35	CE22005b1	NZ 2035 GP	Base	Base	R 2030/33	LE 2034	NG 2028				1,240			800	500		2,540		1,000		1,446				625		3,071
36	CE22005b2	NZ 2050 GP	Base	Low	R 2035/46	LE 2034	NG 2028		1,000								1,000		1,000		207			800	500		2,507
37	CE22005c	NZ 2035 GP	High	High	R 2030/30	LE 2034	NG 2028		1,000		413			1,400	875		3,688		1,000		413			2,200	1,375		4,988
38	CE22005c1	NZ 2050 GP	High	High	R 2036/47	LE 2034	NG 2028				620			800	500		1,920		1,000		620			1,800	1,125		4,545
39	CE22005d	NZ 2050	Low	Low	R 2036/50	R 2034	NG 2028				206		600				806		1,000		413		600				2,013
40	CE22005e	NZ 2050 GP	Base	Base	R 2032/45	R 2034	NG 2028				826		600	200	125		1,751		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	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		1,000	348	620			2,600	1,625	50	6,243
43	CE22006a	NZ 2050	Low	Low	R 2050 CCS 2050	R 2034	NG2028				826						826	386	1,000		826			800	500		3,512
44	CE22006b	NZ 2050 GP	Base	Base	CCS 2034 R 2044	R 2034	NG2028				826			600	375		1,801		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		207			1,200	750		3,157		1,000		620			1,800	1,125		4,545
46	CE22007a	NZ 2050	Low	Low	R 2050/50	R 2034	R 2028				1,033						1,033		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		620			800	500		2,920		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			1,800	1,125		4,545		1,000		620			2,000	1,250		4,870
49	CE22007d	NZ 2050	High	High	R 2050/50	R 2034	R 2050				826			400	250		1,476		1,000		1,653			2,600	1,625		6,878
50	CE22008a	NZ 2050	Low	Low	R 2050/50	R 2034	NG 2028				826			200	125		1,151		1,000		826			1,200	750		3,776
51	CE22008b	NZ 2050 GP	Base	Base	R 2038/47	R 2034	NG 2028		1,000		413			800	500		2,713		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					1,400	875		3,661	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				620			1,600	1,000		3,220				1,859			3,200	2,000		7,059
54	CE22009b2	NZ 2050 GP	Base	Alt High	R 2038/47	LE 2034	NG 2028				207			1,000	625		1,832				1,240			2,400	1,500		5,140