



2025 NEBRASKA POWER ASSOCIATION LOAD AND CAPABILITY REPORT

August 2025

Disclosure

The 2025 NPA L&C is based on the best information available at the time of development and contains forward-looking statements. Future conditions may differ materially from those discussed. In general, the utility supplied data was current through 6/1/2025, although some modifications were made after that date based on feedback received during the NPA Board's review process.

Acknowledgements

Resource planning is an ongoing process for all Nebraska utilities. These planning processes align with the utility board of directors' directives. Directives are designed to guide efforts to address current and future challenges and mitigate risks. The Nebraska Power Association files and publishes a Load and Capability report annually with the Nebraska Power Review Board.

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Acronyms / Definitions

AC – Alternating Current

ACAP – Accredited Capacity

BESS – Battery Energy Storage System

BTM – Behind the Meter

CCS – Carbon Capture and Sequestration

CNS – Cooper Nuclear Station

DC – Direct Current

DR – Demand Response

EE – Energy Efficiency

EFOF – Equivalent Forced Outage Factor

EFOR – Estimated Forced Outage Rate

EFORd – Equivalent Forced Outage Rate - Demand

EFORd' – Adjusted Equivalent Forced Outage Rate - Demand

EIA – Energy Information Administration

ELCC – Effective Load Carrying Capability

EPA – Environmental Protection Agency

FERC – Federal Energy Regulatory Commission

FORd – Demand Forced Outage Rate

GADS – Generating Availability Data System

GI – Generation Interconnection

HVAC – Heating, Ventilation, and Air Conditioning

ICAP – Installed Capacity

IRP – Integrated Resource Plan

kW – Kilowatt

L&C – Load and Capability

LED – Light Emitting Diode

LRE – Load Responsible Entity

LES – Lincoln Electric System

LOI – Letter of Intent

LOLE – Loss of Load Expectation

MEAN – Municipal Energy Agency of Nebraska

MW – Megawatt

MWh – Megawatt Hour

NGC – Net Generating Capability

NPA – Nebraska Power Association

NPPD – Nebraska Public Power District

NPRB – Nebraska Power Review Board

NRC – Nuclear Regulatory Commission

OATT – Open Access Transmission Tariff

OPPD – Omaha Public Power District

PBA – Performance Based Accreditation

PPA – Purchase Power Agreement

PWP – Power with Purpose

PRM – Planning Reserve Margin

PURPA – Public Utility Regulatory Policies Act

REC – Renewable Energy Credits

RTO – Regional Transmission Operator

SAWG – Supply Adequacy Working Group

SEP – Sustainable Energy Program

SPP – Southwest Power Pool

WAPA – Western Area Power Administration

Existing – In-service accreditable generating resource. Seasonal capability typically listed.

Committed – Projects have NPRB approval if required but are not in service. PURPA qualifying and non-utility renewable projects do not need NPRB approval. These resources are generally expected to be available to be placed in service in a one-to-four year timeframe, subject to the SPP generator interconnection study process. Times can vary due to utility procurement and lead times.

Planned – Resources for which utilities have authorized expenditures for engineering analysis, architect/engineer contract, or permitting but do not have required NPRB approval or do not have a contractual offtake commitment. These resources are generally expected to be placed in service in a three-to-seven year timeframe. Times can vary due to utility procurement and lead times.

Studied – Resources that acknowledge future resource requirements beyond Existing, Committed, and Planned resources. For any future years when Existing, Committed, and Planned resources would not meet a utility’s minimum obligation, each utility establishes Studied resources in a quantity to meet this deficit gap.

1.0 Executive Summary

The Nebraska Power Association Load and Capability report reflects an annual update inclusive of the collective resource planning efforts of Nebraska Public Power District (NPPD), Omaha Public Power District (OPPD), Lincoln Electric System (LES), Municipal Energy Agency of Nebraska (MEAN), Hastings Utilities, City of Grand Island Utilities, City of Fremont Utilities, City of Beatrice, Falls City Utilities, City of Neligh, Nebraska City Utilities, Northeast Nebraska Public Power District (NNPPD), City of Scribner, South Sioux City, City of Superior, Tri-State Generation & Transmission, City of Valentine, City of Wakefield, Village of Walthill, and City of Wayne. This includes solving for near-term load growth while also providing a foundation for future resource needs.

1.1 Statewide Summer Position

Utilizing Existing, Committed, and Planned resources applied to the current and projected cumulative SPP summer resource adequacy requirement, *Figure 1* illustrates that a statewide capacity deficit would occur starting in 2040. *Table 1* contains the corresponding load and capability data in tabular format. The statewide summer deficit based on the state's minimum load obligation in last year's report occurred in 2035. While forecasted loads in the near term are slightly lower than last year's expectations, there is also a corresponding reduction in the utilities' expected net generating capability.

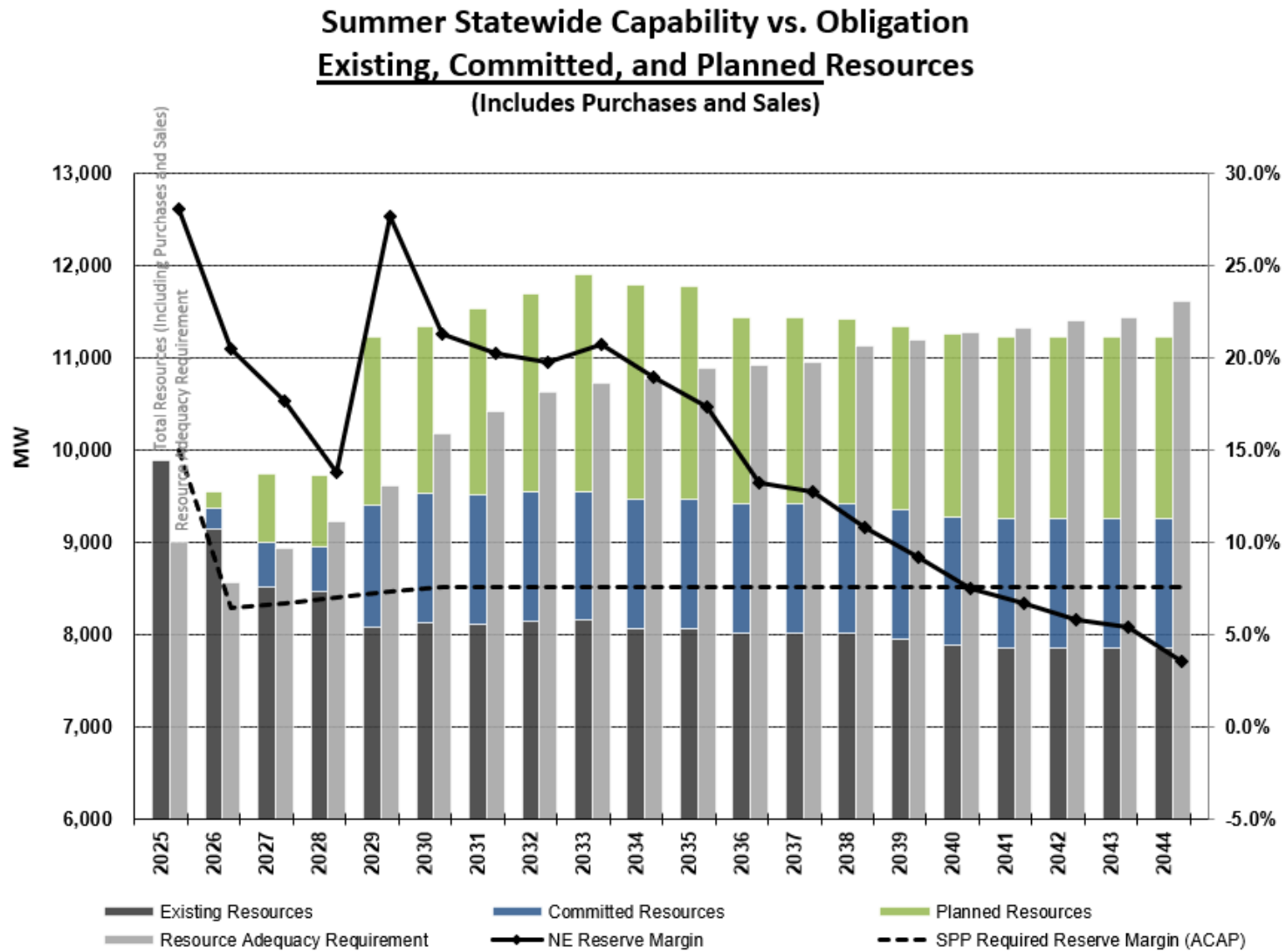


Figure 1 - Summer Statewide Capability vs. Obligation Existing, Committed, and Planned Resources (Includes Purchases and Sales)

Table 1 - Nebraska Statewide Existing, Committed, & Planned Load & Generating Capability in MW - Summer Conditions (June 1 to September 30)

NEBRASKA STATEWIDE Existing & Committed, & Planned Load & Generating Capability in MW Summer Conditions (June 1 to September 30)																				
Year	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
1 Annual System Demand	7,966	8,115	8,444	8,690	9,028	9,544	9,771	9,953	10,049	10,091	10,201	10,235	10,264	10,416	10,480	10,556	10,599	10,674	10,710	10,873
2 Firm Power Purchases - Total	1,173	1,174	1,176	1,178	1,180	1,182	1,183	1,185	1,187	1,189	1,191	1,193	1,195	1,196	1,198	1,200	1,202	1,204	1,206	1,207
3 Firm Power Sales - Total	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70
4 Annual Net Peak Demand (1-2+3)	6,863	7,011	7,338	7,582	7,918	8,432	8,657	8,838	8,932	8,972	9,080	9,112	9,139	9,290	9,352	9,426	9,467	9,540	9,574	9,735
5 Net Generating Capability (owned)	8,258	7,663	7,837	7,833	9,279	9,365	9,547	9,784	10,003	9,996	9,990	9,964	9,958	9,944	9,868	9,798	9,767	9,764	9,763	9,762
6 Firm Capacity Purchases	1,597	1,581	1,595	1,551	1,589	1,581	1,572	1,507	1,489	1,381	1,369	1,059	1,053	1,055	1,052	1,041	1,037	1,035	1,031	1,026
7 Firm Capacity Sales	1,067	798	798	758	758	716	706	706	705	705	705	705	705	705	705	705	705	705	705	705
8 Adjusted Net Capability (5+6-7)	8,788	8,447	8,634	8,626	10,110	10,231	10,413	10,585	10,786	10,672	10,653	10,317	10,306	10,294	10,216	10,134	10,100	10,094	10,089	10,084
9 Net Reserve Capacity Obligation (4 x PRM)	1,030	452	494	532	579	641	658	672	679	682	690	693	695	706	711	716	720	725	728	740
10 Total Firm Capacity Obligation (4+9)	7,893	7,463	7,832	8,114	8,497	9,073	9,315	9,509	9,611	9,654	9,770	9,805	9,834	9,996	10,062	10,142	10,187	10,265	10,302	10,475
11 Surplus (+) or Deficit (-) (8-10)	896	984	802	512	1,613	1,158	1,098	1,076	1,175	1,017	883	513	472	298	153	-8	-87	-171	-212	-392
12 Nebraska Reserve Margin ((8-4)/4)	28.0%	20.5%	17.7%	13.8%	27.7%	21.3%	20.3%	19.8%	20.8%	18.9%	17.3%	13.2%	12.8%	10.8%	9.2%	7.5%	6.7%	5.8%	5.4%	3.6%
13 Nebraska Capacity Margin ((8-4)/8)	21.9%	17.0%	15.0%	12.1%	21.7%	17.6%	16.9%	16.5%	17.2%	15.9%	14.8%	11.7%	11.3%	9.8%	8.5%	7.0%	6.3%	5.5%	5.1%	3.5%
Existing, Committed, Planned Resources (8+2-3)	9,891	9,551	9,740	9,734	11,220	11,342	11,527	11,701	11,903	11,790	11,774	11,440	11,430	11,420	11,344	11,264	11,232	11,228	11,225	11,221
Resource Adequacy Requirement (MW) (1+9)	8,996	8,567	8,938	9,222	9,607	10,184	10,428	10,625	10,728	10,773	10,891	10,927	10,959	11,122	11,191	11,272	11,319	11,399	11,437	11,612
SPP Minimum Reserve Margin (ACAP)	15%	6%	7%	7%	7%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%
First Year of Deficit - Minimum																2040	2040	2040	2040	2040

If the proposed Studied resources are added to the Existing, Committed, and Planned resources, the statewide deficit year occurs after 2044, which is the last year of the report's twenty-year study period. Last year's report with all resource categories also indicated a deficit year that was beyond the twenty-year study period.

1.2 Statewide Winter Position

Utilizing Existing, Committed, and Planned resources applied to the current and projected statewide cumulative SPP winter resource adequacy requirement, *Figure 2* illustrates that a statewide capacity deficit would occur starting in 2043. *Table 2* contains the corresponding load and capability data in tabular format. The statewide winter resource adequacy deficit in last year's report occurred beyond the twenty-year study period. The deficit condition moved to an earlier year relative to last year's report due to the forecasted addition of loads being added within the service territory of the state's larger utilities and the significant changes to SPP's winter resource accreditation methodology.

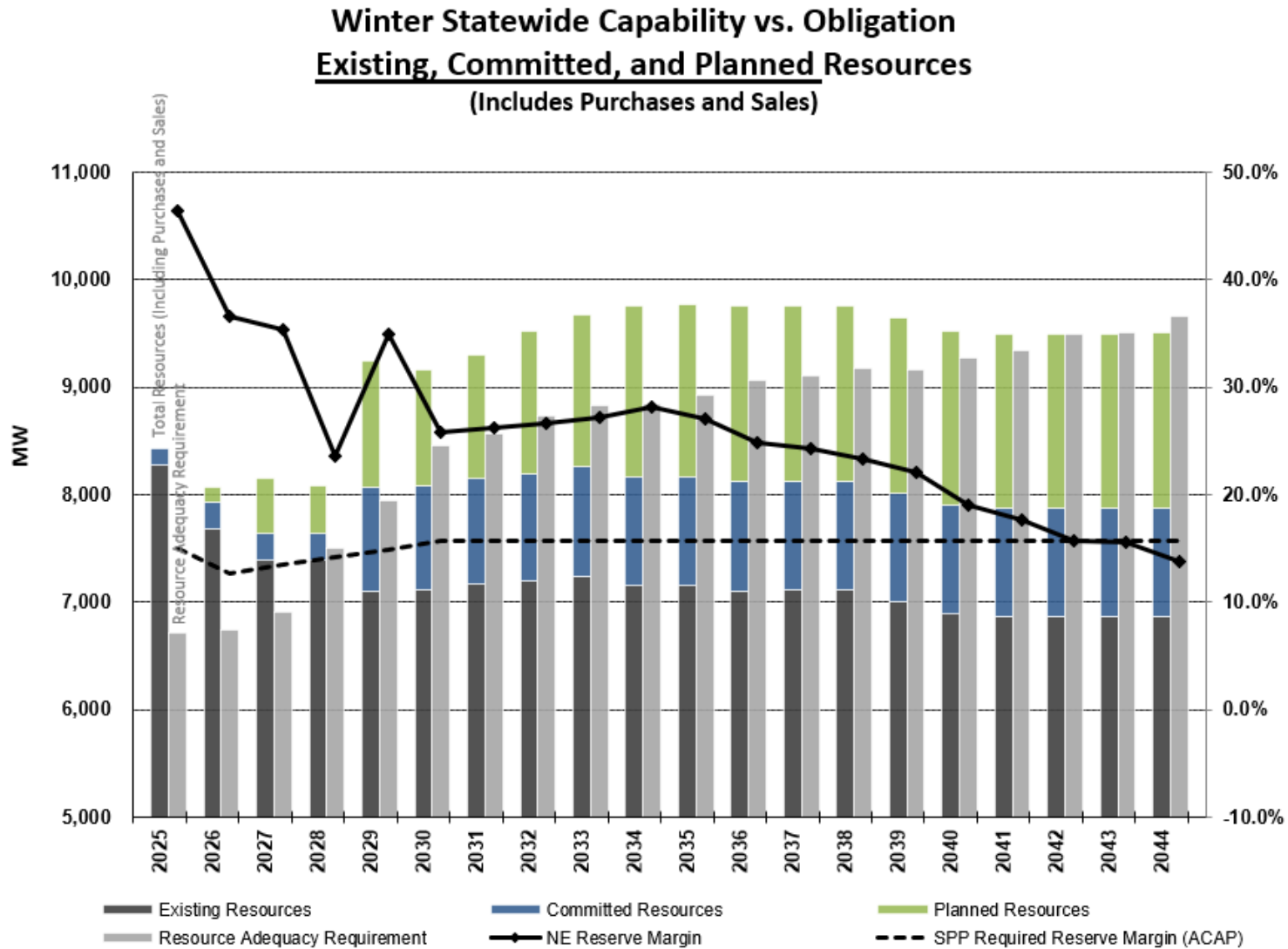


Figure 2 - Winter Statewide Capability vs. Obligation Existing, Committed, and Planned Resources (Includes Purchases and Sales)

Table 2 - Nebraska Statewide Existing, Committed, & Planned Load & Generating Capability in Megawatts - Winter Conditions (Dec. 1 to Mar. 31)

NEBRASKA STATEWIDE Existing & Committed, & Planned Load & Generating Capability in MW Winter Conditions (December 1 to March 31)																				
Year	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
1 Annual System Demand	5,891	6,025	6,134	6,623	6,967	7,368	7,460	7,611	7,696	7,707	7,778	7,900	7,934	7,993	7,979	8,074	8,136	8,269	8,275	8,406
2 Firm Power Purchases - Total	483	484	487	488	492	494	495	496	497	499	500	501	502	504	505	506	507	509	510	511
3 Firm Power Sales - Total	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61
4 Annual Net Peak Demand (1-2+3)	5,469	5,601	5,709	6,196	6,537	6,935	7,026	7,176	7,260	7,270	7,339	7,460	7,493	7,551	7,535	7,629	7,690	7,822	7,826	7,956
5 Net Generating Capability (owned)	7,876	6,960	6,956	6,948	8,237	8,249	8,278	8,521	8,784	8,985	8,990	8,971	8,972	8,964	8,850	8,744	8,711	8,710	8,709	8,709
6 Firm Capacity Purchases	1,180	1,424	1,501	1,400	1,224	1,125	1,216	1,203	1,084	976	976	980	981	983	984	973	974	978	978	979
7 Firm Capacity Sales	1,050	730	728	687	644	643	627	634	637	639	640	640	641	637	637	637	637	637	637	637
8 Adjusted Net Capability (5+6-7)	8,006	7,654	7,729	7,661	8,818	8,731	8,867	9,090	9,232	9,322	9,326	9,310	9,312	9,310	9,197	9,080	9,048	9,051	9,051	9,052
9 Net Reserve Capacity Obligation (4 x PRM)	820	714	770	881	978	1,089	1,103	1,127	1,140	1,141	1,152	1,171	1,176	1,185	1,183	1,198	1,207	1,228	1,229	1,249
10 Total Firm Capacity Obligation (4+9)	6,290	6,315	6,478	7,077	7,515	8,024	8,129	8,303	8,400	8,411	8,492	8,631	8,669	8,736	8,718	8,827	8,897	9,049	9,055	9,205
11 Surplus (+) or Deficit (-) (8-10)	1,716	1,339	1,251	583	1,303	707	737	787	832	911	834	680	643	574	479	254	150	1	-4	-154
12 Nebraska Reserve Margin ((8-4)/4)	46.4%	36.6%	35.4%	23.6%	34.9%	25.9%	26.2%	26.7%	27.2%	28.2%	27.1%	24.8%	24.3%	23.3%	22.1%	19.0%	17.7%	15.7%	15.7%	13.8%
13 Nebraska Capacity Margin ((8-4)/8)	31.7%	26.8%	26.1%	19.1%	25.9%	20.6%	20.8%	21.1%	21.4%	22.0%	21.3%	19.9%	19.5%	18.9%	18.1%	16.0%	15.0%	13.6%	13.5%	12.1%
Existing, Committed, Planned Resources (8+2-3)	8,428	8,077	8,154	8,087	9,248	9,164	9,301	9,525	9,668	9,759	9,765	9,750	9,753	9,752	9,641	9,525	9,494	9,498	9,500	9,502
Resource Adequacy Requirement (MW) (1+9)	6,712	6,738	6,904	7,504	7,945	8,457	8,563	8,738	8,836	8,848	8,930	9,071	9,110	9,179	9,162	9,272	9,344	9,497	9,504	9,655
SPP Minimum Reserve Margin (ACAP)	15%	13%	13%	14%	15%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%
First Year of Deficit - Minimum																			2043	2043

If the proposed Studied resources are added to the Existing, Committed, and Planned resources, the state's utilities maintain an even higher margin until the statewide deficit occurs after 2044, which is the last year of the report's twenty-year study period. Last year's report with all resource categories included also indicated a deficit year that was beyond the twenty-year study period.

1.3 New Generation Timing Uncertainty

A significant number of Committed & Planned resources in this report are expected to be installed in the next few years by Nebraska utilities. As already stated, if this generation is constructed and commissioned as planned, the statewide deficit is projected to occur beginning in 2040. However, there are many inherent risks that can impact the actual generator commission date.

- Supply chain issues in the procurement of generation and delivery equipment are being experienced industry wide. Longer-than-expected lead times for critical equipment could delay commission dates.
- Environmental permits, especially at green field sites, along with location specific siting regulations can take considerable time to work through to final approval and authorization.
- SPP's Generation Interconnection (GI) queue currently has more than 161,000 MW of generation, only a portion of which will get built but nonetheless has asked for an interconnection study. SPP is working on streamlining the GI process, but with the sheer number of generators requesting interconnection studies, this lengthy process can cause delays in commission dates.
- Utility load forecasts and large load requests have recently been at unprecedented levels. Along with this comes uncertainty of whether the new load additions will materialize, as well as the timing and magnitude of loads that do materialize. Sudden increases and decreases in projected loads create a risk to new generation timing.

Nebraska utilities work closely with their current and prospective customers to satisfy their load timing needs. Given the above risks, it may be necessary to have some flexibility in the expected in-service dates of prospective large loads. Additionally, if new generation project delays occur, shorter term capacity purchases could serve as a bridge until "iron in the ground" generation is commissioned.

Inversely, there are resources being actively pursued that are currently designated in the Studied category and shown in Section 4.4 Seasonal Load and Capability which may ultimately be financed and developed into Planned resources on a more aggressive schedule than what is currently assumed. This provides a potential offset to the impact of schedule delays of Planned resources.

2.0 Background

The Joint Planning Subcommittee of the Nebraska Power Association (NPA) has prepared this annual statewide load and capability report for the Nebraska Power Review Board (NPRB), in accordance with subsection (3) of the statute below. It provides the cumulative position of Nebraska's utilities' peak demand forecasts and resources over a twenty-year period (2025-2044).

2.1 Nebraska Statutes

State Statute (70-1025) Requirement 70-1025. Power supply plan; contents; filing; annual report.(1) The representative organization shall file with the board a coordinated long-range power supply plan containing the following information:(a) The identification of all electric generation plants operating or authorized for construction within the state that have a rated capacity of at least twenty-five thousand kilowatts;(b) The identification of all transmission lines located or authorized for construction within the state that have a rated capacity of at least two hundred thirty kilovolts; and(c) The identification of all additional planned electric generation and transmission requirements needed to serve estimated power supply demands within the state for a period of twenty years.(2) Beginning in 1986, the representative organization shall file with the board the coordinated long-range power supply plan specified in subsection (1) of this section, and the board shall determine the date on which such report is to be filed, except that such report shall not be required to be filed more often than biennially.(3) An annual load and capability report shall be filed with the board by the representative organization. The report shall include statewide utility load forecasts and the resources available to satisfy the loads over a twenty-year period. The annual load and capability report shall be filed on dates specified by the board. Source Laws 1981, LB 302, § 3; Laws 1986, LB 948, § 1.

2.2 Nebraska Power Review Board Requests

In January of 2023, the NPRB and the NPA agreed to the inclusion of additional information beginning with the 2023 Annual Load and Capability Report. *Table 3* lists each information request and the corresponding section of the report that addresses the request.

Table 3 - NPRB Requests for Additional Information

NPRB Requested Information	Section of Report
How each utility with a zero-carbon or carbon neutral goal approved by its governing body plans to meet the goal (such as decommissioning fossil fuel facilities, etc.)	Section 2.4, Decarbonization Goals
Address what would happen, or need to happen, if all generation facilities over 60 years old were to be suddenly removed from service.	Section 4.4.4, Age-Based Retirement
Number of units or percentage of capacity that are currently dual fuel.	Section 5.1.2, Dual Fuel and On-Site Fuel Storage
The number of facilities and capacity that have onsite fuel storage. Fuel storage data will be in aggregate, providing ranges for information such as coal pile storage, etc. No fuel storage information for any individual facility will be identified.	Section 5.1.2, Dual Fuel and On-Site Fuel Storage
What percentage or megawatts of total statewide capacity is capable of ramping up from startup to reach maximum capacity during certain ranges of time (e.g., 0-15 minutes, 16-60 minutes, 61 minutes to four hours, greater than four hours). The submitted generating unit data will be based on the physical characteristics and capabilities of the units and will not include any external or other subjective factors that may influence the units.	Section 5.1.3, Ramp Rates

Show system stress periods for the aggregate of the large in-state electric suppliers (LES, NPPD and OPPD, and others as applicable) for both the summer and winter peaks, and the aggregate resources that were available to meet the load requirements during those stress periods. Include historical data on stress periods, and what generating capacity was available to meet the load demand. Stress periods will be defined as the statewide summer peak hour and the statewide winter peak hour of the most recent summer and winter seasons for the aggregation of LES, NPPD, and OPPD. The data provided for these two periods will include aggregated load consumption data, generator production data, and generator availability data for LES, NPPD and OPPD. Additionally, the report will include sensitivity analysis of the stress periods by evaluating the potential impact of selected extreme event scenarios (e.g., extreme weather conditions, extreme localized events).	Section 5.1.4, Stress Period(s)/Stress Test
Include the winter peak loads and aggregate winter accreditation of units.	Section 4.4.2, Winter Load and Capability
Charts showing the statewide fuel diversity (coal, diesel, hydro, landfill gas, natural gas, nuclear, solar, wind and storage batteries), showing the percentage of the State's generation resources in each category by nameplate capacity, accredited capacity, and the previous year's energy production.	Section 5.1.1, Fuel Diversity
Perform an aggregate calculation based on non-public historical GADS data showing the combined EFOR or FORd for LES, NPPD and OPPD. Compare the result to the SPP regional EFOR or FORd rate to demonstrate how Nebraska's largest generation resources are performing in comparison to the overall SPP. SPP is considering using EFORd and EFORd' for the performance-based accreditation process. Consequently, EFORd and EFORd' will also be acceptable metrics for LES, NPPD and OPPD to use for comparison purposes.	Section 3.4, Resource Accreditation
A brief assessment of reasonably anticipated changes to the grid that might complement or complicate resource adequacy. Examples might include greater penetration of electric vehicles or federal regulatory policies.	Section 3.6, Grid Changes, Section 3.7, Electrification

Information on some of these items has been included in previous reports due to prior requests by the NPRB.

2.3 Other requirements

In late 2023, the NPRB requested additional modifications and clarifications to be incorporated into the Report. One clarification included utilizing the most readily available historical forced outage data from SPP – specifically, either the EFORd or EFORd' metric – for the aggregate comparison of Nebraska's generation performance. This comparison is included in Section 3.4 using EFORd data published by SPP on a generation capacity weighted basis. The NPRB also requested better definitions and application of the Committed, Planned, and Studied generation categories. Estimated timeframes for these future generation additions are now included in definitions for the Report and are utilized by the reporting utilities. After ongoing dialogue, the NPRB and NPA Joint Planning Subcommittee also agreed to provide a more subjective review of a sensitivity case of a system stress period, which for this year's edition of the Report was determined to be extreme heat and drought coincident with low wind generation. The discussion of this summer weather sensitivity is included at the end of Section 5.1.4. Lastly, the NPRB requested various chart type modifications and formatting modifications for ease of use and readability. These modifications are incorporated throughout the Report.

2.4 Decarbonization Goals

Most power utilities across the nation are addressing decarbonization and are actively evaluating specific goals or have put in place plans to meet these goals 20 to 30 years in the future. Each utility is necessarily unique in their approach, seeking to balance reliability/resiliency, affordability, and sustainability while meeting customer expectations and adhering to their specific market rules regarding resource adequacy. Additionally, as technology is expected to advance rapidly, each plan represents a directional path that will continually adapt with evolving conditions.

The following are the current decarbonization goals for Nebraska utilities that have established goals. Utilities will continue to monitor progress and evaluate targets:

2.4.1 NPPD

In 2021, NPPD's Board of Directors established a strategic directive (SD-05) to achieve net-zero carbon emissions from generation resources by 2050. This will be achieved by continuing the use of proven, reliable generation until alternative, reliable sources of generation are developed and by using 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, then current resources.

In addition, NPPD finalized their IRP in 2023. The IRP incorporated SD-05 and provides directionally correct insight to the most favorable approach to adding resources and reducing carbon emissions under various scenarios. Specific resource decisions will require additional analysis. At this time NPPD has no plans to retire or decommission any of its existing generation units.

2.4.2 OPPD

In 2019, OPPD’s Board of Directors adopted a goal in its Strategic Directives to achieve net-zero carbon production by 2050. The goal was adopted by OPPD’s Board of Directors as part of its Strategic Directive 7 (SD-7) on Environmental Stewardship. The decision reflects OPPD’s long-term planning objectives and is balanced with other Strategic Directives, particularly those related to cost (SD-2, Rates) and reliability (SD-4, Reliability).

OPPD completed its *Pathways to Decarbonization* study in 2021, which evaluated resource options to meet future electric demand while upholding reliability and controlling costs. The results of the study emphasized the need for a pragmatic approach and a balanced resource mix—including renewable energy, energy storage, and dispatchable generation—to navigate evolving market, reliability, and policy risks.

This balanced resource approach helps reduce exposure to fuel supply disruptions, market volatility, and periods of low renewable output. It reflects OPPD’s continued commitment to system reliability and prudent cost management while aligning with long-term carbon reduction goals.

OPPD remains committed to a thoughtful, data-driven planning process that ensures reliable electric service, meets evolving energy needs, supports the electrical load of current and new economic development, and responsibly transitions the energy portfolio over time. OPPD will not take actions that compromise the reliability of service to its customers, nor allow inaction to delay timely service. If new information or system conditions reveal that any aspect of the net-zero plan could negatively impact reliability, OPPD would be required—consistent with its Strategic Directives and federal requirements—to modify its plans accordingly. Reliability and meeting service obligations will always take precedence, and OPPD will act decisively to ensure adequate resources are in place to meet the needs of the community it serves.

2.4.3 MEAN

In January 2020, the MEAN Board of Directors approved a resolution establishing MEAN’s 2050 Vision, with a goal of achieving a carbon neutral resource portfolio by the year 2050. MEAN’s 2022 Integrated Resource Plan formed the initial direction for future actions and

resource decisions to realize the 2050 Vision. Following the IRP's direction, MEAN staff is working in collaboration with Participants to construct policies around resource planning, portfolio optimization, and emissions reduction to achieve the 2050 carbon neutral goal.

MEAN's IRP analysis and modeling favored a plan that would meet future MEAN capacity and energy needs by incorporating additional renewable resources into the portfolio. Renewable resource portfolios offered comparatively low costs in several scenarios as well as the potential to create local benefits for MEAN communities. The Board recommended portfolios for future resource needs as identified in the IRP include natural gas combined cycle with carbon capture, landfill gas, hydropower, wind with energy storage, and solar with energy storage.

Portfolio diversification remains a very high priority for MEAN to balance the need for reliability with the desire for decarbonization.

2.4.4 LES

After participating in a yearlong educational series on establishing a new carbon reduction goal and soliciting public opinion, the LES Administrative Board in November 2020 adopted a goal that LES believes to be one of the more aggressive utilities decarbonization goals in the United States. This new goal will aim to achieve net-zero carbon dioxide production from LES' generation portfolio by 2040, with the ultimate path and pace to achieving the goal balanced in part by a commitment to maintaining high electric system reliability and a fiscally responsible focus that carefully considers financial impacts to all customers.

LES completed its latest IRP in 2022, laying out an initial plan for achieving this corporate decarbonization goal. The majority of this plan still rings true today, including the following cornerstones:

- Maintain LES' wind portfolio.
- Continue the Sustainable Energy Program (SEP), a collection of energy efficiency and demand response resources that represents a cost-effective alternative to building new generation.
- Seek to maintain LES' existing fleet of natural gas resources, representing both a low-cost and, because they rarely operate, relatively low-emissions foundation of its future portfolio.
- Continually watch for the right time to either retire or upgrade its existing coal resources with carbon capture technology. The financial impact of these coal plant decisions is considerable, both when (i) retiring them too early, while they still bring considerable financial value to LES, and (ii) retiring them too late, when market forces and/or environmental regulations make them less economically viable.

LES believes this preliminary decarbonization plan strikes an important balance, closing enough of the gap to make the goal attainable, while still recognizing that additional decisions will be required as the future unfolds.

2.4.5 Hastings Utilities

Hastings Utilities does not have decarbonization goals currently. Hastings plans to continue to monitor the energy market and all its resources available.

2.4.6 City of Grand Island Utilities

Grand Island does not have any formal decarbonization goals. Grand Island continues to utilize a diverse resource portfolio that includes wind, solar, hydro, coal, gas, and oil.

2.4.7 City of Fremont Utilities

At this point, Fremont has no plans on retiring/decommissioning any of its coal or natural gas units. Fremont will continue to annually look at available generation and capacity options. Unfortunately, there is nothing more to report at this point due to too many unknowns.

3.0 Operational Environment

3.1 Nebraska

Section 2 of this Report describes statutory requirements related to the NPRB and its ongoing mission established in 1963 to regulate certain aspects of Nebraska's publicly owned electric utility industry. The NPRB is governed by a five member Board approved by the Governor and confirmed by the Nebraska Legislature. The NPA is a voluntary organization of the approximately 160 municipal, public power district, and cooperative electric utilities that operate within Nebraska. The NPA was formed in 1980 to address statewide electricity policies and related issues and is currently the organization designated by the NPRB to assemble this Report.

Additionally, the electric utility industry interacts with a variety of other regulatory agencies that address environmental, financial, operational, safety & health, and labor & employment issues. A non-exhaustive list of these agencies includes entities like the U.S. Environmental Protection Agency, U.S. Fish & Wildlife Service, Nebraska Department of Environment and Energy, Nebraska Department of Revenue, Federal Energy Management Agency, Nebraska Public Service Commission, Nebraska State Fire Marshal, U.S. Department of Homeland Security, Nebraska Commission of Industrial Relations, Occupational Safety & Health Administration, and the Federal Energy Regulatory Commission.

3.2 Southwest Power Pool

The Southwest Power Pool (SPP), based in Little Rock, Arkansas, was created in 1941 to provide electric reliability and coordination for eleven regional power companies. SPP has since expanded its scope of services and was approved as a Regional Transmission Organization (RTO) by the Federal Energy Regulatory Commission (FERC) in 2004. In 2007, SPP initiated a real-time energy imbalance services market, which was ultimately transitioned to a full combined day-ahead and real-time market in 2014. The services that SPP currently provides for its members include:

- Transmission tariff administration
- Regional scheduling
- Transmission expansion planning
- Reliability coordination
- Wholesale energy market operations and Integrated Marketplace
- Consolidated balancing authority

- Generation reserve sharing

SPP expanded its services in the west in December 2019 when it launched its Western Reliability Coordination service on a contract basis, and in February 2021 with the successful launch of the Western Energy Imbalance Service (WEIS) Market. SPP employs approximately 600 employees and operates a system footprint spanning across 17 states.

In July 2021, Southwest Power Pool's Board of Directors and Strategic Planning Committee approved the submitted policy-level terms and conditions for RTO expansion in the Western Interconnection. In April 2023, SPP announced the 31 parties who executed agreements to participate in the first phase of Markets+ development. Later in 2023, seven utilities approved their transition from WEIS to membership in SPP's RTO West, which is scheduled to begin full operations in spring of 2026. By joining the RTO, they will gain access to SPP's Integrated Marketplace, transmission planning, reliability coordination, and other RTO services. SPP's expansion into the Western Interconnection positions it as the first U.S. grid operator to provide full RTO services across both the Eastern and Western Interconnections. This development is expected to enhance grid reliability, increase market efficiency, and facilitate greater integration of renewable energy sources. *Figure 3* shows the current SPP footprint.

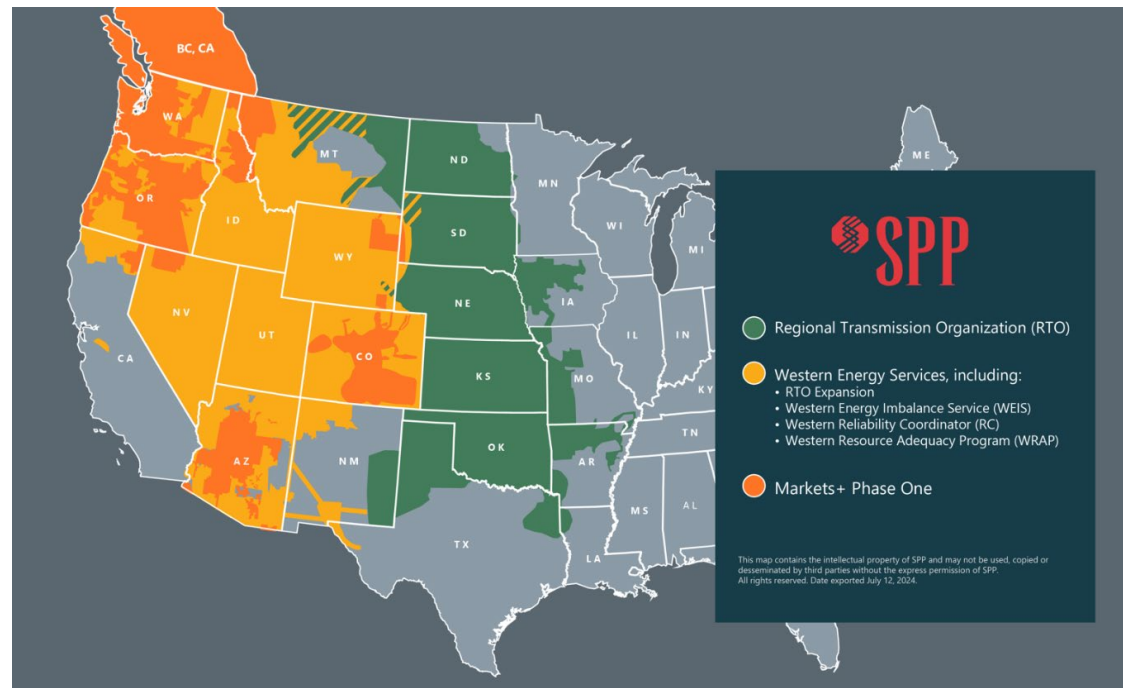


Figure 3 - SPP Footprint Overview

3.3 Planning Reserve Margin

In order to ensure reliability in the face of resource outages, load fluctuations, fuel availability, and intermittent resource generation, SPP established a Planning Reserve Margin (PRM), which requires each Load Responsible Entity (LRE) to maintain resource capability equal to its expected peak load plus an additional capability equal to a calculated margin. This requirement is enforced to ensure LREs have adequate capacity to serve the SPP Balancing Authority Area's peak demand. Failure to meet the resource adequacy requirement results in a deficiency payment as calculated in accordance with Section 14.2 of Attachment AA of the SPP Tariff. LREs submit an annual Resource Adequacy Workbook to SPP to demonstrate compliance to fulfill resource adequacy obligations.

The Base PRM is determined via a probabilistic Loss of Load Expectation (LOLE) Study which analyzes the ability of resources to reliably serve the SPP Balancing Authority Area's forecasted peak demand. The LOLE study is performed biennially. SPP studies the Base PRM such that the loss of load for the applicable planning year does not exceed one day in ten years. Historically, SPP had required LREs to provide this margin in relation to only the forecasted summer peak load but duplicated the same Base PRM requirement in the winter season for the first time for the 2025/2026 winter.

Last year, SPP approved a summer Base PRM of 16% and a winter Base PRM of 36% to become effective starting the summer season of 2026. The significantly increased winter Base PRM accounts for the increased electric system risks experienced during the winter season. SPP has since established a higher requirement of 17% which will start the summer of 2029 and a winter requirement of 38% which will start the winter of 2029/2030.

3.4 Resource Accreditation

Resources being utilized to meet regional resource adequacy requirements must qualify through an SPP administered accreditation process which evaluates the effectiveness of individual resources to meet system resource adequacy needs. There are multiple processes for accrediting resources based on the type of resource.

Thermal resources are currently accredited based on their peak generating capability and are tested during defined summer conditions. Generators must conduct this peak test once every five years and must prove that they can reach 90% of this amount every year. There is no consideration of individual unit reliability within this accreditation method.

Starting with the summer season of 2026, new SPP Performance Based Accreditation (PBA) and Fuel Assurance (FA) policies will affect the future accreditation of thermal generators. PBA considers the historical reliability of individual generators to calculate individual unit accreditation. Units with increased forced outage rates will receive lower accreditation. This is expected to incent reliability enhancements for poorly performing generators.

In addition to the PBA policy, the FA policy will further impact thermal generator accreditation during the winter season based on performance during the most critical system periods. This policy is intended to further encourage generation to be available when needed most. This year's Load and Capability Report is based on the new resource accreditation methodology, effective summer 2026.

It is also important to note that the reductions in thermal unit accreditation associated with the PBA and FA policies will correspond with a change in the basis for determining the regional PRM. As SPP adopts these policies, the seasonal PRM requirements will transition from an Installed Capacity (ICAP) basis to an Accredited Capacity (ACAP) basis beginning in summer 2026. This change in basis will result in a lower overall ACAP PRM than the corresponding ICAP PRM, or Base PRM, for each season. Thus, LREs with unit reliability that is higher than the SPP system average will achieve the benefits of maintaining high generator accreditation while subject to a lower PRM requirement. LREs with unit reliability that is worse than the system average will be incentivized to continue to invest in reliability improvements. This ACAP PRM will be recalculated by SPP annually and these recurring adjustments could likely be a source of uncertainty for the LRE's when they are attempting to determine their individual reserve margins relative to a changing footprint wide PRM. The calculations in this year's report are based on the SPP-approved seasonal ACAP PRM values.

Table 4 below includes the historical equivalent forced outage rate data published by SPP along with aggregate Nebraska data for the applicable generator categories.

Table 4 - Aggregate Outage Metrics

SPP Footprint Fuel and Technology Type	SPP Summer Weighted Average EFORd	SPP Winter Weighted Average EFORd + EFOF	Nebraska Capacity Weighted Summer EFORd	Nebraska Capacity Weighted Winter EFORd + EFOF	Nebraska Summer Original Claimed Capacity (MW)	Nebraska Winter Original Claimed Capacity (MW)	Nebraska Summer Adjusted Capacity (ACAP) (MW)	Nebraska Winter Adjusted Capacity (ACAP) (MW)
Conventional Hydroelectric	0.41%	0.46%	0.39%	1.73%	125.6	133.3	125.1	131.0
Conventional Steam Coal	9.01%	15.93%	10.27%	16.50%	3,601.6	3,555.6	3,231.8	2,968.8
CT w/ Onsite Fuel Storage	9.67%	14.96%	10.56%	19.39%	974.6	1,058.0	871.7	852.9
CT w/o Onsite Fuel Storage	6.11%	31.05%	5.39%		313.4	-	296.5	-
Hydroelectric Pumped Storage	7.92%	8.46%			-	-	-	-
NG Fired Combined Cycle	4.46%	9.25%	3.25%	12.13%	246.9	248.1	238.9	218.0
NG Steam Turbine	11.19%	18.85%	11.67%	14.50%	339.3	99.3	299.7	84.9
Nuclear	1.08%	1.23%	0.79%	1.73%	768.5	768.5	762.4	755.2
RICE w/ Onsite Fuel Storage	5.59%	11.31%	5.36%	9.82%	67.2	67.2	63.6	60.6
RICE w/o Onsite Fuel Storage	7.97%	5.10%	2.08%	10.42%	4.8	4.8	4.7	4.3

Variable energy resources, such as wind and solar, are currently accredited according to their production during a utility's peak load hours. The current process utilizes the 60th percentile of production during the top 3% of load conditions. In other words, the resource must meet or exceed the accreditation value 60% of the time during top load hours.

The current accreditation methodology for variable energy resources does not account for the diminishing marginal resource adequacy value of these resources with their increasing penetration on the electric system. To properly account for this, SPP will move to an Effective Load Carrying Capability (ELCC) methodology for accreditation starting in the summer of 2026. ELCC accounts for historical weather variability across the region and periods of regionally low renewable generation.

SPP's ELCC, FA and PBA policies have been approved by SPP's Board of Directors and are currently filed for ruling by FERC.

3.4.1 Effective Load Carrying Capability

This method, applicable to wind, solar and energy storage, captures correlations between variable energy resources and load. Key outputs from this approach are the total capacity requirement (MW) to meet the 1-day-in-10-year loss of load expectation standard. ELCC values are not static throughout long-term planning horizons. For each resource, ELCC depends on the penetration of the given resource as well as the quantity and type of other resources on the system. There are diminishing return impacts of variable and energy-limited resources, reflected by a decline in ELCC value at higher penetrations. The formula for calculating the accredited capacity of resources using the ELCC percentages is as follows:

$$\text{Accredited Capacity} = \text{Nameplate Capacity} * \text{ELCC}$$

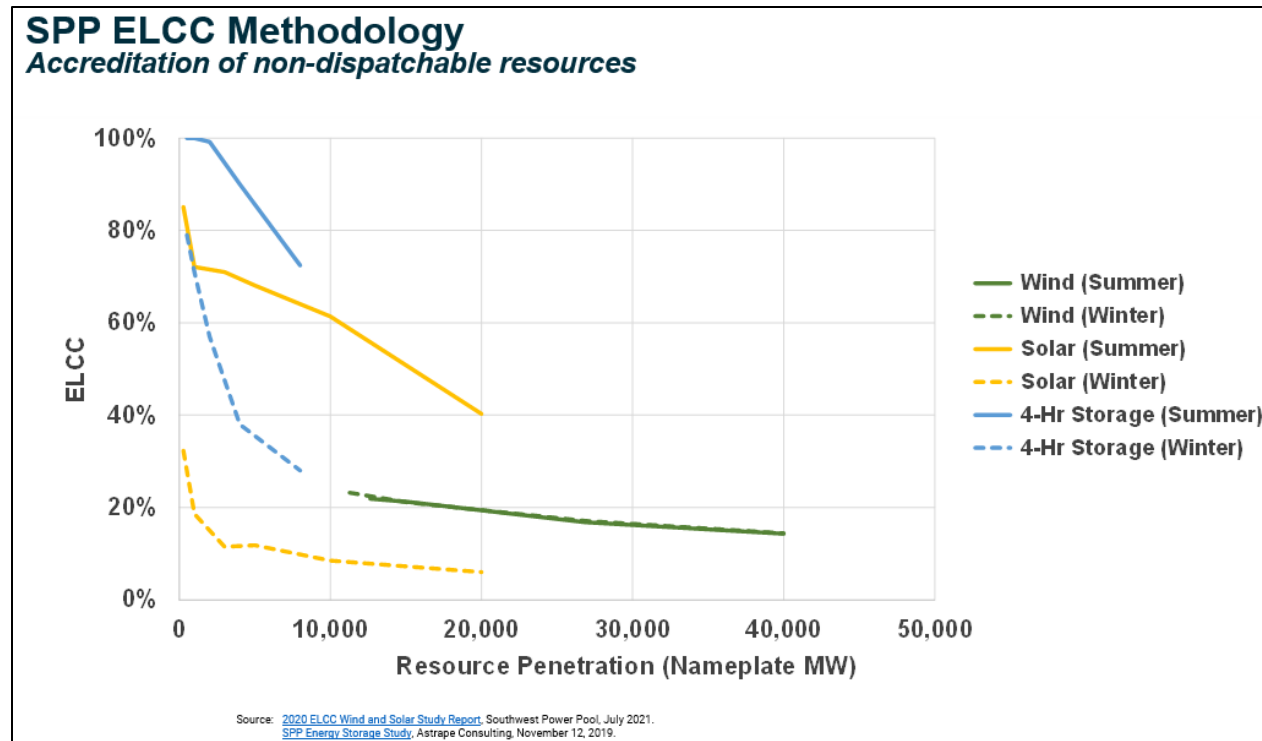


Figure 4 - SPP ELCC Methodology Examples

3.4.2 Performance Based Accreditation

This method calculates each conventional resource's Accredited Capacity. Conventional resources are defined as thermal fuel type resources, pumped storage hydroelectric resources, and hydroelectric resources with reservoir storage capability not subject to hourly river flow limitations similar to run-of-river hydro. Accredited Capacity is determined using the demonstrated Net Generating Capability (NGC) and the resource's calculated EFORD for the applicable season. PBA takes into account actual unit performance over a rolling seven-year historical time period. The formula for calculating the accredited capacity of resources using the EFORD percentages (see Table 4) is as follows:

$$\text{Accredited Capacity} = \text{NGC} * (1 - \text{EFORD})$$

3.4.3 Fuel Assurance

The SPP FA policy is designed to address outages that occurred during recent extreme cold weather events due to fuel unavailability. An additional winter accreditation reduction will be determined by the total amount of correlated cold weather outages experienced in the region and incorporated into the SPP LOLE study. The reduction will then be allocated according to individual thermal generator equivalent forced outage factors (EFOF) during the top 3% of seasonal net load hours. Net load is defined as the SPP system load less renewable production and may represent periods of tight supply.

3.4.4 Demand Response Accreditation

SPP is currently in the process of developing revised rules to address the accreditation of demand response programs, considering the resources' ability to be called upon prior to energy emergency events on the system, the type of demand response program and various other factors.

3.5 Generation Interconnection Queue

The SPP Generation Interconnection (GI) process provides a means for planners and developers to submit new generation projects for interconnection to the SPP system. SPP requires potential projects to be entered into the GI queue for validation, study, analysis and, ultimately, execution of a Generator Interconnection Agreement. This agreement is required for new generation to be able to connect to the regional transmission system and receive accreditation to satisfy SPP resource adequacy requirements. Potential transmission system upgrades required to support the new resources are identified during this process, and the costs are allocated to those facilities causing the need for upgrades.

The continued declining costs of renewable generation technologies has led to a large influx of generation interconnection requests into the SPP GI study process in recent years. This growth in the volume of study requests, coupled with the requirement for equal treatment according to federal OATT requirements, has led to a significant backlog in the study process and has caused increased delays in this process. The current study process is approximately 4 to 5 years from the date the request is submitted to study completion, depending on the specific study cluster. This is a national issue with RTOs, FERC, utilities, and industry groups working diligently to improve these processes to allow resources to connect to the transmission system and serve load in faster, more predictable timeframes.

A listing of the projects in the GI Queue from June 17, 2025, within the state of Nebraska shows around 2,138 MW of nameplate capacity for battery storage (14 projects), 3,975 MW of solar (21 projects), 3,598 MW of wind (15 projects), and 1,107 MW considered hybrid (6 projects). It should be noted that the GI queue for Nebraska includes study requests entered by both Nebraska and non-Nebraska utility entities. For reference, at this time there is approximately 3,500 MW of nameplate wind installed in the state including merchant wind projects and behind the meter

wind projects. Also listed in the Queue are conventional combustion turbines and diesel generation amounting to 6,161 MW (about 2,628 MW more than shown in the 2024 report). Based on history, many or most of these proposed projects listed in the SPP Queue will not get built, but due to FERC policy requiring non-discriminatory and open access to the transmission grid, each request must be equally treated and evaluated.

3.6 Grid changes

Many potential future challenges confront Nebraska utilities in addition to those posed by new and changing SPP requirements, the potential for large load additions, and the pursuit of decarbonization goals. For example, in April of 2024, the U.S. EPA issued the final rule for CO₂ limits for new combustion turbines and CO₂ emissions guidelines for existing coal, oil, and natural gas fired steam generating units. For existing coal units, the regulations would require either retirement date commitments, annual capacity factor restrictions, co-firing with natural gas, or the installation of carbon capture and sequestration (CCS) systems. For applicable combustion turbines, the requirements are based on the anticipated capacity factor of the unit and include restrictions on certain fuel types, limitations on CO₂ emissions rates, or the installation of CCS systems. Given that these regulations include compliance dates ranging from 2031 to 2039, and that effective CCS technologies do not yet exist as commercially viable options, meeting these requirements would no doubt be difficult. The JPS acknowledges current challenges to these proposed rules and the introduction of actions to repeal existing emissions regulations. This uncertainty and volatility creates an environment wherein policy is constantly monitored, and extremes are a consideration of portfolio risk analysis.

3.7 Electrification

In addition to the regulatory changes mentioned above regarding generating resources and energy supply, there is also support at the national level to electrify more end-user processes, shifting loads to electricity and thereby reducing the related CO₂ emissions. Some of the primary applications are electrifying transportation and converting building heating from natural gas or other fossil fuels to electrically powered equipment. Transformations like these pose a challenge to Nebraska utilities, as they add to already growing energy demands and resource adequacy needs. Although some of these changes may materialize at a slower pace in Nebraska compared to elsewhere around the country, they appear to continually be gaining momentum.

4.0 Load and Capability

This section assesses the state's load and resource balance, comparing the aggregate forecasted electric load to Existing, Committed, Planned, and Studied resources. Specifically, this section provides detail on the state's reference load forecast, including projections of summer peak demand, winter peak demand, and annual energy requirements.

4.1 Load Forecast

The current combined statewide forecast of non-coincident peak demand is derived by summing the demand forecasts for each individual utility on an annual basis. Each utility supplied an annual peak demand forecast and a load and capability table. The peak demand values represent a 50th percentile value, a statistical midpoint suggesting the expectation that this demand may be exceeded with 50% probability. Over the twenty-year period of 2025 through 2044, the average annual compounded peak demand growth rate for the state is projected at 1.7% per year (individual utilities range from -1.1%/yr. to 2.7%/yr.). The escalation rate shown in last year's report for 2024 through 2043 was 1.4%.

4.2 Utility Approach to Service Requests and Potential Load

It should be noted that several Nebraska utilities continue to be approached by potential customers regarding the utility's ability to interconnect large, new loads. Many times, the nature of the requests is vague, with uncertain timing and magnitude. Unverified or speculative large loads are often not included in the utilities' demand forecasts submitted to SPP, but some are included in this report if the utilities have determined in their judgment that there is a sufficiently high degree of confidence that the load may eventually materialize. The magnitudes of these loads can reach the hundreds of MWs and can represent large percentage increases to a utility's existing peak demand. The inclusion of these large loads here is intended to reflect the potential impacts to statewide demand and capacity expectations for illustrative planning purposes but may remain too uncertain to include in the more specific SPP Balancing Authority (BA) resource planning.

4.3 Statewide Resources

4.3.1 Existing and Committed Resources

The state has an Existing summer accredited generating resource capability of 8,250 MW. Existing resources are those resources that are in-service, can obtain an accreditation rating, and may have different accreditation values based on the season. This is an increase from the 7,810 MW shown in the 2024 report. An additional 2,770 MW of existing firm power purchases and firm capacity purchases contributes to utility capabilities.

There are 1,775 MW nameplate, or 1,397 MW accredited Committed resources included in this report over the study period. Committed projects have Nebraska Power Review Board approval if required. (PURPA qualifying and non-utility renewable projects do not need NPRB approval).

There are several additional Committed projects either currently in development or recently placed in service within Nebraska:

- Addition of 25 MW of Behind-The-Meter renewable generation is forecasted to be added between 2025 and 2026.
- Construction of OPPD's new dual fuel generation, the 150 MW Standing Bear Lake facility and the 442 MW Turtle Creek facility. The Turtle Creek facility achieved completion in June 2025 and is fully available. The Standing Bear Lake Facility is approaching completion later in 2025. These resources are part of the 2020 SPP GI Queue Cluster Study. OPPD currently holds Interim Generation Interconnection Agreements for these facilities and is in the process of negotiating full agreements with SPP.
- In March of 2024, OPPD obtained NPRB approval for the construction of 900 MW of dual fuel combustion turbines to be located at two existing OPPD plant sites. These resources are expected to come online in 2029. This generation was approved as part of OPPD's Near Term Generation board resolution authorizing the development of up to 2.5 GW of diverse portfolio additions.

[4.3.1.1 Firm Dispatchable Resources](#)

The state has 7,734 MW of commercially operating firm dispatchable accredited resources for the summer peak of 2025. These resources are accredited based on the current unit accreditation methodologies as the SPP PBA based methodologies are not in use yet. PBA accreditation values are utilized in the report for summer 2026 and beyond

[4.3.1.2 Renewable and Demand Side Resources](#)

The state has 2,279 MW (nameplate) of commercially operating renewable resources for the summer peak of 2025. There are also 108 MW of accredited in-state hydro for Nebraska's use not included in this total. These amounts do not include wind installed by developers in Nebraska for export to load outside the state. Due to its intermittency, Nebraska utilities rely upon wind for only a small percentage of its full nameplate rating to meet peak load conditions. Correspondingly, SPP has criteria for wind and solar to determine the specific accredited capacity percentage. The criteria are based on actual performance of solar and wind facilities specifically during actual utility peak load hours. The accredited rating based on actual performance generally requires a minimum of three years of operating history. For new installations with less than three years of historical generation, SPP criteria allows for a 5% accreditation rating for new wind installations and a 10% accreditation rating for solar.

Demand side resources are loads that can be reduced, shifted, turned off or taken off the grid with the goal of lowering the overall load that utilities are required to serve. Ideally this load is best reduced to correspond to utilities' peak load hours. The advantage for utilities is avoidance of the need to add accredited generation in current or future years due to the reduction in peak demand obligation. SPP is currently in the process of revising standards for these resources and these revisions may impact the ability to utilize a portion of existing demand response programs, particularly controllable and dispatchable response programs, to satisfy SPP resource adequacy requirements.

Figure 5 shows the existing and committed statewide renewable and greenhouse gas mitigating generation by both nameplate and accredited capacity.

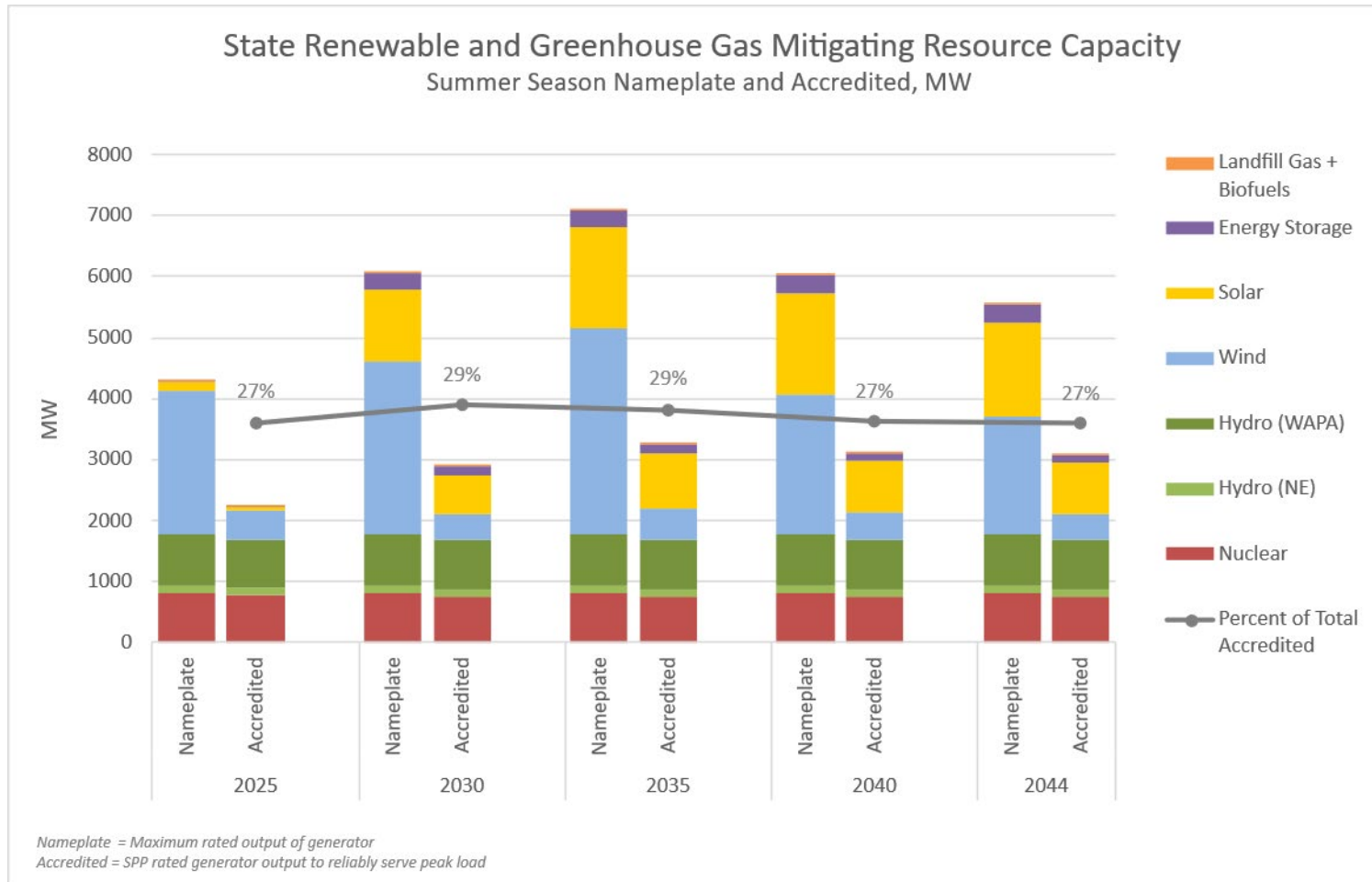


Figure 5 - Statewide Renewable and Greenhouse Gas Mitigating Resources - Summer Season

4.3.1.3 Distributed Generation

Distributed generation generally refers to a variety of technologies that generate electricity at or near the point of consumption. These resources are providing wholesale and retail power suppliers numerous new opportunities to interface with customers. Power purchase agreements with smaller wind developers are available to retail power suppliers in the magnitude of 1.5 to 10 MW. This capacity is facilitated through agreements between wholesale and retail power suppliers. These agreements allow for a portion of the retail power supplier's energy requirements to come from renewable energy resources located behind the wholesale power supplier's meter.

With the decline in the cost of solar installations, the continuation of tax benefits and net metering rates, retail customers are installing small scale solar arrays and energy storage systems. These installations are being installed in both rural and residential applications. Also, larger solar array installations that are not eligible for net metering rates are being considered and installed. Many of these arrays are community solar projects. For example, Lincoln Electric System contracted with a developer to install a 4 MW array and offered the ability for customers to purchase shares. NPPD has retail communities with operating community solar facilities ranging in size from 100 kW to 9.7 MW. OPPD has a community solar facility sized at 5 MW, and OPPD's customers have already subscribed to the full production of this facility. With these applications, private involvement with local utilities is providing additional opportunities to increase the utilization of renewable energy.

In addition, an NPPD retail community has recently commissioned a 1 MW / 2 MWh battery energy storage system (BESS) at a community solar project. The BESS will be charged through generation provided by the solar facility and discharged to accomplish several goals, such as demand management, voltage support, and smoothing and shifting variable renewable energy generation. The BESS unit will store approximately the amount of electricity that a small home would use over the course of two months.

Another committed project – which is currently under construction – is the 3 MW / 12 MWh BESS with a commercial operating date around Fall of 2025. The facility will be used by LES through a power purchase agreement. With the primary purpose to function as a generator asset, the BESS will be interconnected with an existing substation of LES, with the goal of improving the reliability and resiliency of the Lincoln Community Microgrid.

4.3.2 Planned

Planned resources are units for which utilities have authorized expenditures for engineering analysis, an architect/engineer contract, or permitting, but do not have required NPRB approval, or do not have a contractual offtake commitment.

There are 1,571 MW of accredited Planned resources anticipated in this report which includes 1,243 MW of dual fueled thermal resources, 202 MW of solar generation, and 125 MW of energy storage. There is also 10 MW of Planned nameplate solar generation that is located behind the meter for which no accredited capacity is being claimed. (This is exclusive of Planned future capacity purchases.)

4.3.3 Studied

Resources identified as Studied for this report provide a perspective of future resource requirements beyond the timeframes of Existing, Committed, and Planned resources. For any future years when Existing, Committed, and Planned resources would not meet a utility's minimum load obligation, each utility establishes Studied resources in a quantity to meet this deficit gap. These Studied resources are identified as renewable, base load, intermediate, peaking, or unspecified resources considering current and future needs. The result is a listing of the preferable mix of resources for each year. The summation of Studied resources will provide the basis for the NPRB and the state's utilities to understand the forecasted future need by year and by resource type. This can be used as a joint planning document and a tool for coordinated, long-range power supply planning.

There are 1,684 MW of accredited Studied resources anticipated in the final year of this report that includes 850 MW of dual fueled thermal, 589 MW of solar, and 245 MW of wind.

4.4 Seasonal Load and Capability

Nebraska utilities' goals are to support the achievement of resource adequacy by ensuring sufficient capacity to meet the needs of all end-use customers in their service territory. The SPP OATT requires LREs to maintain adequate capacity to meet resource adequacy requirements for both the summer and winter seasons

4.4.1 Summer Load and Capability

Utilizing Existing, Committed, and Planned resources applied to the current and projected cumulative SPP summer resource adequacy requirement, *Figure 6* illustrates that a statewide capacity deficit would occur starting in 2040. *Table 5* contains the corresponding load and capability data in tabular format. The statewide deficit based on the state's resource adequacy requirement in last year's report occurred in 2035 calculated using Existing, Committed, and Planned resources. The Planned resources in this year's report reflect formulated plans in varying stages of implementation, approved and initiated by utilities. While forecasted loads in the near term are slightly lower than last year's expectations, there is also a corresponding reduction in the utilities' expected net generating capability. Beginning in 2026, PBA accreditation is utilized for the state's conventional resources. The statewide Resource Adequacy Requirement is based on the Base PRM for 2025, and the ACAP PRM starting in 2026.

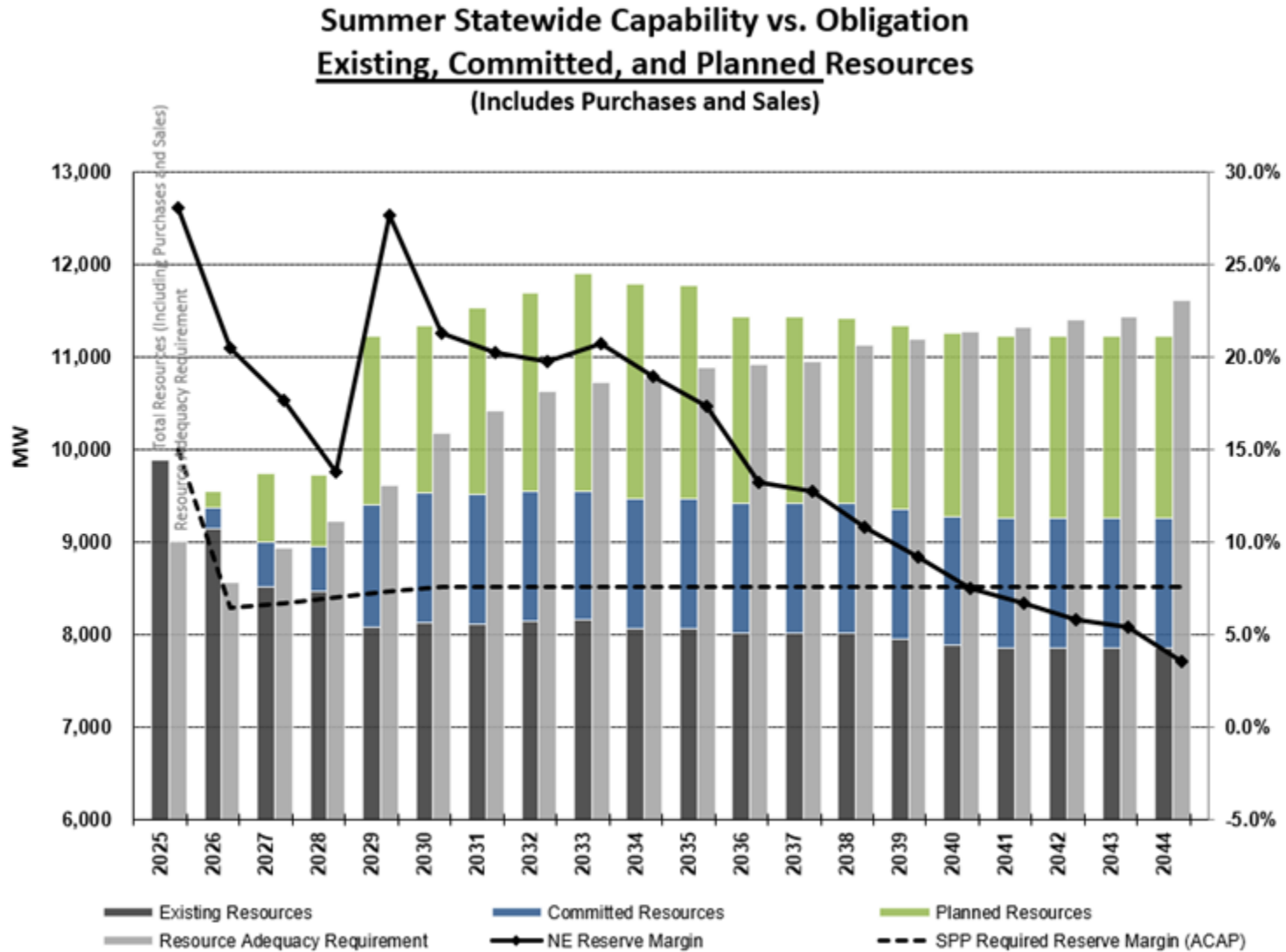


Figure 6 - Summer Statewide Capability vs. Obligation Existing, Committed, and Planned Resources (Includes Purchases and Sales)

Table 5 - Nebraska Statewide Existing, Committed, & Planned Load & Generating Capability in MW - Summer Conditions (June 1 to September 30)

NEBRASKA STATEWIDE Existing & Committed, & Planned Load & Generating Capability in MW Summer Conditions (June 1 to September 30)																				
Year	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
1 Annual System Demand	7,966	8,115	8,444	8,690	9,028	9,544	9,771	9,953	10,049	10,091	10,201	10,235	10,264	10,416	10,480	10,556	10,599	10,674	10,710	10,873
2 Firm Power Purchases - Total	1,173	1,174	1,176	1,178	1,180	1,182	1,183	1,185	1,187	1,189	1,191	1,193	1,195	1,196	1,198	1,200	1,202	1,204	1,206	1,207
3 Firm Power Sales - Total	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70
4 Annual Net Peak Demand (1-2+3)	6,863	7,011	7,338	7,582	7,918	8,432	8,657	8,838	8,932	8,972	9,080	9,112	9,139	9,290	9,352	9,426	9,467	9,540	9,574	9,735
5 Net Generating Capability (owned)	8,258	7,663	7,837	7,833	9,279	9,365	9,547	9,784	10,003	9,996	9,990	9,964	9,958	9,944	9,868	9,798	9,767	9,764	9,763	9,762
6 Firm Capacity Purchases	1,597	1,581	1,595	1,551	1,589	1,581	1,572	1,507	1,489	1,381	1,369	1,059	1,053	1,055	1,052	1,041	1,037	1,035	1,031	1,026
7 Firm Capacity Sales	1,067	798	798	758	758	716	706	706	705	705	705	705	705	705	705	705	705	705	705	705
8 Adjusted Net Capability (5+6-7)	8,788	8,447	8,634	8,626	10,110	10,231	10,413	10,585	10,786	10,672	10,653	10,317	10,306	10,294	10,216	10,134	10,100	10,094	10,089	10,084
9 Net Reserve Capacity Obligation (4 x PRM)	1,030	452	494	532	579	641	658	672	679	682	690	693	695	706	711	716	720	725	728	740
10 Total Firm Capacity Obligation (4+9)	7,893	7,463	7,832	8,114	8,497	9,073	9,315	9,509	9,611	9,654	9,770	9,805	9,834	9,996	10,062	10,142	10,187	10,265	10,302	10,475
11 Surplus (+) or Deficit (-) (8-10)	896	984	802	512	1,613	1,158	1,098	1,076	1,175	1,017	883	513	472	298	153	-8	-87	-171	-212	-392
12 Nebraska Reserve Margin ((8-4)/4)	28.0%	20.5%	17.7%	13.8%	27.7%	21.3%	20.3%	19.8%	20.8%	18.9%	17.3%	13.2%	12.8%	10.8%	9.2%	7.5%	6.7%	5.8%	5.4%	3.6%
13 Nebraska Capacity Margin ((8-4)/8) Existing, Committed, Planned Resources (8+2-3)	21.9%	17.0%	15.0%	12.1%	21.7%	17.6%	16.9%	16.5%	17.2%	15.9%	14.8%	11.7%	11.3%	9.8%	8.5%	7.0%	6.3%	5.5%	5.1%	3.5%
Resource Adequacy Requirement (MW) (1+9)	8,996	8,567	8,938	9,222	9,607	10,184	10,428	10,625	10,728	10,773	10,891	10,927	10,959	11,122	11,191	11,272	11,319	11,399	11,437	11,612
SPP Minimum Reserve Margin (ACAP)	15%	6%	7%	7%	7%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%
First Year of Deficit - Minimum																2040	2040	2040	2040	2040

A significant number of Committed & Planned resources in this report are expected to be installed in the next few years by Nebraska utilities. As already stated, if this generation is constructed and commissioned as planned, the statewide deficit is projected to occur beginning in 2040. However, there are many inherent risks that can impact the actual generator commission date.

- Supply chain issues in the procurement of generation and delivery equipment are being experienced industry wide. Longer-than-expected lead times for critical equipment could delay commission dates.
- Environmental permits, especially at greenfield sites, along with location specific siting regulations can take considerable time to work through to approval and authorization.
- SPP's Generation Interconnection (GI) queue currently has more than 161,000 MW of generation, only a portion of which will get built but nonetheless has asked for an interconnection study. SPP is working on streamlining the GI process, but with the sheer number of generators requesting interconnection studies, this lengthy process can cause delays in commission dates.
- Utility load forecasts and large load requests have recently been at unprecedented levels. Along with this comes uncertainty of whether the new load additions will materialize, as well as the timing and magnitude of loads that do materialize. Sudden increases and decreases in projected loads create a risk to new generation timing.

Nebraska utilities work closely with their current and prospective customers to satisfy their load timing needs. Given the above risks, it may be necessary to have some flexibility in the expected in-service dates of prospective large loads. Additionally, if new generation project delays occur, shorter term capacity purchases could serve as a bridge until “iron in the ground” generation is commissioned.

Inversely, there are resources being actively pursued that are currently designated in the Studied category and shown in the figures below which may ultimately be financed and developed into Planned resources on a more aggressive schedule than what is currently assumed. This provides a potential offset to the impact of schedule delays of Planned resources.

Figure 7 shows the statewide projected load and capability position inclusive of 8,250 MW of accredited Existing (summer 2025), 1,395 MW accredited Committed (summer 2044), 945 MW accredited Planned (summer 2044), and 2,309 MW of accredited Studied (summer 2044) resources. Some existing wind renewables are currently shown with no accredited capability due to the small accreditation values allowable under SPP’s Criteria. *Table 6* provides the corresponding load and capability data. As intended, these exhibits show how the Resource Adequacy Requirement can be met with the addition of Studied resources through the twenty-year study period.

The Committed, Planned, and Studied resources are summarized in *Table 7*.

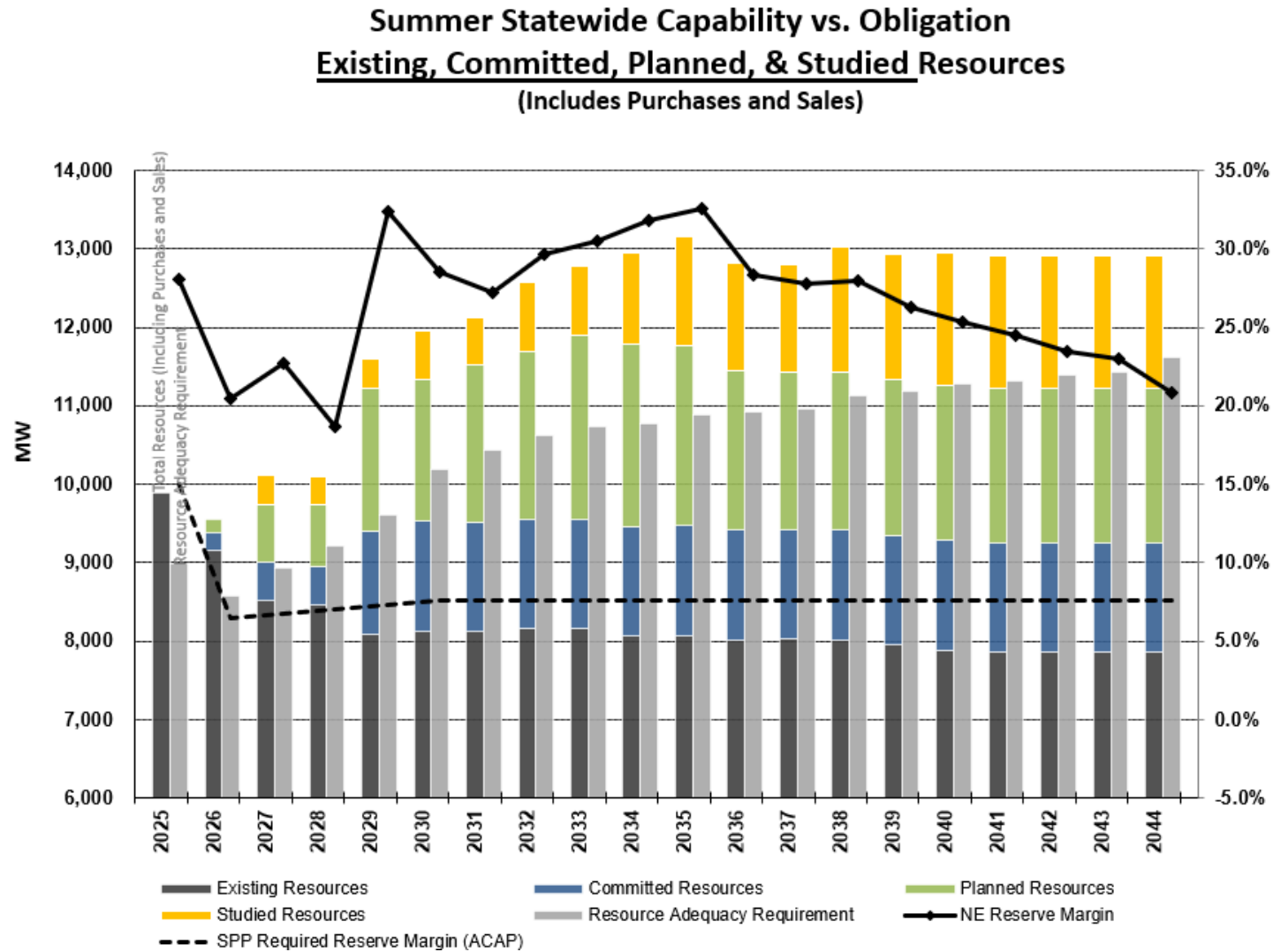


Figure 7 - Summer Statewide Capability vs. Obligation Existing, Committed, Planned & Studied Resources (Includes Purchases and Sales)

Table 6 - Nebraska Statewide Existing, Committed, Planned & Studied Load & Generating Capability in MW - Summer Conditions (June 1 to September 30)

NEBRASKA STATEWIDE Existing & Committed, Planned, & Studied Load & Generating Capability in MW Summer Conditions (June 1 to September 30)																				
Year	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
1 Annual System Demand	7,966	8,115	8,444	8,690	9,028	9,544	9,771	9,953	10,049	10,091	10,201	10,235	10,264	10,416	10,480	10,556	10,599	10,674	10,710	10,873
2 Firm Power Purchases - Total	1,173	1,174	1,176	1,178	1,180	1,182	1,183	1,185	1,187	1,189	1,191	1,193	1,195	1,196	1,198	1,200	1,202	1,204	1,206	1,207
3 Firm Power Sales - Total	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70
4 Annual Net Peak Demand (1-2+3)	6,863	7,011	7,338	7,582	7,918	8,432	8,657	8,838	8,932	8,972	9,080	9,112	9,139	9,290	9,352	9,426	9,467	9,540	9,574	9,735
5 Net Generating Capability (owned)	8,258	7,663	8,208	8,203	9,649	9,969	10,150	10,659	10,877	11,154	11,374	11,341	11,328	11,542	11,460	11,482	11,451	11,447	11,447	11,446
6 Firm Capacity Purchases	1,597	1,581	1,595	1,551	1,589	1,581	1,572	1,507	1,489	1,381	1,369	1,059	1,053	1,055	1,052	1,041	1,037	1,035	1,031	1,026
7 Firm Capacity Sales	1,067	798	798	758	758	716	706	706	705	705	705	705	705	705	705	705	705	705	705	705
8 Adjusted Net Capability (5+6-7)	8,788	8,447	9,004	8,997	10,480	10,835	11,017	11,460	11,660	11,830	12,037	11,695	11,676	11,892	11,808	11,818	11,783	11,778	11,773	11,767
9 Net Reserve Capacity Obligation (4 x PRM)	1,030	452	494	532	579	641	658	672	679	682	690	693	695	706	711	716	720	725	728	740
10 Total Firm Capacity Obligation (4+9)	7,893	7,463	7,832	8,114	8,497	9,073	9,315	9,509	9,611	9,654	9,770	9,805	9,834	9,996	10,062	10,142	10,187	10,265	10,302	10,475
11 Surplus (+) or Deficit (-) (8-10)	896	984	1,172	882	1,984	1,762	1,702	1,951	2,050	2,176	2,267	1,890	1,842	1,896	1,745	1,675	1,597	1,513	1,471	1,292
12 Nebraska Reserve Margin ((8-4)/4)	28.0%	20.5%	22.7%	18.7%	32.4%	28.5%	27.3%	29.7%	30.5%	31.8%	32.6%	28.3%	27.8%	28.0%	26.3%	25.4%	24.5%	23.5%	23.0%	20.9%
13 Nebraska Capacity Margin ((8-4)/8)	21.9%	17.0%	18.5%	15.7%	24.4%	22.2%	21.4%	22.9%	23.4%	24.2%	24.6%	22.1%	21.7%	21.9%	20.8%	20.2%	19.7%	19.0%	18.7%	17.3%
Existing, Committed, Planned, Studied Resources (8+2-3)	9,891	9,551	10,111	10,105	11,590	11,946	12,130	12,576	12,778	12,949	13,158	12,817	12,801	13,018	12,936	12,948	12,915	12,912	12,909	12,905
Resource Adequacy Requirement (MW) (1+9)	8,996	8,567	8,938	9,222	9,607	10,184	10,428	10,625	10,728	10,773	10,891	10,927	10,959	11,122	11,191	11,272	11,319	11,399	11,437	11,612
SPP Minimum Reserve Margin (ACAP)	15%	6%	7%	7%	7%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%
First Year of Deficit - Minimum																				

Table 7 - Committed, Planned and Studied Resources, MW

Resource Category	Unit Status	Fuel Type	Total Nameplate	Accredited Capacity 2025	Accredited Capacity 2030	Accredited Capacity 2035	Accredited Capacity 2040	Accredited Capacity 2044
Coal - Committed	C	SUB	0.0	0.0	0.0	0.0	0.0	0.0
Coal - Planned	P	SUB	0.0	0.0	0.0	0.0	0.0	0.0
Coal - Studied	S	SUB	0.0	0.0	0.0	0.0	0.0	0.0
NG - Committed	C	NG	0.0	0.0	249.5	249.5	249.5	249.5
NG - Planned	P	NG	0.0	0.0	0.0	0.0	0.0	0.0
NG - Studied	S	NG	0.0	0.0	0.0	0.0	0.0	0.0
DFO - Committed	C	DFO	12.0	0.0	11.3	11.3	11.3	11.3
DFO - Planned	P	DFO	0.0	0.0	0.0	0.0	0.0	0.0
DFO - Studied	S	DFO	0.0	0.0	0.0	0.0	0.0	0.0
NG/DFO - Committed	C	NG/DFO	1318.9	0.0	1056.5	1055.1	1063.4	1063.4
NG/DFO - Planned	P	NG/DFO	1517.0	0.0	617.5	1242.9	1242.9	1242.9
NG/DFO - Studied	S	NG/DFO	1060.0	0.0	233.7	610.2	849.5	849.5
Wind - Committed	C	WND	463.4	7.5	81.8	77.0	72.8	70.0
Wind - Planned	P	WND	0.0	0.0	0.0	0.0	0.0	0.0
Wind - Studied	S	WND	1475.0	0.0	22.4	148.1	245.3	245.3
Solar - Committed	C	SUN	0.0	0.0	0.0	0.0	0.0	0.0
Solar - Planned	P	SUN	420.0	0.0	249.9	233.5	202.4	202.4
Solar - Studied	S	SUN	1064.0	0.0	348.0	626.0	588.9	588.9
Hydro - Committed	C	WAT	0.0	0.0	0.0	0.0	0.0	0.0
Hydro - Planned	P	WAT	0.0	0.0	0.0	0.0	0.0	0.0
Hydro - Studied	S	WAT	0.0	0.0	0.0	0.0	0.0	0.0
Storage - Committed	C	ES	3.0	0.0	2.5	1.0	0.5	0.5
Storage - Planned	P	ES	170.0	0.0	143.8	133.9	125.2	125.2
Storage - Studied	S	ES	0.0	0.0	0.0	0.0	0.0	0.0
Nuclear - Committed	C	NUC	0.0	0.0	0.0	0.0	0.0	0.0
Nuclear - Planned	P	NUC	0.0	0.0	0.0	0.0	0.0	0.0
Nuclear - Studied	S	NUC	0.0	0.0	0.0	0.0	0.0	0.0
LFG - Committed	C	LFG	0.0	0.0	0.0	0.0	0.0	0.0
LFG - Planned	P	LFG	0.0	0.0	0.0	0.0	0.0	0.0
LFG - Studied	S	LFG	0.0	0.0	0.0	0.0	0.0	0.0
OBL - Committed	C	OBL	0.0	0.0	0.0	0.0	0.0	0.0
OBL - Planned	P	OBL	0.0	0.0	0.0	0.0	0.0	0.0
OBL - Studied	S	OBL	0.0	0.0	0.0	0.0	0.0	0.0

4.4.2 Winter Load and Capability

Figure 8 and *Table 8* provide a view of the statewide winter load and capability with the application of only Existing, Committed, and Planned resources. As a state, Nebraska meets the planning reserve margin throughout the twenty-year study period. The winter load and capability calculations include each utility's projected winter peak load values, reduced WAPA allocations, and lower winter accreditation of solar resources. Beginning in 2026, PBA and FA accreditation are utilized for the state's conventional resources. The statewide Resource Adequacy Requirement is based on the Base PRM for 2025, and the ACAP PRM starting in 2026.

Figure 9 and *Table 9* incorporate Studied resources into the state's generation fleet.

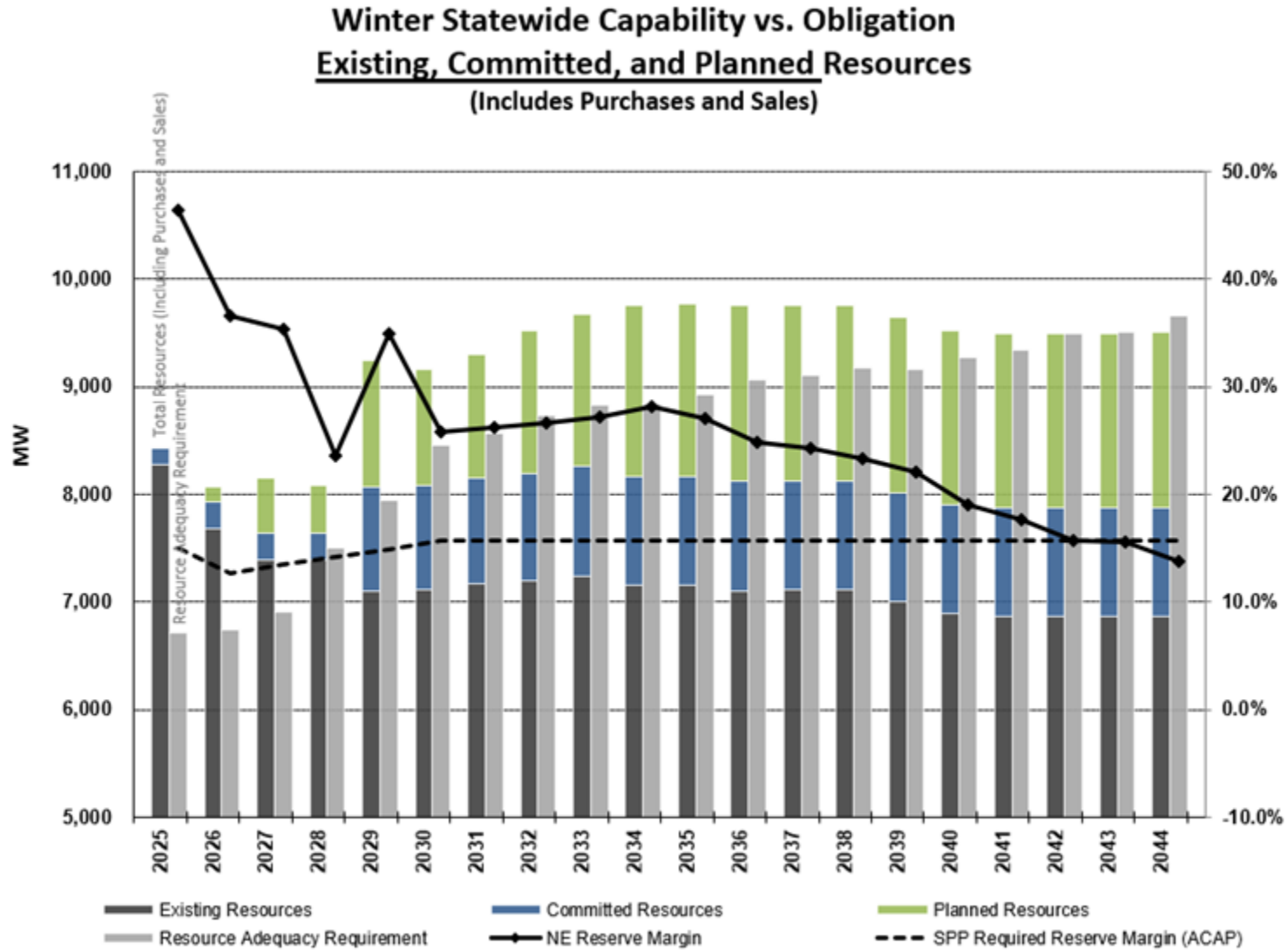


Figure 8 - Winter Statewide Capability vs. Obligation Existing, Committed, and Planned Resources (Includes Purchases and Sales)

Table 8 - Nebraska Statewide Existing, Committed & Planned Load & Generating Capability in Megawatts - Winter Conditions (Dec. 1 to Mar. 31)

NEBRASKA STATEWIDE Existing & Committed, & Planned Load & Generating Capability in MW Winter Conditions (December 1 to March 31)																				
Year	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
1 Annual System Demand	5,891	6,025	6,134	6,623	6,967	7,368	7,460	7,611	7,696	7,707	7,778	7,900	7,934	7,993	7,979	8,074	8,136	8,269	8,275	8,406
2 Firm Power Purchases - Total	483	484	487	488	492	494	495	496	497	499	500	501	502	504	505	506	507	509	510	511
3 Firm Power Sales - Total	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61
4 Annual Net Peak Demand (1-2+3)	5,469	5,601	5,709	6,196	6,537	6,935	7,026	7,176	7,260	7,270	7,339	7,460	7,493	7,551	7,535	7,629	7,690	7,822	7,826	7,956
5 Net Generating Capability (owned)	7,876	6,960	6,956	6,948	8,237	8,249	8,278	8,521	8,784	8,985	8,990	8,971	8,972	8,964	8,850	8,744	8,711	8,710	8,709	8,709
6 Firm Capacity Purchases	1,180	1,424	1,501	1,400	1,224	1,125	1,216	1,203	1,084	976	976	980	981	983	984	973	974	978	978	979
7 Firm Capacity Sales	1,050	730	728	687	644	643	627	634	637	639	640	640	641	637	637	637	637	637	637	637
8 Adjusted Net Capability (5+6-7)	8,006	7,654	7,729	7,661	8,818	8,731	8,867	9,090	9,232	9,322	9,326	9,310	9,312	9,310	9,197	9,080	9,048	9,051	9,051	9,052
9 Net Reserve Capacity Obligation (4 x PRM)	820	714	770	881	978	1,089	1,103	1,127	1,140	1,141	1,152	1,171	1,176	1,185	1,183	1,198	1,207	1,228	1,229	1,249
10 Total Firm Capacity Obligation (4+9)	6,290	6,315	6,478	7,077	7,515	8,024	8,129	8,303	8,400	8,411	8,492	8,631	8,669	8,736	8,718	8,827	8,897	9,049	9,055	9,205
11 Surplus (+) or Deficit (-) (8-10)	1,716	1,339	1,251	583	1,303	707	737	787	832	911	834	680	643	574	479	254	150	1	-4	-154
12 Nebraska Reserve Margin ((8-4)/4)	46.4%	36.6%	35.4%	23.6%	34.9%	25.9%	26.2%	26.7%	27.2%	28.2%	27.1%	24.8%	24.3%	23.3%	22.1%	19.0%	17.7%	15.7%	15.7%	13.8%
13 Nebraska Capacity Margin ((8-4)/8)	31.7%	26.8%	26.1%	19.1%	25.9%	20.6%	20.8%	21.1%	21.4%	22.0%	21.3%	19.9%	19.5%	18.9%	18.1%	16.0%	15.0%	13.6%	13.5%	12.1%
Existing, Committed, Planned Resources (8+2-3)	8,428	8,077	8,154	8,087	9,248	9,164	9,301	9,525	9,668	9,759	9,765	9,750	9,753	9,752	9,641	9,525	9,494	9,498	9,500	9,502
Resource Adequacy Requirement (MW) (1+9)	6,712	6,738	6,904	7,504	7,945	8,457	8,563	8,738	8,836	8,848	8,930	9,071	9,110	9,179	9,162	9,272	9,344	9,497	9,504	9,655
SPP Minimum Reserve Margin (ACAP)	15%	13%	13%	14%	15%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%
First Year of Deficit - Minimum																			2043	2043

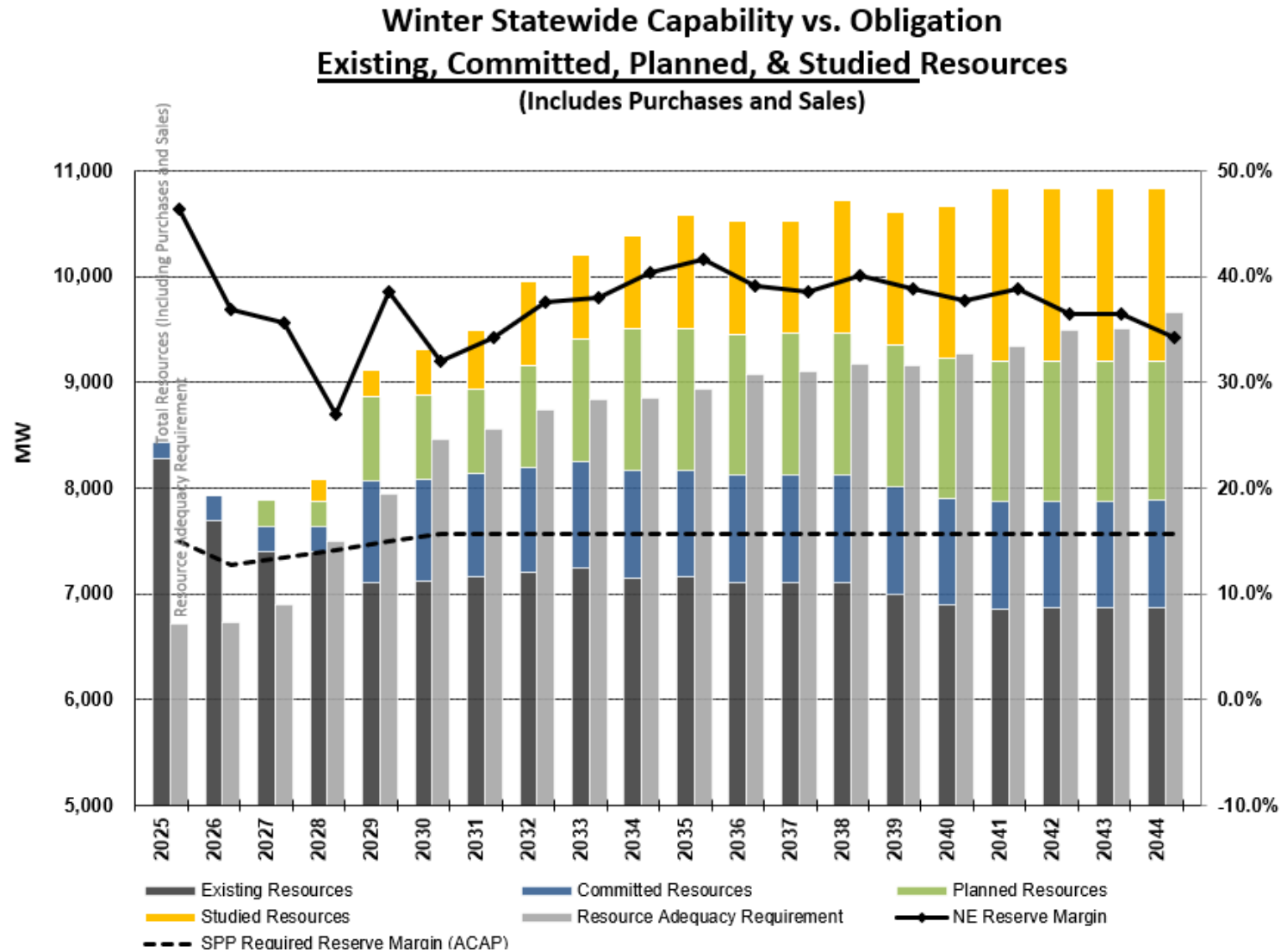


Figure 9 - Winter Statewide Capability vs. Obligation Existing, Committed, Planned & Studied Resources (Includes Purchases and Sales)

Table 9 - Nebraska Statewide Existing, Committed, Planned, & Studied Load & Generating Capability in Megawatts - Winter Conditions (Dec. 1 to Mar. 31)

NEBRASKA STATEWIDE Existing & Committed, Planned, & Studied Load & Generating Capability in MW Winter Conditions (December 1 to March 31)																				
Year	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
1 Annual System Demand	5,891	6,025	6,134	6,623	6,967	7,368	7,460	7,611	7,696	7,707	7,778	7,900	7,934	7,993	7,979	8,074	8,136	8,269	8,275	8,406
2 Firm Power Purchases - Total	483	484	487	488	492	494	495	496	497	499	500	501	502	504	505	506	507	509	510	511
3 Firm Power Sales - Total	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61
4 Annual Net Peak Demand (1-2+3)	5,469	5,601	5,709	6,196	6,537	6,935	7,026	7,176	7,260	7,270	7,339	7,460	7,493	7,551	7,535	7,629	7,690	7,822	7,826	7,956
5 Net Generating Capability (owned)	7,876	6,977	6,974	7,157	8,482	8,676	8,846	9,304	9,572	9,863	10,062	10,041	10,042	10,231	10,116	10,173	10,339	10,338	10,338	10,337
6 Firm Capacity Purchases	1,180	1,424	1,501	1,400	1,224	1,125	1,216	1,203	1,084	976	976	980	981	983	984	973	974	978	978	979
7 Firm Capacity Sales	1,050	730	728	687	644	643	627	634	637	639	640	640	641	637	637	637	637	637	637	637
8 Adjusted Net Capability (5+6-7)	8,006	7,671	7,747	7,870	9,063	9,158	9,434	9,873	10,020	10,200	10,398	10,381	10,382	10,577	10,463	10,508	10,676	10,679	10,679	10,680
9 Net Reserve Capacity Obligation (4 x PRM)	820	714	770	881	978	1,089	1,103	1,127	1,140	1,141	1,152	1,171	1,176	1,185	1,183	1,198	1,207	1,228	1,229	1,249
10 Total Firm Capacity Obligation (4+9)	6,290	6,315	6,478	7,077	7,515	8,024	8,129	8,303	8,400	8,411	8,492	8,631	8,669	8,736	8,718	8,827	8,897	9,049	9,055	9,205
11 Surplus (+) or Deficit (-) (8-10)	1,716	1,356	1,268	793	1,548	1,134	1,305	1,570	1,620	1,789	1,907	1,750	1,713	1,840	1,745	1,682	1,779	1,630	1,624	1,475
12 Nebraska Reserve Margin ((8-4)/4)	46.4%	37.0%	35.7%	27.0%	38.6%	32.0%	34.3%	37.6%	38.0%	40.3%	41.7%	39.2%	38.6%	40.1%	38.9%	37.7%	38.8%	36.5%	36.5%	34.2%
13 Nebraska Capacity Margin ((8-4)/8)	31.7%	27.0%	26.3%	21.3%	27.9%	24.3%	25.5%	27.3%	27.5%	28.7%	29.4%	28.1%	27.8%	28.6%	28.0%	27.4%	28.0%	26.8%	26.7%	25.5%
Existing, Committed, Planned, Studied Resources (8+2-3)	8,428	8,094	8,172	8,297	9,493	9,591	9,868	10,308	10,456	10,638	10,837	10,821	10,823	11,019	10,907	10,953	11,122	11,127	11,128	11,130
Resource Adequacy Requirement (MW) (1+9)	6,712	6,738	6,904	7,504	7,945	8,457	8,563	8,738	8,836	8,848	8,930	9,071	9,110	9,179	9,162	9,272	9,344	9,497	9,504	9,655
SPP Minimum Reserve Margin (ACAP)	15%	13%	13%	14%	15%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%
First Year of Deficit - Minimum																				

4.4.3 Resource Expected Service Life

The Nebraska utilities are cognizant of the age of their existing generating fleets and strive to maximize resource viability and value while making long term planning decisions on a portfolio-wide basis. The diverse mix of nuclear, fossil fuel fired, and renewable resources presents an array of regulatory, economic, reliability, and contractual based factors that should be considered when performing resource life evaluations. These considerations are discussed below in relation to the implications of age-related retirements.

4.4.3.1 Nuclear Resources

The Nuclear Regulatory Commission (NRC) determined in August 2014 that a new rule making was not required and confirmed that existing license renewals, where granted, provided a robust framework for second license renewals beyond the initial twenty-year renewal term. In addition, no changes are needed to environmental regulations to allow for future license renewal activities.

Cooper Nuclear Station's operating license is set to expire January 18, 2034. NPPD's 2023 IRP indicated CNS reduces future CO₂ restriction risk and provides resiliency and generation diversity to NPPD's overall generation mix. NPPD's Board of Directors has approved proceeding with a second relicense renewal process. Therefore, it is assumed CNS will continue to operate through the end of the study period.

4.4.3.2 Hydroelectric Resources

NPPD's listed North Platte and Columbus hydro facilities operate under a Federal Energy Regulatory Commission license. The North Platte facility is presently operating under a 40-year license, with the license requiring renewal in 2038. The Columbus Hydro facility received a new 30-year operating license, with the license requiring renewal in 2047. Given the focus on carbon free generation resources, NPPD and Loup are assuming these facilities will continue to be maintained and licensed and will remain an essential part of NPPD's generation mix for an extended period.

4.4.3.3 Fossil Fuel Resources

In August of 2022 the OPPD Board of Directors approved the staff recommended extension of its North Omaha Station in its current state until at least 2026. OPPD had previously planned on converting units 4 and 5 from coal to natural gas and retiring units 1, 2, and 3 at the end of 2023. The continued operation of these facilities will mitigate risks associated with the delayed SPP GI study process for OPPD's new Turtle Creek and Standing Bear Lake stations. OPPD seeks to have certainty on its ability to interconnect and generate from these two new dual fuel facilities prior to converting North Omaha Station, which demonstrates OPPD's commitment to ensuring reliability and resiliency for its system.

4.4.3.4 Renewable Resource Power Purchase Agreements

The wind plants included in this report are shown at the life listed in the various Power Purchase Agreements (PPA), typically 20 or 25 years. Most agreements have an option for life extension. Utilities will decide whether to exercise those options when the PPAs near their end. In order for those utilities to maintain their renewable and/or carbon reduction goals, these utilities will have to either exercise those options or develop other renewable resources.

4.4.4 Age-Based Retirement

Nebraska's existing generating resources are listed by unit in *Appendix 1*. Nebraska has 10,609 MW nameplate of existing resources. 2,610 MW or 24.6% of that total are greater than 50 years old today. Another 2,573 MW or 24.25% are 41 to 50 years old today. Most of these units have no planned retirement date. By 2044 approximately 5,236 MW will reach 60 years of age. Utilities may face increased environmental restrictions that could require the retirement of older fossil units. This would potentially advance the statewide deficit date several years earlier.

For illustration purposes only, if a 60-year age-based retirement for fossil units is arbitrarily chosen, the state would hover near the planning reserve margin for the next few years but fall permanently below the margin in 2028, while a 70-year age-based retirement date would show a state deficit even farther into the future. *Figure 10* shows the 60-year in-service life chart. Since a statewide deficit occurs in 2028 for a 60-year retirement date, utilities would have little time to plan their next steps but could acquire short term capacity, evaluate methods to re-rate their units, or develop additional resources to alleviate the deficit. This 60-year unit retirement example is considered conservative since fossil units are capable of operating for more than 70 years. Each utility will make its own determination on the life of their generating plants while considering many factors, including economics. It is important to note that a unit's operation is a far more reliable predictor of its useful life than age alone. With an increase in a unit's equity over time, utilities are incentivized to operate the unit in a manner that allows efficient generation in the present as well as extended life into the future. At this time, there are no plans to retire these older units unless stated in the Report.

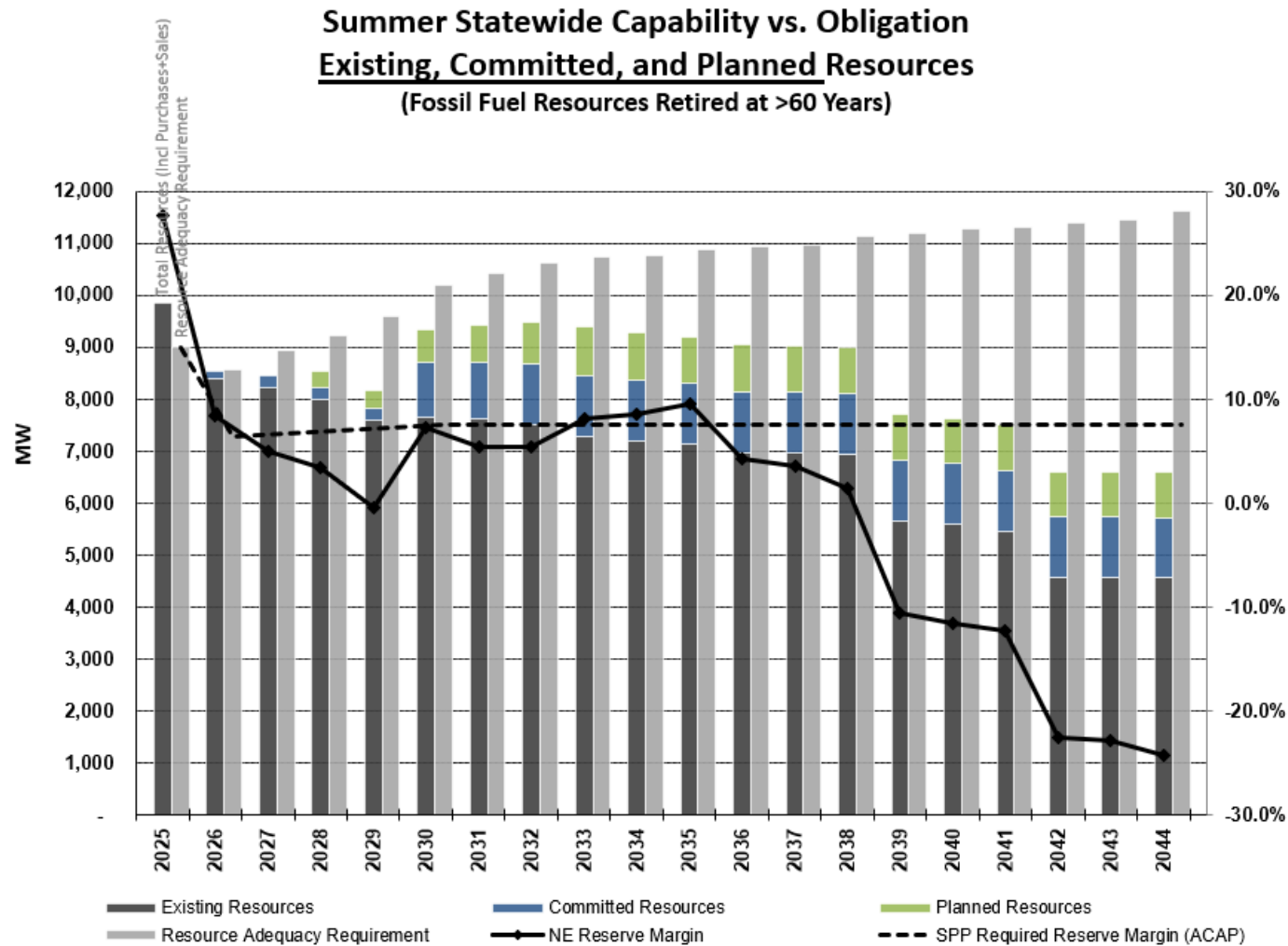


Figure 10 - Summer Statewide Capability vs. Obligation Existing, Committed, and Planned Resources (Fossil Fuel Resources Retired at >60 Years)

4.5 Utility Resource Plans

This section of the report focuses on the individual utility resource plans. These plans include Existing and Committed resources as well as Planned and Studied resources. The resources discussed include both supply side and demand side resources. Supply side resources include firm dispatchable, renewable, and energy storage solutions. Demand side resources include distributed generation resources and demand response applications. These plans are reflected in the corresponding resource categories throughout this report.

4.5.1 NPPD

For more than five decades, NPPD has provided low cost, reliable electricity to Nebraskans through a diverse generation mix. Recently, there are many companies, particularly in the agriculture industry, that have shown interest in locating NPPD's service territory. NPPD plans to support this coming expansion by pursuing cost-effective, responsive solutions that will add new generation capacity to complement its existing generation mix.

NPPD's New "Planned" and "Studied" Generation Resources

- Planned - 50 MWs of battery storage capacity purchased from an existing privately-owned wind facility.
- Planned - 216 MWs of dual fuel reciprocating internal combustion engines (RICE) that would use natural gas as a primary fuel source and have the option to utilize diesel.
- Planned – 1300 MWs of dual fuel combustion turbines (CT) that would use natural gas as a primary fuel source and have the option to utilize diesel.
- Studied – 524 MWs of solar generation via Power Purchase Agreement (PPA).
- Studied – 115 MWs of wind generation via PPA.

Based on indicative cost and delivery estimates provided to NPPD by equipment vendors, the first round of "Planned" CT (520 MWs) & RICE (216 MWs) resources are targeted to be in service by the Summer of 2029. The second round of "Planned" CTs (260 MW each) are tentatively targeted for 2031, 2032 & 2033 start-up. In the event any of these resources are delayed in their completion, NPPD would pursue available capacity purchases to cover any resource adequacy requirements. NPPD also recently implemented a new load queue process to ensure adequate capacity resources and reserves are available prior to any new prospective loads beginning to take service.

NPPD owns or has agreements with these non-carbon resources:

- 549 MW of hydroelectric generation, including the Western Area Power Administration agreement.
- 770 MW of nuclear power at Cooper Nuclear Station.
- 337 MW of nameplate wind (NPPD's share).

Using a 2023-2024 rolling average, non-carbon generation resources were approximately 58% of NPPD's Native Load Energy Sales from the resources discussed above. Most of the non-carbon generation is due to nuclear.

NPPD's Demand Side Management program consists of Demand Response and Energy Efficiency. NPPD presently has a successful demand response program, called the Demand Waiver Program, to reduce summer billable peaks. Most savings in this program are due to irrigation load control by various wholesale customers, which accounted for approximately 697 MW of demand reduction from NPPD's billable peak during the summer of 2024.

NPPD implemented an interruptible rate, Special Power Product #8, allowing qualified large end-use customers (served by wholesale or retail) to curtail demand during NPPD specified peak periods. NPPD is anticipating more customers to take advantage of this rate in the future. Another 45 MW of demand reduction was realized from this and other sources during the 2024 summer peak.

NPPD has a series of energy efficiency and demand-side management initiatives under the EnergyWiseSM name. Annually, these programs have sought to achieve first-year savings of more than 12,000 MWh and demand reductions greater than 2 MW. Accumulated first year energy savings through 2024 are 436 GWh and demand reductions are 69 MW.

4.5.2 OPPD

OPPD is experiencing extraordinary economic development across its service territory, driven by growth across its customer classes and particularly large-scale load requests at a pace and scale not experienced in OPPD's history. Since 2019 OPPD has experienced a compound annual growth rate of 4.08% for winter peak load and 3.00% for summer peak load. This marks a departure from the nearly flat growth experienced in the decade prior. To meet this growing demand, OPPD is advancing a diverse mix of new resources to ensure reliable, affordable electric service for both new and existing customers. These efforts underscore the utility's commitment to supporting Nebraska's continued economic growth.

Since May 2024, OPPD has successfully brought online 674 MW (nameplate) of new generation—its most significant expansion in recent decades. This includes 442 MW of simple-cycle combustion turbines at Turtle Creek Station, 151 MW of reciprocating

internal combustion engines at Standing Bear Lake Station (expected summer 2025), and 81 MW of solar from the Platteview Solar Facility near Yutan, Nebraska. These additions represent the largest increase in thermal generating capacity across SPP in the past eight years and demonstrate OPPD's ability to deliver new resources at pace with the needs of the community.

Also in the summer of 2024, OPPD entered into a collaborative agreement with Google and NextEra Energy to acquire the capacity of the 600 MW High Banks wind farm. In September of the same year, OPPD entered into a Power Purchase Agreement to receive capacity and energy from the 300 MW Milligan wind farm. In 2027 the Pierce County Energy Center will reach commercial operation, providing OPPD with energy from 210 MW of solar and 85MW of battery storage and capacity from a total of 420 MW of solar and 170 MW of battery energy storage.

At the close of 2024, 36.6% of OPPD's portfolio generation was produced by wind energy, energy from landfill gas, hydro energy, and solar energy. OPPD's renewable portfolio at 2024 year-end consisted of 1,272 MW of wind by nameplate, 86 MW of nameplate solar, 6.3 MW of landfill gas generation as well as purchased hydro power. These resources continue to provide a cost-effective energy supply, reduce OPPD's dependence on fuel prices, and enhance overall portfolio diversity.

OPPD's 2023 Near-Term Generation Plan also approved 950 MW of additional dual-fuel combustion turbine generation, with 900 MW approved by the NPRB in March 2024 and targeted for operation in 2029. OPPD is progressing with the addition of these facilities, with equipment and EPC contracts executed and construction underway to add the incremental capacity to both its new Turtle Creek Station and its Cass County Station.

OPPD's Planned and Studied Generation Resources:

- Planned - Pierce County Energy Center, a hybrid facility combining 420 MW of solar and 170 MW of battery storage.
- Studied - 900 MW of future dual fueled natural gas capacity (incremental to current portfolio)
- Studied - 500 MW of future solar (incremental to current portfolio)
- Studied - 1350 MW of future wind (replacement for expiring renewable contracts)

As defined in this report, these Studied resources represent an acknowledged need for future resources to serve anticipated load growth and/or replace retiring assets and expiring capacity and energy contracts, as opposed to approved or initiated plans for specific resources or technologies.

OPPD's demand-side management programs currently provide more than 123 MW of peak load reduction capability through residential thermostat control, commercial curtailment options, and targeted energy efficiency initiatives. OPPD is actively evaluating and refining its programs to ensure they continue to deliver measurable and dependable system benefits, aligning with evolving requirements of SPP policy.

While OPPD is already taking proactive actions to rapidly expand its system to support load requests, OPPD continues to receive strong interest in economic development inquiries in OPPD's service territory, totaling several thousand megawatts. If these inquiries fully materialized, this would represent further doubling or tripling in system size in just a few years compared to the resource investments that OPPD has grown into over the past 78 years. However, these inquiries often represent early-stage projects that may not materialize at their full stated capacity due to siting, permitting, financing, or timing constraints.

In an effort provide greater certainty for both OPPD and potential customers, the utility is developing an enhanced process to support large load requests. This includes readiness requirements and financial commitments between customers and the utility. This process will provide a clearer signal on the amount of resources which OPPD will need to plan for, while reducing the risk of stranded assets for other customers. This approach is being increasingly adopted by utilities across the country amid rapid and uncertain growth and will allow OPPD to act decisively in support of growing load.

An additional constraint to be noted is the timeline associated with procuring major transmission and distribution system electrical components. Often times, the lead time on major components like large transformers and switchgear often exceeds the desired operational timelines of projects. Due to global supply chain constraints, it can now take several years (4+) to procure, manufacture, and take delivery of these high-cost specialty components. For customers willing to make financial commitments, OPPD is actively working to secure these long-lead items and facilitate load growth as quickly as possible.

As OPPD accelerates the buildout of new resources to meet growing customer demand, consistent and predictable planning and zoning processes will be essential across all types of projects including thermal generation, renewables, energy storage, or the supporting transmission and distribution infrastructure. Delays in permitting or uncertainty in local land use decisions can impact, and unfortunately already have significantly impacted, project timelines and costs to the detriment of the economic health of Nebraska.

Looking ahead, OPPD's next major planning milestone will be its 2026 Integrated Resource Plan, which will assess long-term needs in a transparent and accessible manner. This plan will further evaluate current and emerging technologies and strategies to support growth with a reliable, cost-effective, environmentally sensitive power supply. This process will be transparent and accessible for public participation.

4.5.3 MEAN

In serving the needs of its total membership, MEAN's system-wide resource portfolio includes 56.4% non-carbon resources based on nameplate capacity, consisting of 30% contracted hydro, small hydro, and WAPA hydro allocations, 22% renewables (wind, WAPA Displacement, and landfill gas). Portfolio diversification remains a high priority for MEAN to balance the need for reliability with the desire for decarbonization.

As a member driven utility, MEAN procures renewable energy assets at the direction of its owners. Currently, MEAN maintains a Green Energy Program, which allows member communities to subscribe for purchase of a requested amount of renewable energy on an annual basis. This allows each community to tailor its resource portfolio to meet its specific demands and obligations as individual municipal utilities have renewable goals that can range from 0% to 100% of energy requirements. MEAN surveys its owners to determine individual goals for renewable energy requirements. When there are significant changes in demand for renewable energy, and in accordance with 2050 vision the MEAN Board considers the approval of new renewable purchases. MEAN's Green Energy Program is currently fully subscribed, and the Board has approved power purchase agreements for additional carbon free energy.

In 2019, MEAN surveyed member communities regarding interest in installation of community-owned solar assets. On behalf of these communities, MEAN released a Request for Proposals for community-owned solar facilities. The interested communities were required to supply a controlled site adequate for the project size and would contract directly with the solar developer. MEAN assisted members in sizing and specifications of the installation. The aggregated Request for Proposals was pursued as the increased volume of solar installation required of the combined projects provided advantageous pricing compared to a standalone project in one community. In 2021 MEAN assisted several member communities in preparing and releasing a Request for Proposal (RFP) for community based solar facilities. After evaluation of bids and consultation with members, MEAN awarded the bid to eight of its Nebraska member communities for a total of 8.2 MW-AC of community-sited and contracted solar facilities through power purchase agreements. As interest grew, the project expanded to 19.8 MW in 15 communities throughout Nebraska, Iowa, and Colorado. Installation of these projects commenced in the summer of 2024, and the Nebraska community solar projects are commercially operable as of June 2025.

MEAN previously established a committee to focus on the integration of renewable resources within member communities. The increasing presence of renewable distributed generation offers unique opportunities that can benefit both MEAN and local residents. In 2017 and again in 2019, MEAN revised its Renewable Distributed Generation policy to increase the size of allowable community owned and locally sited renewable energy resources. Should Participant communities desire a larger allowance for community-owned renewables, the Board can take up the issue for an increase in this limitation. MEAN communities have also expressed interest in the installation of alternate distributed generation technologies, such as fuel cells, cogeneration facilities, and energy storage. Under evolving policy, projects may be incorporated into MEAN's load and resource balance into the future and would ultimately decrease the need for other resources.

MEAN has identified the investigation of new MEAN-contracted generation opportunities located in Participant communities as a goal in MEAN's Strategic Plan and also as a portfolio preference in the IRP. MEAN initiated discussion on this concept with the Membership as it relates to potential solar facilities, and policy updates were approved in 2022 by the Power Supply Committee and the MEAN Board of Directors to accommodate MEAN Distributed Generation resources located in MEAN member communities. As communities are installing generation under the Renewable Distribution Generation Policy, there is potential to concurrently install Distributed Generation directly owned or contracted to MEAN, provided participating communities have sufficient space available for lease to MEAN. This concept has numerous benefits: renewable resources generating directly on member distribution systems, lower interconnection costs, incremental sizing for resource portfolio changes, potential savings on property leases, public appeal, and grid modernization with distributed generation and micro-grid systems. Working in parallel to the RFP process, MEAN investigated the potential for MEAN member communities to host MEAN contracted solar facilities where additional land was available to lease. Three Nebraska members expressed interest in allowing MEAN to install 10.5 MW-AC of MEAN contracted solar within their community. Project installation for these projects were installed along with the community solar projects, and the Nebraska MEAN solar contracted sites have been commercially operable since June 2025. In addition to these communities, MEAN will continue to explore opportunities with several additional members to potentially host MEAN contracted solar for further project expansion

MEAN has utilized a variety of demand side management tools to help reduce load and energy requirements. MEAN presently administers an ENERGYsmart commercial LED lighting program, which includes cash incentives paid directly to commercial customers to help cover the cost of lighting upgrades and replacements. This program is available to commercial businesses of MEAN long-term power participants. In 2019, MEAN initiated additional energy efficiency incentives offered to residential end-use customers of its Participants. These new programs include rebates for programmable thermostats, residential insulation, and HVAC tune-ups. In May of 2021, the Board again approved an expansion of this program to include a residential heat pump program. MEAN staff continues to evaluate the benefits of

additional energy efficiency and demand side management options to decrease demand-related costs for MEAN and its participants. Discussions are planned with the Board and Committees regarding an incentive program for residential vehicle chargers.

4.5.4 LES

Over the last decade-plus, LES' renewable footprint has grown significantly, with the latest addition being a 2025 Power Purchase Agreement with the Central Nebraska Public Power and Irrigation District for their 22-MW Jeffrey Hydro project. On a nameplate basis, approximately 35% of LES' current supply-side resources are renewable (primarily wind and hydro), with 35% fueled by natural gas and 30% by coal. From 2010 – 2024 LES reduced its carbon dioxide emissions by 50%.

LES has numerous Committed resources expected to come online in the next few years, including the following:

- 3-MW battery storage Power Purchase Agreement, expected to achieve commercial operation in the fall of 2025. This zinc-based battery will support LES' existing Community Microgrid, helping to ensure reliable and resilient service to critical loads in the downtown Lincoln area.
- 198-MW Bluestem Wind Capacity Agreement, effective November 2025. This capacity-only contact was sourced via a partnership with Google, who entered into a traditional Power Purchase Agreement for the wind resource. Google is selling the related capacity to LES to help meet the SPP resource adequacy requirements associated with their local datacenter load.
- 225-MW Great Western Wind Capacity Agreement, effective November 2025. This is another capacity-only contract with Google.
- Two 52-MW dual fuel, aeroderivative combustion turbines to be installed at LES' existing Terry Bundy Generating Station, targeting commercial operation in 2029.

On the demand side, LES' SEP offers customers and contractors incentives for energy-efficient installations and upgrades at their home or business. First adopted in 2009, the SEP now offsets the energy use of about 15,000 average Lincoln homes.

Under the Peak Rewards program, LES leverages residential customers' own smart thermostats to pre-cool spaces prior to the initiation of an LES-controlled demand response event, allowing for a reduction in summer peak demand while still maintaining residential comfort. LES has also introduced various pilot programs to investigate similar demand response initiatives. These included a one-year plug-in electric vehicle program in 2021, incentivizing vehicle owners to also avoid charging during peak load periods, and a water heater demand response program established in 2023 and planned to operate for 2024 – 2026.

LES has two programs that support customers wishing to pursue their own renewable generation. Under LES' net-metering rate rider, customers can install a 25-kW or smaller renewable generator to serve their homes or small businesses. LES also has a renewable

generation rate for customers interested in generating and selling all output to the utility rather than serving a home or small business. Systems greater than 25 kW up to 100 kW will qualify for this rate. Customers at each rate receive a one-time capacity payment based on the value of the avoided generating capacity on system peak. The energy payment amount for new installations is based on LES' existing retail rates and is scheduled to be reduced as predetermined, total service area renewable-installation thresholds are met over time.

In August 2014, LES launched the SunShares program, allowing customers to voluntarily support a local community solar project through their monthly bill. This program led to LES contracting for a local, approximately 5-MW_{DC}/4-MW_{AC} solar facility, which began commercial operation in June 2016. The facility represented the first utility-scale solar project in Nebraska.

The community solar project also supports LES' virtual net metering program. As part of this program, customers receive a credit on their monthly bill based on their level of enrollment and the actual output of the facility. Enrollment began in December 2016, with the first credits appearing on bills in January 2017. The enrollment fee was originally a one-time, upfront payment, but in 2019 LES also added the option for customers to pay the associated fee over 36 months via their normal LES bill. The program will run for nearly twenty years, coinciding with the life of the solar project contract.

4.5.5 Hastings Utilities

Hastings Utilities will work with customers who are interested in pursuing renewable energy to find mutual benefit for a successful project. Hastings Utilities worked with its customer, Central Community College, to implement a 1.7 MW wind turbine on the Hastings CCC campus.

Hastings Utilities has completed the construction of a 1.5 MW Community Solar Project to respond to customer requests for renewable energy. Customers can participate by purchasing solar panels or solar shares. The project was completed in September of 2019. Phase 2 of the community solar farm is an additional 4.6 MW and was completed in December of 2024. Hastings Utilities will continue monitoring the economics and interest of renewable energy.

4.5.6 City of Grand Island Utilities

The City of Grand Island aims to maintain a generation fleet that is diversified in resource type and age.

The Grand Island generation fleet includes:

- 40 MW of nameplate wind generation (35.8 MW Prairie Breeze III (2015), 4 MW NPPD wind farms (2005, 2009, 2011, 2012)).
- 10.9 MW of nameplate behind the meter solar generation (1 MW (2018) and 9.9 MW (2024)).
- 9 MW of WAPA Hydro.

- 149 MW Coal (100 MW PGS (1982), 34 MW NC 2 (2009), 15 MW WEC2 (2011))
- 83 MW of Natural Gas/Fuel Oil (13 MW GT-1 (1968), 35 MW GT-2 and 35 MW GT-3 (2003))

Grand Island's renewable portfolio began in 1970 with WAPA hydro power.

In 2015 Grand Island made changes to City Code to allow small scale demand side resources, with more changes later to allow for 25 kW to 100 kW facilities. Grand Island now has several small scale residential solar customers and two larger commercial/industrial solar installations operating.

In 2024 Grand Island added an interruptible rate to City Code for large scale customers. This rate allows the City to curtail a customer during peak loads or other SPP designated events.

In 2024 Grand Island also added a stand-by rate to City Code. This rate is for customers operating co-generation.

Currently, the Grand Island nameplate capacity is 21% renewables, 50% coal, and 29% natural gas/oil.

4.5.7 City of Fremont Utilities

Fremont currently operates two solar arrays, which offers residents two options for the project. Electric customers can either purchase their own solar panels or purchase solar shares from the Community Solar Farm. Seventy six percent (76%), which can vary month to month, of the panels are either owned or purchased shares by the rate payers of Fremont. Solar array #1 is 1.32 MW and solar array #2 is 0.99 MW. Both have been in operation since 2018. In 2017 Fremont signed a Purchase Power Agreement with NextEra for 40.89 MW of wind energy from the Cottonwood Wind Farm in Webster County, NE. Fremont will continue to evaluate the needs for renewable energy.

4.5.8 Non-Utility Resources

The Nebraska Department of Environment and Energy tracks renewable developments within the State on its website. Currently Sandhills Energy is in the process of solving a permit issue to build a 58.8 MW wind project consisting of 14 wind turbines in Cherry County.

Non-utility wind purchases are summarized as follows. This information is gathered from publicly available industry publications and newspapers and may not be complete. These projects also do not represent retail choice, as they are not directly attributed to serving retail customers within the state.

- The 318 MW (nameplate rated) Rattlesnake Creek wind facility began commercial operation in December 2018. Energy and capacity from this facility are purchased by Meta and Adobe Systems. Meta procures energy from Rattlesnake Creek for their data facility in Sarpy County.
- The WEC Energy Group (an electric generation and distribution and natural gas delivery holding company), based in Milwaukee, Wisconsin, signed a Purchase and Sale Agreement for 80% of the Upstream Wind Energy Center (202.5 MW nameplate) located just north of the City of Neligh. Invenergy, the developer, has retained a 20% interest in the project which went commercial in the first part of 2019.
- The J.M. Smucker Company and Vail Resorts have Power Purchase Agreements in place to purchase energy from the 230 MW (nameplate) Plum Creek Wind Project in Wayne County which went commercial in July 2020. Smucker's purchase is for 60 MW while Vail Resorts will purchase 310,000 MWh annually for 12 years.
- Hormel Foods has announced a Power Purchase Agreement for wind energy from a new wind plant near Milligan (Milligan 3), located in Saline County 60 miles southwest of Lincoln which now has a projected completion date of December 2024. This wind plant has a planned capacity of 73.4 MW (nameplate) of power.
- The 300 MW Thunderhead Wind Energy Center was built in Antelope and Wheeler counties and began producing energy in late 2022.
- NextEra's 250 MW Little Blue Wind Project located in Webster and Franklin Counties became commercial in December 2021. No information on off-takers is available.
- The 300 MW Haystack Wind Farm built by Oersted in Wayne County (5 MW wind turbines) went commercial in 2022. Hormel, Target, and PepsiCo are the off takers.

5.0 Resource Adequacy

A core responsibility of Nebraska’s utilities is to plan for sufficient resources to reliably and predictably serve current and future customer electric demand. Utilities must plan to have sufficient resources to supply power under a variety of stressed grid conditions, such as unexpected generator outages, extreme weather events, and periods of low renewable production.

Participating in a larger regional reserve sharing pool such as SPP helps the Nebraska utilities to mitigate system risks and support reliability. This pool connects many different types of generation resources across a large geographic area with the goal of enhancing system reliability and resiliency. However, there are many considerations beyond simply meeting SPP’s PRM requirements.

5.1 Reliability and Resilience

Maintaining system reliability and resilience is foundational for Nebraska utilities. This becomes increasingly important as the electric grid transitions to lower-carbon sources of energy, as customers increasingly rely on the electric grid for basic needs, and as weather becomes more volatile due to the impacts of climate change. These reliability and resilience considerations form the basis of several information requests from the NPRB, discussed below.

5.1.1 Fuel Diversity

One benefit of fuel diversity is that it allows utilities to absorb instability in one energy source by increasing the use of a different energy source. Fuel diversity also provides varying levels of protection from price volatility, fuel unavailability, and shifting regulatory practices. These characteristics all help maintain the stability and reliability of the overall supply of electricity.

Figure 11 and Figure 12 illustrate the statewide resource mix in terms of fuel diversity (coal, diesel, hydro, landfill gas, natural gas, nuclear, solar, wind and battery storage), showing the nameplate and accredited capacity and percentage of the state’s generation resources in each category. *Figure 13* shows the 2024 annual energy production for these resources.

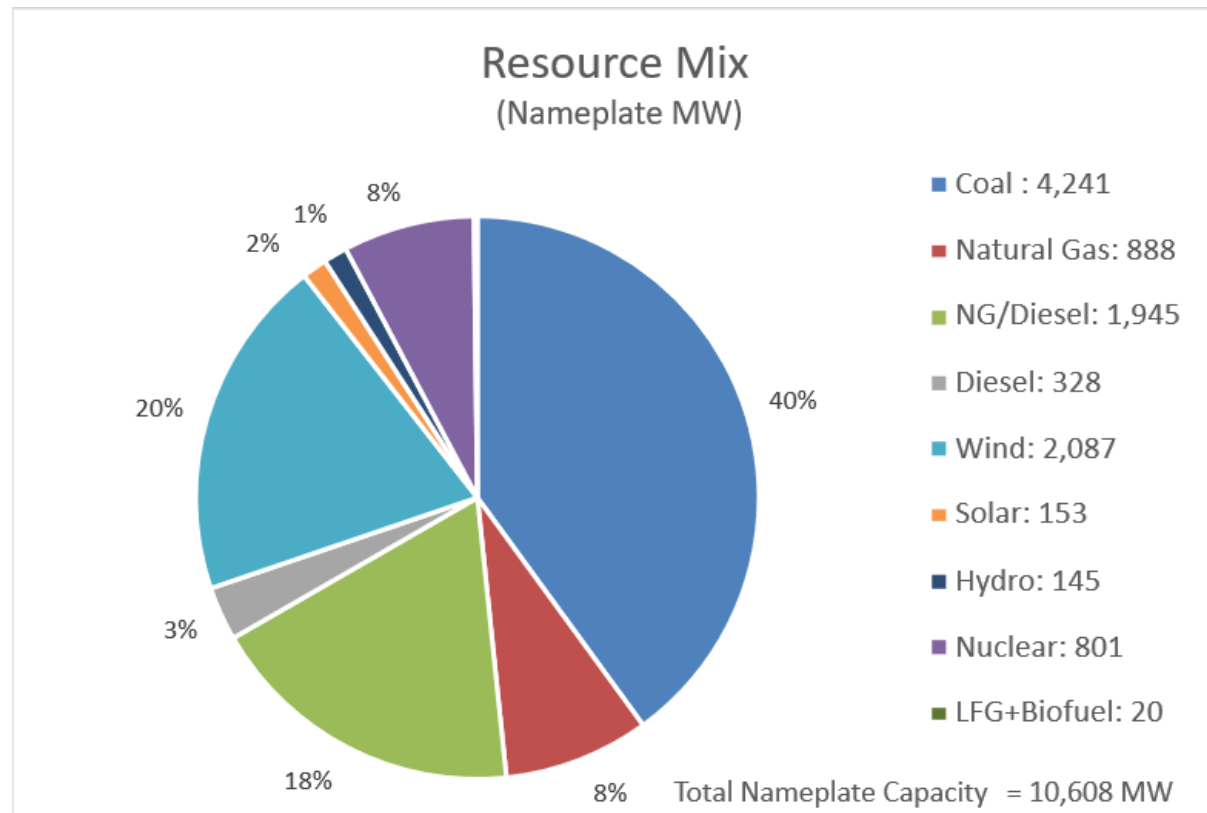


Figure 11 - Resource Mix (Nameplate MW)

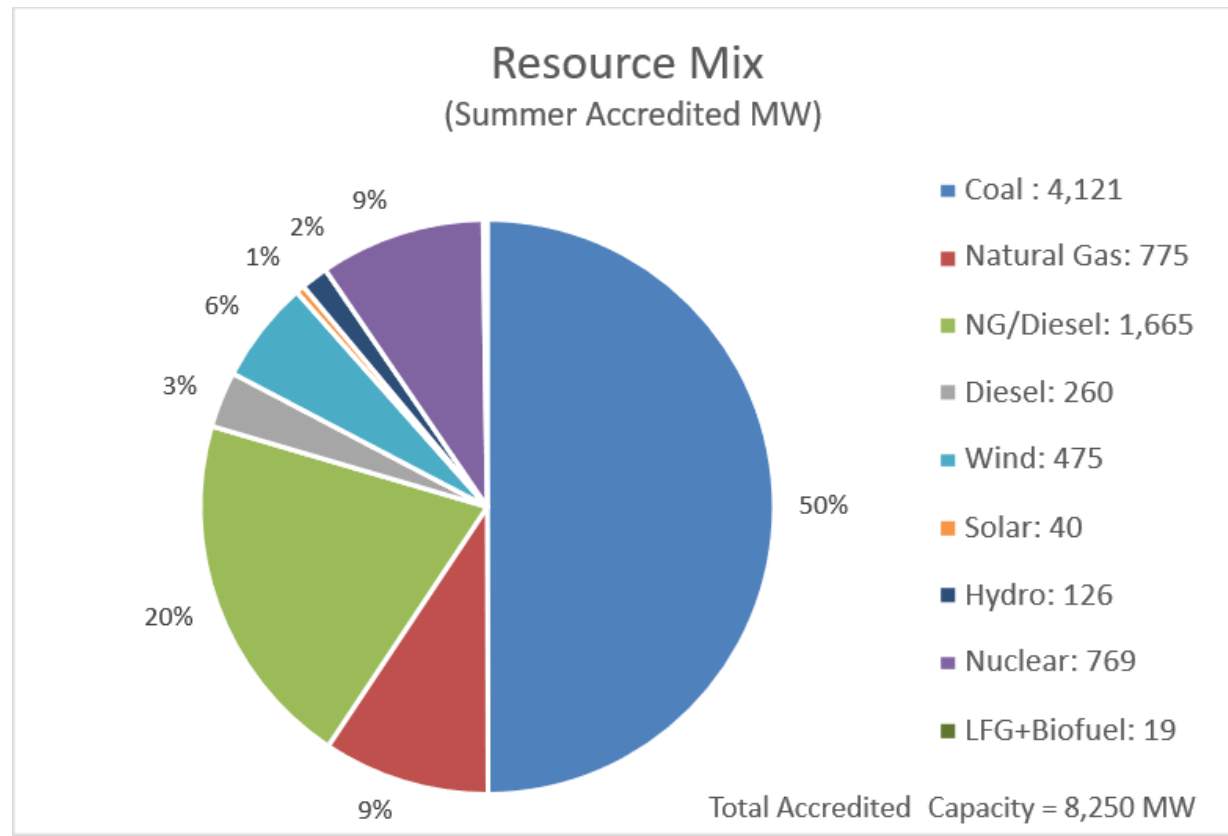


Figure 12 - Resource Mix (Summer Accredited MW)

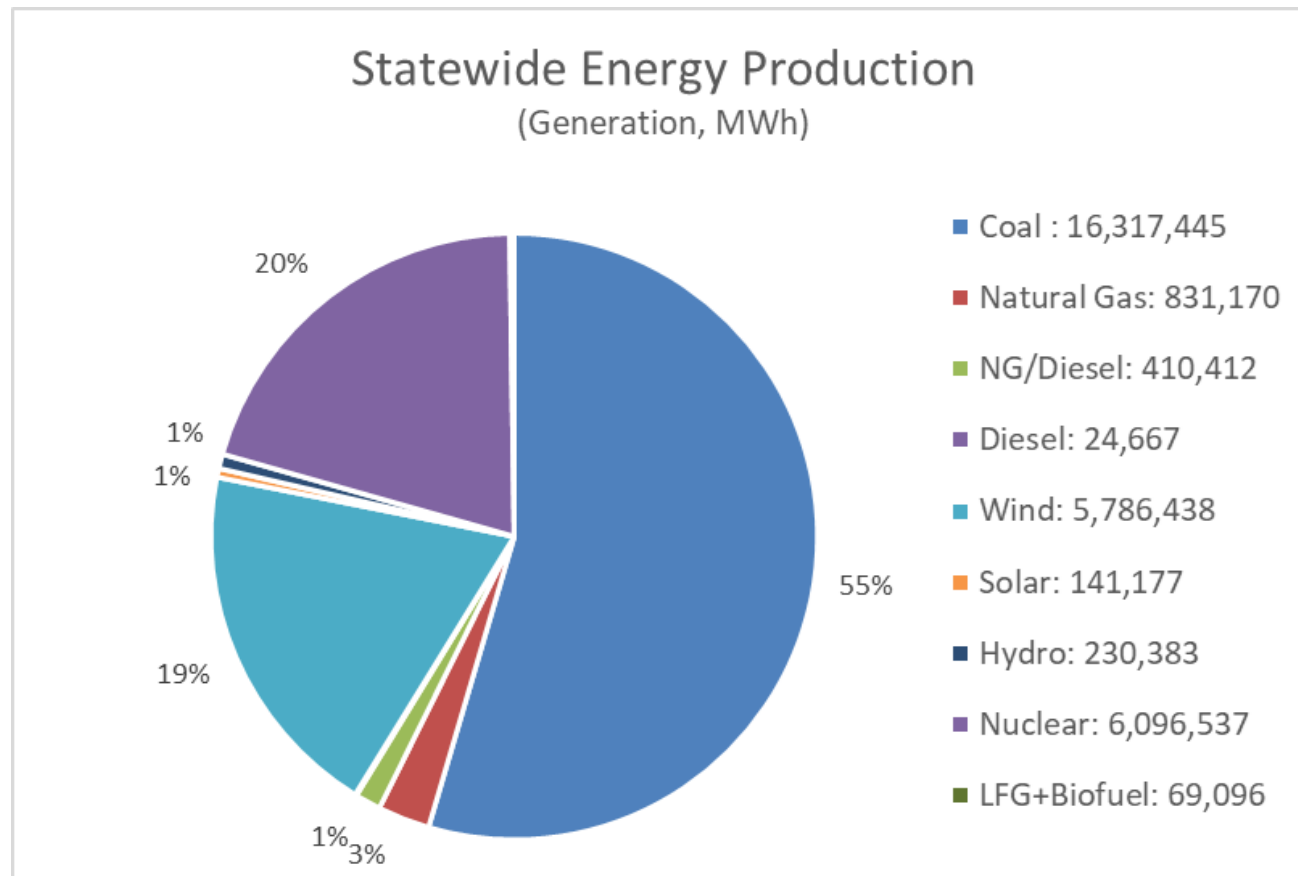


Figure 13 - Statewide 2024 Energy Production (MWh Generation)

5.1.2 Dual Fuel and On-Site Fuel Storage

In support of reliability and resilience, Nebraska utilities have generation resources that utilize on-site fuel storage and dual fuel sources. Dual fuel resources increase energy assurance in the event the primary fuel is unavailable. On-site fuel storage allows for unit operation in the event of temporary fuel supply chain interruptions. *Figure 14* illustrates that 23% (1,762 MW) of the State's winter accredited capacity is provided by dual fuel generating units. Many of the dual fuel generating units are very small internal combustion or reciprocating units.

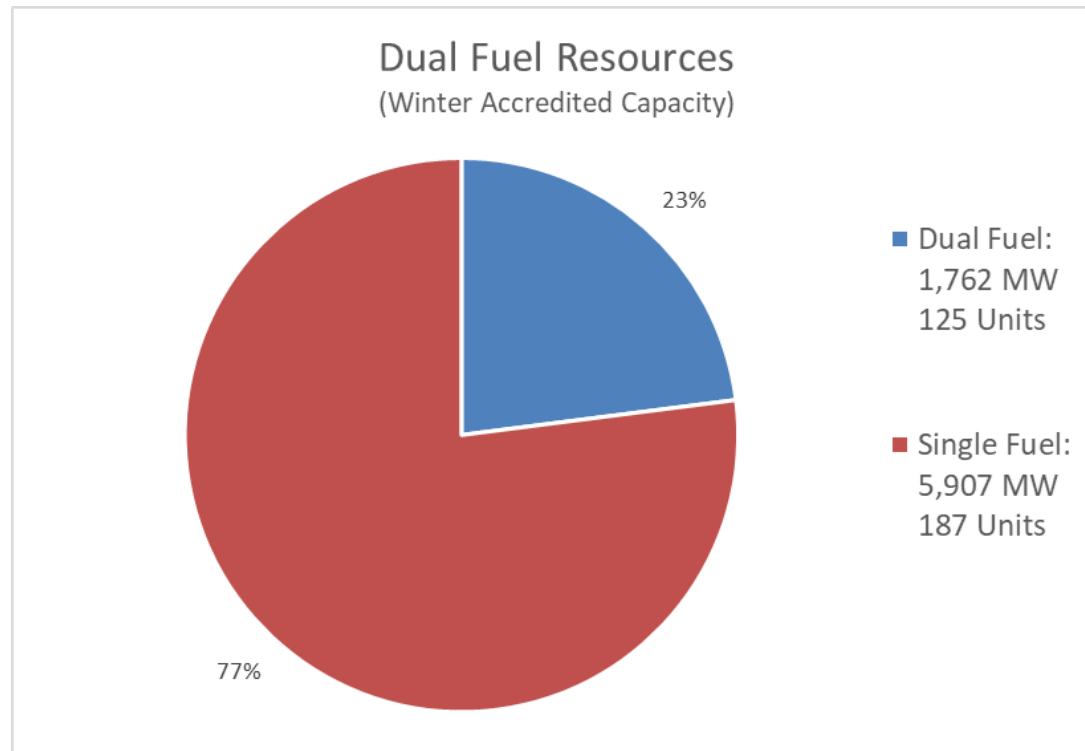


Figure 14 - Dual Fuel Resources (Winter Accredited Capacity)

NPPD, OPPD and LES own or operate coal units amounting to 3,603 MW of winter accredited generating capability with onsite fuel storage, with an average of 32.7 days of storage available as shown in *Figure 15*. Also, 1,470 MW of dual fuel natural-gas/diesel-fuel-oil generating units and 178 MW of diesel fuel only generating units have diesel fuel storage on site. On average, NPPD, OPPD, and LES's dual fuel generating units could operate at full output for 1.5 to 1.7 days with the quantity of fuel the generating units have in storage. These numbers represent a full output equivalent and do not consider the actual load factor or resupply rates. NPPD's Cooper Nuclear Station is on a 2-year refueling cycle, with refueling outages occurring during the fall of even years. Coming out of a refueling outage, CNS has 2 years of fuel in the reactor, which declines as the fuel cycle occurs during the last month and a half of the cycle.

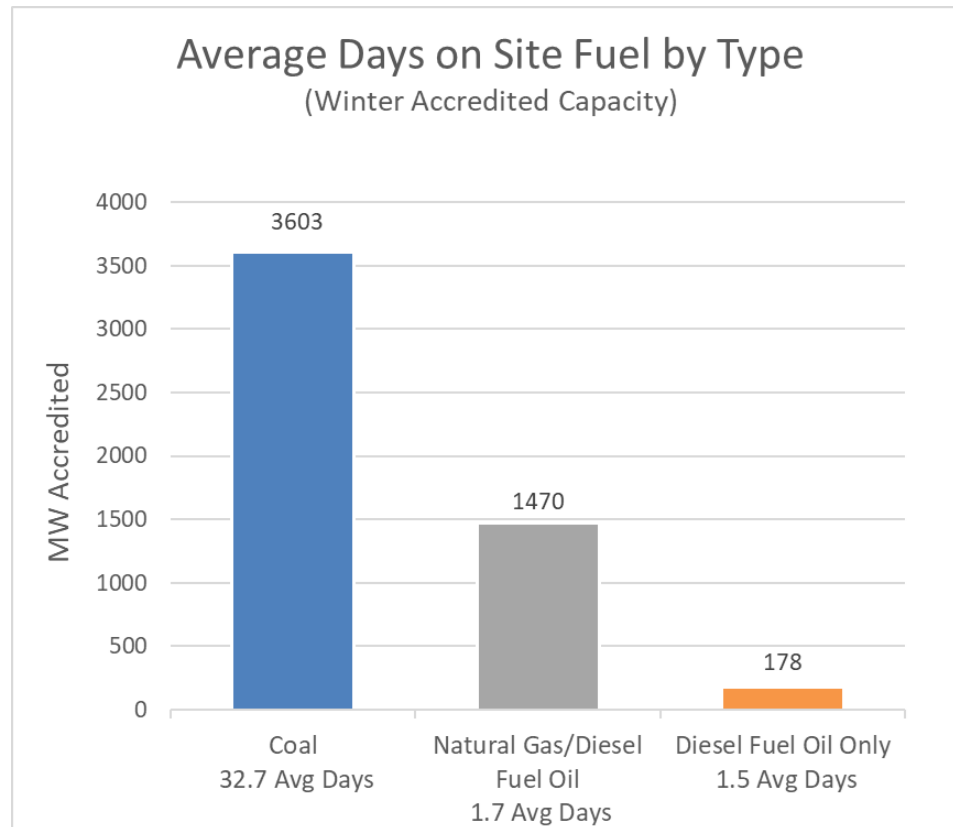


Figure 15 - Average Days on Site Fuel by Type (Winter Accredited Capacity)

5.1.3 Ramp Rates

The generation ramp rate, or time required for a unit to reach maximum capacity, is shown in *Figure 16*. The ramp rate categories are defined by the EIA in their EIA 860 information gathering. These four ramp rate categories range from 0-10 minutes to over 12+ hours. 797 MW of in-state resources can ramp to full load in 0 -10 minutes, 1,394 MW can ramp to full load in 10 – 60 minutes, 2,281 MW can ramp to full load in 1 – 12 hours, and 2,868 MW can ramp to full load in 12+ hours. The remainder of the state’s Existing resource capacity is not dispatchable.

The generating unit data is based on the physical characteristics and capabilities of the units and does not include any subjective factors.

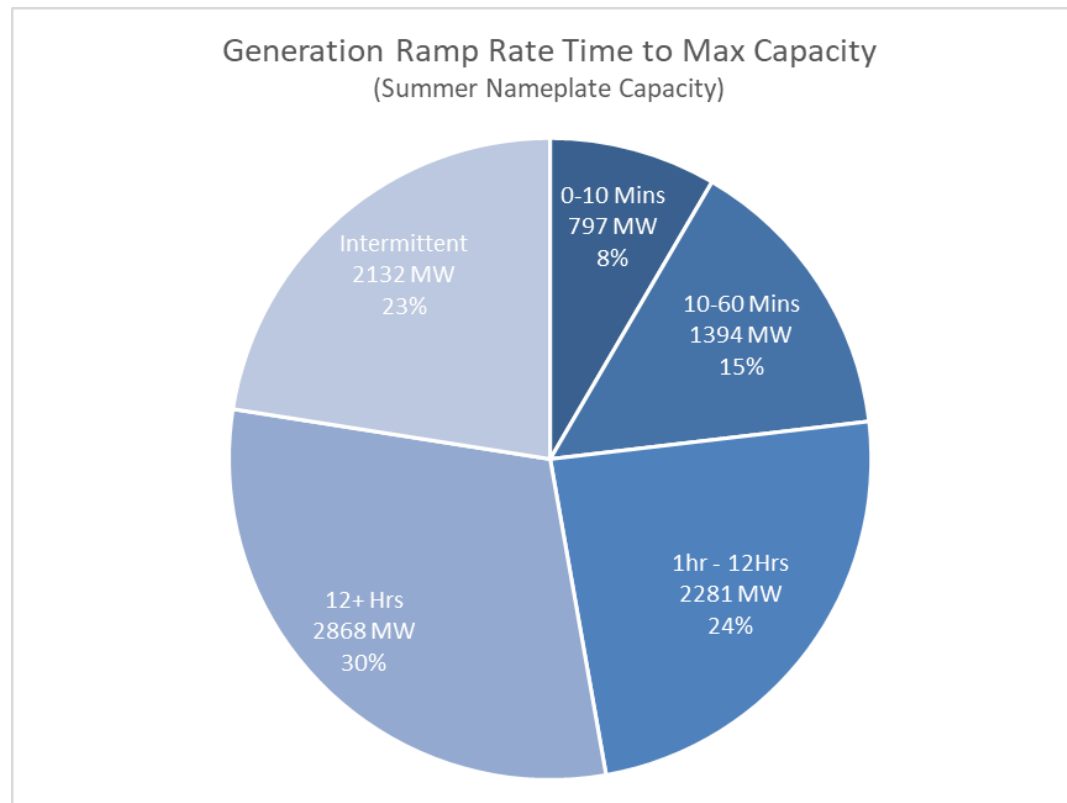


Figure 16 - Generation Ramp Rate time to Max Capacity (Summer Nameplate Capacity)

5.1.4 Seasonal Stress Periods

In response to the NPRB request to demonstrate the state's actual performance during peak load periods, this report summed the coincident hourly loads of the largest state utilities (NPPD, OPPD, and LES) to determine the seasonal stress periods. In this manner, the NPA identified that the peak summer load occurred on 7/15/24, with a peak statewide demand of 6,562.5 MW. Likewise, the peak winter load occurred on 28/20/25, with a peak demand of 5,511.5 MW. To calculate the cumulative state capability to serve these peak loads, the report sums up the resources available to generate as well as the resources that were actively generating at the time of the peak. A dispatchable generating resource was deemed "Available" if the unit was believed to be in operable condition and was expected to be capable of starting and running if called upon by the SPP Integrated Marketplace. Units that were derated to partial capability at the peak hours were considered "Available" and were included in the summation at that derated capacity level. The "Available" generation capability listed for non-dispatchable generating resources such as wind was determined by the resources' day-ahead offers into the SPP Marketplace for the peak hour.

Figure 17 and *Figure 18* respectively display the peak load, available generation, and actual generation for the aggregate of LES, NPPD and OPPD during the identified summer peak hour and winter peak hour. This historical information indicates that these utilities had available resources that exceeded the winter peak loads but that available capacity was below the state's coincident demand during the summer peak load. This shortfall was due to outages experienced at several units throughout the state, including OPPD's 650 MW Nebraska City 1 coal-fired unit. The actual generation from these resources was less than the summer and winter peak loads.

This discrepancy might appear to be problematic but instead is an illustration of the successful operation of the SPP Integrated Marketplace generation dispatch functionality since other available, deliverable, and economical generation in the SPP footprint was being utilized to serve the Nebraska load that was in excess of the Nebraska generation being dispatched. In this way, Nebraska and the entire SPP region benefit from operating within a pool that maintains adequate resource capacity and reserve margin and economically dispatches units at a financial and reliability benefit to the membership. This stress period represents a single hourly snapshot of the state's resource availability and generation and excludes many other hours of the year when the state's resources are generating at a level exceeding the combined load.

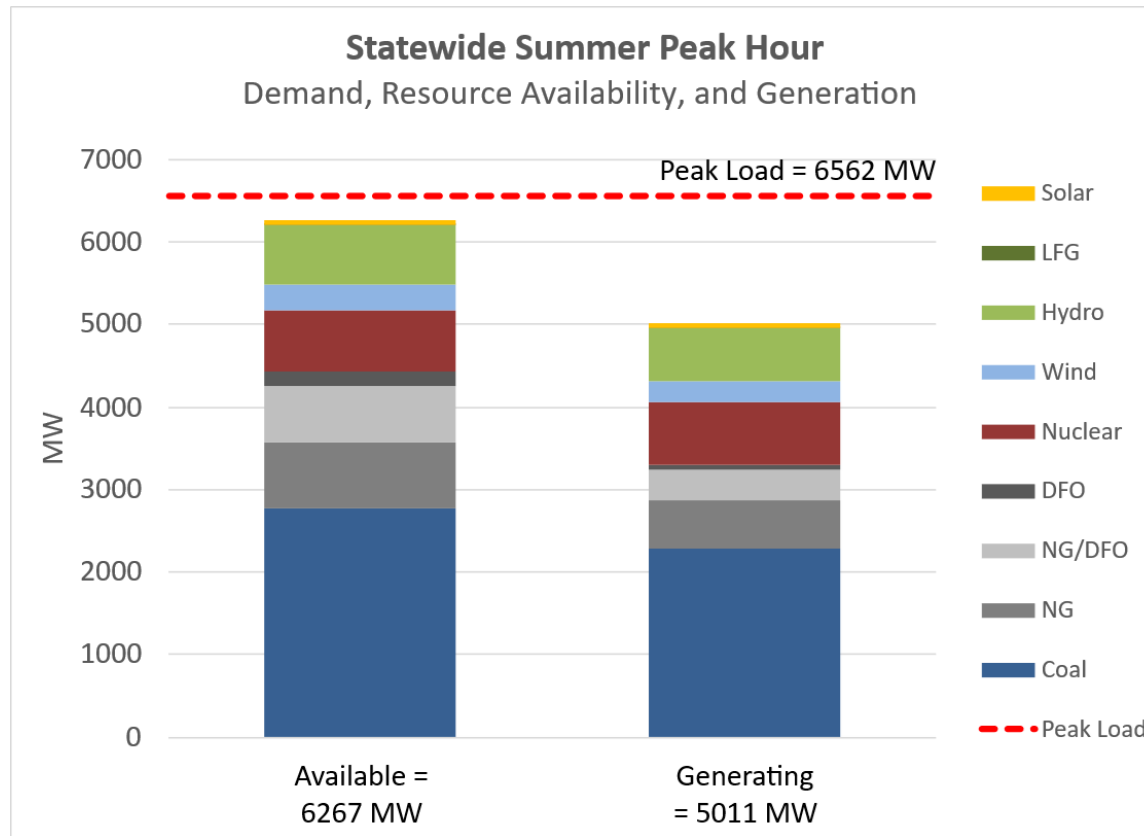


Figure 17 - Statewide Summer Peak Hour - Demand, Resource Availability, and Generation

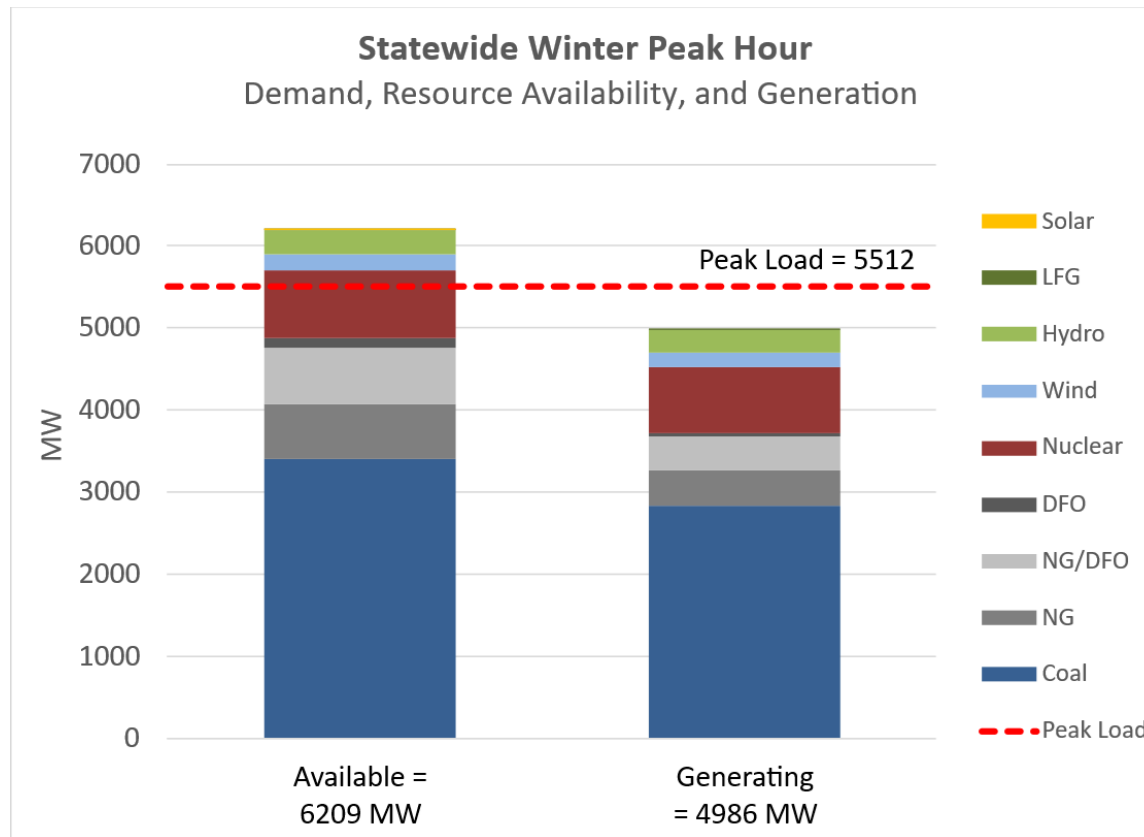


Figure 18 - Statewide Winter Peak Hour - Demand, Resource Availability, and Generation

5.1.5 Extreme Scenario Analysis

Per request of the Nebraska Power Review Board, the Load and Capability Report includes a sensitivity analysis of the stress periods under a defined extreme event scenario. For this year's report, the PRB has requested an analysis of extreme and sustained heat and drought conditions across the majority of Nebraska, causing reduced river flows and heat related complications at generating facilities concurrent with low wind generation.

This extreme condition would threaten the full operational capabilities of thermal units reliant on river cooling due to the potential of low flow volumes and elevated temperatures of the river. Units potentially impacted would be OPPD's Nebraska City Station (NCS) unit 1 (650 MW of capacity), OPPD's North Omaha Station (NOS) units 4 and 5 (combined capacity of 324 MW), and NPPD's Cooper Nuclear Station (768.5 MW of capacity.)

Although the OPPD-owned Nebraska City unit 2 is located on the Missouri River, it uses a cooling tower supplied with make-up water from the Missouri River and does not have a discharge temperature limitation like that of NC1 and the NOS units. A degradation of the temperature differential available to the cooling tower may reduce the efficiency of the unit, and sustained drought may limit the availability of make-up water from the river. However, during the identified peak demand hour from summer 2024, the NC2 unit was in outage, and therefore the extreme scenario would cause no incremental reduction in capacity due to derates at NC2.

The report "Missouri River Recovery Management Plan and Environmental Impact Statement, Thermal Power Environmental Consequences Analysis, Technical Report" conducted in August 2018 by the Kansas City and Omaha Districts of the U.S. Army Corps of Engineers studied the impacts of various potential alternatives to the established Missouri River Recovery Management Plan (MRRMP). This study included an evaluation of the environmental consequences of the MRRMP alternatives on the thermal power performance of plants located along the Missouri River. Within the study are the results of continuation of the current management plan, various alternate plans, and a robust set of historical data on river conditions and thermal generation. The study states "Generally, thermal power plants are impacted by the Missouri River flows, stages, and temperature conditions affecting intake access to water, the ability to discharge cooling water, and power plant operations and generation." The study collected data on river stages from 1931 to 2012 relative to intake elevations of dependent thermal plants and created a model of river temperatures from 1975 to 2012. The analysis modeled the entire river and reservoir system and incorporated specific operational parameters of each of the power plants. This report informs of the extreme scenario in terms of historical metrics and expected conditions along the river system, as well as operational plans for upstream facilities under various conditions.

The study describes federal regulations, state water quality standards, and operating permits that place maximum temperature limits on the river water, which in high heat conditions would restrict power plants from discharging cooling water to the river, thereby curtailing generation. The study results are based on the assumption that river temperatures above 90°F would require plants to shut down. In reality, this assumption can be superseded by exceptions granted to power entities to generate during emergency conditions. In fact, during the heat dome event in August of 2023, Nebraska Governor Jim Pillen issued an Executive Order authorizing the state's public power entities to take all steps necessary to meet power demands during the emergency, including the suspension of any restrictive permit, regulation, or law. This exemption was imposed for a three-week period. It is assumed that during this contemplated extreme scenario such an exception may be available. This would allow units to continue operating, but the impact of temperature may still act to derate the units.

The USACE has acknowledged that extended heat and drought conditions to a degree that would negatively impact downstream thermal generation would be a slow developing scenario that would allow the Corps to modulate reservoir releases within navigation and environmental limitations to mitigate downstream complications. Release plans per location are calculated based on seasonal reservoir levels and conditions on the remainder of the system. The USACE maintains a plan for low spring storage conditions that considers navigation support and defines minimum release rates per season. Spring and fall rates are lower because water temperature is expected to be cooler and supplemented with tributary flow to a degree that provides adequate downstream volumes. In summer, flows are increased due to the higher temperatures and lower tributary flow. Plans responding to low spring storage volumes have not been executed in recent memory, but modeling in the study showed required operation approaching these levels during the drought conditions of the 1930s. (Note that this time frame is prior to installation of the dams operating on the river system, which has changed the hydrology conditions and control of downstream flows.) Historically, the highest risk of low river elevations has occurred in September when navigation is at reduced levels. In the past, this has been relieved by increased flow from tributaries and increased upstream release rates. In general, summer operational risk due to river conditions has been minimal and is lower than the risk in winter months.

The configuration of Nebraska City unit 1 includes established operational plans that modify the pumping schemes to respond to certain low water levels (904' MSL) to allow the plant to continue operation, as well as plans that reduce pumping capabilities at critical low water levels (902' MSL) and result in a unit derate. It is possible that, as a result of sustained drought and increased heat, the combined effects of the plant's operational temperature limitation and required river water intake elevations could force a derate of 100-200 MW at Nebraska City 1. It is important to note that this hypothetical scenario is in excess of historically observed reductions of 50-70 MW during extreme summer conditions. USGS historical site river level data from 1930 to present indicates that actual summer conditions do not approach the plant's low river level threshold, but it was assumed for this exercise that unprecedented conditions should be contemplated.

Although not observed in USGS data for summer river gauge levels in well over 50 years, OPPD's North Omaha station is more likely to experience critical intake water levels in the summer months than the Nebraska City site. The plant maintains operational plans for normal and low water levels, including a Mitigation Phase, Preservation Phase, and Equipment Protection Phase that would balance the need for continued generation with the long-term health of the plant. Cross-tie functions are available to extend the function of circulating water pumps, and further plans are in place to derate the plant and eventually to force unit shut down. The North Omaha plant also has the ability to utilize city water on a limited basis if river water is not at adequate levels for system intake. However, this is not intended for extended operations. In summary, unprecedented summer conditions may eventually cause the North Omaha units to become inoperable and result in a loss of the 324 MW at the plant. However, this would require the USACE to reduce flow rates to the minimum winter or fall release levels during summer months. Because North Omaha unit 5 was in outage

during the statewide peak demand hour referenced in this report, the incremental loss of available capacity would be the 117.7 MW of accredited capacity of North Omaha unit 4.

At Gerald Gentleman Station (GGS), cooling water needs are fed from reservoirs filled from the North and South Platte Rivers. In extreme and extended drought conditions (spanning multiple years) reduced river flows can lead to reduced reservoir levels and increased circulating water inlet temperatures. The increased circulating water inlet temperature can affect the plant's production in two ways, 1) condenser performance may physically limit the generating capability, and 2) regulated circulating water discharge temperature limit may cause a generation limitation. However, GGS does have a well field designed to supply cool makeup water to the circulating water system to help mitigate the above circumstances. GGS has experienced several drought years in the past and has not been significantly derated. The supplemental well system has not been used for cooling circulating water inlet temperature but has been used to maintain release temperatures. In summary, GGS has a supplemental well system to help mitigate drought conditions. It would likely take a multiple year drought to have an impact on generation levels.

At Cooper Nuclear Station (CNS), cooling water is primarily fed from the Missouri River with major tributaries from the Platte River in Nebraska and the Nishnabotna River in Iowa. In extreme and extended drought conditions affecting the Missouri River Basin upstream of the plant, reduced river flows can affect the local river elevation. This combined with occasionally seasonal high temperatures can lead to increased circulating water inlet temperatures. The increased circulating water inlet temperature can affect the plant's production in three ways, 1) condenser performance may physically limit the generating capability, 2) regulated circulating water discharge temperature limit (109.4 °F) may cause a generation limit. The actual highest observed discharge temperature was 106.9 °F, and 3) if the cooling water inlet temperature exceeds 95 °F, the station is required to shutdown per our NRC Licensing basis Technical Specifications. Historically, the highest inlet temperature that has been observed at the station is 89.1 °F. Independent of temperature, the station's Technical Specifications also require a plant shutdown when the Missouri River's elevation lowers to less than or equal to 865 feet mean sea level (MSL), measured at the plant intake. The actual lowest observed river level is 870.3 feet MSL (50 years of operating time). To mitigate river temperature limits, Cooper revised its technical requirements several years ago by increasing the limit of the inlet temperature from 90 °F to 95 °F and revised the outlet temperature limit from 107 °F to 109.4 °F. Overall, CNS has experienced several years of drought conditions and / or conditions of low river level and was able to maintain full power operations throughout these periods.

In the 2024 summer peak load hour, statewide wind generation was already comparatively low at 295.8 MW. To quantify an extreme low wind condition, it is useful to acknowledge that Nebraska's wind generation profile is moderately correlated with the wind generation of SPP as a whole. It is then valuable to consider extreme summer conditions observed in SPP. SPP's State.of.the.Market. report for Summer 2024 identified an EEA1 event where wind generation dropped from 18 GW in the morning hours to a low of just 1.3 GW during the daily peak of August 26 (Figure 6-3 of the Summer 2024 State.of.the.Market report.) Using this historical scenario

to model the extreme summer scenario of low wind during a peak load hour, and assuming correlation of wind generation between Nebraska and SPP, we reference SPP's total 1.3 GW of wind online out of the total 34.5 GW installed in the footprint. Applying this same ratio to the nameplate wind in the statewide portfolio, we would expect generation of only 88.4 MW during the peak hour in the extreme scenario.

In drought conditions, the hydropower facilities that supply the Upper Great Plains Western Area Power Administration allocations to the area could be forced to reduce generation. Other WAPA regions have experienced this in recent years. In this case, WAPA regulations require the administration to provide replacement power to its customers at cost. Therefore, although the Nebraska utilities would not see a resource deficiency, the replacement power may be supplied at a price premium.

However, the remaining 125.6 MW of hydropower facilities operated in the state would be at risk for low flows and low power generation. Locally-sited hydropower facilities may be subject to outages and derates in the event of sustained drought conditions. A very conservative projection of the impact of this scenario assumes a full outage of the state's operated hydropower. The total statewide local hydropower, which achieved 63.6 MW of generation during the previous summer peak, is reduced in this analysis to 0 MW.

In summary, if the generation that is believed to be at the highest risk for being unavailable during a sustained heat and drought event with low wind generation was concurrently removed from service (i.e. 317.7 MW of coal, 0 MW of nuclear, 219.5 MW wind, and 63.6 MW hydro), this represents a 600.8 MW generation reduction. Figure 19 depicts the summer extreme scenario with the loss of this availability and generation and illustrates that Nebraska would experience an even higher level of deficiency in available generation to meet the summer peak demand.

This extreme scenario analysis emphasizes the importance of resource reliability and further highlights the value of membership in the Southwest Power Pool and the availability of regional capacity to serve Nebraska load. It should be restated that this extreme scenario is extraordinarily conservative in nature and contains an unprecedented coincidence of rare conditions resulting in a scenario of very low likelihood.

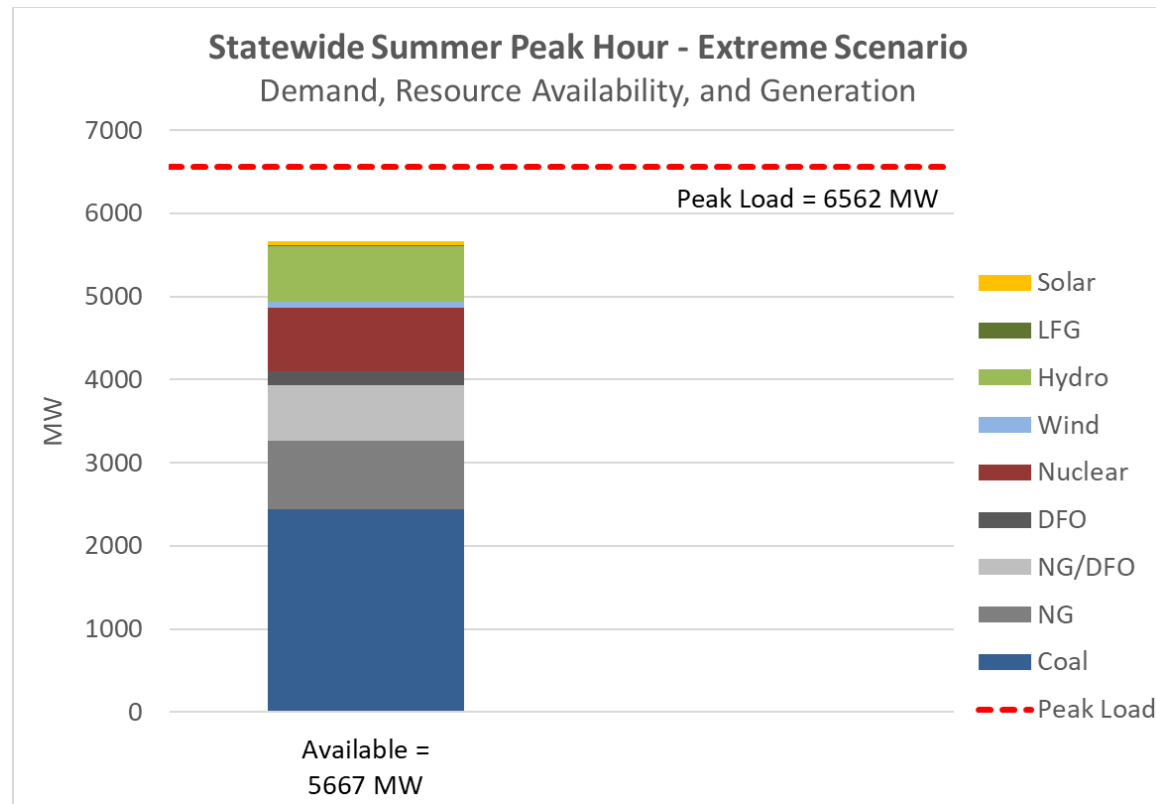


Figure 19 - Statewide Winter Peak Hour - Extreme Scenario - Demand, Resource Availability, and Generation

APPENDIX 1 - EXISTING RESOURCES
2025 Statewide Existing Generating Capability Data (Nameplate Capacity)

Utility	Unit Name	Unit Status	Duty Cycle	Unit Type	Fuel Type	Commercial Operation Date	On Site Fuel Storage (Y/N)	Behind the Meter	Nameplate Capacity
Beatrice	Cottonwood Wind Farm Beatrice	E	I	WT	WND	2017	N	N	16.1
Beatrice Total									16.1
Falls City	Falls City #7	E	P	RE	NG/DFO	1972	Y	N	6.2
Falls City	Falls City #8	E	P	RE	NG/DFO	1981	Y	N	6
Falls City	Falls City #9	E	P	RE	NG/DFO	2018	Y	N	9.3
Falls City	Falls City #1	E	E	RE	DFO	1930	Y	Y	2.75
Falls City	Falls City #2	E	E	RE	DFO	1937	Y	Y	1
Falls City	Falls City #3	E	E	RE	NG/DFO	1965	Y	Y	2
Falls City	Falls City #4	E	E	RE	NG/DFO	1946	Y	Y	2
Falls City	Falls City #5	E	E	RE	NG/DFO	1951	Y	Y	6.25
Falls City	Falls City #6	E	E	RE	NG/DFO	1958	Y	Y	6
Falls City Total									41.5
Fremont	Fremont Unit 6	E	B	ST	SUB/NG	1958	Y	N	16.86
Fremont	Fremont Unit 7	E	B	ST	SUB/NG	1963	Y	N	22.01
Fremont	Fremont Unit 8	E	B	ST	SUB/NG	1976	Y	N	85.25
Fremont	Fremont CT	E	P	CT	NG/DFO	2003	Y	N	37.55
Fremont	Fremont Cottonwood Wind	E	I	WT	WND	2018	N	N	40.36
Fremont	Fremont Solar	E	I	S	SUN	2018	N	Y	2.31
Fremont Total									204.3
Grand Island	Burdick GT1	E	P	GT	NG/DFO	1968	Y	N	18
Grand Island	Burdick GT2	E	P	GT	NG/DFO	2003	Y	N	74.588
Grand Island	Burdick GT3	E	P	GT	NG/DFO	2003	Y	N	74.588
Grand Island	Platte Generating Station	E	B	ST	SUB	1982	Y	N	120
Grand Island	Prairie Breeze 3 Wind	E	I	WT	WND	2016	N	N	35.8
Grand Island	Grand Island Solar I	E	I	S	SUN	2019	Y	Y	1
Grand Island Total									324.0
Hastings	CCC Hastings Wind	E	I	WT	WND	2016	N	N	1.7
Hastings	DHPC #1	E	P	GT	NG/DFO	1972	Y	N	18
Hastings	Hastings-NDS#4	E	P	ST	NG/DFO	1957	Y	N	15.5
Hastings	Hastings-NDS#5	E	P	ST	NG/DFO	1967	Y	N	23.6
Hastings	Whelan Energy Center #1	E	B	ST	SUB	1981	Y	N	76
Hastings	Whelan Energy Center #2	E	B	ST	SUB	2011	Y	N	220
Hastings	Hastings Community Solar	E	I	S	SUN	2019	N	Y	1.5
Hastings Total									356.3
LES	Laramie River Station	E	B	ST	SUB	1982	Y	N	187.9
LES	J St	E	P	GT	NG/DFO	1972	Y	N	30.1
LES	Rokeby 1	E	P	GT	NG/DFO	1975	Y	N	67
LES	Rokeby 2	E	P	GT	NG/DFO	1997	Y	N	90.3
LES	Rokeby 3	E	P	GT	NG/DFO	2001	Y	N	94.51
LES	TBS CT1/CC1	E	P	CC	NG/DFO	2003	Y	N	122.3
LES	TBS CT 3	E	P	GT	NG/DFO	2003	Y	N	47.1

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Utility	Unit Name	Unit Status	Duty Cycle	Unit Type	Fuel Type	Commercial Operation Date	On Site Fuel Storage (Y/N)	Behind the Meter	Nameplate Capacity
LES	WSEC4	E	B	ST	SUB	2007	Y	N	102.37
LES	Rokeby Black Start	E	E	RE	DFO	1997	Y	N	3.2
LES	TBS Black Start	E	E	RE	DFO	2004	Y	N	1.6
LES	Landfill Gas Generator	E	B	RE	LFG	2014	N	N	4.8
LES	Arbuckle Mountain Wind	E	I	WT	WND	2016	N	N	100
LES	Buckeye Wind	E	I	WT	WND	2016	N	N	100
LES	Prairie Breeze 2 Wind	E	I	WT	WND	2016	N	N	73.4
LES	LES Community Solar	E	B	S	SUN	2016	N	Y	3.6
LES	LES Wind	E	I	WT	WND	1999	N	Y	0
LES	Jeffrey Hydro	E	B	H	WAT	2025		N	21.6
LES Total									1049.8
MEAN	Alliance #1	E	P	RE	DFO	2002	Y	N	1.825
MEAN	Alliance #2	E	P	RE	DFO	2002	Y	N	1.825
MEAN	Alliance #3	E	P	RE	DFO	2002	Y	N	1.825
MEAN	Ansley #2	E	P	RE	NG/DFO	1972	Y	N	0.91
MEAN	Ansley #3	E	P	RE	NG/DFO	1968	Y	N	0.675
MEAN	Benklemen	E	P	RE	NG/DFO	1968	Y	N	0.9
MEAN	Broken Bow #2	E	P	RE	NG/DFO	1971	Y	N	3.5
MEAN	Broken Bow #4	E	P	RE	NG/DFO	1949	Y	N	0.8
MEAN	Broken Bow #5	E	P	RE	NG/DFO	1959	Y	N	1
MEAN	Broken Bow #6	E	P	RE	NG/DFO	1961	Y	N	2.25
MEAN	Burwell #1	E	P	RE	NG/DFO	1962	Y	N	1.365
MEAN	Burwell #2	E	P	RE	NG/DFO	1967	Y	N	1.14
MEAN	Burwell #3	E	P	RE	NG/DFO	1972	Y	N	0.9
MEAN	Callaway #3	E	P	RE	DFO	1958	Y	N	0.5
MEAN	Callaway #4	E	P	RE	DFO	2004	Y	N	0.4
MEAN	Chappell #5	E	P	RE	DFO	1982	Y	N	1.1
MEAN	Crete #7	E	P	RE	NG/DFO	1972	Y	N	6
MEAN	Curtis #1	E	P	RE	NG/DFO	1975	Y	N	1.36
MEAN	Curtis #2	E	P	RE	NG/DFO	1969	Y	N	1.14
MEAN	Curtis #4	E	P	RE	NG/DFO	1955	Y	N	0.9
MEAN	Kimball #1	E	P	RE	NG/DFO	1955	Y	N	1
MEAN	Kimball #2	E	P	RE	NG/DFO	1956	Y	N	1
MEAN	Kimball #3	E	P	RE	NG/DFO	1959	Y	N	1.25
MEAN	Kimball #4	E	P	RE	NG/DFO	1960	Y	N	1.25
MEAN	Kimball #5	E	P	RE	NG/DFO	1951	Y	N	0.9
MEAN	Kimball #6	E	P	RE	NG/DFO	1975	Y	N	3.9
MEAN	Oxford #2	E	P	RE	NG/DFO	1952	Y	N	0.675
MEAN	Oxford #3	E	P	RE	NG/DFO	1956	Y	N	0.9
MEAN	Oxford #4	E	P	RE	NG/DFO	1956	Y	N	0.675
MEAN	Oxford #5	E	P	RE	DFO	1972	Y	N	1.365

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2025 Statewide Existing Generating Capability Data (Nameplate Capacity)

						Commercial	On Site Fuel		
Utility	Unit Name	Unit Status	Duty Cycle	Unit Type	Fuel Type	Operation Date	Storage (Y/N)	Behind the Meter	Nameplate Capacity
MEAN	Pender #1	E	P	RE	NG/DFO	1968	Y	N	1.629
MEAN	Pender #2	E	P	RE	NG/DFO	1973	Y	N	1.566
MEAN	Pender #3	E	P	RE	DFO	1953	Y	N	0.56
MEAN	Pender #4	E	P	RE	DFO	1961	Y	N	0.9
MEAN	Red Cloud #2	E	P	RE	NG/DFO	1953	Y	N	0.984
MEAN	Red Cloud #3	E	P	RE	NG/DFO	1960	Y	N	1.36
MEAN	Red Cloud #4	E	P	RE	NG/DFO	1968	Y	N	1.365
MEAN	Red Cloud #5	E	P	RE	NG/DFO	1974	Y	N	2.28
MEAN	Stuart #1	E	P	RE	NG/DFO	1965	Y	N	0.675
MEAN	Stuart #4	E	P	RE	NG/DFO	1996	Y	N	0.784
MEAN	Stuart #5	E	P	RE	DFO	2024	Y	Y	1.96
MEAN	West Point #1	E	P	RE	NG/DFO	1947	Y	N	2.314
MEAN	West Point #2	E	P	RE	NG/DFO	1959	Y	N	1.25
MEAN	West Point #3	E	P	RE	NG/DFO	1965	Y	N	0.9
MEAN	Wisner #4	E	P	RE	DFO	2008	Y	N	1.5
MEAN	Wisner #5	E	P	RE	DFO	2008	Y	N	1.5
MEAN	Arnold #1	E	E	RE	NG/DFO	1960	Y	Y	0
MEAN	Arnold #2	E	E	RE	NG/DFO	1942	Y	Y	0
MEAN	Arnold #3	E	E	RE	NG/DFO	1946	Y	Y	0
MEAN	Beaver City #1	E	E	RE	NG/DFO	1958	Y	Y	0
MEAN	Beaver City #2	E	E	RE	NG/DFO	1961	Y	Y	0
MEAN	Beaver City #4	E	E	RE	NG/DFO	1968	Y	Y	0
MEAN	Blue Hill#1	E	E	RE	NG/DFO	1964	Y	Y	0.8
MEAN	Blue Hill#2	E	E	RE	DFO	1948	Y	Y	0.4
MEAN	Broken Bow #1	E	E	RE	DFO	1933	Y	Y	0.56
MEAN	Broken Bow #3	E	E	RE	NG/DFO	1936	Y	Y	0.89
MEAN	Burwell#1	E	E	RE	NG/DFO	1955	Y	Y	0.67
MEAN	Chappell #2	E	E	RE	DFO	1945	Y	Y	0.2
MEAN	Crete #1	E	E	RE	NG/DFO	1939	Y	Y	0
MEAN	Crete #2	E	E	RE	NG/DFO	1955	Y	Y	0
MEAN	Crete #3	E	E	RE	NG/DFO	1951	Y	Y	0
MEAN	Crete #4	E	E	RE	NG/DFO	1947	Y	Y	0
MEAN	Crete #5	E	E	RE	NG/DFO	1962	Y	Y	0
MEAN	Crete #6	E	E	RE	NG/DFO	1965	Y	Y	0
MEAN	Sidney #1	E	E	RE	NG/DFO	1967	Y	Y	1.25
MEAN	Sidney #2	E	E	RE	NG/DFO	1973	Y	Y	0
MEAN	Sidney #3	E	E	RE	DFO	1953	Y	Y	0.75
MEAN	Sidney #4	E	E	RE	NG/DFO	1961	Y	Y	0
MEAN	Sidney #5	E	E	RE	NG/DFO	1939	Y	Y	3.12
MEAN	Stuart #2	E	E	RE	DFO	1960	Y	Y	0.3
MEAN	Stuart #3	E	E	RE	DFO	1954	Y	Y	0.25
MEAN	Stuart #4	E	E	RE	DFO	1946	Y	Y	0.8
MEAN Total									74.7

APPENDIX 1 - EXISTING RESOURCES
2025 Statewide Existing Generating Capability Data (Nameplate Capacity)

Utility	Unit Name	Unit Status	Duty Cycle	Unit Type	Fuel Type	Commercial Operation Date	On Site Fuel Storage (Y/N)	Behind the Meter	Nameplate Capacity
NELIGH	Neligh #1	E	P	RE	OBL	2012	Y	N	1.803
NELIGH	Neligh #2	E	P	RE	OBL	2012	Y	N	1.786
NELIGH	Neligh #3	E	P	RE	OBL	2012	Y	N	1.801
NELIGH	Neligh #4	E	P	RE	OBL	2012	Y	N	0.335
Neligh Total									5.7
Nebraska City	Nebraska City #5	E	P	RE	NG/DFO	1964	Y	N	2
Nebraska City	Nebraska City #6	E	P	RE	NG/DFO	1967	Y	N	2.1
Nebraska City	Nebraska City #7	E	P	RE	NG/DFO	1969	Y	N	2.1
Nebraska City	Nebraska City #8	E	P	RE	NG/DFO	1970	Y	N	4.1
Nebraska City	Nebraska City #9	E	P	RE	NG/DFO	1974	Y	N	6.4
Nebraska City	Nebraska City #10	E	P	RE	NG/DFO	1979	Y	N	6.5
Nebraska City	Nebraska City #11	E	P	RE	NG/DFO	1998	Y	N	4.6
Nebraska City	Nebraska City #12	E	P	RE	NG/DFO	1998	Y	N	4.6
Nebraska City	Nebraska City #2	E	E	RE	NG/DFO	1953	Y	Y	1.5
Nebraska City	Nebraska City #3	E	E	RE	NG/DFO	1955	Y	Y	2.5
Nebraska City	Nebraska City #4	E	E	RE	NG/DFO	1957	Y	Y	3.1
Nebraska City	Nebraska City #13	E	E	RE	DFO	1998	Y	Y	4.59
Nebraska City	Nebraska City #14	E	E	RE	DFO	2013	Y	Y	0.6
Nebraska City Total									44.7
Northeastern NPPD	Cottonwood	E	I	WT	WND	2018	N	N	17.5
Northeastern NPPD	Osmond 1	E	I	RE	DFO	2024	N		1.6
Northeastern Total									19.1
NPPD	ADM	E	B	ST	SUB	2009	Y	N	71.4
NPPD	Ainsworth Wind	E	I	WT	WND	2005	N	N	59.4
NPPD	Auburn #1	E	P	RE	NG/DFO	1982	Y	N	2.41
NPPD	Auburn #2	E	P	RE	NG/DFO	1949	Y	N	1
NPPD	Auburn #4	E	P	RE	NG/DFO	1993	Y	N	3.75
NPPD	Auburn #5	E	P	RE	NG/DFO	1973	Y	N	3.35
NPPD	Auburn #6	E	P	RE	NG/DFO	1967	Y	N	2.75
NPPD	Auburn #7	E	P	RE	NG/DFO	1987	Y	N	5.6
NPPD	Beatrice Power Station	E	I	CC	NG	2005	N	N	247.1
NPPD	Belleville 4	E	P	RE	NG/DFO	1955	Y	N	0
NPPD	Belleville 5	E	P	RE	NG/DFO	1961	Y	N	1.75
NPPD	Belleville 6	E	P	RE	NG/DFO	1966	Y	N	3.75
NPPD	Belleville 7	E	P	RE	NG/DFO	1971	Y	N	5.125
NPPD	Belleville 8	E	P	RE	NG/DFO	2006	Y	N	2.8
NPPD	Broken Bow Wind	E	I	WT	WND	2013	N	N	80
NPPD	Broken Bow II Wind	E	I	WT	WND	2014	N	N	73.1
NPPD	Cambridge	E	P	RE	DFO	1972	Y	N	4
NPPD	Canaday	E	P	ST	NG/DFO	1958	N	N	108.8

APPENDIX 1 - EXISTING RESOURCES
2025 Statewide Existing Generating Capability Data (Nameplate Capacity)

Utility	Unit Name	Unit Status	Duty Cycle	Unit Type	Fuel Type	Commercial Operation Date	On Site Fuel Storage (Y/N)	Behind the Meter	Nameplate Capacity
NPPD	Columbus 1	E	B	H	WAT	1936	Y	N	15.2
NPPD	Columbus 2	E	B	H	WAT	1936	Y	N	15.2
NPPD	Columbus 3	E	B	H	WAT	1936	Y	N	15.2
NPPD	Cooper	E	B	ST	NUC	1974	N	N	801
NPPD	Crofton Bluffs Wind	E	I	WT	WND	2013	N	N	42
NPPD	David City 1	E	P	RE	NG/DFO	1960	Y	N	1.5
NPPD	David City 2	E	P	RE	DFO	1949	Y	N	1
NPPD	David City 3	E	P	RE	NG/DFO	1955	Y	N	1
NPPD	David City 4	E	P	RE	NG/DFO	1966	Y	N	2.25
NPPD	David City 5	E	P	RE	DFO	1996	Y	N	1.6
NPPD	David City 6	E	P	RE	DFO	1996	Y	N	1.6
NPPD	David City 7	E	P	RE	DFO	1996	Y	N	1.6
NPPD	Elkhorn Ridge Wind	E	I	WT	WND	2009	N	N	80
NPPD	Franklin 1	E	P	RE	NG/DFO	1963	Y	N	0.675
NPPD	Franklin 2	E	P	RE	NG/DFO	1974	Y	N	1.365
NPPD	Franklin 3	E	P	RE	NG/DFO	1968	Y	N	1.14
NPPD	Franklin 4	E	P	RE	NG/DFO	1955	Y	N	0.9
NPPD	Gentleman 1	E	B	ST	SUB	1979	Y	N	681.3
NPPD	Gentleman 2	E	B	ST	SUB	1982	Y	N	681.3
NPPD	Hallam	E	P	GT	NG/DFO	1973	Y	N	56.7
NPPD	Hebron	E	P	GT	DFO	1973	N	N	56.7
NPPD	Keamey	E	B	H	WAT	1921	N	N	1.5
NPPD	Kingsley (CNPPID)	E	B	H	WAT	1985	Y	N	41.67
NPPD	Laredo Ridge Wind	E	I	WT	WND	2011	N	N	80
NPPD	Madison 1	E	P	RE	NG/DFO	1969	Y	N	2.07
NPPD	Madison 2	E	P	RE	NG/DFO	1959	Y	N	1.36
NPPD	Madison 3	E	P	RE	NG/DFO	1953	Y	N	1.136
NPPD	Madison 4	E	P	RE	DFO	1946	Y	N	1.365
NPPD	McCook	E	P	GT	DFO	1973	Y	N	56.7
NPPD	Monroe	E	B	H	WAT	1936	N	N	8.4
NPPD	North Platte 1	E	B	H	WAT	1935	Y	N	13.1
NPPD	North Platte 2	E	B	H	WAT	1935	Y	N	13.1
NPPD	Ord 1	E	P	RE	NG/DFO	1973	Y	N	5
NPPD	Ord 2	E	P	RE	NG/DFO	1966	Y	N	1.5
NPPD	Ord 3	E	P	RE	NG/DFO	1963	Y	N	2.5
NPPD	Ord 4	E	P	RE	DFO	1997	Y	N	1.45
NPPD	Ord 5	E	P	RE	DFO	1997	Y	N	1.45
NPPD	Sargent	E	P	RE	DFO	1964	Y	N	1.94
NPPD	Sheldon 1	E	B	ST	SUB	1961	Y	N	108.8
NPPD	Sheldon 2	E	B	ST	SUB	1965	Y	N	119.9
NPPD	Springview Wind	E	I	WT	WND	2012	N	N	3
NPPD	Steele Flats Wind	E	I	WT	WND	2013	N	N	75
NPPD	Wahoo #1	E	P	RE	NG/DFO	1960	Y	N	2.1

APPENDIX 1 - EXISTING RESOURCES
2025 Statewide Existing Generating Capability Data (Nameplate Capacity)

Utility	Unit Name	Unit Status	Duty Cycle	Unit Type	Fuel Type	Commercial Operation Date	On Site Fuel Storage (Y/N)	Behind the Meter	Nameplate Capacity
NPPD	Wahoo #3	E	P	RE	NG/DFO	1973	Y	N	4.415
NPPD	Wahoo #5	E	P	RE	NG/DFO	1952	Y	N	2.19
NPPD	Wahoo #6	E	P	RE	NG/DFO	1969	Y	N	3.5
NPPD	Western Sugar	E	B	ST	SUB	2014	Y	N	5
NPPD	Wilber 4	E	P	RE	DFO	1949	Y	N	0.9
NPPD	Wilber 5	E	P	RE	DFO	1958	Y	N	0.78
NPPD	Wilber 6	E	P	RE	DFO	1997	Y	N	1.6
NPPD	Loup PPD - Creston Ridge Wind	E	I	WT	WND	2016	N	Y	6.8
NPPD	Loup PPD - Creston Ridge (#2)	E	I	WT	WND	2017	N	Y	6.9
NPPD	Loup PPD - City of Schuyler Solar	E	I	S	SUN	2019	N	Y	0.46
NPPD	Loup PPD - City of Schuyler Solar Phase 2	E	I	S	SUN	2021	N	Y	0.48
NPPD	Loup PPD - City of Schuyler Solar Phase 3	E	I	S	SUN	2025	N	Y	1.26
NPPD	Scottsbluff Community Solar 1	E	I	S	SUN	2017	N	Y	0.128
NPPD	Scottsbluff Community Solar 2	E	I	S	SUN	2020	N	Y	4.375
NPPD	Venango Community Solar	E	I	S	SUN	2017	N	Y	0.096
NPPD	Kearney Community Solar	E	I	S	SUN	2018	N	Y	5.7
NPPD	City of Central City Solar Park	E	I	S	SUN	2015	N	Y	0.17
NPPD	City of Central City Solar Park (2)	E	I	S	SUN	2017	N	Y	0.424
NPPD	City of Cozad Solar	E	I	S	SUN	2021	N	Y	2
NPPD	City of Gothenburg Solar 1	E	I	S	SUN	2018	N	Y	0.468
NPPD	City of Gothenburg Solar 2	E	I	S	SUN	2019	N	Y	0.462
NPPD	Village of Hemingford Solar	E	I	S	SUN	2021	N	Y	1
NPPD	City of Holdrege Housing Proj Solar	E	I	S	SUN	2017	N	Y	0.056
NPPD	City of Lexington Solar	E	I	S	SUN	2017	N	Y	3.57
NPPD	City of Lexington Airport Solar	E	I	S	SUN	2021	N	Y	1
NPPD	City of Seward Wind	E	I	WT	WND	2018	N	Y	1.7
NPPD	Comhusker PPD - Renewable Solar LLC	E	I	S	SUN	2019	N	Y	0.28
NPPD	Cuming County RPPD - Wisner Wind	E	I	WT	WND	2020	N	Y	2.5
NPPD	Custer PPD - Sterner Solar	E	I	S	SUN	2017	N	Y	0.475
NPPD	Custer PPD - Sunny Delight Solar	E	I	S	SUN	2017	N	Y	0.3
NPPD	Custer PPD - Blowers Solar	E	I	S	SUN	2017	N	Y	0.3
NPPD	Custer PPD - JDRM LLC Solar	E	I	S	SUN	2016	N	Y	0.3
NPPD	Custer PPD - B&R LLC Solar	E	I	S	SUN	2016	N	Y	0.3
NPPD	Custer PPD - Pandorf Solar	E	I	S	SUN	2017	N	Y	0.6
NPPD	Custer PPD - Cockerill Fertilizer Solar 1	E	I	S	SUN	2018	N	Y	0.475
NPPD	Custer PPD - Cockerill Fertilizer Solar 2	E	I	S	SUN	2019	N	Y	0.45
NPPD	Dawson PPD - Willow Island Solar	E	I	S	SUN	2017	N	Y	0.308
NPPD	Howard Greeley RPPD - St Paul North Solar	E	I	S	SUN	2024	N	Y	0.999
NPPD	Loup Valleys RPPD - North Loup Solar	E	I	S	SUN	2020	N	Y	0.178
NPPD	Perennial PPD - Faimont Area Wind Farm	E	I	WT	WND	2019	N	Y	6.9
NPPD	Polk Co PPD - Osceola Wind	E	I	WT	WND	2019	N	Y	2.5

APPENDIX 1 - EXISTING RESOURCES
2025 Statewide Existing Generating Capability Data (Nameplate Capacity)

Utility	Unit Name	Unit Status	Duty Cycle	Unit Type	Fuel Type	Commercial Operation Date	On Site Fuel Storage (Y/N)	Behind the Meter	Nameplate Capacity
NPPD	Polk Co PPD Solar	E	I	S	SUN	2024	N	Y	1
NPPD	South Central PPD Solar Project	E	I	S	SUN	2022	N	Y	0.999
NPPD	Burt Co PPD - Dodge Co Solar	E	I	S	SUN	2022	N	Y	0.999
NPPD	Burt Co PPD - Burt Co Solar	E	I	S	SUN	2022	N	Y	0.999
NPPD	Norfolk Community Solar	E	I	S	SUN	2023	N	Y	8.7
NPPD	Norfolk Battery Energy Storage System	E	ES	ES	ES	2023	N	Y	1
NPPD	Ainsworth Solar	E	I	S	SUN	2022	N	Y	0.5
NPPD	Elkhorn RPPD - Acklic	E	I	S	SUN	2021	N	Y	3
NPPD	Elkhorn RPPD - Uecker	E	I	S	SUN	2021	N	Y	2
NPPD	Elkhorn RPPD - Poulsen	E	I	S	SUN	2021	N	Y	1.5
NPPD	Southern PD Franklin County Wind	E	I	WT	WND	2023	N	Y	5.64
NPPD	Ogallala Solar	E	I	S	SUN	2023	N	Y	1.5
NPPD	York Solar	E	I	S	SUN	2023	N	Y	3.2
NPPD	Norris PPD - Centerville Solar	E	I	S	SUN	2024	N	Y	0.999
NPPD	Norris PPD - Deshler Solar	E	I	S	SUN	2024	N	Y	0.999
NPPD	Norris PPD - Ruby Solar	E	I	S	SUN	2024	N	Y	0.999
NPPD	City of Wahoo Solar	E	I	S	SUN	2024	N	Y	2
NPPD	York 1	E	E	RE	DFO	1980	Y	Y	1
NPPD	York 2	E	E	RE	DFO	1996	Y	Y	1.6
NPPD Total									3789.3
OPPD	BRIGHT Battery	E	I	ES	ES	2022	N	Y	1
OPPD	Turtle Creek #1	E	P	GT	NG/DFO	2025	Y	N	264
OPPD	Turtle Creek #2	E	P	GT	NG/DFO	2025	Y	N	264
OPPD	Platteview Solar	E	I	S	SUN	2024	N	N	81
OPPD	Jones St. #1	E	P	GT	DFO	1973	Y	N	65
OPPD	Jones St. #2	E	P	GT	DFO	1973	Y	N	65
OPPD	Tecumseh #1	E	P	RE	DFO	1949	Y	N	0.6
OPPD	Tecumseh #2	E	P	RE	DFO	1968	Y	N	1.4
OPPD	Tecumseh #3	E	P	RE	DFO	1952	Y	N	1
OPPD	Tecumseh #4	E	P	RE	DFO	1960	Y	N	1.2
OPPD	Tecumseh #5	E	P	RE	DFO	1993	Y	N	2.3
OPPD	Elk City Station #1-4	E	B	RE	LFG	2002	N	N	3.09
OPPD	Elk City Station #5-8	E	B	RE	LFG	2006	N	N	2.92
OPPD	Cass County #1	E	P	GT	NG	2003	N	N	172.5
OPPD	Cass County #2	E	P	GT	NG	2003	N	N	172.5
OPPD	North Omaha #1	E	B	ST	NG	1954	N	N	73.5
OPPD	North Omaha #2	E	B	ST	NG	1957	N	N	108.8
OPPD	North Omaha #3	E	B	ST	NG	1959	N	N	108.8
OPPD	Sarpy County #1	E	P	GT	NG/DFO	1972	Y	N	55.4
OPPD	Sarpy County #2	E	P	GT	NG/DFO	1972	Y	N	55.4
OPPD	Sarpy County #3	E	P	GT	NG/DFO	1996	Y	N	105.6
OPPD	Sarpy County #4	E	P	GT	NG/DFO	2000	Y	N	58.9
OPPD	Sarpy County #5	E	P	GT	NG/DFO	2000	Y	N	58.9

APPENDIX 1 - EXISTING RESOURCES
2025 Statewide Existing Generating Capability Data (Nameplate Capacity)

Utility	Unit Name	Unit Status	Duty Cycle	Unit Type	Fuel Type	Commercial Operation Date	On Site Fuel Storage (Y/N)	Behind the Meter	Nameplate Capacity
OPPD	Nebraska City #1	E	B	ST	SUB	1979	Y	N	651.6
OPPD	Nebraska City #2	E	B	ST	SUB	2009	Y	N	738
OPPD	North Omaha #4 (NG)	E	P	ST	NG	1963	N	N	
OPPD	North Omaha #4 (Coal)	E	B	ST	SUB/NG	1963	Y	N	136
OPPD	North Omaha #5 (NG)	E	P	ST	NG	1968	Y	N	
OPPD	North Omaha #5 (Coal)	E	B	ST	SUB/NG	1968	Y	N	217.6
OPPD	OPPD Community Solar	E	I	S	SUN	2020	N	Y	5
OPPD	Milligan Wind	E	I	WT	WND	2023	N	N	300
OPPD	Flat Water Wind	E	I	WT	WND	2011	N	N	60
OPPD	Grande Prairie Wind	E	I	WT	WND	2016	N	N	400
OPPD	Petersburg Wind	E	I	WT	WND	2012	N	N	40.5
OPPD	Prairie Breeze Wind	E	I	WT	WND	2014	N	N	200.6
OPPD	Sholes Wind	E	I	WT	WND	2019	N	N	160
OPPD Total									4632.1
SCRIBNER	Scribner #1	E	P	RE	OBL	2020	N	N	1.875
SCRIBNER	Scribner #2	E	P	RE	OBL	2020	N	N	1.875
Scribner Total									3.8
South Sioux City	SSC Solar	E	I	S	SUN	2018	N	Y	2.1
South Sioux City	Cottonwood Wind	E	I	WT	WND	2020	N	N	15.6
South Sioux City	WWTP Gen	E	I	RE	DFO	2023	Y	Y	1.75
South Sioux City	NG Generation Plant	E	P	RE	NG	2022	N	Y	4.95
South Sioux City Total									24.4
Superior	Community Solar	E	I	S	SUN	2018	N	Y	0
Superior Total									0
WAKEFIELD	Wakefield 2	E	P	RE	NG/DFO	1955	Y	N	0.5
WAKEFIELD	Wakefield 4	E	P	RE	NG/DFO	1961	Y	N	0.8
WAKEFIELD	Wakefield 5	E	P	RE	NG/DFO	1966	Y	N	1.2
WAKEFIELD	Wakefield 6	E	P	RE	NG/DFO	1971	Y	N	1.1
Wakefield Total									3.6
WAYNE	Wayne 1	E	P	RE	DFO	1951	Y	N	0.75
WAYNE	Wayne 3	E	P	RE	DFO	1956	Y	N	1.9
WAYNE	Wayne 4	E	P	RE	DFO	1960	Y	N	2.1
WAYNE	Wayne 5	E	P	RE	DFO	1966	Y	N	3.5
WAYNE	Wayne 6	E	P	RE	DFO	1968	Y	N	5.3
WAYNE	Wayne 7	E	P	RE	DFO	1998	Y	N	3.25
WAYNE	Wayne 8	E	P	RE	DFO	1998	Y	N	3.6
Wayne Total									20.4
NE Total									10609.8

Appendix 1 - 2025 Statewide Existing Generating Capability Data

Duty Cycle	B	Base
	DR	Demand Response
	E	Emergency Only
	ES	Energy Storage
	I	Intermediate
	M	Mobile/Emergency
	P	Peaking
Unit Type	CC	Combined Cycle
	CT	Combustion Turbine
	D	Diesel
	DR	Demand Response
	ES	Energy Storage
	GT	Gas Turbine
	H	Hydro
	N	Nuclear
	RE	Reciprocating Engine
	S	Solar
	ST	Steam Turbine
	WT	Wind Turbine
Fuel Type	BD	Biodiesel
	DFO	Diesel Fuel Oil
	DR	Demand Response
	ES	Energy Storage
	H	Hydrogen
	HR	Reservoir
	LFG	Landfill Gas
	NG	Natural Gas
	NG/DFO	Natural Gas & Diesel Fuel Oil
	NUC	Uranium
	OBL	Other Biomass Gas
	SUB	Coal
	SUB/NG	Coal & Natural Gas
	SUN	Solar
	WAT	Run of River
	WND	Wind