2026 NEBRASKA POWER ASSOCIATION

LOAD AND CAPABILITY REPORT

August 21, 2026

Disclosure

The 2026 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 6/1/2026, 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.

Table of Contents

Index of Figures

Index of Tables

Appendix

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

CPP – Consolidated Planning Process

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

FA – Fuel Assurance

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

ITP – Integrated Transmission Planning

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

NDWEE - Nebraska Department of Water, Energy, and Environment

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, City of Wayne, and City of Sidney. 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 2043. *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 2040. While forecasted loads in the near term are slightly higher than last year's expectations, there is also a corresponding increase in the utilities' expected net generating capability.

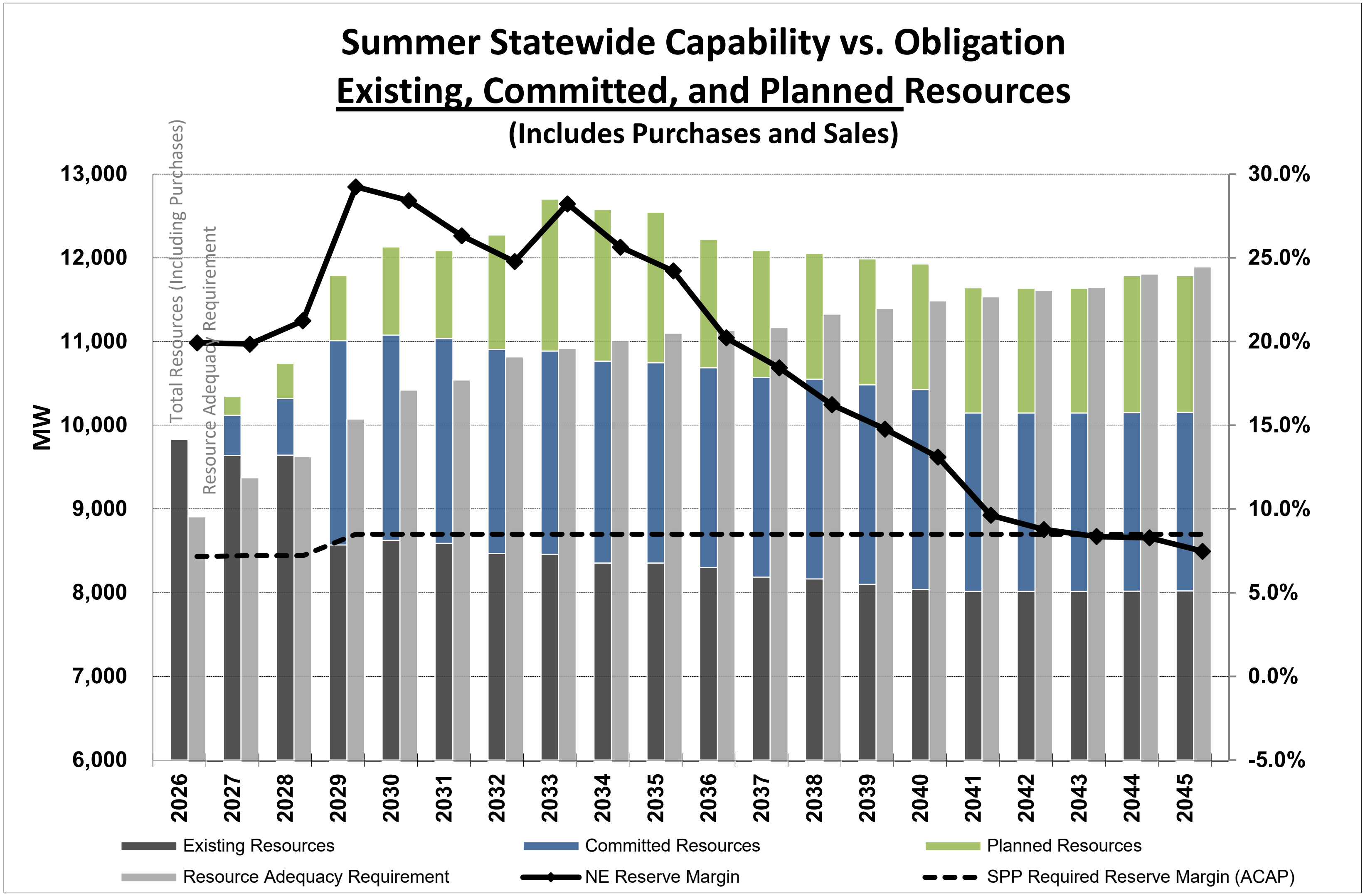

Figure 1 - Summer Statewide Capability vs. Obligation Existing, Committed, and Planned Resources (Includes Purchases and Sales)

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

Year	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
1 Annual System Demand	8,384	8,816	9,051	9,371	9,690	9,801	10,056	10,149	10,238	10,318	10,350	10,379	10,526	10,588	10,675	10,717	10,790	10,824	10,971	11,048
2 Firm Power Purchases - Total	1,181	1,183	1,184	1,186	1,188	1,190	1,192	1,193	1,195	1,197	1,199	1,201	1,203	1,205	1,207	1,208	1,210	1,212	1,214	1,216
3 Firm Power Sales - Total	84	84	84	84	84	84	84	84	84	84	84	84	84	84	84	84	84	84	84	84
4 Annual Net Peak Demand (1-2+3)	7,287	7,718	7,951	8,269	8,585	8,695	8,948	9,039	9,126	9,204	9,235	9,262	9,407	9,467	9,553	9,593	9,663	9,696	9,841	9,916
5 Net Generating Capability (owned)	7,881	8,440	8,673	9,921	10,151	10,097	10,253	10,684	10,670	10,637	10,601	10,468	10,430	10,357	10,308	10,020	10,014	10,006	10,004	10,005
6 Firm Capacity Purchases	1,607	1,541	1,698	1,457	1,513	1,520	1,556	1,554	1,462	1,462	1,167	1,167	1,168	1,174	1,161	1,161	1,162	1,165	1,316	1,316
7 Firm Capacity Sales	749	732	732	691	639	634	644	648	666	666	666	666	665	665	665	665	665	665	665	665
8 Adjusted Net Capability (5+6-7)	8,739	9,249	9,639	10,687	11,025	10,983	11,164	11,590	11,466	11,433	11,102	10,970	10,933	10,866	10,804	10,516	10,511	10,506	10,656	10,657
9 Net Reserve Capacity Obligation (4 x PRM)	522	556	572	703	730	739	761	768	776	782	785	787	800	805	812	815	821	824	837	843
10 Total Firm Capacity Obligation (4+9)	7,809	8,273	8,523	8,972	9,315	9,434	9,708	9,807	9,902	9,987	10,020	10,050	10,207	10,272	10,365	10,408	10,485	10,520	10,678	10,759
11 Surplus (+) or Deficit (-) (8-10)	930	976	1,116	1,715	1,710	1,549	1,456	1,783	1,564	1,447	1,083	921	726	594	439	108	26	-14	-22	-102
12 Nebraska Reserve Margin ((8-4)/4)	19.9%	19.8%	21.2%	29.2%	28.4%	26.3%	24.8%	28.2%	25.6%	24.2%	20.2%	18.4%	16.2%	14.8%	13.1%	9.6%	8.8%	8.4%	8.3%	7.5%
13 Nebraska Capacity Margin ((8-4)/8)	16.6%	16.6%	17.5%	22.6%	22.1%	20.8%	19.9%	22.0%	20.4%	19.5%	16.8%	15.6%	14.0%	12.9%	11.6%	8.8%	8.1%	7.7%	7.6%	7.0%
Existing, Committed, Planned Resources (8+2-3)	9,836	10,348	10,740	11,789	12,129	12,089	12,272	12,700	12,577	12,547	12,217	12,087	12,052	11,987	11,926	11,640	11,637	11,634	11,786	11,789
Resource Adequacy Requirement (MW) (1+9)	8,906	9,372	9,624	10,074	10,420	10,540	10,816	10,917	11,013	11,100	11,135	11,167	11,326	11,393	11,487	11,533	11,611	11,648	11,808	11,891
SPP Minimum Reserve Margin (ACAP)	7.16%	7.20%	7.20%	8.50%	8.50%	8.50%	8.50%	8.50%	8.50%	8.50%	8.50%	8.50%	8.50%	8.50%	8.50%	8.50%	8.50%	8.50%	8.50%	8.50%
First Year of Deficit - Minimum																				

If the proposed Studied resources are added to the Existing, Committed, and Planned resources, the statewide deficit year occurs after 2045, which is the last year of the report's twenty-year study period. Last year's report with all resource categories indicated a deficit in the final year of 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 past 2045. *Table 2* contains the corresponding load and capability data in tabular format. The statewide winter resource adequacy deficit in last year's report occurred in 2043. The deficit condition moved to a later year relative to last year's report due to committed and planned resources to serve the forecasted addition of loads being added within the service territory of the state's larger utilities.

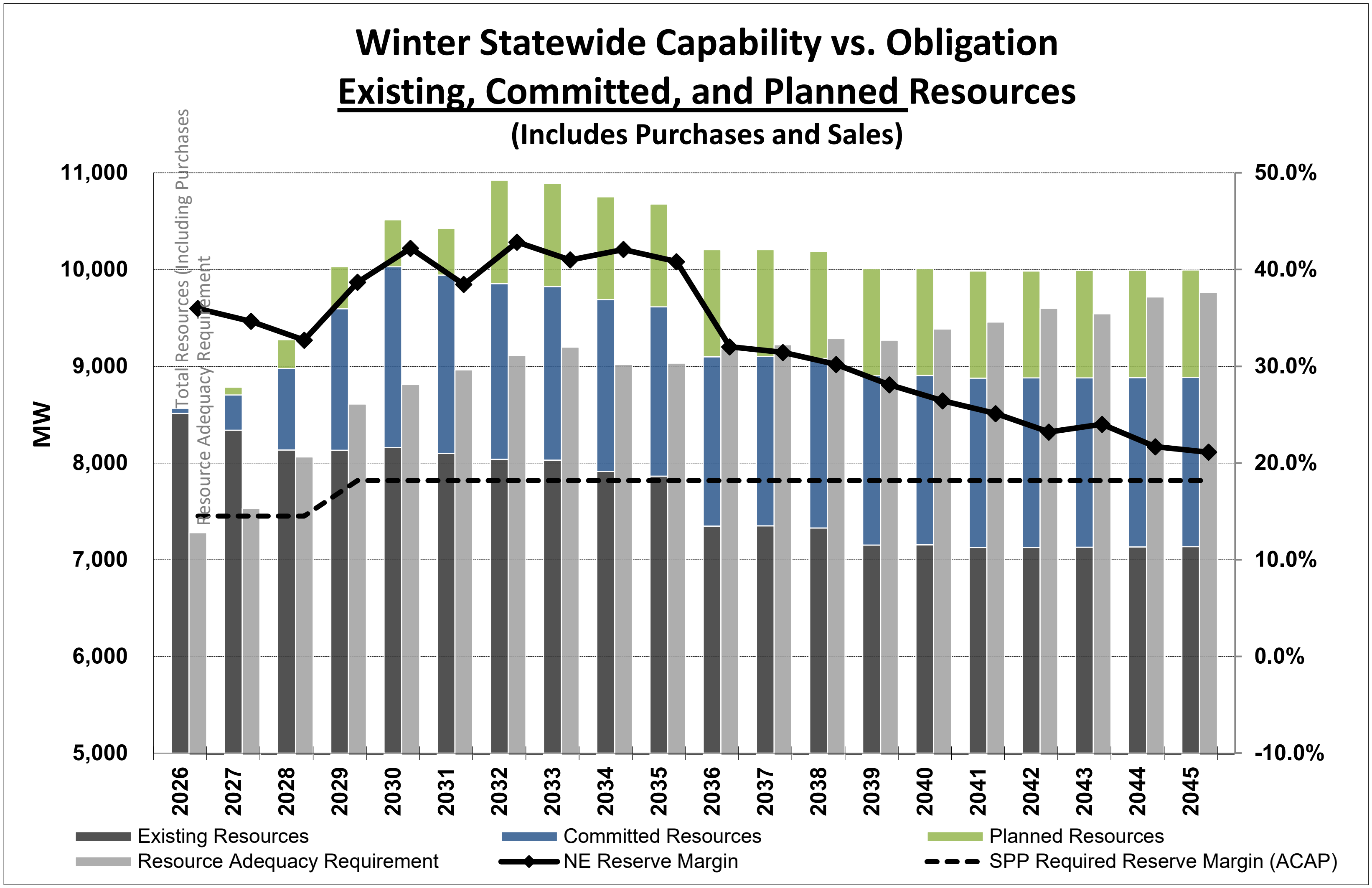

Figure 2 - Winter Statewide Capability vs. Obligation Existing, Committed, and Planned Resources (Includes Purchases and Sales)

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

Year	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
1 Annual System Demand	6,408	6,630	7,093	7,349	7,520	7,650	7,775	7,848	7,695	7,708	7,835	7,869	7,924	7,910	8,009	8,068	8,188	8,142	8,290	8,330
2 Firm Power Purchases - Total	491	492	495	496	500	502	503	504	505	507	508	509	510	512	513	514	516	517	518	519
3 Firm Power Sales - Total	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75
4 Annual Net Peak Demand (1-2+3)	5,992	6,213	6,673	6,929	7,095	7,222	7,347	7,419	7,265	7,276	7,402	7,435	7,489	7,473	7,571	7,628	7,747	7,700	7,847	7,885
5 Net Generating Capability (owned)	7,504	7,743	8,030	8,774	9,197	9,166	9,578	9,532	9,507	9,482	9,302	9,301	9,279	9,115	9,114	9,085	9,085	9,085	9,085	9,086
6 Firm Capacity Purchases	1,498	1,428	1,562	1,491	1,550	1,489	1,567	1,574	1,461	1,411	1,116	1,116	1,117	1,100	1,100	1,101	1,102	1,105	1,106	1,106
7 Firm Capacity Sales	853	806	737	657	659	655	652	647	647	647	646	646	646	642	642	642	642	642	642	642
8 Adjusted Net Capability (5+6-7)	8,148	8,366	8,855	9,608	10,089	10,000	10,494	10,460	10,321	10,247	9,771	9,771	9,749	9,572	9,572	9,544	9,544	9,548	9,549	9,550
9 Net Reserve Capacity Obligation (4 x PRM)	870	902	969	1,261	1,291	1,314	1,337	1,350	1,322	1,324	1,347	1,353	1,363	1,360	1,378	1,388	1,410	1,401	1,428	1,435
10 Total Firm Capacity Obligation (4+9)	6,863	7,115	7,642	8,190	8,386	8,537	8,684	8,769	8,587	8,601	8,749	8,788	8,852	8,833	8,949	9,016	9,157	9,101	9,275	9,320
11 Surplus (+) or Deficit (-) (8-10)	1,286	1,251	1,213	1,419	1,702	1,463	1,810	1,691	1,734	1,646	1,022	983	897	739	624	527	387	446	274	230
12 Nebraska Reserve Margin ((8-4)/4)	36.0%	34.7%	32.7%	38.7%	42.2%	38.5%	42.8%	41.0%	42.1%	40.8%	32.0%	31.4%	30.2%	28.1%	26.4%	25.1%	23.2%	24.0%	21.7%	21.1%
13 Nebraska Capacity Margin ((8-4)/8)	26.5%	25.7%	24.6%	27.9%	29.7%	27.8%	30.0%	29.1%	29.6%	29.0%	24.2%	23.9%	23.2%	21.9%	20.9%	20.1%	18.8%	19.4%	17.8%	17.4%
Existing, Committed, Planned Resources (8+2-3)	8,564	8,783	9,275	10,029	10,514	10,428	10,922	10,889	10,752	10,679	10,204	10,205	10,185	10,009	10,010	9,983	9,985	9,990	9,992	9,995
Resource Adequacy Requirement (MW) (1+9)	7,279	7,532	8,062	8,610	8,811	8,964	9,112	9,198	9,018	9,033	9,182	9,222	9,287	9,270	9,387	9,456	9,598	9,543	9,718	9,765
SPP Minimum Reserve Margin (ACAP)	14.52%	14.52%	14.52%	18.20%	18.20%	18.20%	18.20%	18.20%	18.20%	18.20%	18.20%	18.20%	18.20%	18.20%	18.20%	18.20%	18.20%	18.20%	18.20%	18.20%
First Year of Deficit - Minimum																				

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 2045, 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 2043. However, there are many inherent risks that can impact a generator's actual commercial operation 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 6.9 GW 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 grown to unprecedented levels. Along with this comes uncertainty as to whether the new load requests 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 (2026-2045).

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.)	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.	4.4.4 Age-Based Retirement
Number of units or percentage of capacity that are currently dual fuel.	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.	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.	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).	5.1.4 Stress Period(s)/ Stress Test
Include the winter peak loads and aggregate winter accreditation of units.	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.	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.	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.	3.6 Grid , 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 Report Requirements

In late 2023, the NPRB requested additional modifications and clarifications to be incorporated into the Report. One such request was a comparison of the most readily available historical forced outage data of the total SPP fleet – specifically, either the EFORd or EFORd' metric – to the aggregate forced outage rate of Nebraska's generation fleet. This comparison is included in Section 3.4 using forced outage rate data published by SPP on a generation capacity weighted basis. The NPRB also requested specific 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 an interruption of natural gas supply coincident with extreme cold temperatures. The discussion of this winter fuel sensitivity is included at the end of Section 5.1.5. 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 decarbonization 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 to 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 as part of the Board's 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.

In its 2026 Integrated System Plan, OPPD will continue to evaluate the incremental cost of feasible decarbonization actions and the resulting impact to system reliability. The ISP will determine optimal plans for capacity expansion that arrive at the 2050 net zero goal along a variety of decarbonization trajectories. The achievable pace of emission reduction will change in response to the rate of load growth and the availability of carbon-free emerging technologies. 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 6.4% for winter peak load and 2.9% for summer peak load. This marks a departure from the nearly flat growth experienced in the decade prior. In fact, the growth rate experienced by OPPD from 2019-2026 even exceeds the 1.89% growth of ERCOT in Texas and the 0.1% growth in the California ISO (CAISO.)

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 voluntary 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.

In December 2025, OPPD's Board of Directors voted to extend North Omaha Station (NOS) in its current state, directing OPPD staff to proceed with SPP Transmission Tariff processes and internal Integrated System Plan studies to transition NOS by retiring units 1-3 and converting units 4-5 from coal to natural gas by the earliest feasible date. The earliest feasible date to complete the NOS transition is winter 2028-29, which is assumed in the calculations underlying this NPA report.

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 resource mix includes hydro, solar, wind, gas, coal, and fuel oil. 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 the U.S. Environmental Protection Agency, U.S. Fish & Wildlife Service, Nebraska Department of Water, Energy, and Environment, 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 began full operations as scheduled in spring of 2026. By joining the RTO, they have gained 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 expanded SPP footprint.

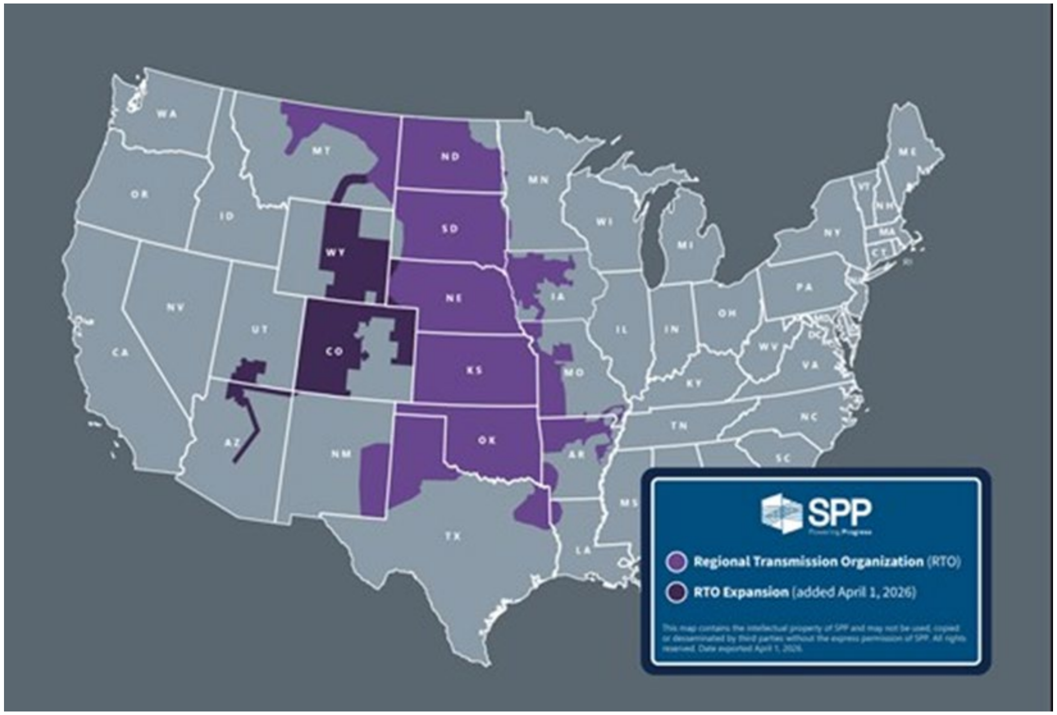

Figure 3 - SPP Footprint Overview

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 seasonal summer and winter Resource Adequacy Workbooks 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 calculate the required incremental capacity, or 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.

SPP previously 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. The most recent LOLE study and SPP Board of Directors action extended these requirements through at least 2032.

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. The accreditation process assigns a capacity value to each individual resource to be counted toward an LRE's resource adequacy requirement. There are multiple processes for accrediting resources based on the type of resource.

Over the past few years, SPP has enacted new policies for accreditation of virtually all resource types. SPP's Effective Load Carrying Capability (ELCC), Fuel Assurance (FA), and Performance Based Accreditation (PBA) policies have been approved by SPP's Board of Directors and have received final approval at FERC.

3.4.1 Effective Load Carrying Capability

Until last year, variable energy resources, such as wind and solar, were accredited according to their production during a utility's peak load hours. The process utilized the 60th percentile of production during the top 3% of load conditions. In other words, the resource met or exceeded the accreditation value 60% of the time during top load hours.

This accreditation methodology for variable energy resources did not account for the diminishing marginal resource adequacy value of these resources with increasing penetration on the electric system. To properly account for this, in the summer of 2026, SPP moved to an Effective Load Carrying Capability (ELCC) methodology for accreditation. ELCC accounts for historical weather variability across the region and periods of regionally low renewable generation and in this way measures how each resource type contributes to system reliability during peak conditions.

The ELCC method, applicable to wind, solar and energy storage, captures real-time correlations between variable energy resources and load. The calculations determine how well a given resource type is able to act as "perfect capacity" 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:

$$Accredited\ Capacity = Nameplate\ Capacity * ELCC$$

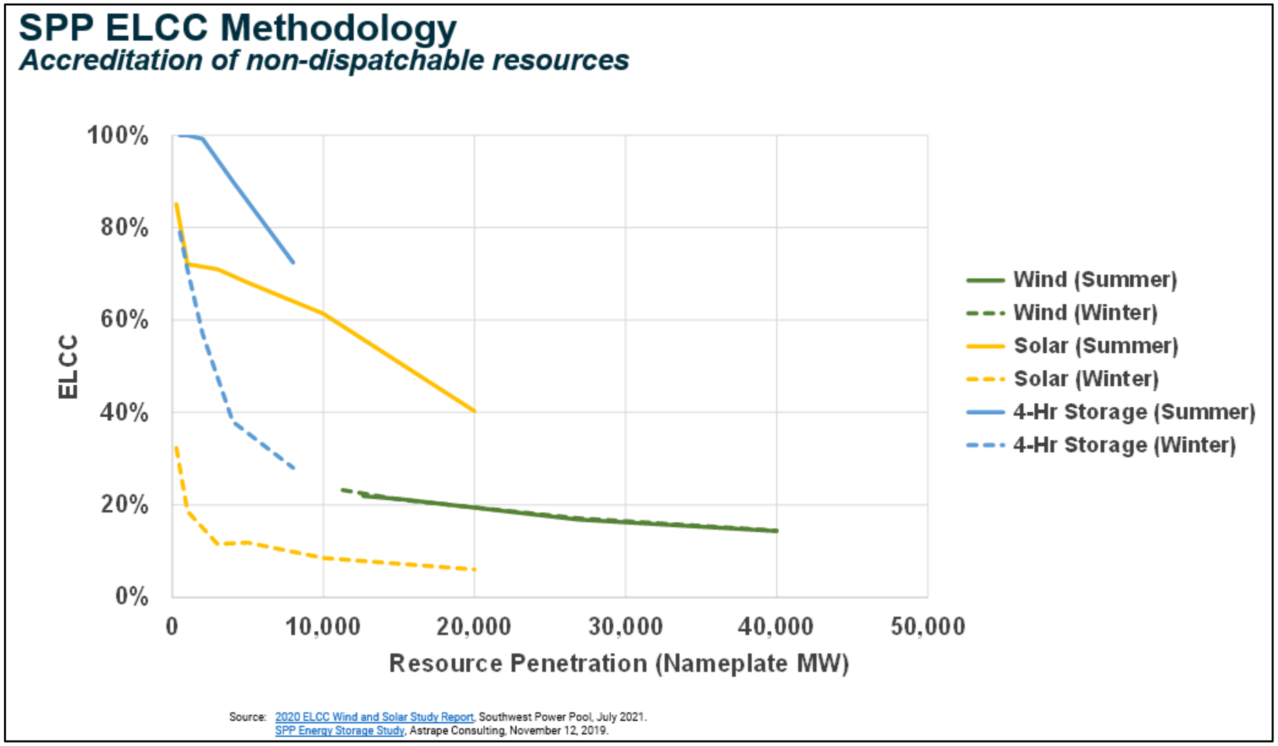

Figure 4 - SPP ELCC Methodology Examples

3.4.2 Performance Based Accreditation

Thermal resources were formerly accredited based on their peak generating capability as 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. Basing unit accreditation on a one-time test neglected the real-time reliability contribution of each individual unit.

With the summer season of 2026, new SPP Performance Based Accreditation (PBA) and Fuel Assurance (FA) policies became effective for accreditation of thermal generators. PBA considers the historical reliability of individual generators, specifically the rate of forced outages a unit experiences over a given time period, to calculate individual unit accreditation. Units with increased forced outage rates will receive lower accreditation and will therefore contribute less to an LRE's resource adequacy requirements. This is expected to incent reliability enhancements for poorly performing generators.

This PBA 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 Equivalent Forced Outage Rate (demand), or EFORd, for the applicable season. The PBA calculation utilizes 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 *Figure 4*) is as follows:

$$Accredited\ Capacity = NGC * (1 - EFORd)$$

3.4.3 Fuel Assurance

In addition to the PBA policy, the FA policy further impacts thermal generator accreditation during the winter season based on performance during the most critical system periods of the season. This policy is intended to further encourage generation to be available when needed most. The statewide Load and Capability Report is based on this resource accreditation methodology, effective in the summer of 2026.

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.

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	0.58%	1.88%	0.38%	1.82%	126.0	133.7	125.5	131.3
Conventional Steam Coal	9.77%	17.53%	10.16%	16.70%	3,602.9	3,536.9	3,236.9	2,946.1
CT w/ Onsite Fuel Storage	9.90%	18.66%	12.76%	21.91%	979.8	1,042.7	854.7	814.2
CT w/o Onsite Fuel Storage	6.65%	32.10%	5.70%	-	321.0	-	302.7	-
Hydroelectric Pumped Storage	5.29%	5.81%	-	-	-	-	-	-
NG Fired Combined Cycle	4.73%	11.19%	4.76%	11.68%	246.9	248.1	235.2	219.1
NG Steam Turbine	11.62%	22.45%	11.83%	14.50%	334.0	99.3	294.5	84.9
Nuclear	2.09%	0.87%	1.95%	1.39%	768.5	807.9	753.5	796.7
RICE w/ Onsite Fuel Storage	5.30%	6.89%	5.31%	6.59%	218.4	218.4	206.8	204.0
RICE w/o Onsite Fuel Storage	2.89%	7.87%	7.62%	14.56%	4.7	4.7	4.3	4.0

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. The reduction in unit accreditation now allocates a portion of the Base PRM to individual units based on performance and reliability. The remaining portion of the system margin required to meet the reliability standards is recalculated and applied equally to all LREs. Therefore, as SPP adopts these accreditation policies, the seasonal PRM requirements have transitioned from an Installed Capacity (ICAP) basis to an Accredited Capacity (ACAP) basis, also effective since summer 2026. This change in basis results in a lower overall ACAP PRM as a portion of the Base PRM, for each season. Thus, LREs with unit reliability that is higher than the SPP system average 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 subject to a higher ACAP PRM and are thereby incentivized to continue to invest in reliability improvements. The seasonal ACAP PRM values will be recalculated by SPP annually, and these recurring adjustments could likely be a source of uncertainty for the LREs when 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 most recent SPP-approved seasonal ACAP PRM values and unit accreditation.

3.4.4 Demand Response Accreditation

SPP is currently in the process of developing revised rules to address the accreditation of demand response programs. SPP has submitted proposed tariff language to FERC in Docket No. ER26-2249-000 and ER26-2249-001 which will allow market-registered demand response resources to be used as capacity resources for SPP's Resource Adequacy Requirements, create a new type of demand response resource to deploy during conservative operations advisories and energy emergency alerts which an LRE may use as Accredited Capacity, permit LREs to utilize Non-Registered Demand Response programs as load modifiers to reduce forecasted Peak Demand, and implement a new Peak Demand Assessment process that will assess a Deficiency Payment on an LRE's actual, weather-normalized Net Peak Demand instead of an LRE's forecasted load. SPP is seeking an effective date of January 1, 2027 for this language; however, FERC action in the docket is pending.

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 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.

Recent declining costs of renewable generation technologies and projected load growth 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.

To address these challenges and improve the efficiency, predictability, and coordination of the generator interconnection process, SPP has developed the Consolidated Planning Process (CPP). CPP represents a significant shift from the existing approach by integrating generator interconnection studies with regional transmission planning activities. Rather than evaluating generation additions and transmission needs through separate processes, CPP will allow SPP to assess future generation, load growth, reliability requirements, economic needs, and transmission expansion opportunities through a coordinated planning framework.

The implementation of CPP will occur through a phased transition from the existing Integrated Transmission Planning (ITP) process. SPP will continue to perform ITP studies during the transition period, while introducing CPP elements through transition assessments. The final ITP cycle is expected to conclude with the 2027 ITP Sunset Assessment, after which CPP will become the primary transmission planning framework. The first full CPP-10 assessment is expected to begin in 2028, followed by the first CPP-20 assessment in 2030. Through this transition, SPP intends to reduce study duplication, improve the coordination between transmission planning and generator interconnection, and provide a more streamlined and predictable process for new resources seeking interconnection to the transmission system.

A listing of the projects in the GI Queue from July 8th, 2026, within the state of Nebraska shows around 1,608 MW of nameplate capacity for battery storage (7 projects), 3,304 MW of solar (18 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 3.5 GW 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 6,131 MW (24 projects). 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.

Executed GIA with commercial operation dates from 2024 to 2031 account for 6.5 GW of nameplate capacity as shown in the figure below. (567 MW of thermal, 1,602 MW of wind, 2,662 MW of solar, 535 MW of hybrid, and 1,137 MW of storage). Once again, it should be noted that an executed GIA does not indicate certainty that a resource will reach full execution and operation. On September 30, 2025, SPP submitted FERC Docket No. ER25-3570-000, Submission of Tariff Revisions to Attachment V of the Open Access Transmission Tariff to Implement Accelerated Processing of Incremental Capacity Additions to Existing Generating Facilities. In the filing, SPP discussed historical generator interconnection queue attrition, noting that approximately 60% of queued capacity is expected to withdraw, with only a portion of the remaining projects ultimately reaching commercial operation due to supply chain, permitting, and commercial challenges.

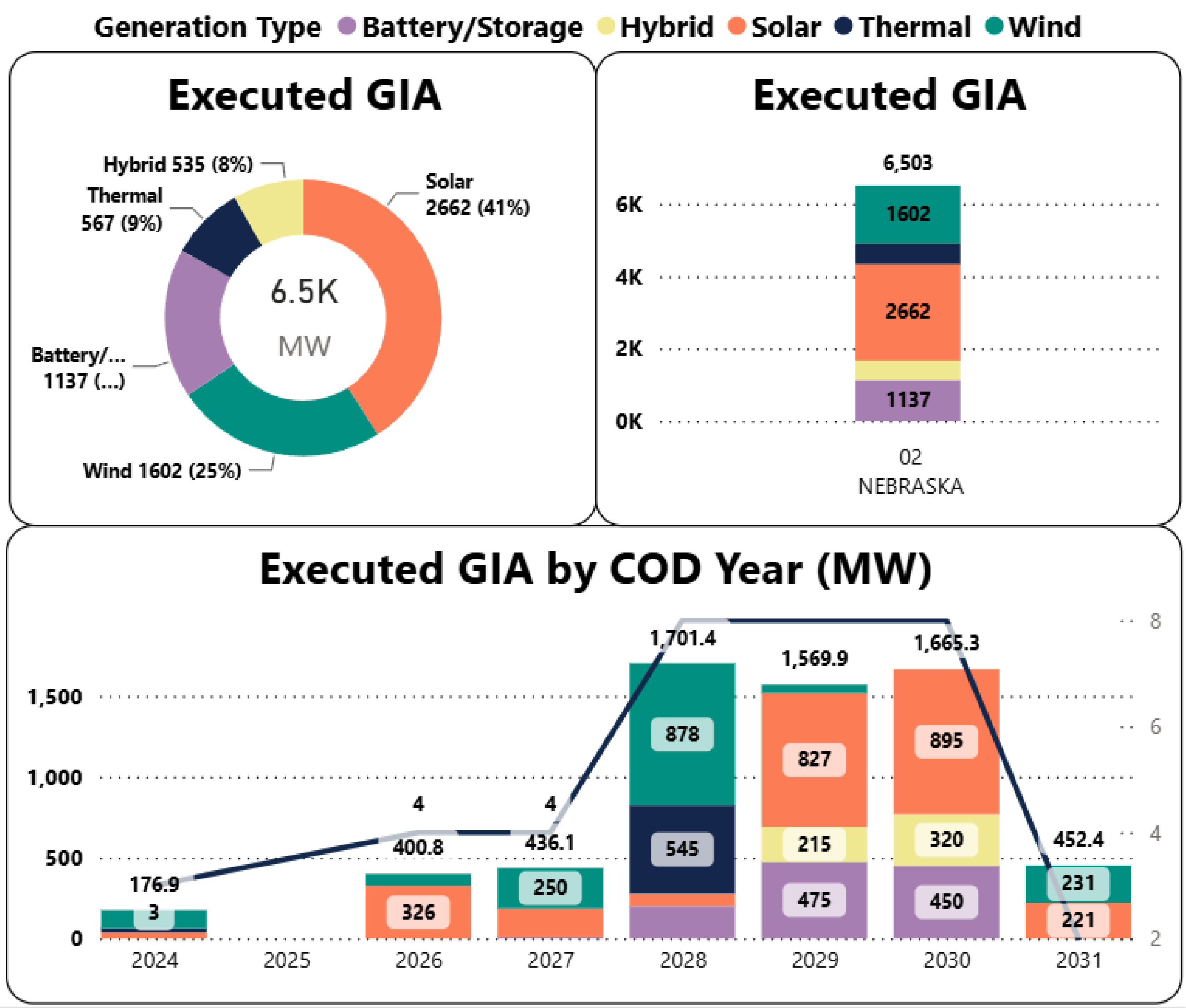

Figure 5: executed GIA in the state of Nebraska (from spp.org)

Figure 5 illustrates SPP projects with executed Generator Interconnection Agreements (GIAs) that have not yet reached commercial operation. While execution of a GIA represents a significant milestone in the interconnection process, it does not indicate that a project has reached commercial operation. As discussed previously, projects with executed GIAs may still experience delays, be suspended, or ultimately withdraw due to financing, permitting, equipment procurement, market conditions, or other commercial considerations. Accordingly, execution of a GIA should be viewed as an indicator of project maturity rather than a guarantee that the project will ultimately achieve commercial operation.

3.6 Grid Changes

Nebraska utilities face a variety of future challenges beyond evolving Southwest Power Pool (SPP) requirements and the pursuit of decarbonization goals. Among these challenges is the uncertainty surrounding future environmental and energy policies, regulations, and compliance requirements. Regulatory frameworks affecting generation resources, emissions, reliability, and market operations continue to evolve, creating uncertainty regarding future operational and investment decisions. As utilities develop long-term resource plans, it is important to consider a range of potential regulatory outcomes and associated risks. This evolving policy environment requires ongoing monitoring and assessment to help ensure resource portfolios remain reliable, affordable, and adaptable.

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 CO_2 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 generation.

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 seasonal summer and winter peak demand forecasts and corresponding load and capability tables. 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 2026 through 2045, the average annual compounded peak demand growth rate for the state is projected at 1.5% per year (individual utilities range from -0.6%/yr. to 2.0%/yr.). The escalation rate shown in last year's report for 2025 through 2044 was 1.7%.

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

For the following sub-chapters, if not stated otherwise, accredited capacity MW values refer to the calculated need-year, which, in this year, shows to be 2043 in summer. This clarification is needed because accredited capacity values differ from year to year for some resource types and tend to decrease in future years. In fact, the higher a renewable resource type's (wind, solar, storage) total SPP wide penetration, the lower the resulting ELCC calculation.

4.3.1 Existing and Committed Resources

The state has an Existing summer accredited generating resource capability of 7,881 MW. Existing resources are those resources that are in-service and can obtain an accreditation rating in SPP. These resources may have different accreditation values based on the season. This is a decrease from the 8,250 MW shown in the 2025 report due to the implementation of new accreditation policies in SPP and is accompanied by the lower ACAP Planning Reserve Margin. An additional 2,788 MW of existing firm power purchases and firm capacity purchases contribute to utility capabilities.

There are 2,870 MW nameplate, or 2,133 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 Committed projects either currently in development or recently placed in service within Nebraska:

- Addition of 23.3 MW of Behind-The-Meter renewable generation was added between 2023 and 2024.
- In March of 2024, OPPD obtained NPRB approval for the construction of 900 MW of dual fuel combustion turbines to be located at the existing Cass County Station and Turtle Creek Station 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.
- In 2027 the Pierce County Energy Center will reach commercial operation, providing OPPD with energy from 210 MW of solar and 85 MW of battery storage and capacity from a total of 420 MW of solar and 170 MW of battery energy storage. Thus, OPPD is entitled to 50% of the project's energy, while the full 100% of the project's capacity is available for accreditation to OPPD.
- Earlier in 2026 OPPD executed an agreement for offtake of capacity and energy from the 250 MW Burt County solar project.
- NPPD is preparing to meet the state's growing energy needs with Princeton Road Station (PRS). The plant will be built on NPPD-owned land near Sheldon Station in southern Lancaster County, just north of Hallam. Expected to be completed in 2029, PRS will generate up to 694 megawatts of electricity—enough to power about 318,000 homes—using a mix of dual-fuel combustion turbines and reciprocating internal combustion engines.
- With 115 MW of additional capacity, Greeley Wind is a significant renewable energy project in Greeley County, Nebraska with enough generating capacity to power thousands of homes and businesses. This wind facility is expected to be in service by the end of 2029.

- NPPD has also committed to a PPA for a 50 MW / 200 MWh battery energy storage facility co-located with the Steele Flats wind facility in southeast Nebraska. This facility will have the ability to provide 50 MWs of power during peak hours, serve as a quick dispatch facility, and provide system reliability and resiliency.
- LES has also added committed resources to its portfolio plan, consisting of two 52-MW dual fuel, aeroderivative combustion turbines that will be installed at LES' existing Terry Bundy Generating Station, targeting commercial operation in 2029, and a 3-MW battery storage Power Purchase Agreement which is expected to achieve commercial operation in September 2026. This zinc-based battery is supporting LES' existing Community Microgrid, helping to ensure reliable and resilient service to critical loads in the downtown Lincoln area.
- In December 2025, OPPD's Board of Directors voted to extend North Omaha Station (NOS) in its current state, directing OPPD staff to proceed with SPP Transmission Tariff processes and internal Integrated System Plan studies to transition NOS by retiring units 1-3 and converting units 4-5 from coal to natural gas by the earliest feasible date. The earliest feasible date to complete the NOS transition is winter 2028-29, which is assumed in the calculations underlying this NPA report.

4.3.1.1 Firm Dispatchable Resources

The state has 7,207 MW of commercially operating firm dispatchable accredited resources for the summer peak of 2026. These resources are accredited based on the SPP PBA based methodologies. As stated in "3.4 Resource Accreditation", PBA, ELCC, and FA accreditation values are utilized for summer 2026 and beyond.

4.3.1.2 Renewable and Demand Side Resources

The state has 2,729 MW (nameplate) of commercially operating renewable resources for the summer peak of 2026, of which 145 MW are coming from in-state hydro for Nebraska's use. 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, under SPP's current resource accreditation process, a new wind or solar resource may be included in the applicable ELCC study (Tier 1 or Tier 2) by satisfying the submission requirements specified in Section 7.1.6.2 of the SPP Planning Criteria. These include submitting the resource in the Generator Owner's or LRE's current-year workbook by May 15 and providing three years of engineered generation shapes, with the first year corresponding to the current submittal year. If engineered generation shapes are not provided for a new wind or solar resource, the Transmission Provider develops the required profiles in accordance with the procedures described in Section 7.1.6.2(1)(b) of the SPP Planning Criteria. In addition, for Tier 1 eligibility, Designated Resources, resources associated with Point-to-Point Transmission Service, and other resources with firm transmission service must confirm the appropriate level of transmission service by June 1, as specified in Section 7.1.6.2 of the SPP Planning Criteria. Resources that satisfy these requirements are included in the applicable ELCC study and receive an accreditation determined by the ELCC methodology. By contrast, under SPP's former Net Capability accreditation methodology, if the Load-Serving Entity (LSE) elected not to perform the prescribed net capability calculations during a facility's first three years of commercial operation, the resource could instead be assigned a default accredited capacity equal to 5% of the facility's nameplate rating for wind or 10% of the facility's nameplate rating for solar, as provided in Section 8.1.1.3 of the SPP Planning Criteria. These values served as default planning assumptions under the legacy methodology and are distinct from the ELCC-based accreditation process.

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 has submitted to FERC a new methodology revising the standards for these resources. 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 6 shows the existing and committed statewide renewable and greenhouse gas mitigating generation by both nameplate and accredited capacity.

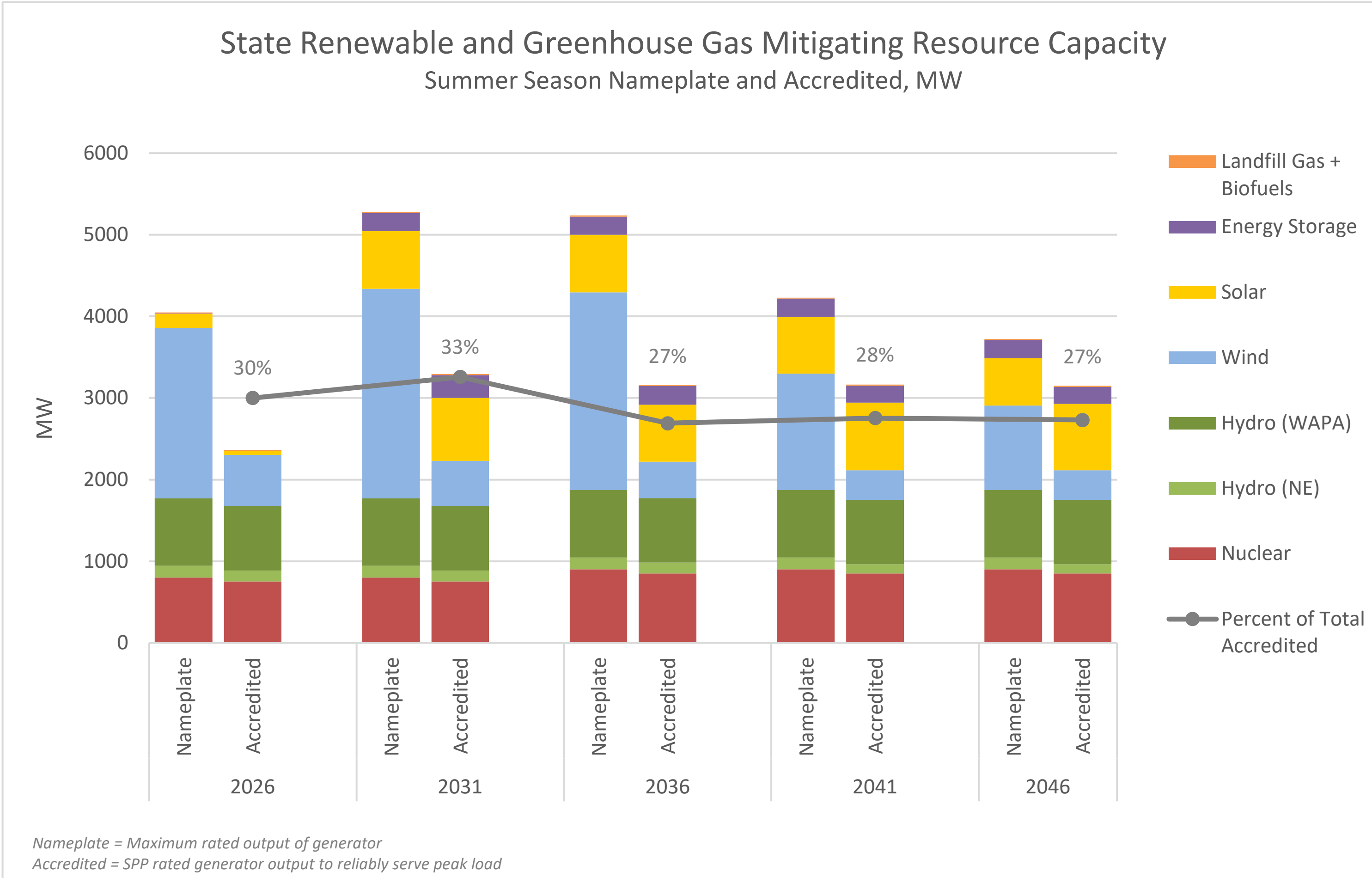

Figure 6 - Statewide Renewable and Greenhouse Gas Mitigating Resources - Summer Season

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 subscribed to the full production of this facility. With these applications, customer participation with local utilities is providing additional opportunities to increase the utilization of renewable energy.

In addition, an NPPD retail community has 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 a 3 MW / 12 MWh BESS with a commercial operating date around September 2026. 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 945 MW of accredited Planned resources anticipated in this report which includes 669 MW of dual fueled thermal resources, 262 MW of solar generation, and 14 MW of energy storage. There is also 10.9 MW of Planned nameplate solar generation that is located behind the meter for which no accredited capacity is being claimed (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 1,372 MW of accredited Studied resources anticipated in the first deficit year of this report that includes 1,027 MW of dual fueled thermal, 171 MW of solar, and 174 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 7* illustrates that a statewide capacity deficit would occur starting in 2043. *Table 5* contains the corresponding load and capability data in tabular format. The statewide deficit for the summer season based on the state's resource adequacy requirement in last year's report occurred in 2040 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. Forecasted loads throughout the study's time horizon have increased from last year's report, and there is also a corresponding increase in the utilities' expected net generating capability. Beginning in 2026, ELCC accreditation is utilized for the state's renewable resources, and PBA accreditation is utilized for the state's conventional resources. The statewide Resource Adequacy Requirement is based on the ACAP PRM for 2026.

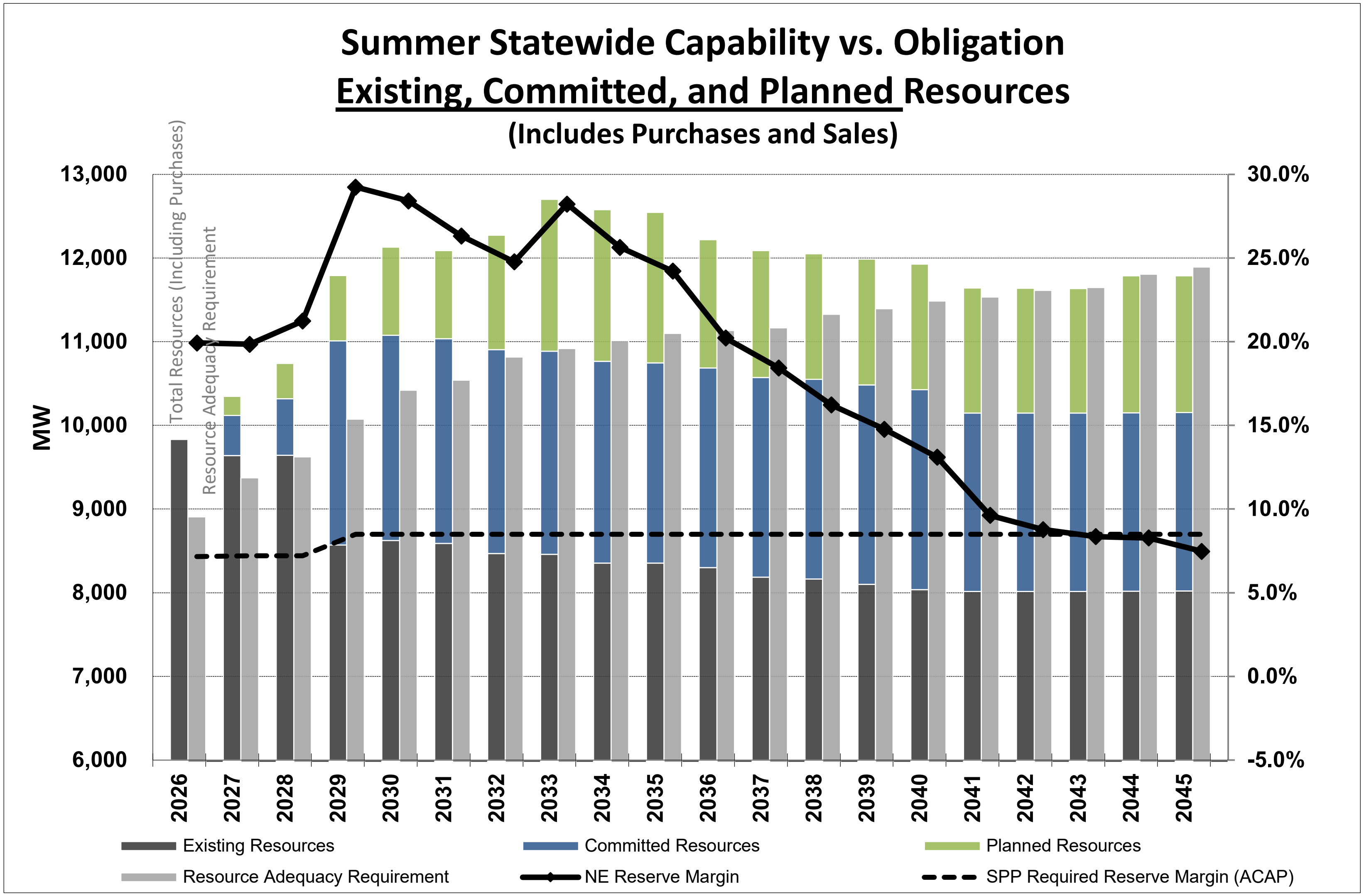

Figure 7 - Summer Statewide Capability vs. Obligation Existing, Committed, and Planned Resources (Includes Purchases and Sales)

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

Year	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
1 Annual System Demand	8,384	8,816	9,051	9,371	9,690	9,801	10,056	10,149	10,238	10,318	10,350	10,379	10,526	10,588	10,675	10,717	10,790	10,824	10,971	11,048
2 Firm Power Purchases - Total	1,181	1,183	1,184	1,186	1,188	1,190	1,192	1,193	1,195	1,197	1,199	1,201	1,203	1,205	1,207	1,208	1,210	1,212	1,214	1,216
3 Firm Power Sales - Total	84	84	84	84	84	84	84	84	84	84	84	84	84	84	84	84	84	84	84	84
4 Annual Net Peak Demand (1-2+3)	7,287	7,718	7,951	8,269	8,585	8,695	8,948	9,039	9,126	9,204	9,235	9,262	9,407	9,467	9,553	9,593	9,663	9,696	9,841	9,916
5 Net Generating Capability (owned)	7,881	8,440	8,673	9,921	10,151	10,097	10,253	10,684	10,670	10,637	10,601	10,468	10,430	10,357	10,308	10,020	10,014	10,006	10,004	10,005
6 Firm Capacity Purchases	1,607	1,541	1,698	1,457	1,513	1,520	1,556	1,554	1,462	1,462	1,167	1,167	1,168	1,174	1,161	1,161	1,162	1,165	1,316	1,316
7 Firm Capacity Sales	749	732	732	691	639	634	644	648	666	666	666	666	665	665	665	665	665	665	665	665
8 Adjusted Net Capability (5+6-7)	8,739	9,249	9,639	10,687	11,025	10,983	11,164	11,590	11,466	11,433	11,102	10,970	10,933	10,866	10,804	10,516	10,511	10,506	10,656	10,657
9 Net Reserve Capacity Obligation (4 x PRM)	522	556	572	703	730	739	761	768	776	782	785	787	800	805	812	815	821	824	837	843
10 Total Firm Capacity Obligation (4+9)	7,809	8,273	8,523	8,972	9,315	9,434	9,708	9,807	9,902	9,987	10,020	10,050	10,207	10,272	10,365	10,408	10,485	10,520	10,678	10,759
11 Surplus (+) or Deficit (-) (8-10)	930	976	1,116	1,715	1,710	1,549	1,456	1,783	1,564	1,447	1,083	921	726	594	439	108	26	-14	-22	-102
12 Nebraska Reserve Margin ((8-4)/4)	19.9%	19.8%	21.2%	29.2%	28.4%	26.3%	24.8%	28.2%	25.6%	24.2%	20.2%	18.4%	16.2%	14.8%	13.1%	9.6%	8.8%	8.4%	8.3%	7.5%
13 Nebraska Capacity Margin ((8-4)/8)	16.6%	16.6%	17.5%	22.6%	22.1%	20.8%	19.9%	22.0%	20.4%	19.5%	16.8%	15.6%	14.0%	12.9%	11.6%	8.8%	8.1%	7.7%	7.6%	7.0%
Existing, Committed, Planned Resources (8+2-3)	9,836	10,348	10,740	11,789	12,129	12,089	12,272	12,700	12,577	12,547	12,217	12,087	12,052	11,987	11,926	11,640	11,637	11,634	11,786	11,789
Resource Adequacy Requirement (MW) (1+9)	8,906	9,372	9,624	10,074	10,420	10,540	10,816	10,917	11,013	11,100	11,135	11,167	11,326	11,393	11,487	11,533	11,611	11,648	11,808	11,891
SPP Minimum Reserve Margin (ACAP)	7.16%	7.20%	7.20%	8.50%	8.50%	8.50%	8.50%	8.50%	8.50%	8.50%	8.50%	8.50%	8.50%	8.50%	8.50%	8.50%	8.50%	8.50%	8.50%	8.50%
First Year of Deficit - Minimum																				

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 2043. 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 6.9 GW 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 8 shows the statewide projected load and capability position inclusive of 7,881 MW of accredited Existing (summer 2026), 2,133 MW accredited Committed (summer 2043), 945 MW accredited Planned (summer 2043), and 1,372 MW of accredited Studied (summer 2043) 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*.

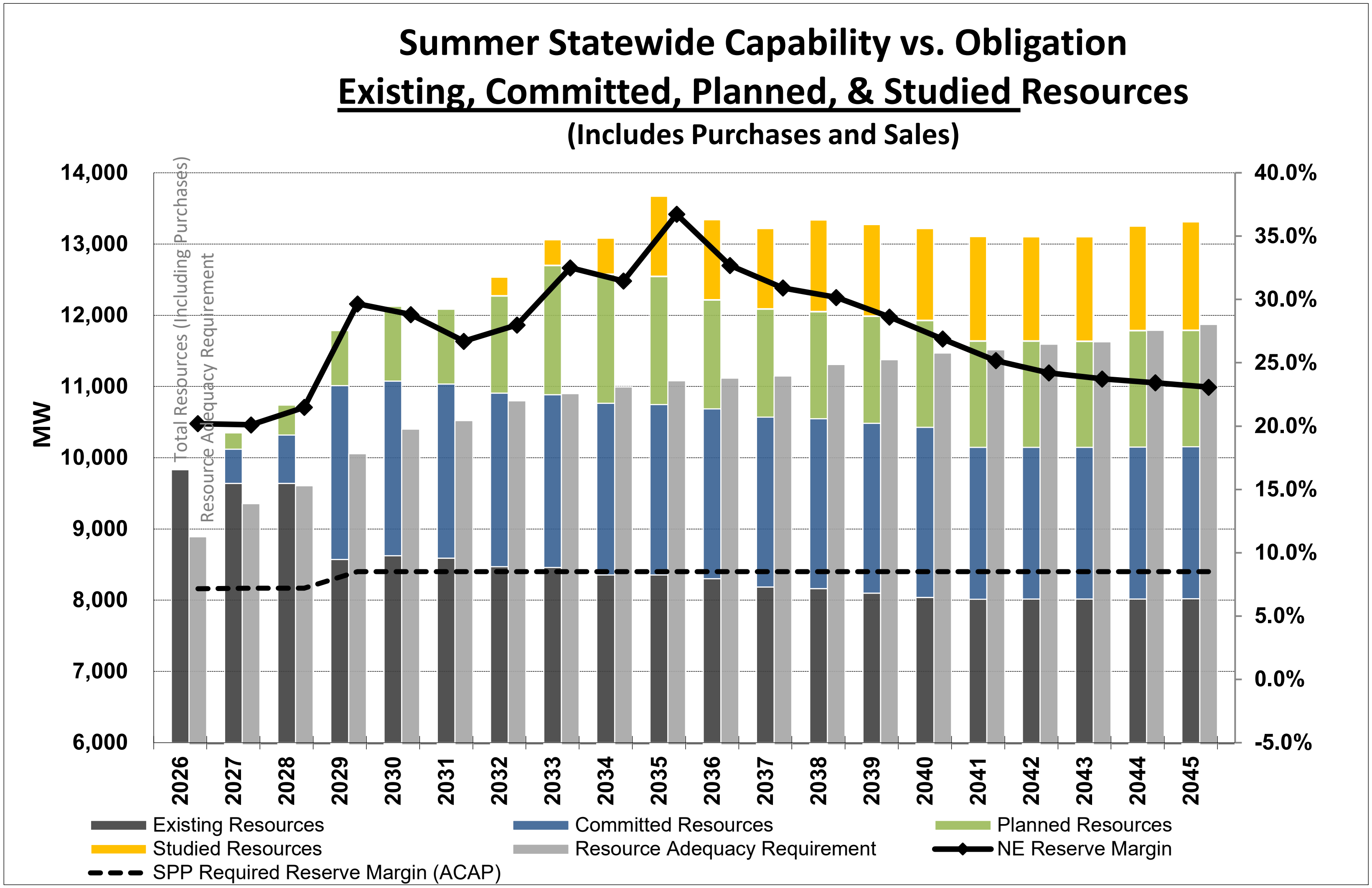

Figure 8 - Summer Statewide Capability vs. Obligation Existing, Committed, Planned & Studied Resources (Includes Purchases and Sales)

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

Year	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
1 Annual System Demand	8,368	8,800	9,035	9,355	9,673	9,785	10,039	10,132	10,221	10,301	10,333	10,362	10,509	10,571	10,658	10,700	10,773	10,807	10,954	11,030
2 Firm Power Purchases - Total	1,181	1,183	1,184	1,186	1,188	1,190	1,192	1,193	1,195	1,197	1,199	1,201	1,203	1,205	1,207	1,208	1,210	1,212	1,214	1,216
3 Firm Power Sales - Total	84	84	84	84	84	84	84	84	84	84	84	84	84	84	84	84	84	84	84	84
4 Annual Net Peak Demand (1-2+3)	7,271	7,702	7,934	8,253	8,569	8,679	8,931	9,022	9,109	9,188	9,218	9,245	9,390	9,450	9,535	9,575	9,646	9,679	9,824	9,898
5 Net Generating Capability (owned)	7,881	8,440	8,673	9,934	10,164	10,110	10,520	11,049	11,179	11,766	11,731	11,602	11,720	11,646	11,603	11,490	11,484	11,475	11,474	11,531
6 Firm Capacity Purchases	1,607	1,541	1,698	1,457	1,513	1,520	1,556	1,554	1,462	1,462	1,167	1,167	1,168	1,174	1,161	1,161	1,162	1,165	1,316	1,316
7 Firm Capacity Sales	749	732	732	691	639	634	644	648	666	666	666	666	665	665	665	665	665	665	665	665
8 Adjusted Net Capability (5+6-7)	8,739	9,249	9,639	10,699	11,038	10,996	11,431	11,955	11,975	12,563	12,232	12,104	12,222	12,155	12,099	11,985	11,981	11,976	12,125	12,183
9 Net Reserve Capacity Obligation (4 x PRM)	521	555	571	701	728	738	759	767	774	781	784	786	798	803	811	814	820	823	835	841
10 Total Firm Capacity Obligation (4+9)	7,791	8,256	8,506	8,954	9,297	9,416	9,690	9,789	9,884	9,969	10,001	10,031	10,188	10,254	10,346	10,389	10,466	10,501	10,659	10,740
11 Surplus (+) or Deficit (-) (8-10)	948	993	1,133	1,746	1,740	1,580	1,741	2,166	2,091	2,594	2,230	2,072	2,034	1,901	1,753	1,596	1,515	1,474	1,466	1,443
12 Nebraska Reserve Margin ((8-4)/4)	20.2%	20.1%	21.5%	29.7%	28.8%	26.7%	28.0%	32.5%	31.5%	36.7%	32.7%	30.9%	30.2%	28.6%	26.9%	25.2%	24.2%	23.7%	23.4%	23.1%
13 Nebraska Capacity Margin ((8-4)/8)	16.8%	16.7%	17.7%	22.9%	22.4%	21.1%	21.9%	24.5%	23.9%	26.9%	24.6%	23.6%	23.2%	22.3%	21.2%	20.1%	19.5%	19.2%	19.0%	18.8%
Existing, Committed, Planned, Studied Resources (8+2-3)	9,836	10,348	10,740	11,802	12,142	12,102	12,539	13,065	13,087	13,676	13,347	13,221	13,341	13,276	13,222	13,110	13,107	13,104	13,255	13,314
Resource Adequacy Requirement (MW) (1+9)	8,888	9,355	9,606	10,056	10,402	10,522	10,798	10,899	10,995	11,082	11,117	11,148	11,307	11,375	11,469	11,514	11,592	11,629	11,789	11,872
SPP Minimum Reserve Margin (ACAP)	7.16%	7.20%	7.20%	8.50%	8.50%	8.50%	8.50%	8.50%	8.50%	8.50%	8.50%	8.50%	8.50%	8.50%	8.50%	8.50%	8.50%	8.50%	8.50%	8.50%
First Year of Deficit - Minimum																				

Table 7 –Summer Committed Resources, MW

Summer Committed Resources	C	Fuel Type	Total Nameplate	Accredited Capacity 2026	Accredited Capacity 2031	Accredited Capacity 2036	Accredited Capacity 2041	Accredited Capacity 2045
Coal - Committed	**C**	**SUB**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
NG - Committed	**C**	**NG**	**0.0**	**0.0**	**249.7**	**255.2**	**0.0**	**0.0**
DFO - Committed	**C**	**DFO**	**8.2**	**0.0**	**7.0**	**7.0**	**7.0**	**7.0**
Future BTMG (MEAN) in 2026			8.2					
NG/DFO - Committed	**C**	**NG/DFO**	**1,854.0**	**0.0**	**1,551.0**	**1,554.4**	**1,554.4**	**1,554.4**
TBGS CT5/CT6 (LES) in 2029			104.0					
PRS_CT_12 (NPPD) in 2029			478.0					
PRS_RICE (NPPD) in 2029			216.0					
Cass County #3 (OPPD) in 2029			264.0					
Cass County #4 (OPPD) in 2029			264.0					
Cass County #5 (OPPD) in 2029			264.0					
Turtle Creek #3 (OPPD) in 2028			264.0					
Wind - Committed	**C**	**WND**	**115.0**	**0.0**	**20.6**	**20.6**	**20.6**	**20.6**
Greeley Co Wind (NPPD) in 2030			115.0					
Solar - Committed	**C**	**SUN**	**670.0**	**0.0**	**406.5**	**357.7**	**358.9**	**358.9**
City of Madison Solar (NPPD) in 2025			2.0					
Pierce Co Solar (OPPD) in 2027			420.0					
Future Solar 1 (OPPD) in 2029			250.0					
Hydro - Committed	**C**	**WAT**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Storage - Committed	**C**	**ES**	**223.0**	**3.0**	**209.6**	**192.6**	**191.9**	**191.9**
Committed ES (LES) in 2026			3.0					
Steele Flats Battery PPA (NPPD) in 2027			50.0					
Pierce Co Battery (OPPD) in 2027			170.0					
Nuclear - Committed	**C**	**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**
OBL - Committed	**C**	**OBL**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**

Table 8 – Summer Planned Resources, MW

Summer Planned Resources	P	Fuel Type	Total Nameplate	Accredited Capacity 2026	Accredited Capacity 2031	Accredited Capacity 2036	Accredited Capacity 2041	Accredited Capacity 2045
Coal - Planned	**P**	**SUB**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
NG - Planned	**P**	**NG**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
DFO - Planned	**P**	**DFO**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
NG/DFO - Planned	**P**	**NG/DFO**	**717.0**	**0.0**	**0.0**	**669.3**	**669.3**	**669.3**
BPS CT_1 (NPPD) in 2032			239.0					
BPS CT_2 (NPPD) in 2033			239.0					
BPS CT_3 (NPPD) in 2033			239.0					
Wind - Planned	**P**	**WND**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Solar - Planned	**P**	**SUN**	**514.2**	**0.0**	**318.7**	**299.8**	**273.9**	**260.2**
Planned Solar (LES) in 2027			124.2					
Planned Solar (MEAN) in 2028			40.0					
Burt Co Solar (NPPD) in 2030			350.0					
Hydro - Planned	**P**	**WAT**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Storage - Planned	**P**	**ES**	**80.0**	**0.0**	**68.4**	**32.2**	**14.4**	**14.4**
Planned ESR (LES) in 2027			80.0					
Nuclear - Planned	**P**	**NUC**	**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**
OBL - Planned	**P**	**OBL**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**

Table 9 – Summer Studied Resources, MW

Summer Studied Resources	S	Fuel Type	Total Nameplate	Accredited Capacity 2026	Accredited Capacity 2031	Accredited Capacity 2036	Accredited Capacity 2041	Accredited Capacity 2045
Coal - Studied	**S**	**SUB**	**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 - Studied	**S**	**DFO**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
NG/DFO - Studied	**S**	**NG/DFO**	**1,060.0**	**0.0**	**0.0**	**1,018.8**	**1,026.9**	**1,083.2**
Future Peaking (LES) in 2034			160.0					
Future CT 1 (OPPD) in 2032			300.0					
Future CT 2 (OPPD) in 2035			300.0					
Future CT 3 (OPPD) in 2035			300.0					
Wind - Studied	**S**	**WND**	**700.0**	**0.0**	**0.0**	**0.0**	**174.0**	**174.0**
Future Wind 2 (OPPD) in 2041			700.0					
Solar - Studied	**S**	**SUN**	**320.0**	**0.0**	**12.8**	**12.8**	**170.7**	**170.7**
Future Solar (MEAN) in 2029			20.0					
Future Solar 2 (OPPD) in 2038			300.0					
Hydro - Studied	**S**	**WAT**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Storage - Studied	**S**	**ES**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Nuclear - Studied	**S**	**NUC**	**0.0**	**0.0**	**0.0**	**98.0**	**98.0**	**98.0**
CNS EPU (NPPD) in 2033			100.0					
LFG - Studied	**S**	**LFG**	**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 9 and *Table 10* provide a view of the statewide winter load and capability with the application of only Existing, Committed, and Planned resources. As a state, Nebraska does not experience a resource adequacy deficiency within the study horizon, extending beyond the 2043 deficiency demonstrated in last year's report. The winter load and capability calculations include each utility's projected winter peak load values, reduced WAPA allocations, and lower winter accreditation of solar and thermal resources. Beginning in 2026, ELCC accreditation is utilized for the state's renewable resources, and PBA and FA accreditation are utilized for the state's conventional resources. The statewide Resource Adequacy Requirement is based on the ACAP PRM.

Figure 10 and *Table 11* incorporate Studied resources into the state's generation fleet to satisfy the resource adequacy requirement throughout the study time period.

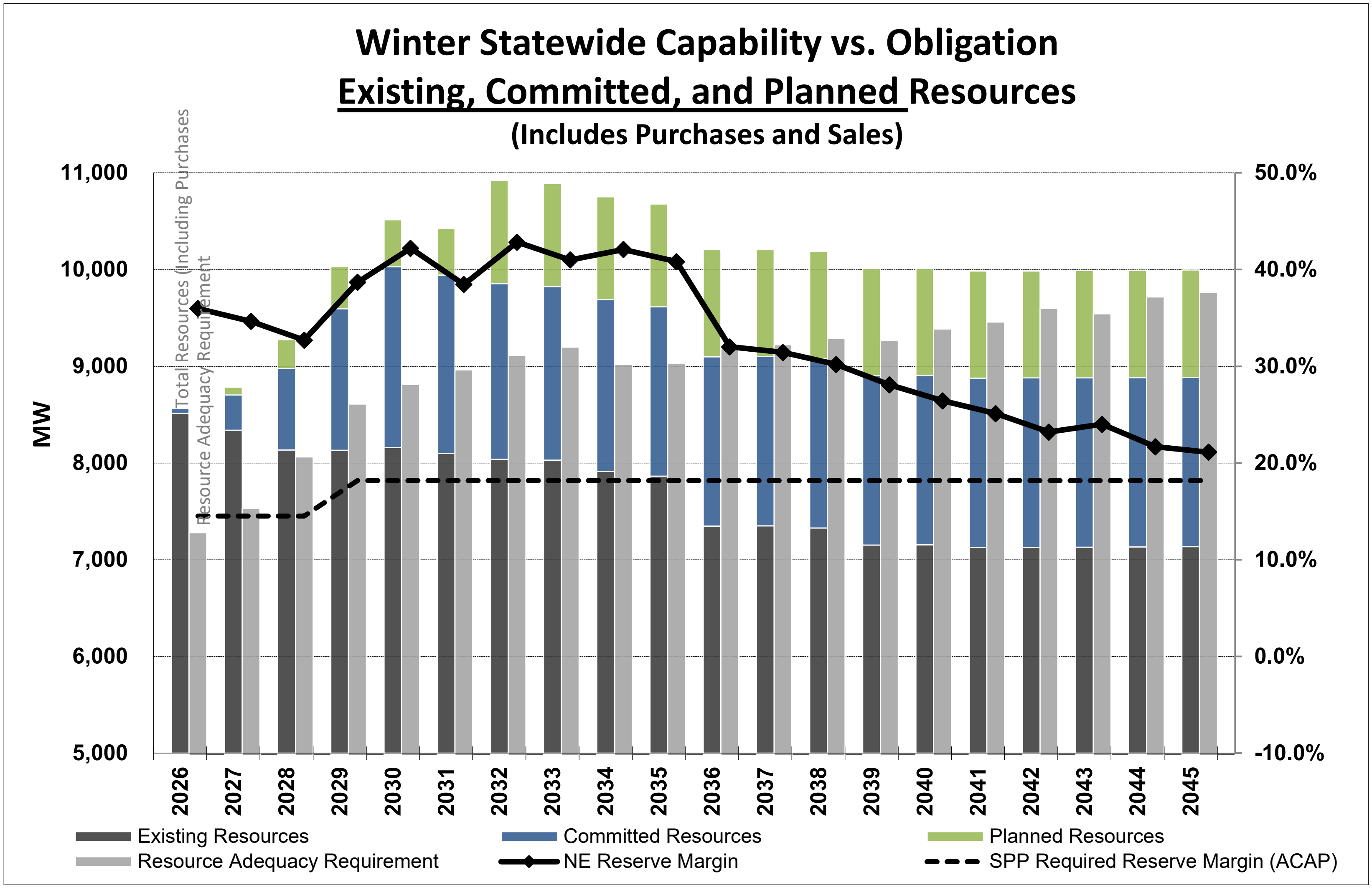

Figure 9 - Winter Statewide Capability vs. Obligation Existing, Committed, and Planned Resources (Includes Purchases and Sales)

Table 10 - Nebraska Statewide Existing, Committed & Planned Load & Accredited Generating Capability in MW - Winter Conditions (Dec. 1 to Mar. 31)

Year	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
1 Annual System Demand	6,408	6,630	7,093	7,349	7,520	7,650	7,775	7,848	7,695	7,708	7,835	7,869	7,924	7,910	8,009	8,068	8,188	8,142	8,290	8,330
2 Firm Power Purchases - Total	491	492	495	496	500	502	503	504	505	507	508	509	510	512	513	514	516	517	518	519
3 Firm Power Sales - Total	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75
4 Annual Net Peak Demand (1-2+3)	5,992	6,213	6,673	6,929	7,095	7,222	7,347	7,419	7,265	7,276	7,402	7,435	7,489	7,473	7,571	7,628	7,747	7,700	7,847	7,885
5 Net Generating Capability (owned)	7,504	7,743	8,030	8,774	9,197	9,166	9,578	9,532	9,507	9,482	9,302	9,301	9,279	9,115	9,114	9,085	9,085	9,085	9,085	9,086
6 Firm Capacity Purchases	1,498	1,428	1,562	1,491	1,550	1,489	1,567	1,574	1,461	1,411	1,116	1,116	1,117	1,100	1,100	1,101	1,102	1,105	1,106	1,106
7 Firm Capacity Sales	853	806	737	657	659	655	652	647	647	647	646	646	646	642	642	642	642	642	642	642
8 Adjusted Net Capability (5+6-7)	8,148	8,366	8,855	9,608	10,089	10,000	10,494	10,460	10,321	10,247	9,771	9,771	9,749	9,572	9,572	9,544	9,544	9,548	9,549	9,550
9 Net Reserve Capacity Obligation (4 x PRM)	870	902	969	1,261	1,291	1,314	1,337	1,350	1,322	1,324	1,347	1,353	1,363	1,360	1,378	1,388	1,410	1,401	1,428	1,435
10 Total Firm Capacity Obligation (4+9)	6,863	7,115	7,642	8,190	8,386	8,537	8,684	8,769	8,587	8,601	8,749	8,788	8,852	8,833	8,949	9,016	9,157	9,101	9,275	9,320
11 Surplus (+) or Deficit (-) (8-10)	1,286	1,251	1,213	1,419	1,702	1,463	1,810	1,691	1,734	1,646	1,022	983	897	739	624	527	387	446	274	230
12 Nebraska Reserve Margin ((8-4)/4)	36.0%	34.7%	32.7%	38.7%	42.2%	38.5%	42.8%	41.0%	42.1%	40.8%	32.0%	31.4%	30.2%	28.1%	26.4%	25.1%	23.2%	24.0%	21.7%	21.1%
13 Nebraska Capacity Margin ((8-4)/8)	26.5%	25.7%	24.6%	27.9%	29.7%	27.8%	30.0%	29.1%	29.6%	29.0%	24.2%	23.9%	23.2%	21.9%	20.9%	20.1%	18.8%	19.4%	17.8%	17.4%
Existing, Committed, Planned Resources (8+2-3)	8,564	8,783	9,275	10,029	10,514	10,428	10,922	10,889	10,752	10,679	10,204	10,205	10,185	10,009	10,010	9,983	9,985	9,990	9,992	9,995
Resource Adequacy Requirement (MW) (1+9)	7,279	7,532	8,062	8,610	8,811	8,964	9,112	9,198	9,018	9,033	9,182	9,222	9,287	9,270	9,387	9,456	9,598	9,543	9,718	9,765
SPP Minimum Reserve Margin (ACAP)	14.52%	14.52%	14.52%	18.20%	18.20%	18.20%	18.20%	18.20%	18.20%	18.20%	18.20%	18.20%	18.20%	18.20%	18.20%	18.20%	18.20%	18.20%	18.20%	18.20%
First Year of Deficit - Minimum																				

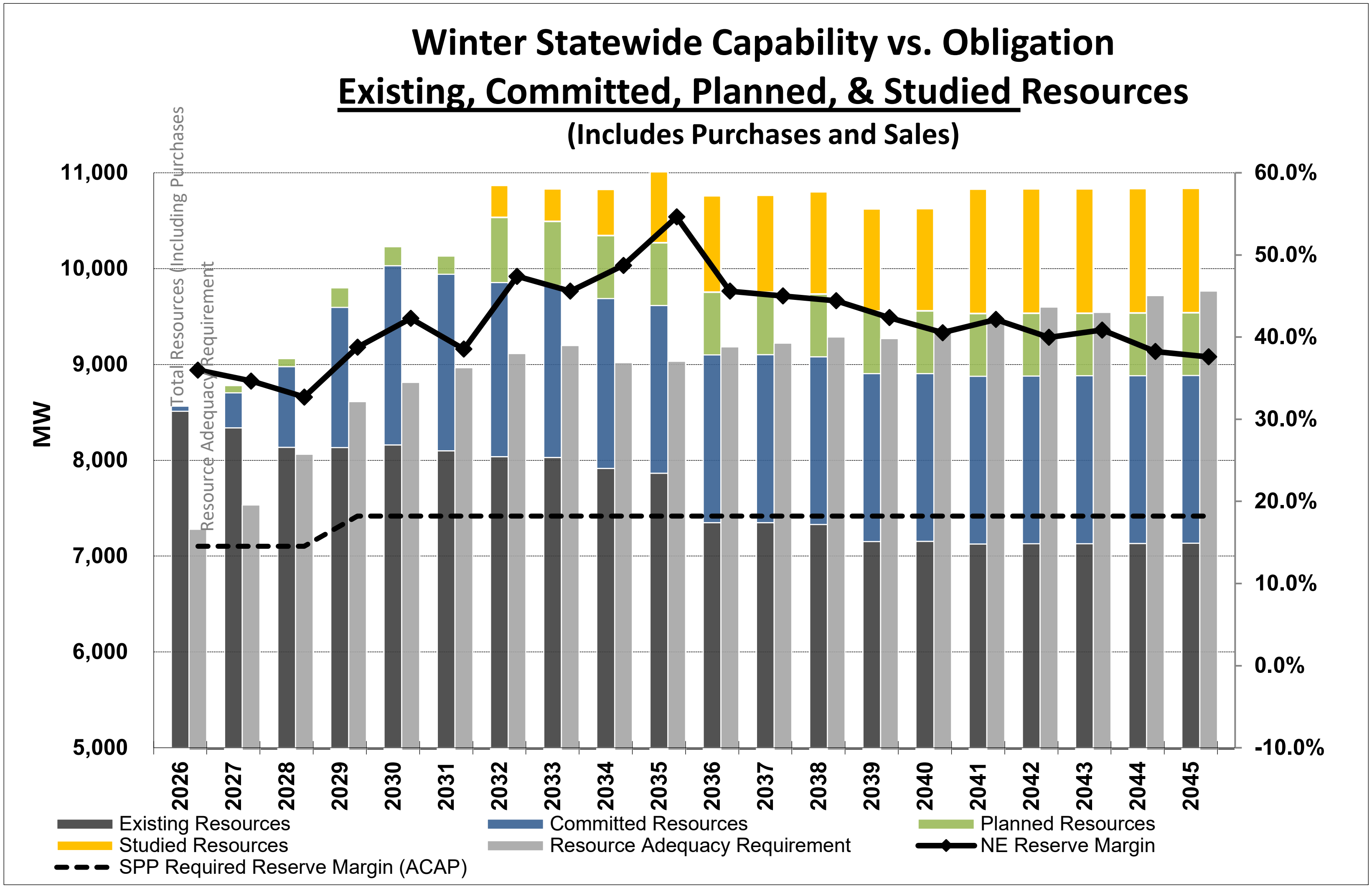

Figure 10 - Winter Statewide Capability vs. Obligation Existing, Committed, Planned & Studied Resources (Includes Purchases and Sales)

Table 11 - Nebraska Statewide Existing, Committed, Planned, & Studied Load & Accredited Generating Capability in MW - Winter Conditions (Dec. 1 to Mar. 31)

Year	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
1 Annual System Demand	6,408	6,630	7,093	7,349	7,520	7,650	7,775	7,848	7,695	7,708	7,835	7,869	7,924	7,910	8,009	8,068	8,188	8,142	8,290	8,330
2 Firm Power Purchases - Total	491	492	495	496	500	502	503	504	505	507	508	509	510	512	513	514	516	517	518	519
3 Firm Power Sales - Total	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75
4 Annual Net Peak Demand (1-2+3)	5,992	6,213	6,673	6,929	7,095	7,222	7,347	7,419	7,265	7,276	7,402	7,435	7,489	7,473	7,571	7,628	7,747	7,700	7,847	7,885
5 Net Generating Capability (owned)	7,504	7,743	8,030	8,780	9,203	9,172	9,913	9,873	9,991	10,487	10,306	10,310	10,344	10,182	10,181	10,383	10,383	10,383	10,383	10,384
6 Firm Capacity Purchases	1,498	1,428	1,562	1,491	1,550	1,489	1,567	1,574	1,461	1,411	1,116	1,116	1,117	1,100	1,100	1,101	1,102	1,105	1,106	1,106
7 Firm Capacity Sales	853	806	737	657	659	655	652	647	647	647	646	646	646	642	642	642	642	642	642	642
8 Adjusted Net Capability (5+6-7)	8,148	8,366	8,855	9,614	10,094	10,005	10,828	10,800	10,805	11,252	10,776	10,780	10,815	10,639	10,640	10,842	10,843	10,846	10,847	10,849
9 Net Reserve Capacity Obligation (4 x PRM)	870	902	969	1,261	1,291	1,314	1,337	1,350	1,322	1,324	1,347	1,353	1,363	1,360	1,378	1,388	1,410	1,401	1,428	1,435
10 Total Firm Capacity Obligation (4+9)	6,863	7,115	7,642	8,190	8,386	8,537	8,684	8,769	8,587	8,601	8,749	8,788	8,852	8,833	8,949	9,016	9,157	9,101	9,275	9,320
11 Surplus (+) or Deficit (-) (8-10)	1,286	1,251	1,213	1,424	1,708	1,469	2,145	2,032	2,218	2,651	2,027	1,992	1,963	1,806	1,691	1,826	1,686	1,745	1,572	1,528
12 Nebraska Reserve Margin ((8-4)/4)	36.0%	34.7%	32.7%	38.8%	42.3%	38.5%	47.4%	45.6%	48.7%	54.6%	45.6%	45.0%	44.4%	42.4%	40.5%	42.1%	40.0%	40.9%	38.2%	37.6%
13 Nebraska Capacity Margin ((8-4)/8)	26.5%	25.7%	24.6%	27.9%	29.7%	27.8%	32.2%	31.3%	32.8%	35.3%	31.3%	31.0%	30.8%	29.8%	28.8%	29.6%	28.6%	29.0%	27.7%	27.3%
Existing, Committed, Planned, Studied Resources (8+2-3)	8,564	8,783	9,275	10,034	10,519	10,433	11,257	11,230	11,235	11,683	11,209	11,214	11,251	11,076	11,078	11,282	11,283	11,288	11,290	11,293
Resource Adequacy Requirement (MW) (1+9)	7,279	7,532	8,062	8,610	8,811	8,964	9,112	9,198	9,018	9,033	9,182	9,222	9,287	9,270	9,387	9,456	9,598	9,543	9,718	9,765
SPP Minimum Reserve Margin (ACAP)	14.52%	14.52%	14.52%	18.20%	18.20%	18.20%	18.20%	18.20%	18.20%	18.20%	18.20%	18.20%	18.20%	18.20%	18.20%	18.20%	18.20%	18.20%	18.20%	18.20%
First Year of Deficit - Minimum																				

Table 12 - Winter Committed Resources, MW

Winter Committed Resources	C	Fuel Type	Total Nameplate	Accredited Capacity 2026	Accredited Capacity 2031	Accredited Capacity 2036	Accredited Capacity 2041	Accredited Capacity 2045
Coal - Committed	**C**	**SUB**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
NG - Committed	**C**	**NG**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
DFO - Committed	**C**	**DFO**	**8.2**	**0.0**	**7.0**	**7.0**	**7.0**	**7.0**
Future BTMG (MEAN) in 2026			12.0					
NG/DFO - Committed	**C**	**NG/DFO**	**1,854.0**	**0.0**	**1,453.2**	**1,423.7**	**1,423.7**	**1,423.7**
TBGS CT5/CT6 (LES) in 2029			104.0					
PRS_CT_12 (NPPD) in 2029			478.0					
PRS_RICE (NPPD) in 2029			216.0					
Cass County #3 (OPPD) in 2029			264.0					
Cass County #4 (OPPD) in 2029			264.0					
Cass County #5 (OPPD) in 2029			264.0					
Turtle Creek #3 (OPPD) in 2028			264.0					
Wind - Committed	**C**	**WND**	**115.0**	**0.0**	**35.4**	**35.4**	**35.4**	**35.4**
Greeley Co Wind (NPPD) in 2029			115.0					
Custer PPD - Prairie Hills Wind (NPPD) in 2026			8.0					
Solar - Committed	**C**	**SUN**	**670.0**	**0.0**	**152.3**	**120.6**	**120.6**	**120.6**
City of Madison Solar (NPPD) in 2026			2.0					
Norris PPD - Hoag Solar (NPPD) in 2026			1.0					
Pierce Co Solar (OPPD) in 2027			420.0					
Future Solar 1 (OPPD) in 2029			250.0					
Hydro - Committed	**C**	**WAT**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Storage - Committed	**C**	**ES**	**223.0**	**52.3**	**196.0**	**164.2**	**164.2**	**164.2**
Committed ES (LES) in 2026			3.0					
Steele Flats Battery PPA (NPPD) in 2026			50.0					
Pierce Co Battery (OPPD) in 2027			170.0					
Nuclear - Committed	**C**	**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**
OBL - Committed	**C**	**OBL**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**

Table 13 – Winter Planned Resources, MW

Winter Planned Resources	P	Fuel Type	Total Nameplate	Accredited Capacity 2026	Accredited Capacity 2031	Accredited Capacity 2036	Accredited Capacity 2041	Accredited Capacity 2045
Coal - Planned	**P**	**SUB**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
NG - Planned	**P**	**NG**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
DFO - Planned	**P**	**DFO**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
NG/DFO - Planned	**P**	**NG/DFO**	**717.0**	**0.0**	**0.0**	**494.5**	**494.5**	**494.5**
BPS CT_1 (NPPD) in 2032			239.0					
BPS CT_2 (NPPD) in 2032			239.0					
BPS CT_3 (NPPD) in 2032			239.0					
Wind - Planned	**P**	**WND**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Solar - Planned	**P**	**SUN**	**514.2**	**0.0**	**150.0**	**146.6**	**146.4**	**146.4**
Planned Solar (LES) in 2027			124.2					
Planned Solar (MEAN) in 2028			40.0					
Burt Co Solar (NPPD) in 2027			350.0					
Hydro - Planned	**P**	**WAT**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Storage - Planned	**P**	**ES**	**80.0**	**0.0**	**42.7**	**13.6**	**13.6**	**13.6**
Planned ESR (LES) in 2027			80.0					
Nuclear - Planned	**P**	**NUC**	**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**
OBL - Planned	**P**	**OBL**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**

Table 14 - Winter Studied Resources, MW

Winter Studied Resources	S	Fuel Type	Total Nameplate	Accredited Capacity 2026	Accredited Capacity 2031	Accredited Capacity 2036	Accredited Capacity 2041	Accredited Capacity 2045
Coal - Studied	**S**	**SUB**	**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 - Studied	**S**	**DFO**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
NG/DFO - Studied	**S**	**NG/DFO**	**1,060.0**	**0.0**	**0.0**	**901.2**	**909.5**	**909.5**
Future Peaking (LES) in 2034			160.0					
Future CT 1 (OPPD) in 2032			300.0					
Future CT 2 (OPPD) in 2035			300.0					
Future CT 3 (OPPD) in 2035			300.0					
Wind - Studied	**S**	**WND**	**700.0**	**0.0**	**0.0**	**0.0**	**231.3**	**231.3**
Future Wind 2 (OPPD) in 2041			700.0					
Solar - Studied	**S**	**SUN**	**320.0**	**0.0**	**5.4**	**5.4**	**59.4**	**59.4**
Future Solar (MEAN) in 2029			20.0					
Future Solar 2 (OPPD) in 2038			300.0					
Hydro - Studied	**S**	**WAT**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Storage - Studied	**S**	**ES**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Nuclear - Studied	**S**	**NUC**	**0.0**	**0.0**	**0.0**	**98.3**	**98.3**	**98.3**
CNS EPU (NPPD) in 2032			100.0					
LFG - Studied	**S**	**LFG**	**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**

4.4.3 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 C02 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 license renewal process. Therefore, it is assumed that 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 December of 2025, the OPPD Board of Directors approved the staff recommended extension of its North Omaha Station due to evolving market conditions and grid support concerns. OPPD had previously extended the conversion of units 4 and 5 from coal to natural gas and retirement of units 1, 2, and 3 from 2023 to 2026 to mitigate the risks associated with the delayed SPP GI study process for OPPD's new Turtle Creek and Standing Bear Lake stations. OPPD's 2026 Integrated System Plan will further study system solutions to support the station conversion and retirement and will determine a recommended action plan.

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 utility and unit in the *Appendix.* Nebraska has 11,218 MW nameplate of existing resources. 2,689 MW or 23.98% of that total are greater than 50 years old today. Another 2,542 MW or 22.67% are 41 to 50 years old today. Most of these units have no planned retirement date. By 2045 approximately 5,231 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 2029, while a 70-year age-based retirement date would show a state deficit even farther into the future. *Figure 11* shows the 60-year in-service life chart. Since a statewide deficit occurs in 2029 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. At this time, there are no plans to retire these older units unless stated in the Report.

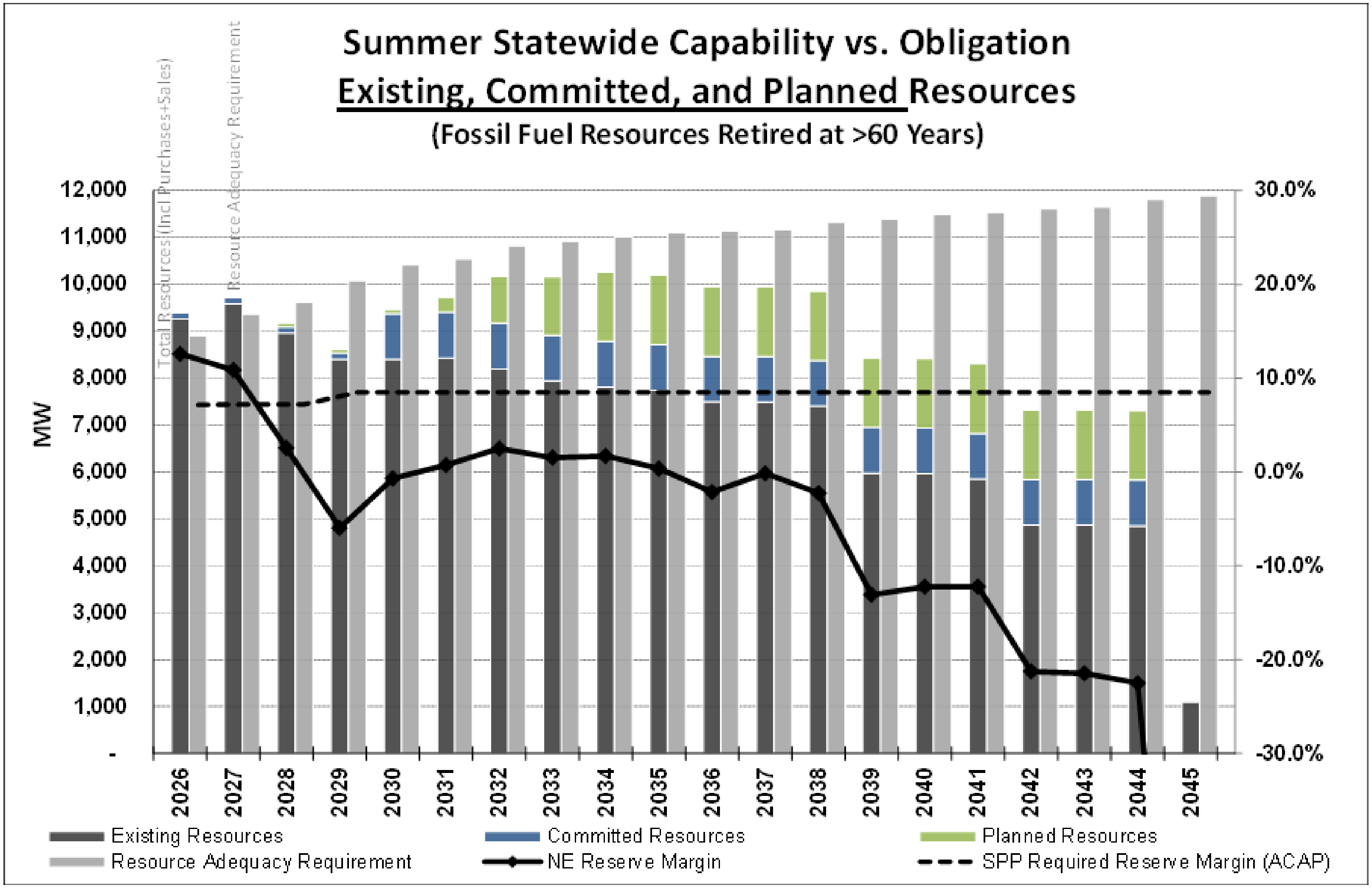

Figure 11 - Summer Statewide Capability vs. Obligation Existing, Committed, and Planned Resources (Fossil Fuel Resources Retired at >60 Years)

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 "Committed" and "Planned" Generation Resources

- Committed - 50 MWs of battery storage capacity purchased from an existing privately-owned wind facility.
- Committed - 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.
- Committed – 478 MWs of dual fuel combustion turbines (CT) that would use natural gas as a primary fuel source and have the option to utilize diesel.
- Committed – 115 MWs of wind generation via Power Purchase Agreement (PPA)
- Planned – 717 MWs of dual fuel CTs that would use natural gas as a primary fuel source and have the option to utilize diesel.
- Planned – 350 MWs of solar generation via PPA.

Based on indicative cost and delivery estimates provided to NPPD by equipment vendors, the "Committed" CT (478 MWs) & RICE (216 MWs) resources are targeted to be in service by the Summer of 2029. The "Planned" CTs (239 MW each) are tentatively targeted for June, September & December 2032 start-up, respectively. 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:

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

Using a 2024-2025 rolling average, non-carbon generation resources were approximately 57% 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 487 MW of demand reduction from NPPD's billable peak during the summer of 2025.

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 and any new demand response rates in the future. Another 89 MW of demand reduction was realized from this and other sources during the 2025 summer peak.

NPPD has a series of energy efficiency and demand-side management initiatives under the EnergyWise℠ 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 2025 are 451 GWh and demand reductions are 71 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 6.4% for winter peak load and 2.9% for summer peak load. This marks a departure from the nearly flat growth experienced in the decade prior. In fact, the growth rate experienced by OPPD from 2019-2026 even exceeds the 1.89% growth of ERCOT in Texas and the 0.1% growth in the California ISO (CAISO). 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, 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.

OPPD is also expanding its portfolio via new Purchased Power Agreements. 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 85 MW of battery storage and capacity from a total of 420 MW of solar and 170 MW of battery energy storage. And most recently, earlier in 2026 OPPD executed an agreement for offtake of capacity and energy from the 250 MW Burt County solar project.

At the close of 2025, 34.7% of OPPD's portfolio generation was produced by wind energy, energy from landfill gas, hydro energy, and solar energy. OPPD's renewable portfolio at 2025 year-end consisted of 1,272 MW of wind by nameplate, and 86 MW of nameplate solar, 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 up to 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. In parallel, OPPD is also navigating the regulated SPP generation interconnection study process to determine necessary transmission upgrades to support these and other Nebraska area GI requests which could impact the target operational date.

OPPD Existing and Committed resources added since 2019:

- 1574 MW of Conventional Generation:
    - Turtle Creek Station Units 1-2: 442 MW, 2025 COD
    - Standing Bear Lake Station: 151 MW, 2025 COD
    - Turtle Creek Station Unit 3: 225 MW, Expected 2028 COD
    - Cass Co Units 3-5: 675 MW, Expected 2029 COD

- 1057 MW of Renewable Generation:
    - OPPD Community Solar: 5 MW, 2020 COD
    - Bright Battery: 1 MW, 2022 COD
    - Platteview Solar: 81 MW, 2024 COD
    - Milligan Wind: 300 MW, 2024 PPA Execution
    - Pierce County Energy Center: 420 MW Solar and 170 MW Storage, Expected 2027 COD (OPPD will receive 100% of the capacity and 50% of the energy from this facility)
    - Burt County Solar: 250 MW, Expected 2029 COD

OPPD's Planned and Studied Generation Resources:

- Studied - 900 MW of future dual fueled natural gas capacity (incremental to current portfolio)
- Studied - 300 MW of future solar (incremental to current portfolio)
- Studied - 700 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. SPP's proposed Demand Response and Peak Demand Assessment policy is currently filed at FERC and awaiting decision. Should this policy ultimately be approved, OPPD will ensure the future value of existing and planned demand response programs claimed as Load Modifying Resources is reflective of the new resource adequacy requirements.

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 to provide greater certainty for both OPPD and potential customers, the utility has developed 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 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 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 System 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 has already introduced opportunity for valuable customer engagement and will remain 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% non-carbon resources based on nameplate capacity, consisting of 30% contracted hydro, small hydro, and WAPA hydro allocations, 26% renewables (wind, solar, 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 is studying the potential for an additional 40 MW solar PPA to help address future renewable goals and resource needs.

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 Power Purchase Agreements with Google for 198-MW Bluestem Wind, and 225-MW Great Western Wind, as well as a Power Purchase Agreement with the Central Nebraska Public Power and Irrigation District for their 22-MW Jeffrey Hydro project. Google is selling the related capacity to LES to help meet the SPP resource adequacy requirements associated with their local datacenter load. On a nameplate basis, approximately 49% of LES' current supply-side resources are renewable (primarily wind and hydro), with 30% fueled by natural gas and 21% 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 is expected to achieve commercial operation in September 2026. This zinc-based battery is supporting LES' existing Community Microgrid, helping to ensure reliable and resilient service to critical loads in the downtown Lincoln area.

- 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 2019. Phase 2 of the community solar farm is an additional 4.6 MW and was completed in December 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:

- 39 MW of nameplate wind generation (35.8 MW Prairie Breeze III (2015), 3 MW NPPD wind farms (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 Water, Energy, and Environment 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.
- 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 12, Figure 13, and *Figure 14* 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 15 shows the 2025 annual energy production for these resources.

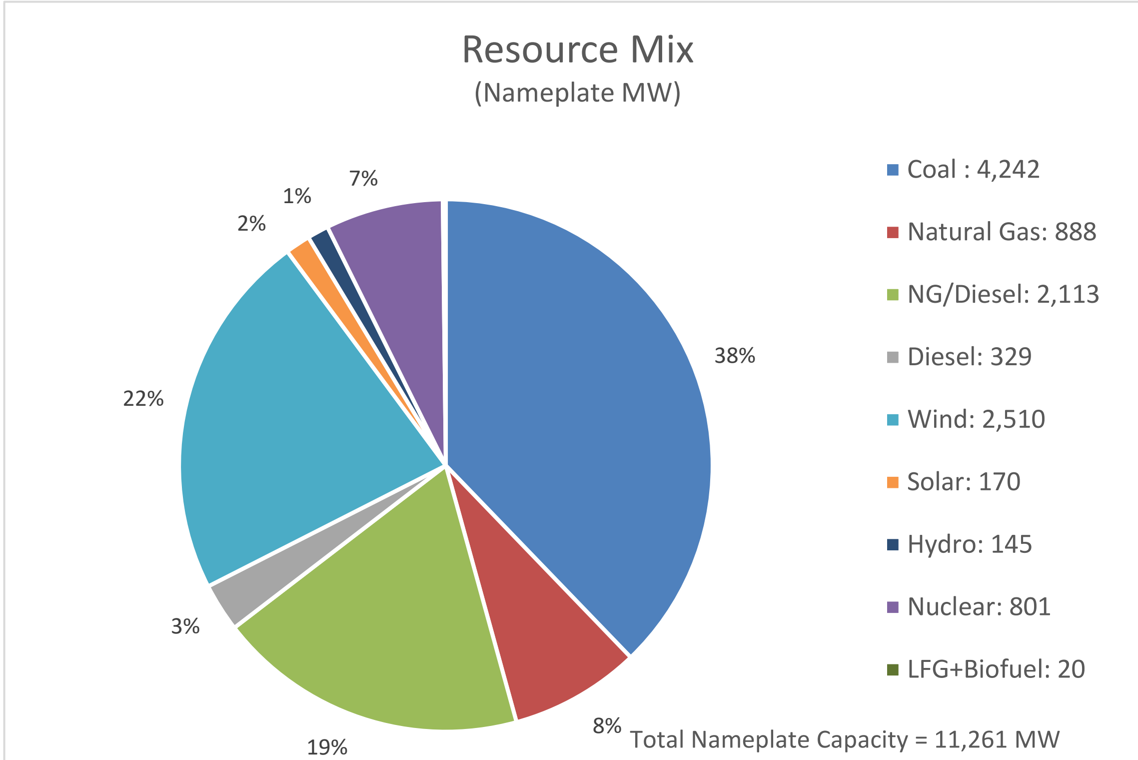

Figure 12 - Resource Mix (Nameplate MW)

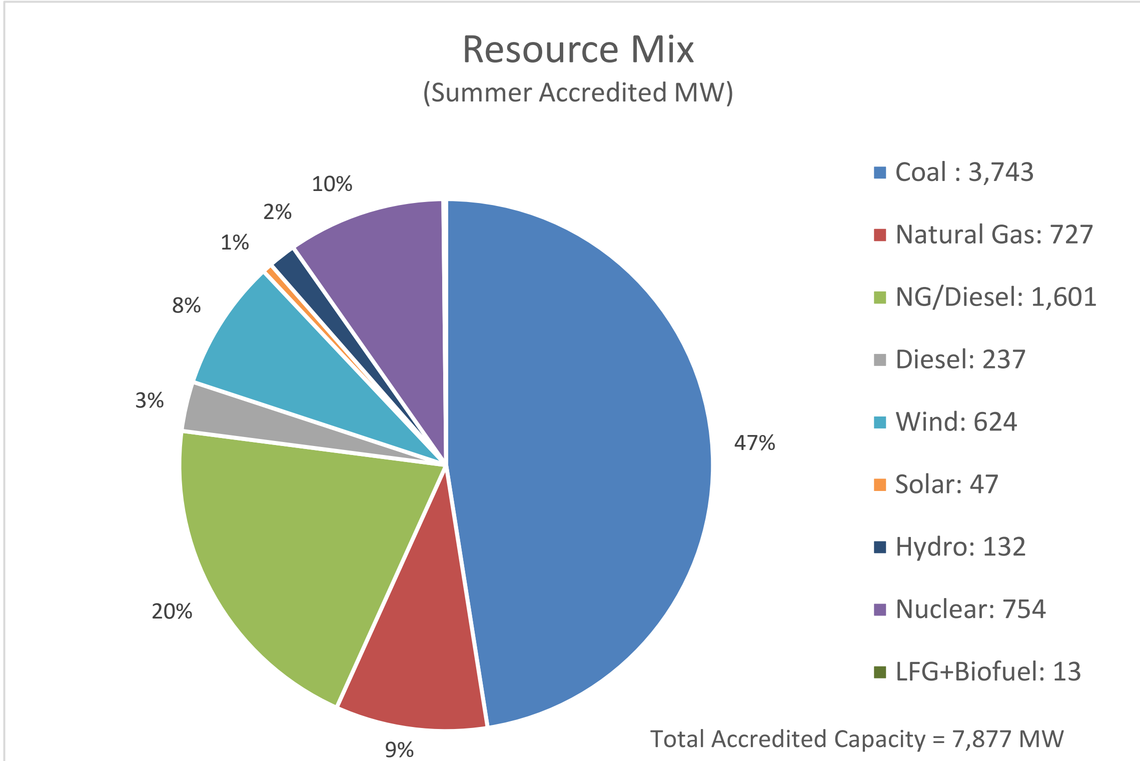

Figure 13 - Resource Mix (Summer Accredited MW)

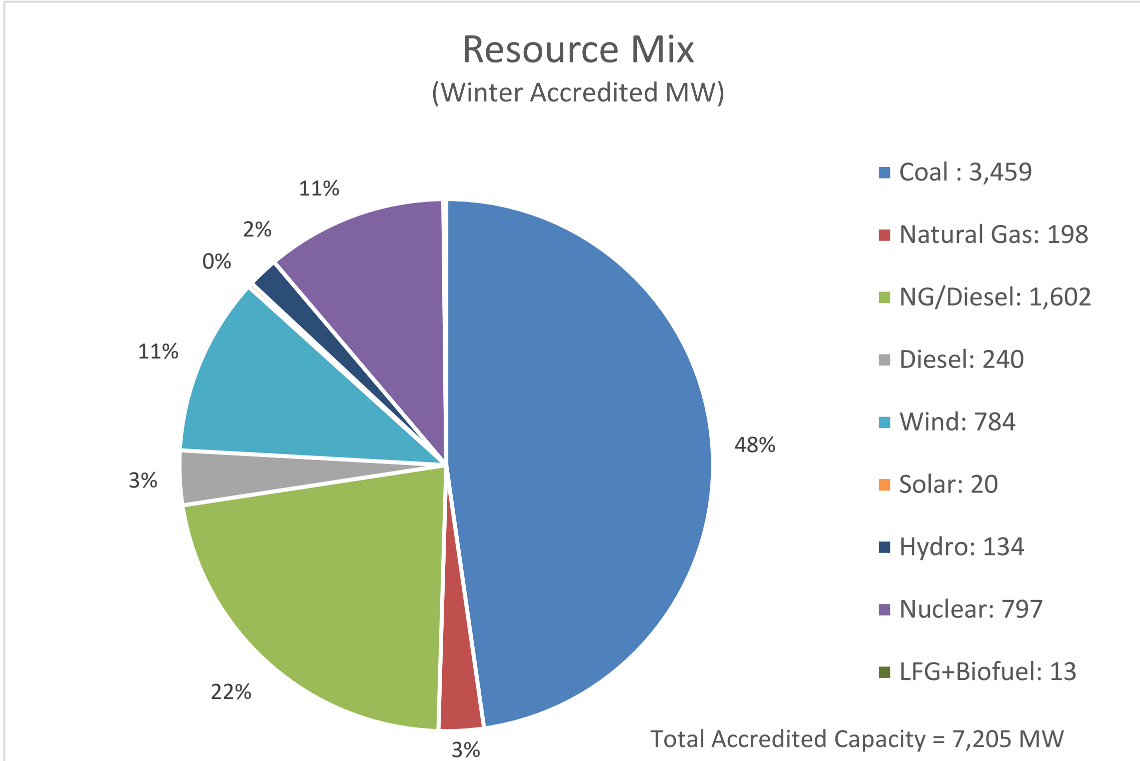

Figure 14 - Resource Mix (Winter Accredited MW)

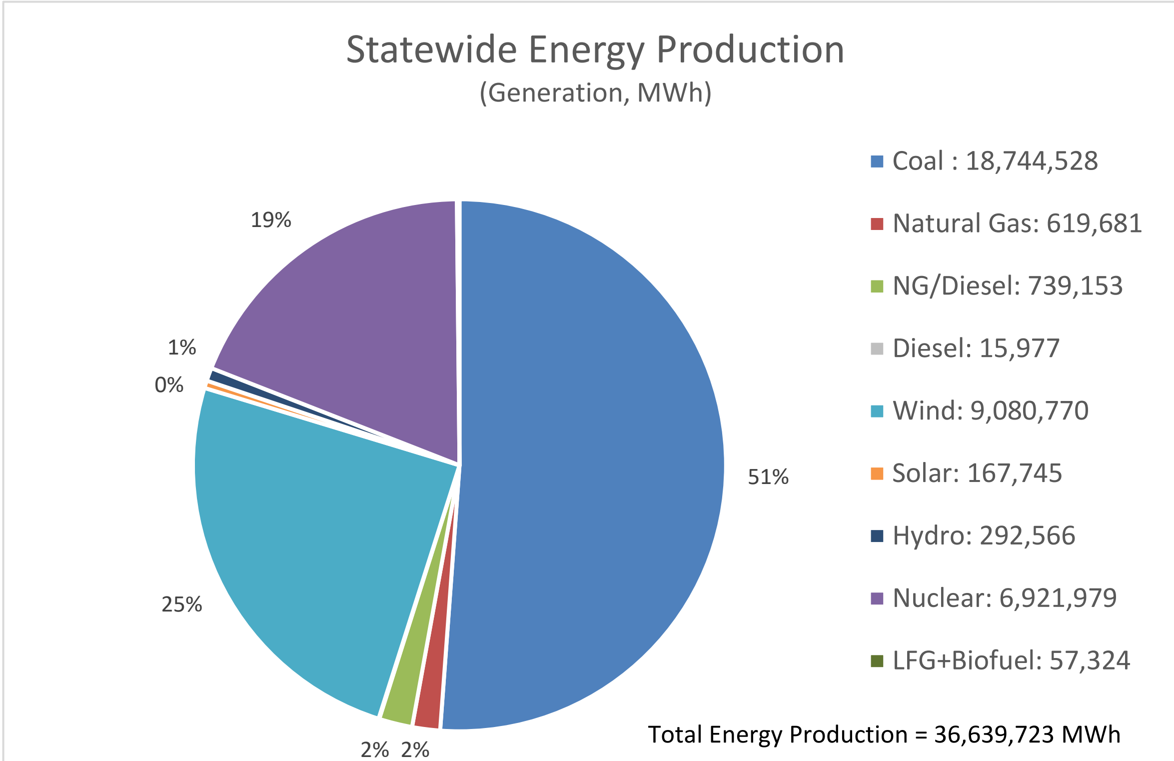

Figure 15 - Statewide 2025 Energy Production (MWh Generation)

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 16* illustrates that 22% (1,602 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.

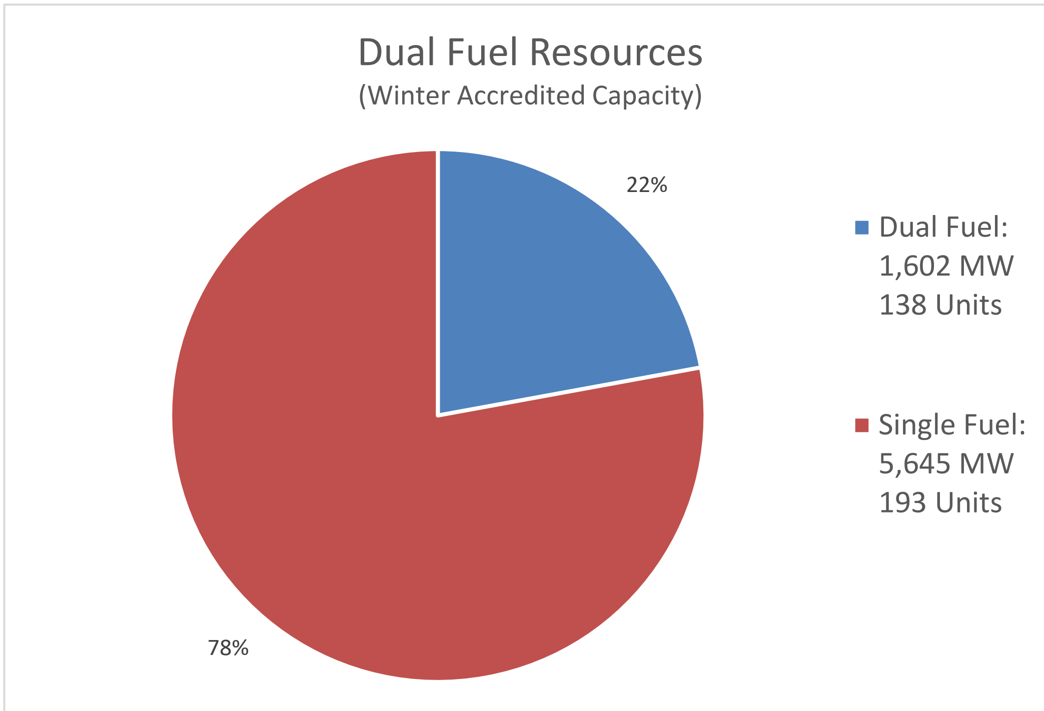

Figure 16 - Dual Fuel Resources (Winter Accredited Capacity)

NPPD, OPPD and LES own or operate coal units amounting to 2,986 MW of winter accredited generating capability with onsite fuel storage, with an average of 32.6 days of storage available as shown in *Figure 17*. Also, 1,254 MW of dual fuel natural-gas/diesel-fuel-oil generating units and 166 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 2.1 days with the quantity of fuel the generating units have in storage. 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 transpires.

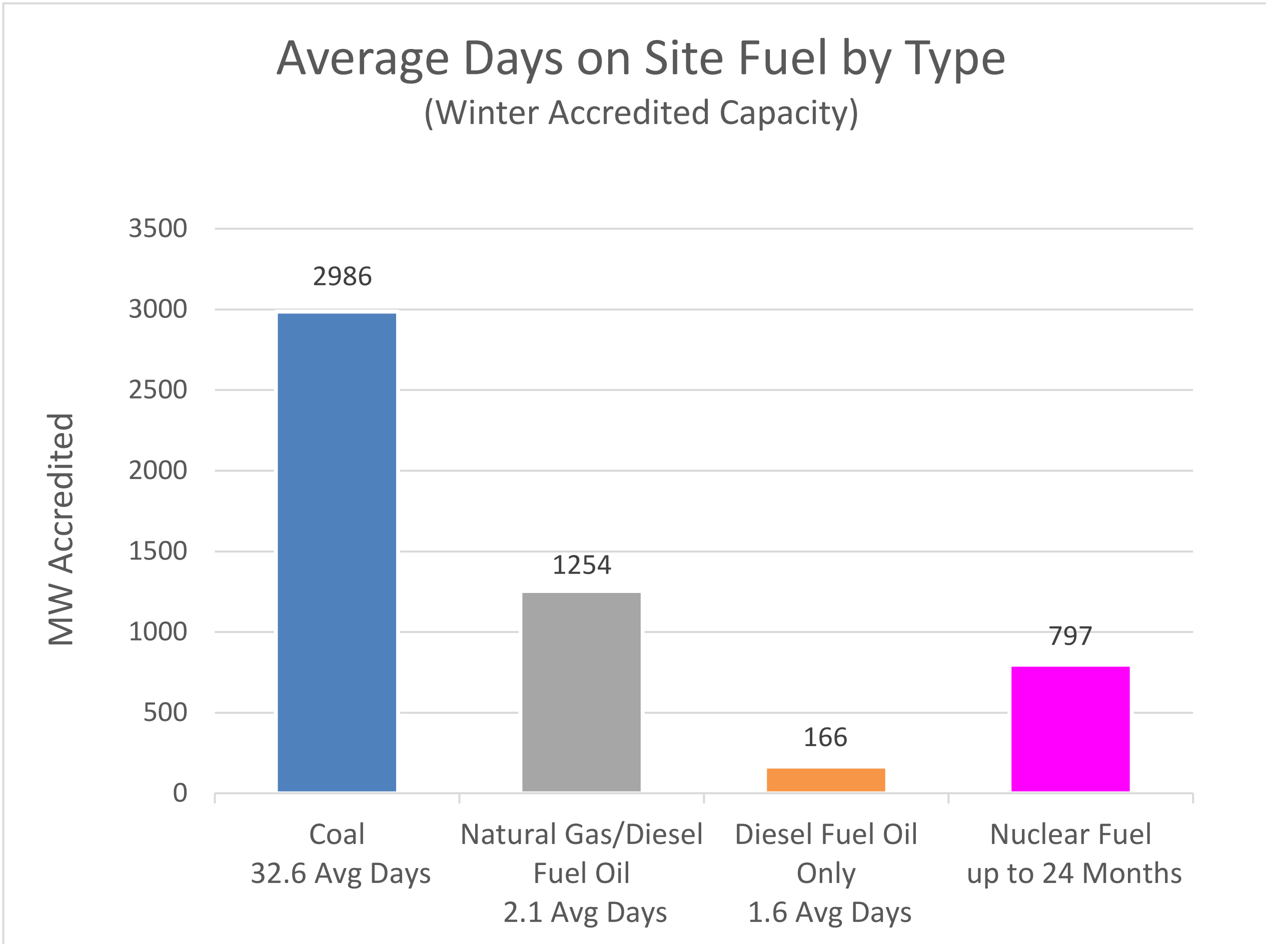

Figure 17 - Average Days On Site Fuel by Type (Winter Accredited Capacity)

5.1.3 Ramp Rates

The generation ramp rate, or time required for a unit to reach maximum capacity, is shown in *Figure 18.* 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. 870 MW of in-state resources can ramp to full load in 0 -10 minutes, 1,896 MW can ramp to full load in 10 – 60 minutes, 2,697 MW can ramp to full load in 1 – 12 hours, and 2,992 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.

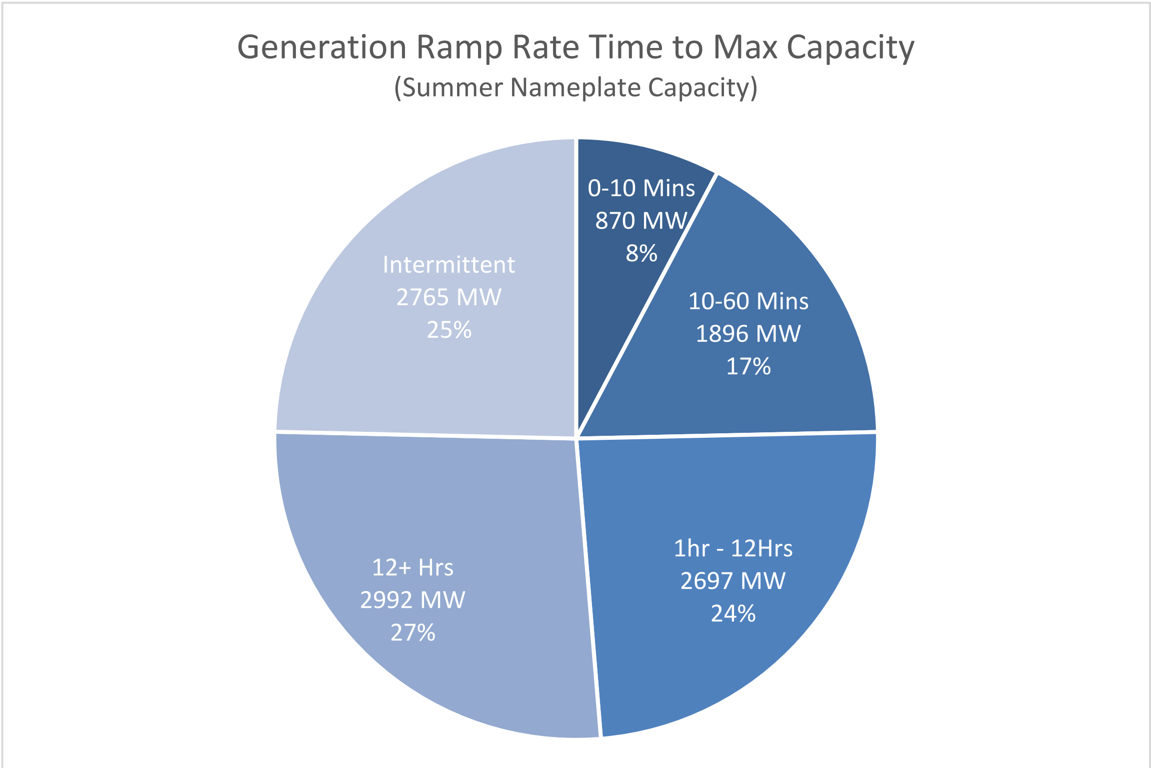

Figure 18 - Generation Ramp Rate Time to Max Capacity (Summer Nameplate Capacity)

5.1.4 Stress Period(s)/ Stress Test

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 7/28/25, with a peak statewide demand of 7,619 MW which is a significant increase of 1,057 MW compared to last year. Likewise, the peak winter load occurred on 1/23/26, with a peak demand of 6,277 MW, 766 MW higher than last year. 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 19 and *Figure 20* 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 load and the summer peak load. The tight summer position was due to outages experienced at a few units throughout the state, including OPPD's 687 MW Nebraska City 2 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.

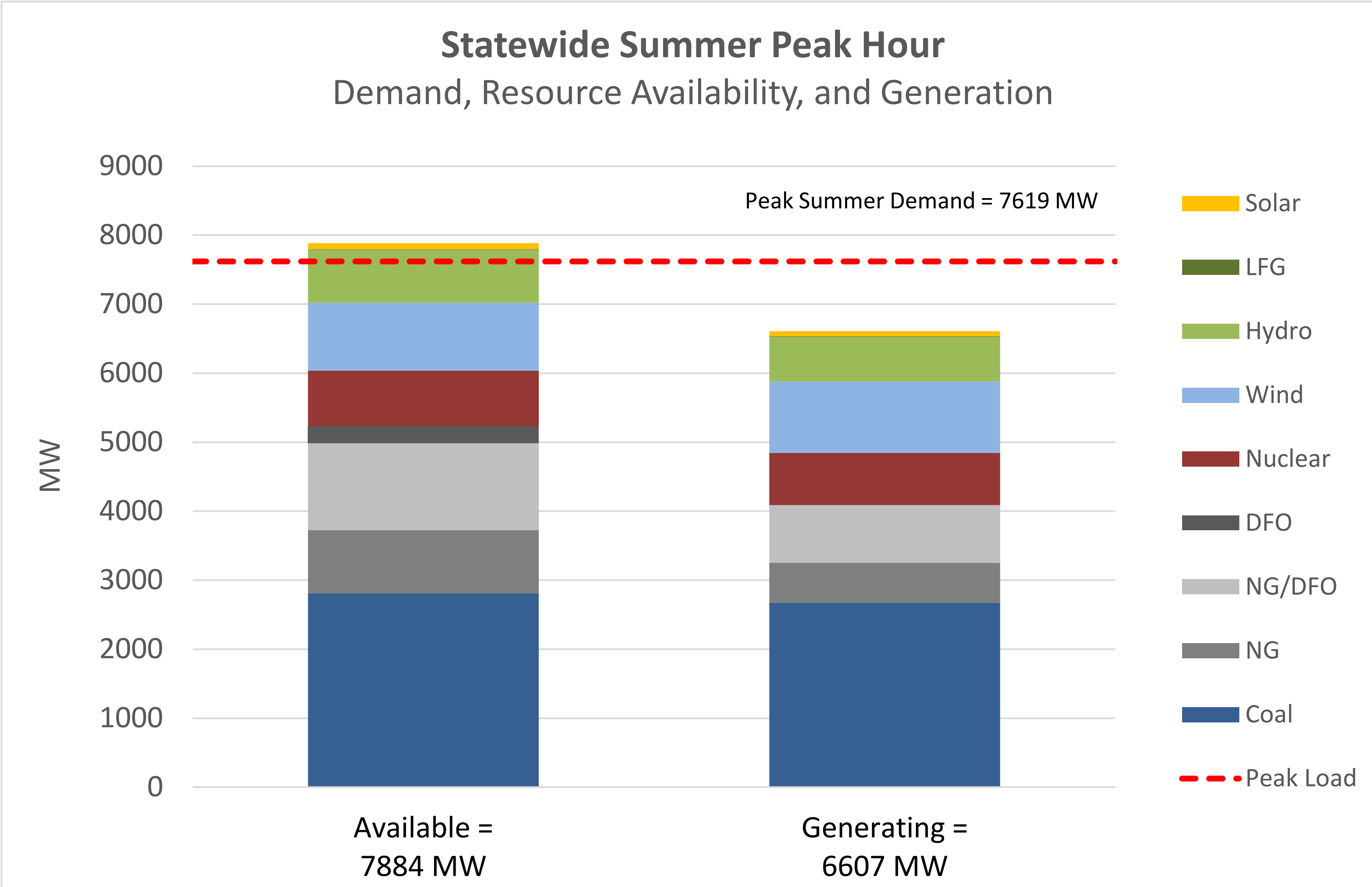

Figure 19 - Statewide Summer Peak Hour - Demand, Resource Availability, and Generation

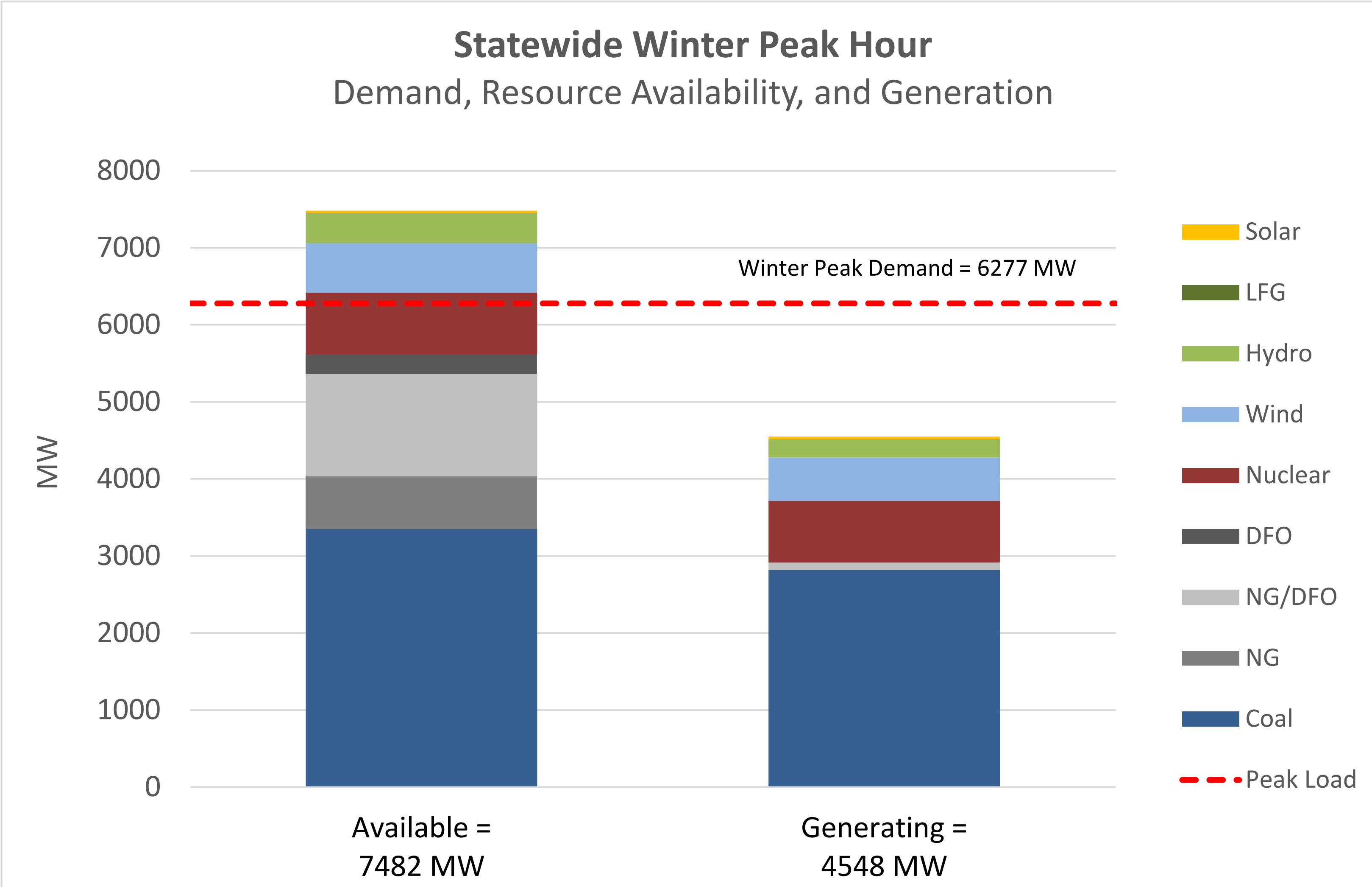

Figure 20 - Statewide Winter Peak Hour - Demand, Resource Availability, and Generation

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 Statewide disruptions in natural gas supply caused by extreme and sustained cold temperatures, resulting in unavailability of natural gas during a winter peak demand event. The PRB requested an analysis that considers the extreme scenario to occur in 2032.

Evaluating the extreme scenario in this future year means that not only the forecasted peak winter demand but also the anticipated future resources must be considered as of the year 2032. Only Existing, Committed, and Planned resources were included in the calculations. No Studied resources were included.

In total, between 2026 and 2032, 2,871 MW of nameplate dual fuel (natural gas and fuel oil) units will be added. 345 MW of natural gas only units will undergo installation of onsite fuel oil to become dual fuel units, and 354 MW of coal units will be converted to natural gas only units. In addition, 115 MW of wind resources, 1,204 MW of solar resources, and 300 MW of storage resources are anticipated for installation prior to 2032.

All resources expected to be in operation in 2032 were assumed to be available at the same capacity level experienced during the peak winter demand hour in 2026. For future units, initial availability was based on a calculated ratio of the 2026 available MW to nameplate MW per fuel type. This equates to added available capacity 2,769 MW of dual fuel gas units, 4.5 MW of wind, 446.8 MW of solar, and 300 MW of storage.

When applying the extreme scenario, first all natural gas units without dual fuel capability were considered unavailable. This removed 680 MW of available capacity.

Second, an assumption was made that the actual peak demand hour would occur after the consumption of 24 hours of onsite fuel oil. Therefore, all dual fuel units with less than 24 hours of onsite storage were considered unavailable. This represents a circumstance where the natural gas disruption and the extreme cold temperatures persist longer than 24 hours and complicate any number of logistics of fuel oil resupply. This removed 618 MW of available dual fuel capacity and 130 MW of fuel oil capacity. A similar assumption was made in relation to battery storage, and 50% of the capacity was assumed to be unavailable in the extreme scenario.

The negative impacts of the extreme scenario are greatly diminished due to a commitment by state utilities to invest in onsite fuel storage for newly constructed or expanded gas plants. All 2871 MW of new thermal units installed between 2026 and 2032 are planned to be dual fuel units with between 1.5 and 3.3 days of onsite fuel storage. The new fuel oil storage project will supply 3 days of onsite fuel as well.

The forecasted 2032 winter peak demand of 7,775 MW (a 1,734 MW, or 27.3% increase from the 2026 winter peak demand) would have exceeded the available capacity of the 2026 winter, but the planned capacity additions will result in a total available capacity of 11,071 MW, far in excess of the peak. Applying the extreme scenario decreases the available capacity from all resources to 9,393 MW, still sufficient to serve the projected peak.

Applying an even more stringent requirement for dual fuel units to have 2 days or more of onsite fuel storage to be available during the extreme scenario, the total system availability falls to 9,141 MW.

Figure 21 shows the forecasted winter peak demand of 8,078 MW against the available capacity during the 2026 winter peak, the expected available capacity for the 2032 winter peak, and the capacity projected to be available during the defined extreme scenario in 2032.

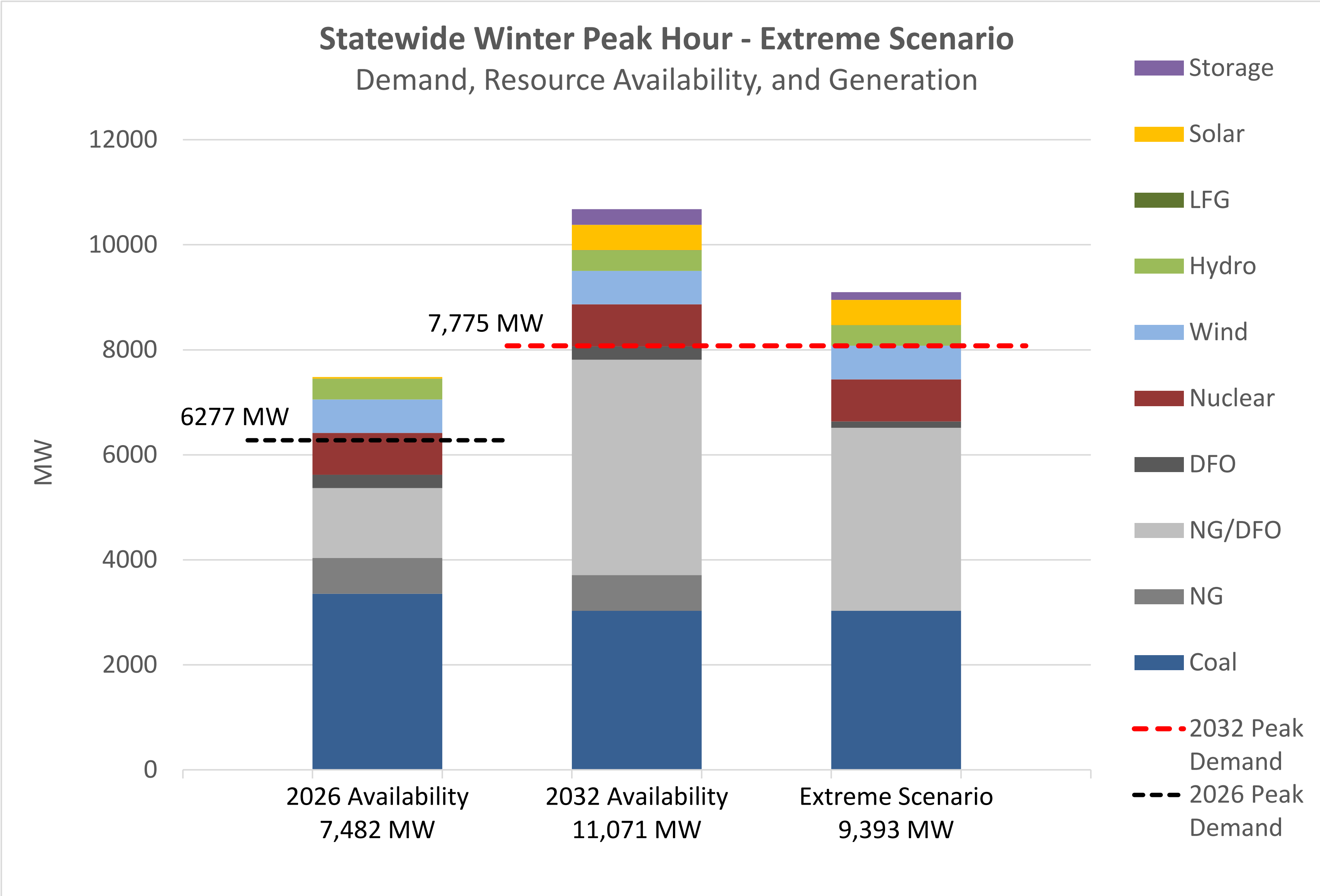

Figure 21 - Statewide Winter Peak Hour - Extreme Scenario - Demand, Resource Availability, and Generation

Addendum – Large Load Integration

On December 19th, 2025, the NPRB met with the NPA JPS in a virtual meeting and asked the NPA to provide additional information related to the timeframes and challenges faced by Nebraska's utilities to provide service to "large loads" and the broad categories of the types of "large loads" that have requested to connect to the system.

After thorough review and consideration of legal circumstances and restrictions concerning the "large load" customers as well as meetings between the CEOs of some of the Nebraska utilities and certain members of the NPRB, the NPA and the NPRB have reached an agreement to include the following items in this Addendum to the Report:

1. The "large load" discussion will be in a separate section of the Report as an addendum to the Report.
2. The utilities (particularly NPPD, OPPD, and LES) will each write their own section in the addendum to address the unique situations they are encountering with respect to economic development, with special focus on large loads.
3. For consistency, the utilities will categorize prospective economic development large loads into the following NERC defined categories:
    a. **Data Centers and Other Computational Load**: Data Centers used for cloud computing, AI, cryptocurrencies, and other digital services.
    b. **Industrial Loads**: Industrial loads consist of facilities and equipment used for producing, processing, or assembling goods
    c. **Hydrogen Production Facilities**: Hydrogen production facilities that use electricity to perform electrolysis.
4. The utilities will describe the timeframes and commitment levels of the "large loads" by using the following categories (or something similar):
    a. **Contracted Loads**: A contract (or similar arrangement) between the customer and utility is signed and the load is most likely already incorporated into the L&C Report. Loads in this category are expected to be fully interconnected within the next five years.
    b. **Prospective Loads**: The potential customer and the utility have reached a verbal agreement and there is a high confidence that a formal arrangement will be reached and at least a portion of the load will connect to the system. Loads in this category are not expected to interconnect for at least two years and could require an additional estimated five years to reach their full electrical consumption levels. The prospective category serves as the transition between the highly certain and highly speculative categories, and as a result, its boundaries are naturally less distinct and may be somewhat subjective.
    c. **Speculative Loads**: The potential customer and the utility have not reached any type of agreement and the inquiry may be vague and lacking in detail regarding the timeframe to connect to the system and the magnitude of the potential customer's demand on the system. The timeframe for loads in this category could be similar to prospective loads and may not be expected to interconnect for at least two years and may require an additional five years to reach their peak demand levels. The potential customer provides enough information that the utility is considering the likely effects on the system, but not sufficient information for the utility to make commitments to serve the customer. The potential exists for the customer to be making interconnection inquires in multiple utility service areas, so load inquiries may unintentionally be double counted.

5. The utilities will use prudent utility planning and forecasting practices regarding determination of the categories they choose and use to describe the “large loads.”
6. Confidentiality of “large load” customer related information will be maintained.
7. The utilities will utilize their best efforts to minimize double counting of potential “large load” customers in the reported data. They may choose to provide aggregated “large load” data for the entire state.

NPPD:

NPPD updates and completes a distributor level or bottom-up forecast annually. In all, NPPD develops forecasts for nearly 90 data series of demand and energy for each of their wholesale distributors (including their retail division). In addition, approximately every five years, NPPD develops econometric, or top down, summer and winter peak demand forecasts. The econometric models for peak demand use inputs like personal income, customers, appliance stocks, and peak day weather conditions. Peak models also include irrigation contribution which can vary considerably from year to year.

When significant new load or expansion of existing load becomes certain, it enters the forecast as a step change or step increase to the wholesale customer (bottom-up) forecast. Examples include ethanol plant development & carbon capture or other ag related production facilities, crypto mining, and data centers.

To deal with these recent large load inquiries, NPPD implemented a New Load Process in 2024 to provide a structured, transparent approach for evaluating new electric load requests by first defining the load and its location, then assessing whether the existing transmission system can serve it or if upgrades are required. The process ensures full compliance with SPP and NPPD transmission requirements. For projects 5 MW and greater, it also requires a Generation Security Deposit of $12,000 per MW to demonstrate customer commitment and to help offset early study costs for the generation resources needed to serve the load. NPPD then pursues the necessary generation resources for capacity, energy, and ancillary services, returning the security deposit when full build out conditions are met. The process also identifies the estimated date that transmission facilities and energy capacity will be available to serve these loads.

The “contracted” loads are either recently energized or expected to be online by the end of 2029. The “prospective” loads, if they come to fruition, will likely take up to 5 years to energize. The energization of the “speculative” loads range from 2027 to an unspecified in-service date as these projects are at the beginning stages of NPPD’s new load process and have the most uncertainty.

NPPD is also implementing a new Large Load Rate in accordance with LB 1010 that fairly allocates costs and shields other customers from financial risks. This rate is for new or expanding customers larger than 20 MW. These customers will be required to curtail load or deploy onsite backup generation during system emergencies. This rate is slated to go into effect on January 1, 2027. New large loads less than 20 MW will be on existing NPPD rates, which offer firm or interruptible service.

OPPD:

To manage the recent influx of large-load inquiries, OPPD implemented a Large Load Request Policy that provides a structured and transparent framework for evaluating all new electric load requests 2 MW and greater. The process begins with the customer defining the proposed load, location, and energy profile and is followed by OPPD's assessment of the existing system's capability to support the load and any system upgrades required. This approach ensures full compliance with SPP and OPPD transmission and generation requirements.

Following the initial inquiry, the customer moves through a pre-defined process with each step requiring an increasing level of commitment from the customer, both financially and contractually, and each step allowing OPPD a more accurate planning assessment of how the system can serve the requested load. Because the list of requests and request status is dynamic, customer commitment and system assessment of all active inquiries are accumulated at regular intervals to weight and aggregate requests to determine future planning load levels.

For projects under 20 MW, customers are required to contribute funding for OPPD transmission and distribution studies. The customer is responsible for paying for any required SPP studies as well. Line Extension Agreements (LEAs) are used to ensure that customers fund their fair share of infrastructure investments and revenue projections are achieved.

For projects 20 MW and above, customers must pay the greater of a flat fee or a price per MW for the OPPD transmission and distribution studies, as well as funding for the SPP study. OPPD also requires an Energy Security Deposit based on the size of the load request to demonstrate customer commitment and help offset early study costs for the generation resources needed to serve the load. The process identifies and communicates to the customer the expected timeline for available transmission facilities and energy capacity to serve each load. LEAs are required for these customers, along with Energy Supply Agreements (ESAs), which include revenue certainty provisions based on customer forecasted load as well as surety for the forecasted revenue. The Energy Security Deposit is credited toward these surety requirements.

OPPD is currently revising its Large Load Request Policy to ensure compliance with Nebraska's new LB1010 regulation. Many of the law's provisions are already accounted for in the policy, but adjustments will be made to align OPPD's internal procedures with the state's new large load interconnection requirements.

For OPPD, the categorization of load requests is largely a function of customer commitment rather than the timing of interconnection. "Contracted" loads are requests within the process that are less than 20 MW or load requests that have executed ESA and/or LEA contracts and are generally expected to be energized within the next 1-5 years. "Prospective" loads have completed an application to fully enter the Large Load Request Process or have progressed to completion of a Definitive System Impact Study. Loads in this category have requested service starting anywhere from 2-7 years in the future. The remaining "Speculative" loads have the lowest level of customer commitment as defined in the required process steps, not having submitted a complete application or committed to a transmission study. The timeline for requested interconnection of these loads ranges from 2028-2040.

LES:

LES has a history of using various modeling tools to estimate the future number of customers that will connect in its service area and the growth of both the quantity of energy that will be consumed by these customers and the electrical demand these customers will place on the system. These tools have a track record of producing reasonably accurate future projections, but they did not anticipate the proliferation of "large load" customers. For LES, the categorization of a "large load" can be based on LES' published Large Power with Market Energy rate that delineates a "large load" as being 20 MW or greater.

These potential "large loads" have proven to be particularly challenging since they can create an annual increase in load growth that can be many multiples larger than utilities have previously experienced. They can also be challenging to the traditional generating resource addition process since the "large load" can be constructed and placed in service in very short timeframes relative to the typical timeframes to install generating resources. Additionally, these "large loads" can raise questions about infrastructure costs and the related customer rate development processes since the necessary infrastructure can be highly concentrated near the "large load" customer and quite costly due to its magnitude which can create rate equity issues regarding how those costs are allocated across the existing customer base.

LES developed an approach to interconnecting "large loads" that strove to balance the expectation that customers requesting service should be accommodated with the desire to not burden the existing customer base with unjustified costs or reliability issues. This approach produced the Large Power with Market Energy rate mentioned above. It also produced a contractual relationship arrangement with the customers that clearly defines the risks and costs that the "large load" customers would be required to absorb and minimizes the risks and costs LES's existing customers would be exposed to.

Although new and unique, LES's overall approach successfully interconnected and began serving its first "large load" in late 2025. The framework and philosophy appear to be working. The arrangements have received positive reviews from the financial industry, LES's existing customers have not had any related reliability or service issues, and the rate and contractual structure LES has implemented has protected the existing customer base from negative effects.

After aggregating contracted, prospective, and speculative Large Loads on a Nebraska statewide level, the results are listed in the following table:

NE Statewide	Contracted Loads	Prospective Loads	Speculative Loads
Data Centers and Other Computational Load	from 800 MW to 1100 MW	from 350 MW to 1950 MW	from 1800 MW to 4300 MW
Industrial Loads	from 60 MW to 530 MW	from 90 MW to 250 MW	from 950 MW to 1950 MW
Hydrogen Production Facilities	from 0 MW to 0 MW	from 30 MW to 400 MW	from 0 MW to 0 MW
Total	from 860 MW to 1630 MW	from 470 MW to 2600 MW	from 2750 MW to 6250 MW

SPP's HILL, CHILLS, and PAL Policies for Large Loads

The Southwest Power Pool (SPP) has developed several complementary initiatives to address the rapid growth in requests from very large electricity customers, including AI data centers, advanced manufacturing facilities, hydrogen production, and other industrial loads that can require hundreds of megawatts to more than one gigawatt of electricity. Traditional transmission planning and interconnection processes were not designed to accommodate this scale or pace of new demand, leading to lengthy study timelines and significant infrastructure requirements. In response, SPP introduced the High Impact Large Load (HILL), Conditional High Impact Large Load Service (CHILLS), and Price Adaptive Load (PAL) initiatives to provide more flexible and efficient pathways for connecting these large customers while maintaining system reliability.

The **High Impact Large Load (HILL)** framework serves as the foundation of SPP's approach. HILL establishes a dedicated process for evaluating large load interconnection requests through coordinated transmission and reliability studies. Instead of relying on multiple sequential studies, HILL integrates the assessment of transmission impacts, operational requirements, and system reliability into a single process, allowing qualifying projects to receive study results in approximately 90 days. This accelerated approach provides developers with earlier information regarding transmission upgrades, operating requirements, and potential constraints, enabling faster project planning while ensuring that new loads can be accommodated without jeopardizing grid reliability.

Building on the HILL framework, **High Impact Large Load Generation Assessment (HILLGA)** allows large loads to be studied together with dedicated supporting generation. This "bring-your-own-generation" model enables projects such as AI data centers or industrial facilities to pair new demand with on-site or nearby generation resources, including natural gas generation, renewable energy, or battery storage. By evaluating the generation and load simultaneously rather than requiring the generation resource to complete the traditional interconnection queue independently, HILLGA can reduce transmission impacts, shorten development timelines, and allow projects to reach commercial operation more quickly.

While HILL and HILLGA accelerate the study and planning process, **Conditional High Impact Large Load Service (CHILLS)** addresses situations in which a customer's facilities are ready before permanent transmission upgrades have been completed. CHILLS establishes a conditional, long-term non-firm transmission service that allows qualifying large loads to begin operating before all required network upgrades are in service. Because the service is interruptible, SPP retains the ability to curtail the load during periods of system stress or reliability concerns. This conditional service can remain in place for up to seven years, providing a bridge between project completion and the availability of permanent firm transmission service.

The **Price Adaptive Load (PAL)** initiative, which remains under development, introduces an economic approach to managing large loads. Rather than relying solely on transmission upgrades or mandatory curtailments, PAL would allow participating customers to voluntarily reduce electricity consumption during periods of high market prices or system stress in exchange for economic incentives. This concept is particularly well suited for flexible loads such as AI data centers or industrial processes that can shift portions of their electricity consumption without significantly affecting operations. By encouraging demand flexibility, PAL has the potential to reduce congestion, improve system reliability, and make more efficient use of existing transmission infrastructure.

Together, these initiatives provide multiple pathways for integrating large electricity consumers into the SPP system. HILL accelerates the study process, HILLGA facilitates projects that include dedicated generation, CHILLS enables earlier energization through conditional transmission service, and PAL seeks to use market-based demand flexibility to reduce system impacts. Collectively, these policies represent one of the most comprehensive regional responses to the rapid growth in large-load requests, with the shared objective of reducing interconnection timelines while preserving reliability and minimizing cost impacts on existing customers.

Key Timeline

- **2024–2025:** SPP stakeholders developed the High Impact Large Load (HILL) framework in response to growing requests from large electricity consumers.

- **September 2025:** The SPP Board of Directors approved the HILL framework, establishing an accelerated process for evaluating large-load interconnection requests.
- **January 2026:** The Federal Energy Regulatory Commission (FERC) approved the HILL and HILLGA tariff revisions, including the expedited study process for qualifying projects.
- **February 2026:** SPP submitted tariff revisions establishing the Conditional High Impact Large Load Service (CHILLS).
- **June 2026:** FERC approved CHILLS, allowing eligible large-load customers to receive conditional, non-firm transmission service while permanent network upgrades are completed.
- **2026 and beyond:** SPP continues stakeholder development of the Price Adaptive Load (PAL) initiative as an additional tool for integrating flexible, high-impact loads.

Appendix – All Existing Resources by Utilities

Appendix 1 – Beatrice

Energy Resources	Unit Name	Unit Status	Duty Cycle	Unit Type	Fuel Type	COD	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**

Appendix 2 – Falls City

Energy Resources	Unit Name	Unit Status	Duty Cycle	Unit Type	Fuel Type	COD	On Site Fuel Storage (Y/N)	Behind the Meter	Nameplate Capacity
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	6.0
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	2.8
Falls City	Falls City #2	E	E	RE	DFO	1937	Y	Y	1.0
Falls City	Falls City #3	E	E	RE	NG/DFO	1965	Y	Y	2.0
Falls City	Falls City #4	E	E	RE	NG/DFO	1946	Y	Y	2.0
Falls City	Falls City #5	E	E	RE	NG/DFO	1951	Y	Y	6.3
Falls City	Falls City #6	E	E	RE	NG/DFO	1958	Y	Y	6.0
Falls City Total									**41.6**

Appendix 3 – Fremont

Energy Resources	Unit Name	Unit Status	Duty Cycle	Unit Type	Fuel Type	COD	On Site Fuel Storage (Y/N)	Behind the Meter	Nameplate Capacity
Fremont	Fremont Unit 6	E	B	ST	SUB/NG	1958	Y	N	16.9
Fremont	Fremont Unit 7	E	B	ST	SUB/NG	1963	Y	N	22.0
Fremont	Fremont Unit 8	E	B	ST	SUB/NG	1976	Y	N	85.3
Fremont	Fremont CT	E	P	CT	NG/DFO	2003	Y	N	37.6
Fremont	Fremont Cottonwood Wind	E	I	WT	WND	2018	N	N	40.4
Fremont	Fremont Solar	E	I	S	SUN	2018	N	Y	2.3
Fremont Total									**204.3**

Appendix 4 – Grand Island

Energy Resources	Unit Name	Unit Status	Duty Cycle	Unit Type	Fuel Type	COD	On Site Fuel Storage (Y/N)	Behind the Meter	Nameplate Capacity
Grand Island	Burdick GT1	E	P	GT	NG/DFO	1968	Y	N	18.0
Grand Island	Burdick GT2	E	P	GT	NG/DFO	2003	Y	N	74.6
Grand Island	Burdick GT3	E	P	GT	NG/DFO	2003	Y	N	74.6
Grand Island	Platte Generating Station	E	B	ST	SUB	1982	Y	N	120.0
Grand Island	Prairie Breeze 3 Wind	E	I	WT	WND	2016	N	N	35.8
Grand Island	GIUD Solar I	E	I	S	SUN	2019	Y	Y	1.0
Grand Island	Museum Drive Solar East	E	I	S	SUN	2024	Y	Y	9.9
Grand Island Total									**333.9**

Appendix 5 – Hastings

Energy Resources	Unit Name	Unit Status	Duty Cycle	Unit Type	Fuel Type	COD	On Site Fuel Storage (Y/N)	Behind the Meter	Nameplate Capacity
Hastings	CCC Hastings Wind	E	I	WT	WND	2016	N	N	1.7
Hastings	DHPC-#1	E	P	GT	NG/DFO	1972	Y	N	18.0
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	76.0
Hastings	Whelan Energy Center #2	E	B	ST	SUB	2011	Y	N	220.0
Hastings	Hastings Community Solar	E	I	S	SUN	2019	N	Y	1.5
Hastings	Hastings Community Solar Phase 2	E	I	S	SUN	2024	N	Y	4.6
Hastings Total									**360.9**

Appendix 6 – LES

Energy Resources	Unit Name	Unit Status	Duty Cycle	Unit Type	Fuel Type	COD	On Site Fuel Storage (Y/N)	Behind the Meter	Nameplate Capacity
LES	Laramie River Station	E	B	ST	SUB	1982	Y	N	188.1
LES	J St	E	P	GT	NG/DFO	1972	Y	N	30.1
LES	Rokeby 1	E	P	GT	NG/DFO	1975	Y	N	68.2
LES	Rokeby 2	E	P	GT	NG/DFO	1997	Y	N	90.3
LES	Rokeby 3	E	P	GT	NG/DFO	2001	Y	N	94.5
LES	TBGS ST1/CT2/CT3	E	P	CC	NG/DFO	2003	Y	N	121.8
LES	TBGS CT 4	E	P	GT	NG/DFO	2003	Y	N	47.6
LES	WSEC4	E	B	ST	SUB	2007	Y	N	102.6
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	4.7
LES	Arbuckle Mountain Wind	E	I	WT	WND	2016	N	N	100.0
LES	Buckeye Wind	E	I	WT	WND	2016	N	N	100.0
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	0.0
LES	Great Western Wind	E	I	WT	WND	2026		N	225.0
LES	Bluestem Wind	E	I	WT	WND	2026		N	198.0
LES	Jeffrey Hydro	E	B	H	WAT	1941		N	21.6
LES Total									**1,474.3**

Appendix 7 – MEAN

Energy Resources	Unit Name	Unit Status	Duty Cycle	Unit Type	Fuel Type	COD	On Site Fuel Storage (Y/N)	Behind the Meter	Nameplate Capacity
MEAN	Alliance #1	E	P	RE	DFO	2002	Y	N	1.8
MEAN	Alliance #2	E	P	RE	DFO	2002	Y	N	1.8
MEAN	Alliance #3	E	P	RE	DFO	2002	Y	N	1.8
MEAN	Ansley #2	E	P	RE	NG/DFO	1972	Y	N	0.9
MEAN	Ansley #3	E	P	RE	NG/DFO	1968	Y	N	0.7
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	1.0
MEAN	Broken Bow #6	E	P	RE	NG/DFO	1961	Y	N	2.3
MEAN	Burwell #1	E	P	RE	NG/DFO	1962	Y	N	1.4
MEAN	Burwell #2	E	P	RE	NG/DFO	1967	Y	N	1.1
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	6.0
MEAN	Curtis #1	E	P	RE	NG/DFO	1975	Y	N	1.4
MEAN	Curtis #2	E	P	RE	NG/DFO	1969	Y	N	1.1
MEAN	Curtis #4	E	P	RE	NG/DFO	1955	Y	N	0.9
MEAN	Kimball #1	E	P	RE	NG/DFO	1955	Y	N	1.0
MEAN	Kimball #2	E	P	RE	NG/DFO	1956	Y	N	1.0
MEAN	Kimball #3	E	P	RE	NG/DFO	1959	Y	N	1.3
MEAN	Kimball #4	E	P	RE	NG/DFO	1960	Y	N	1.3
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	0.7
MEAN	Oxford #3	E	P	RE	NG/DFO	1956	Y	N	0.9
MEAN	Oxford #4	E	P	RE	NG/DFO	1956	Y	N	0.7
MEAN	Oxford #5	E	P	RE	DFO	1972	Y	N	1.4
MEAN	Pender #1	E	P	RE	NG/DFO	1968	Y	N	1.6
MEAN	Pender #2	E	P	RE	NG/DFO	1973	Y	N	1.6
MEAN	Pender #3	E	P	RE	DFO	1953	Y	N	0.6
MEAN	Pender #4	E	P	RE	DFO	1961	Y	N	0.9
MEAN	Red Cloud #2	E	P	RE	NG/DFO	1953	Y	N	1.0
MEAN	Red Cloud #3	E	P	RE	NG/DFO	1960	Y	N	1.4
MEAN	Red Cloud #4	E	P	RE	NG/DFO	1968	Y	N	1.4
MEAN	Red Cloud #5	E	P	RE	NG/DFO	1974	Y	N	2.3

Energy Resources	Unit Name	Unit Status	Duty Cycle	Unit Type	Fuel Type	COD	On Site Fuel Storage (Y/N)	Behind the Meter	Nameplate Capacity
MEAN	Stuart #1	E	P	RE	NG/DFO	1965	Y	N	0.7
MEAN	Stuart #4	E	P	RE	NG/DFO	1996	Y	N	0.8
MEAN	Stuart #5	E	P	RE	DFO	2024	Y	Y	2.0
MEAN	West Point #1	E	P	RE	NG/DFO	1947	Y	N	2.3
MEAN	West Point #2	E	P	RE	NG/DFO	1959	Y	N	1.3
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	0.0
MEAN	Arnold #2	E	E	RE	NG/DFO	1942	Y	Y	0.0
MEAN	Arnold #3	E	E	RE	NG/DFO	1946	Y	Y	0.0
MEAN	Beaver City #1	E	E	RE	NG/DFO	1958	Y	Y	0.0
MEAN	Beaver City #2	E	E	RE	NG/DFO	1961	Y	Y	0.0
MEAN	Beaver City #4	E	E	RE	NG/DFO	1968	Y	Y	0.0
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	0.6
MEAN	Broken Bow #3	E	E	RE	NG/DFO	1936	Y	Y	0.9
MEAN	Burwell#1	E	E	RE	NG/DFO	1955	Y	Y	0.7
MEAN	Chappell #2	E	E	RE	DFO	1945	Y	Y	0.2
MEAN	Crete #1	E	E	RE	NG/DFO	1939	Y	Y	0.0
MEAN	Crete #2	E	E	RE	NG/DFO	1955	Y	Y	0.0
MEAN	Crete #3	E	E	RE	NG/DFO	1951	Y	Y	0.0
MEAN	Crete #4	E	E	RE	NG/DFO	1947	Y	Y	0.0
MEAN	Crete #5	E	E	RE	NG/DFO	1962	Y	Y	0.0
MEAN	Crete #6	E	E	RE	NG/DFO	1965	Y	Y	0.0
MEAN	Sidney #1	E	E	RE	NG/DFO	1967	Y	Y	1.3
MEAN	Sidney #2	E	E	RE	NG/DFO	1973	Y	Y	0.0
MEAN	Sidney #3	E	E	RE	DFO	1953	Y	Y	0.8
MEAN	Sidney #4	E	E	RE	NG/DFO	1961	Y	Y	0.0
MEAN	Sidney #5	E	E	RE	NG/DFO	1939	Y	Y	3.0
MEAN	Stuart #2	E	E	RE	DFO	1960	Y	Y	0.3
MEAN	Stuart #3	E	E	RE	DFO	1954	Y	Y	0.3
MEAN	Stuart #4	E	E	RE	DFO	1946	Y	Y	0.8
MEAN Total									**74.8**

Appendix 8 – Neligh

Energy Resources	Unit Name	Unit Status	Duty Cycle	Unit Type	Fuel Type	COD	On Site Fuel Storage (Y/N)	Behind the Meter	Nameplate Capacity
NELIGH	Neligh #1	E	P	RE	OBL	2012	Y	N	1.8
NELIGH	Neligh #2	E	P	RE	OBL	2012	Y	N	1.8
NELIGH	Neligh #3	E	P	RE	OBL	2012	Y	N	1.8
NELIGH	Neligh #4	E	P	RE	OBL	2012	Y	N	0.3
NELIGH Total									**5.7**

Appendix 9 – Nebraska City

Energy Resources	Unit Name	Unit Status	Duty Cycle	Unit Type	Fuel Type	COD	On Site Fuel Storage (Y/N)	Behind the Meter	Nameplate Capacity
Nebraska City	Nebraska City #5	E	P	RE	NG/DFO	1964	Y	N	2.0
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	4.6
Nebraska City	Nebraska City #14	E	E	RE	DFO	2013	Y	Y	0.6
Nebraska City Total									**44.7**

Appendix 10 – Northwestern NPPD

Energy Resources	Unit Name	Unit Status	Duty Cycle	Unit Type	Fuel Type	COD	On Site Fuel Storage (Y/N)	Behind the Meter	Nameplate Capacity
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 NPPD Total									**19.1**

Appendix 11 – NPPD

Energy Resources	Unit Name	Unit Status	Duty Cycle	Unit Type	Fuel Type	COD	On Site Fuel Storage (Y/N)	Behind the Meter	Nameplate Capacity
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	2.4
NPPD	Auburn #2	E	P	RE	NG/DFO	1949	Y	N	1.0
NPPD	Auburn #4	E	P	RE	NG/DFO	1993	Y	N	3.8
NPPD	Auburn #5	E	P	RE	NG/DFO	1973	Y	N	3.4
NPPD	Auburn #6	E	P	RE	NG/DFO	1967	Y	N	2.8
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	0.0
NPPD	Belleville 5	E	P	RE	NG/DFO	1961	Y	N	1.8
NPPD	Belleville 6	E	P	RE	NG/DFO	1966	Y	N	3.8
NPPD	Belleville 7	E	P	RE	NG/DFO	1971	Y	N	5.1
NPPD	Belleville 8	E	P	RE	NG/DFO	2006	Y	N	2.8
NPPD	Broken Bow Wind	E	I	WT	WND	2013	N	N	80.0
NPPD	Broken Bow II Wind	E	I	WT	WND	2014	N	N	73.1
NPPD	Cambridge	E	P	RE	DFO	1972	Y	N	4.0
NPPD	Canaday	E	P	ST	NG/DFO	1958	N	N	108.8
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	801.0
NPPD	Crofton Bluffs Wind	E	I	WT	WND	2013	N	N	42.0
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	1.0
NPPD	David City 3	E	P	RE	NG/DFO	1955	Y	N	1.0
NPPD	David City 4	E	P	RE	NG/DFO	1966	Y	N	2.3
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	80.0
NPPD	Franklin 1	E	P	RE	NG/DFO	1963	Y	N	0.7
NPPD	Franklin 2	E	P	RE	NG/DFO	1974	Y	N	1.4
NPPD	Franklin 3	E	P	RE	NG/DFO	1968	Y	N	1.1
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

Energy Resources	Unit Name	Unit Status	Duty Cycle	Unit Type	Fuel Type	COD	On Site Fuel Storage (Y/N)	Behind the Meter	Nameplate Capacity
NPPD	Hebron	E	P	GT	DFO	1973	N	N	56.7
NPPD	Kearney	E	B	H	WAT	1921	N	N	1.5
NPPD	Kingsley (CNPPID)	E	B	H	WAT	1985	Y	N	41.7
NPPD	Laredo Ridge Wind	E	I	WT	WND	2011	N	N	80.0
NPPD	Madison 1	E	P	RE	NG/DFO	1969	Y	N	2.1
NPPD	Madison 2	E	P	RE	NG/DFO	1959	Y	N	1.4
NPPD	Madison 3	E	P	RE	NG/DFO	1953	Y	N	1.1
NPPD	Madison 4	E	P	RE	DFO	1946	Y	N	1.4
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	5.0
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	1.5
NPPD	Ord 5	E	P	RE	DFO	1997	Y	N	1.5
NPPD	Sargent	E	P	RE	DFO	1964	Y	N	1.9
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	3.0
NPPD	Steele Flats Wind	E	I	WT	WND	2013	N	N	75.0
NPPD	Wahoo #1	E	P	RE	NG/DFO	1960	Y	N	2.1
NPPD	Wahoo #3	E	P	RE	NG/DFO	1973	Y	N	4.4
NPPD	Wahoo #5	E	P	RE	NG/DFO	1952	Y	N	2.2
NPPD	Wahoo #6	E	P	RE	NG/DFO	1969	Y	N	3.5
NPPD	Western Sugar	E	B	ST	SUB	2014	Y	N	5.0
NPPD	Wilber 4	E	P	RE	DFO	1949	Y	N	0.9
NPPD	Wilber 5	E	P	RE	DFO	1958	Y	N	0.8
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	0.5
NPPD	Loup PPD - City of Schuyler Solar Phase 2	E	I	S	SUN	2021	N	Y	0.5
NPPD	Loup PPD - City of Schuyler Solar Phase 3	E	I	S	SUN	2025	N	Y	1.3
NPPD	Scottsbluff Community Solar 1	E	I	S	SUN	2017	N	Y	0.1
NPPD	Scottsbluff Community Solar 2	E	I	S	SUN	2020	N	Y	4.4

Energy Resources	Unit Name	Unit Status	Duty Cycle	Unit Type	Fuel Type	COD	On Site Fuel Storage (Y/N)	Behind the Meter	Nameplate Capacity
NPPD	Kearney Community Solar	E	I	S	SUN	2018	N	Y	5.7
NPPD	City of Central City Solar Park	E	I	S	SUN	2016	N	Y	0.2
NPPD	City of Central City Solar Park (2)	E	I	S	SUN	2016	N	Y	0.4
NPPD	City of Cozad Solar	E	I	S	SUN	2021	N	Y	2.0
NPPD	City of Gothenburg Solar 1	E	I	S	SUN	2018	N	Y	0.5
NPPD	City of Gothenburg Solar 2	E	I	S	SUN	2019	N	Y	0.5
NPPD	Village of Hemingford Solar	E	I	S	SUN	2021	N	Y	1.0
NPPD	City of Holdrege Housing Proj Solar	E	I	S	SUN	2017	N	Y	0.1
NPPD	City of Lexington Solar	E	I	S	SUN	2017	N	Y	3.6
NPPD	City of Lexington Airport Solar	E	I	S	SUN	2021	N	Y	1.0
NPPD	City of Seward Wind	E	I	WT	WND	2018	N	Y	1.7
NPPD	Cornhusker PPD - Renewable Solar LLC	E	I	S	SUN	2019	N	Y	0.3
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	0.5
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	0.5
NPPD	Custer PPD - Cockerill Fertilizer Solar 2	E	I	S	SUN	2019	N	Y	0.5
NPPD	Dawson PPD - Willow Island Solar	E	I	S	SUN	2017	N	Y	0.3
NPPD	Howard Greeley RPPD - St Paul North Solar	E	I	S	SUN	2024	N	Y	1.0
NPPD	Loup Valleys RPPD - North Loup Solar	E	I	S	SUN	2020	N	Y	0.2
NPPD	Perennial PPD - Fairmont 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
NPPD	Polk Co PPD Solar	E	I	S	SUN	2024	N	Y	1.0
NPPD	South Central PPD Solar Project	E	I	S	SUN	2022	N	Y	1.0
NPPD	Burt Co PPD - Dodge Co Solar	E	I	S	SUN	2022	N	Y	1.0
NPPD	Burt Co PPD - Burt Co Solar	E	I	S	SUN	2022	N	Y	1.0
NPPD	Norfolk Community Solar	E	I	S	SUN	2023	N	Y	9.7
NPPD	Norfolk Battery Energy Storage System	E	ES	ES	ES	2023	N	Y	1.0
NPPD	Ainsworth Solar	E	I	S	SUN	2022	N	Y	0.5
NPPD	Elkhorn RPPD - Acklic	E	I	S	SUN	2021	N	Y	3.0
NPPD	Elkhorn RPPD - Uecker	E	I	S	SUN	2021	N	Y	2.0
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	5.6

Energy Resources	Unit Name	Unit Status	Duty Cycle	Unit Type	Fuel Type	COD	On Site Fuel Storage (Y/N)	Behind the Meter	Nameplate Capacity
NPPD	York Solar	E	I	S	SUN	2023	N	Y	3.2
NPPD	Norris PPD - Centerville Solar	E	I	S	SUN	2023	N	Y	1.0
NPPD	Norris PPD - Deshler Solar	E	I	S	SUN	2023	N	Y	1.0
NPPD	Norris PPD - Ruby Solar	E	I	S	SUN	2023	N	Y	1.0
NPPD	Norris PPD - Tobias Solar	E	I	S	SUN	2024	N	Y	1.0
NPPD	Norris PPD - Diller Solar	E	I	S	SUN	2025	N	Y	1.0
NPPD	City of Wahoo Solar	E	I	S	SUN	2024	N	Y	2.0
NPPD	York 1	E	E	RE	DFO	1980	Y	Y	1.0
NPPD	York 2	E	E	RE	DFO	1996	Y	Y	1.6
NPPD Total									**3,792.3**

Appendix 12 – OPPD

Energy Resources	Unit Name	Unit Status	Duty Cycle	Unit Type	Fuel Type	COD	On Site Fuel Storage (Y/N)	Behind the Meter	Nameplate Capacity
OPPD	BRIGHT Battery	E	I	ES	ES	2022	N	Y	1.0
OPPD	Standing Bear Lake #1	E	P	GT	NG/DFO	2025	Y	N	18.1
OPPD	Standing Bear Lake #2	E	P	GT	NG/DFO	2025	Y	N	18.1
OPPD	Standing Bear Lake #3	E	P	GT	NG/DFO	2025	Y	N	18.1
OPPD	Standing Bear Lake #4	E	P	GT	NG/DFO	2025	Y	N	18.1
OPPD	Standing Bear Lake #5	E	P	GT	NG/DFO	2025	Y	N	18.1
OPPD	Standing Bear Lake #6	E	P	GT	NG/DFO	2025	Y	N	18.1
OPPD	Standing Bear Lake #7	E	P	GT	NG/DFO	2025	Y	N	18.1
OPPD	Standing Bear Lake #8	E	P	GT	NG/DFO	2025	Y	N	18.1
OPPD	Standing Bear Lake #9	E	P	GT	NG/DFO	2025	Y	N	18.1
OPPD	Turtle Creek #1	E	P	GT	NG/DFO	2025	Y	N	264.0
OPPD	Turtle Creek #2	E	P	GT	NG/DFO	2025	Y	N	264.0
OPPD	Platteview Solar	E	I	S	SUN	2024	N	N	81.0
OPPD	Jones St. #1	E	P	GT	DFO	1973	Y	N	65.0
OPPD	Jones St. #2	E	P	GT	DFO	1973	Y	N	65.0
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	1.0
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	3.1
OPPD	Elk City Station #5-8	E	B	RE	LFG	2006	N	N	2.9
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
OPPD	Nebraska City #1	E	B	ST	SUB	1979	Y	N	651.6
OPPD	Nebraska City #2	E	B	ST	SUB	2009	Y	N	738.0
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	136.0
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

Energy Resources	Unit Name	Unit Status	Duty Cycle	Unit Type	Fuel Type	COD	On Site Fuel Storage (Y/N)	Behind the Meter	Nameplate Capacity
OPPD	OPPD Community Solar	E	I	S	SUN	2020	N	Y	5.0
OPPD	Milligan Wind	E	I	WT	WND	2023	N	N	300.0
OPPD	Flat Water Wind	E	I	WT	WND	2011	N	N	60.0
OPPD	Grande Prairie Wind	E	I	WT	WND	2016	N	N	400.0
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	160.0
OPPD Total									**4,795.0**

Appendix 13 – Scribner

Energy Resources	Unit Name	Unit Status	Duty Cycle	Unit Type	Fuel Type	COD	On Site Fuel Storage (Y/N)	Behind the Meter	Nameplate Capacity
SCRIBNER	Scribner #1	E	P	RE	OBL	2020	N	N	1.9
SCRIBNER	Scribner #2	E	P	RE	OBL	2020	N	N	1.9
Scribner Total									**3.8**

Appendix 14 – South Sioux City

Energy Resources	Unit Name	Unit Status	Duty Cycle	Unit Type	Fuel Type	COD	On Site Fuel Storage (Y/N)	Behind the Meter	Nameplate Capacity
South Sioux City	SSC Solar	E	I	S	SUN	2018	N	Y	2.1
South Sioux City	Cotttonwood Wind	E	I	WT	WND	2020	N	N	15.6
South Sioux City	WWTP Gen	E	I	RE	DFO	2023	Y	Y	1.8
South Sioux City	NG Generation Plant	E	P	RE	NG	2022	N	Y	5.0
South Sioux City Total									**24.4**

Appendix 15 – Sidney

Energy Resources	Unit Name	Unit Status	Duty Cycle	Unit Type	Fuel Type	COD	On Site Fuel Storage (Y/N)	Behind the Meter	Nameplate Capacity
Sidney	Sidney #1	E	E	RE	NG/DFO	1967	Y	Y	1.3
Sidney	Sidney #2	E	E	RE	NG/DFO	1973	Y	Y	0.0
Sidney	Sidney #3	E	E	RE	DFO	1953	Y	Y	0.8
Sidney	Sidney #4	E	E	RE	NG/DFO	1961	Y	Y	0.0
Sidney	Sidney #5	E	E	RE	NG/DFO	1939	Y	Y	3.1
Sidney Total									**5.1**

Appendix 16 – Superior

Energy Resources	Unit Name	Unit Status	Duty Cycle	Unit Type	Fuel Type	COD	On Site Fuel Storage (Y/N)	Behind the Meter	Nameplate Capacity
Superior	Community Solar	E	I	S	SUN	2018	N	Y	0.0
Superior Total									**0.0**

Appendix 17 – Tri-State

No existing resources – capacity is being purchased from other entities.

Appendix 18 – Valentine

No existing resources – capacity is being purchased from other entities.

Appendix 19 – Wakefield

Energy Resources	Unit Name	Unit Status	Duty Cycle	Unit Type	Fuel Type	COD	On Site Fuel Storage (Y/N)	Behind the Meter	Nameplate Capacity
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**

Appendix 20 – Walthill

No existing resources – capacity is being purchased from other entities.

Appendix 21 – Wayne

Energy Resources	Unit Name	Unit Status	Duty Cycle	Unit Type	Fuel Type	COD	On Site Fuel Storage (Y/N)	Behind the Meter	Nameplate Capacity
WAYNE	Wayne 1	E	P	RE	DFO	1951	Y	N	0.8
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	3.3
WAYNE	Wayne 8	E	P	RE	DFO	1998	Y	N	3.6
Wayne Total									**20.4**

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