Direct Testimony and Schedules
Todd Z. Simmons

Before the Minnesota Public Utilities Commission

State of Minnesota

In the Matter of the Application of Minnesota Power
For Authority to Increase Rates for Electric Utility
Service in Minnesota

MPUC Docket No. E015/GR-26-199

Exhibit _____

GENERATION OPERATIONS

November 2, 2026

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I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Todd Z. Simmons, and my business address is 30 West Superior Street, Duluth, Minnesota 55802.

Q. By whom are you employed and in what position?

A. I am employed by ALLETE, Inc., ("ALLETE") doing business as Minnesota Power ("Minnesota Power" or the "Company"). My current position is Vice President – MP Generation Operations.

Q. Please describe your educational background and work experience with ALLETE and Minnesota Power.

A. I hold a Bachelor of Arts degree in Business Management from The College of St. Scholastica in Duluth, Minnesota. Additionally, I hold a Chief "A" Engineer's License with the State of Minnesota. As a college student, I began working for Minnesota Power at the Boswell Energy Center ("BEC") as a seasonal employee in 1993 and became a full-time employee in the fuels department in 1994. From 1997 through 1999, I was a union employee in Operations for both Laskin Energy Center ("Laskin" or "LEC") and BEC. In January 2000, I accepted a supervisory position at BEC and worked as an Operations Superintendent. In 2005, I accepted a position with the Generation Operations group working as Production Specialist supporting all of Minnesota Power's generation facilities. I was promoted to Thermal Business Operations Manager at BEC in 2008 before I transferred to North Dakota as part of the Bison Wind Energy Center ("Bison") development as the Wind Operations Manager in 2010. I was promoted to General Manager of Wind Operations for North Dakota in 2013. In 2017, I became General Manager Renewable Operations for all of Minnesota Power's renewable facilities, as well as the Generation Operations engineering, generation information technology, and generation coordination departments. In 2022, I was named Vice President of Generation Operations. As the Vice President of Generation Operations, I am currently responsible for the generating facilities in Minnesota and Bison, located in

North Dakota. MP Exhibit ___ (Simmons), Direct Schedule 1 to my Direct Testimony provides my experience and qualifications.

Q. What is the purpose of the testimony you are presenting on behalf of Minnesota Power?

A. The purpose of my Direct Testimony is to describe how the Company continues to transform its generation fleet while increasing renewable resources and maintaining efficient, reliable, and cost-effective services for our customers. While some of these efforts were discussed in Minnesota Power's rate case filed in 2023 (Docket No. E015/GR-23-155) (the "2023 Rate Case"), the Company has continued to make progress on its Energy*Forward* strategy. Additionally, I will give an overview of capital projects and operations and maintenance ("O&M") expenses for the Generation Operations work area included in Minnesota Power's 2027 test year and review assets placed in service since the 2023 Rate Case. Lastly, I will provide information on environmental compliance costs as it relates to the Coal Combustion Residual ("CCR") regulations.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring the following schedules to my Direct Testimony:

- MP Exhibit ___ (Simmons), Direct Schedule 1 – Statement of Qualifications; and
- MP Exhibit ___ (Simmons), Direct Schedule 2 – 2027 Test Year Capital Additions

II. GENERATION FORWARD-LOOKING FLEET

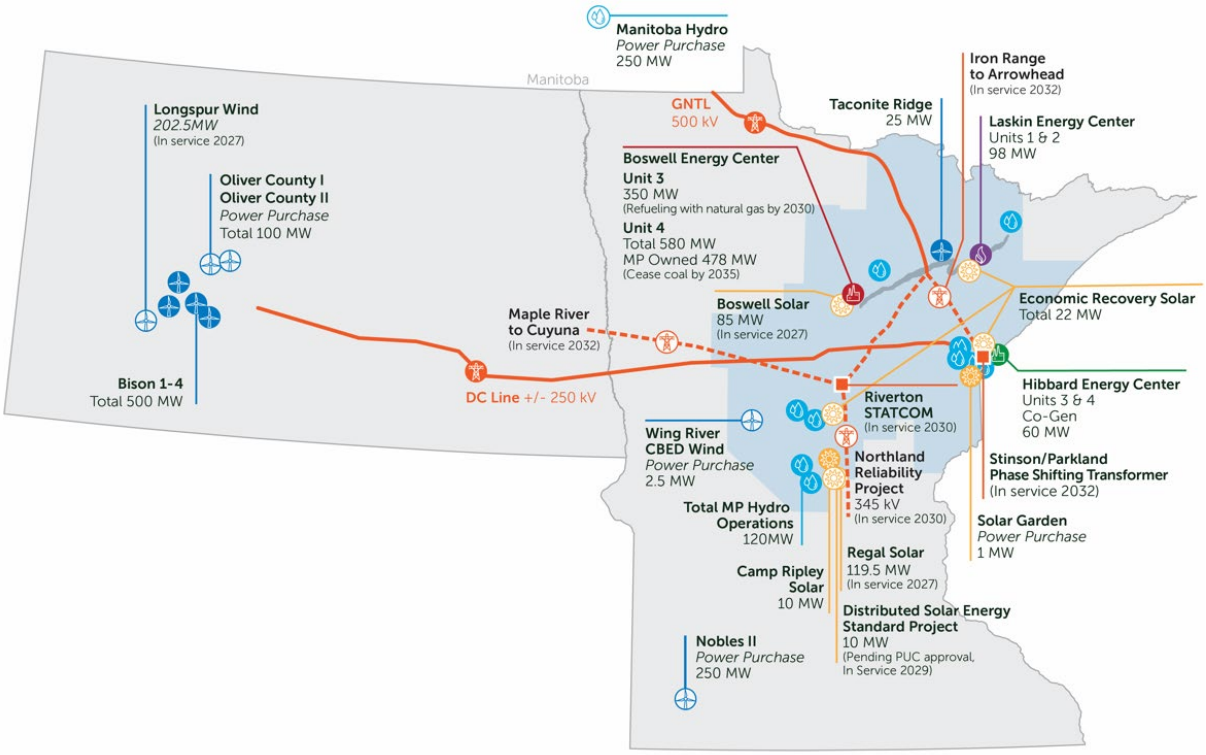
Q. What is the purpose of this section of your testimony?

A. The purpose of my Direct Testimony is to describe how the Company continues to transform its generation fleet while increasing renewable resources and maintaining efficient, reliable, and cost-effective services for our customers. While some of these efforts were discussed in Minnesota Power's 2023 Rate Case, the Company has continued to make progress on its Energy*Forward* strategy.

Q. Please describe Minnesota Power's current generation portfolio.

A. Minnesota Power's generation facilities have a net maximum capability of over 1,800 megawatts ("MW") and rely on a variety of fuel sources, including hydro, solar, wind, coal, natural gas, and biomass, to generate power. These resources, combined with a number of power purchase agreements ("PPA"), supply energy for our approximately 150,000 residential and commercial customers, 14 municipalities, and some of the nation's largest industrial customers. Figure 1 provides a graphical representation of Minnesota Power's generating portfolio. Since 2005, the Company has reduced coal fired generation by 700 MW through the retirement, refueling, or re-missioning of seven of its nine coal-fired power generators in northern Minnesota.

Figure 1. Minnesota Power's Generation Supply Portfolio



Q. What is Minnesota Power's philosophy when it comes to Generation Operations?

A. The mission of Minnesota Power's Generation Operations is to operate and manage the Company's generation assets in a manner that protects both people and the planet while maintaining financial responsibility to our customers. This mission is the driving force behind maintaining the operational integrity of the Company's generation resources and

is supported by a robust, comprehensive, and system-wide reliability effort. Electric generating assets serve a duty cycle that reflects the inherent design and power market demands for economic dispatch, baseload, intermediate load, and peak load. Preserving the usefulness of generation assets requires capital investment and maintenance expenditures to sustain a unit's economic viability, availability, and reliability for the duty cycle it serves. Minnesota Power's generating units have traditionally served a baseload mission due to the large component of around-the-clock industrial service in the Company's customer base, as shown by the Company's load factor of more than 80 percent, one of the highest in the nation. Over time, the Company's mission of serving its customers with large baseload generation has changed with significant additions of intermittent renewable generation already placed in service and further planned wind and solar for the future across the Midcontinent Independent System Operator ("MISO") footprint and within the Company's system.

Coupling the variable nature of renewable generation with high load factors may require changes to the operation of dispatchable assets to maintain a reliable and affordable energy supply, particularly when renewable generation is high and market demands are low. The degree of impact on dispatchable resources depends on renewable energy generation and system demand. Currently, weather impacts on renewable generation are managed by backing down the Company's dispatchable units to lower loads. However, as the renewable fleet on the system expands, there are times when dispatchable units may need to be taken off-line to make room for renewable generation. Significantly increasing the number of on/off cycles of dispatchable generating units to accommodate the availability of renewable generation may change the generation maintenance strategy due to thermal stresses and wear associated with starting and stopping equipment as well effects on fuel procurement and inventory levels. A generation plant requires maintenance to ensure that the generating units are available to meet customer demands and the intended mission of each unit.

The Company continues to evolve maintenance programs consistent with good utility practices to address impacts to generating unit operation, reliability, and maintenance

costs while operating in a region where the generation fleet is transitioning to reduce carbon and add more renewable energy sources. Minnesota Power continues to focus on reliability while maintaining compliance with all pertinent regulations and environmental permits.

Q. How has the Company's generation supply changed since the 2023 Rate Case?

A. Table 1 provides the changes in generation from 2023 the 2027 test year, based on capability.

Table 1. Minnesota Power Owned Generation

	Unit No.	Year Installed	2023 Net Capability (MW)	2027 Net Capability (MW)
Coal				
Boswell Energy Center ("BEC") in Cohasset, MN	1	1958	_(R)	_(R)
	2	1960	_(R)	_(R)
	3	1973	352	352
	4*	1980	468	468
			820	820
Total Coal			820	820
Biomass/Coal/Natural Gas				
Hibbard Renewable Energy Center ("HREC") in Duluth, MN	3 & 4	1949, 1951	60	60
Laskin Energy Center ("Laskin") in Hoyt Lakes, MN	1 & 2	1953	98	98
Total Biomass/Coal/Natural Gas			158	158
Hydro				
Group of ten stations in MN	Multiple	Multiple	120	120
Wind				
Taconite Ridge Energy Center ("Taconite Ridge") in Mt. Iron, MN	Multiple	2008	25	25
Bison Wind Energy Center ("Bison") in Oliver and Morton Counties, ND	Multiple	2010-2014	497	497
Longspur Wind Energy Center ("Longspur") in Morton and Mercer Counties, ND	Multiple	2027	0	200
Total Wind			522	722
Solar				
Camp Ripley -Little Falls, MN		2017	10	10
HSC Solar Garden		2016	0.04	0.04
Boswell Solar - Cohasset, MN		2027	0	85
Regal Solar - Royalton, MN		2027	0	119.5
Total Solar			10	215
Total Company Generation			**1630**	**2035**

(R) BEC1 and BEC2 were retired on December 26 and 27, 2018, respectively

*BEC 4 is jointly owned by WPPi

Q. Have any Company generation resources been retired since the 2023 Rate Case?

A. No.

Q. Has the Company added any generation resources since the 2023 Rate Case?

A. Yes. More than 200 MW of solar generation and 200 MW of wind has been added or is under construction for Minnesota Power's generation portfolio since the 2023 Rate Case, including the Boswell and Regal Solar projects, Longspur wind as well as the Camp Ripley Solar asset purchase, which had previously been leased. Each of these generation resources are explained in Section IV below.

III. GENERATION BUDGETING OVERVIEW

A. Generation Capital Budgets

Q. How does Generation Operations identify its capital budget for any given year?

A. The overall capital budgeting process for any work area is explained in the Direct Testimony of Company witness Joshua G. Rostollan. Generation Operations augments the budget development process discussed by Company witness Rostollan by including an additional level of review of the portfolio of capital projects by the Project Review Committee ("PRC"). Once approved by the PRC, each project receives management approval and is then included in the annual corporate capital budget presented for review and approval by the Board of Directors.

Q. Who comprises the PRC?

A. The PRC is comprised of an experienced team that includes budget analysts, reliability and facility engineers, internal technical experts, and Generation Operations leadership.

Q. What is the role of the PRC in the budget process?

A. Generation Operations' capital projects are reviewed and approved by the PRC before they are included in the Generation Operations capital budget. The PRC is a group of experienced individuals responsible for ensuring that capital projects within Generation Operations are effectively and efficiently aligned with Minnesota Power's overall business strategy, identifying and prioritizing resources, establishing appropriate project management process and controls for transparency, and managing contingency and risk across the Generation Operations work area. Projects are presented to the PRC for additional vetting. The PRC may approve a project, send the project back for additional

review or information, or deny approval of a project before the project is forwarded for management approval and included in the Company's capital budget. A complete list of the planned 2027 test year Generation Operations capital additions is included in MP Exhibit ___ (Simmons), Direct Schedule 2.

Q. Please describe Minnesota Power's recent Generation Operations capital additions.

A. The Company continues to invest capital in our generation resources to support the safe, reliable, and economic generation of electricity for our customers. There are Company-owned generation resources that continue to provide cost-effective electricity for our customers based on our careful and thoughtful capital investments over the asset life cycle. A summary of the Company's Generation Operations actual capital additions in 2023 – 2025, 2026 projected year capital additions, and capital additions (Total Company) included in the 2027 test year is provided in Table 2 and capital additions (MN Jurisdictional) included in the 2027 test year is provided in Table 3.

Table 2. Generation Operations Capital Additions (Total Company) ($ in Millions)

Capital Plant Additions (including Contra) -- Total Company	2023	2024	2025	2026	2027
	Actuals	Actuals	Actuals	Projected Year	Test Year
Steam Generation	$27.1	$35.2	$42.7	$34.1	$37.2
Boswell Common	$7.5	$5.6	$23.6	$3.5	$3.2
Boswell Unit 3	$5.1	$21.6	$5.8	$15.5	$2.2
Boswell Unit 4	$11.2	$2.2	$2.8	$2.6	$20.7
Hibbard Renewable Energy Center	$3.2	$3.8	$7.0	$6.6	$8.2
Laskin Energy Center	$0.7	$2.0	$3.6	$5.9	$2.9
Taconite Harbor Energy Center	($0.7)	-	-	-	-
Hydro Generation	$7.4	$5.6	$6.1	$2.2	$31.5
Birch Lake Reservoir	-	-	-	$0.1	-
Blanchard HE Station	$2.9	$1.1	$1.4	-	$16.3
Fish Lake Reservoir	-	-	$0.1	-	-
Fond du Lac HE Station	$0.1	$1.6	$0.2	-	$2.6
Island Lake Reservoir	-	$0.4	-	-	-
Knife Falls HE Station	-	-	$0.3	$0.6	$0.3
Little Falls HE Station	$0.1	$0.2	$2.7	-	$1.1
Prairie River HE Station	$0.4	-	$0.5	-	-
Rice Lake Reservoir	-	-	-	$0.4	-
Scanlon HE Station	$2.7	-	$0.1	$0.4	$4.2
Sylvan HE Station	-	$0.2	-	-	$0.3
Thomson HE Station	$1.1	$0.1	$0.7	$0.2	$4.8
Winton HE Station	-	$1.9	$0.2	$0.4	$1.9
Wind Generation	$2.8	$3.8	$5.6	$2.0	$11.8
Bison	$1.8	$1.7	$1.1	$1.9	$7.7
Taconite Ridge	$1.0	$2.2	$4.5	$0.1	$4.2
Solar Generation	-	-	-	-	$5.2
Generation Subtotal, excluding Riders	**$37.3**	**$44.6**	**$54.4**	**$38.7**	**$85.8**

Amounts in millions.

Amounts may not total due to rounding.

Table 3. Generation Operations Capital Additions (MN Jurisdictional) ($ in Millions)

Capital Plant Additions (including Contra) -- MN Jurisdictional	2023	2024	2025	2026	2027
	Actuals	Actuals	Actuals	Projected Year	Test Year
Steam Generation	$23.7	$31.2	$37.5	$30.1	$30.9
Boswell Common	$6.5	$4.9	$20.8	$3.1	$2.6
Boswell Unit 3	$4.5	$19.2	$5.1	$13.7	$1.8
Boswell Unit 4	$9.8	$1.9	$2.4	$2.3	$17.2
Hibbard Renewable Energy Center	$2.8	$3.3	$6.2	$5.8	$6.8
Laskin Energy Center	$0.6	$1.8	$3.1	$5.2	$2.4
Taconite Harbor Energy Center	($0.6)	-	-	-	-
Hydro Generation	$6.4	$5.0	$5.3	$1.9	$26.1
Birch Lake Reservoir	-	-	-	$0.1	-
Blanchard HE Station	$2.5	$1.0	$1.2	-	$13.5
Fish Lake Reservoir	-	-	$0.1	-	-
Fond du Lac HE Station	$0.0	$1.4	$0.2	-	$2.1
Island Lake Reservoir	-	$0.3	-	-	-
Knife Falls HE Station	-	-	$0.2	$0.6	$0.2
Little Falls HE Station	$0.1	$0.2	$2.3	-	$0.9
Prairie River HE Station	$0.4	-	$0.4	-	-
Rice Lake Reservoir	-	-	-	$0.3	-
Scanlon HE Station	$2.4	-	$0.1	$0.4	$3.5
Sylvan HE Station	-	$0.2	-	-	$0.3
Thomson HE Station	$1.0	$0.1	$0.6	$0.1	$4.0
Winton HE Station	-	$1.7	$0.1	$0.4	$1.6
Wind Generation	$2.5	$3.4	$4.9	$1.8	$9.9
Bison	$1.6	$1.5	$1.0	$1.6	$6.4
Taconite Ridge	$0.9	$1.9	$3.9	$0.1	$3.5
Solar Generation	-	-	-	-	$0.4
Generation Subtotal, excluding Riders	**$32.7**	**$39.5**	**$47.8**	**$34.0**	**$67.3**

Amounts in millions.

Amounts may not total due to rounding.

Q. What recent capital additions have been made to the Generation Operations fleet?

A. Generation Operations' additions to plant in service totaled $37.3 million Total Company ($32.7 million MN Jurisdictional) for 2023; $44.6 million Total Company ($39.5 million MN Jurisdictional) for 2024; $54.4 million Total Company ($47.8 million MN Jurisdictional) for 2025; $38.7 million Total Company ($34.0 million MN Jurisdictional) for the 2026 projected year; and $85.8 million Total Company ($67.3 million MN Jurisdictional) for the 2027 test year. Capital additions for the generation fleet are evaluated to prioritize the needs of each asset to meet its intended mission and ensure compliance with regulatory requirements. Projects are also reviewed to ensure alignment with outage schedules and make any identified safety improvements. In addition, operational and maintenance needs are reviewed to ensure the approach meets

competitiveness targets for each asset and the intended mission of each site. This helps to ensure reasonable costs of the projects.

Q. What is driving the $38.7 million Total Company ($34.0 million MN Jurisdictional) capital additions included in the 2026 projected year?

A. The 2026 projected year additions are driven by a scheduled duty cycle outage at BEC Unit 3 ("BEC3"). This includes the boiler air heater overhaul, cooling tower stack refurbishment, and boiler superheat pendant refurbishment, in addition to other necessary work as part of the overall maintenance cycles for the facility. Investment in Hibbard Renewable Energy Center's ("HREC") fuel system is also a significant part of the total.

Q. What is driving the $85.8 million Total Company ($67.3 million MN Jurisdictional) capital additions included in the 2027 test year budget?

A. The 2027 test year additions are driven by a 38-day duty cycle outage at BEC Unit 4 ("BEC4"). This is discussed in more detail later in my Direct Testimony. The budget also includes investments at HREC and LEC in 2027 to maintain reliability at these locations. The Blanchard hydro facility refurbishment work on the head gates and Unit 1 are also considerable investments being made. MP Exhibit ____ (Simmons), Direct Schedule 2 contains a complete list of projects. These projects are part of typical maintenance cycle projects that need to be performed to maintain these important facilities for continued service to customers.

Q. What impacts are you seeing on capital projects as a result of increased materials costs, resource constraints, and overall inflation?

A. Supply chain challenges initially experienced during the COVID-19 pandemic have continued in the electric utility sector and caused prices and lead times to increase, and contractor availability to decrease. The explosive growth in electricity demand across the country has greatly impacted supply chains for electric utilities. Historically, utilities planned around slow growth and modest replacement cycles. That changed quickly because of artificial intelligence, electric vehicles, the electrification of buildings and

industry, semiconductor manufacturing expansion, and domestic industrial reshoring. Contractors often decline to bid on projects because they do not have the labor and capacity to perform more work. The annual U.S. Consumer Price Index ("CPI") inflation rate fluctuated significantly from 2019-2026, reaching a peak of 8.0 percent in 2022 before cooling to around 3.5 percent by mid-2026. All these factors have increased the cost of the projects and the time required to complete them. The Direct Testimony of Company witness Diana C. McFadden details supply chain processes and efforts taken by Minnesota Power to mitigate these risks.

B. Generation Operating & Maintenance Budgets

Q. Describe Generation Operations' 2027 O&M budget.

A. The Generation Operations O&M budget is based on expenses incurred while operating and maintaining the assets in our generation portfolio. Budget development at the work area level occurs through the collaboration of subject matter experts, including budget analysts, maintenance leads, engineers, and the responsible budget owner. These individuals, known as the work area "business team," identify and estimate prudent and practical O&M needs to support the production obligations of the units during the period of time for which the budget is being developed. The overall O&M budgeting process for any work area is explained in the Direct Testimony of Company witness Joshua G. Rostollan.

Q. What are the components of the Generation Operations O&M budget?

A. The Generation Operations O&M budget consists of expenses that are expected to occur while operating and maintaining the assets in our generation portfolio. The O&M budget is primarily comprised of the internal and contractor labor required to operate the Company's generation facilities on a day-to-day basis, as well as expenses to perform necessary maintenance and repairs of these facilities to ensure their reliable operation. One expense included in the O&M budget, falling within the contractor labor category, is the annual expense associated with the long-term service maintenance agreement at Bison. This expense is discussed further in my testimony in Section IV.D. In addition, each work area's O&M costs for purchases such as safety equipment, office supplies,

small tools, and spare parts are included. These categories of costs, along with salaries, collectively represent the bulk of the Generation Operations O&M budget and are necessary to operate the facilities to provide electric service to benefit the Company's customers.

Q. What is Generation Operations' O&M Budget for the 2027 test year?

A. The 2027 budgeted Federal Energy Regulatory Commission ("FERC") level O&M for Generation Operations is provided in Table 4 at the Total Company level and the MN Jurisdictional level.

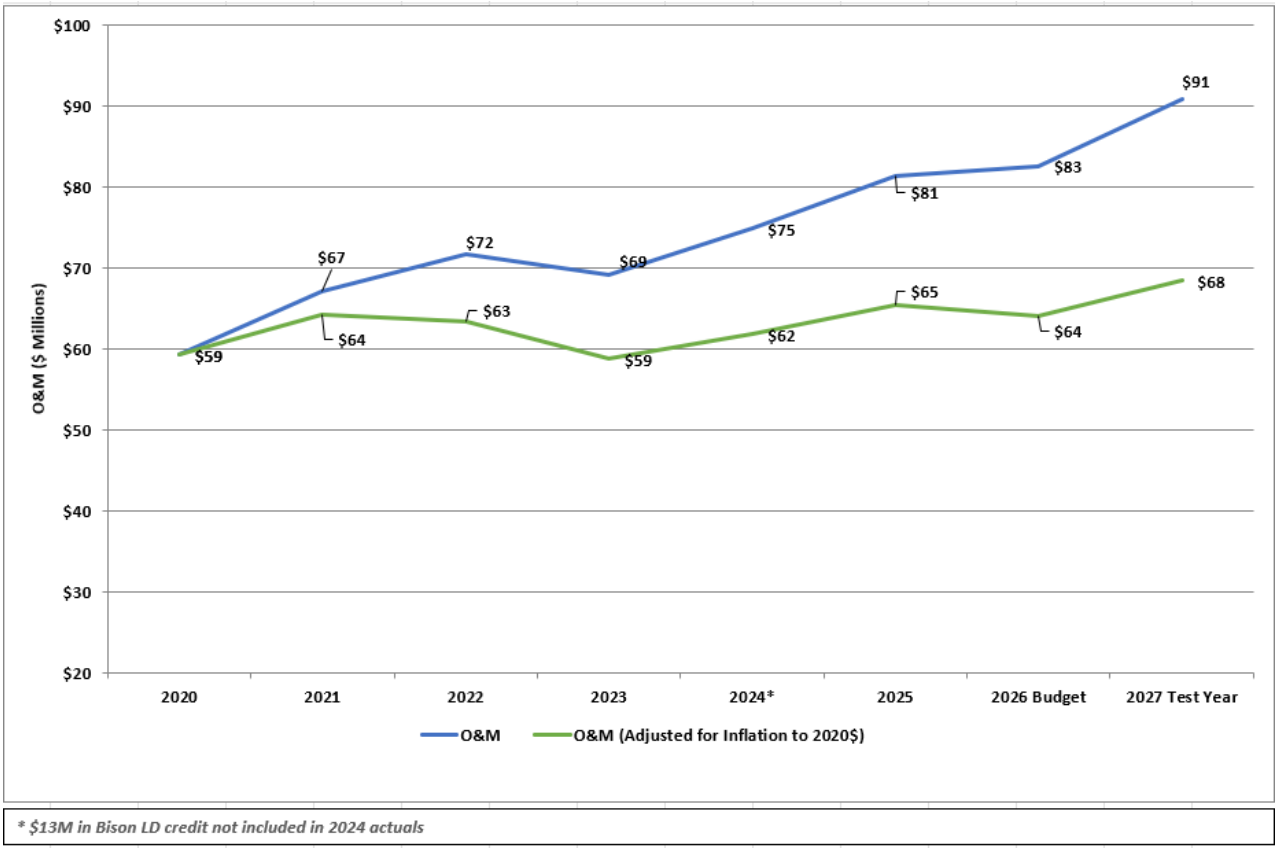
Table 4. Generation Operations FERC Level O&M (2027 Test Year)

	2027 UTY	2027 UTY
POWER PRODUCTION	Total Company	MN Jurisdictional
Steam Power Generation		
Operation	183,816,928	148,516,744
Less: Fuel Costs (Fuel Costs in FERC 50100)	(150,236,601)	(121,126,757)
Total Operation	33,580,327	27,389,987
Total Maintenance	27,330,605	22,387,019
Total Steam Power Production Expenses	60,910,932	49,777,006
Hydraulic Power Generation		
Total Operation	2,261,506	1,844,356
Total Maint	3,968,774	3,236,707
Total Hydro Power Production	6,230,280	5,081,063
Other Power Generation (Solar)		
Total Operation	880,692	0
Total Maint	1,100,949	0
Total Other Power Production	1,981,641	0
Other Power Generation (Wind)		
Total Operation	15,779,286	13,088,760
Total Maint	2,666,539	2,211,867
Total Other Power Production	18,445,825	15,300,627
Other Power Generation (Other)		
Total Operation	631,644	523,942
Total Maint	22,408	209
Total Other Power Production	654,052	524,151
Other Power Supply Expenses		
Purchased Power	267,248,861	215,976,945
System Control and Dispatch	443,790	368,119
Other Expenses	2,246,278	1,863,265
Less: Purchased Power (FERC 55500)	(267,248,861)	(215,976,945)
Total Other Power Supply	2,690,068	2,231,384
Total Power Production Expenses	90,912,798	72,914,231

Q. Can you illustrate the Company's Generation Operations O&M levels over the most recent five-year period?

A. Yes. A summary of the Generation Operations O&M spending is provided in Figure 2. This figure also includes the spend adjusted for inflation.

Figure 2. Generation Operations O&M Spend (Total Company)
Including CPI Inflation



** $13M in Bison LD credit not included in 2024 actuals*

Q. How has the Company managed generation O&M expense in recent years?

A. Minnesota Power has continued to invest thoughtfully in O&M at its generation facilities. When looking at the direct O&M spend in annual dollars (blue line) in Figure 2, the Company has included $91 million for generation O&M compared to $83 million budgeted for 2026. Factors contributing to the 2027 test year O&M increase include overall payroll increases, required FERC hydroelectric dam inspections, vegetation management costs for hydroelectric dams, increased contractor costs for HREC ash hauling, and outage costs for an extended five-year low pressure turbine overhaul outage on BEC4. However, when generation O&M is adjusted for inflation (green line), it is apparent that the Company held O&M relatively flat over the last several years including through the 2027 test year.

IV. GENERATION FLEET RESOURCES

A. Boswell Energy Center

Q. What is BEC?

A. BEC, located in Cohasset, Minnesota, is Minnesota Power's largest thermal facility and only remaining source of baseload generation operations. BEC, at its peak, generated coal-fired power from four operating units, which were constructed over a period from 1958 to 1980. In 2016, the facility had an overall net generation capability of 957 MW. BEC Units 1 and 2 ("BEC1" and "BEC2") were retired from operation in 2018. The two remaining operating units, BEC3 and BEC4 have a combined net generating capability of approximately 820 MW. These two units have historically provided approximately half the energy needs of Minnesota Power's customers.

BEC3 was commissioned in 1973, followed by BEC4 in 1980, to serve the region's growing natural resource industrial electric loads. The net generating capability of BEC3 is 352 MW, after turbine efficiencies were made to this asset in 2009. BEC4 is Minnesota Power's largest baseload generator. Subsequent turbine efficiency investments in BEC4 in 2010 expanded the net generating capability of this unit to 585 MW. WPPI Energy (formerly Wisconsin Public Power, Inc.) has a 20 percent (or 117 MW) ownership interest in BEC4. Both BEC3 and BEC4 have undergone major environmental control system retrofits, completed in 2009 and 2015, respectively. These environmental retrofits primarily targeted mercury emissions but also improved the removal of other air pollutants. The operation and maintenance strategy for BEC3 and BEC4 focuses on reliability to ensure the units serve our customers and maintain safety and environmental compliance.

Q. What has the Minnesota Public Utilities Commission ("Commission") ordered the Company to do regarding operations of BEC?

A. In the 2021 Integrated Resource Plan ("IRP"), the Company proposed to cease coal-fired operations at BEC3 by 2030 and at BEC4 by 2035. The Commission approved this proposal in January 2023.[1]

Q. What has transpired since the 2021 IRP regarding "ceasing coal-fired operations" at BEC3 and BEC4?

A. The 2025 IRP hearing was held on September 10, 2026., and the Commission issued its order on October 21, 2026.[2] The Commission approved refueling BEC3 with natural gas by 2030 and affirmed ceasing coal as a fuel source for BEC4 by 2035 but deferred a decision regarding the replacement technology for BEC4. Minnesota Power will be submitting its next IRP by December 2027 that will address the replacement action required.

Q. What are the significant capital additions at BEC since the 2023 Rate Case?

A. While the Company is proposing to refuel BEC3 by 2030 and possible replacement technology for BEC4, Minnesota Power must still invest capital to ensure the safe and reliable operation of the generation facility. Projects completed since the 2023 Rate Case to ensure safety environmental compliance, and reliability include investments in the fuel handling systems, dry bottom ash systems, installation of an auxiliary heating boiler, boiler and boiler auxiliary systems, a turbine generator, environmental control systems, and fuel burning systems.

Q. Does the 2027 test year include capital additions at BEC?

A. Yes. As I mentioned above, the 2027 test year includes a spring 38-day scheduled outage on BEC4. This recurring long outage coincides with the cyclical five-year low-pressure

[1] *In the Matter of Minnesota Power's Application for Approval of its 2021-2035 Integrated Resource Plan,* Docket No. E015/RP-21-33, ORDER APPROVING PLAN AND SETTING ADDITIONAL REQUIREMENTS (Jan. 9, 2023) (eDocket No. 20231-191970-01).

[2] *In the Matter of Minnesota Power's Application for Approval of its 2025–2039 Integrated Resource Plan*, Docket No. E015/RP-25-127, ORDER APPROVING MODIFIED INTEGRATED RESOURCE PLAN (Oct. 21, 2026).

turbine overhaul cycle and generator testing for the unit. During this outage, the capital investment on BEC4 will include, but is not limited to, turbine valve overhaul, main steam hanger replacement, induced draft ("ID") fan drive replacements, baghouse bag replacement, boiler tube replacement, and cooling tower structural reinforcement.

In transitioning BEC3 to economic dispatch in July 2021, it became necessary to install backup boilers at the station to maintain adequate temperature during cold weather months and eliminate the risk of freezing in the winter months should BEC4 become unavailable for generation. The heating season in northern Minnesota starts in September and ends in May, with the critical heating months being December through February. Commissioning of the heating boilers was completed in the first quarter of 2026.

B. Laskin Energy Center

Q. Please describe LEC.

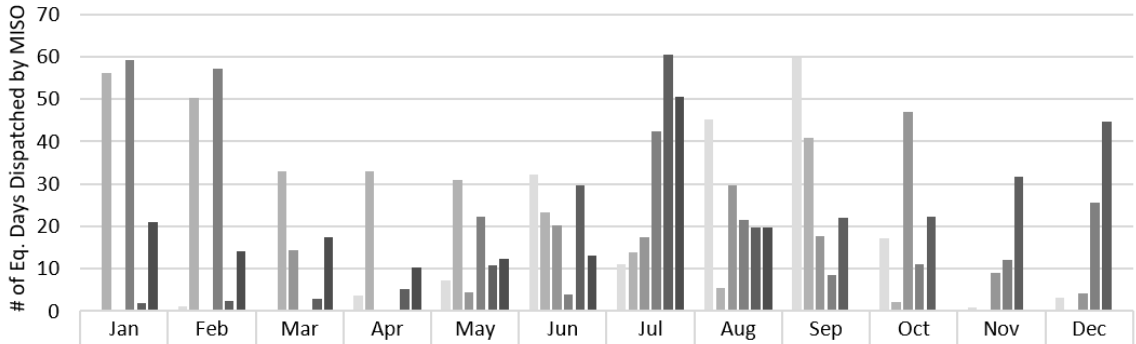
A. LEC is located in Hoyt Lakes, Minnesota, and was commissioned in 1953 as a coal-fired facility. LEC has two generating units, Units 1 and 2, that are similar in design and intended operation with a total net capability of 98 MW. To help achieve Minnesota Power's Energy*Forward* strategy to diversify its power supply portfolio while reducing carbon emissions, the conversion of LEC from coal-fired to natural gas-fired generation was completed in 2015.

Q. How has LEC been a benefit to Minnesota Power customers?

A. Minnesota Power is now operating LEC Units 1 and 2 as a peaking facility rather than a baseload resource remaining a key capacity resource for meeting resource adequacy requirements. As a peaking facility, LEC provides daily value to our customers by serving as a hedge against high regional power prices and responding to capacity needs when called upon for grid reliability. Since 2021, MISO has dispatched LEC, as a peaking facility, an average of 18.5 equivalent days per month, as shown in Figure 3. In 2021 and 2022, LEC ran more frequently due to reliability needs from transmission line construction work (2021 averaged 15.1 run days and 2022 averaged 24.1 run days). In

2023, due to low natural gas prices, LEC was dispatched more frequently due to economic reasons and to assist with system reliability during conservative operations events and during severe storms in the region until other transmission line contingencies were reestablished. This value has continued beyond 2023. From 2024 through August 2026, LEC averaged 21.1 equivalent days per month, demonstrating its continued benefit to Minnesota Power customers as a flexible dispatch resource that can respond to both market conditions and reliability events. Figure 3 provides information on LEC dispatch days from 2021 through June 2026.

Figure 3. Laskin MISO Dispatch (Equivalent Days by Month)



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2021	0	1.2	0	3.6	7.3	32.3	11	45.3	59.8	17.1	1	3.1
2022	56.3	50.3	33.1	33.1	31	23.2	14	5.4	40.9	2.1	0	0
2023	0	0	14.3	0	4.4	20.2	17.4	29.7	17.6	46.9	9.1	4.2
2024	59.3	57.1	0	0	22.3	3.9	42.4	21.4	8.6	11.1	12	25.5
2025	1.8	2.3	2.9	5.1	10.8	29.8	60.5	19.7	22.1	22.3	31.7	44.6
2026	20.9	14.2	17.5	10.3	12.4	13.1	50.6	19.8				

Q. What are the significant capital additions at LEC since the 2023 Rate Case?

A. As MISO continues to utilize this resource as a grid-support resource, the facility is experiencing increased dispatch than was originally estimated when the facility transitioned from a baseload to a grid-support resource. LEC Unit 1 and Unit 2 underwent turbine generator overhauls in 2026 and 2025 respectively. Included in the test year for LEC are investments totaling $2.9 million Total Company ($2.4 million MN Jurisdictional). The largest investment in the test year is the replacement of the Digital Control System "DCS" that is critical to the operation of the facility.

C. Hibbard Renewable Energy Center

Q. What is HREC?

A. HREC has been a part of Minnesota Power's renewable generation, regulation services, and spinning reserves for over 30 years. HREC Units 3 and 4 provide 60 MW of net capacity along with dispatchable renewable energy for Minnesota Power customers. HREC is capable of burning biomass, coal, and natural gas. HREC is a critical component as a dispatchable facility in the renewable energy strategy of Minnesota Power.

Q. What is the benefit of Minnesota Power's continued operations of HREC?

A. HREC is capable of, and originally designed for, baseload operation. Today it supports capacity and economic dispatched generation when required. HREC's multi-fuel boilers provide steam that drives HREC's Units 3 and 4 turbine generators. Until July 2020, HREC supported papermaking processes at an adjacent Duluth paper mill by providing steam.

As MISO continues to utilize this resource as a grid-support resource, the facility is experiencing increased dispatch than was originally estimated when the facility transitioned from a baseload to a grid-support resource. HREC now operates when market prices and grid reliability warrant, as the baseload steam demand is no longer required to support a customer paper mill site. HREC is most often used as a capacity and dispatchable renewable energy resource, rather than as a baseload energy resource. As a dispatchable renewable energy resource, HREC provides a ready source of renewable energy, offering an economic cost hedge for Minnesota Power's customers as a flexible resource to support the expansion of variable renewable energy in the portfolio. As a dispatchable renewable resource, HREC also provides reliability services that are critical to the regional grid following the idling, re-missioning, or retiring of nine of eleven regional coal-fired baseload generating resources. Additionally, HREC is one of a limited number of facilities in Minnesota that is permitted to burn diseased

wood. HREC continues to be offered under an economic dispatch model and is called upon to support MISO needs and Minnesota Power customer demand as needed.

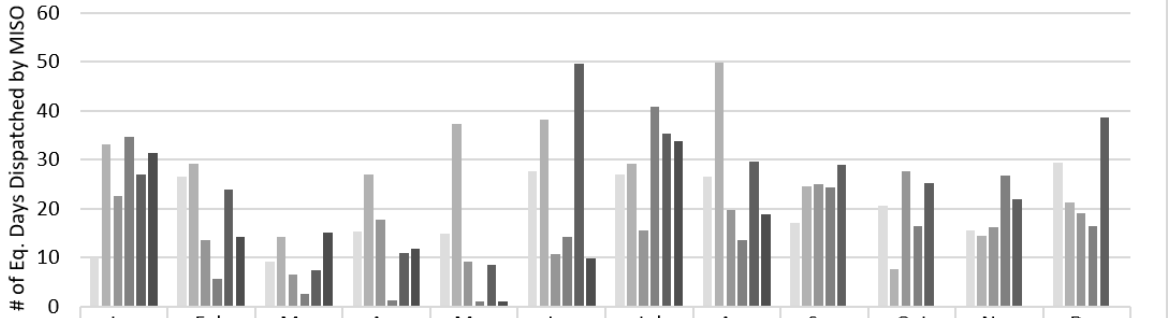
Q. What investments are included at HREC in the 2027 test year?

A. HREC's capital spend for 2027 includes projects that coincide with a scheduled turbine overhaul project for Unit 3. The turbine overhaul, boiler refractory work, truck scale replacement, and condensate pump rebuilds make up a majority of the capital additions at HREC. These projects are all necessary based on inspections and original equipment manufacturer ("OEM") guidelines to keep the units reliable and affordable, allowing them to remain available for dispatch to support MISO needs and customer demand. The last turbine overhaul was completed in 2012.

Q. How often does MISO dispatch HREC?

A. HREC generated to support customer needs an average of 20.7 equivalent days per month from January 2021 through August 2026, as shown in Figure 4. During 2025, periods of increased generation demand, particularly from June through September, combined with the need to support grid reliability during transmission project work, resulted in HREC operating for an average of 35.9 equivalent days per month across both units. These results demonstrate that HREC continues to provide valuable dispatchable energy and remains an important resource for maintaining regional grid reliability for the region. Figure 4 illustrates HREC dispatch days from 2021 through August 2026.

Figure 4. HREC MISO Dispatch (Equivalent Days by Month)



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2021	10.1	26.5	9.2	15.4	14.8	27.7	27	26.5	17.1	20.6	15.6	29.3
2022	33.2	29.2	14.3	27	37.3	38.1	29.1	49.8	24.5	7.6	14.4	21.2
2023	22.6	13.6	6.6	17.7	9.1	10.7	15.6	19.6	25	27.7	16.2	19.1
2024	34.6	5.6	2.5	1.3	1.0	14.2	40.9	13.6	24.3	16.3	26.8	16.4
2025	26.9	23.8	7.3	10.8	8.4	49.6	35.4	29.5	29	25.3	21.9	38.7
2026	31.3	14.2	15	11.8	0.9	9.8	33.7	18.9				

D. Bison Wind Energy Center

Q. What is Bison?

A. Bison, located in Oliver and Morton counties, is the largest wind farm operation in North Dakota at 497 MW. Bison was built in four phases over five years from 2010 and 2014, with all phases being constructed on time and below budget.

Q. How is the O&M currently managed at Bison?

A. Bison uses a zero-based budgeting approach to set an annual budget comprised of prudent expenses for the planned year in alignment with maintenance schedules and production estimates. Easement agreements with landowners and a long-term service agreement with the Original Equipment Manufacturer have escalation built into the contracts and make up approximately 75 percent of the Bison O&M budget. During 2026, the long-term service agreement with the Original Equipment Manufacturer changed per the terms of the agreement. Approximately 63 percent of the Bison wind turbines ended their coverage under the agreement. Minnesota Power now self-performs maintenance on these additional turbines while retaining a reduced-service agreement with the Original Equipment Manufacturer for technical support, parts supply, training,

and other materials and services as needed. The O&M reduction due to the self-perform model is approximately 5 percent from previous year's budgets.

E. Taconite Ridge Wind Energy Center

Q. Describe the Taconite Ridge Wind Energy Center ("Taconite Ridge").

A. Taconite Ridge, the first commercial wind energy center in northeastern Minnesota, began operating in June 2008. The 25 MW facility is located on property leased from U.S. Steel in Mountain Iron, Minnesota.

Q. Are there capital additions at Taconite Ridge or Bison in the 2027 test year?

A. Yes. The 2027 test year includes capital additions of $4.2 million Total Company ($3.5 million MN Jurisdictional) for Taconite Ridge and $7.7 million Total Company ($6.4 million MN Jurisdictional) for Bison. These costs include the anticipated replacement of generators exhibiting conditions that warrant replacement to keep assets used and useful along with delta module replacements and a high-performance park pilot Supervisory Control and Data Acquisition ("SCADA") server replacement. This work is necessary because wind turbine components require periodic repair and replacement. This level of service is also in line with recommended operating parameters and manufacturer specifications. The 2027 test year capital additions also include generator, gearbox replacements, and turbine blade refurbishment projects at Taconite Ridge.

F. Longspur Wind Project

Q. Please describe the Longspur Wind Project.

A. The Longspur Wind Project is a 200 MW wind facility currently under construction near Center, North Dakota. This project consists of 45 turbines and utilizes the Company's HVDC Line to deliver wind energy to its customers. Commission approval was received on March 5, 2026, in Docket No. E015/M-25-309.

Q. Are there O&M costs included in the 2027 test year for the Longspur Wind Project?

A. No. O&M costs for the Longspur Project will continue to be recovered in the Renewable Resources Rider filing, Docket E015/M-24-344, until the project is in service.[3] Costs will then be included in base rates in a future rate case filing.

Q. What types of O&M costs are associated with the Longspur Wind Project?

A. O&M activities include cleaning and inspecting wind turbines, maintenance, major component replacements (blades, gearboxes, generators), snow removal, road maintenance, electrical collection and substation support, and vegetation management. Additional ongoing costs include insurance costs, taxes and land lease payments.

F. Hydroelectric Generation Facilities

Q. Please describe Minnesota Power's hydroelectric generation resources.

A. Minnesota Power has used water to generate energy and serve customers since its formation more than 100 years ago. Today, the Company is the largest hydroelectric energy producer in the state, with a generating capability of approximately 120 MW. The Company's largest hydroelectric station, Thomson, has been generating renewable power for more than a century. Minnesota Power maintains the dams for the ten hydroelectric stations and six headwater storage reservoirs. The Company's stations and reservoirs are operated under seven federal licenses issued by FERC and play a critical role in the Company's local load restoration plan and support grid reliability.

Q. Are any capital additions at the hydroelectric stations included in the 2027 test year?

A. Yes. The Company has identified capital additions of $31.5 million Total Company ($26.1 million MN Jurisdictional) at the hydroelectric stations in 2027. Repowering of several hydro turbines and generators is expected to be completed and placed into

[3] *In the Matter of the Petition of Minnesota Power for Approval of Investments and Expenditures in the Boswell Solar Project for Recovery through Minnesota Power's Renewable Resources Rider under Minn. Stat. § 216B.1645*, Docket No. E015/M-24-344, INITIAL FILING (Nov, 13, 2024) (eDocket No. 202411-211891-01).

service in 2027. This includes Blanchard Unit 1, Scanlon Unit 2, and Thomson Unit 3 following major overhauls. In addition, the Scanlon west channel gates will be replaced along with investments on water control structures at Knife Falls, Little Falls, and Thomson Reservoir as part of a strategic, multi-year, infrastructure replacement and revitalization effort taking place across the Company's hydroelectric system. Along with these projects, Island Lake main dam stabilization project requires considerable investment in the facility to meet FERC stability requirements. This is a multi-year project that began in 2023 and is scheduled to be in service by year-end 2027.

Q. Is the Company considering the applicability of tax credits in connection with hydroelectric capital projects?

A. Yes. The Company is actively working with our tax advisors to maximize the availability of Investment Tax Credits ("ITCs") and Production Tax Credits ("PTCs") for hydroelectric capital projects that are already planned or underway. The Company intends to evaluate the applicability of these credits for all eligible hydroelectric capital investments through the duration of the credit eligibility period. Unlike wind and solar tax credits, the phaseout of tax credits applicable to hydroelectric projects was not accelerated by H.R. 1 (119th Congress). The Company anticipates that the repowers at Scanlon Unit 2 and Blanchard Unit 1, scheduled to be in serviced in 2027, will qualify, although the tax credits are not anticipated to be included in the 2027 test year or renewable resource rider ("RRR"). Any benefits earned will be passed back to customers in subsequent RRR filings.

G. Solar Generation Facilities

Q. Please describe the Boswell Solar Project.

A. The Boswell Solar Project is an 85 MW solar facility currently under construction in Cohasset, Minnesota. This project consists of 178,000 635-watt bifacial solar modules, central inverters, and single-axis trackers.

Q. Are there O&M costs included in the 2027 test year for the Boswell Solar Project?

A. No. O&M costs for the Boswell Solar Project will continue to be recovered in the Renewable Resources Rider filing, Docket E015/M-24-344, until the project is in service.[4] Costs will then be included in base rates in a future rate case filing.

Q. What types of O&M costs are associated with the Boswell Solar Project?

A. Ongoing costs include, but are not limited to, landowner payments, property insurance, internal labor, vegetation management, and corrective and preventative maintenance.

Q. Describe the Regal Solar Project.

A. The Regal Solar Project is a 119.5 MW solar facility under construction near Royalton, Minnesota. This project consists of 251,000 630-watt bifacial solar modules, central inverters, and single axis trackers.

Q. Are there O&M costs included in the 2027 test year for the Regal Solar Project?

A. No. As with the Boswell Solar Project, O&M costs for the Regal Solar Project will continue to be recovered in the RRR filing, Docket E015/M-24-343, until the project is in service.[5] Costs will then be included in base rates in a future rate case filing.

Q. What types of O&M costs are associated with the Regal Solar Project?

A. Ongoing costs include but are not limited to landowner payments, property insurance, annual educational fund payments, internal labor, vegetation management, and corrective and preventative maintenance.

[4] *In the Matter of the Petition of Minnesota Power for Approval of Investments and Expenditures in the Boswell Solar Project for Recovery through Minnesota Power's Renewable Resources Rider under Minn. Stat. § 216B.1645*, Docket No. E015/M-24-344, INITIAL FILING (Nov, 13, 2024) (eDocket No. 202411-211891-01).

[5] *In the Matter of the Petition of Minnesota Power for Approval of Investments and Expenditures in the Regal Solar Project for Recovery through Minnesota Power's Renewable Resources Rider under Minn. Stat. § 216B.1645*, Docket No. E015/M-24-343, INITIAL FILING (Nov, 13, 2024) (eDocket No. 202411-211895-01).

Q. Has the Company considered the applicability of tax credits for the Boswell and Regal Solar Projects?

A. Yes. Those projects are eligible for tax credits available under the Inflation Reduction Act ("IRA"). Recent federal legislation, H.R. 1 (119th Congress), modified certain aspects of the IRA, but the Company began construction on the Boswell and Regal Solar Projects before July 4, 2026, so the tax credits that will be obtained for those projects under the IRA are not affected by H.R. 1 (119th Congress). Additional information on the IRA and H.R. 1 (119th Congress) is available in the Direct Testimony of Company witness Rena E. Verdoljak.

Q. Describe the Camp Ripley Solar Facility ("Camp Ripley Solar").

A. Camp Ripley Solar is a 10.8 MW solar facility located within the Camp Ripley Minnesota National Guard base near Little Falls, Minnesota.

Q. What types of O&M costs are associated with Camp Ripley Solar?

A. Ongoing costs include but are not limited to landowner payments, property insurance, vegetation management, and corrective and preventative maintenance.

Q. Does Minnesota Power own and operate Camp Ripley Solar?

A. On March 3, 2026, Minnesota Power's petition to purchase the Camp Ripley Solar generation assets was approved through the Commission's consent agenda in Docket No. E015/PA-25-368.[6] Minnesota Power will own and continue to operate Camp Ripley Solar Project as of January 1, 2027. Costs related to Camp Ripley Solar are recovered in Minnesota Power's Solar Renewable Factor under its Rider for Renewable Resources.

[6] *See In the Matter of Minnesota Power's Request for Approval to Purchase the Camp Ripley Solar Generation Assets*, Docket No. E015/PA-25-368, ORDER at Order Point 3 (March 3, 2026) (eDocket No. 20263-228858-01).

H. Reliability

Q. Describe Minnesota Power's reliability program.

A. Reliability of assets are tied directly to generation performance. Maintaining a high level of asset availability for a mix of baseload, intermediate and peak demand generation is important as generation sources change. In 2025, Minnesota Power Generation Operations updated its Reliability Principles, to make them durable, applicable to assets, and easy to remember and apply. The Reliability Principles are: Persistent Pursuit of Resilience; Dedication to Condition Monitoring, Develop and Utilize Experts; Learning and Improving is Vital; and Systems and Processes Drive Reliability. These interconnected principles help guide reliability initiatives, financial investment, and resource allocation because reliability ensures the system can meet continuous and fluctuating customer demands. Sustaining reliability requires ongoing maintenance and capital investment using established programs and processes.

Q. What reliability initiatives has the Company undertaken since the last rate case?

A. Thirty-one Minnesota Power operations and maintenance staff attended Reliability Solutions Essential Reliability Manufacturing Skills ("ERMS") Leadership Bootcamp in the second quarter of 2026. This five-day course highlighted:

- Comprehensive Coverage: The course covers essential skills for improving manufacturing reliability, from strategy development to technical skills.
- Leadership Focus: Emphasizes the importance of leadership in driving measurable and sustainable improvements.
- Practical and Field-Applicable Knowledge: Offers tips and real-world examples for on-the-floor application.

All generation employees are receiving a high-level reliability 101 training, developed in-house, that covers reliability principles, maintenance strategies, tools, work and learning processes, everyone's role, and the importance of reliability as a core function of the business.

Q. Why is reliability an important consideration is this rate case?

A. Reliability is Minnesota Power's core responsibility. The Company's leadership team is dedicated to ensuring reliability for customers, and costs in the test year reflect what is needed to do that. Minnesota Power committed to facility competitiveness through maintaining and upgrading in a cost-effective manner, equipment integrity, reliability and technology.

Generation Operations has also been working to review its preventative maintenance programs and related work order process to update and enhance use of the processes directly supporting our maintenance strategies.

V. ENVIRONMENTAL COMPLIANCE

Q. What is the CCR Rule?

A. In 2015, the U.S. Environmental Protection Agency ("EPA") published a final rule ("2015 Rule") regulating CCR as nonhazardous waste under Subtitle D of the Resource Conservation and Recovery Act ("RCRA") in the Federal Register. The 2015 Rule established additional requirements for new landfill and impoundment construction as well as closure activities related to certain existing impoundments. As described below, compliance with the CCR rule has shifted over time as policy has changed. The costs to comply also change significantly with subsequent rule changes, technology, and compliance timeframe.

Minnesota Power continues to work on minimizing compliance costs through evaluation of beneficial reuse and recycling of CCR. In 2018, a U.S. District Court for the District of Columbia decision vacated specific provisions of the 2015 Rule, resulting in a change to the status of existing clay-lined impoundments at BEC being considered unlined. In 2020, the EPA finalized the CCR Part A Rule, which required all unlined impoundments to cease disposal and initiate closure. Upon completion of dry ash conversion activities, BEC ceased disposal in both impoundments in 2022. Both impoundments are now inactive and have initiated closure.

Q. What is the CCR Legacy Rule and its status?

A. The EPA's 2024 CCR Legacy Rule ("CCR Legacy Rule"), then built on the 2015 Rule framework, by extending similar compliance and closure requirements to previously exempt legacy impoundments, plus a new category—CCR management units ("CCRMUs") creating a single, integrated CCR program with multiple unit types and compliance timelines. CCRMUs are areas where CCR was historically disposed of outside regulated CCR units. In February 2026, the EAP finalized a rule extending key compliance deadlines, while in a separate April 2026 proposed rule, currently on public notice, would either rescind or significantly scale back the CCRMU requirements, if finalized. Timing for potential resolution of the April 2026 proposed CCRMU adjustment rule is uncertain and likely to extend into 2027 or later, given the ongoing rulemaking, expected litigation over both the CCR Legacy Rule and any rollback, and persistent legal vulnerabilities following the 2018 D.C. Circuit decision, which continues to shape EPA's obligations to regulate CCR risks comprehensively.

On April 13, 2026, the EPA published a proposed rule that would amend the CCR regulations, including potential rescission of CCRMU requirements; establishment of new site-specific permitting compliance pathways for groundwater monitoring, corrective action, and closure; and finalization of several outstanding provisions from the March 2020 Part B proposed rule related to beneficial reuse of CCR and use of CCR during closure. The April 2026 proposed amendments have not been finalized. If finalized as proposed, the rescission or revision of CCRMU regulations could potentially reduce compliance obligations and associated costs. The EPA is also pursuing a federal CCR permitting program for tribal lands and nonparticipating states.

In its Order dated October 29, 2025, in Docket No. E015/M-24-437, the Commission approved Minnesota Power's request to track and defer its costs resulting from the CCR

Legacy Rule.[7] Given that the expense related to the CCR Legacy Rule are deferred, Minnesota Power is not including recovery of these costs in the test year.

Q. What has the Company done to maintain compliance with the CCR regulations?

A. Minnesota Power has a history of excellence in environmental stewardship that has contributed to the state's overall track record of leadership on environmental issues. Capital investments made by Minnesota Power to comply with the CCR Rule include conversion to dry bottom ash systems on BEC3 and BEC4, installation of a flue gas desulfurization ("FGD") gypsum dewatering system, and installation of a thermal evaporation system on BEC4. These projects eliminated wet ash sluicing and storage operations to facilitate final closure of the existing CCR impoundments at BEC. The thermal evaporator, dry ash conversion, and gypsum dewatering projects were completed in 2022.

LEC is no longer producing CCR. Cessation of coal ash disposal at LEC eliminated the need for future impoundment or landfill construction. Existing impoundments were closed in accordance with the 2015 Rule provisions. However, additional work may be needed for LEC (and potentially for HREC) as I describe below.

Minnesota Power's closure plan and post-closure plan for CCR can be found at https://mp-ccr.azurewebsites.net.

Q. Are other new costs emerging for the Company as a result of the 2015 Rule?

A. Yes. As discussed in the Company's 2026 Remaining Life Depreciation Petition,[8] the Company anticipates changes to its non-Legacy CCR and decommissioning costs associated primarily with BEC, but also LEC and HREC, totaling $13,094,024 Total

[7] *In the Matter of Minnesota Power's Petition for Approval to Track and Defer Costs Resulting from The Legacy Coal Combustion Rule Surface Impoundment Rule*, Docket No. E015/M-24-437, ORDER (Oct. 29, 2025) (eDocket No. 202510-224380-01).

[8] *In the Matter of Minnesota Power's 2026 Remaining Life Depreciation Petition*, Docket No. E015/D-26-327, INITIAL FILING at 2 (Sept. 1, 2026) (eDocket No. 20269-236018-01) ("2026 Remaining Life Study"). Of this total, approximately $2.28 million pertains to increased labor and oversight costs to dismantle the plants at HREC and LEC.

Company. The primary driver of these changes (approximately half of the total) is the anticipated work required for dewatering at the BEC ash ponds.[9] As discussed in the 2026 Remaining Life Study, the 2015 Rule included requirements for groundwater monitoring and corrective action at existing CCR impoundments at BEC. However, current estimates from December 2025 include dewatering costs for the BEC ash ponds for the first time, as the Company previously expected to dewater the impoundments by routine consumptive use of pond water in plant operations. Evolving state and federal regulations and standards now indicate that the Company will need to treat and discharge portions of the ash pond water as part of closure. The closure plan for dewatering, sequencing, and closure increments reflects the best available information, but the proposed plan remains dynamic and will require continued review and verification as closure progresses, trial results are refined, and permitting advances. Accordingly, the ultimate dewatering method and associated costs will depend on the outcome of ongoing design, technology evaluation, and regulatory permitting.[10] The Company therefore expects to incur additional costs to comply with these regulations, although the total scope and costs of that work remain uncertain.

With respect to LEC and HREC, compliance costs related to the 2015 Rule may include additional water removal (dewatering) and stabilization of previously closed CCR units and/or CCRMUs. This will depend on obtaining more certainty from the EPA, which is expected in the next year. At this time, the Company's estimate of the incremental decommissioning costs for 2027 does not include dewatering for HREC or LEC.

Q. Is the Company testing new measures to comply with dewatering requirements at BEC?

A. Yes. The Company is investigating and testing multiple technologies and operational efficiencies to comply with CCR requirements and the ability to dewater the CCR units at BEC. Some of these technologies are dependent on permitting requirements at BEC. Examples of options being reviewed to dewater the CCR units include ice harvesting,

[9] 2026 Remaining Life Study at 2, 14 and Appendix A-1.
[10] 2026 Remaining Life Study at Section VI.

thermo-evaporation, an advanced accelerated modular evaporation system and water shock treatment for discharge. While there are technology options available for dewatering, each option or technology comes with a potential set of unknowns. Some are climate dependent; some are dependent on operation of the facility and equipment, and some have permit restrictions. Testing and pilot installation of dewatering technology has been on-going.

Q. What is your perspective on the work necessary to comply with the 2015 Rule, particularly in relation to the pending closure of BEC Units 3 and 4?

A. Dewatering and closure of BEC's impoundments will occur within the next 10 years, in accordance with CCR Rule closure timelines. Minnesota Power is contending with the fact that decommissioning dates for BEC Units 3 and 4 are drawing near, while at the same time additional information is emerging regarding the work likely to be needed to comply with the 2015 Rule and the associated costs. The Company is working to find cost-effective ways to comply with federal regulations while also working to ensure the costs associated with compliance with these requirements are spread over a reasonable time period. Additional information regarding proposed recovery of these costs is described in the Direct Testimony of Company witness Levi A. Peterson**.**

VI. CONCLUSION

Q. Does this complete your Direct Testimony?

A. Yes.

Statement of Qualifications

Todd Z. Simmons

Vice President – Generation Operations

Minnesota Power

Todd Z. Simmons is the Vice President of Generation Operations for Minnesota Power and is responsible for all fossil, gas, and renewable operation and maintenance programs and staff. This responsibility includes the generating facilities in Minnesota and North Dakota.

Mr. Simmons has earned a Bachelor of Arts Degree in Business Management from the College of St. Scholastica, in Duluth, Minnesota, and holds a Chief A Engineer's License with the State of Minnesota.

Mr. Simmons has 32 years of regulated utility experience. He joined Minnesota Power in 1994, wherein his career areas of focus have included generation facility maintenance and operations, generation operation engineering and reliability, and production planning.

Throughout his career with Minnesota Power, he has held several positions of increasing responsibility within the areas of operation, maintenance, engineering, project management support, and support service functions. Each new role has had an increased level of intricacy for operating, maintenance and engineering protocols, as well as management of employees, budgets, and facilities.

Area	Classification	Project Description	Total Company	MN Jurisdictional
Steam - Boswell Unit 3	Steam Production	BEC-3 2027 Blanket	95,000	78,802
Steam - Boswell Unit 3	Steam Production	BEC-3 3A and 3B Pulv Overhaul	699,034	579,842
Steam - Boswell Unit 3	Steam Production	BEC-3 3B FGD Recycle Pump Rebuild	83,801	69,512
Steam - Boswell Unit 3	Steam Production	BEC-3 BOTTOM ASH GRINDER REPL	186,000	154,285
Steam - Boswell Unit 3	Steam Production	BEC-3 Cooling Tower Components	137,752	114,264
Steam - Boswell Unit 3	Steam Production	BEC-3 Generator Circuit Breaker OH	380,261	315,423
Steam - Boswell Unit 3	Steam Production	BEC3 NR CEM UMBILICAL REPLACEMENT	418,681	347,292
Steam - Boswell Unit 3	Steam Production	BEC3 TURBINE DC BOP STARTER UPGRAD	208,810	173,206
Steam - Boswell Unit 4	Steam Production	BEC U4 Old BES(DC5) Roof	157,628	130,751
Steam - Boswell Unit 4	Steam Production	BEC-4 2027 Blanket	75,800	62,875
Steam - Boswell Unit 4	Steam Production	BEC4 4A BCP Repl-Year 1 of 2	924,887	767,185
Steam - Boswell Unit 4	Steam Production	BEC-4 4A BFP Valve Overhaul	294,372	244,179
Steam - Boswell Unit 4	Steam Production	BEC4 4A NID Comp Rebuild	128,922	106,940
Steam - Boswell Unit 4	Steam Production	BEC-4 4A Vacuum Pump	70,124	58,167
Steam - Boswell Unit 4	Steam Production	BEC-4 4B Air Heater Support Bearing	392,501	325,576
Steam - Boswell Unit 4	Steam Production	BEC-4 4B BFP Valve Overhaul	294,372	244,179
Steam - Boswell Unit 4	Steam Production	BEC-4 4B&4D Pulv Grinding Section &	771,641	640,069
Steam - Boswell Unit 4	Steam Production	BEC-4 4C Condensate Pump	88,345	73,281
Steam - Boswell Unit 4	Steam Production	BEC4 4C Pulverizer Gearbox Rebuild	1,380,077	1,144,760
Steam - Boswell Unit 4	Steam Production	BEC4 BMS Upgrade	710,342	589,221
Steam - Boswell Unit 4	Steam Production	BEC-4 Boiler Tube Replacement	1,243,426	1,031,409
Steam - Boswell Unit 4	Steam Production	BEC-4 Bottom Ash Grinder Replacemen	288,000	238,893
Steam - Boswell Unit 4	Steam Production	BEC-4 Bottom Ash Hopper Cricket Sha	170,886	141,748
Steam - Boswell Unit 4	Steam Production	BEC-4 Burner Replacement	430,399	357,012
Steam - Boswell Unit 4	Steam Production	BEC-4 Conveyor Chains 4-1 and 4-2 R	235,000	194,930
Steam - Boswell Unit 4	Steam Production	BEC-4 Cooling Tower Components	1,231,798	1,021,764
Steam - Boswell Unit 4	Steam Production	BEC-4 Cooling Tower Riser Piping	406,558	337,236
Steam - Boswell Unit 4	Steam Production	BEC-4 Cooling Tower VFD	262,296	217,572
Steam - Boswell Unit 4	Steam Production	BEC-4 DCS Server Workstation Repl	459,513	381,161
Steam - Boswell Unit 4	Steam Production	BEC-4 Economizer Outlet Expansion J	490,156	406,579
Steam - Boswell Unit 4	Steam Production	BEC4 ID Fan Drive Rebuilds	1,681,876	1,395,100
Steam - Boswell Unit 4	Steam Production	BEC-4 ID Fan Outlet Duct Expansion	156,479	129,798
Steam - Boswell Unit 4	Steam Production	BEC-4 MSTM Hanger Replacement - 2yr	1,009,885	837,689

Area	Classification	Project Description	Total Company	MN Jurisdictional
Steam - Boswell Unit 4	Steam Production	BEC-4 NID Module Refurbishment	293,076	243,103
Steam - Boswell Unit 4	Steam Production	BEC-4 NID Reactor Duct Liner Repl.	121,182	100,520
Steam - Boswell Unit 4	Steam Production	BEC-4 Overhaul 4B Boiler Circ Pump	404,741	335,729
Steam - Boswell Unit 4	Steam Production	BEC-4 Tripper Room (DC5) Roof	234,668	194,655
Steam - Boswell Unit 4	Steam Production	BEC-4 Turbine Valve Overhaul	1,989,455	1,650,233
Steam - Boswell Unit 4	Steam Production	BEC-4 Voltage Regulator Upgrade	350,857	291,033
Steam - Boswell Unit 4	Steam Production	BEC-4 WSD Recycle Tank D Agitators	124,951	103,645
Steam - Boswell Unit 4	Steam Production	BEEC-4 Baghouse & Cage Replacement	3,871,634	3,211,482
Steam - Boswell Common	General Plant	BEC Admin Cubicles & Carpeting Repl	218,459	186,391
Steam - Boswell Common	General Plant	BEC ESO Cushman Replacement	20,577	17,556
Steam - Boswell Common	General Plant	BEC Forklift Replacement	74,224	63,329
Steam - Boswell Common	General Plant	BEC SKF DBA Analyzers	79,525	67,852
Steam - Boswell Common	General Plant	GEN OPS Cisco Video Install	37,239	31,773
Steam - Boswell Common	Steam Production	BEC Fuels 2027 Blanket	82,963	68,817
Steam - Boswell Common	Steam Production	BEC Replace Jockey Pump	42,051	34,881
Steam - Boswell Common	Steam Production	BEC West Warehouse Roof Replacement	513,894	426,270
Steam - Boswell Common	Steam Production	BEC-3 Overhaul 4A Fire Pump	63,886	52,993
Steam - Boswell Common	Steam Production	BEC-4 4B Centac Compressor	776,454	644,061
Steam - Boswell Common	Steam Production	BEC-4 Spray Water Pump Addition	132,123	109,594
Steam - Boswell Common	Steam Production	BEC-F 3A Fly Ash Air Compressor Reb	150,565	124,893
Steam - Boswell Common	Steam Production	BEC-F 5 Coal Silo Feeder Overhaul	69,586	57,721
Steam - Boswell Common	Steam Production	BEC-F C9 Scale Replacement	75,468	62,600
Steam - Boswell Common	Steam Production	BEC-F Conveyor Belt Replacement	170,304	141,266
Steam - Boswell Common	Steam Production	BEC-F MCC Roof	118,004	97,883
Steam - Boswell Common	Steam Production	BEC-F Replace Loop Rail	200,948	166,684
Steam - Boswell Common	Steam Production	Intake Traveling Screen Lower Frame	338,923	281,133
Steam - Hibbard Renewable Energy Center	General Plant	HREC Ash PLC Overhaul	134,828	115,037
Steam - Hibbard Renewable Energy Center	General Plant	HREC Coal PLC Overhaul	89,883	76,689
Steam - Hibbard Renewable Energy Center	Steam Production	HREC #4 Air Compressor	113,356	94,027
Steam - Hibbard Renewable Energy Center	Steam Production	HREC #5 BOILER FEED PUMP OVERHAUL	173,632	144,026
Steam - Hibbard Renewable Energy Center	Steam Production	HREC Blanket 2027	99,999	82,948
Steam - Hibbard Renewable Energy Center	Steam Production	HREC CEMS Upgrade	409,829	339,949
Steam - Hibbard Renewable Energy Center	Steam Production	HREC F Belt Replace	122,758	101,827
Steam - Hibbard Renewable Energy Center	Steam Production	HREC Truck Scale	345,664	286,725
Steam - Hibbard Renewable Energy Center	Steam Production	HREC U3 A&B Condensate Pump	580,869	481,825

Area	Classification	Project Description	Total Company	MN Jurisdictional
Steam - Hibbard Renewable Energy Center	Steam Production	HREC U3 Boiler Gas Burner Overhaul	352,689	292,552
Steam - Hibbard Renewable Energy Center	Steam Production	HREC U3 Circulating Water PumpRehab	188,506	156,364
Steam - Hibbard Renewable Energy Center	Steam Production	HREC U3 Condensor Tube Rehab	232,259	192,656
Steam - Hibbard Renewable Energy Center	Steam Production	HREC U3 Refractory 2027	69,168	57,374
Steam - Hibbard Renewable Energy Center	Steam Production	HREC U3 Sootblower Motor Cables	198,905	164,990
Steam - Hibbard Renewable Energy Center	Steam Production	HREC U3 Turbine Overhaul	3,907,908	3,241,571
Steam - Hibbard Renewable Energy Center	Steam Production	HREC U3 Wood Bin Screw Replacement	550,040	456,253
Steam - Hibbard Renewable Energy Center	Steam Production	HREC U4 Automated OFA Nozzles	168,714	139,947
Steam - Hibbard Renewable Energy Center	Steam Production	HREC U4 BOILER REFRACTORY 2027	68,944	57,188
Steam - Hibbard Renewable Energy Center	Steam Production	HREC U4 EHC System Tubing	34,479	28,600
Steam - Hibbard Renewable Energy Center	Steam Production	HREC U4 Sand Classifiers Overhaul	90,273	74,881
Steam - Hibbard Renewable Energy Center	Steam Production	HREC Vac System Overhaul	306,590	254,314
Steam - Laskin Energy Center	General Plant	2027 Voice & Video Program - Laskin	17,658	15,066
Steam - Laskin Energy Center	General Plant	Laskin Network EOL 2027	93,231	79,546
Steam - Laskin Energy Center	General Plant	LEC PLC 5 UPGRADE- LAMELLA BLDG	95,111	81,149
Steam - Laskin Energy Center	Steam Production	LEC 2027 BLANKET	70,000	58,064
Steam - Laskin Energy Center	Steam Production	LEC DCS UPGRADE	1,747,136	1,449,232
Steam - Laskin Energy Center	Steam Production	LEC TURBINE ROOF	848,555	703,868
		Total Steam Generation	**37,231,364**	**30,903,461**
Hydro - Blanchard HE Station	Hydro	Blanchard Repl Tainter Gates 1,7,8	6,030,547	4,985,453
Hydro - Blanchard HE Station	Hydro	Blanchard Replace U2 Head Gates	3,095,654	2,559,177
Hydro - Blanchard HE Station	Hydro	Blanchard Replace U3 Headgates	2,941,704	2,431,907
Hydro - Blanchard HE Station	Hydro	Blanchard U1 Rehab	4,246,016	3,510,182
Hydro - Fond du Lac HE Station	Hydro	Fond du Lac Replace Gate 6	2,593,515	2,144,059
Hydro - Knife Falls HE Station	Hydro	Knife Falls PLC Upgrade	207,648	171,663
Hydro - Knife Falls HE Station	Hydro	Knife Falls Station Battery Replace	79,890	66,045
Hydro - Little Falls HE Station	Hydro	Little Falls Tailrace ConcreteRehab	1,069,889	884,477
Hydro - Scanlon HE Station	Hydro	Scanlon U2 Replace	4,235,195	3,501,235
Hydro - Sylvan HE Station	Hydro	Sylvan U1 Wall Concrete Rehab	316,636	261,763
Hydro - Thomson HE Station	General Plant	Hydro PDMA Tool	44,961	38,361
Hydro - Thomson HE Station	General Plant	Thomson Floor Scrubber Tool	3,201	2,731
Hydro - Thomson HE Station	Hydro	Hydro Blanket 2027	100,000	82,670
Hydro - Thomson HE Station	Hydro	Thomson Basement Ventilation Coolin	800,796	662,018
Hydro - Thomson HE Station	Hydro	Thomson U3 Runner Overhaul	3,894,272	3,219,395
Hydro - Winton HE Station	Hydro	Winton HVAC Upgrade Louvers	45,408	37,539

Area	Classification	Project Description	Total Company	MN Jurisdictional
Hydro - Winton HE Station	Hydro	Winton Hydro Tuck Pointing	781,086	645,724
Hydro - Winton HE Station	Hydro	Winton TG3 Bays Concrete Rehab	1,050,183	868,186
		Total Hydro Generation	**31,536,599**	**26,072,583**
Wind - Bison	General Plant	BSN HPPP SCADA UPGRADE 2027	859,950	733,718
Wind - Bison	General Plant	BSN WIND PROD SYSTEM (WPS) UPGRADE	1,880,687	1,604,621
Wind - Bison	Wind Generation	BSN 1A DELTA MODULE UPGRADE	2,675,689	2,219,458
Wind - Bison	Wind Generation	BSN 1A GENERATOR REPL 2027	105,913	87,854
Wind - Bison	Wind Generation	BSN 2027 BLANKET	2,046,000	1,697,137
Wind - Bison	Wind Generation	BSN ELECTRIC TORQUE TOOLS PURCHASE	98,700	81,871
Wind - Taconite Ridge	General Plant	Tac Ridge EOL 2027	64,069	54,664
Wind - Taconite Ridge	Wind Generation	2027 MET Tower Instrument Replace	128,472	106,566
Wind - Taconite Ridge	Wind Generation	2027 TREC Blade Refurb Blanket	700,007	580,649
Wind - Taconite Ridge	Wind Generation	2027 TREC Gearbox Replacement	2,822,878	2,341,549
Wind - Taconite Ridge	Wind Generation	2027 TREC Inverter Matrix Replace	72,246	59,927
Wind - Taconite Ridge	Wind Generation	2027 TREC Turbine Generator Replace	44,889	37,235
Wind - Taconite Ridge	Wind Generation	TREC Pitch Bearing Replacement	347,591	288,323
		Total Wind Generation	**11,847,091**	**9,893,571**
Solar - Solar Generation	General Plant	2027 Boswell Solar Heavy Equipment	514,754	439,193
Solar - Solar Generation	Solar Generation	Camp Ripley Solar Purchase	4,646,527	-
		Total Solar Generation	**5,161,281**	**439,193**
		Total Generation	**85,776,335**	**67,308,808**