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

Docket No. E015/GR-23-155

Exhibit ________

GENERATION OPERATIONS

November 1, 2023

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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., doing business as Minnesota Power ("Minnesota Power" or the "Company"). My current position is Vice President – MP Generation Operations.

Q. Please summarize your qualifications and experience.

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") 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. Most recently, 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. Exhibit ___ (Simmons), Direct Schedule 1 to my Direct Testimony provides my experience and qualifications.

Q. What is the purpose 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 2021 Rate Case, Docket No. E015/GR-21-335 ("2021 Rate Case"), the Company has continued to make progress on its *EnergyForward* 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 2024 test year and review assets placed in service since the 2021 Rate Case. Lastly, I will provide information on environmental compliance costs that the Company is seeking approval for recovery through the Fuel Adjustment Clause ("FAC Rider").

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 – 2024 Test Year Capital Additions.

II. GENERATION FORWARD LOOKING FLEET

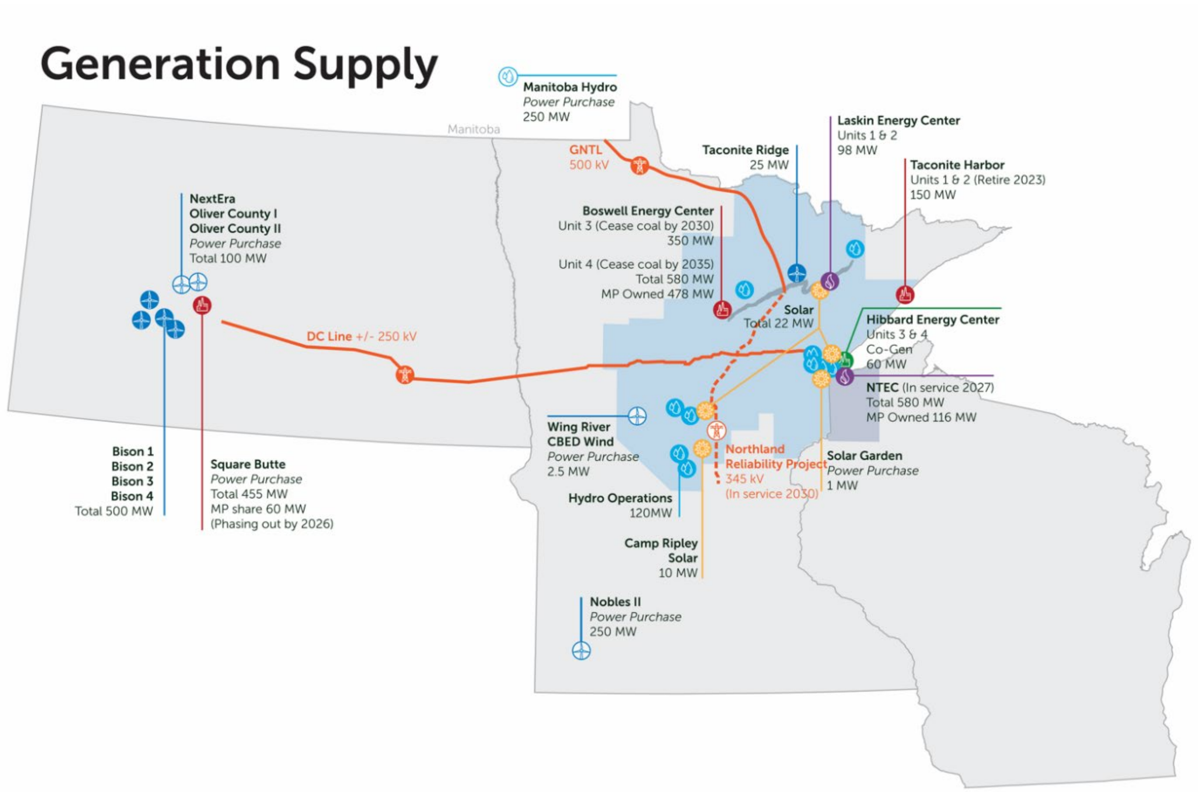
Q. What is the purpose of this section of your testimony?

A. The purpose of this section 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 the 2021 Rate Case, the Company has continued to make significant progress on its *EnergyForward* strategy, including receiving Commission approval of Minnesota Power's Integrated Resource Plan, Docket No. E015/RP-21-33 (the "2021 IRP"), filed in 2021. Additionally, I will provide an overview of capital projects and O&M expenses for the Generation Operations work area included in Minnesota Power's 2024 test year and applicable updates to the generating fleet.

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

A. Minnesota Power's generation facilities have a net maximum capability of over 1,600 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 remissioning 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. Minnesota Power's Generation Operations' mission is to operate, maintain, and manage the Company's generation assets in a manner that protects both people and the environment, is financially responsible to our customers, and provides a fair return for Company shareholders. 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 the power market demands for economic dispatch, baseload, intermediate load, and peak load. Preserving the usefulness of the 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. For context, Minnesota Power has added approximately 850 MW of wind power to the benefit of the Company's customers since 2005. The testimony of Company witness Julie I. Pierce outlines the breakdown of that 850 MW. The Company is seeking to add an additional 400 MW of wind and 300 MW of solar as part of the stakeholder supported and approved 2021 IRP outcome to its 1,570 MW peak demand system, consistent with Minnesota Power's 100 percent carbon-free strategy.

Coupling the variable nature of renewable generation with high load factors may require changes to dispatchable asset operation to maintain a reliable and affordable energy supply, particularly when renewable generation is high and market demands are low.

The degree of impact to dispatchable resources depends upon how much renewable energy is being generated 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 will change the generation maintenance strategy due to thermal stresses and wear and tear of starting and stopping equipment as well as impacts to fuel procurement and inventory levels. A generation plant's operating strategy 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 within 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 increasingly 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 2021 Rate Case?

A. Table 1 provides information on the Company's current generation portfolio, including the fleet transformation that the Company has undergone since Minnesota Power filed the 2021 Rate Case.

Table 1. Minnesota Power Owned Generation

	Unit No.	Year Installed	2021 Net Capability (MW)	2023 Net Capability (MW)
Coal				
Boswell Energy Center ("BEC") in Cohasset, MN	1	1958	—[a]	—[a]
	2	1960	—[a]	—[a]
	3	1973	352	352
	4	1980	468[b]	468[b]
			820	820
Taconite Harbor Energy Center ("THEC") in Schroeder, MN	1	1957	75	--[c]
	2	1957	75	--[c]
	3	1967	--[c]	--[c]
			150	0
Total Coal			970	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[e]				
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
Total Wind			522	522
Solar				
Camp Ripley –Little Falls, MN[f]		2017	10	10
HSC Solar Garden[g]		2016	0.04	0.04
Total Company Generation			**1,780**	**1,630**

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

(b) BEC4 net capability shown above reflects Minnesota Power's ownership percentage of 80 percent. WPPI Energy owns 20 percent of BEC4.

(c) THEC3 was retired in May 2015. Economic idling of THEC1 and THEC2 commenced in the fall of 2016, followed by retirement in March 2023.

(d) Laskin was converted from coal to natural gas in June 2015.

(e) Hydro consists of ten stations with 34 generating units and a total nameplate capacity of 120 MW. Hydro stations are Prairie River, Pillager, Sylvan, Little Falls, Blanchard, Knife Falls, Scanlon, Winton, Thomson, and Fond du Lac.

(f) Camp Ripley is not currently owned by Minnesota Power, but Minnesota Power is obligated to make financing payments during the financing term, which expires in 2027. Minnesota Power currently anticipates that at the end of the financing term, the Company will exercise the option to purchase the solar array.

(g) HSC Solar Garden is currently owned by Minnesota Power, HSC Solar Garden is a 40 kW solar array in Duluth, Minnesota and is part of the approved April 21, 2017 CSG Pilot Program.

Q. Have any Company generation resources been retired since the 2021 Rate Case?

A. Yes. Taconite Harbor Energy Center ("THEC") Unit 1 and Unit 2 were retired as of March 31, 2023 in compliance with the Commission's order in the Company's 2021 IRP. I discuss these retirements and the resulting impacts later in my Direct Testimony.

Q. Has the Company added any generation resources since the 2021 Rate Case?

A. The Jean Duluth, Laskin, and Sylvan Solar PPA sites were commissioned in 2022 and 2023 in response to the Commission's request to accelerate the implementation of these projects and assist local community economic recovery from the COVID-19 pandemic (Docket Nos. E,G999/CI-20-492 and E015/M-20-828). Camp Ripley Solar was commissioned in 2017. Though not currently owned by Minnesota Power, the Company is obligated to make financing payments through 2027 and currently operates and maintains the site.

III. GENERATION BUDGETING OVERVIEW

A. <u>Generation Capital Budgets</u>

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 Colin B. Anderson. Generation Operations augments the budget development process discussed by Company witness Mr. Anderson 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 also receives management approval and is then compiled into 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, installing appropriate project management process and controls for transparency, and managing contingency and risk related to the Generation Operations work area, as a whole. 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 2024 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. While Company witness Ms. Pierce discusses in her Direct Testimony ways in which Minnesota Power has leveraged PPAs to meet certain generation needs, 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 2022, 2023 projected year capital additions, and capital additions included in the 2024 test year is provided in Table 2.

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

Capital Plant Additions (including Contra) -- Total Company	2022	2023	2024
	Actuals	Projected Year	Test Year
Steam Generation	$66.3	$26.4	$24.3
Boswell Common	$47.8	$6.0	$4.6
Boswell Unit 3	$12.5	$6.1	$12.9
Boswell Unit 4	$4.3	$10.2	$1.7
Hibbard Renewable Energy Center	$1.1	$2.9	$3.3
Laskin Energy Center	$0.6	$1.1	$1.8
Taconite Harbor Energy Center	-	$0.1	-
Hydro Generation	$2.0	$10.0	$6.3
Birch Lake Reservoir	-	-	-
Blanchard HE Station	-	$4.3	$2.0
Boulder Lake Reservoir	-	-	-
Fish Lake Reservoir	$0.1	-	-
Fond du Lac HE Station	$1.4	$0.3	-
Island Lake Reservoir	$0.1	-	$3.3
Knife Falls HE Station	-	-	-
Little Falls HE Station	-	$0.2	-
Pillager HE Station	$0.1	-	-
Prairie River HE Station	-	$0.2	-
Rice Lake Reservoir	-	-	-
Scanlon HE Station	-	$3.6	-
Sylvan HE Station	-	-	$0.2
Thomson HE Station	$0.3	$0.7	$0.4
Whiteface Reservoir	-	-	-
Winton HE Station	-	$0.6	$0.5
Wind Generation	$2.1	$5.1	$2.8
Bison	$1.9	$1.6	$0.7
Taconite Ridge	$0.2	$3.5	$2.0
Solar Generation	-	-	-
Generation Subtotal, excluding Riders	**$70.3**	**$41.5**	**$33.4**

Amounts may not total due to rounding.
Amounts may include Intangible & General Plant Additions.

Table 3. Generation Operations Capital Additions (MN Jurisdictional)[1] ($ in Millions)

Capital Plant Additions (including Contra) -- MN Jurisdictional	2022	2023	2024
	Actuals	Projected Year	Test Year
Steam Generation	$58.4	$23.3	$21.5
Boswell Common	$42.1	$5.3	$4.1
Boswell Unit 3	$11.0	$5.4	$11.4
Boswell Unit 4	$3.8	$9.0	$1.5
Hibbard Renewable Energy Center	$1.0	$2.6	$2.9
Laskin Energy Center	$0.5	$1.0	$1.6
Taconite Harbor Energy Center	-	$0.0	-
Hydro Generation	$1.7	$8.8	$5.5
Birch Lake Reservoir	-	-	-
Blanchard HE Station	-	$3.8	$1.7
Boulder Lake Reservoir	-	-	-
Fish Lake Reservoir	-	-	-
Fond du Lac HE Station	$1.3	$0.3	-
Island Lake Reservoir	$0.1	-	$2.8
Knife Falls HE Station	-	-	-
Little Falls HE Station	-	$0.1	-
Pillager HE Station	$0.1	-	-
Prairie River HE Station	-	$0.2	-
Rice Lake Reservoir	-	-	-
Scanlon HE Station	-	$3.2	-
Sylvan HE Station	-	-	$0.2
Thomson HE Station	$0.3	$0.6	$0.4
Whiteface Reservoir	-	-	-
Winton HE Station	-	$0.5	$0.4
Wind Generation	$1.9	$4.5	$2.5
Bison	$1.7	$1.4	$0.7
Taconite Ridge	$0.2	$3.1	$1.8
Solar Generation	-	-	-
Generation Subtotal, excluding Riders	**$62.0**	**$36.6**	**$29.5**

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 $70.3 million Total Company ($62.0 million MN Jurisdictional) for 2022; $41.5 million Total Company ($36.6 million MN Jurisdictional) for the 2023 projected year; and $33.4 million Total Company ($29.5 million MN Jurisdictional) for the 2024 test year. Table 2 above provides the Total Company capital additions made by location. Table 3 above provides

[1] A summary of allocation factors used across the Company for purposes of calculating the Minnesota Jurisdictional totals is provided in Volume 3, Direct Schedules B-16 to B-19 and C-13 to C-16.

the Minnesota Jurisdictional ("MN Jurisdictional") capital additions made by location. Capital additions for the Generation fleet are evaluated to prioritize the needs of each asset to meet its intended mission and assure compliance with regulatory requirements. Projects are also reviewed to assure alignment with outage schedules and make any identified safety improvements. In addition, operational and maintenance needs are reviewed to assure 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. Why are the capital additions for Generation Operations less in the 2023 projected year and the 2024 test year than actual capital additions were in 2022?

A. During 2022, there were major investments at BEC that were completed, such as BEC Unit 4 ("BEC4") cooling tower overhaul, BEC Unit 3 ("BEC3") Boiler equipment refurbishments, gypsum dewatering project, and BEC4 turbine generator overhaul. Also, in 2022 there was investment in a Federal Aviation Administration lighting project at Bison that are not expected to occur in 2024, nor are they part of an ongoing maintenance cycle.

Q. What is driving the $41.5 million Total Company ($36.6 million MN Jurisdictional) capital additions included in the 2023 projected year?

A. The 2023 projected year additions are driven by a scheduled duty cycle outage at BEC4. 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. Two hydro stations have large investments forecasted in the 2023 projected year. The Scanlon hydro station ("Scanlon") has gate replacements and the Blanchard hydro station ("Blanchard") will be replacing the gantry crane used for unit work.

Q. What is driving the $33.4 million Total Company ($29.5 million MN Jurisdictional) capital additions included in the 2024 test year Budget?

A. The 2024 test year budgeted investment additions are driven by a 49-day duty cycle outage at BEC3. This is discussed in more detail later in my Direct Testimony. There are also investments at the HREC and hydro facilities in 2024 to maintain reliability at these locations. MP Exhibit ____ (Simmons), Direct Schedule 2 contains a complete list of projects. These are part of typical maintenance cycle projects that need to be performed to maintain these important facilities for continued service to customers.

Q. How does the Company manage capital projects once they are approved?

A. Following review and approval by the PRC, the project manager is responsible for the effective execution of the project. This includes building a complete scope of work, project schedule, and construction management plan. While many projects are long-planned with extended lead times, specialized equipment, and detailed outage schedules and planning, certain project schedules may be advanced or deferred when other conditions require such flexibility. Despite strong reliability, programs and condition-based monitoring systems, daily operations of a 24/7 facility will experience unforeseen failures. The Company manages to its overall budget, and where an emergent issue presents itself within that year, some projects through reprioritization may need to be rescheduled or replaced with projects that address emergent work with a higher priority for employee and public safety, environmental compliance, or reliable service for our customers.

At the same time, deviations to a project with regard to any changes in cost, scope, or schedule require that the project be reviewed again by the PRC to balance the year's capital projection and competing priorities while still assuring the safe, reliable, affordable, and environmentally compliant energy our customers expect.

Q. Please explain more about what you mean when you said the Company has needed to reassess its reliability programs.

A. The increased use of plant components and changes in how plants are dispatched require increased capital investment to maintain reliability. Furthermore, when use of generating assets increases, reliability is more important and additional capital investments to improve reliability are justified. While long-term reliability has always been a goal, increasing changes in energy market conditions make it difficult to adjust the level of investment to be commensurate with asset use. Inspections, testing, capital budgeting, and project execution are most effective when given the proper time to be developed and planned. In light of this, a longer term three- to five-year plan to improve reliability programs is underway. This, along with other assessments of equipment condition and processes and programs used to promote and sustain reliability, will prioritize efforts and resources for the fleet's long-term reliability.

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

A. Supply chain challenges initially experienced during the COVID-19 pandemic have continued and the increased demand in the electric utility sector (*see* Gunderson Direct, Section IV.F) have caused prices to increase, lead times to increase, and contractor availability to drop. Lead times for the electric utility segment increased 160 percent since January 2021. Contractors are often declining to bid on projects because they do not have the labor and capacity to perform more work and when they do bid, prices are 9-–10 percent higher. All of these factors have increased the cost and time to execute projects. To mitigate these risks, we are planning further into the future, starting the procurement process earlier, working with vendors to understand material and contractor availability, establishing partnerships with vendors, and increasing inventory where it makes sense.

Q. What has Minnesota Power done to increase supplier diversity and mitigate potential cost increases?

A. Minnesota Power continues to work with multiple utilities, prime contractors, and the Edison Electric Institute to learn and build best practices into supplier diversity programs including: sharing lists of diverse suppliers with Xcel Energy and CenterPoint Energy; completing a data enrichment process, finding over 200 diverse active suppliers in our procurement database, along with more than 500 small businesses; and building an internal dashboard to easily track the Company's spend with diverse and small businesses. Minnesota Power has attended and sponsored over a dozen in-person and virtual networking events held by organizations such as the Women's Business

Development Center, North Central Minority Supplier Development Council, Minnesota Tribal Contractor Council, Small and Disadvantaged Business Opportunities Council, Disability: IN (MN and WI), National Veterans-Owned Business Association, and National Veterans Business Development Council.

Minnesota Power is managing a Tier 2 spend reporting process with over a dozen prime contractors, added Tier 2 supplier diversity language into all new contracts starting in 2022, is seeking Tier 2 information from prime suppliers on bids over $250,000, gathering data quarterly from our credit card provider on diverse supplier spend, and publishing an external supplier website for all prospective and current suppliers to utilize in working with the Company (www.allete.com/supplier). This "Tier 2" process gathers information on subcontractors or suppliers used by those prime contractors.

B. Generation Operating & Maintenance Budgets

Q. Describe Generation Operations' 2024 O&M budget.

A. The Generation 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.

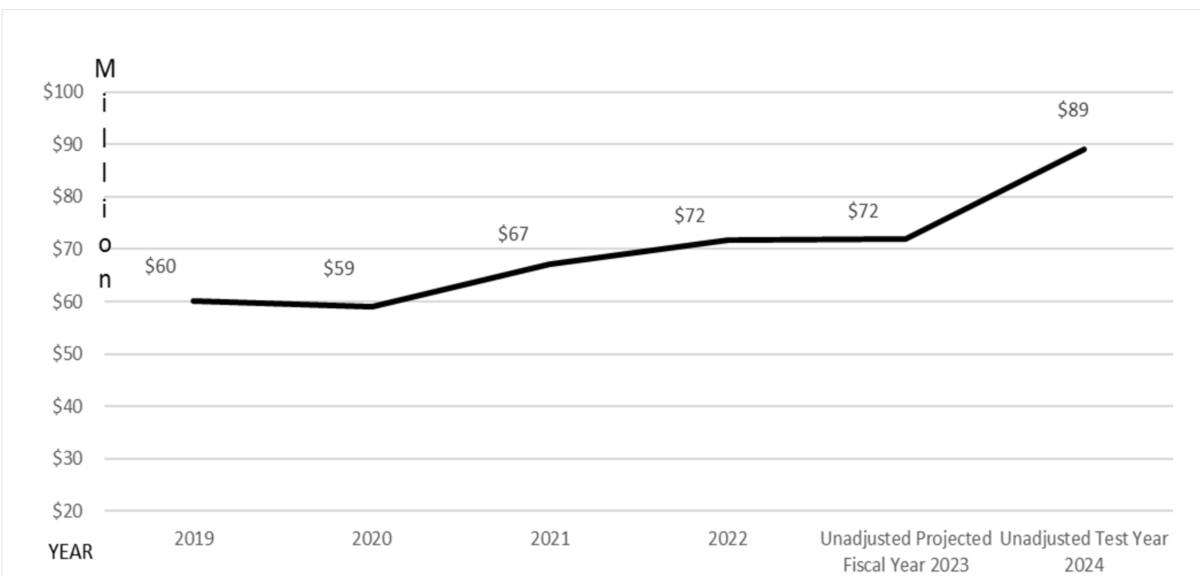
Q. What are the components of the Generation O&M budget?

A. The Generation O&M budget is comprised 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 long-term service maintenance agreement, an annual expense, at Bison. This expense is discussed further in my testimony in Section IV.E. Another example of a cost driver of the O&M budget is the chemical reagents that reduce emissions at our coal-fired generation facilities. Generation Operations utilizes reagents such as ammonia, halogenated activated carbon, and lime continuously whenever these generation facilities are operating. 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 O&M budget and are necessary to operate the facilities to provide power generation to benefit the Company's customers.

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

A. Yes. A summary of the Generation O&M is provided in Figure 2.

Figure 2. Generation O&M Spend (Total Company) *



*2024 includes $10.8 million in oxides of nitrogen ("NOx") Allowance Expense for compliance with the Good Neighbor Rule ("GNR").

Q. What is Generation's O&M Budget for the 2024 test year?

A. The 2024 budgeted Federal Energy Regulatory Commission ("FERC") level O&M for Generation is provided in Table 4 at the Total Company level and the MN Jurisdictional level.

Table 4. Generation Operations FERC Level O&M (2024 Test Year)

	2024 UTY Total Company	2024 UTY MN Jurisdictional
POWER PRODUCTION		
Steam Power Generation		
Operation	171,627,731	148,088,961
Less: Fuel Costs (Fuel Costs in FERC 50100)	(130,229,872)	(111,880,483)
Total Operation	41,397,859	36,208,478
Total Maintenance	19,885,950	17,462,250
Total Steam Power Production Expenses	61,283,809	53,670,728
Hydraulic Power Generation		
Total Operation	2,020,783	1,759,213
Total Maint	3,740,350	3,256,199
Total Hydro Power Production	5,761,133	5,015,412
Other Power Generation (wind)		
Total Operation	5,689,502	5,043,857
Total Maint	14,905,619	13,214,129
Total Other Power Production	20,595,121	18,257,986
Other Power Supply Expenses		
Purchased Power	349,337,042	302,057,767
System Control and Dispatch	287,919	255,246
Other Expenses	1,413,020	1,252,670
Less: Purchased Power (FERC 55500)	(349,337,042)	(302,057,767)
Total Other Power Supply	1,700,939	1,507,916
Total Power Production Expenses	89,341,002	78,452,042

Q. Why is the 2024 test year O&M budget approximately 23 percent higher than O&M for the 2023 projected year?

A. The 2024 test year O&M is higher than 2023 due to increased commodity costs for reagents, an increase in the Consumer Price Index used for escalation in the service maintenance agreement contract at Bison, escalation of landowner easements payments at Bison, increased salaries for internal labor due to the renegotiation of International Brotherhood of Electrical Workers Local 31 contract ratification, increased forecasted generation at both Laskin and HREC, and the inclusion of NOx allowances as estimated to comply with the GNR, discussed in more detail later in Section V of my Direct Testimony (Environmental Compliance).

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. 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&2 ("BEC1&2") were retired from operation in 2018. The two remaining operating units, BEC3 and BEC4 have a combined 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, which was placed into service in 1980, is Minnesota Power's largest baseload generator. Subsequent turbine efficiency investments in BEC4 during 2010 expanded the net generating capability of this unit to 585 MW. WPPI Energy (formerly Wisconsin Public Power, Inc.) has a 20 percent (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 is aligned with a focus on reliability to ensure the units serve our customers and maintain safety and environmental compliance.

Q. What has the Commission ordered the Company to do regarding operations of BEC?

A. In the 2021 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.

Q. What does "ceasing coal-fired operations" of BEC3 and BEC4 mean regarding the staffing of operations at BEC?

A. Ceasing coal-fired operations means that the Company is investigating options other than coal-fired generation at BEC. Investing, educating, and maintaining the local workforce and the Cohasset, Minnesota community is something the Company continues to evaluate. The benefits of BEC stretch to many outlying communities surrounding the plant's host community. Stakeholder outreach with the host community will begin at the end of 2023, building on the stakeholder work that was done as part of the 2021 IRP.

Q. Beyond the changes to the BEC facility, are there other Minnesota Power systems impacted by the ceasing of coal-fired operations at BEC?

A. Yes. As discussed further in the Direct Testimony of Company witness Mr. Daniel W. Gunderson, these operational changes require Company investments in transmission infrastructure to ensure continued reliable, safe, prudent, and efficient delivery of electricity to our customers on both our transmission and distribution systems.

Q. What are the significant capital additions at BEC since the 2021 Rate Case?

A. An important investment at BEC relates to the facility's compliance with the Coal Combustion Residuals ("CCR") Rule. These important projects were put into service in 2022 as follows:

Gypsum Dewatering ($7.8 million of Total Company capital additions) – This BEC3 project went into service in the fall of 2022. This technology is a belt filter system, which dewaters the gypsum waste stream from the existing flue gas desulfurization system. The system is currently operating and provides improvement to various processes, including load variability and product consistency. By installing this system, the need for the current BEC3 CCR pond has been eliminated. This pond is currently being dewatered and will be closed.

Dry Bottom Ash Systems for BEC3 and BEC4 ($26.6 million of Total Company capital additions) – This BEC Common project went into service in the fall of 2022. This technology, a submerged grit conveyor, was installed on both BEC3 and BEC4, where both units share an ash unloading building. The system is currently operating. Tuning for the controls logic and water management are underway. This installation has eliminated the need for the BEC Bottom Ash Pond, which is also being dewatered and will be closed.

Install Wastewater Treatment System ($18.9 million of Total Company capital additions) – This BEC Common project went into service in the spring of 2022. This system has the ability to completely remove wastewater streams from around the plant by utilizing flue gas from the boiler and atomizing the water to evaporate the water. The dried solids and flue gas continue to the existing Novel Integrated Desulfurization ("NID") scrubber for pollution control. This is particularly important as the ponds are no longer able to be used for water management, and ponds need to be dewatered and closed. This system is currently in operation, and optimization around continuous water flow, particularly at low load operation, is being worked on.

Non-CCR wastewater management ($3.2 million of Total Company capital additions) – This BEC Common project, which consisted of constructing a new on-site wastewater storage pond, went into service fall of 2022. The BEC CCR impoundments did not meet one or more of the CCR Rule requirements and therefore are no longer receiving

CCRs. The BEC Bottom Ash Pond received not only CCRs, but also multiple non-CCR wastewater streams from the plant. Because the Bottom Ash Pond will be closed and decommissioned, this alternate means of managing non-CCR wastewater streams was required.

Q. Does the 2024 budget include capital additions at BEC?

A. Yes. As I mentioned above, the 2024 test year includes a spring 49-day scheduled outage on BEC3. This recurring long outage coincides with the cyclical five-year low-pressure turbine overhaul cycle and Generator testing for the unit. During this outage, the capital investment on BEC3 will include, but is not limited to, Selective Catalyst Reduction ("SCR"), NOx reducing layer replacement, baghouse bag replacement, hot reheat line insulation replacement, turbine-generator overhaul, and cooling tower structural reinforcement.

In transitioning BEC3 to economic dispatch in July 2021, the need to install back-up boilers at the station became necessary 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. The installation of these heating boilers will take place during 2024 and 2025 to be available for the critical winter months.

Q. What is the driver behind the $19.2 million investment at BEC in 2024?

A. During 2024, BEC3 has a scheduled 49-day spring duty cycle maintenance outage. This reliability outage will include, but is not limited to, reinvestment in the turbine, boiler, SCR, cooling tower, and baghouse. Outside of BEC3's projects, additional investment in the facility radio communication system, ash hauling trucks, D10 dozer, and pulverizer gearbox are included in the 2024 test year.

Q. What are the benefits of ongoing capital investments at BEC3 and BEC4?

A. Given the current operations of these two units, ongoing maintenance is needed to ensure the safe and reliable operation of the facility for the benefit of our customers. By making continuous prudent investments, the Company maintains, and improves, the reliability of BEC3 and BEC4. As Minnesota Power's last remaining baseload generation assets, the benefits of ongoing BEC capital investments to maintain reliability for customers are even more critical.

B. <u>Laskin Energy Center</u>

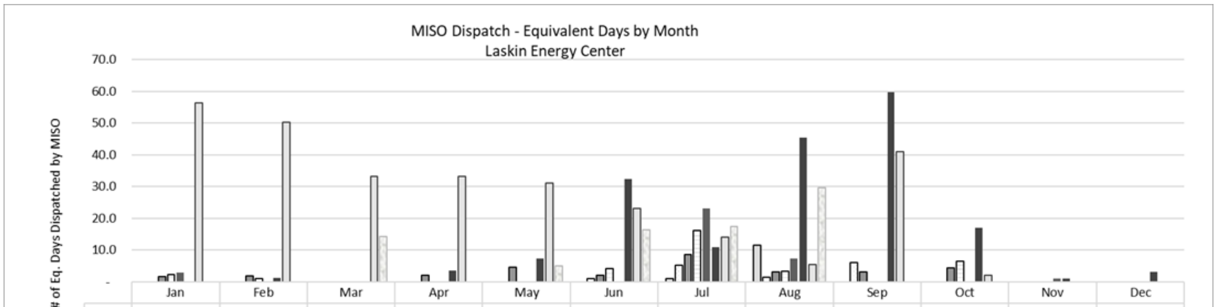
Q. Please describe Laskin.

A. Laskin is located in Hoyt Lakes, Minnesota and was commissioned in 1953 as a coal-fired facility. Laskin 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 *EnergyForward* strategy to diversify its power supply portfolio while reducing carbon emissions, the conversion of Laskin from coal-fired to natural gas-fired generation was complete in 2015.

Q. Are there changes at Laskin because of its conversion to natural gas?

A. Yes. While the conversion to natural gas has increased the accredited capacity to 80–101 MW for planning year 2023–2024 (dependent on season) from 69.5 MW for planning year 2015–2016 (the last year of coal operation), Minnesota Power is now operating Laskin as a peaking facility rather than a baseload resource. As a peaking facility, Laskin provides 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 2016, MISO has requested Laskin, as a peaking facility, to operate on average 7.5 equivalent days per month, as shown in Figure 3. In 2021 and 2022, Laskin ran more frequently due to reliability needs from transmission line work (2021 averaged 15.1 run days and 2022 averaged 24.1 run days). In 2023, due to low natural gas prices, Minnesota Power has seen Laskin more frequently dispatched due to economics and has assisted with system reliability during conservative operations events and during severe storms in the region until other transmission line contingencies were reestablished. Figure 3 provides information on Laskin dispatch days from 2016 through August 2023.

Figure 3. Laskin Dispatch Days*



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2016	-	-	-	-	-	-	1.0	11.6	-	-	-	-
2017	-	-	-	-	-	1.0	5.2	1.5	6.0	-	-	-
2018	1.7	1.8	-	2.0	4.6	2.0	8.5	3.2	3.1	4.4	-	-
2019	2.2	1.1	-	-	-	4.2	16.2	3.3	-	6.5	-	-
2020	2.9	-	-	-	-	-	23.0	7.3	-	-	1.0	-
2021	-	1.2	-	3.6	7.3	32.3	11.0	45.3	59.8	17.1	1.0	3.1
2022	56.3	50.3	33.1	33.1	31.0	23.2	14.0	5.4	40.9	2.1	-	-
2023	-	-	14.3	-	5.1	16.4	17.4	29.7				

*Dispatch information as of August 31, 2023

*For planning year 2024–2025, Laskin switched to Seasonal Accredited Capacity

Q. Are there other benefits as a result of the Laskin natural gas conversion?

A. Yes. In addition to increasing capacity and diversifying the Company's energy sales, the natural gas conversion has also led to emissions reductions when compared to the coal operation of Laskin. Comparing the last three years of coal operations (2012 to 2014) to the first five years of natural gas operations (2016 to 2020), the Laskin conversion is estimated to have reduced carbon dioxide emissions by 735 pounds per megawatt hour ("MWh"). In addition, sulfur dioxide, mercury, and filterable particulate matter emissions were reduced by over 99 percent, and nitrogen oxide emissions were reduced by approximately 98 percent from prior coal emission levels. These emissions reductions bring significant environmental benefits to the region.

C. <u>Hibbard Renewable Energy Center</u>

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 wood, wood waste, coal, and natural gas. HREC is a critical component as a dispatchable facility in the carbon-free strategy of Minnesota Power.

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

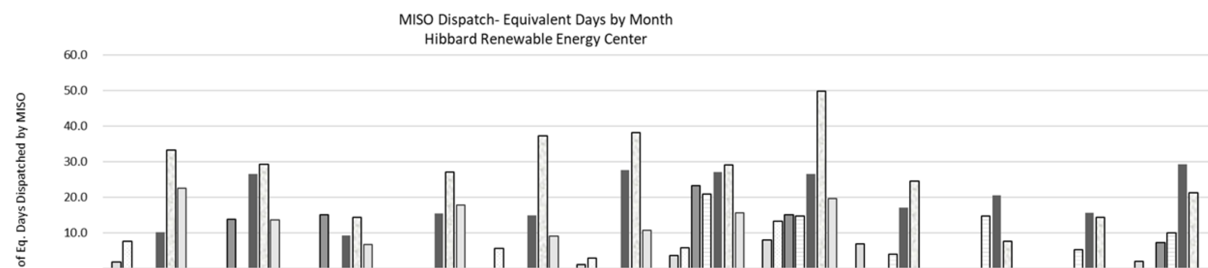
A. HREC is capable of, and originally designed for, baseload operation. It supports capacity and baseload energy generation when required. HREC's multi-fuel boilers provide steam that drives HREC's Units 3 and 4 turbine generators. Until July 2020, HREC supported papermaking processes at the adjacent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

HREC is now run when market prices and grid reliability warrant, as the baseload steam demand is no longer required to support the customer paper mill site. HREC is 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. Additionally, as a dispatchable renewable resource, HREC also provides carbon-neutral reliability services that are critical to the regional grid following the idling, re-missioning, or retiring of nine out of eleven regional coal-fired baseload generating resources. HREC continues to be offered under an economic dispatch model and is called upon to support MISO needs and Minnesota Power customer demand when needed.

Q. How often does MISO dispatch HREC?

A. HREC generated to support customer needs an average of 28 equivalent days per month (July 2020–August 2023) as shown in Figure 4. During peak times in February, June, July, and August of 2020 to 2023, HREC operated an average of 28 equivalent days per month across both units. HREC continues to generate dispatchable energy, demonstrating that these assets are used and very useful to providing grid reliability services. Figure 4 provides information on HREC dispatch days from 2017 through August 2023.

Figure 4. HREC Dispatch Days*



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2017	1.7					1.1	3.6	7.9	6.9			2.0
2018	7.5				5.5	2.8	5.8	13.3				
2019		13.7	15.0				23.3	15.0				7.3
2020							20.9	14.7	4.0	14.6	5.2	10.0
2021	10.1	26.5	9.2	15.4	14.8	27.7	27.0	26.5	17.1	20.6	15.6	29.3
2022	33.2	29.2	14.3	27.0	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				

*Actual Dispatch as of August 31, 2023

D. Taconite Harbor Energy Center

Q. What is Taconite Harbor Energy Center ("THEC")?

A. THEC is located on the North Shore of Lake Superior near Schroeder, Minnesota. It originally included three coal-fired units, with two units installed in 1957 and one unit installed in 1967. The original output capability for THEC was 225 MW. Minnesota Power acquired the facility in 2001 from the bankrupt LTV Steel Mining Company.

Minnesota Power ceased coal-fired generation at THEC Unit 3 in 2015, and the unit was retired-in-place. THEC Unit 1 and Unit 2 were idled in the fall of 2016. From 2012 to 2016, the Company sponsored a Community Advisory Panel of regional North Shore leaders, which offered a communication platform for operating decisions. Since 2016, this group has met annually to discuss facility updates, security, and potential repurposing and redevelopment options. Repurposing ideas range from refueling the existing boilers with biomass, natural gas, or propane, or utilizing existing land and interconnect for new solar or energy storage. To date, the ideas explored have been determined unsuitable for the site and the existing infrastructure due to a variety of reasons. Some of these remissioning hurdles include no existing natural gas pipeline infrastructure, the limited availability of wood for biomass due to its location on Lake Superior, challenging topography and geology for solar, and high costs to implement energy storage efficiently. After investigating several options for THEC, the Company determined that retirement in 2023 is the best option for customers and the site but will maintain the depreciable life of THEC until 2026.

Q. Are there any capital additions for THEC in the 2024 test year Budget?

A. No, there are no capital additions to THEC in the 2024 test year. However, while not a capital addition, it is important to recognize that THEC will, as a retired facility, require ongoing O&M even beyond December 31, 2026, the date the Commission set for a sunset for THEC expenses in the 2021 Rate Case.

Q. Please explain the O&M requirements of THEC.

A. O&M expense at THEC can be separated into two distinct areas. While the Commission has set a sunset date of 2026 for THEC expenses, ongoing O&M will still be required to comply with regulations past 2026 at the ash cell adjacent to the plant. These costs include, but are not limited to, ash cell vegetation management, ground-water monitoring, electric utilities at a storage building located on the property, and road maintenance.

The Company has set up separate tracking for these costs to separate ash cells O&M from any remaining plant expenses.

Q. Are there any changes to THEC since the 2021 Rate Case?

A. During the 2021 Rate Case, the Commission ordered: "Minnesota Power must establish sunset provision for Taconite Harbor Energy Center Operations and Maintenance (O&M) expenses, such that the Company will cease collecting these expenses once it begins decommissioning the facility."[2] Minnesota Power is in the process of requesting proposals for decommissioning the THEC facility and will have final estimates by the end of 2023. Decommissioning work at the site will begin in 2024. THEC's original

[2] 2021 Rate Case, Findings of Fact, Conclusions, and Order at Order Point 9 (Feb. 28, 2023).

coal pile has been removed and remediation work will be complete in the spring of 2024. All ash cells at THEC were closed prior to 2022.

As an outcome of the Company's 2021 Rate Case, the Commission ordered that "Minnesota Power must establish a sunset provision ending December 31, 2026, for the Company's recovery of Taconite Harbor Energy Center's remaining depreciation expense."[3] THEC has a remaining life through December 31, 2026, and will be fully depreciated as of January 1, 2027. When Minnesota Power retired THEC in March 2023, the remaining plant balances were transferred to regulated assets and the regulated assets are being amortized through 2026. Minnesota Power proposes that any excess amortization collected from customers after this date be tracked as a regulatory liability and refunded to customers in the Company's next rate review proceeding.

E. Bison Wind Energy Center

Q. What is Bison?

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

Q. How does the Company currently manage ongoing O&M 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 ("OEM") have escalation built into the contracts. This escalation is set by terms of these agreements, and the combined escalation in all of these contracts accounts for roughly 75 percent of the Bison O&M budget. The 2024 test year reflects this escalation.

[3] 2021 Rate Case, Findings of Fact, Conclusions, and Order at Order Point 8 (Feb. 28, 2023).

Q. What is the source of other O&M at Bison?

A. The remaining O&M for Bison includes labor and the plant materials and services that are necessary to maintain the balance of plant as well as unit availability for the facility but are outside the scope of the long-term service agreement with the OEM.

F. Taconite Ridge Energy Center

Q. Please describe 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 any capital additions for either Taconite Ridge or Bison in the 2024 test year?

A. Yes. The 2024 test year includes capital additions of $2.0 million Total Company ($1.8 million MN Jurisdictional) for Taconite Ridge and $0.7 million Total Company ($0.7 million MN Jurisdictional) for Bison. These costs include the anticipated replacement of generators and gearboxes that are showing signs that warrant replacement for assets to remain used and useful. 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 2024 test year capital additions also include projects at Taconite Ridge to address road erosion and turbine blade refurbishment and a project at Bison to purchase snow removal equipment due to the 80 miles of roads that require clear access to the wind turbines during the winter months for maintenance and repair.

G. Hydroelectric Generation Facilities

Q. Please describe Minnesota Power's hydro 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 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 there any planned capital additions at the hydroelectric stations included in the 2024 test year Budget?

A. Yes. The Company has identified capital additions of $6.3 million Total Company ($5.5 million MN Jurisdictional) at the hydro stations in 2024. The Scanlon and Blanchard hydroelectric stations have submitted letters of intent to the DOE for funding to support a full overhaul and new runner on Blanchard Unit 1 generator, and a replacement of Scanlon Unit 2 generator along with gate upgrades. The Blanchard project, if approved for DOE funding, is slated for the 2025 and 2026 construction season, while Scanlon's investment is multiyear with construction beginning in 2023 and completing in 2025. Along with these projects, Island Lake main dam stabilization is a project with considerable investment at the facility to meet FERC stability requirements. This is a two-year project that began in 2023 and will be in-service by year-end 2024.

Q. Are there any other changes to the Company's hydroelectric stations planned for 2024?

A. The Company continues to evaluate our historic hydroelectric station operations. These evaluations include the sale or lease of land no longer necessary to comply with FERC-required hydroelectric boundary requirements. The Company obtained Commission approval to begin land sales on October 14, 2021 in Docket No. E-015/PA-20-675. Minnesota Power subsequently began the process of platting the lots and offering lots to leaseholders once platting was completed. The first lots were offered to leaseholders in August 2022. Minnesota Power has received approximately $13 million from lot sales. Net proceeds will be returned to the Company's customers in the form of a regulatory liability that will be credited to customers in either a future rate case or through the Company's Renewable Resources Rider.

V. ENVIRONMENTAL COMPLIANCE

A. The Good Neighbor Rule

Q. What is the Good Neighbor Rule?

A. The GNR (also referred to as the Final Rule, Good Neighbor Plan, or Federal Implementation Plan ("FIP")) is a new U.S. Environmental Protection Agency ("EPA") regulation requiring significant national reductions in ozone-forming emissions of NOx from power plants and industrial facilities. The rule applies during the summertime period of May 1–September 30, known as "ozone season," and will affect 23 states, including Minnesota. The regulation will result in three new states being subject to ozone season requirements for the first time ever—Minnesota, Nevada, and Utah. It will also expand/alter existing requirements for numerous other states already subject to the ozone season interstate transport air quality requirements under the Cross State Air Pollution Rule ("CSAPR") program. While the GNR is the latest iteration of the CSAPR regulatory regime, along with its the geographic scope expansion and shift, the Final Rule also carries additional requirements and concepts not previously present under CSAPR, such as NOx rate limits, significantly reduced allowance budgets, and dynamic allowance budgeting. The GNR is also the first interstate transport rule to pull in non-utility sources of emissions, expanding CSAPR to also cover certain large industrial sources in all but three states (Minnesota, Wisconsin, and Alabama) among those subject to the rule. The Direct Testimony of Company witness Ms. Pierce provides further details on the GNR and the impact of allowances to the Minnesota Power fleet.

The original CSAPR was finalized in 2011 and implemented beginning in 2015, becoming the successor to the original transport regulation, the 2005-era Clean Air Interstate Rule ("CAIR"), which was vacated in 2008. The CSAPR originally required fossil fuel-fired coal-, gas-, and oil-fired facilities (specifically, electric utilities) in 27 states to reduce emissions to help downwind areas attain fine particle and/or ozone national ambient air quality standards ("NAAQS"). These reductions are accomplished primarily through CSAPR allowance programs that require a minimum of one allowance per ton of subject pollutant emissions during the applicable compliance period, with an additional surrender ratio triggered by certain circumstances.

If a company does not have sufficient allowances to comply, and/or cannot meet its rate-based NOx limits under the new GNR, it will be required to install controls, to curtail or cease operations, and/or to rely on allowance market procurement. Some Minnesota Power generating units, as with most other utilities nationally, are not granted sufficient NOx allowances under the new rule to continue operating "as is" into the future when compared to their historical NOx emissions.

Typically, the states implement federal requirements such as this through a State Implementation Plan ("SIP") process. In this case, the SIPs must ensure that emissions from within a state are prohibited from significantly contributing to nonattainment or interfering with maintenance of the 2015 8-hour ozone NAAQS. In the absence of a submitted and/or approved SIP, the EPA created a replacement regulatory structure in the form of a FIP. For the 2015 ozone NAAQS, the State of Minnesota submitted its SIP in 2018, which the EPA later proposed to disapprove in 2022. On February 13, 2023, the EPA finalized its partial disapproval of the State of Minnesota's SIP, along with full or partial disapproval for 20 other state SIPs, creating the opportunity for FIP (the Good Neighbor Rule) applicability to occur in those states. The GNR was finalized soon after (March 15, 2023), then published in the Federal Register on June 5, 2023, with an effective date of August 4, 2023.

On April 14, 2023, a coalition of parties co-filed challenges to the EPA's final Minnesota SIP disapproval, submitting a petition for reconsideration and stay to the EPA and a petition for judicial review to the United States Court of Appeals for the Eighth Circuit. The parties are challenging and requesting reconsideration of certain technical components of the EPA's review and subsequent partial disapproval of the state of Minnesota's SIP, including the rulemaking process, air modeling practices, and other emissions inventory aspects. On May 31, 2023, the parties filed a "Motion to Stay the SIP Disapproval" with the Eighth Circuit Court, which granted the stay on July 5, 2023, precluding the ability for the GNR to take effect in the State of Minnesota while a stay remains in effect. Subsequently, on August 4, 2023, the parties also filed challenges against the FIP rule itself, in the form of a Petition for Administrative Reconsideration and Stay to the EPA, as well as a Petition for Judicial Review to the Eighth Circuit Court.

The Company therefore does not currently anticipate that the State of Minnesota will be subject to compliance obligations for the shortened GNR 2023 ozone season, which would have gone into effect on August 4, 2023, without the stay issued on July 5, 2023. Future compliance obligations and timing will depend on the eventual resolution of the Eighth Circuit stay in the SIP disapproval case, as well as the ultimate disposition of the August 4, 2023, FIP challenge filings.

Q. How are NOx allowances currently handled?

A. Under prior iterations of the annual CSAPR/CAIR programs applicable in the State of Minnesota, an adequate number of NOx allowances were historically granted to cover compliance obligations at affected Company units, and the Company has therefore not needed to purchase NOx allowances before now. Circumstances have changed under the new GNR due to the insufficient number of NOx allowances granted by the EPA to the Company's affected units subject to the GNR. Because mechanisms do not already exist to recover NOx allowance costs, the Company is working expeditiously to develop internal and external allowance procurement and funding processes and practices.

Q. What is Minnesota Power asking of the Commission in this current rate case?

A. NOx allowance costs have been included in the 2024 test year. Minnesota Power believes that the best way to track and recover the costs and revenues of NOx allowances is in the Company's FAC Rider. Therefore, the Company requests that the Commission approve NOx allowances to be recovered through the FAC Rider as sulfur dioxide ("SO_2") allowances are recovered, as these allowances relate directly to the amounts of fuel used in the Company's generating facilities, rather than through base rates effective with the implementation of final rates in the current rate case proceeding.

Because of the uncertainty with pending litigation around implementation timing of the GNR, the Company decided to remove NOx allowance costs from its interim rate request. This is a voluntary adjustment to ensure that customers do not pay for allowance costs that may be delayed into and beyond the 2024 test year. Therefore, Minnesota Power is not factoring NOx allowances into its interim rate calculation.

Q. Why does Minnesota Power believe NOx allowances should be included in the FAC Rider?

A. Because the level of allowances necessary for operation will directly correlate with Minnesota Power's generation decisions and fuel use (and therefore will likely vary significantly from year to year), it will be important to consider these costs as a part of generation dispatch decisions, along with fuel, purchased power, and other costs which currently flow through the FAC Rider. As described in the following section of my Direct Testimony, the energy landscape has changed over the past several years and it has become more important to consider variable costs of thermal generation when making economic dispatch decisions. Additionally, the FAC Rider review process has changed since the Commission last considered including NOx allowances in the FAC Rider (Docket No. E999/CI-03-802), as discussed in the Direct Testimony of Company witness Ms. Pierce.

Q. What are the estimated costs included in the test year base rate O&M for NOx Allowances?

A. The total amount of NOx allowances included for the HREC and Laskin facilities for the 2024 test year is $10,763,360, as shown in Table 5.

Table 5. 2024 NOx Allowance Budget*

	MWhs	NOx Tons	NOx Allowances	Allowance surplus/shortage	Allowance Cost	Total Cost
	[TRADE SECRET DATA BEGINS					
BEC3	[redacted]					
BEC4						
Laskin 1						
Laskin 2						
HREC 3						
HREC 4						
						TRADE SECRET DATA ENDS]
Total NOx Allowance Cost						**$10,763,360**

*Total Company

Q. Has the Company previously asked the Commission to allow the Company to handle these allowances differently?

A. In the Company's 2009 rate case (Docket No. E015/GR-09-1151), Minnesota Power initially proposed to recover expenses and revenues relating to NOx emission allowances through the fuel clause rider, like the way it recovers SO_2 emission allowances. However, the Department of Commerce ("Department") proposed delaying a determination until there was a greater likelihood that allowance revenues or expenses related to NOx emissions would be incurred, and until certain marketplace uncertainties—such as the future of the Clean Air Interstate Rule—were resolved. In Rebuttal Testimony, Minnesota Power agreed with this recommendation.

Q. Has the overall generation market experienced changes that support a fresh look at this approach?

A. Yes. Given the overall market changes and the way in which the Company's generating units are dispatched in the market, as discussed by Company witness Ms. Pierce in her Direct Testimony, the Commission should grant a variance under Minn. R. 7829.3200 and include NOx allowances in the FAC Rider, as it has allowed the Company to do for SO2 allowances. This change will allow the Company to align cost recovery with changes to the regulatory and dispatch environment.

B. <u>Generation Operations Reagents</u>

Q. What are Generation Operations reagents?

A. Reagents are used at certain Minnesota Power generation facilities, specifically at BEC, for emissions reductions purposes. The reagents are introduced during combustion or post combustion and use kinetics to drive pollutants into forms that can be scrubbed or removed from the flue gas streams. The reagents can also be used to avoid the formation of certain pollutants.

Q. What types of reagents does the Company use?

A. The main chemicals consumed during the combustion or post-combustion process include: urea, ammonia, lime, limestone, activated carbon, and halogenated activated carbon. Urea is used in BEC4 for NOx reduction while ammonia is used in BEC3 for NOx reduction. Limestone is utilized at BEC3 for SO_2 control and BEC4 uses lime to control SO_2. BEC3 uses a standard activated carbon to remove mercury, while BEC4 uses a halogenated activated carbon to reduce mercury.

Q. How are the costs of these reagents currently handled by the Company?

A. Reagent costs are currently estimated each year during the budget cycle and are included in base customer rates. These reagent costs are directly related to, and estimated based on, the production of the units (which production is directly related to the fuel used) and can fluctuate considerably after they are estimated.

Q. Does the Company have any requests pending before the Commission regarding reagent costs?

A. Yes. As part of Docket No. E015/M-22-547 ("Reagent Docket"), Minnesota Power made a filing in 2022 requesting that the Commission approve accounting for reagent use in the FAC Rider mechanism, rather than in base rates, as authorized by Minn. Stat. § 216B.16, subd. 7, which provides that the Commission "may permit a public utility to file rate schedules containing provisions for the automatic adjustment of charges for public utility service in direct relation to changes in . . . prudent costs incurred by a public utility for sorbents, reagents, or chemicals used to control emissions from an electric generation facility." Company witness Ms. Pierce provides additional testimony on reagents and the FAC Rider mechanism.

Q. What is the current status of the Reagent Docket?

A. The Reagent Docket was suspended at Minnesota Power's request in a letter dated March 28, 2023, before the Commission decided on the issue. At that time, the Company was preparing for the current rate request and ultimately determined that including the reagent request in the rate case proceeding would provide a better forum for vetting the request. The contested case proceeding will allow the issue to be considered in the broader context of Company operations and changes to energy markets.

Q. What is the Company requesting in this rate case regarding reagent costs?

A. Similar to the treatment of NOx allowances in this case, Minnesota Power is requesting that reagent costs be moved to the Company's FAC Rider effective with the implementation of final rates in this rate proceeding. Minnesota Power is also requesting Commission approval to formally withdraw the Reagent Docket, because the request in that docket is now being considered in the current rate case.

Q. Has the Company sought Commission review of reagent costs and recovery in a prior rate case?

A. Yes. In Minnesota Power's 2016 Rate Case, Docket No. E015/GR-16-663 ("2016 Rate Case"), the Company asked the Commission to approve accounting for the cost of reagents through the FAC Rider mechanism. In that case, the Department opposed FAC Rider recovery, arguing that limiting recovery of reagent costs to base rates gives Minnesota Power an incentive to minimize these costs between rate cases. The ALJ agreed with the Department and recommended the Commission deny the Company's request. The Commission agreed with the ALJ in the 2016 Rate Case, leaving reagent costs in the Company's base rates.

Q. Has the Commission addressed reagents in any other utility dockets since the 2016 Rate Case?

A. Yes. In Otter Tail Power Company's 2020 rate case, Otter Tail Power Company requested, and the Commission approved, recovery of reagent costs through its energy adjustment rider (Docket No. E017/GR-20-719). In that proceeding the Commission noted that the Legislature "clearly contemplated the possibility of reagent cost recovery" through a rider and that "[i]f reagent costs do begin to rise disproportionately, the Commission will have the opportunity to investigate further and modify recovery in future" rider proceedings. Minnesota Power is requesting the same treatment in this case.

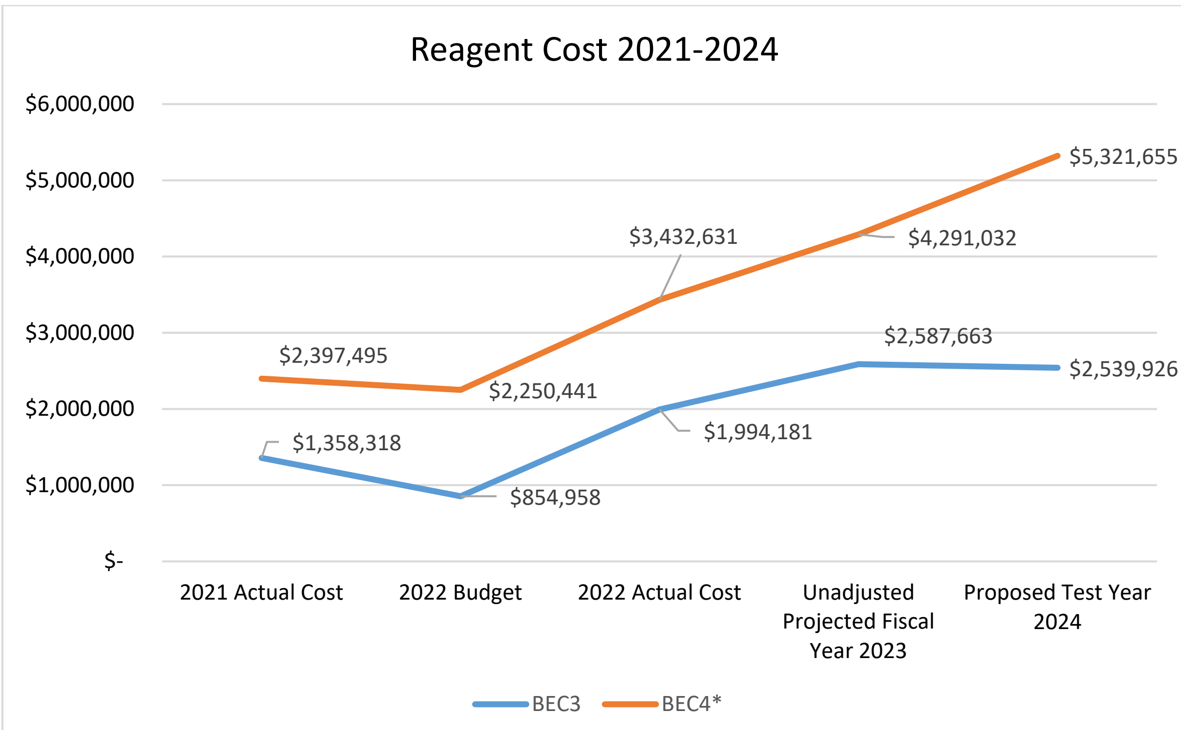
Q. How do recent generation resource operations and market pricing incentivize efficiency and cost control of reagents?

A. In the past several years, utilities have changed power supply to more renewable generation sources, the MISO market has become more volatile, and thermal generation has been subject to increased cycling and variable dispatch. As a result, thermal generation units, which were once treated as a fixed resource, are now operating as a variable resource. Costs that are directly incurred with running the unit, such as reagents, also become variable in nature and are included in the overall cost of operation of the facility.

As these costs become more variable, there is more volatility from year to year and it becomes more appropriate to recover the costs in the FAC Rider, where customers pay only for the costs incurred. Additionally, changes in the power supply make it more important to align all the variable costs of a thermal generating unit when making dispatch decisions, so that the full environmental cost is considered at the time a power supply decision is made. If these environmental costs are fixed in base rates, the incremental cost of running a thermal generating unit may be artificially low when compared to non-thermal resources. Aligning both the revenue and expenses of thermal generation provides the best cost signals for economic dispatch. Including reagent costs in the FAC Rider would also allow further support for the use of the economic dispatch model for these coal-fired generation resources.

Figure 5 provides reagent costs from 2021 through the 2024 test year. In the 2024 test year, BEC3 has a scheduled 49-day spring maintenance outage, so both BEC3 and BEC4 have a commodity escalation of 20 percent and 25 percent on carbon and limestone, respectively.

Figure 5. 2021-2024 Reagent Costs



*BEC4 includes WPPI share (Total Company)

Q. What additional factors should be considered when determining how to account for reagent costs?

A. The MISO market and the changing power supply to a more renewable generation source has impacted thermal generation, which is now subjected to increased cycling and variable dispatch more than ever, as illustrated by Figure 5 above for reagent costs from 2021. Leaving both revenue and expenses in base rates could lead to a mismatch in cost signals when making dispatch decisions, which could result in an "artificially" low cost of coal-fired baseload generation, increased rate case filings, greater revenues or expenses in between rate cases, and cash flow issues. The ability to account for both revenue and expenses in the FAC Rider aligns costs to the cost causers in a timelier fashion. Further, as Company witness Ms. Pierce discusses, the use of reagents is a piece of the overall market price of a unit and should be treated in a similar fashion in ratemaking treatment by including these costs in the FAC Rider. Finally, the FAC Rider review and compliance process will allow the Department and the Commission to monitor reagent pricing and make cost recovery adjustments in the event that regent costs begin rising disproportionately.

Q. Please summarize the Company's request as it relates to reagents.

A. Minnesota Power respectfully requests that the Commission acknowledge the market changes, discussed by Company witness Ms. Pierce and myself in Direct Testimony, for the Company's generation resources and how the cost of reagents interacts with market pricing. Allowing cost recovery for reagents in the FAC Rider mechanism will not only allow alignment of these costs with actual market dispatch of these resources but will ensure that the Department and Commission can evaluate these costs in the annual FAC Rider filing, without the need to wait until a future rate case. Finally, allowing Minnesota Power to recover reagent costs in the FAC Rider mechanism would be consistent with the Commission's recent decision to allow Otter Tail Power to implement similar cost recovery.

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 Bison, in 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 29 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 a number of positions of increasing responsibility within the areas of operation, maintenance, engineering, project management support, and support service functions. Each new role had an increased level of diversity in operating and maintenance protocols, as well as management of employees, budgets, and facilities.

Capital Additions (including Contra), 2024 Test Year

Area	Classification	Project Description	Total Company	MN Jurisdictional
Steam - Boswell Common	General Plant	Boswell Tait Radio System - 2024	447,000	397,769
Steam - Boswell Common	General Plant	24 Voice & Video Program - Boswell	96,316	85,708
Steam - Boswell Common	General Plant	24 Boswell EOL Network Switch Repl	58,721	52,254
Steam - Boswell Common	Steam Production	BEC NID Air Compressor Cross Tie	303,599	269,146
Steam - Boswell Common	Steam Production	BEC Admin Hallway Roof	99,996	88,649
Steam - Boswell Common	Steam Production	BEC "A" SVG Filter Replacement	135,293	119,940
Steam - Boswell Common	Steam Production	BEC-F C-15 Conveyor Belt Replacemen	148,111	131,303
Steam - Boswell Common	General Plant	Boswell Security System Upgrade	83,284	74,111
Steam - Boswell Common	Steam Production	BEC-F DCS Workstation Repl. & Virtu	281,517	249,570
Steam - Boswell Common	Steam Production	BEC-F DC-14 Dust Collector Replacem	198,298	175,795
Steam - Boswell Common	General Plant	BEC-F D10T Dozer Rebuild - B2007	590,276	525,265
Steam - Boswell Common	General Plant	BEC Brake, Lathe, V Mill, and Shear	308,430	274,460
Steam - Boswell Common	Steam Production	BEC-F C8 Crusher Building Hoist Rep	97,411	86,356
Steam - Boswell Common	Steam Production	BEC-F C6&C7 Structural Steel	127,473	113,008
Steam - Boswell Common	General Plant	BEC BOTTOM ASH/GYPSUM HAUL TRUCKS	963,160	857,080
Steam - Boswell Common	Steam Production	BEC TRAVELIG SCREENS OVERHAUL	138,345	122,646
Steam - Boswell Common	General Plant	BEC 3 EOL TAIT RADIO REPLACEMENT	509,166	453,088
Steam - Boswell Common	General Plant	Gen Ops Security System Upgrade	13,731	12,219
Steam - Boswell Unit 3	Steam Production	BEC 3 SCR CATALYST LAYER REPL	2,868,596	2,543,067
Steam - Boswell Unit 3	Steam Production	BEC 3 FABRIC FILTER BAG REPLACEMENT	1,535,440	1,361,198
Steam - Boswell Unit 3	Steam Production	BEC-3C BOILER CIRC PUMP	139,000	123,226
Steam - Boswell Unit 3	Steam Production	BEC 3A & 3B CIRCULATING WATER PUMP	160,000	141,843
Steam - Boswell Unit 3	Steam Production	BEC-3 HRH INSULATION REPLACEMENT	142,000	125,886
Steam - Boswell Unit 3	Steam Production	BEC 3 INSULATION FOR FAC INSPECTION	53,000	46,986
Steam - Boswell Unit 3	Steam Production	BEC 3D MILL EXHAUSTER OVERHAUL	405,000	359,041
Steam - Boswell Unit 3	Steam Production	BEC 3 TURBINE-GENERATOR OVERHAUL	3,311,553	2,935,758
Steam - Boswell Unit 3	Steam Production	BEC 3 COOLING TOWER STRUCTURE REBUI	542,500	480,937
Steam - Boswell Unit 3	Steam Production	BEC BOTTOM ASH PIT COLUMNS	84,500	74,911
Steam - Boswell Unit 3	Steam Production	BEC 3 2B FGD AIR COMPRESSOR	187,000	165,779
Steam - Boswell Unit 3	Steam Production	BEC-3 BOILER TUBE REPLACEMENT	1,376,000	1,219,852
Steam - Boswell Unit 3	Steam Production	BEC-3 BURNER REPLACEMENT	1,016,000	900,704
Steam - Boswell Unit 3	Steam Production	BEC 3 MBFP BARREL OVERHAUL	393,404	348,761
Steam - Boswell Unit 3	Steam Production	BEC 3 FGD ABSORBER TANK LEVEL INDIC	38,000	33,688
Steam - Boswell Unit 3	Steam Production	BEC 3 FGD MIST ELIMINATOR REPLACEME	443,000	392,728
Steam - Boswell Unit 3	Steam Production	BEC 3 BOTTOM ASH HOPPER REFRACTORY	189,000	167,552
Steam - Boswell Unit 4	Steam Production	BEC-4 Rebuild Atlas Copco 4B NID Bu	128,922	114,292
Steam - Boswell Unit 4	Steam Production	BEC-4 Replace 2 East Side Drum Safe	116,480	103,262
Steam - Boswell Unit 4	Steam Production	BEC-4 SH DSH Check Valve System	26,560	23,546
Steam - Boswell Unit 4	Steam Production	BEC-4 NID Reactor Duct Liner Repl.	121,016	107,283
Steam - Boswell Unit 4	General Plant	Boswell 4 Security System Upgrades	16,634	14,802
Steam - Boswell Unit 4	Steam Production	BEC-4 Mercury Umbilical Replacement	84,104	74,560
Steam - Boswell Unit 4	Steam Production	BEC-4 Old Diesel Generator Roof	38,108	33,784
Steam - Boswell Unit 4	Steam Production	BEC-4 4B Pulverizer Gearbox Overhau	1,196,172	1,060,431
Steam - Hibbard Renewable Energy Center	Steam Production	HREC Turbine Roof Replace	263,319	233,438
Steam - Hibbard Renewable Energy Center	General Plant	HREC VRTX Server Replacement	96,427	85,807
Steam - Hibbard Renewable Energy Center	Steam Production	HREC F Belt Replacement	115,333	102,245
Steam - Hibbard Renewable Energy Center	Steam Production	HREC U4 Grate Overhaul	548,292	486,072
Steam - Hibbard Renewable Energy Center	Steam Production	HREC Ash System Overhaul	110,527	97,984
Steam - Hibbard Renewable Energy Center	Steam Production	HREC U4 Cinder Reinjection Piping	88,342	78,317
Steam - Hibbard Renewable Energy Center	Steam Production	HREC U4 A Turbine Condensate Pipe	103,329	91,604
Steam - Hibbard Renewable Energy Center	Steam Production	HREC U3 Turbine Valve Overhaul	393,395	348,753
Steam - Hibbard Renewable Energy Center	Steam Production	HREC U3 Header Replacement	1,457,412	1,292,025
Steam - Hibbard Renewable Energy Center	Steam Production	HREC Blanket	100,000	88,652
Steam - Laskin Energy Center	Steam Production	LEC 2024 BLANKET	100,000	88,652
Steam - Laskin Energy Center	General Plant	24 Voice & Video Program - Laskin	125,000	111,233
Steam - Laskin Energy Center	General Plant	LEC Security System Upgrades	22,398	19,931
Steam - Laskin Energy Center	Steam Production	LEC CIRC PUMP OVERHAUL	342,407	303,550
Steam - Laskin Energy Center	Steam Production	LEC U1 TURBINE GOV VALVES	57,606	51,069
Steam - Laskin Energy Center	Steam Production	LEC U2 TURBINE GOV VALVES	58,926	52,239
Steam - Laskin Energy Center	Steam Production	LEC U2 BOILER REFRACTORY REPL	79,345	70,341
Steam - Laskin Energy Center	Steam Production	LEC GREEN SAND MEDIA FILTER REPL	42,000	37,234

Capital Additions (including Contra), 2024 Test Year

Area	Classification	Project Description	Total Company	MN Jurisdictional
Steam - Laskin Energy Center	Steam Production	LEC INTAKE NETS REPL	127,060	112,642
Steam - Laskin Energy Center	Steam Production	LEC CONTROL ROOM & SERVER ROOM HVAC	196,395	174,108
Steam - Laskin Energy Center	General Plant	LEC VRTX SERVER REPL	97,323	86,604
Steam - Laskin Energy Center	Steam Production	LEC U1 BOILER INSULATION	144,971	128,520
Steam - Laskin Energy Center	Steam Production	LEC U2 BOILER INSULATION	174,975	155,119
Steam - Laskin Energy Center	Steam Production	LEC GE FILTER MEDIA REPL	72,000	63,829
Steam - Laskin Energy Center	Steam Production	LEC BOILER CHEMISTRY ANALYZER	78,000	69,149
Steam - Laskin Energy Center	Steam Production	LEC U2 BOILER FEEDPUMP CHECK VALVE	81,350	72,119
		Total Steam Generation:	**24,288,249**	**21,543,478**
Hydro - Blanchard HE Station	Hydro	BLA Replace Gate Hoist Car	861,526	763,760
Hydro - Blanchard HE Station	Hydro	Blanchard Replace U2 Head Gates	804,684	713,369
Hydro - Blanchard HE Station	General Plant	Voice & Video Program - Blanchard	20,000	17,797
Hydro - Blanchard HE Station	Hydro	Blanchard U1 Head Gate Sill Rehab	145,079	128,616
Hydro - Blanchard HE Station	Hydro	Blanchard Shop Stucco Rehab	119,541	105,975
Hydro - Island Lake Reservoir	Hydro	Island Lake Main Dam Stability	2,800,929	2,406,278
Hydro - Island Lake Reservoir	Hydro	Island Lake Concrete Rehab	471,539	405,099
Hydro - Little Falls HE Station	General Plant	24 Voice&Video Program-Little Falls	15,000	13,348
Hydro - Sylvan HE Station	Hydro	Sylvan Hydro Concrete Rehab	170,734	151,359
Hydro - Thomson HE Station	General Plant	Hydro VRTX Server Replacement	95,677	85,139
Hydro - Thomson HE Station	General Plant	24 Voice & Video Program - Thomson	25,000	22,247
Hydro - Thomson HE Station	Hydro	Hydro Steamer Trailer Replace	209,085	185,358
Hydro - Thomson HE Station	Hydro	Hydro Blanket Project	100,000	88,652
Hydro - Winton HE Station	Hydro	White Iron Stilling Well	34,537	30,617
Hydro - Winton HE Station	Hydro	Winton U2 Scrollcase Rehab	429,322	380,603
		Total Hydro Generation:	**6,302,653**	**5,498,217**
Wind - Bison	General Plant	24 Voice & Video Program - Bison	25,000	22,247
Wind - Bison	Wind Generation	BSN GENERATOR REPLACEMENT	101,605	90,075
Wind - Bison	General Plant	BSN VRTX SERVER REPL	99,893	88,891
Wind - Bison	General Plant	BSN HEAVY EQUIPMENT PURCHASE	522,000	464,508
Wind - Taconite Ridge	Wind Generation	TREC BLADE BLANKET 2024	513,686	455,393
Wind - Taconite Ridge	General Plant	24 Voice & Video Program-Tac Ridge	15,000	13,348
Wind - Taconite Ridge	General Plant	TREC VIDEOSCOPE	48,737	43,369
Wind - Taconite Ridge	Wind Generation	TREC ACCESS ROAD IMPROVEMENTS	377,961	335,070
Wind - Taconite Ridge	Wind Generation	TREC GEARBOX REPLACEMENT	1,075,728	953,655
		Total Wind Generation:	**2,779,610**	**2,466,555**
		Total Solar Generation:	**-**	**-**
		Total Generation:	**33,370,512**	**29,508,250**