Direct Testimony and Schedule
Joshua J. Skelton

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-19-442

Exhibit ________

GENERATION

November 1, 2019

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I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Joshua J. Skelton 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 – Generation Operations for Minnesota Power and ALLETE Safety.

Q. Please summarize your qualifications and experience.

A. I am originally from Hoyt Lakes, MN. I hold a Bachelor of Science degree in chemical engineering from Michigan Technological University, in Houghton, Michigan, and a Master of Science degree in engineering management from the University of Minnesota – Duluth. I am a licensed professional engineer in the State of Minnesota. I joined Minnesota Power at the Laskin Energy Center as an engineering intern in 1999, and became a full-time employee and engineer in 2001. In 2004, I was promoted to the Maintenance Superintendent role. I was named Renewable Operations Business Manager at the Rapids Energy Center in 2007, working directly with our customer, UPM Blandin. In 2009, I was promoted to Thermal Business Operations Manager at the Boswell Energy Center. In 2014, I was promoted to General Manager of Thermal Operations, and in August of 2016, I was promoted to Vice President – Generation Operations for Minnesota Power. With additional workforce transition continuing into 2019, I was assigned direct leadership of the ALLETE Safety team. As the Vice President – Generation Operations and ALLETE Safety, I am responsible for all of the generating facilities of Minnesota Power including wind operations, thermal operations, hydro operations, co-generation operations, and various support services. I also have responsibilities for the corporate safety professionals and programs at ALLETE. These work areas include approximately 260 employees, with approximately 180 of those employees as members of International Brotherhood of Electric Workers ("IBEW") Local 31.

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 our last rate case (Docket No. E015/GR-16-664) ("2016 Rate Case"), the Company has continued to make significant 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 2020 test year and review various cost control measures that Generation Operations has put into place.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring the following exhibits:

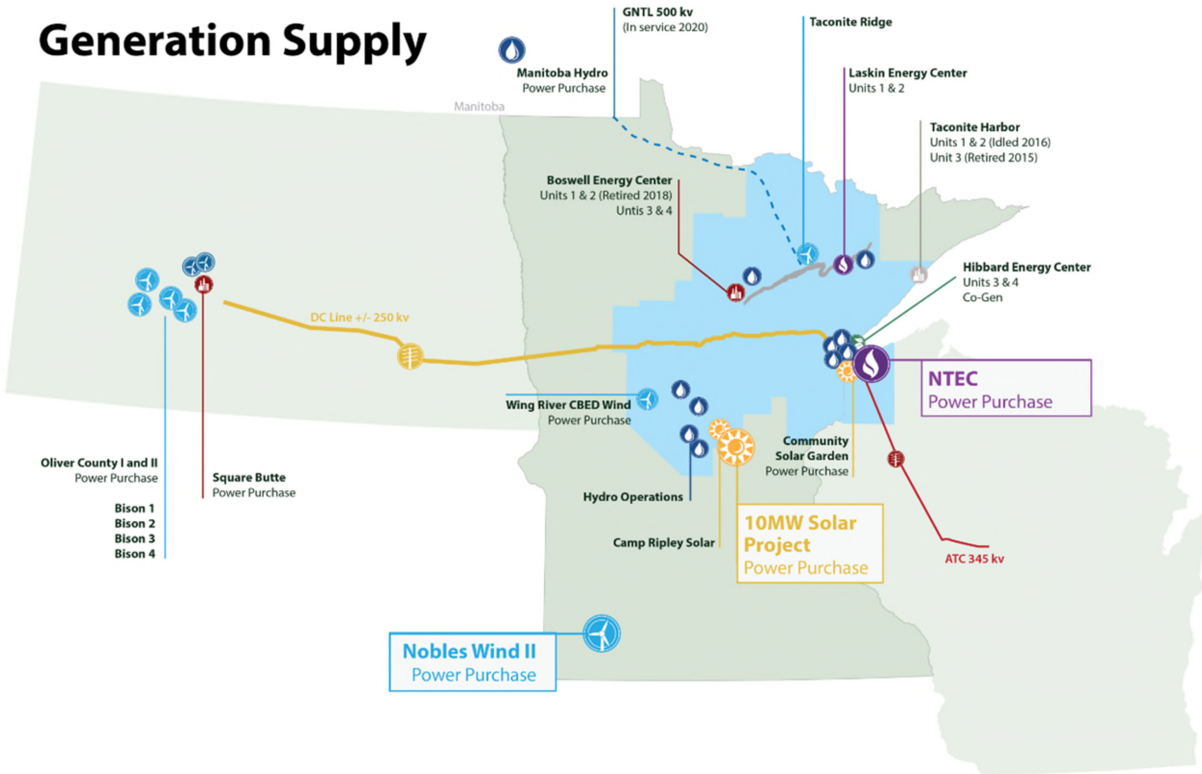
- MP Exhibit ___ (Skelton), Direct Schedule 1 – Generation Operations 2020 Test Year Capital Additions

II. GENERATION FLEET TRANSFORMATION

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

A. Minnesota Power's generation facilities have a net maximum capability of nearly 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 combine with a number of Power Purchase Agreements to supply energy for our approximately 145,000 residential and commercial customers, 15 municipalities, and some of the nation's largest industrial customers. Figure 1 provides a graphical representation of Minnesota Power's generating portfolio.

Figure 1. Minnesota Power Generation Supply



Q. How has the Company's generation supply changed since the 2016 Rate Case?

A. Table 1 provides information on the Company's current generation portfolio, including the fleet transformation that the Company has undergone since I filed Direct Testimony in Minnesota Power's 2016 Rate Case.

Table 1. Minnesota Power Owned Generation

	Unit No.	Year Installed	2016 Net Capability (MW)	2019 Net Capability (MW)
Coal-fired Generation				
Boswell Energy Center ("BEC") in Cohasset, MN	1	1958	67	—(a)
	2	1960	67	—(a)
	3	1973	355	355
	4	1980	468(b)	468(b)
			957	823
Taconite Harbor Energy Center ("THEC") in Schroeder, MN	1	1957	75	75
	2	1957	75	75
	3	1967	--(c)	--(c)
			150	150
Total Coal-fired			1,107	973
Biomass/Coal/Natural Gas				
Hibbard Renewable Energy Center ("HREC") in Duluth, MN	3 & 4	1949, 1951	62	62
Laskin Energy Center ("Laskin") in Hoyt Lakes, MN	1 & 2	1953	110(d)	110(d)
Total Biomass/Coal Natural Gas			172	172
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
Total Company Generation			**1,921**	**1,797**

(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.
(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. Thomson returned to full production in the fourth quarter of 2015. 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.

Q. Have any Company generation resources been retired since the 2016 Rate Case?

A. Yes. Boswell Unit 1 ("BEC1") and Boswell Unit 2 ("BEC2") were retired on December 26 and 27, 2018, respectively. I discuss these retirements and the resulting impacts of these retirements further in my Direct Testimony.

Q. Has the Company added any generation resources since the 2016 Rate Case?

A. While it has not added any Company-owned generation resources since the Commission issued its final rate Order in our 2016 Rate Case, we have added other generation resources to our energy supply portfolio.

In 2017, 10 MW of solar generation were commissioned at Camp Ripley, near Little Falls, Minnesota. This resource was brought online during the pendency of the 2016 Rate Case and is not part of this filing. While this resource is not currently owned by Minnesota Power, the Company is obligated to make the financing payments for the solar array and has the option to purchase the solar array at the end of the financing term. As described later in my testimony, the Company is not including costs for the Camp Ripley financing payments (or other solar costs incurred to meet the Solar Energy Standard) in the current rate proceeding. Additionally, we have continued supporting customer-owned installations of distributed energy resources as a part of our energy supply portfolio. I discuss these in Section IV.G of my testimony, and Company witness Mr. Frank L. Frederickson provides additional information on these resources in his Direct Testimony.

III. GENERATION OPERATIONS BUDGETING

A. 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 Mr. Joshua G. Rostollan. Generation Operations does augment the budget development process discussed by Mr. Rostollan, by including an additional level of review by the Project Review Committee prior to presenting a budget to the Vice President for approval.

Q. Who comprises the Project Review Committee?

A. The Project Review Committee is comprised of principal engineers, budget analysts, reliability engineers and Generation Operations leadership.

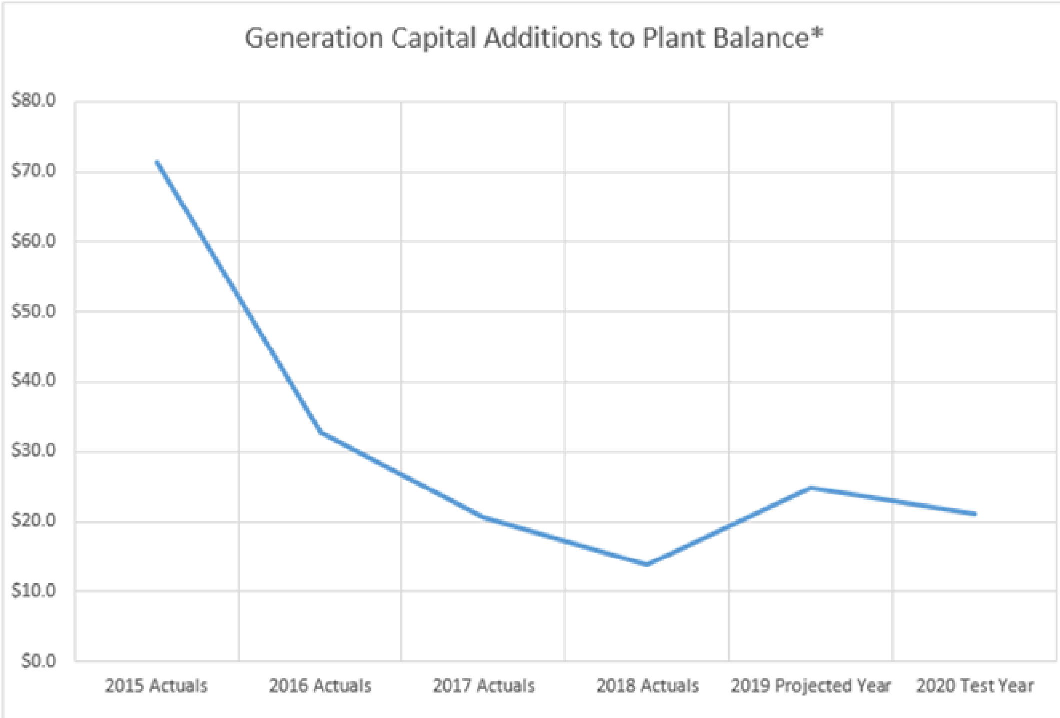
Q. What is the role of the Project Review Committee in the budget process?

A. Generation Operations' project budgets must be approved by the Project Review Committee before they are included in the Generation Operations budget that is then presented to the Minnesota Power Board of Directors and the ALLETE Board of Directors for approval. The Project Review Committee is a group of experienced individuals who are responsible for ensuring that capital projects within Generation Operations are effectively and efficiently aligned with Minnesota Power's overall business strategy to identify and utilize resources, install appropriate project management process and controls for transparency, and also to manage contingency and risk related to the Generation Operations work area, as a whole. Projects are presented to the Project Review Committee for additional vetting. The Project Review Committee may approve a project, send the project back for additional review or information, or deny approval of a project before the project is included in the Company's capital budget. A complete list of the planned 2020 additions can be seen in MP Exhibit ___ (Skelton), Direct Schedule 1.

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

A. The Company's last five years of Generation Operations capital additions are illustrated in Figure 2. Overall, capital additions for Generation Operations have decreased since 2015. Further, since 2017, capital additions have averaged out to a nearly flat level, with the 2020 test year only slightly higher than the 2017 actuals.

Figure 2. Capital Additions for Generation Operations – Total Company



**Amounts may include Intangible & General Plant additions.*

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

A. Generation Operations' additions to plant in-service for 2018 totaled $13.8 million Total Company ($11.8 million MN Jurisdictional),[1] 2019 projected year totals $24.7 million Total Company ($21.4 million MN Jurisdictional), and 2020 budget totals $21.0 million Total Company ($18.3 million MN Jurisdictional). Table 2 illustrates the Total Company additions made by location. Table 3 illustrates the Minnesota Jurisdictional 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

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[1] A summary of allocation factors used across the Company for purposes of calculating the Minnesota Jurisdictional totals is provided with the Direct Testimony of Company witness Mr. Stewart J. Shimmin at MP Exhibit ___ (Shimmin), Direct Schedule 1—Guide to Minnesota Power's CCOSS, at Table 4.

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

Table 2. Generation Fleet Capital Plant Additions (including Contra Allowance for Funds Used During Construction ("AFUDC")) – Total Company

Capital Plant Additions (including Contra) -- Total Company	2018 Actuals	2019 Projected Year	2020 Test Year
Steam Generation	$7.0	$21.4	$16.6
Boswell Common	$3.8	$3.0	$0.6
Boswell Unit 1	($1.4)	-	-
Boswell Unit 2	($0.8)	-	-
Boswell Unit 3	$3.4	$14.4	$0.5
Boswell Unit 4	$1.5	$2.9	$15.0
Hibbard Renewable Energy Center	$0.7	$0.8	$0.5
Laskin Energy Center	($0.1)	$0.4	-
Taconite Harbor Energy Center	$0.1	-	-
Hydro Generation	$6.1	$3.1	$3.6
Birch Lake Reservoir	-	-	-
Blanchard HE Station	$2.1	-	$0.7
Boulder Lake Reservoir	-	-	$0.8
Fish Lake Reservoir	-	-	$0.1
Fond du Lac HE Station	$0.2	-	$0.1
Island Lake Reservoir	$0.3	$2.7	-
Knife Falls HE Station	-	-	-
Little Falls HE Station	$0.4	-	-
Pillager HE Station	-	-	-
Prairie River HE Station	-	-	-
Rice Lake Reservoir	-	-	-
Scanlon HE Station	-	$0.1	$0.3
Sylvan HE Station	-	-	-
Thomson HE Station	$2.7	$0.3	-
Whiteface Reservoir	-	-	$1.6
Winton HE Station	$0.4	-	-
Wind Generation	$0.4	$0.1	$0.8
Bison	$0.4	-	$0.1
Taconite Ridge	-	-	$0.7
Generation Other	$0.2	$0.1	-
Grand Total	**$13.8**	**$24.7**	**$21.0**

Amounts in millions.
Amounts may not total due to rounding.
Amounts may include Intangible & General Plant additions.

Table 3. Generation Fleet Capital Plant Additions (including Contra AFUDC) – MN Jurisdictional

Capital Plant Additions (including Contra) -- MN Jurisdictional	2018 Actuals	2019 Projected Year	2020 Test Year
Steam Generation	$6.0	$18.6	$14.5
Boswell Common	$3.2	$2.6	$0.5
Boswell Unit 1	($1.2)	-	-
Boswell Unit 2	($0.7)	-	-
Boswell Unit 3	$2.9	$12.5	$0.5
Boswell Unit 4	$1.3	$2.5	$13.1
Hibbard Renewable Energy Center	$0.6	$0.7	$0.4
Laskin Energy Center	($0.1)	$0.4	-
Taconite Harbor Energy Center	$0.1	-	-
Hydro Generation	$5.2	$2.7	$3.1
Birch Lake Reservoir	-	-	-
Blanchard HE Station	$1.8	-	$0.6
Boulder Lake Reservoir	-	-	$0.7
Fish Lake Reservoir	-	-	$0.1
Fond du Lac HE Station	$0.2	-	-
Island Lake Reservoir	$0.2	$2.4	-
Knife Falls HE Station	-	-	-
Little Falls HE Station	$0.3	-	-
Pillager HE Station	-	-	-
Prairie River HE Station	-	-	-
Rice Lake Reservoir	-	-	-
Scanlon HE Station	-	-	$0.3
Sylvan HE Station	-	-	-
Thomson HE Station	$2.3	$0.2	-
Whiteface Reservoir	-	-	$1.4
Winton HE Station	$0.4	-	-
Wind Generation	$0.4	$0.1	$0.7
Bison	$0.3	-	$0.1
Taconite Ridge	-	-	$0.6
Generation Other	$0.2	$0.1	-
Grand Total	**$11.8**	**$21.4**	**$18.3**

Amounts in millions.
Amounts may not total due to rounding.
Amounts may include Intangible & General Plant additions.

Q. What is driving the $21.0 million Total Company ($18.3 million MN Jurisdictional) in capital additions included in the 2020 budget?

A. The primary driver of the 2020 capital additions is the approximately $15.0 million Total Company that will be spent at BEC4 to complete regularly-scheduled and necessary critical turbine repairs and replacement of worn parts. The 2020 test year includes other capital additions related to ongoing, necessary, and prudent activities to maintain the Company-owned generation facilities.

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

A. Each project within a budgeted year has been previously reviewed by the Project Review Committee and assigned to a project manager. 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 monitoring systems, daily operation of a 24x7 facility can lend itself to unforeseen failures; the Company manages to its overall budget, and where an emergent issue presents itself within that year, certain projects may need to be delayed or replaced with projects that address emergent work that may have 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 scope, schedule, or management require that the project be reviewed by the Project Review Committee so as to balance the year's capital project projections and competing priorities while still assuring the safe, reliable, affordable and environmentally-compliant energy our customers expect.

B. O&M Budgets

Q. Describe Generation Operations' 2020 O&M budget.

A. The Generation O&M budget is based on expenses incurred while operating and maintaining the assets in our generation portfolio. Each budget at the work area level is developed through the collaboration of subject matter experts and a responsible budget owner, who identify and estimate prudent and practical operating and maintenance needs to support the production obligations of the units during the period of time for which the budget is being developed.

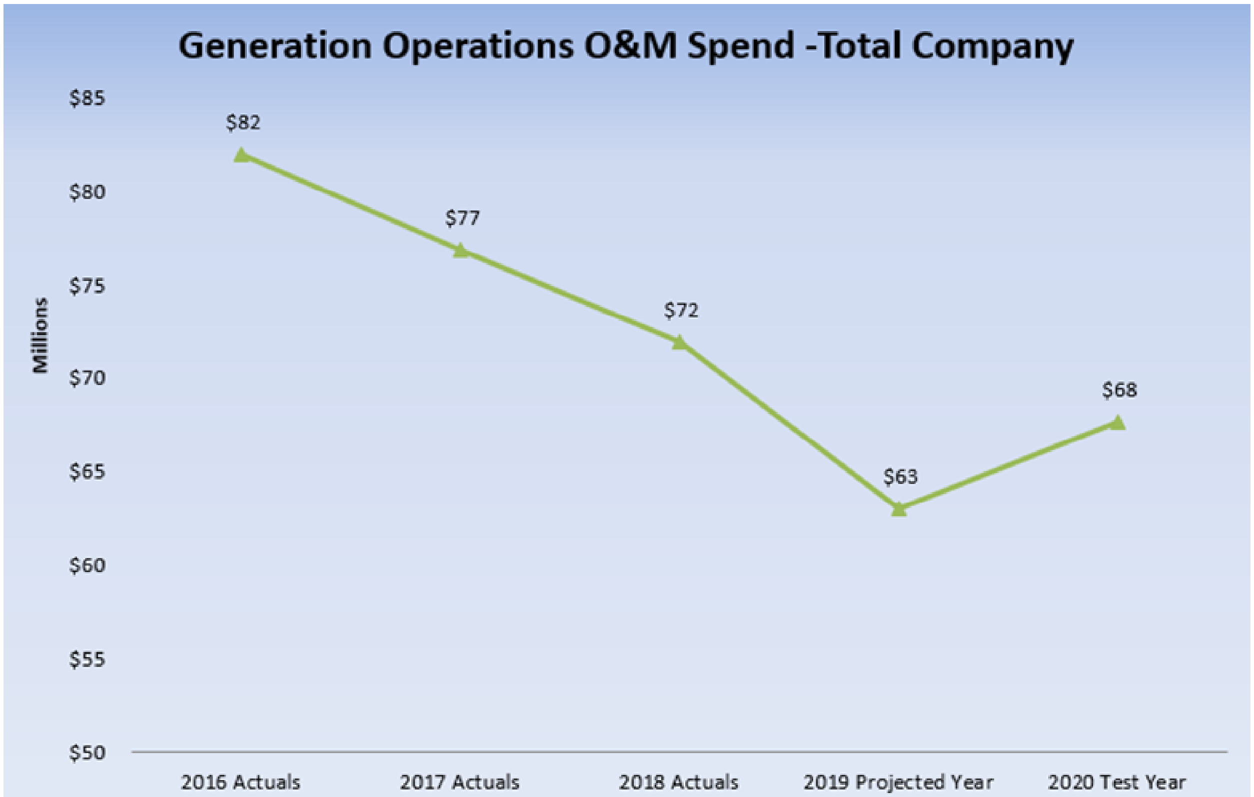
Q. What are the components of the Generation O&M budget?

A. The Generation O&M budget is comprised of expenses that are anticipated to be incurred 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 to perform necessary maintenance and repairs of these facilities to ensure their reliable operation. Another major cost driver of the O&M budget is the chemical reagents that reduce emissions at our coal-fired generation facilities. Generation 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 equipment purchases such as safety equipment, office supplies, and small tools and spare parts are included. These categories of costs are 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 since the 2016 Rate Case?

A. Yes. A summary of the Generation O&M is provided in Figure 3.

Figure 3. Generation Operations O&M



Q. Please explain the Generation Operations O&M trend over this period.

A. Figure 3 shows the trend of O&M costs in aggregate for the Generation Operations work area from 2016 Rate Case to the 2020 test year. The graph's trend highlights Generation Operations' commitment to reviewing and keeping costs at a competitive level while transforming the generation fleet. A more detailed definition of the Company's Federal Energy Regulatory Commission ("FERC") Account cost breakdown can be reviewed in the Direct Testimony of Mr. Rostollan.

Q. What steps have led to the decreasing trend in O&M for the Generation Operations sites in recent years?

A. In the 2016 Rate Case, my Direct Testimony highlighted a number of the practices and efforts the Generation Operations sites have deployed to contain costs as the fleet has transformed. These efforts have continued as the fleet transformation has continued, including the retirement of BEC1 and BEC2, and the subsequent rescaling of the

Generation Operations support services. Some specific examples of continued cost reduction supporting this trend are continued staffing organization design efforts at all Generation Operations sites and the reduction of contractor services as our talent is redeployed and maintenance practices have evolved.

Q. How has the Company also improved its budgeting process over the past few years?

A. The Company has increased its data validation practices of reviewing expenditures by cost types and has shifted to a more rigorous FERC Account view. This FERC Account review has been a shift from the historic practice of primarily focusing on work area and cost types ("responsibility centers"). Training has also been provided to staff who are responsible for budgeting O&M costs, as well as those who are writing work orders to execute work. This training has helped align the budgeting and work execution process to more accurately reflect the FERC Accounts where costs are accumulated. In addition, open labor positions are now typically budgeted with an embedded hiring lag so as to reflect a more realistic labor outlook given reasonable attrition assumptions across a number of the generating sites, as discussed in the Direct Testimony of Company witness Ms. Laura E. Krollman.

Q. What is Generation's O&M Budget for the 2020 test year?

A. The 2020 budgeted FERC level O&M for Generation is provided in Table 4 at the Total Company level and the Minnesota Jurisdictional level.

Table 4. Generation O&M for 2020 Budget*

	Total Company	MN Jurisdictional
POWER PRODUCTION		
Steam Power Generation		
Operation	125,282,750	108,398,342
Less: Fuel Costs (Fuel Costs in FERC 50100)	(102,825,751)	(88,928,851)
Total Operation	22,456,999	19,469,491
Total Maintenance	20,509,678	17,801,498
Total Steam Power Production Expenses	42,966,677	37,270,989
Hydraulic Power Generation		
Total Operation	1,651,581	1,432,142
Total Maint	3,833,745	3,324,371
Total Hydro Power Production	5,485,326	4,756,513
Other Power Generation (wind)		
Total Operation	5,295,438	4,612,168
Total Maint	11,885,217	10,351,667
Total Other Power Production	17,180,655	14,963,835
Other Power Supply Expenses		
Purchased Power	262,159,614	227,074,793
System Control and Dispatch	612,572	533,532
Other Expenses	1,436,769	1,251,383
Less: Purchased Power (FERC 55500)	(262,159,614)	(227,074,793)
Total Other Power Supply	2,049,341	1,784,915
Total Power Production Expenses	67,681,999	58,776,251

* Amounts may not total due to rounding

Q. Why is the 2020 O&M budget higher than the O&M for the 2019 projected year?

A. The 2020 O&M budget increase from 2019, is due, in part, to maintenance that is planned at BEC to support the reliability of the facility and the fuel handling systems. The increase also represents the escalation factors within the contracts for the Bison Wind Generating Facility ("Bison"). Additionally, the 2020 O&M budget reflects higher labor and benefit expenses based on current business needs and our expectations for compensation and benefits expense levels. In recent years, these types of increases have been offset through other cost reduction efforts or through the idling, retiring, or re-missioning of the Company's baseload coal generation resources. Given the current production planning and stabilization in the fleet transformation, such offsetting reductions cannot be maintained in perpetuity. Although the Company continues to scrutinize costs, certain increases are to be expected on a going-forward basis related to escalation and inflation in the Company's operating costs for labor and materials, which have been offset in recent years by reductions in headcount and one-time changes in operations at baseload coal generation facilities.

IV. GENERATION RESOURCES

A. <u>Boswell Energy Center</u>

Q. What is the Boswell Energy Center ("BEC")?

A. BEC, located in Cohasset, Minnesota, is Minnesota Power's largest thermal facility. 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. As I mentioned above, BEC1 and BEC2 were retired from operation in 2018. The two remaining operating units, Boswell Unit 3 ("BEC3") and Boswell Unit 4 ("BEC4") have a combined capability of approximately 823 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 355 MW, after turbine efficiencies were made to this asset in 2009. BEC4 was placed into service in 1980 and 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 improved the removal of other air pollutants. The operation and maintenance strategy for BEC3 and BEC4 is aligned with 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 Integrated Resource Plan filed by Minnesota Power on July 18, 2016 (Docket E015/RP-15-690) ("2015 IRP"), the Company recommended rerouting the flue gas from BEC1 and BEC2 through the air quality control systems of BEC3, to achieve emissions reductions and continue serving the region under lower emissions targets of modified air permit conditions. Such rerouting or other emissions control for BEC1 and BEC2 was necessary due to conditions imposed under the renewed BEC air permit that was to go into effect on January 1, 2019.

Upon review of the Company's recommendation regarding BEC1 and BEC2, the Commission ordered that the Company retire BEC1 and BEC2 no later than 2022. As a result, Minnesota Power re-evaluated the investments needed to maintain compliance with the air permit conditions that would be required if operation of BEC1 and BEC2 continued beyond December 31, 2018. Given the shortened economic life, Minnesota Power decided to retire BEC1&2 just ahead of the January 1, 2019, date on which the air permit conditions took effect. In Minnesota Power's 2009 rate case (Docket No. E015/GR-09-1151) and in Minnesota Power's 2018 Remaining Life Depreciation Petition (Docket No. E015/D-18-544), the Commission approved an end of life for BEC1 and BEC2 of 2022. When Minnesota Power retired BEC1 and BEC2 in December 2018, a regulated asset was set up to reflect this continued recovery through 2022. The regulated asset is being amortized through 2022. Please see the Direct Testimony of Company witness Ms. Marcia A. Podratz for additional information regarding the adjustment for the BEC1 and BEC2 regulated asset and accumulated amortization.

As it relates to BEC3 and BEC4, in the proceedings for the proposed Energy*Forward* resource strategy (Docket No. E015/AI-17-568), the Commission ordered the Company to make additional assessments of BEC3 and BEC4 in a "Baseload Retirement Study" and submit a Securitization Plan.[2] These are to be submitted with the Company's next Integrated Resource Plan, which is anticipated to be filed on October 1, 2020.

Q. What does "retirement" of BEC1 and BEC2 mean regarding the staffing of operations at BEC?

A. With the BEC1 and BEC2 retirements in late 2018, in addition to other fleet changes that have occurred with the Energy*Forward* strategy, the BEC staff completed a workforce planning exercise to align and optimize the staffing resources needed to operate the facility and support the remaining fleet after retirement of BEC1 and BEC2. This workforce planning exercise resulted in the elimination of 57 positions and a new operations and maintenance structure at BEC. This exercise also resulted in a rescaled support services group of technical and professional staff called "Generation Operations" at Minnesota Power's central support services group. This new BEC organizational structure is comprised of 160 people at BEC3, BEC4, and Fuel Handling.

Q. Please describe what the Company has done with the BEC1 and BEC2 assets as part of this retirement.

A. The BEC1 and BEC2 assets remain in place, disconnected from the utility system, and have been retired in a way so as to not pose a safety or environmental risk to the BEC staff and site. The decision to retire-in-place the BEC1 and BEC2 assets was carefully planned and executed so as not to impair the operation of BEC3 and BEC4. Because BEC1 and BEC2 were the first units to be constructed and placed in service at BEC, certain total-facility infrastructure was integrated into the BEC1 and BEC2 assets. As BEC3 and BEC4 were constructed, these units were tied into some of the critical BEC1 and BEC2 infrastructure.

Portions of the BEC1 and BEC2 infrastructure are needed to support BEC3 and BEC4, including the intake structure, service water pumps, electrical infrastructure, and

[2] The Commission also required development of a Securitization Plan in the 2016 Rate Case.

condensate make-up water systems. Prior to retirement, BEC1 and BEC2 also provided the steam heating needs of BEC. With the retirement of BEC1 and BEC2, a new auxiliary steam system had to be engineered and installed. This new auxiliary steam system now provides BEC heating needs from either BEC3 or BEC4 during the winter months. The system was placed into service in 2018.

Q. Beyond the changes to the BEC facility, are there other Minnesota Power systems impacted by the retirements of BEC1 and BEC2?

A. Yes. As discussed further in the Direct Testimony of Company witness Mr. Daniel W. Gunderson, the retirement of critically-located units such as BEC1 and BEC2 necessitate 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 2016 Rate Case?

A. The investment strategy for BEC3 and BEC4 is aligned with the reliability needs of our customers and current mission of the facility. BEC3 completed a regularly-scheduled turbine cycle maintenance outage on June 22, 2019. Along with turbine repairs, other projects undertaken during this planned outage included a selective catalytic reduction catalyst layer replacement, baghouse bag replacement, continuous emissions monitoring umbilical replacement, burner and boiler critical replacement of parts, refurbishment of the stack liner and the addition of a stack extension, replacement of a boiler circulating water pump, replacement of the main boiler feed pump discharge elbow, pulverizer overhauls, and air heater basket replacement. In total, the Company prudently added approximately $14.4 million Total Company ($12.5 million MN Jurisdictional) to plant in-service during the BEC3 spring turbine cycle outage to support the safe, reliable, and compliant operation of BEC3. This investment is aligned with the ten-year turbine major maintenance cycle for an asset of this class and function. Finally, as I discuss later in my testimony, the Company expended capital to achieve reduced fuels costs for Minnesota Power's customers.

Q. Does the 2020 budget include capital additions at BEC3?

A. Yes. BEC3 will require certain capital additions to coincide with routine maintenance intervals identifying overhauls or replacements needed. This work includes a coal pulverizer overhaul and a coal feeder control replacement as parts have reached obsolescence and the end of their useful life. These projects total $0.5 million Total Company ($0.5 million MN Jurisdictional). These estimates are based upon the last inspection period and scope identified for upgrade or replacement.

Q. Does the 2020 budget include capital additions at BEC4?

A. Yes. The 2020 capital additions for BEC4 are aligned with routine investment aimed at supporting the designed performance of the assets, replacing worn parts, critical maintenance to maintain efficiencies and environmental compliance, and supporting continued reliability to cost effectively serve as a baseload resource for Minnesota Power customers and the regional grid. The planned capital investment in 2020 is aligned with a ten-year turbine major maintenance cycle which identifies upgrades and replacements needed and requires a longer duration outage. These investments are reasonable and prudent capital additions to maintain the useful life of this asset for the continued safe, reliable, cost-effective, and efficient generation of electricity for our customers. Some of the planned projects for 2020 include pulverizer overhauls, replacement of the "Hot Reheat Line," overhaul of the BEC4 turbine (including a generator inspection), boiler and burner critical maintenance, station battery replacement, and a cooling tower structure replacement. In total, $15.0 million Total Company ($13.1 million MN Jurisdictional) in capital additions is planned to be placed in-service at BEC4 in 2020. This scope of work is aligned with our ten-year capital plan and scheduled life of BEC4.

Q. What is the schedule for the BEC4 capital additions you discuss above?

A. An eight-week outage is planned for BEC4 in 2020. Beginning in early 2020, materials needed to execute the planned projects will be ordered. The outage is scheduled to commence in Spring 2020 and is expected to be completed by Summer 2020.

Additional work will occur during the outage and in the months following. The projects will be put in service prior to year-end 2020.

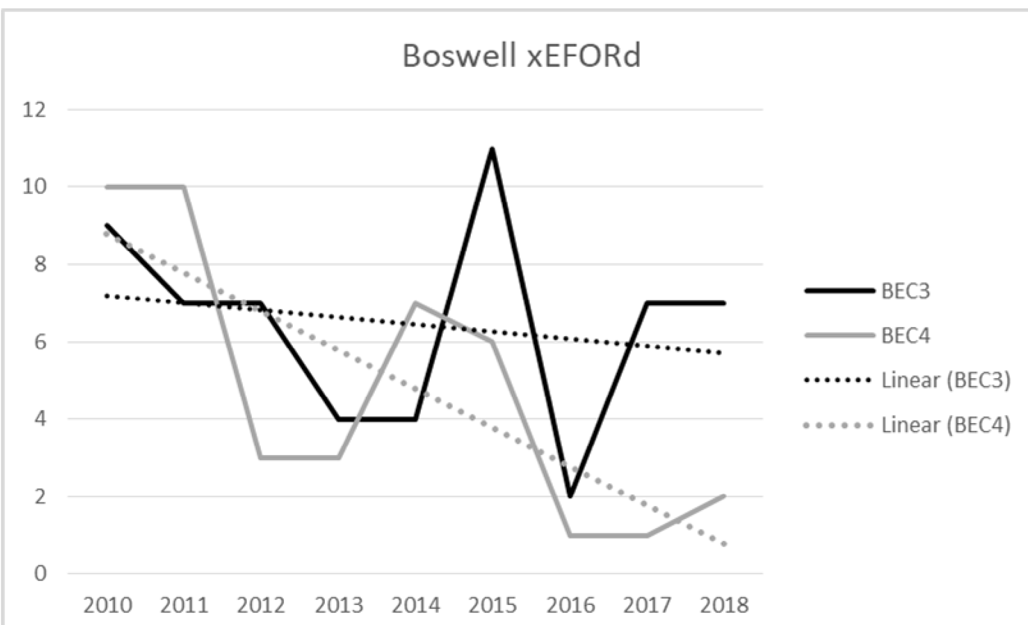
Q. Are there any capital additions for BEC1 and BEC2 in 2020?

A. No.

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 in many cases improves, the reliability of BEC3 and BEC4. Additionally, this work is necessary to align with the assets' maintenance schedules. Focused projects have led to an improved xEFORd trend in reliability over time for these critical baseload assets, as can be seen in Figure 4.

Figure 4. BEC3 and BEC4 Overall Reliability Trends



Q. What is "xEFORd"?

A. The industry metric for reliability, xEFORd (Equivalent Forced Outage Rate demand), was developed for non-baseloaded units and is now used for all dispatched generation types to help measure reliability of generation assets. xEFORd measures the probability that a unit will not be available to meet customer demand; the lower the xEFORd the more reliable the unit is. xEFORd measures forced outages and forced derates, which are tracked in a Generating Availability Data System for monitoring and reporting. Scheduled outages and derates (maintenance and planned) are not part of the xEFORd calculation, so it is used to indicate reliability of the units over a long period of time (typically annually). xEFORd omits forced outages that are out of management control, and is used by the Midcontinent Independent System Operator, Inc. ("MISO") to determine the capacity accreditation of each unit used for Resource Adequacy. MISO uses three years of historical performance data to calculate xEFORd. xEFORd is a component of MISO's Resource Adequacy program that ensures reliability for customers.

Q. What does this information mean for BEC3 and BEC4?

A. As shown in Figure 4, the reliability of BEC3 and BEC4 continues to trend in a positive direction, which is critical to support customer energy supply needs and create customer value. The overall reliability of BEC3 and BEC4 was tested during late January 2019, when an extreme weather event, the Polar Vortex, occurred across the Midwest with temperatures well below zero degrees Fahrenheit in our service territory. The reliability of these units and the resiliency of the Minnesota Power transmission system made it possible to serve customers even under these extreme weather conditions.

1. <u>Coal Combustion Residuals</u>

Q. What other benefits does BEC provide to customers?

A. BEC began marketing its fly ash in 2009 after the BEC3 environmental upgrades were completed. These environmental upgrades allowed for beneficial use of dry fly ash from BEC3 given the physical and marketable characteristics of the ash. Since 2013, nearly all of the fly ash generated by the BEC3 operations has been sold, and current contracts in place are estimated to generate revenues of approximately $2.2 million over the 2017 to 2020 period. It is estimated that this would offset approximately $1.8 million in anticipated capital and O&M costs at BEC ($0.6 million in O&M and $1.2 million in capital Total Company) by eliminating the handling costs and preventing additional estimated investment to accommodate its disposal in the ash landfill. An example of one of the benefits of the Company's efforts was the usage of BEC fly ash in the precast concrete risers installed at the Minnesota Vikings' US Bank Stadium in 2015. Other uses include several highway construction projects in northern Minnesota and in the Twin Cities metro area.

Q. Are there other potential beneficial uses for the BEC fly ash?

A. Yes. In addition to the BEC fly ash, Minnesota Power continues to explore other beneficial ash use markets, including BEC4 fly ash/scrubber material and BEC3 gypsum. These products have generated a small amount of revenue and have allowed Minnesota Power to explore other long-term resale options and offset expenses for our customers all while aligning with our environmental stewardship values.

Q. Are there other fly ash-related environmental considerations for the Company?

A. Yes. The Company continues to evaluate all coal ash impoundments/ponds that it controls under the Coal Combustion Residuals ("CCR") rule.

Q. What is the CCR rule?

A. The CCR rule sets federal compliance requirements for the disposal of coal ash in ash ponds/impoundments and dry ash landfills. The CCR rule was the Environmental Protection Agency's response to a 2008 dam failure at Tennessee Valley Authority's Kingston plant that released over one billion gallons of ash slurry. The spill devastated homes and local infrastructure and contaminated nearby waterways. Since first publication in the Federal Register (April 2015), portions of the rule have been litigated and revised, making compliance a moving target for industry. As a result of this changing regulatory landscape, Minnesota Power continues to explore projects and alternatives to achieve compliance and support competitive operation. This includes efforts to study the recovery and reuse of coal combustion products, as studies have indicated that ash recovery and marketing is not only the most prudent and reasonable alternative for the Company's compliance with the CCR Rule, but also minimizes impacts on the external world through beneficial reuse.

Q. What impact does the CCR Rule have on BEC's ash impoundments?

A. BEC's ash impoundments are subject to the requirements of the CCR Rule and ongoing revisions to that rule. The ash management strategy for BEC must include a migration toward alternative technology and operation to achieve compliance. In addition, compliance deadlines are subject to change under new rulemaking and will set the stage for Minnesota Power's overall compliance strategy.

Q. Are any of the projects Minnesota Power has identified as necessary for CCR rule compliance included in the 2020 budget?

A. While the Company plans to spend capital in 2020 related to CCR rule compliance, there are currently no projects related to CCR rule compliance scheduled to be placed in-service during 2020. The Company does, however, continue to monitor the current rulemaking efforts and, if conditions warrant, may accelerate certain projects that will be necessary for compliance with the CCR rule.

2. <u>Itasca Rail Initiative</u>

Q. What is the Itasca Rail Initiative?

A. The Itasca Rail Initiative is an effort that Minnesota Power undertook to allow the Company to obtain competitive rail delivery rates for BEC fuel and, in turn, reduce costs for our customers.

Q. Why was such an undertaking necessary?

A. The State of Minnesota is served by four major Class 1 Railroads: BNSF Railway ("BNSF"), Canadian National ("CN"), Canadian Pacific ("CP"), and Union Pacific ("UP"). Rail users on the Minnesota Iron Range only have access to the BNSF and CN lines. Within the Iron Range customer base, rail connections are generally only available to one of the two Class 1 railroads—either BNSF (as is the case for Minnesota Power's BEC) or CN. The lack of competitive rail in the region has led to a reduction in service quality, perceived higher rates for these captive shippers (i.e., shippers that have access to only one Class 1 Railroad), and has been considered an impediment to economic development in the area. BEC's status as a captive shipper has a direct impact on the rates Minnesota Power has to pay for rail deliveries to BEC.

Q. How were options to create additional access explored?

A. Studies performed for the Surface Transportation Board, the Federal agency tasked with the economic oversight of the railroad industry, found that rail competition at coal shipment destinations can have a significant impact on railroad pricing. Studies and testimonials from other utilities support the premise that railroad competition leads to lower transportation rates, and subsequently lower costs for fuel delivery, than are currently available in today's captive shipper situation. Creating this kind of competition would lead to lower costs for Minnesota Power's customers.

Q. How could competitive rail lead to lower costs for Minnesota Power's customers?

A. Because Minnesota Power's costs of fuel delivery are directly borne by its customers through the electric rate structure, a decline in such costs, resulting from competitive rail transportation rates, would lead to lower energy costs for Minnesota Power customers. Conversely, increases in the cost of coal delivery will be passed through to consumers in the form of higher electric costs. Effective rail competition would also provide pricing stability and protect ratepayers from volatility in fuel delivery costs.

Q. How does all of this relate to Minnesota Power and the Itasca Rail Initiative?

A. In early 2015 Minnesota Power began further studying the feasibility of building competitive rail to Minnesota Power's BEC and to serve the broader region. Given the captive rail environment in the region that I previously described, such an undertaking was the most effective way to create a regional competitive rail environment. The study work was broken into two parts: (1) the West Range Connector Project and (2) the Central & East Range Industrial User Access Study. Given the physical location of

BEC, Minnesota Power's involvement has been primarily on the West Range Connector Project, which looked at building a new connector railroad from near Taconite/Bovey, Minnesota, to Cohasset, Minnesota, a distance of approximately 11 to 18 miles, depending on route options. This line would expand rail service to allow CN and UP access to serve Itasca County, the BEC, and other West Range large industrial users, including iron mines and a paper mill, creating a competitive rail environment. Letters of support for the project came from most of our large industrial customers (UPM-Blandin, Boise, Essar, Magnetation, Minorca, Polymet, US Steel, and Verso). The local cities of Grand Rapids and Cohasset were also supportive stakeholders in the study process.

Q. Were any consulting resources contracted for purposes of this analysis?

A. Yes. To determine the feasibility of building the West Range Connector, an environmental scoping and pre-engineering assessment was completed by Krech Ojard & Associates, a Duluth engineering firm specializing in rail industrial transportation infrastructure projects. That firm took a stepwise approach that included determining the functional value to the industrial stakeholders, identifying environmental and community impacts, investigating and defining the required regulatory processes, estimating project costs, and developing the likely project ownership/financing/implementation structure. The study further expanded to include the development of rail routing alternatives, a proposed rail layout, and cost estimates for construction.

Q. What other actions did Minnesota Power undertake to achieve the same results as the possible Itasca Rail Initiative?

A. The Company continued conversations with various rail companies that could potentially connect to and use the proposed West Range Connector Project. In the end, leveraging the possibility of introducing competition led to lower transportation rates that were successfully negotiated with BNSF for 2019 to 2021. Although a captive rail customer, the Company showed that it is willing to explore all options related to competitive rail resource opportunities. The negotiated rates were significantly lower than typical captive rates and all savings are being passed on to Minnesota Power's customers. The activity also provided a significant first step with local economic development efforts to identify options for securing more competitive shipping costs to facilitate regional economic development that could support jobs lost due to the Company's baseload coal retirements.

Q. What is the current status of the Itasca Rail Initiative?

A. Given the specific regional concerns on the western Iron Range, the West Range Connector Itasca portion of the study was carried into a more detailed phase to include the vetting of options or potential scenarios for rail solutions with a higher priority and urgency given the impact to the local communities and customers, while the central and east range focus was limited to the feasibility of user access phase. The Central and East Range Study did not extend into these next phases and currently resides at the user connectivity and feasibility phase.

Q. Does Minnesota Power propose to recover the costs related to the Itasca Rail Initiative?

A. Yes. Minnesota Power proposes recovery of the $2.0 million Total Company of capital costs incurred for the Itasca Rail Initiative as a regulatory asset. Minnesota Power proposes amortizing the resulting regulatory asset over a five-year period. The effect of this amortization is discussed in the Direct Testimony of Ms. Podratz.

B. <u>Taconite Harbor Energy Center</u>

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 three units had an originally-designed generation capability of 225 MW. Minnesota Power acquired the facility in 2001 from the bankrupt LTV Steel Mining Company.

Q. What is the current operational status of the THEC units?

A. Minnesota Power ceased coal-fired generation at THEC Unit 3 ("THEC3") in May 2015, and the unit was retired-in-place. THEC Unit 1 ("THEC1") and Unit 2 ("THEC2") were idled in the fall of 2016. These two units remain available to be called upon as needed to provide regional reliability or provide market pricing protection for customers.

Q. Please explain what you mean by these two units remaining "available to be called upon as needed."

A. Through its integrated resource plan process, Minnesota Power identified that economic idling of these two units is in our customers' interest. These idled units could be restarted to maintain grid reliability of the bulk system both locally and regionally as system conditions require in both the short-term (i.e., unforeseen major transmission outage) and long-term (i.e., insufficient regional generation, transmission resources and large customer growth). Thus, THEC can be used when conditions require it to stabilize the bulk electric system until other generation or transmission alternatives can be executed. With Commission approval in the 2015 IRP, Minnesota Power idled THEC1 and THEC2 in the fall of 2016, with all coal-fired operations to cease at the facility by 2020. While these two THEC units are capable of being restarted from their present idled state to address transmission reliability issues, this would not be an instant turnaround. They remain available for resource planning and energy marketing purposes and serve as an important contingency in a rapidly changing regional energy landscape.

Q. Who decides if THEC1 and THEC2 are needed for these purposes?

A. Minnesota Power or MISO decides if these units are needed depending on system condition. For short-term or local reliability concerns Minnesota Power would determine if operating THEC1 or THEC2 is in the interest of customers. MISO decides if operating these units would resolve broader reliability issues on the bulk electric system and can call upon Minnesota Power to operate the assets.

Q. What is necessary for the Company to ensure THEC1 and THEC2 remain viable and available for these purposes?

A. To keep these units viable and available for these purposes, Minnesota Power must annually submit a letter signed by a Company officer demonstrating to MISO these resources are available for resource adequacy through the Planning Resource Auction and Organization of MISO States-MISO Resource Adequacy Survey. If the units are cleared in the annual auction, a Generation Verification Test Capacity test will be performed. The Planning Year 2019-2020 is the most recent period for which these two THEC units were made available to MISO for resource adequacy.

Q. Are there other benefits for customers to keeping these units and associated infrastructure available for use?

A. Yes, there is value for customers to maintain the reliability infrastructure and generation interconnection at THEC. Minnesota Power continues to investigate opportunities at the site for potential inclusion in its next Integrated Resource Plan, to be filed by October 1, 2020. The facility has several favorable attributes including a deep water port, rail line, and power generation infrastructure. These assets have been prudently maintained and invested in by the Company, meaning they could be used for alternative energy generation at the site or other industrial infrastructure in the future. Since the filing of Minnesota Power's 2015 IRP, the cost to interconnect new generation resources in MISO has risen. This has increased the value of maintaining the THEC infrastructure and interconnection for customers.

Q. Is it necessary to ensure THEC1 and THEC2 remain assets in Minnesota Power's power supply?

A. Yes. THEC1 and THEC2 are valuable assets for customers. By keeping these units idle, they are available for all the reasons explained above, and the Company preserves its strategic interconnection rights.

Q. What O&M expenses are reasonable and necessary to ensure availability of THEC1 and THEC2?

A. The O&M 2020 budget for the THEC is approximately $300,000 Total Company ($260,000 MN Jurisdictional). This budget includes minimal costs for site inspections, groundskeeping, electricity, storm water disposal, and environmental compliance tasks.

Q. Are any capital additions for THEC included in the 2020 test year?

A. No.

C. Hibbard Renewable Energy Center

Q. What is the Hibbard Renewable Energy Center ("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 62 MW of net capability along with dispatchable renewable energy for Minnesota Power customers. HREC is capable of burning wood and wood wastes, coal, and natural gas.

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

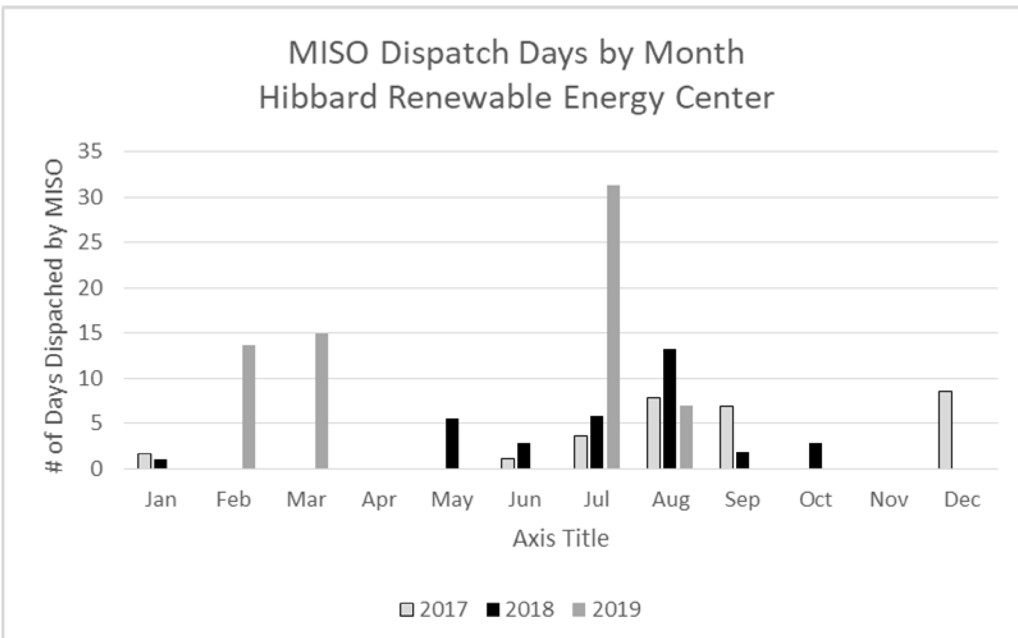
A. HREC is capable of, and originally designed for, baseload operation. It supports capacity and baseload energy generation when required. HREC's multi-fuel boilers provide steam that drives HREC's Units 3 and 4 turbine generators and supports papermaking processes at the adjacent Verso paper mill.

In recent years, there has been a shift in the strategic operation of HREC: it is run when market prices and grid reliability warrant. This has resulted in HREC being used more 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. 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 Minnesota Power customer demand when needed.

Q. How often does MISO dispatch HREC?

A. HREC was called upon to support customer needs many times in early 2019 during February and March, as well as the peak summer energy months of July and August. As shown in Figure 5, HREC continues to be called upon to dispatch, showing that these assets are used and very useful to provide grid reliability services.

Figure 5. HREC Dispatch Days*



*dispatch information as of 9/30/2019

Q. Have there been capital additions at HREC since the 2016 Rate Case?

A. Yes. Aligned with our reliability practices to support operating these assets and ongoing compliance of the facility, investments have been made in fuel delivery, ash handling systems, distributed control replacements, environmental controls and monitors, and a roof replacement.

Q. Are there any capital additions included in the 2020 test year for HREC?

A. There are two projects budgeted in 2020 for HREC: a rotor replacement on the biomass wood hog, and boiler grate replacement on Unit 4. These capital additions total $0.5 million Total Company ($0.4 million MN Jurisdictional).

Q. Are there any specific actions that Company would like the Commission to take with respect to HREC?

A. The necessary, reasonable, and prudent capital additions that have been made at HREC to bring the facility into a successful generating position within the Minnesota Power generation fleet are complete. HREC is used and useful and, as such, Minnesota Power respectfully requests that the Commission conclude that the Company has satisfied its requirements under Order Point 4.a of the Commission's Order Approving Purchase and Making Findings Relevant to Recovery of Upgrade Expenditures through the Renewable Energy Rider (E015/PA-08-928). The Company will continue, in all subsequent rate cases, as it does with all of its capital investments, to make information on future HREC investments available to the Commission for review to ensure the continued prudent investment in Minnesota Power's generation fleet.

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

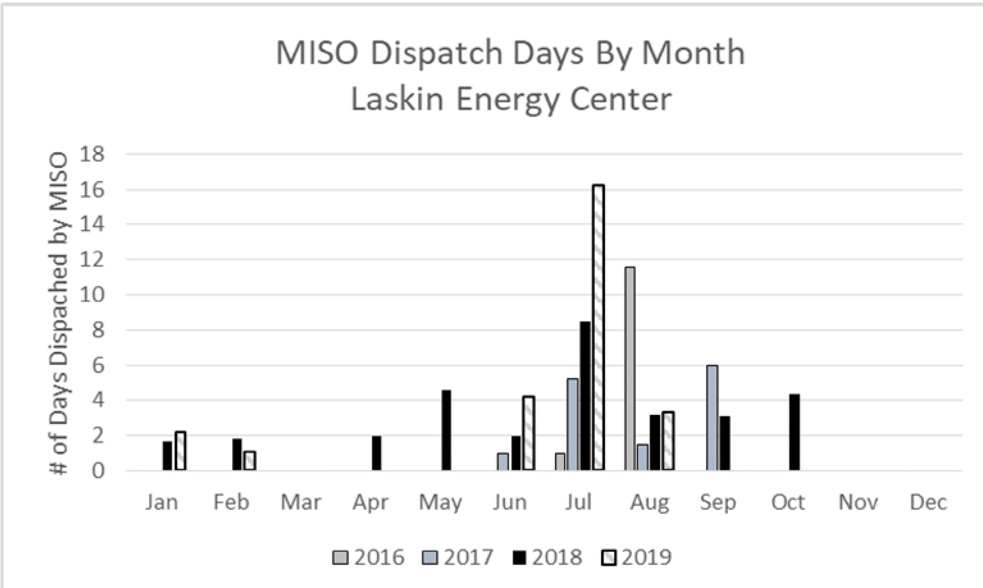
Q. Please describe Laskin.

A. Laskin is located in Hoyt Lakes, Minnesota, and was commissioned in 1953 as a coal-fired facility. Laskin has two 55 MW net capability generating units, Units 1 and 2, that are similar in design and intended operation. To help achieve the Energy*Forward* goal of having a mix of power generation resources and more flexible operations, the conversion of Laskin from coal-fired to natural gas-fired generation was completed in 2015.

Q. Are there changes at Laskin as a result of its conversion to natural gas?

A. Yes. While the conversion to natural gas has increased the accredited capacity to 91 MW for planning year 2019-2020 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 1.5 days per month, as shown in Figure 6, with over 16 days requested in July 2019.

Figure 6. Laskin Dispatch Days*



*Dispatch information as of 9/30/2019

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 three years of natural gas operations (2016 to 2018), the Laskin conversion is estimated to have reduced carbon dioxide emissions by 680 pounds per megawatt hour ("MWh"). In addition, sulfur dioxide, mercury, and filterable PM emissions were reduced by over 99 percent, while nitrogen oxide emissions were reduced by approximately 98 percent, from prior coal emission levels. These emissions reductions bring significant environmental benefit to the region.

Q. Are there any O&M savings as a result of the conversion to natural gas?

A. Yes. As a coal-fired generation facility, Laskin employed 40 full-time employees. With the facility's transition to natural gas, Laskin now employs nine full-time employees and one part-time employee. In addition, contracted services, materials, maintenance activities, and supplies have been reduced to levels that support Laskin's new capacity mission. This one-time reduction has primarily been achieved through attrition and by allowing retained employees to build new skills in their roles and careers.

E. Wind Energy Facilities

Q. What wind energy centers does Minnesota Power currently own?

A. Minnesota Power owns Bison, located in North Dakota, and the Taconite Ridge Wind Energy Center ("Taconite Ridge"), located in northern Minnesota.

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 2009 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.

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 facility but are outside the scope of the long-term service agreement with the OEM.

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. Have there been any changes to the operations and maintenance of Taconite Ridge since the 2016 Rate Case?

A. Yes. In 2018, the federal production tax credits for Taconite Ridge expired, changing the economics of the energy production from the site. Prior to the expiration, an internal review was performed to find ways to help lower operating costs and improve competitiveness in the energy market. Operationally, we lowered the output on assets to 2.1 MW per tower, to maximize the operating life of the equipment and lower the overall operating cost per MWh. The result has been reduced maintenance costs and longer run times for equipment. As part of the change in strategy, total staffing was reduced to three wind technicians supporting the site from the previous four.

Q. Are there any capital additions for either Taconite Ridge or Bison in the 2020 test year?

A. Yes. The 2020 test year includes capital additions of $0.7 million Total Company ($0.6 million MN Jurisdictional) for Taconite Ridge and $0.1 million Total Company ($0.1 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.

F. <u>Hydro Generation Facilities</u>

Q. Please describe Minnesota Power's hydro resources.

A. Minnesota Power has used water to generate energy since its formation. 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 100 years. Minnesota Power maintains the dams for the ten hydroelectric stations and six headwater storage reservoirs. The stations and reservoirs are operated under eight federal licenses issued by FERC and play a critical role in the Company's "black start" program and grid reliability.

Q. What key investments have been made at the Company hydro facilities?

A. A number of investments were made since filing the 2016 Rate Case at hydro facilities including but not limited to Island Lake Reservoir, Whiteface Reservoir, Thomson hydroelectric station, and Blanchard hydroelectric generating station. In 2017, the Company began construction on a three-year project to replace five deep sluice gates at the Island Lake Reservoir that were originally constructed in 1915. In 2017 and 2018, the Company completed the Thomson Spillway Capacity and Thomson Refurbishment of Dam 6 projects (the "Thomson Spillway and Dam 6 Projects"), which were the last portions of a multi-year refurbishment at the Thomson Hyrdroelectric Facility ("Thomson Restoration Project"). In 2019, the Company began construction on a two-year project to replace two sluice gates at the Whiteface Reservoir that were originally constructed in 1922. The Blanchard station needed extensive refurbishment of the structure at the generating shop.

Q. Have the Thomson Spillway and Dam 6 Projects been completed?

A. Yes. While restoration of the generating station was complete at the time of the 2016 Rate Case, two on-going projects associated with improving spill capacity at the Thomson Hydroelectric Facility were still in progress at that time. As spill capacity alternatives were evaluated, the Company determined that a phased approach to increasing spill capacity, as represented by these two projects, was in the best interest of our customers and communities. This approach was approved by FERC and supported by the Independent Board of Consultants.[3] The Company completed construction on the first phase of these spill capacity improvements in 2017, which increased the total spill capacity to approximately 74,000 cubic feet per second, compared to 48,000 cubic feet per second at the time of the 2012 flood. The Thomson Refurbishment of Dam 6, the last of the spillway work, was completed in 2018.

Q. Are these Thomson Spillway and Dam 6 Projects currently included in base rates?

A. No. The Thomson Spillway and Dam 6 Projects were completed after our 2016 Rate Case was filed. As a result, they are the last two Thomson projects that have been included in the Company's current Rider for Renewable Resources ("RRR"). We are asking that these projects, along with all Thomson Restoration Project costs, be moved into base rates effective with interim rates on January 1, 2020. This request was also made in Minnesota Power's most recent RRR filing (Docket No. E015/M-19-523), filed August 15, 2019.

Q. What was the total cost of the Thomson Restoration Project?

A. When the Company filed its original petition for the entire Thomson Restoration Project, including the Thomson Spillway and Dam 6 Projects (Docket No. E015/M-14-577), costs were estimated at $90.4 million (Total Company), net of insurance proceeds, and this is the amount the Commission approved for inclusion in the RRR. The total cost of the Thomson Restoration Project was finalized at $93.3 million (Total Company), net of insurance proceeds. As part of the 2016 Rate Case, $83.5 million was approved for inclusion in base rates for the Thomson Restoration Project.

Q. How much is currently in the RRR for the Thomson Spillway and Dam 6 Projects?

A. The Thomson Spillway and Dam 6 Projects were completed at a final cost of $9.8 million. This means that there is $6.98 million currently in the RRR, and Minnesota Power requests that this amount be rolled into base rates. Additionally, Minnesota

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[3] The Independent Board of Consultants is approved by the FERC Director to review the design, plans and specifications, and construction of the project. The Independent Board of Consultants is expected to assess the construction inspection program, construction procedures and progress, planned instrumentation, the filling procedures for the reservoir, and plans for surveillance during initial filling of the reservoir.

Power requests that the $2.9 million it reasonably and prudently incurred to complete the overall Thomson Restoration Project at the Thomson Hydroelectric Facility in excess of the early estimate of $90.4 million also be included in base rates. This request is consistent with that of the Direct Testimony of Company witness Mr. Stewart J. Shimmin.

Q. Why were final costs of the Thomson Restoration Project higher than the project cost estimate?

A. The difference is not directly attributable to any particular aspect of the project. Instead, the $90.4 million estimate, net of insurance proceeds, was developed during the initial design stage in 2012. The majority of the Thomson Restoration Project costs had already been reviewed by this Commission in the 2016 Rate Case to determine if the costs were incurred prudently. The initial costs of the Thomson Spillway and Dam 6 projects, which had not yet been reviewed by this Commission, were developed based on the information available in 2012. FERC and the Independent Board of Consultants required several additional engineering studies, related to probable maximum precipitation and river flow models, that could not have been anticipated at the time the estimate was complete. Further, once these studies were completed, FERC required an independent review of the entire design package for both projects, including reports, engineering studies, design plans, and construction specifications, before construction could commence. Certain design elements could not be estimated or finalized until after FERC and the Independent Board of Consultants reviewed the studies and approved the designs based on those studies. Finally, procurement and construction costs slightly exceeded the early estimates for the Thomson Restoration Project due to general inflation. Overall, the Thomson Restoration Project was completed within approximately three percent of early estimates and all costs were prudently incurred by the Company.

Q. Are there any planned capital additions at the hydroelectric stations included in the 2020 Budget?

A. Yes. The Company has identified capital additions to replace aging gates from timber to steel and to refurbish current steel gates that are in need of recoating. Concrete exposed to weather conditions will be refurbished, and other equipment that is needed to support the hydro operations across multiple generating sites will be invested in. The Company will invest $3.6 million Total Company ($3.1 million MN Jurisdictional) at its hydroelectric facilities in 2020.

G. Solar Energy

Q. Please describe Minnesota Power's capital additions in solar generation resources and how these investments have provided value for Minnesota Power's customers?

A. Minnesota Power is pursuing solar energy resources that are consistent with Minnesota's Solar Energy Standard ("SES") and the Company's Energy*Forward* strategy, which is designed to deliver safe and reliable service to customers while protecting and improving the region's quality of life and preserving the affordability of electricity.

Q. How has Minnesota Power incorporated solar energy resources into its generation portfolio?

A. Minnesota Power has incorporated Camp Ripley and its Community Solar Garden ("CSG") Pilot Program into its resources for the benefit of Company customers.

Q. What is the Camp Ripley solar project?

A. Minnesota Power completed its first large-scale solar project at the Camp Ripley Army National Guard Base near Little Falls, Minnesota in 2016. Minnesota Power is obligated to make financing payments for the Camp Ripley solar array totaling $1.4 million Total Company annually during the financing term, which expires in 2027. The 10 MW solar array is producing nearly one third of the energy required for the Company to meet the SES (see Docket No. E015/M-15-773).

Q. Please describe the CSG Pilot Program.

A. The Company filed its CSG Pilot Program with the Commission in September 2015 and received final approval of the program, tariff sheets, and customer contracts on April 21, 2017 (Docket No. E015/M-15-825). The CSG Pilot Program was intentionally designed to provide flexibility and optionality for customers who wish to participate in solar programs but do not have a site that is well-suited for a solar installation. The CSG Pilot Program consists of a purchase power agreement of a 1 MW solar array on underutilized land in Wrenshall, Minnesota, and a Company-owned 40 kilowatt ("kW") solar array on one of the most heavily trafficked thoroughfares in Duluth, Minnesota, adjacent to Minnesota Power's Herbert Service Center. Combined, the two arrays represent a total of 1,040 one kW blocks that customers can subscribe to. The program offers three convenient ways for customers to participate: a onetime upfront payment, a fixed monthly subscription fee, or a per-kilowatt hour charge.

Q. When were these CSG Pilot Projects completed?

A. Construction of the 40 kW array was complete in 2016 and the 1 MW array was complete in 2017.

Q. Are there any other solar resources included in the Company's generation portfolio in addition to the CSG Pilot Program and Camp Ripley?

A. Yes. Mr. Frederickson discusses the Company's plans to acquire an additional 10 MW of solar to support Minnesota Power's efforts to achieve nearly 50 percent renewable energy by 2021.

Q. Is Minnesota Power requesting that solar investments be included in this rate case?

A. Minnesota Power has not included its solar investments in this rate case. Minn. Stat. § 216B.1691, Subd. 2f(f) excludes recovery of SES costs from certain customers, namely large iron mining and paper production businesses. In 2015, Minnesota Power proposed a method to meet this requirement in its Camp Ripley Solar Project Filing (Docket No. E015/M-15-773). In its February 24, 2016 Order, the Commission approved the Company's general approach to allocate costs to customers by creating a new Rider for Solar Energy Adjustment, in conjunction with the Company's existing Rider for Fuel and Purchased Energy Adjustment, and a new Solar Renewable Factor as part of the Company's Renewable Resources Rider.

Q. Has the Company submitted a Solar Renewable Factor Filing?

A. No. Minnesota Power has not yet submitted a Solar Renewable Factor Filing for approval from the Commission, so the costs for the Camp Ripley Solar Project and the Company's 40 kW[4] CSG solar array have not yet been recovered. The Solar Renewable Factor Filing is expected to be submitted for Commission approval in the next year. The Company continues to incur costs related to compliance with the SES and will include a solar capacity credit to allocate the solar capacity benefits of the Camp Ripley Solar Project appropriately. Solar paying customers will see an additional line item on their monthly bill for these costs when the Company files and receives approval of the Solar Renewable Factor Filing. Meanwhile, these costs are excluded from base rates.

V. CONCLUSION

Q. Does this complete your testimony?

A. Yes.

[4] Only the 40 kW is owned by Minnesota Power. The one MW installation is obtained via a purchased power agreement.

Capital Additions (including Contra), 2020 Test Year

Area	Classification	Project Description	Total Company	MN Jurisdictional
Steam Generation - Boswell Common	Steam Production	BEC HYDROGEN SYS SAFETY IMPROVEMENT	42,904	37,368
Steam Generation - Boswell Common	Steam Production	BEC 3&4C Service Water Pump Rebuild	70,048	61,010
Steam Generation - Boswell Common	Steam Production	BEC RO PRO 150 & 200 MEMBRANE REPL	40,579	35,343
Steam Generation - Boswell Common	Steam Production	BEC-F VC-2 Replacement	50,043	43,586
Steam Generation - Boswell Common	Steam Production	BEC P6 Sump System to BA Pond Insta	65,726	57,245
Steam Generation - Boswell Common	General Plant	Rebuild of Dozer B2005 - New T	262,773	235,048
Steam Generation - Boswell Common	Steam Production	Loop Track Area Reclamation - 2 yr	78,804	68,636
Steam Generation - Boswell Unit 3	Steam Production	BEC 3B MILL FEEDER CONTROLS REPLACE	36,000	31,355
Steam Generation - Boswell Unit 3	Steam Production	BEC 3B PULVERIZER OVERHAUL	501,798	437,051
Steam Generation - Boswell Unit 4	Steam Production	BEC4 Baghouse Bag Replacement	1,795,084	1,563,464
Steam Generation - Boswell Unit 4	Steam Production	BEC-4 Burner Replacement	870,010	757,753
Steam Generation - Boswell Unit 4	Steam Production	BEC-4 CT Water Basin & Stack Repl.	1,730,047	1,506,819
Steam Generation - Boswell Unit 4	Steam Production	BEC-4 Classifier & Grinding Section	350,468	305,247
Steam Generation - Boswell Unit 4	Steam Production	BEC-4 DCS IO Replacement	655,151	570,617
Steam Generation - Boswell Unit 4	Steam Production	BEC-4 Turbine Roof Fan Replacement	100,046	87,137
Steam Generation - Boswell Unit 4	Steam Production	BEC-4C Boiler Circ Pump Rebuild	222,134	193,472
Steam Generation - Boswell Unit 4	Steam Production	BEC-4 Polisher Tube Bundle Replacem	322,659	281,026
Steam Generation - Boswell Unit 4	Steam Production	BEC-4 Gaseous CEMS Replacement	207,855	181,035
Steam Generation - Boswell Unit 4	Steam Production	BEC-4 Hg Analyzer Replacement	82,792	72,109
Steam Generation - Boswell Unit 4	Steam Production	BEC-4 Replace Station Battery	116,025	101,054
Steam Generation - Boswell Unit 4	Steam Production	BEC-4 Sofa Expansion Joints Replace	51,200	44,594
Steam Generation - Boswell Unit 4	Steam Production	BEC-4 Boiler Component Replacement	460,686	401,244
Steam Generation - Boswell Unit 4	Steam Production	BEC-4 Hot Reheat Pipe Replacement	5,214,914	4,542,034
Steam Generation - Boswell Unit 4	Steam Production	BEC-F U4 Fly Ash Silo Fluidiz. Air	176,208	153,472
Steam Generation - Boswell Unit 4	Steam Production	BEC-4 Turbine Overhaul	2,661,326	2,317,935
Steam Generation - Hibbard Renewable EC	Steam Production	HREC Replace Hog Rotor	175,555	152,903
Steam Generation - Hibbard Renewable EC	Steam Production	HREC REHAB U4 GRATES	294,705	256,679
		Total Steam Generation:	**16,635,539**	**14,495,236**
Hydro Generation - Blanchard HE Station	Hydro	Blanchard Replace U2 Head Gates	700,223	609,324
Hydro Generation - Boulder Lake Reservoir	Hydro	Boulder Lake - Replace Gate & Hoist	399,502	347,641
Hydro Generation - Boulder Lake Reservoir	Hydro	Hydro Concrete Dam Refurbishment	400,010	348,083
Hydro Generation - Fish Lake Reservoir	General Plant	Fish Lake Security Camera	80,036	71,592
Hydro Generation - Fond du Lac HE Station	Hydro	Fond du Lac Stream Gauging	30,000	26,106
Hydro Generation - Fond du Lac HE Station	Hydro	Fond du Lac Powerhouse Ventilation	25,000	21,755
Hydro Generation - Scanlon HE Station	Hydro	Scanlon Replace Wst Channel Gate 16	294,559	256,321
Hydro Generation - Whiteface Reservoir	Hydro	Whiteface-Replace Sluice Gates	1,625,300	1,414,312
		Total Hydro Generation:	**3,554,631**	**3,095,132**
Wind Generation - Bison	Wind Generation	Bison 2020 Generator Replacement	134,872	117,470
Wind Generation - Taconite Ridge	Wind Generation	TREC T1 Gearbox Replacement	670,835	584,277
		Total Wind Generation:	**805,707**	**701,747**
		Total Generation:	**20,995,878**	**18,292,115**