414 Nicollet Mall
Minneapolis, MN 55401

**PUBLIC DOCUMENT –
NOT PUBLIC DATA HAS BEEN EXCISED**

September 26, 2017

—Via Electronic Filing—

Daniel P. Wolf
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101

RE: PETITION
ACQUISITION OF 302.4 MW WIND GENERATION
DOCKET NO. E002/M-17-____

Dear Mr. Wolf:

Northern States Power Company, doing business as Xcel Energy, submits to the Minnesota Public Utilities Commission the enclosed Petition for Approval under Minn. Stat. § 216B.2422, subd. 5 for the Company to build, own, and operate the 302.4 MW Dakota Range I and II wind project.

Portions of the enclosed documents are marked "NOT PUBLIC" as they contain information the Company considers to be trade secret data as defined by Minn. Stat. §13.37(1)(b). This data includes confidential pricing and other contract terms, as well as bid evaluation criteria. This information has independent economic value from not being generally known to, and not being readily ascertainable by, other parties who could obtain economic value from its disclosure or use. We have marked additional information as "NOT PUBLIC" trade secret because the knowledge of such information in conjunction with public information in our Petition also adversely impact future contract negotiations, potentially increasing costs for these services for our customers. Thus, the Company maintains this information as a trade secret.

Attachments A and B provided with the Non-Public version of this response contains data classified as trade secret pursuant to Minn. Stat. §13.37 and are marked as "Non-Public" in their entirety. Pursuant to Minn. R. 7829.0500, subp. 3, the Company provides the following description of the excised material:

Attachment A:

1. **Nature of the Material**: Revenue requirement model for the Dakota Range wind project.
2. **Authors:** The model was prepared by the Corporate Development group with inputs provided by multiple areas across the Company.
3. **Importance:** The model contains competitively sensitive data related to project costs.
4. **Date the Information was Prepared**: The model was prepared during the third quarter of 2017.

Attachment B:

1. **Nature of the Material**: The attachment contains the purchase and sale agreement for the Dakota Range wind project.
2. **Authors:** The agreement was prepared by the law firms of Orrick, Herrington & Sutcliffe (representing Xcel Energy) and McGuireWoods (representing Apex).
3. **Importance:** The attachment contains confidential pricing and contract terms as well as bid evaluation criteria.
4. **Date the Information was Prepared**: The agreement was prepared during the third quarter of 2017.

We have electronically filed this document with the Minnesota Public Utilities Commission, and copies have been served on the parties on the attached service list. Please contact me at aakash.chandarana@xcelenergy.com or (612) 215-4663 or bria.e.shea@xcelenergy.com or (612) 330-6064 if you have any questions regarding this filing.

Sincerely,

/s/

AAKASH H. CHANDARANA
REGIONAL VICE PRESIDENT
RATES AND REGULATORY AFFAIRS

Enclosures
c: Service Lists

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Nancy Lange	Chair
Dan Lipschultz	Commissioner
Matthew Schuerger	Commissioner
Katie J. Sieben	Commissioner
John A. Tuma	Commissioner

IN THE MATTER OF THE PETITION OF XCEL ENERGY FOR APPROVAL OF THE ACQUISITION OF 302.4 MW WIND GENERATION

DOCKET NO. E002/M-17-____

PETITION

INTRODUCTION

Northern States Power Company, doing business as Xcel Energy, submits to the Minnesota Public Utilities Commission this Petition for Approval under Minn. Stat. § 216B.2422, subd. 5 for the Company to build, own, and operate the 302.4 MW Dakota Range I and II wind project (collectively "Dakota Range").

The Dakota Range project was initially bid into our Request for Proposals (RFP) process in the recently concluded wind portfolio acquisition docket[1] and while we did not pursue it at that time, we are bringing it forward for the Commission's approval now for a few reasons. First, the project has significantly improved in several ways since the RFP process concluded. Second, this project may likely be one of the last projects in NSPM to have transmission certainty for quite some time. Third, the project will provide substantial benefits to our customers, the environment, and the communities we serve even when using conservative assumptions. And finally, we need to move with some expediency in order to secure the maximum production tax credits (PTC) available at this time.

We believe this proposal is consistent with the Commission's January 2017 Order in our integrated resource planning docket,[2] as well as the Commission's suggestion during the July 2017 wind acquisition docket hearing that the Company should continue to evaluate and bring forward wind projects that will result in customer

[1] Docket No. E002/M-16-777
[2] Docket No. E002/RP-15-21

benefits. And while beneficial and cost-effective in its own right, we believe the Dakota Range project also addresses the Commission's and stakeholders' concerns that the Company have backup projects available should one of the projects in the recently approved 1,550 MW portfolio not reach commercial operation.

Dakota Range is a 302.4 MW self-build wind project located in South Dakota with an expected in-service date of 2021 and a projected Levelized Cost of Energy (LCOE) of **[PROTECTED DATA BEGINS PROTECTED DATA ENDS].** This LCOE compares favorably to the Company's recently approved wind projects, which had LCOEs in the range of **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]**.[3] We can achieve this competitive LCOE notwithstanding the project's 2021 in-service date and qualification for only 80 percent of the PTC due—in large part—**[PROTECTED DATA BEGINS PROTECTED DATA ENDS]**, as discussed further below.

As mentioned above, Apex Clean Energy (APEX) bid this project in response to our initial RFP conducted in late 2016 as part of our project acquisition efforts in the wind portfolio acquisition docket. APEX offered the following multiple options for the project: 1) a 700 MW Power Purchase Agreement (PPA) for Dakota Range I-V, 2) a 300 MW PPA for Dakota Range I and II, 3) a 300 MW Build-Own-Transfer (BOT) for Dakota Range I and II, and 4) a 300 MW PPA for Dakota Range III and IV. We ultimately did not pursue negotiations with APEX during the RFP based on our evaluation of the price and non-price factors during the RFP.[4]

Since that time, however, MISO's August 2015 DPP Study Cycle concluded—assigning a reasonable amount of network upgrade costs to Dakota Range I and II and affording the Project substantially greater transmission certainty. This had the effect of not only lowering the total expected costs of the project but also increasing our overall confidence in the project's ability to reach commercial operation. Additionally, since the time of the RFP bid, the Company has conducted additional due diligence on other outstanding Project issues and confirmed the viability of the Project on all fronts.

---

[3] Using the same discount rate and weighted average cost of capital used to determine the LCOEs of the projects in Docket No. E002/M-16-777 results in an LCOE of **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]**.

[4] The LCOE for the Dakota Range I-II BOT option was **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** and PPA option was **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]**.

While we appreciate that we are bringing this project forward on the heels of the recently concluded wind portfolio acquisition docket, we believe the resulting project will provide numerous and substantial benefits to our customers and system. Most importantly, Dakota Range offers system cost savings to our customers over the life of the project. Like the 1,550 MW Portfolio, production at this facility will displace more expensive fossil fuel generation or purchases in the MISO wholesale market. We also conducted additional Strategist modeling runs to evaluate the addition of this 302.4 MW project in 2021. That modeling demonstrates approximately $309 million in present value of societal costs (PVSC) savings compared to adding no additional wind beyond the previously approved 1,550 MW in the same period.

The addition of Dakota Range will also enable the Company to continue to improve environmental performance in a cost-effective manner and meet or exceed compliance with Minnesota's Renewable Energy Standard (RES), and Minnesota's overarching goal of an 80 percent reduction in carbon emissions by 2050. While this project may further secure our compliance with the RES requirement well into the 2040s, we believe this is appropriate and reasonable given the project pricing and expected customer savings.

Next, the Dakota Range project will generate significant and lasting economic benefits for the communities we serve. These include the provision of low-cost energy to meet our customers' needs, income to landowners in exchange for wind easements on their property, the creation of construction and ongoing maintenance jobs, and increased tax revenues and other fees in the impacted states and communities.

Lastly, based on prior experience, projects can fail and have failed, and this project provides surety that we will secure 1,550 MW of wind or more. And, even if all our recently proposed projects move forward, there are still significant benefits to be gained by the addition of this project.

To achieve these benefits, it is necessary to place the Dakota Range into service by the end of 2021, so that it qualifies for 80 percent of the PTC. In light of this timing, we respectfully request that the Commission complete deliberations sometime before March 15, 2018, so we have sufficient certainty to proceed with the project and capture the PTC for our customers.

We respectfully request the Commission take the following actions:

- Allow the Company to build, own, and operate the 302.4 MW Dakota Range wind project;

- Approve an aggregate, symmetrical capital cap for the initial construction of the project;
- Approve the use of our Capital Services affiliate agreement for Dakota Range that was approved by the Commission in its July 13, 2017 Order in Docket No. E002/AI-17-215;
- Confirm the 302.4 MW proposed Dakota Range wind project is a reasonable and prudent way to continue to meet our obligations under Minnesota's RES; and
- Establish a procedural schedule such that the Commission may complete deliberations in March of 2018 so we may proceed with this project and secure the maximum available PTC benefits.

We plan to apply for an Advanced Determination of Prudence (ADP) for the Dakota Range wind project with the North Dakota Public Service Commission (NDPSC). We will also be seeking cost recovery for our proposed project with the South Dakota Public Utilities Commission.

Our wind portfolio is also under discussion in the currently pending Resource Treatment Framework (RTF) proceeding before the Commission and the NDPSC (Docket No. E002/M-16-223). However, based on the overall benefits provided by the proposed wind project, we believe the Commission can proceed with their consideration of our proposed new wind generation in this docket as it would with any other resource and any jurisdictional allocation issues can be addressed later in the RTF docket.

In the balance of this Petition, we:

- Discuss the project selection process;
- Provide an overview of the PTC;
- Outline the project description, costs, and schedule;
- Identify the contracts necessary to support the proposed project;
- Discuss our economic analysis of the project and associated rate impacts.

We provide the following attachments with this Petition:

- Attachment A – Project costs and LCOE calculation
- Attachment B – Purchase and Sale Agreement (PSA) with APEX
- Attachment C – Strategist Modeling Assumptions
- Attachment D – CO_2 Externality Costs Compliance Filing

I. SUMMARY OF FILING

A one-paragraph summary is attached to this filing pursuant to Minn. R. 7829.1300, subp. 1.

II. SERVICE ON OTHER PARTIES

Pursuant to Minn. R. 7829.1300, subp. 2, the Company has served a copy of this filing on the Office of the Attorney General – Antitrust and Utilities Division. We have also distributed copies of our filing to those on our current Resource Plan service list (Docket No. E002/RP-15-21) and our Miscellaneous Electric service list.

III. GENERAL FILING INFORMATION

Pursuant to Minn. R. 7829.1300, subp. 3, the Company provides the following information.

A. Name, Address, and Telephone Number of Utility

Northern States Power Company, doing business as:
Xcel Energy
414 Nicollet Mall
Minneapolis, MN 55401
(612) 330-5500

B. Name, Address, and Telephone Number of Utility Attorney

Ryan Long
Principal Attorney
Xcel Energy
414 Nicollet Mall, 401 – 8th Floor
Minneapolis, MN 55401
(612) 215-4659

C. Date of Filing

The date of this filing is September 26, 2017. The Company requests that approval of this Petition be effective upon the date of the Commission Order. If this Petition is approved, the Company will make a separate cost recovery filing at a later date.

D. Statute Controlling Schedule for Processing the Filing

This filing is made pursuant to Minn. Stat. § 216B.2422, subd. 5, which provides an exemption from the Certificate of Need statute (Minn. Stat. § 216B.243) for resources selected through a bidding process approved or established by the Commission.

No specific statute controls the timeframe for processing this filing. The processing is therefore controlled by the Commission's rules on Miscellaneous Filings, Minn. R. 7829.1300 and 7829.1400. We have included the information required under Minn. R. 7829.1300, subp. 3 for miscellaneous filings that, like this one, are subject to specific content requirements. We also note that while Minn. R. 7829.1400, subps. 1 and 4 specify the time periods for initial and reply comments for miscellaneous filings; it has been the past practice of the Commission to set a comment schedule by notice to interested parties pursuant to Minn. R. 7829.1400, subp. 7.

E. Utility Employee Responsible for Filing

Bria Shea
Director, Regulatory and Strategic Analysis
Xcel Energy
414 Nicollet Mall, 401 – 7th Floor
Minneapolis, MN 55401
(612) 330-6064

IV. MISCELLANEOUS INFORMATION

Pursuant to Minn. R. 7829.0700, the Company requests that the following persons be placed on the Commission's official service list for this proceeding:

Ryan Long
Principal Attorney
Xcel Energy
414 Nicollet Mall, 401 – 8th Floor
Minneapolis, MN 55401
ryan.j.long@xcelenergy.com

Carl Cronin
Regulatory Administrator
Xcel Energy
414 Nicollet Mall, 401 – 7th Floor
Minneapolis, MN 55401
regulatory.records@xcelenergy.com

Any information requests in this proceeding should be submitted to Mr. Cronin at the Regulatory Records email address above.

V. DESCRIPTION AND PURPOSE OF FILING

In this section, we describe how we selected this project, the PTC, the project description, estimated costs, and schedule, the contracts necessary to execute our proposal, and finally the economic analysis supporting the proposed project.

A. Project Selection Process Overview

As discussed in our most recent wind portfolio acquisition docket, part of our acquisition process for wind resources included issuing an RFP for wind project proposals. After receiving bids in response to our RFP, the Company, along with an independent auditor, evaluated the bids.

The bids were evaluated in a four step process: (1) completeness and threshold review to confirm that all information required had been included and that each proposal met the RFP criteria; (2) calculation of LCOE for each project; (3) non-price review which scored the projects on areas such as permitting, site control, and transmission; and (4) final ranking.[5] Upon completion of these steps, four projects totaling 1,100 MW materialized to the shortlist, with another two projects totaling 200 MW listed as backup. Our analysis and review was overseen and confirmed appropriate by the auditor.

We assessed all projects on the basis of LCOE in order to group them into similarly priced groups, or tiers. The maximum LCOE to make it into one of the top three tiers was **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]**. These top three tiers, which included the two of the four bid configurations for the Dakota Range wind project, included a total of 26 projects.[6] The two bids with LCOEs low enough to qualify for consideration included the 700 MW Dakota Range I-V PPA option and the 300 MW Dakota Range III-IV PPA option. The other two bids, a PPA and BOT option for 300 MW of Dakota Range I-II, had LCOEs above the price threshold in the third tier.

While the Dakota Range wind project was in the initial scope of projects under close consideration for negotiations, we then narrowed the 26 projects as they moved through the non-price review and final rankings. As a result, Dakota Range did not advance through to negotiations. Although we initially set out to negotiate contracts for 1,100 MW of projects from the RFP process, two bidders withdrew from the

---

[5] This process was discussed in detail in our March 16, 2017 Supplement in Docket No. E002/M-16-777.
[6] The final ranking of the projects were included in Attachment B1 of our March 16, 2017 Supplement in Docket No. E002/M-16-777.

process during negotiations, and we were unable to reach agreement on contract terms with a third bidder. In light of the tight timeline for negotiations and filing submission to the Commission, which was necessary to ensure full capture of the PTC, we were unable to initiate any new negotiations at that point. This process resulted in 800 MW of projects from the RFP, which along with our self-build projects, comprised our total 1,550 MW portfolio.

As discussed earlier, APEX contacted the Company soon after the RFP process concluded to advise us they had additional information from MISO and now had much greater certainty surrounding the Project's expected transmission costs. As a result, they wanted to reduce their bid pricing. However, due to the RFP process rules as well as those agreed to with the independent auditor, we were unable to authorize a bid modification at that time.

Since that time, we have engaged in periodic conversations with APEX and discovered that the primary issues that held the Project back from advancing in the RFP—price and transmission uncertainty—has been favorably resolved.

B. PTC

Projects that begin construction in 2018, such as the Dakota Range wind project, are eligible for 80 percent of the PTC amount due to the phased step down from 100 percent that began in 2017. Wind facilities must begin construction in 2018 to qualify for the 80 percent PTC "safe harbor." By law, there are two ways to begin construction for purposes of the safe harbor: (1) commencing "physical work of significant nature" at the project site or at a factory on equipment for the project or (2) incurring at least five percent of the total project cost.[7] With respect to the five percent method, it is important to note that costs are not incurred merely by spending money; the developer must actually take delivery of the equipment either by year-end or within 105 days from incurring the cost. Under either safe-harbor method, the projects must be placed in service within four years from the end of the year that construction commenced.

In this case, the Company leveraged its pre-existing relationship with Vestas to assure PTC qualification in 2021 by securing its own safe-harbor turbines (the largest component of the project). This method of qualification was possible as a result of our relationship with Vestas, our experience in qualifying projects for the PTC, and our previously approved Capital Services affiliate agreement *that was used to support our*

[7] The Consolidated Appropriations Act, 2016.

1,550 MW portfolio.[8]

During the course of our negotiations, we were also able to **[PROTECTED DATA BEGINS**

PROTECTED DATA ENDS].

As discussed below, we have developed a project schedule that optimizes pricing and keeps the project on track to ensure qualification of the maximum PTC at this time, 80 percent.

C. Project Description, Costs, and Schedule

In this section, we provide project information including affiliation, location, project size, interconnection details and anticipated network upgrades, net capacity factor, projected annual energy output, total project cost, LCOE, and the project implementation schedule. We provide underlying calculations for the LCOE and project costs in Attachment A.

1. Project Description

The Dakota Range wind project is being developed by APEX AGL, LLC, and is located on an approximately 40,000 acre site located 20 miles North of Watertown, South Dakota. The site is primarily grazing, farming and rolling open fields. The site borders the prairie pothole region, which is a biologically diverse area of the Great Plains.

We currently anticipate that the Project will consist of **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** wind turbines, resulting in 302.4 MW of nameplate wind power capacity. That said, should Vestas release new turbine technologies before construction that could result in higher annual energy production, we will have the ability to explore and possibly implement those technologies if we conclude that they will result in greater customer benefits. In addition to wind turbines, the Project will consist of an electrical collection system, access roads, substation and interconnection facilities, an operation and maintenance facility, and other infrastructure typical of a wind farm.

---

[8] We note that we intend to use the same terms and contracts that have been previously approved for Capital Services by the Commission in its July 13, 2017 Order in Docket No. E002/AI/17-215.

APEX applied to interconnect the Dakota Range project to the Otter Tail Power transmission system in March 2015 and was assigned project numbers J436 and J437 by MISO. This project will connect to the Otter Tail Power and Montana–Dakota Utilities 345 kV Big Stone – Ellendale transmission line at a new substation. The project was studied under the MISO August 2015 DPP Study Cycle. The MISO system impact and facility studies have been completed and all required transmission upgrades are known. These upgrades will be included in the Dakota Range Generator Interconnection Agreement (GIA) that is expected to be executed in the fourth quarter of 2017. The Company anticipates that the project will qualify as a capacity resource beginning in the 2023/2024 planning year.

The required transmission upgrades for the project include: (1) construction of a new 345 kV interconnection substation named Twin Brooks; (2) construction of a +/- 200 Mvar STATCOM at the Stone Lake 345 kV substation; (3) upgrades to the Big Stone–Blair 230 kV transmission line; (4) upgrades to the Oaks-Foreman 230 kV transmission line and; (5) construction of capacitor banks at Electrafarm, Washburn, MidPort and Shaulis Roaad 161 kV substations. The MISO facility studies for the transmission upgrades were used to estimate the transmission upgrade costs required for the Dakota Range project. The final costs associated with the transmission upgrades will not be known until the facilities are placed into service and all accounting work has been completed.

We have estimated the transmission upgrades will cost **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** and interconnection costs will be **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]**.

APEX is responsible for obtaining the necessary approvals to interconnect the Dakota Range project with the MISO transmission system. With respect to project curtailment, we expect that, over the lifetime of the project, curtailment will be consistent with the overall Company curtailment average of approximately four percent, as discussed in the wind portfolio acquisition docket.

Figure 1: Dakota Range Wind Project Location

Our wind performance analysis predicts a net capacity factor (NCF) of **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** percent. We additionally project average Annual Energy Production (AEP) of approximately **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]**, depending on final layout and turbine selection. This NCF **[PROTECTED DATA BEGINS**

PROTECTED DATA ENDS]. While APEX initially submitted an NCF with their RFP bid, we further worked with APEX and Vaisala (an independent wind consultant) to provide an energy production estimate for the updated turbine type.

2. Project Costs

Total capital costs for the Dakota Range Project are currently estimated at approximately **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]**, which includes allowance for funds used during construction (AFUDC), the estimated transmission upgrades and interconnection costs discussed above and anticipated siting and permitting costs. The projected LCOE for the Dakota Range Project is **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]**, which assumes that (1) we will begin utilizing the PTC benefits from this project in 2026, and (2) we will obtain a South Dakota sales tax rebate for the project.[9]

As with the self-build portion of our 1,550 MW wind portfolio and our Black Dog 6 Project, we propose to subject our cost recovery to a symmetrical cost cap (including AFUDC) of **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** for the Dakota Range wind project. We would track and recover this separately from our previously approved symmetrical cost cap for the 1,550 MW portfolio. As with our previously approved proposals, we will agree to forgo recovery of any costs that exceed our proposal (plus financing costs) and in turn, if we are able to achieve any cost-savings, the Company would retain those savings.

While APEX initially submitted a bid into our RFP with their costs and estimates, we compiled our own costs and estimates as the plans transitioned into a Company-built project. Our cost estimate of **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]**. Our analysis was based on the PSA and our wind project balance of plant (BOP) construction and operating cost model. Our cost model was initially developed for the Grand Meadow Wind Farm in 2008, and we have since used it with the Nobles, Pleasant Valley, Border Winds, and Courtenay wind projects – and most recently, the wind portfolio acquisition docket and Public Service of Colorado Rush Creek wind project in Colorado. Our cost model has evolved over the years to reflect our experience with the construction and operation of these wind farms, as well as cost trends in the wind energy industry.

3. Implementation Schedule

We expect our primary construction activities on the Dakota Range Project will occur in 2020 and 2021. However, engineering and some procurement will occur in 2019. The current schedule indicates that wind turbine generators will be delivered to the project site starting in time to begin turbine erection in 2021. Under the current estimated schedule, we anticipate that commercial operation will be achieved by November 2021.

[9] Using the same discount rate and weighted average cost of capital used to determine the LCOEs of the projects in Docket No. E002/M-16-777 results in an LCOE of **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]**.

D. Supporting Contracts

1. PSA

The PSA for the Dakota Range wind project is provided as Attachment B.

We will continue with iterations of the due diligence review process until the closing date of the PSA for the project.[10] The continued due diligence process is necessary to ensure the contractual deliverables for the site development are received timely, and to further support our project development, engineering, construction and commissioning toward the planned in-service date.

2. Master Supply Agreement (MSA)

As discussed above, to meet the safe harbor requirements for this wind project, Xcel Energy's subsidiary, Capital Services, LLC is currently negotiating a fixed price MSA with Vestas American Wind Technology, Inc. for the provision of wind turbines to support our proposed Dakota Range wind project. Pursuant to the agreed-upon terms, Xcel Energy will secure sufficient turbine equipment to meet the five percent safe harbor requirement.

The MSA terms will be similar to those negotiated in the 2016 MSA with Vestas that supported the projects in our recent wind portfolio acquisition docket

3. BOP

As part of our development of this Company-build project, we will issue an RFP and enter into BOP construction contract with third-party construction companies experienced in wind project construction. The BOP contract will be a fixed price contract, which will minimize schedule and cost risk.

The scope of the BOP contracts will include installation of the wind turbines and construction of the site infrastructure. Site infrastructure includes access roads, turbine foundations, electrical cable collection system, collection substations, and operations and maintenance building.

---

[10] We will not close on the PSA or begin construction on the project until the Commission approves this petition.

We note that in preparation for our cost estimates for the relevant scope of work for this project, we relied on the information gathered and bids received in our wind portfolio acquisition docket and also received indicative pricing from BOP contractors to support erection costs for various turbine types.

E. Economic Analysis

To evaluate the impact on our customers of the proposed wind portfolio, we used the Strategist resource planning model. The Strategist planning model simulates the operation of the NSP System and estimates the cost to serve load through the life of the project. We use the model to test results under a range of input assumptions. To assess their impact on customer costs, we simulated the operation of the NSP System through 2053, with and without the addition of the 302.4 MW Dakota Range wind project proposed in this filing. All of our analysis assumes the addition of the 1,550 MWs of wind generation approved by the Commission in Docket No. E002/M-16-777.

As discussed in our previous wind acquisition petition, we note that wind generation has no fuel costs so the marginal cost to produce the next unit of energy is zero. In other words, after capital and on-going O&M costs are accounted for, it costs a wind generator nothing to produce the next MWh of energy. As a result, MISO generally provides for wind production ahead of other, higher marginally-priced generation such as gas- and coal-based generation. Consequently, as more wind generation is integrated into the system, coal and gas-fired thermal generation is dispatched less often. When the energy from the proposed project is produced, it displaces energy production from other Company resources or purchased energy from the MISO market. This displacement of other generation or market purchases largely drives the portfolio benefits shown in our modeling results.

We believe we have taken a conservative approach in developing the base assumptions as well as the sensitivities we used to analyze the proposed wind additions. We used the same assumptions regarding congestion that we used in the analysis of our last wind acquisition and did not change the methodology we used to model curtailment. Due to the addition of an incremental 302.4 MWs of wind, overall curtailment was impacted slightly, resulting in total curtailment of our wind additions of 4.2 percent compared to 3.8 percent shown in our previous analysis. We have updated other base assumptions consistent with the most recent modeling provided in our RTF filing,[11] which provided updated impacts of the 1550 MW wind addition.

[11] Docket No. E002/M-16-223

Those updated assumptions include an updated load forecast and natural gas forecast and are provided in Attachment C.

1. *Strategist Modeling*

As noted above, we evaluated the proposed wind project assuming the addition of the 1,550 MWs of wind previously approved by the Commission. Therefore, the results of the Strategist analysis provide the incremental savings due the addition of the Dakota Range project. The results of the Strategist analysis shows that this new wind resource will result in net savings for our customers under all sensitivity tests conducted. Table 1, below, shows the PVSC and present value of revenue requirement (PVRR) savings. The base PVSC assumptions include a regulated cost of \$21.50 for each ton of CO_2 emitted in 2022, escalating at two percent thereafter, as well as externality costs for emissions of criteria pollutants and CO_2 before 2022. The PVRR savings do not include CO_2 costs or other externality costs and do not include Surplus Capacity Credit.

Table 1: Incremental PVSC and PVRR Savings from Reference Case
(\$millions)

	PVSC								
	Base	Markets Off	Low Gas Price	High Gas Price	Low CO_2 Extern	High CO_2 Extern	+5% Cap Factor	-5% Cap Factor	Preferred Plan Renew
Reference Case	0	0	0	0	0	0	0	0	0
Dakota Range	(309)	(220)	(239)	(398)	(234)	(473)	(392)	(224)	(280)

	PVRR								
	Base	Markets Off	Low Gas Price	High Gas Price			+5% Cap Factor	-5% Cap Factor	Preferred Plan Renew
Reference Case	0	0	0	0			0	0	0
Dakota Range	(182)	(132)	(106)	(274)			(245)	(119)	(133)

Under either a PVSC or PVRR view, the proposed wind project provides significant benefits. As we continue to transition our fleet to include more renewables and less coal generation, there will be periods of time where the generation on our system exceeds our native load serving requirement. During these periods, we are likely to make energy sales into the MISO market. Revenues from those sales will be credited to customers through the monthly FCA. Thus, assumptions regarding the likely value of these potential sales are an important factor in predicting the likely rate impact of the proposed wind portfolio. Therefore, we have analyzed the PVSC and PVRR under three different scenarios, "markets on", "preferred plan renewables" and "markets off," to assess how project revenues from the MISO market may be impacted under various conditions.

<u>Base Assumptions</u>
Under our base assumptions, we allow market sales and purchases. Once resources are added to the MISO system, they are typically dispatched based on the economic signals provided in the energy market. Thus, if it costs less to buy energy from the market as compared to running a system resource, market purchases are made. Relying on the market to reduce costs provides savings to our customers. To evaluate the likely impact on customer rates, we modeled market purchases and sales based on hourly forecasted LMPs at the Minnesota Hub. By matching hourly wind profiles with our forecast of hourly energy prices we are able to analyze the impact of the proposed wind additions. The impact of the market interactions can be seen by comparing the base assumptions to the "markets off" sensitivity.

<u>Markets Off Sensitivity</u>
In a "markets off" optimization, the model does not consider the ability to make market purchases and sales. Thus, the cost-effectiveness of resource additions are based on their effectiveness in serving only system (not market) needs. Because the markets-off sensitivity does not allow market purchases or sales, any generation in excess of system requirements is categorized as "dump energy." In this extreme sensitivity we did not give any value to the "dump energy." All benefits in this sensitivity come from savings attributable to our system resources. Even under this extreme case, the benefits of the additional wind project are significant at $132 million on a PVRR basis or approximately 73 percent of the base assumptions.

<u>Preferred Plan Renewables Sensitivity</u>
Our base assumptions do not include additional renewables beyond 2020.[12] However, our preferred plan in our recent IRP[13] included additions of solar and wind beyond what we proposed here. We note that, all else equal, additions of non-dispatchable resources will result in diminishing system benefits as future increments are added. Thus, we believe it is appropriate to analyze the impacts of the proposed portfolio without diminishing its value by assuming additions of renewable resources beyond

---

[12] All cases include our updated small solar forecast which assumes that 580 MW of small solar will be added by 2020.
[13] Docket No. E002/RP-15-21

what we are proposing here. However, to analyze the impact of the proposed additions in the context of our preferred plan, we ran a sensitivity that included an additional of 1,650 MW of utility-scale solar resources between 2022 and 2030. While inclusion of these additional renewable resources reduces the benefit of the wind by $29 million PVSC and $49 million PVRR, the proposed portfolio continues to provide significant benefits of $280 million PVSC and $133 million PVRR to our customers.

<u>Additional Sensitivities</u>
We performed six additional sensitivities to further test the cost effectiveness of the proposed wind projects.

- *Capacity Factor Sensitivities*

The capacity factors we included are based on an independent evaluation by Vaisala. Specifically, we worked with Vaisala to review and advise on the energy production that could be expected from the company-owned Vestas turbines.

We further tested our assumptions regarding capacity factors and the proposed projects show significant cost savings to our customers under all sensitivities.

- *Gas Price Forecast*

Our gas price forecast is based on a blend of the latest market information and long-term fundamentally-based forecasts acquired from third parties. We have included a low gas sensitivity to evaluate project the impacts of lower gas prices. The proposed wind resource is cost-effective under the low gas sensitivity.

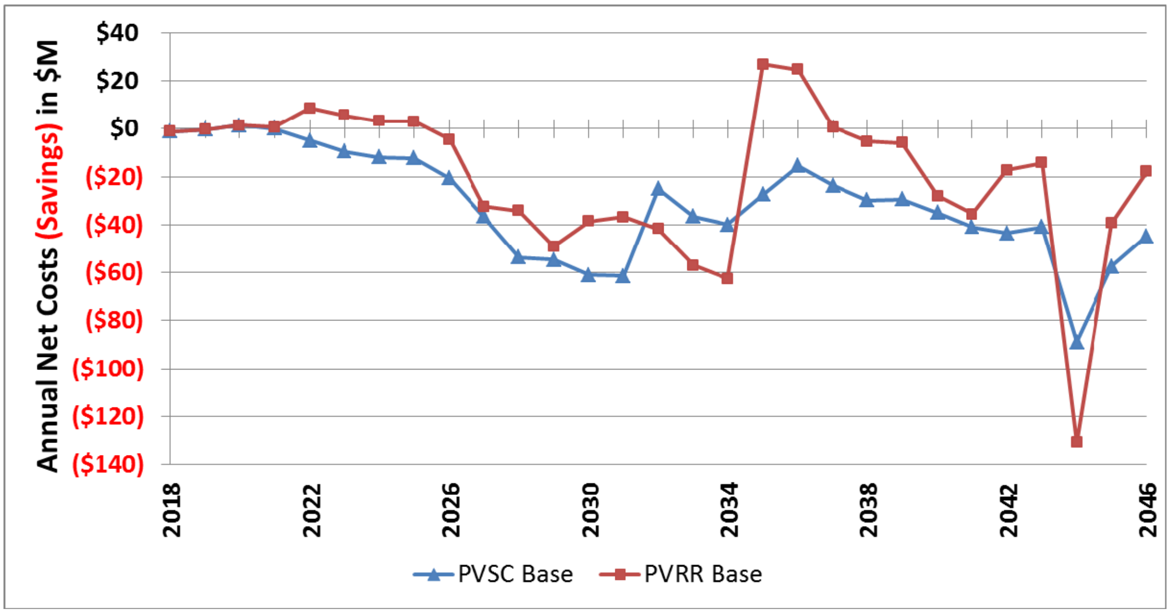
- *Cost of Carbon*

On July 27, 2017 in Docket No. E999/CI-14-643, the Commission adopted two sets of economic assumptions for its range of values for carbon dioxide and required Great River Energy, Minnesota Power, and Otter Tail Power to make a compliance filing providing the CO_2 environmental cost values using those assumptions. We have included the values provided in that compliance filing in Attachment D. While the Commission has not yet issued its Order on the updated CO_2 values, the Company performed two sensitivities using the high and low CO_2 values as shown in Attachment C for all years. We included these sensitives to provide the Commission with insight on how the updated CO_2 values may impact the benefits of the proposed project. We note that the base assumptions use the $21.50 per ton regulated cost, beginning in 2022.

2. *Annual Impacts*

To understand how the costs (savings) change over time, Figure 2 below visually portrays the annual costs (savings) impacts of the total portfolio as compared to the Reference Case for the PVSC and PVRR Base assumptions.

Figure 2: Annual Costs (Savings) Compared to Reference Case



It is important to note that PVSC Base assumptions savings in Figure 1 includes costs for CO_2. A CO_2 cost of $21.50 results in an increase in savings of approximately $10 million per year. Savings shown in Figure 2 for the PVRR Base assumptions assume we are able to take advantage of the MISO energy market to make energy purchases and sales. As the Company will take advantage of MISO energy market transactions when in the interest of our customers, we believe modeling the availability of the MISO energy market provides a better indicator of the likely rate impacts to customers of the wind resource addition. As noted above, even in an extreme case where we are unable to take advantage of the MISO market or receive any revenue for "dump energy" the wind resources provide significant benefits to our customers. We also note that we have included wind integration costs and coal cycling costs consistent with the wind integration study included in our most recent IRP. Based on those assumptions, we have included an impact of approximately $1 million per year due to the impact of coal cycling. We note that, due to the decision to retire the

Sherco Units 1 and 2, we will likely experience lower cost impacts from cycling of our coal plants; however, we have not reduced these costs in our analysis to ensure a conservative approach.

It is important to note that the addition of the proposed wind resource creates a net cost in 2021-2025. Initially, upfront capital costs of the proposed project drives costs higher in the early years, but over the long term, customers receive significant rate benefits from avoided fuel costs and the accrual of PTCs. As shown in Figure 2, customers are expected to realize significant benefits beyond 2025. Due to a combination of the expiration of the PTC and the impact on deferred capacity, costs are expected to be higher than the base case from 2035 to 2037 before again providing savings through the end of the project's expected life.

An alternate way of assessing the value of the proposed wind to the system is by evaluating the levelized price of the projects and the other costs and benefits associated with them. Levelized prices are a fixed $/MWh price that have the same net present value (NPV) as the actual cost streams generated by Strategist. As mentioned previously, in addition to the direct project costs, the Strategist model also adds cost for wind integration and transmission congestion. The primary benefit of the projects is avoided costs from fossil fuel resources, but the model also tracks benefits from avoided emissions and capacity costs. The below table illustrates how the levelized costs of the proposed projects are more than offset by the value of avoided generation costs.

Table 2: PVSC Levelized Costs Analysis – $/MWh

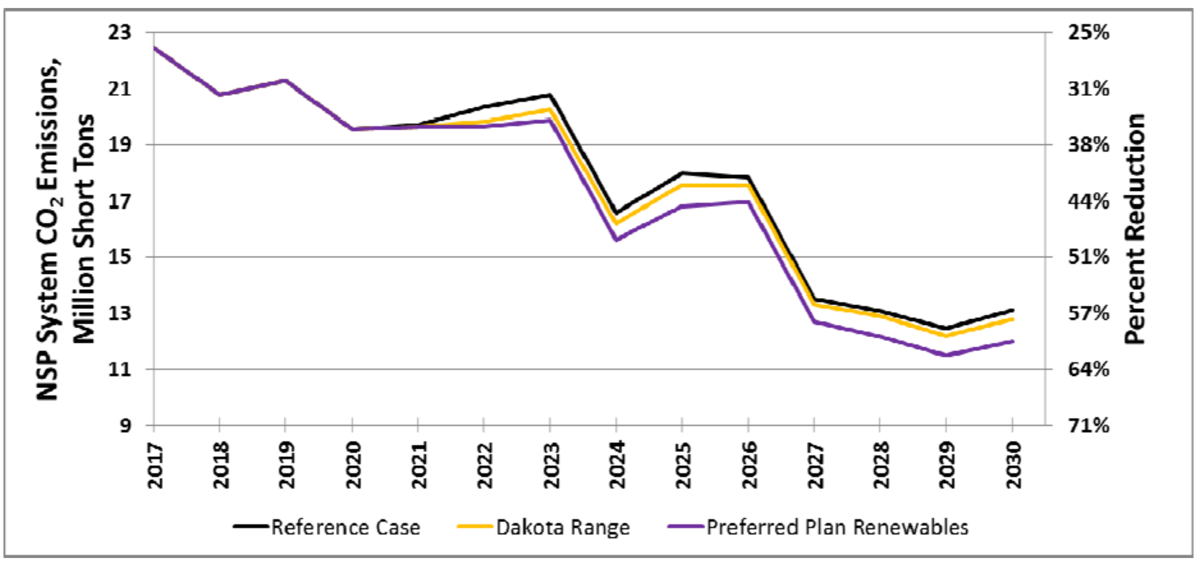
	Dakota Range
LCOE	**[PROTECTED DATA BEGINS** **PROTECTED DATA ENDS]**
Wind Integration	$0.57
Wind Congestion	$3.39
Wind Induced Coal Cycling	$1.44
Avoided Production and Capacity Costs	($44.05)
Avoided Emission Costs	($7.43)
Net Cost/(Benefit)	**[PROTECTED DATA BEGINS** **PROTECTED DATA ENDS]**

Table 3: PVRR Levelized Costs Analysis - $/MWh

	Dakota Range
LCOE	**[PROTECTED DATA BEGINS** **PROTECTED DATA ENDS]**
Wind Integration	$0.57
Wind Congestion	$3.39
Wind Induced Coal Cycling	$1.44
Avoided Production and Capacity Costs	($40.83)
Avoided Emission Costs	$0.00
Net Cost/(Benefit)	**[PROTECTED DATA BEGINS** **PROTECTED DATA ENDS]**

Figure 3 below shows the impact of the proposed wind portfolio on system CO_2 emissions. The Reference Case includes our updated small solar forecast, the shutdown of Sherco Units 1 and 2, and the recently approved 1,550 MW Wind Portfolio. The Preferred Plan Renewables sensitivity includes the addition of the Dakota Range project and 1,650 MW of incremental utility-scale solar additions by 2030.

Figure 3: Impact of Proposed Wind Portfolio on CO_2 Emissions



As shown in Figure 3, the proposed wind addition will further reduce our system

CO_2 emission while lowering customers' bills.

3. Estimated Customer Rate Impacts

We expect that soon after initial operation, customers' overall bills will be lower as a result of the acquisition of the proposed resource. Based on the results of our Strategist modeling, we expect that beginning in 2026, the cost of the proposed wind projects will be more than offset by decreases in the cost of fuel and purchases and increases in revenues from market sales. To develop our rate impacts analysis, we began with the incremental impact of the wind resources as determined by the Strategist modeling that was conducted. Specifically, we used the outputs from the PVRR base assumptions.. We believe this scenario most closely reflects the impacts to customer bills.

Using the annual system-wide costs impact from Strategist, we then applied a jurisdictional allocator based on a current sales forecast to determine the costs allocated to the Minnesota jurisdiction. The jurisdictional costs were then allocated to classes based on Class Cost of Service Study (CCOSS) allocation factors approved in the Company's last Minnesota rate case order.

Table 4 shows the forecasted incremental annual rate impact of the wind additions through 2027. The values in the table reflect incremental costs or savings as compared to the Reference Case where Dakota Range is not included.

Table 4: Incremental Revenue Requirement Impact Proposed Project
($millions)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
New Wind, 300MW	(1.1)	(0.4)	1.4	2.1	23.8	23.9	23.9	24.8	19.6	6.3
Capacity Cost Savings	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(16.3)
Production Cost Savings	0.0	0.0	0.0	(0.8)	(12.8)	(13.2)	(8.8)	(14.1)	(6.4)	(1.1)
MISO Purchases	0.0	0.0	0.0	(0.6)	(2.2)	(2.5)	(6.8)	(3.4)	(6.7)	(11.0)
MISO Sales	0.0	0.0	0.0	(0.5)	(5.9)	(8.5)	(11.1)	(10.4)	(17.4)	(16.7)
Wind Congestion Costs*	0.0	0.0	0.0	0.3	3.4	3.5	3.6	3.6	3.7	3.8
Wind Integration Costs	0.0	0.0	0.0	0.0	0.6	0.6	0.6	0.6	0.6	0.6
Wind Coal Cycling Costs	0.0	0.0	0.0	0.1	1.7	1.8	1.8	1.8	1.9	1.9
Net Costs	**(1.1)**	**(0.4)**	**1.4**	**0.6**	**8.6**	**5.6**	**3.2**	**3.1**	**(4.6)**	**(32.4)**

* Congestion Costs reflected as cost adder to wind generation rather than lower generator LMP.

Table 5, below, shows the forecasted incremental impact on average monthly bills in Minnesota. It is important to note that the recovery mechanism used to recover the costs of this wind addition will impact the actual timing of the recovery and the actual class allocation. We have provided an estimated impact below.

Table 5: MN Forecasted Incremental Impact on Average Monthly Bills

Year	Residential	Commercial Non Demand	C&I Demand	Lighting
2018	($0.02)	($0.02)	($0.93)	($0.01)
2019	($0.01)	($0.01)	($0.32)	($0.00)
2020	$0.02	$0.03	$1.22	$0.01
2021	$0.01	$0.01	$0.53	$0.00
2022	$0.14	$0.18	$7.03	$0.07
2023	$0.06	$0.08	$3.12	$0.03
2024	$0.05	$0.07	$2.48	$0.01
2025	$0.05	$0.07	$2.39	$0.01
2026	($0.06)	($0.09)	($3.82)	($0.06)

VI. CAPITAL SERVICES AFFILIATE AGREEMENT APPROVAL

As already discussed, we intend to use our Capital Services affiliate for the supply of wind turbines to support the Dakota Range project. Similar to our 1,550 MW wind portfolio, Capital Services has agreed to purchase a sufficient amount of "safe-harbor" wind generation equipment in 2017 to secure eligibility for 80 percent PTC qualification for Dakota Range. Capital Services has also negotiated firm pricing and delivery obligations for the additional wind turbines that will be necessary to construct the project. Thus, the existence of Capital Services and its provision of "safe-harbored" turbines to the Company will result in cost savings for our customers—as was the case in connection with our 1,550 MW wind portfolio.

We also intend to use the same Sale of Components Agreement (Agreement) for Dakota Range that was approved by the Commission in its July 13, 2017 Order in Docket No. E002/AI-17-215. That Agreement provides that the wind generation equipment will be transferred to NSPM (assuming Commission approval) on at "at-cost" basis, plus an AFUDC-level carrying charge. Thus, the price paid by the Company will reflect the cost it would have incurred had it directly purchased turbine equipment to qualify Dakota Range for 80 percent of the PTC.

For these reasons, we believe the Agreement is reasonable and in the public interest, and we respectfully request that the Commission approve its use for Dakota Range under Minn. Stat. § 216B.48, as it did for the 1,550 MW wind portfolio acquisition. Consistent with the Commission's July 13, 2017 Order, we propose to (1) include reporting of the charges billed by Capital Services in the Company's annual jurisdictional report within the affiliate transaction section; and (2) provide a one-time report to the Commission with a breakdown of total costs for the wind generation equipment procured from Capital Services for Dakota Range within 60 days after the transfer to NSP is complete.

VII. EFFECT OF CHANGE UPON XCEL ENERGY REVENUE

This petition results in no change in revenue for the Company. If our petition is approved, we will separately file for approval for cost recovery of the proposed Dakota Range Wind Project.

CONCLUSION

The Dakota Range wind project will provide numerous and substantial benefits to our customers and system. These benefits include cost savings for our customers as well as environmental and economic benefits for the communities we serve. And while the project is beneficial and cost-effective in its own right, the Dakota Range project also addresses the Commission's and stakeholders' concerns that the Company have backup projects available should one of the projects in the recently approved 1,550 MW portfolio not reach commercial operation. We respectfully request the Commission take the following actions:

- Allow the Company to build, own, and operate the 302.4 MW Dakota Range wind project;
- Approve an aggregate, symmetrical capital cap for the initial construction of the project;
- Approve the use our Capital Services affiliate agreement for Dakota Range that was approved by the Commission in its July 13, 2017 Order in Docket No. E002/AI-17-215;
- Confirm the 302.4 MW proposed Dakota Range wind project is a reasonable and prudent way to continue to meet our obligations under Minnesota's RES; and

- Establish a procedural schedule such that the Commission may complete deliberations in March of 2018 so we may proceed with this project and secure the maximum available PTC benefits.

Dated: September 26, 2017

Northern States Power Company

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Nancy Lange	Chair
Dan Lipschultz	Commissioner
Matthew Schuerger	Commissioner
Katie J. Sieben	Commissioner
John A. Tuma	Commissioner

IN THE MATTER OF THE PETITION OF XCEL ENERGY FOR APPROVAL OF THE ACQUISITION OF 302.4 MW WIND GENERATION

DOCKET NO. E002/M-17-____

SUMMARY

SUMMARY OF FILING

Please take notice that on September 26, 2017 Northern States Power Company, doing business as Xcel Energy, filed with the Minnesota Public Utilities Commission a Petition for Approval for the Company to acquire, own, and operate the 302.4 MW Dakota Range I and II wind project.

**PUBLIC DOCUMENT –
NOT PUBLIC (OR PRIVILEGED) DATA HAS BEEN EXCISED**

Attachment A provided with the Non-Public version of this response contains data classified as trade secret pursuant to Minn. Stat. §13.37 and are marked as "Non-Public" in their entirety. Pursuant to Minn. R. 7829.0500, subp. 3, the Company provides the following description of the excised material:

1. **Nature of the Material**: Revenue requirement model for the Dakota Range wind project.
2. **Authors:** The model was prepared by the Corporate Development group with inputs provided by multiple areas across the Company.
3. **Importance:** The model contains competitively sensitive data related to project costs.
4. **Date the Information was Prepared**: The model was prepared during the third quarter of 2017.

[TRADE SECRET BEGINS

TRADE SECRET ENDS]

PUBLIC DOCUMENT –
NOT PUBLIC (OR PRIVILEGED) DATA HAS BEEN EXCISED

Attachment B provided with the Non-Public version of this response contains data classified as trade secret pursuant to Minn. Stat. §13.37 and are marked as "Non-Public" in their entirety. Pursuant to Minn. R. 7829.0500, subp. 3, the Company provides the following description of the excised material:

1. **Nature of the Material**: The attachment contains the purchase and sale agreement for the Dakota Range wind project.
2. **Authors:** The data was prepared by the law firms of Orrick, Herrington & Sutcliffe (representing Xcel Energy) and McGuireWoods (representing Apex).
3. **Importance:** The attachment contains confidential pricing and contract terms as well as bid evaluation criteria.
4. **Date the Information was Prepared**: The agreement was prepared during the third quarter of 2017.

[TRADE SECRET BEGINS

TRADE SECRET ENDS]

I. Strategist Modeling Assumptions

1. Discount Rate and Capital Structure

The discount rate used for levelized cost calculations and the present value of modeled costs is 6.30 percent. The rates shown in Table 1 were calculated by taking a weighted average of NSP jurisdictions from the June 2017 Corporate Assumptions Memo.

Table 1: Capital Structure

	Capital Structure	Allowed Return	Before Tax Electric WACC	After Tax Electric WACC
Long-Term Debt	45.60%	4.87%	2.22%	1.32%
Common Equity	52.50%	9.39%	4.93%	4.93%
Short-Term Debt	1.90%	2.85%	0.05%	0.05%
Total			**7.20%**	**6.30%**

2. Inflation Rates

The inflation rates are used for existing resources, generic resources, and other costs related to general inflationary trends in the modeling. The inflation rates are developed using long-term forecasts from Global Insight. The labor and non-labor inflation rates are from the February 2016 Corporate Assumptions Memo. The General inflation rate is from the "Chained Price Index for Total Personal Consumption Expenditures" published in the third quarter of 2015.

- Variable O&M inflation – 50% labor inflation and 50% non-labor inflation – 2.88%.
- Fixed O&M inflation – 75% labor inflation and 25% non-labor inflation – 3.07%.
- General inflation – The inflation rate used for construction (capital) costs and any other escalation factor related to general inflationary trends is 2.0%.

3. Reserve Margin

The reserve margin at the time of MISO's peak is 7.8 percent. The coincidence factor between the NSP System and MISO system peak is 5 percent. Therefore, the effective reserve margin is:

$$(1 - 5\%) * (1 + 7.8\%) - 1 = 2.41\%.$$

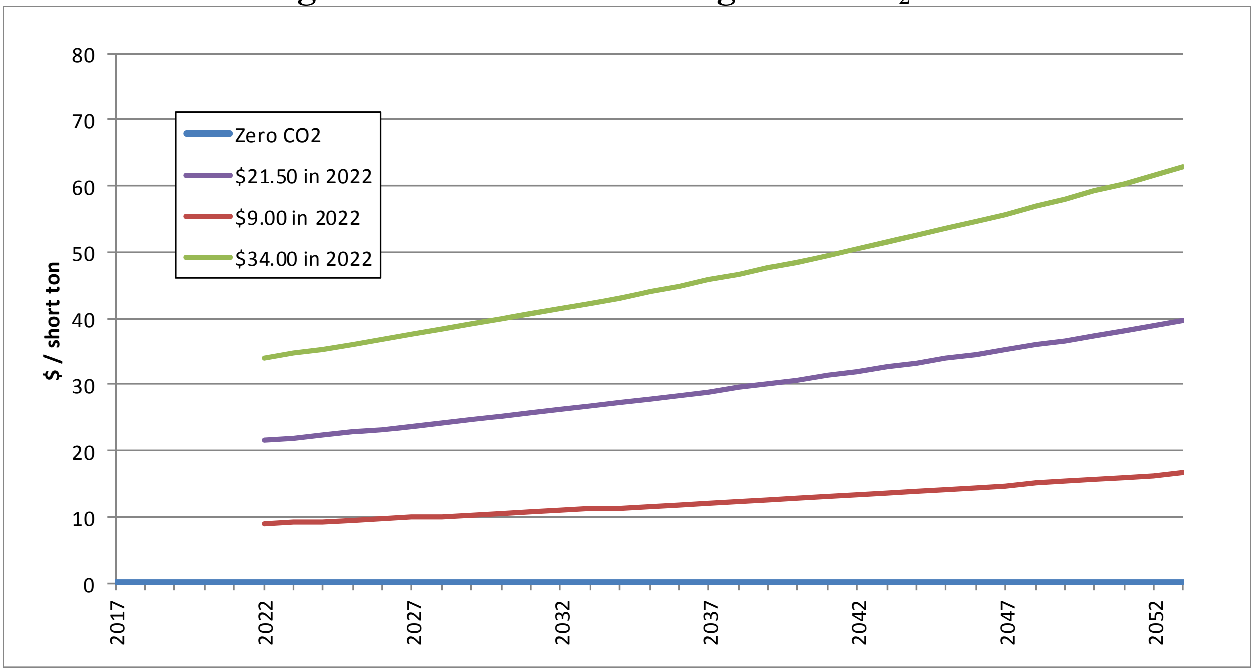
Table 2: Reserve Margin

Reserve Margin	
Coincidence Factor	5.00%
MISO Coincident Peak Reserve Margin %	7.80%
Effective RM Based on Non-coincident Peak	2.41%

4. Regulated CO_2 Costs

Figure 1 shows the annual Regulated CO_2 Costs used in the analysis. The base assumption is $21.50 per short ton starting in 2022 which is the average of $9 per short ton and $34 per short ton. The range of Regulated CO_2 Costs is drawn from the Minnesota Public Utilities Commission's Order Establishing 2016 and 2017 Estimate of Future Carbon Dioxide Regulation Costs in Docket No. E999/CI-07-1199 issued August 5, 2016. All prices escalate at general inflation.

Figure 1: Carbon Dioxide Regulated CO_2 Cost



5. Externality Costs

Externality Costs for NOx, PM10, CO, and Pb are based on the high values from the Minnesota Public Utilities Commission's Notice of Comment Period on Updated Environmental Externality Values issued June 16, 2016 (Docket Nos. E999/CI-93-583 and E999/CI-00-1636) and are shown in Table 3 below. Prices are shown in 2016 dollars and escalate at general inflation. Sulfur dioxide assumed zero cost due to a large surplus of allowances, a weak sales market, and zero externality cost per Commission policy.

Table 3: Externality Costs

MPUC Externality Costs				
$2016 per short ton				
	Urban	**Metro Fringe**	**Rural**	**<200mi**
NOx	$1,466	$399	$153	$153
PM10	$9,627	$4,326	$1,282	$1,282
CO	$3	$2	$1	$1
Pb	$5,808	$2,990	$671	$671

Externality Costs for CO_2 are based on the low and high values from MPUC Docket No. E999-CI-14-643, Fourth Affidavit of Anne E. Smith, Ph.D., Table B. These values in nominal dollars are shown in Table 4.

Table 4: Carbon Dioxide Externality Costs

MPUC CO_2 Externality Costs		
$ per short ton		
Year	Low	High
2017	8.78	41.37
2018	9.17	43.15
2019	9.58	44.99
2020	9.99	46.88
2021	10.42	48.83
2022	10.87	50.84
2023	11.32	52.91
2024	11.80	55.05
2025	12.28	57.24
2026	12.78	59.51
2027	13.29	61.85
2028	13.83	64.25
2029	14.37	66.73
2030	14.94	69.27
2031	15.51	71.89
2032	16.12	74.59
2033	16.72	77.37
2034	17.37	80.23
2035	18.01	83.17
2036	18.69	86.20
2037	19.37	89.31
2038	20.09	92.52
2039	20.81	95.83
2040	21.57	99.22
2041	22.34	102.71
2042	23.15	106.30
2043	23.96	110.00
2044	24.81	113.80
2045	25.67	117.70
2046	26.57	121.72
2047	27.48	125.85
2048	28.43	130.10
2049	29.39	134.46
2050	30.40	138.95
2051	31.42	143.58
2052	32.47	148.32
2053	33.56	153.20

6. Demand and Energy Forecast

The Spring 2017 Load Forecast developed by the Xcel Energy Load Forecasting group is used.

Table 5: Spring 2017 Demand and Energy Forecast

Demand (MW)				Energy (GWh)			
Year	Model Output	W/ Hist DSM, Building Code Adj	Final w DSM/Eff Adjustments	Year	Model Output	W/ Hist DSM, Building Code	Final w DSM/Eff Adjustments
2017	10,435	9,293	9,202	2017	50,828	44,965	44,526
2018	10,485	9,401	9,221	2018	50,739	45,279	44,400
2019	10,559	9,535	9,263	2019	51,173	45,957	44,639
2020	10,646	9,652	9,309	2020	51,485	46,477	44,705
2021	10,726	9,773	9,358	2021	51,715	46,904	44,688
2022	10,815	9,931	9,444	2022	51,912	47,391	44,726
2023	10,911	10,004	9,314	2023	52,217	47,861	44,747
2024	11,013	10,169	9,392	2024	52,566	48,387	44,813
2025	11,123	10,330	9,466	2025	52,831	48,988	44,976
2026	11,239	10,504	9,553	2026	52,984	49,493	45,032
2027	11,343	10,710	9,672	2027	53,258	50,214	45,304
2028	11,445	10,879	9,754	2028	53,630	51,036	45,662
2029	11,558	10,993	9,781	2029	53,930	51,447	45,639
2030	11,673	11,152	9,853	2030	54,118	51,923	45,666
2031	11,779	11,280	10,008	2031	54,414	52,356	46,090
2032	11,883	11,391	10,146	2032	54,778	52,788	46,493
2033	12,005	11,530	10,312	2033	55,080	53,191	46,905
2034	12,127	11,653	10,435	2034	55,263	53,416	47,130
2035	12,234	11,751	10,534	2035	55,551	53,715	47,429
2036	12,335	11,858	10,640	2036	55,903	54,151	47,846
2037	12,450	11,949	10,732	2037	56,184	54,393	48,106
2038	12,570	12,045	10,828	2038	56,363	54,530	48,244
2039	12,679	12,129	10,911	2039	56,675	54,798	48,512
2040	12,784	12,206	10,989	2040	57,059	55,135	48,830
2041	12,900	12,293	11,075	2041	57,371	55,399	49,113
2042	13,020	12,381	11,164	2042	57,560	55,537	49,251
2043	13,124	12,451	11,234	2043	57,877	55,800	49,514
2044	13,237	12,530	11,313	2044	58,241	56,112	49,807
2045	13,326	12,586	11,368	2045	58,563	56,384	50,098
2046	13,438	12,664	11,447	2046	58,748	56,521	50,235
2047	13,540	12,733	11,515	2047	59,117	56,836	50,550
2048	13,644	12,803	11,585	2048	59,590	57,254	50,950
2049	13,748	12,873	11,655	2049	59,729	57,347	51,061
2050	13,851	12,943	11,726	2050	60,036	57,602	51,316
2051	13,955	13,013	11,796	2051	60,342	57,857	51,567
2052	14,059	13,083	11,866	2052	60,818	58,278	51,969
2053	14,163	13,153	11,936	2053	60,955	58,368	52,078

7. DSM Forecast

The DSM forecast assumes impacts expected at a 75 percent rebate level which equals roughly 1.5 percent of sales through the planning period.

Table 6: DSM Forecast

Year	Energy (MWh)	Demand (MW)
2017	439	113
2018	879	227
2019	1,318	342
2020	1,772	429
2021	2,216	516
2022	2,665	603
2023	3,114	690
2024	3,573	777
2025	4,012	864
2026	4,461	951
2027	4,910	1,038
2028	5,375	1,125
2029	5,808	1,212
2030	6,257	1,299
2031	6,266	1,272
2032	6,294	1,245
2033	6,286	1,217
2034	6,286	1,217
2035	6,286	1,217
2036	6,305	1,217
2037	6,286	1,217
2038	6,286	1,217
2039	6,286	1,217
2040	6,305	1,217
2041	6,286	1,217
2042	6,286	1,217
2043	6,286	1,217
2044	6,305	1,217
2045	6,286	1,217
2046	6,286	1,217
2047	6,286	1,217
2048	6,305	1,217
2049	6,286	1,217
2050	6,286	1,217
2051	6,290	1,217
2052	6,308	1,217
2053	6,290	1,217

8. Demand Response Forecast

The 2017 Load Management Forecast developed by the Xcel Energy Load Research group is used. The table below shows the July demand.

Table 7: 2017 Load Management Forecast

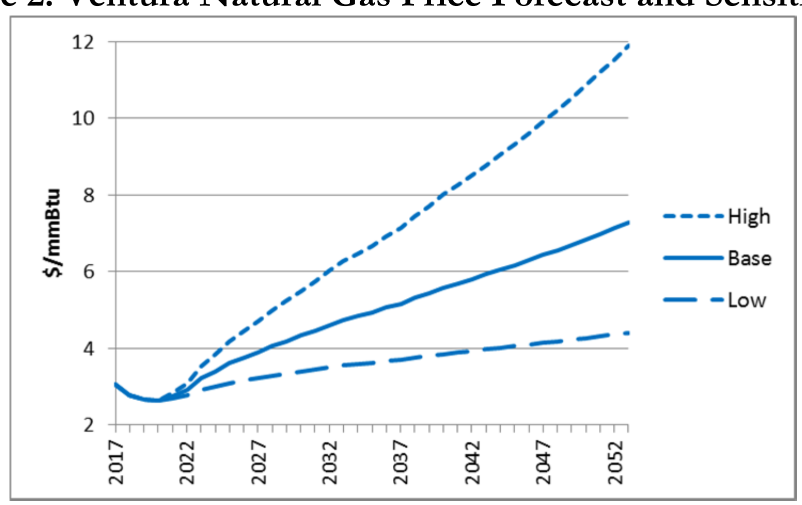
July Demand (MW)	2017	2018	2019	2020	2021	2022	2023	2024
LMF	853	864	880	896	911	926	933	940
July Demand (MW)	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
LMF	947	948	944	940	936	932	928	924
July Demand (MW)	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
LMF	920	916	913	909	905	901	898	894
July Demand (MW)	**2041**	**2042**	**2043**	**2044**	**2045**	**2046**	**2047**	**2048**
LMF	891	887	884	880	877	873	870	866
July Demand (MW)	**2049**	**2050**	**2051**	**2052**	**2053**			
LMF	863	860	856	853	849			

9. Natural Gas Price Forecasts

Henry Hub natural gas prices are developed using a blend of market information (New York Mercantile Exchange futures prices) and long-term fundamentally-based forecasts from Wood Mackenzie, Cambridge Energy Research Associates (CERA) and Petroleum Industry Research Associates (PIRA).

Gas Prices as of February 28, 2017 were used. High and low gas price sensitivities were performed by adjusting the growth rate up and down by 50 percent from the base natural gas cost forecast starting in year 2021.

Figure 2: Ventura Natural Gas Price Forecast and Sensitivities



10. Natural Gas Transportation Costs

Gas transportation variable costs include the gas transportation charges and the Fuel Lost & Unaccounted (FL&U) for all of the pipelines the gas flows through from the Ventura Hub to the generators facility. The FL&U charge is stated as a percentage of the gas expected to be consumed by the plant, effectively increasing the gas used to operate the plant, and is at the price of gas commodity being delivered to the plant. Table 12 contains gas transportation charges for generic thermal resources.

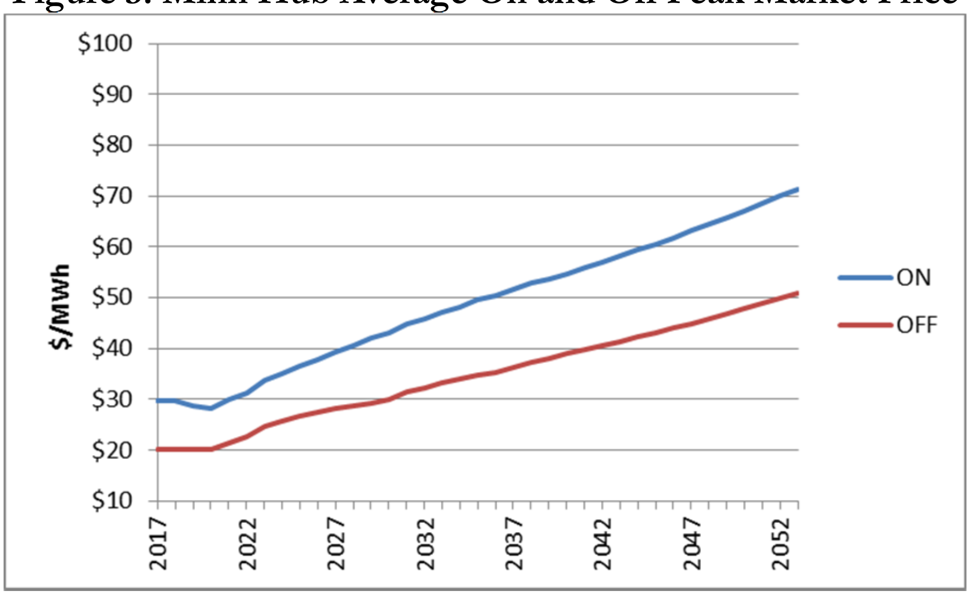
11. Natural Gas Demand Charges

Gas demand charges are fixed annual payments applied to resources to guarantee that natural gas will be available (normally called "firm gas"). Typically, firm gas is obtained to meet the needs of the winter peak as enough gas is normally available during the summer. Table 12 contains gas demand charges for generic thermal resources.

12. Electric Power Market Prices

In addition to resources that exist within the NSP System, the Company is a participant in the MISO Market. Electric power market power prices are developed from fundamentally-based forecasts from Wood Mackenzie, CERA and PIRA. Figure 3 below shows the market prices under zero cost CO_2 assumptions.

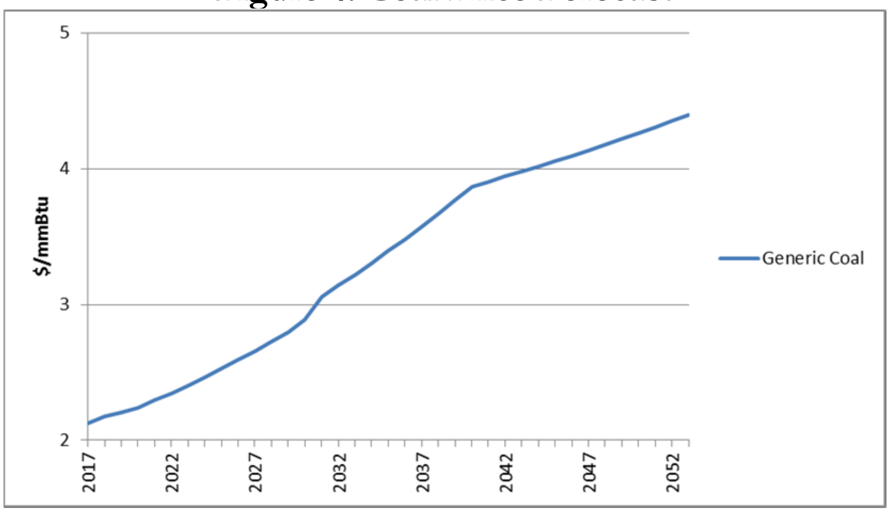
Figure 3: Minn Hub Average On and Off Peak Market Price



13. Coal Price Forecast

Coal price forecasts are developed using two major inputs: the current contract volumes and prices combined with current estimates of required spot volumes and prices. Typically coal volumes and prices are under contract on a plant by plant basis for a one to five year term with annual spot volumes filling the estimated fuel requirements of the coal plant based on recent unit dispatch. The spot coal price forecasts are developed from price forecasts provided by Wood Mackenzie, JD Energy, and John T Boyd Company, as well as price points from recent Request for Proposal (RFP) responses for coal supply. Layered on top of the coal prices are transportation charges, SO_2 costs, freeze control and dust suppressant, as required.

Figure 4: Coal Price Forecast



14. Surplus Capacity Credit

The credit is applied for all twelve months of each year and is priced at the avoided capacity cost of a generic combustion turbine.

Table 8: Surplus Capacity Credit

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
$/kW-mo	4.84	4.94	5.03	5.14	5.24	5.34	5.45	5.56	5.67	5.78

	2027	2028	2029	2030	2031	2032	2033	2034	2035
$/kW-mo	5.90	6.02	6.14	6.26	6.39	6.51	6.64	6.78	6.91

	2036	2037	2038	2039	2040	2041	2042	2043	2044
$/kW-mo	7.05	7.19	7.33	7.48	7.63	7.78	7.94	8.10	8.26

	2045	2046	2047	2048	2049	2050	2051	2052	2053
$/kW-mo	8.43	8.59	8.77	8.94	9.12	9.30	9.49	9.68	9.87

15. Transmission Delivery Costs

Generic 2x1 combined cycle (CC), generic combustion turbine (CT), generic wind and generic solar have assumed transmission delivery costs. The table below shows the transmission delivery costs on a $/kW basis. The CC and CT costs were developed based on the average of several potential sites in the Minnesota. The general site locations were investigated by Transmission Access for impacts to the transmission grid and expected resulting upgrade costs

Table 9: Transmission Delivery Costs

	$/kw
CC	$ 429
CT	$ 158
Solar	$ 70
Wind	$ 96

16. Interconnection Costs

Estimates of interconnection costs of the generic resources were included in the capital cost estimates.

17. Effective Load Carrying Capability (ELCC) Capacity Credit for Wind Resources

Existing wind units is based on current MISO accreditation. New wind additions are given a capacity credit equal to 15.6 percent of their nameplate rating per MISO 2017/2018 Wind Capacity Report.

18. ELCC Capacity Credit for Utility Scale Solar Photovoltaic (PV) Resources

Utility scale generic solar PV additions used in modeling the alternative plans were given a capacity credit equal to 50 percent of the AC nameplate capacity. This value is the MISO proposed solar capacity credit for the 2016/2017 planning year.

19. Spinning Reserve Requirement

Spinning Reserve is the on-line reserve capacity that is synchronized to the grid to maintain system frequency stability during contingency events and unforeseen load swings. The level of spinning reserve modeled is 94 MW and is based on a 12 month rolling average of spinning reserves carried by the NSP System within MISO.

20. Emergency Energy Costs

Emergency Energy Costs were assigned in the Strategist model if there were not enough resources available to meet energy requirements. The cost was set at $500/MWh in 2014 escalating at inflation which is about $150/MWh more than an oil unit with an assumed heat rate of 15 mmBtu/MWh. Emergency energy occurs only in rare instances.

21. Wind Integration Costs

Wind integration costs were priced based upon the results of the NSP System Wind Integration Cost Study. Wind integration costs contain five components:

1. MISO Contingency Reserves
2. MISO Regulating Reserves
3. MISO Revenue Sufficiency Guarantee Charges
4. Coal Cycling Costs
5. Gas Storage Costs

The complete Wind Integration Study is included in Appendix M of the 2015 Upper Midwest Resource Plan. The results of the study as used in Strategist are shown below. The Coal Cycling Costs are zero after 2040 because the last coal unit on the Company's system in the modeling retires in 2040.

Table 10: Wind Integration Costs

	Wind Integration $/MWh		Coal Cycling $/MWh	
	Existing Resources	New Resources	Existing Resources	New Resources
2016	0.41	0.42	0.75	1.26
2017	0.42	0.43	0.77	1.28
2018	0.43	0.44	0.78	1.31
2019	0.44	0.45	0.80	1.33
2020	0.44	0.46	0.82	1.36
2021	0.45	0.46	0.83	1.39
2022	0.46	0.47	0.85	1.41
2023	0.47	0.48	0.87	1.44
2024	0.48	0.49	0.88	1.47
2025	0.49	0.50	0.90	1.50
2026	0.50	0.51	0.92	1.53
2027	0.51	0.52	0.94	1.56
2028	0.52	0.53	0.96	1.59
2029	0.53	0.54	0.98	1.62
2030	0.54	0.55	1.00	1.66
2031	0.55	0.56	1.01	1.69
2032	0.56	0.58	1.04	1.72
2033	0.58	0.59	1.06	1.76
2034	0.59	0.60	1.08	1.79
2035	0.60	0.61	1.10	1.83
2036	0.61	0.62	1.12	1.87
2037	0.62	0.63	1.14	1.90
2038	0.64	0.65	1.17	1.94
2039	0.65	0.66	1.19	1.98
2040	0.66	0.67	1.21	2.02
2041	0.67	0.69	-	-
2042	0.69	0.70	-	-
2043	0.70	0.71	-	-
2044	0.72	0.73	-	-
2045	0.73	0.74	-	-
2046	0.74	0.76	-	-
2047	0.76	0.77	-	-
2048	0.77	0.79	-	-
2049	0.79	0.80	-	-
2050	0.81	0.82	-	-
2051	0.82	0.83	-	-
2052	0.84	0.85	-	-
2053	0.86	0.87	-	-

22. Wind Congestion Costs

Wind Congestion Costs were developed by Xcel Energy Transmission Planning group from PROMOD LMP simulations for years 2020 and 2025 using the MTEP 16 database. Based on those simulations, we included congestion cost of $2.71 per MWh in 2020, escalating at 2% thereafter, for all new wind including the 300MW Dakota Range project.

Table 11: Wind Congestion Costs

	Wind Congestion $/MWh	
	Existing Resources	New Resources
2017	-	-
2018	-	-
2019	-	2.66
2020	-	2.71
2021	-	2.77
2022	-	2.82
2023	-	2.88
2024	-	2.93
2025	-	2.99
2026	-	3.05
2027	-	3.11
2028	-	3.18
2029	-	3.24
2030	-	3.31
2031	-	3.37
2032	-	3.44
2033	-	3.51
2034	-	3.58
2035	-	3.65
2036	-	3.72
2037	-	3.80
2038	-	3.87
2039	-	3.95
2040	-	4.03
2041	-	4.11
2042	-	4.19
2043	-	4.28
2044	-	4.36
2045	-	4.45
2046	-	4.54
2047	-	4.63
2048	-	4.72
2049	-	4.81
2050	-	4.91
2051	-	5.01
2052	-	5.11
2053	-	5.21

23. Distributed Generation and Community Solar Gardens

The small solar inputs are based on the most recent Company forecast.

24. Assumption and Sensitivity Descriptions

The modeling uses the following assumptions and sensitivities. The Base Assumptions are combined with the Sensitivities to test the modeling results for critical variables.

Table 12: Assumption and Sensitivity Descriptions

Base Assumptions	Assumption Description
PVSC Base	All Strategist expansion plans are optimized under the PVSC Base assumption. PVSC Base includes the Regulated CO_2 Cost of $21.50 per short ton in 2022, Externality Costs, and Surplus Capacity Credit. Optimized expansion plans were completed using the PVSC Base assumption and the PVSC Base assumption combined with the following sensitivity: Preferred Plan Renewables. All Strategist outputs except the Markets Off sensitivity assume the modeling of MISO Energy Market interactions.
PVRR Base	This assumption removes Regulated CO_2 Costs, Externality Costs, and the Surplus Capacity Credit from the PVSC Base assumption. All Strategist outputs except the Markets Off sensitivity assume the modeling of MISO Energy Market interactions.
Sensitivities	**Sensitivity Description**
Markets Off	This sensitivity removes the modeling of the Company's hourly purchases and sales in the MISO Energy Market.
Low Gas Price	This sensitivity decreases the annual year-over-year percent change in natural gas prices by 50% starting in year 2021.
High Gas Price	This sensitivity increases the annual year-over-year percent change in natural gas prices by 50% starting in year 2021.
Low CO_2 Externality	This sensitivity removes the Regulated CO_2 Cost and models the Low Externality Price of CO_2 for the modeling period.
High CO_2 Externality	This sensitivity removes the Regulated CO_2 Cost and models the High Externality Price of CO_2 for the modeling period.
+5% Cap Factor	This sensitivity increases the expected capacity factor by 5% for the proposed Dakota Range project.
-5% Cap Factor	This sensitivity decreases the expected capacity factor by 5% for the proposed Dakota Range project.
Preferred Plan Renewables	This sensitivity adds 1650MW of additional utility-scale solar by 2030.

25. Owned Unit Modeled Operating Characteristics and Costs

Company owned units were modeled based upon their tested operating characteristics and historical or projected costs. Below is a list of typical operating and cost inputs for each company owned resource.

a. Retirement Date
b. Maximum Capacity
c. Current Unforced Capacity (UCAP) Ratings
d. Minimum Capacity Rating
e. Seasonal Deration
f. Heat Rate Profiles
g. Variable O&M
h. Fixed O&M

i. Maintenance Schedule
j. Forced Outage Rate
k. Emission rates for SO_2, NO_x, CO_2, Mercury and particulate matter (PM)
l. Contribution to spinning reserve
m. Fuel prices
n. Fuel delivery charges

26. Thermal Power Purchase Agreement (PPA) Operating Characteristics and Costs

PPAs are modeled based upon their tested operating characteristics and contracted costs. Below is a list of typical operating and cost inputs for each thermal PPA.

a. Contract term
b. Maximum Capacity
c. Minimum Capacity Rating
d. Seasonal Deration
e. Heat Rate Profiles
f. Energy Schedule
g. Capacity Payments
h. Energy Payments
i. Maintenance Schedule
j. Forced Outage Rate
k. Emission rates for SO_2, NO_x, CO_2, Mercury and PM
l. Contribution to spinning reserve
m. Fuel prices
n. Fuel delivery charges

27. Renewable Energy PPAs and Owned Operating Characteristics and Costs

PPAs are modeled based upon their tested operating characteristics and contracted costs. Company owned units were modeled based upon their tested operating characteristics and historical or projected costs. Below is a list of typical operating and cost inputs for each renewable energy PPA and owned unit.

a. Contract term
b. Name Plate Capacity
c. Accredited Capacity
d. Annual Energy
e. Hourly Patterns
f. Capacity and Energy Payments
g. Integration Costs

Wind hourly patterns were developed through a "Typical Wind Year" process where individual months were selected from the years 2014-2016 to develop a typical year. Actual generation data from the selected months were used to develop the profiles for each wind farm. For farms where generation data was not complete or not available, data from nearby similar farms were used.

Solar hourly patterns were taken from the Fall 2013 and updated to reflect the ELCC as stated above. The fixed panel pattern is an average of the four orientations and three years (2008-2010) of data and single-axis tracking pattern is an average of three years of data.

28. Generic Assumptions

Generic resources were modeled based upon their expected operating characteristics and projected costs. Below is a list of typical operating and cost inputs for each generic resource.

Thermal

a. Retirement Date
b. Maximum Capacity
c. UCAP Ratings
d. Minimum Capacity Rating
e. Seasonal Deration
f. Heat Rate Profiles
g. Variable O&M
h. Fixed O&M
i. Maintenance Schedule
j. Forced Outage Rate
k. Emission rates for SO_2, NO_x, CO_2, Mercury and PM
l. Contribution to spinning reserve
m. Fuel prices
n. Fuel delivery charges

Renewable

a. Contract term
b. Name Plate Capacity
c. Accredited Capacity
d. Annual Energy
e. Hourly Patterns
f. Capacity and Energy Payments

g. Integration Costs

Tables 13-14 below show the assumptions for the generic thermal and renewable resources.

Table 13: Thermal Generic Information (Costs in 2016 Dollars)

Resource	Coal	Coal w/ Seq	2x1 CC	1x1 CC	CT	Small CT	Biomass
Nameplate Capacity (MW)	511	511	778.3	291.1	229.9	103.4	50
Summer Peak Capacity with Ducts (MW)	NA	NA	766.3	NA	NA	NA	NA
Summer Peak Capacity without Ducts (MW	485	485	649.8	290.2	226.1	100.8	50
Cooling Type	Dry	Dry	Dry	Dry	NA	Wet	Wet
Capital Cost ($/kw)	3,758	5,487	963	1,212	626	1,572	4,731
Electric Transmission Delivery ($/kw)	NA	NA	429	NA	158	NA	NA
Gas Demand ($/kw-yr)	0	0	8.96	11.98	0	0	0
Book life	30	30	40	40	30	30	30
Fixed O&M Cost ($000/yr)	16,973	25,546	7,813	4,299	614	886	5,382
Variable O&M Cost ($/MWh)	2.92	11.00	3.20	1.82	2.36	1.88	4.88
Ongoing Capital Expenditures ($/kw-yr)	9.96	24.31	4.50	4.97	6.11	1.93	14.67
Heat Rate with Duct Firing (btu/kWh)	NA	NA	7725	NA	NA	NA	NA
Heat Rate 100% Loading (btu/kWh)	9,156	12,096	6,822	7,830	9,942	8,867	14,421
Heat Rate 75% Loading (btu/kWh)	9,190	12,565	6,905	8,010	11,048	9,688	14,580
Heat Rate 50% Loading (btu/kWh)	9,710	13,600	6,943	8,583	14,601	11,161	15,570
Heat Rate 25% Loading (btu/kWh)	11,245	17,140	7,583	9,798	NA	15,067	18,650
Forced Outage Rate	6%	7%	3%	3%	3%	2%	4%
Maintenance (weeks/year)	2	5	5	4	2	2	7
CO2 Emissions (lbs/MMBtu)	216	9	118	118	118	118	211
SO2 Emissions (lbs/MWh)	0.447	0.371	0.005	0.005	0.007	0.007	0.577
NOx Emissions (lbs/MWh)	0.45	0.62	0.06	0.05	0.30	0.08	1.01
PM10 Emissions (lbs/MWh)	0.14	0.14	0.01	0.01	0.01	0.01	0.43
Mercury Emissions (lbs/Million MWh)	0.00007	0.00010	0.00000	0.00000	0.00000	0.00000	0.00017

Table 14: Renewable Generic ECC Costs - $/MWh

Year	30% ITC Solar	10% ITC Solar
2020	44	
2021	45	
2022	45	
2023	46	
2024	47	
2025	48	56
2026	49	57
2027	50	58
2028	51	60
2029	52	61
2030	53	62
2031	54	63
2032	55	64
2033	56	66
2034	58	67
2035	59	68
2036	60	70
2037	61	71
2038	62	73
2039	64	74
2040	65	76
2041	66	77
2042	67	79
2043	69	80
2044	70	82
2045		83
2046		85
2047		87
2048		89
2049		90

II. Strategist Modeling Outputs

1. Annual Net Costs and Savings

The PVSC Base and PVRR Base annual costs and savings for the proposed Dakota Range project are in Figure 1 and Table 1.

Figure 1: Annual PVSC and PVRR Net Costs (Savings) in $millions

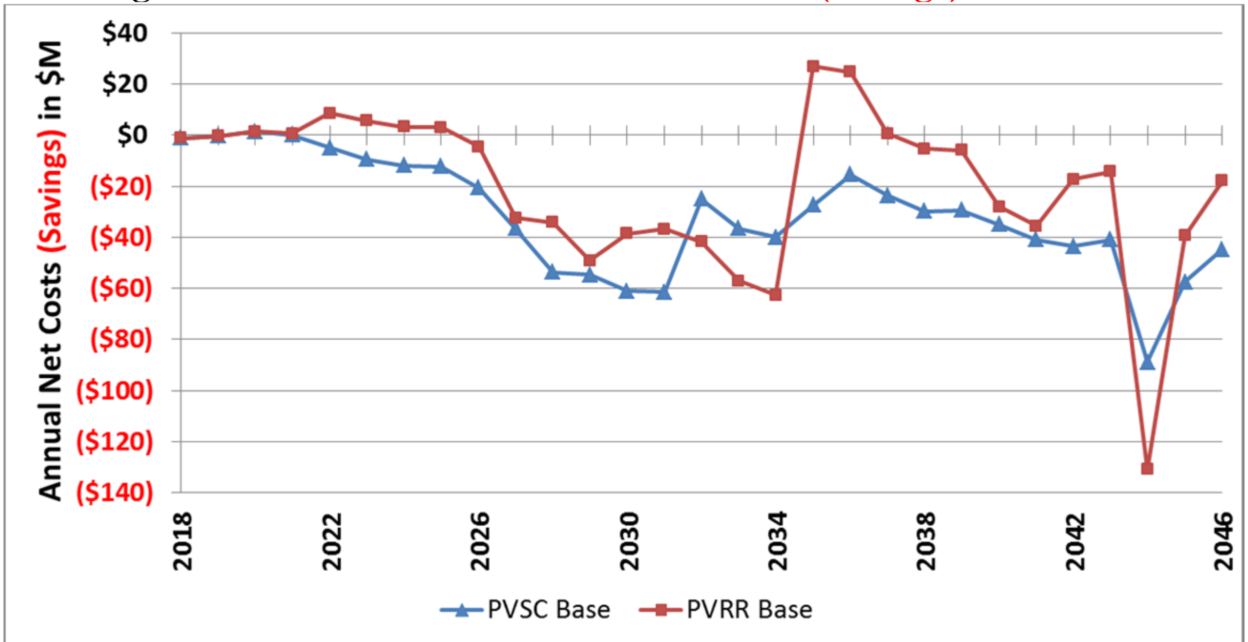


Table 1: Annual PVSC and PVRR Net Costs (Savings) in $millions

Annual Net Costs (Savings) of Dakota Range Project, $M

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
PVSC Base	0	(1)	(0)	1	0	(5)	(10)	(12)	(12)	(21)
PVRR Base	0	(1)	(0)	1	1	9	6	3	3	(5)

	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
PVSC Base	(37)	(54)	(55)	(61)	(61)	(25)	(37)	(40)	(27)	(15)
PVRR Base	(32)	(34)	(49)	(39)	(37)	(42)	(57)	(63)	27	25

	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046
PVSC Base	(24)	(30)	(29)	(35)	(41)	(44)	(41)	(89)	(57)	(45)
PVRR Base	1	(5)	(6)	(28)	(36)	(17)	(14)	(131)	(39)	(18)

2. Expansion Plans

The Reference Case is represented as Table 2 which includes the recently approved 1550MW wind portfolio. The expansion plan with the proposed 300MW Dakota Range wind project is shown as Table 3. Dakota Range is in year 2021, and there are no other wind or utility-scale solar additions after 2021. The 300MW Dakota Range wind project under the Preferred Plan Renewables sensitivity is represented as Table 4 which includes 1650MW of new utility-scale solar by 2030.

Table 2: Reference Case Expansion Plan

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Large Solar	262	-	-	-	-	-	-	-	-	-	-	-	-	-
Generic Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Wind Projects	-	-	1,150	400	-	-	-	-	-	-	-	-	-	-
CT	-	-	232	-	-	-	-	-	920	690	460	230	230	-
CC	-	-	345	-	-	-	-	-	-	-	-	-	-	-
Sherco CC	-	-	-	-	-	-	-	-	-	-	786	-	-	-

	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Large Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Generic Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Wind Projects	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT	230	-	-	-	-	230	230	-	230	230	-	-	-	-
CC	778	778	-	778	778	-	-	778	-	-	778	-	-	778
Sherco CC	-	-	-	-	-	-	-	-	-	-	-	-	-	-

	2045	2046	2047	2048	2049	2050	2051	2052	2053	Total
Large Solar	-	-	-	-	-	-	-	-	-	262
Generic Wind	-	-	-	-	-	-	-	-	-	-
Wind Projects	-	-	-	-	-	-	-	-	-	1,550
CT	-	-	-	-	-	-	-	-	-	3,912
CC	-	-	-	778	778	-	-	-	-	7,347
Sherco CC	-	-	-	-	-	-	-	-	-	786

Table 3: Dakota Range Expansion Plan

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Large Solar	262	-	-	-	-	-	-	-	-	-	-	-	-	-
Generic Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Wind Projects	-	-	1,150	400	300	-	-	-	-	-	-	-	-	-
CT	-	-	232	-	-	-	-	-	920	690	230	460	-	230
CC	-	-	345	-	-	-	-	-	-	-	-	-	-	-
Sherco CC	-	-	-	-	-	-	-	-	-	-	786	-	-	-

	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Large Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Generic Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Wind Projects	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT	230	460	-	-	-	-	-	-	230	-	-	230	-	-
CC	778	-	-	778	1,556	-	-	778	-	-	778	-	-	-
Sherco CC	-	-	-	-	-	-	-	-	-	-	-	-	-	-

	2045	2046	2047	2048	2049	2050	2051	2052	2053	Total
Large Solar	-	-	-	-	-	-	-	-	-	262
Generic Wind	-	-	-	-	-	-	-	-	-	-
Wind Projects	-	-	-	-	-	-	-	-	-	1,850
CT	-	-	-	-	-	-	-	-	-	3,912
CC	778	-	-	778	778	-	-	-	-	7,347
Sherco CC	-	-	-	-	-	-	-	-	-	786

Table 4: Dakota Range Expansion Plan with Preferred Plan Renewables

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Large Solar	262	-	-	-	-	400	200	300	200	150	-	400	-	-
Generic Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Wind Projects	-	-	1,150	400	300	-	-	-	-	-	-	-	-	-
CT	-	-	232	-	-	-	-	-	230	690	230	230	230	-
CC	-	-	345	-	-	-	-	-	-	-	-	-	-	-
Sherco CC	-	-	-	-	-	-	-	-	-	-	786	-	-	-

	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Large Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Generic Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Wind Projects	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT	920	-	-	-	230	230	-	-	230	230	-	-	230	-
CC	-	778	-	778	778	-	-	778	-	-	778	-	-	-
Sherco CC	-	-	-	-	-	-	-	-	-	-	-	-	-	-

	2045	2046	2047	2048	2049	2050	2051	2052	2053	Total
Large Solar	-	-	-	-	-	-	-	-	-	1,912
Generic Wind	-	-	-	-	-	-	-	-	-	-
Wind Projects	-	-	-	-	-	-	-	-	-	1,850
CT	-	-	-	-	-	230	230	-	230	4,602
CC	778	-	-	778	778	-	-	-	-	6,569
Sherco CC	-	-	-	-	-	-	-	-	-	786

DORSEY
always ahead

COLIN WICKER
(612) 492-6687
wicker.colin@dorsey.com

August 3, 2017

VIA ELECTRONIC FILING

Daniel P. Wolf
Executive Secretary
Minnesota Public Utilities Commission
121 Seventh Place East, Suite 350
St. Paul, MN 55101-2147

Re: In the Matter of the Further Investigation into Environmental and Socioeconomic Costs Under Minn. Stat. § 216B.2422, Subd. 3

Compliance Filing, Fourth Affidavit of Anne E. Smith, Ph.D. with Attachment 1

MPUC Docket No. E999-CI-14-643
OAJ Docket No. 80-2500-31888

Dear Mr. Wolf:

At the hearing on July 27, 2017, the Commission ordered Great River Energy, Minnesota Power, and Otter Tail Power Company to make a compliance filing within ten days providing carbon dioxide environmental cost values for additional emission years determined using economic framing assumptions chosen by the Commission. In compliance with that order, attached please find the Fourth Affidavit of Anne E. Smith, Ph.D. along with Attachment 1 to the affidavit, which contains the information required by the Commission.

Thank you for your attention to this matter. Please feel free to contact me at (612) 492-6687 if you have any questions related to this filing or if additional information is required.

Very truly yours,

DORSEY & WHITNEY LLP

/s/ Colin Wicker

Colin Wicker

CW/tjb
Enclosures

cc: Service List (via e-filing) (with encl.)

MINNESOTA PUBLIC UTILITIES COMMISSION
121 Seventh Place East Suite 350
St. Paul, Minnesota 55101-2147

In the Matter of the Further Investigation into Environmental and Socioeconomic Costs Under Minn. Stat. § 216B.2422, Subd. 3

MPUC DOCKET NO. E-999/CI-14-643

FOURTH AFFIDAVIT OF ANNE E. SMITH, Ph.D.

City of Washington)
) ss.
District of Columbia)

Anne E. Smith, being duly sworn, states the following under oath:

1. I am an economist and Managing Director at NERA Economic Consulting.

2. I have provided testimony on behalf of Great River Energy, Minnesota Power, Otter Tail Power Company (collectively, "the Utilities"), and the Minnesota Large Industrial Group ("MLIG"), in the above-referenced proceeding. I have also previously offered a report titled Expert Report of Anne E. Smith, Ph.D., Senior Vice President, NERA Economic Consulting and dated June 1, 2015 (the "Report"), which was marked as Exhibit 302. The Report included a Table 4 at page 43, and I subsequently submitted an affidavit executed on September 21, 2015, which included as an exhibit a modification to Table 4 from the Report, titled Table 4A. My initial affidavit and Table 4A were marked as Exhibit 307. I submitted a second affidavit on July 24, 2017, which included a Table 4B. The values in Table 4B were calculated based on the July 2015 Technical Support Document from the Interagency Working Group ("IWG") and were reported in 2015 dollars per net short ton. I also submitted a third affidavit on July 27, 2017 which contained values for emission years 2017, 2020, 2030, 2040, and 2040 determined using specific sets of economic framing assumptions advocated by the Utilities and MLIG.

3. At the hearing on July 27, 2017, which I viewed online, the Commission adopted two sets of economic framing assumptions for its range of values for carbon dioxide. The low end of the range was based on a 5% discount rate, a time horizon ending in 2100, last ton marginal cost, and global values. The high end of the range is based on a 3% discount rate, a time ending in 2300, last ton marginal cost, and global damages. The Commission had 2020 emission year values for those two sets of framing assumptions in hand at the time it adopted them, but not other emission years. Accordingly, near the close of the hearing the Commission verbally ordered the Utilities to make a compliance filing providing emission year values for additional years.

4. I have used the results of the FUND, DICE, and PAGE models (the IAMs used by the IWG) to calculate values for emission years 2020 and 2050 for the Commission's two sets of economic framing assumptions. Then, I used interpolation to arrive at emission year values for the years in between, including 2030 and 2040. I also used extrapolation to determine emission year values for 2017, 2018, and 2019. As I explained in my prior affidavit, I believe using interpolation is reasonable based on the near-linearity of the Federal Social Cost of Carbon ("FSCC") estimates produced by the Interagency Working Group ("IWG") for the years 2020, 2030, 2040 and 2050.

5. Attachment 1 to this affidavit contains two tables. Table A provides the emission year values for 2017, 2020, 2030, 2040, and 2050 determined using both the low and high end sets of framing assumptions. Table B provides emission year values for every year from 2017 to 2050 for both the low end and high end sets of framing assumptions.

6. All the values in Attachment 1 are reported in 2015 dollars per net short ton and were calculated based on the IWG's July 2015 Technical Support Document.

Further your affiant sayeth not.

By: Anne E. Smith
Anne. E. Smith

Sworn before me on August 3, 2017

Johnnie M. Murphy
Notary Public

District of Columbia: SS
Subscribed and sworn to before me, in my presence,
this 3rd day of August, 2017
Johnnie M. Murphy
Johnnie M. Murphy, Notary Public, D.C.
My commission expires May 14, 2021.

JOHNNIE M. MURPHY NOTARY PUBLIC DISTRICT OF COLUMBIA EXP. 5-14-21

4846-0630-8940\1

Attachment 1. ENVIRONMENTAL COST VALUES FOR CO_2
August 3, 2017

The following tables summarize results of NERA's calculations of ECVs per net ton of change in CO2 emissions for the two sets of policy assumptions adopted by the Commissioners on July 27, 2017 to establish the low and high ends of the range. The low end of the range is based on 5% discount rate, time horizon ending 2100, last ton marginal cost, and global damages. The high end of the range is one set of framing assumptions used by the IWG, namely 3% discount rate, time horizon ending 2300, last ton marginal cost, and global damages. The full suite of IAM runs have been completed for 2050, using the methodology NERA used for its 2020 values. These runs used the versions of the IAM calculations described in the July 2015 Technical Support Document from the Interagency Working Group ("IWG"). The values for emission years between 2020 and 2050 have been interpolated from the 2020 and 2050 estimates. We also provide $/net ton estimates for emissions in 2017 by extrapolating back 3 years from 2020 using the 2020-2050 relationship.

Table A provides the values for 2017, 2020, 2030, 2040 and 2050. Table B (on the next page) provides the values for every individual year from 2017 through 2050, to avoid any uncertainty regarding consistent interpolation. All values are stated in 2015 real dollars and as dollars per net short ton of CO_2.

Table A. Summary of Ranges of ECVs for CO_2 Through 2050
(2015$ per net short ton)

	2017	2020	2030	2040	2050
Low:	$ 8.44	**$ 9.05**	$ 11.10	$ 13.15	**$ 15.20**
High:	$ 39.76	**$ 42.46**	$ 51.47	$ 60.48	**$ 69.48**

TABLE A NOTES:

- Low case is based on: 5%, 2100 horizon, last ton, global damages.
  High case is based on: 3%, 2300 horizon, last ton, global damages.
- Bolded values (for 2020 and 2050) are based on full suite of IAM runs performed by NERA Economic Consulting consistent with the July 2015 IWG Technical Support Document. All unbolded values are based on linear interpolation/extrapolation from 2020 and 2050 model-based values.

Table B. Annual Values (2017-2050) of ECVs for CO_2
(2015$ per net short ton)

Year	Low	High
2017	$8.44	$39.76
2018	$8.64	$40.66
2019	$8.85	$41.56
2020	**$9.05**	**$42.46**
2021	$9.25	$43.36
2022	$9.46	$44.26
2023	$9.66	$45.16
2024	$9.87	$46.06
2025	$10.07	$46.96
2026	$10.28	$47.86
2027	$10.48	$48.77
2028	$10.69	$49.67
2029	$10.89	$50.57
2030	$11.10	$51.47
2031	$11.30	$52.37
2032	$11.51	$53.27
2033	$11.71	$54.17
2034	$11.92	$55.07
2035	$12.12	$55.97
2036	$12.33	$56.87
2037	$12.53	$57.77
2038	$12.74	$58.67
2039	$12.94	$59.58
2040	$13.15	$60.48
2041	$13.35	$61.38
2042	$13.56	$62.28
2043	$13.76	$63.18
2044	$13.97	$64.08
2045	$14.17	$64.98
2046	$14.38	$65.88
2047	$14.58	$66.78
2048	$14.79	$67.68
2049	$14.99	$68.58
2050	**$15.20**	**$69.48**

TABLE B NOTES:

- Low case is based on: 5%, 2100 horizon, last ton, global damages.
  High case is based on: 3%, 2300 horizon, last ton, global damages.
- Bolded values (for 2020 and 2050) are based on full suite of IAM runs performed by NERA Economic Consulting consistent with the July 2015 IWG Technical Support Document. All unbolded values are based on linear interpolation/extrapolation from 2020 and 2050 model-based values.

CERTIFICATE OF SERVICE

I, Carl Cronin, hereby certify that I have this day served copies of the foregoing document on the attached list of persons.

xx by depositing a true and correct copy thereof, properly enveloped with postage paid in the United States mail at Minneapolis, Minnesota

xx electronic filing

Docket Nos. Miscellaneous Electric Service List
E002/RP-15-21

Dated this 26th day of September 2017

/s/
____
Carl Cronin
Regulatory Administrator

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
David	Aafedt	daafedt@winthrop.com	Winthrop & Weinstine, P.A.	Suite 3500, 225 South Sixth Street Minneapolis, MN 554024629	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric
Julia	Anderson	Julia.Anderson@ag.state.mn.us	Office of the Attorney General-DOC	1800 BRM Tower 445 Minnesota St St. Paul, MN 551012134	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric
Christopher	Anderson	canderson@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022191	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric
Alison C	Archer	aarcher@misoenergy.org	MISO	2985 Ames Crossing Rd Eagan, MN 55121	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric
Ryan	Barlow	Ryan.Barlow@ag.state.mn.us	Office of the Attorney General-RUD	445 Minnesota Street Bremer Tower, Suite 1400 St. Paul, Minnesota 55101	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric
James J.	Bertrand	james.bertrand@stinson.com	Stinson Leonard Street LLP	150 South Fifth Street, Suite 2300 Minneapolis, MN 55402	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric
William A.	Blazar	bblazar@mnchamber.com	Minnesota Chamber Of Commerce	Suite 1500 400 Robert Street North St. Paul, MN 55101	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric
James	Canaday	james.canaday@ag.state.mn.us	Office of the Attorney General-RUD	Suite 1400 445 Minnesota St. St. Paul, MN 55101	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric
Jeanne	Cochran	Jeanne.Cochran@state.mn.us	Office of Administrative Hearings	P.O. Box 64620 St. Paul, MN 55164-0620	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric
John	Coffman	john@johncoffman.net	AARP	871 Tuxedo Blvd. St, Louis, MO 63119-2044	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Corey	Conover	corey.conover@minneapolismn.gov	Minneapolis City Attorney	350 S. Fifth Street City Hall, Room 210 Minneapolis, MN 554022453	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric
Carl	Cronin	Regulatory.records@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 7 Minneapolis, MN 554011993	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric
Joseph	Dammel	joseph.dammel@ag.state.mn.us	Office of the Attorney General-RUD	Bremer Tower, Suite 1400 445 Minnesota Street St. Paul, MN 55101-2131	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric
Ian	Dobson	Residential.Utilities@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012130	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric
John	Farrell	jfarrell@ilsr.org	Institute for Local Self-Reliance	1313 5th St SE #303 Minneapolis, MN 55414	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce	85 7th Place E Ste 280 Saint Paul, MN 551012198	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric
Edward	Garvey	edward.garvey@AESLconsulting.com	AESL Consulting	32 Lawton St Saint Paul, MN 55102-2617	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric
Janet	Gonzalez	Janet.gonzalez@state.mn.us	Public Utilities Commission	Suite 350 121 7th Place East St. Paul, MN 55101	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric
Kimberly	Hellwig	kimberly.hellwig@stoel.com	Stoel Rives LLP	33 South Sixth Street Suite 4200 Minneapolis, MN 55402	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric
Michael	Hoppe	il23@mtn.org	Local Union 23, I.B.E.W.	932 Payne Avenue St. Paul, MN 55130	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Julia	Jazynka	jjazynka@energyfreedomcoalition.com	Energy Freedom Coalition of America	101 Constitution Ave NW Ste 525 East Washington, DC 20001	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric
Alan	Jenkins	aj@jenkinsatlaw.com	Jenkins at Law	2265 Roswell Road Suite 100 Marietta, GA 30062	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric
Linda	Jensen	linda.s.jensen@ag.state.mn.us	Office of the Attorney General-DOC	1800 BRM Tower 445 Minnesota Street St. Paul, MN 551012134	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric
Richard	Johnson	Rick.Johnson@lawmoss.com	Moss & Barnett	150 S. 5th Street Suite 1200 Minneapolis, MN 55402	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric
Sarah	Johnson Phillips	sjphillips@stoel.com	Stoel Rives LLP	33 South Sixth Street Suite 4200 Minneapolis, MN 55402	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric
Mark J.	Kaufman	mkaufman@ibewlocal949.org	IBEW Local Union 949	12908 Nicollet Avenue South Burnsville, MN 55337	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric
Thomas	Koehler	TGK@IBEW160.org	Local Union #160, IBEW	2909 Anthony Ln St Anthony Village, MN 55418-3238	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric
Michael	Krikava	mkrikava@briggs.com	Briggs And Morgan, P.A.	2200 IDS Center 80 S 8th St Minneapolis, MN 55402	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric
Peder	Larson	plarson@larkinhoffman.com	Larkin Hoffman Daly & Lindgren, Ltd.	8300 Norman Center Drive Suite 1000 Bloomington, MN 55437	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Douglas	Larson	dlarson@dakotaelectric.com	Dakota Electric Association	4300 220th St W Farmington, MN 55024	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric
Paula	Maccabee	Pmaccabee@justchangelaw.com	Just Change Law Offices	1961 Selby Ave Saint Paul, MN 55104	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric
Peter	Madsen	peter.madsen@ag.state.mn.us	Office of the Attorney General-DOC	Bremer Tower, Suite 1800 445 Minnesota Street St. Paul, Minnesota 55101	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric
Kavita	Maini	kmaini@wi.rr.com	KM Energy Consulting LLC	961 N Lost Woods Rd Oconomowoc, WI 53066	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric
Pam	Marshall	pam@energycents.org	Energy CENTS Coalition	823 7th St E St. Paul, MN 55106	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric
Joseph	Meyer	joseph.meyer@ag.state.mn.us	Office of the Attorney General-RUD	Bremer Tower, Suite 1400 445 Minnesota Street St Paul, MN 55101-2131	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric
David	Moeller	dmoeller@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022093	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric
Andrew	Moratzka	andrew.moratzka@stoel.com	Stoel Rives LLP	33 South Sixth St Ste 4200 Minneapolis, MN 55402	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric
David	Niles	david.niles@avantenergy.com	Minnesota Municipal Power Agency	220 South Sixth Street Suite 1300 Minneapolis, Minnesota 55402	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric
Carol A.	Overland	overland@legalectric.org	Legalectric - Overland Law Office	1110 West Avenue Red Wing, MN 55066	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Jeff	Oxley	jeff.oxley@state.mn.us	Office of Administrative Hearings	600 North Robert Street St. Paul, MN 55101	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric
Kevin	Reuther	kreuther@mncenter.org	MN Center for Environmental Advocacy	26 E Exchange St, Ste 206 St. Paul, MN 551011667	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric
Richard	Savelkoul	rsavelkoul@martinsquires.com	Martin & Squires, P.A.	332 Minnesota Street Ste W2750 St. Paul, MN 55101	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric
Inga	Schuchard	ischuchard@larkinhoffman.com	Larkin Hoffman	8300 Norman Center Drive Suite 1000 Minneapolis, MN 55437	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric
Zeviel	Simpser	zsimpser@briggs.com	Briggs and Morgan PA	2200 IDS Center80 South Eighth Street Minneapolis, MN 554022157	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric
Ken	Smith	ken.smith@districtenergy.com	District Energy St. Paul Inc.	76 W Kellogg Blvd St. Paul, MN 55102	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric
Byron E.	Starns	byron.starns@stinson.com	Stinson Leonard Street LLP	150 South 5th Street Suite 2300 Minneapolis, MN 55402	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric
James M.	Strommen	jstrommen@kennedy-graven.com	Kennedy & Graven, Chartered	470 U.S. Bank Plaza 200 South Sixth Street Minneapolis, MN 55402	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric
Eric	Swanson	eswanson@winthrop.com	Winthrop & Weinstine	225 S 6th St Ste 3500 Capella Tower Minneapolis, MN 554024629	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Lisa	Veith	lisa.veith@ci.stpaul.mn.us	City of St. Paul	400 City Hall and Courthouse 15 West Kellogg Blvd. St. Paul, MN 55102	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric
Joseph	Windler	jwindler@winthrop.com	Winthrop & Weinstine	225 South Sixth Street, Suite 3500 Minneapolis, MN 55402	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric
Cam	Winton	cwinton@mnchamber.com	Minnesota Chamber of Commerce	400 Robert Street North Suite 1500 St. Paul, Minnesota 55101	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric
Daniel P	Wolf	dan.wolf@state.mn.us	Public Utilities Commission	121 7th Place East Suite 350 St. Paul, MN 551012147	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric
Patrick	Zomer	Patrick.Zomer@lawmoss.com	Moss & Barnett a Professional Association	150 S. 5th Street, #1200 Minneapolis, MN 55402	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
David	Aafedt	daafedt@winthrop.com	Winthrop & Weinstine, P.A.	Suite 3500, 225 South Sixth Street Minneapolis, MN 554024629	Electronic Service	No	OFF_SL_15-21_Official
Christopher	Anderson	canderson@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022191	Electronic Service	No	OFF_SL_15-21_Official
Julia	Anderson	Julia.Anderson@ag.state.mn.us	Office of the Attorney General-DOC	1800 BRM Tower 445 Minnesota St St. Paul, MN 551012134	Electronic Service	Yes	OFF_SL_15-21_Official
Alison C	Archer	aarcher@misoenergy.org	MISO	2985 Ames Crossing Rd Eagan, MN 55121	Electronic Service	No	OFF_SL_15-21_Official
Mara	Ascheman	mara.k.ascheman@xcelenergy.com	Xcel Energy	414 Nicollet Mall Fl 5 Minneapolis, MN 55401	Electronic Service	Yes	OFF_SL_15-21_Official
Ryan	Barlow	Ryan.Barlow@ag.state.mn.us	Office of the Attorney General-RUD	445 Minnesota Street Bremer Tower, Suite 1400 St. Paul, Minnesota 55101	Electronic Service	Yes	OFF_SL_15-21_Official
Tracy	Bertram	tbertram@ci.becker.mn.us		12060 Sherburne Ave Becker City Hall Becker, MN 55308-4694	Electronic Service	No	OFF_SL_15-21_Official
James J.	Bertrand	james.bertrand@stinson.com	Stinson Leonard Street LLP	150 South Fifth Street, Suite 2300 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_15-21_Official
Michael J.	Bull	mbull@mncee.org	Center for Energy and Environment	212 Third Ave N Ste 560 Minneapolis, MN 55401	Electronic Service	Yes	OFF_SL_15-21_Official
James	Canaday	james.canaday@ag.state.mn.us	Office of the Attorney General-RUD	Suite 1400 445 Minnesota St. St. Paul, MN 55101	Electronic Service	Yes	OFF_SL_15-21_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Thomas	Carlson	thomas.carlson@edf-re.com	EDF Renewable Energy	10 2nd St NE Ste. 400 Minneapolis, Minnesota 55413	Electronic Service	No	OFF_SL_15-21_Official
Jeanne	Cochran	Jeanne.Cochran@state.mn.us	Office of Administrative Hearings	P.O. Box 64620 St. Paul, MN 55164-0620	Electronic Service	Yes	OFF_SL_15-21_Official
John	Coffman	john@johncoffman.net	AARP	871 Tuxedo Blvd. St, Louis, MO 63119-2044	Electronic Service	No	OFF_SL_15-21_Official
Carl	Cronin	Regulatory.records@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 7 Minneapolis, MN 554011993	Electronic Service	Yes	OFF_SL_15-21_Official
Leigh	Currie	lcurrie@mncenter.org	Minnesota Center for Environmental Advocacy	26 E. Exchange St., Suite 206 St. Paul, Minnesota 55101	Electronic Service	Yes	OFF_SL_15-21_Official
James	Denniston	james.r.denniston@xcelenergy.com	Xcel Energy Services, Inc.	414 Nicollet Mall, Fifth Floor Minneapolis, MN 55401	Electronic Service	Yes	OFF_SL_15-21_Official
Ian	Dobson	Residential.Utilities@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012130	Electronic Service	Yes	OFF_SL_15-21_Official
John	Farrell	jfarrell@ilsr.org	Institute for Local Self-Reliance	1313 5th St SE #303 Minneapolis, MN 55414	Electronic Service	No	OFF_SL_15-21_Official
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce	85 7th Place E Ste 280 Saint Paul, MN 551012198	Electronic Service	No	OFF_SL_15-21_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Mike	Fiterman	mikefiterman@libertydiversified.com	Liberty Diversified International	5600 N Highway 169 Minneapolis, MN 55428-3096	Electronic Service	No	OFF_SL_15-21_Official
Stephen	Fogel	Stephen.E.Fogel@XcelEnergy.com	Xcel Energy Services, Inc.	816 Congress Ave, Suite 1650 Austin, TX 78701	Electronic Service	Yes	OFF_SL_15-21_Official
J Drake	Hamilton	hamilton@fresh-energy.org	Fresh Energy	408 St Peter St Saint Paul, MN 55101	Electronic Service	Yes	OFF_SL_15-21_Official
Kimberly	Hellwig	kimberly.hellwig@stoel.com	Stoel Rives LLP	33 South Sixth Street Suite 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_15-21_Official
Annete	Henkel	mui@mnutilityinvestors.org	Minnesota Utility Investors	413 Wacouta Street #230 St.Paul, MN 55101	Electronic Service	No	OFF_SL_15-21_Official
Patrick	Hentges		City Of Mankato	P.O. Box 3368 Mankato, MN 560023368	Paper Service	No	OFF_SL_15-21_Official
Michael	Hoppe	il23@mtn.org	Local Union 23, I.B.E.W.	932 Payne Avenue St. Paul, MN 55130	Electronic Service	No	OFF_SL_15-21_Official
Alan	Jenkins	aj@jenkinsatlaw.com	Jenkins at Law	2265 Roswell Road Suite 100 Marietta, GA 30062	Electronic Service	No	OFF_SL_15-21_Official
Linda	Jensen	linda.s.jensen@ag.state.mn.us	Office of the Attorney General-DOC	1800 BRM Tower 445 Minnesota Street St. Paul, MN 551012134	Electronic Service	Yes	OFF_SL_15-21_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Richard	Johnson	Rick.Johnson@lawmoss.com	Moss & Barnett	150 S. 5th Street Suite 1200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_15-21_Official
Sarah	Johnson Phillips	sjphillips@stoel.com	Stoel Rives LLP	33 South Sixth Street Suite 4200 Minneapolis, MN 55402	Electronic Service	Yes	OFF_SL_15-21_Official
Mark J.	Kaufman	mkaufman@ibewlocal949.org	IBEW Local Union 949	12908 Nicollet Avenue South Burnsville, MN 55337	Electronic Service	No	OFF_SL_15-21_Official
Hank	Koegel	hank.koegel@edf-re.com	EDF Renewable Eenrgy	10 2nd St NE Ste 400 Minneapolis, MN 55413-2652	Electronic Service	No	OFF_SL_15-21_Official
Thomas	Koehler	TGK@IBEW160.org	Local Union #160, IBEW	2909 Anthony Ln St Anthony Village, MN 55418-3238	Electronic Service	No	OFF_SL_15-21_Official
Frank	Kohlasch	frank.kohlasch@state.mn.us	MN Pollution Control Agency	520 Lafayette Rd N. St. Paul, MN 55155	Electronic Service	No	OFF_SL_15-21_Official
Michael	Krikava	mkrikava@briggs.com	Briggs And Morgan, P.A.	2200 IDS Center 80 S 8th St Minneapolis, MN 55402	Electronic Service	No	OFF_SL_15-21_Official
Peder	Larson	plarson@larkinhoffman.com	Larkin Hoffman Daly & Lindgren, Ltd.	8300 Norman Center Drive Suite 1000 Bloomington, MN 55437	Electronic Service	No	OFF_SL_15-21_Official
Douglas	Larson	dlarson@dakotaelectric.com	Dakota Electric Association	4300 220th St W Farmington, MN 55024	Electronic Service	No	OFF_SL_15-21_Official
Peter	Madsen	peter.madsen@ag.state.mn.us	Office of the Attorney General-DOC	Bremer Tower, Suite 1800 445 Minnesota Street St. Paul, Minnesota 55101	Electronic Service	Yes	OFF_SL_15-21_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Kavita	Maini	kmaini@wi.rr.com	KM Energy Consulting LLC	961 N Lost Woods Rd Oconomowoc, WI 53066	Electronic Service	Yes	OFF_SL_15-21_Official
Pam	Marshall	pam@energycents.org	Energy CENTS Coalition	823 7th St E St. Paul, MN 55106	Electronic Service	No	OFF_SL_15-21_Official
Mary	Martinka	mary.a.martinka@xcelenergy.com	Xcel Energy Inc	414 Nicollet Mall 7th Floor Minneapolis, MN 55401	Electronic Service	Yes	OFF_SL_15-21_Official
Daryl	Maxwell	dmaxwell@hydro.mb.ca	Manitoba Hydro	360 Portage Ave FL 16 PO Box 815, Station Main Winnipeg, Manitoba R3C 2P4 Canada	Electronic Service	No	OFF_SL_15-21_Official
Brian	Meloy	brian.meloy@stinson.com	Stinson,Leonard, Street LLP	150 S 5th St Ste 2300 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_15-21_Official
David	Moeller	dmoeller@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022093	Electronic Service	No	OFF_SL_15-21_Official
Andrew	Moratzka	andrew.moratzka@stoel.com	Stoel Rives LLP	33 South Sixth St Ste 4200 Minneapolis, MN 55402	Electronic Service	Yes	OFF_SL_15-21_Official
Alan	Muller	alan@greendel.org	Energy & Environmental Consulting	1110 West Avenue Red Wing, MN 55066	Electronic Service	No	OFF_SL_15-21_Official
Carl	Nelson	cnelson@mncee.org	Center for Energy and Environment	212 3rd Ave N Ste 560 Minneapolis, MN 55401	Electronic Service	Yes	OFF_SL_15-21_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
J	Newberger	Jnewberger1@yahoo.com	State Rep	14225 Balsam Blvd Becker, MN 55308	Electronic Service	No	OFF_SL_15-21_Official
David	Niles	david.niles@avantenergy.com	Minnesota Municipal Power Agency	220 South Sixth Street Suite 1300 Minneapolis, Minnesota 55402	Electronic Service	No	OFF_SL_15-21_Official
Carol A.	Overland	overland@legalectric.org	Legalectric - Overland Law Office	1110 West Avenue Red Wing, MN 55066	Electronic Service	No	OFF_SL_15-21_Official
Gayle	Prest	gayle.prest@minneapolismn.gov	City of Mpls Sustainability	350 South 5th St, #315 Minneapolis, MN 55415	Electronic Service	No	OFF_SL_15-21_Official
Greg	Pruszinske	gpruszinske@ci.becker.mn.us	City of Becker	Box 250 12060 Sherburne Ave Becker, Minnesota 55308	Electronic Service	No	OFF_SL_15-21_Official
Kevin	Reuther	kreuther@mncenter.org	MN Center for Environmental Advocacy	26 E Exchange St, Ste 206 St. Paul, MN 551011667	Electronic Service	Yes	OFF_SL_15-21_Official
Richard	Savelkoul	rsavelkoul@martinsquires.com	Martin & Squires, P.A.	332 Minnesota Street Ste W2750 St. Paul, MN 55101	Electronic Service	Yes	OFF_SL_15-21_Official
Larry L.	Schedin	Larry@LLSResources.com	LLS Resources, LLC	332 Minnesota St, Ste W1390 St. Paul, MN 55101	Electronic Service	Yes	OFF_SL_15-21_Official
Inga	Schuchard	ischuchard@larkinhoffman.com	Larkin Hoffman	8300 Norman Center Drive Suite 1000 Minneapolis, MN 55437	Electronic Service	No	OFF_SL_15-21_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Janet	Shaddix Elling	jshaddix@janetshaddix.com	Shaddix And Associates	Ste 122 9100 W Bloomington Frwy Bloomington, MN 55431	Electronic Service	Yes	OFF_SL_15-21_Official
Joshua	Smith	joshua.smith@sierraclub.org		85 Second St FL 2 San Francisco, California 94105	Electronic Service	Yes	OFF_SL_15-21_Official
Ken	Smith	ken.smith@districtenergy.com	District Energy St. Paul Inc.	76 W Kellogg Blvd St. Paul, MN 55102	Electronic Service	No	OFF_SL_15-21_Official
Jessie	Smith	jseim@piic.org	Prairie Island Indian Community	5636 Sturgeon Lake Rd Welch, MN 55089	Electronic Service	No	OFF_SL_15-21_Official
Beth H.	Soholt	bsoholt@windonthewires.org	Wind on the Wires	570 Asbury Street Suite 201 St. Paul, MN 55104	Electronic Service	Yes	OFF_SL_15-21_Official
Anna	Sommer	anna@sommerenergy.com	Sommer Energy LLC	PO Box 766 Grand Canyon, AZ 86023	Electronic Service	Yes	OFF_SL_15-21_Official
Mark	Spurr	mspurr@fvbenergy.com	International District Energy Association	222 South Ninth St., Suite 825 Minneapolis, Minnesota 55402	Electronic Service	No	OFF_SL_15-21_Official
Byron E.	Starns	byron.starns@stinson.com	Stinson Leonard Street LLP	150 South 5th Street Suite 2300 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_15-21_Official
James M.	Strommen	jstrommen@kennedy-graven.com	Kennedy & Graven, Chartered	470 U.S. Bank Plaza 200 South Sixth Street Minneapolis, MN 55402	Electronic Service	No	OFF_SL_15-21_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Robert	Stupar	rob.stupar@enel.com	Enel Green Power North America, Inc.	816 Connecticut Avenue NW Suite 600 Washington, DC 20006	Electronic Service	No	OFF_SL_15-21_Official
Eric	Swanson	eswanson@winthrop.com	Winthrop & Weinstine	225 S 6th St Ste 3500 Capella Tower Minneapolis, MN 554024629	Electronic Service	No	OFF_SL_15-21_Official
Douglas	Tiffany	tiffa002@umn.edu	University of Minnesota	316d Ruttan Hall 1994 Buford Avenue St. Paul, MN 55108	Electronic Service	No	OFF_SL_15-21_Official
Lisa	Veith	lisa.veith@ci.stpaul.mn.us	City of St. Paul	400 City Hall and Courthouse 15 West Kellogg Blvd. St. Paul, MN 55102	Electronic Service	No	OFF_SL_15-21_Official
Julie	Voeck	julie.voeck@nee.com	NextEra Energy Resources, LLC	700 Universe Blvd Juno Beach, FL 33408	Electronic Service	No	OFF_SL_15-21_Official
Samantha	Williams	swilliams@nrdc.org	Natural Resources Defense Council	20 N. Wacker Drive Ste 1600 Chicago, IL 60606	Electronic Service	No	OFF_SL_15-21_Official
Cam	Winton	cwinton@mnchamber.com	Minnesota Chamber of Commerce	400 Robert Street North Suite 1500 St. Paul, Minnesota 55101	Electronic Service	No	OFF_SL_15-21_Official
Daniel P	Wolf	dan.wolf@state.mn.us	Public Utilities Commission	121 7th Place East Suite 350 St. Paul, MN 551012147	Electronic Service	Yes	OFF_SL_15-21_Official
Jonathan G.	Zierdt	jzierdt@greatermankato.com	Greater Mankato Growth	1961 Premier Dr Ste 100 Mankato, MN 56001	Electronic Service	No	OFF_SL_15-21_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Patrick	Zomer	Patrick.Zomer@lawmoss.com	Moss & Barnett a Professional Association	150 S. 5th Street, #1200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_15-21_Official