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dave.sederquist@xcelenergy.com

October 2, 2015

- Via Email and Federal Express -

Darrell Nitschke, Executive Director
North Dakota Public Service Commission
State Capitol Building, Dept 408
600 East Boulevard
Bismarck, ND 59505-0480

RE: SUPPLEMENTAL REBUTTAL TESTIMONY
NORTHERN STATES POWER COMPANY APPLICATION FOR ADVANCED PRUDENCE – 345 KW MANKATO ENERGY CENTER
CASE NO. PU-15-96

Dear Mr. Nitschke:

Northern States Power Company, doing business as Xcel Energy, respectfully submits an original and ten copies of our supplemental rebuttal testimony consistent with our procedural agreement with staff in the above-referenced case.

The following supplemental rebuttal testimony is being filed:

- *Kurtis J. Haeger* – providing supplemental rebuttal testimony on the value of the Mankato Energy Center Power Purchase Agreement (PPA) and the Company's resource planning processes.

This supplemental rebuttal testimony is being filed consistent with the Company's procedural agreement with Staff. The purpose for this supplemental rebuttal testimony is to provide the Commission with important information relating to recent changes in the Company's Resource Plan.

Please contact me if you have any questions regarding this filing.

Sincerely,

DAVID H. SEDERQUIST
Sr. Consultant, Regulation & Finance
Enclosures

cc: attached list

cc:

Public Service Commission
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Before the North Dakota Public Service Commission
State of North Dakota

Application of Northern States Power Company
for an Advance Determination of Prudence for a Power Purchase Agreement with Mankato Energy Center, LLC for Approximately 345 MW of Combined-Cycle Gas Generation

Case No. PU-15-96
Exhibit___(KJH-3)

Supplemental Rebuttal Testimony

October 2, 2015

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Schedules

I. INTRODUCTION AND SUMMARY

Q. PLEASE STATE YOUR NAME AND TITLE.

A. My name is Kurtis J. Haeger. I am the Area Vice President of Resource Planning for Xcel Energy Services Inc. (XES), the service company subsidiary of Xcel Energy Inc. In that role I coordinate the resource planning function for Northern States Power Company-Minnesota (NSP, Xcel Energy or the Company).

Q. HAVE YOU PROVIDED OTHER TESTIMONY IN THIS CASE?

A. Yes. I submitted prefiled written Direct Testimony (Exhibit ____(KJH-1)) and prefiled written Rebuttal Testimony (Exhibit ____(KJH-2)) in this proceeding. That testimony provided the Commission with the Company's view of the resource planning context that supports granting an Advance Determination of Prudence (ADP) for the Power Purchase Agreement (PPA) with Calpine for the expansion project at the Mankato Energy Center (the Mankato PPA).

In my Rebuttal Testimony, I also responded to the Direct Testimony of Commission Advocacy Staff witness Mr. Richard A. Polich and in particular responded to his conclusion that the Mankato PPA is not needed until 2025. I concluded that, based on the totality of the circumstances, the Mankato PPA is a prudent resource beginning in 2019 as proposed.

Q. WHAT IS THE PURPOSE OF YOUR SUPPLEMENTAL REBUTTAL TESTIMONY?

A. My Supplemental Rebuttal Testimony provides additional context for the Mankato PPA in light of our October 2, 2015 Resource Plan update. I provide a copy of the October 2, 2015 Resource Plan Update as Schedule 1 to my

Supplemental Rebuttal Testimony.

Q. PLEASE DESCRIBE THE OCTOBER 2, 2015 RESOURCE PLAN UPDATE.

A. On October 2, 2015, the Company filed an update to our 2015 Resource Plan (Case No. PU-15-19). That update presents significant changes to the Company's long-term resource planning activities, including proposals for ceasing coal operations at Units 1 and 2 of the Company's Sherburne County Generating Station. These proposals have a material impact on the analysis of the prudence of the Mankato PPA. I am therefore supplementing my Rebuttal Testimony to reflect the Resource Plan update and provide the Commission with a full and complete record for its consideration. The Company has previously proposed that the Resource Plan and the update be made part of the record in this Case.

II. IMPACT OF RESOURCE PLAN UPDATE

Q. IS THIS THE FIRST UPDATE THAT THE COMPANY HAS MADE SINCE FILING ITS RESOURCE PLAN IN EARLY JANUARY?

A. No. This is the second update we are providing since filing our initial Resource Plan proposal in January of 2015. More specifically, on March 16, 2015, the Company filed a Supplement to the Resource Plan. That Supplement incorporated the resources that we plan to add to our system as a result of the CAP/CON Proceeding (the Mankato PPA, the Aurora Solar PPA and the Company's Black Dog 6 combustion turbine) as well as the Company's proposed 187 MW solar portfolio. That supplement analyzed the increased capacity arising from these proposed resource additions. As described in the March 16, 2015 Supplement, adding these additional resources into our Load and

Resources Tables provided the Company with additional capacity beyond the minimum requirements necessary to meet our load serving obligations and MISO's reserve margin requirements. The Supplement also modified our Preferred Plan to account for the additional capacity.

Q. WHY IS THE COMPANY MAKING A SUBSEQUENT UPDATE?

A. The October 2, 2015 update is in the nature of reply comments to the myriad of comments that we received on July 2, 2015; one of several procedural milestones in the resource plan proceedings underway in Minnesota.

Q. WHAT SIGNIFICANT CHANGES TO THE PREFERRED PLAN IS THE COMPANY PROPOSING IN ITS OCTOBER 2, 2015 UPDATE?

A. The Company is proposing several significant changes to it Preferred Plan. These include:

- Ceasing coal operations at Sherco Unit 2 in 2023;
- Ceasing coal operations at Sherco Unit 1 in 2026;
- Constructing a gas combustion turbine in eastern North Dakota to support system reliability and address capacity needs in the 2023 to 2025 timeframe;
- Constructing at combined-cycle facility at the Sherco site by 2026 to support system stability; and
- Accelerating the addition of renewable energy (approximately 1,200 MW of which approximately 800 MW will be wind) to 2018-2020 timeframe to capture the expected renewal of the production tax credit.

As described more fully in our October 2, 2015 update, in the coming decade we are faced with a number of major decisions about the evolution of our aging

system and impact of future environmental compliance costs. In particular, a number of these changes are necessitated by our aging system and the increasing difficulties we have maintaining baseload coal generation in a cost-effective manner. Further, we believe that this will allow us to cost-effectively achieve a 60 percent reduction in carbon emissions by 2030 while also securing low priced resources when they become available and strengthening the reliability of our system through geographic diversification of future natural gas generation additions, including North Dakota.

Q. ARE THESE CHANGES TO THE COMPANY'S PREFERRED PLAN RELEVANT TO THIS CASE?

A. Yes. The Mankato PPA (along with the other CAP/CON resources and our 187 MW solar portfolio) are key capacity additions that the Company is relying on to achieve the outcome identified in its updated Preferred Plan. The Mankato PPA, with its low cost combined-cycle energy is a fundamental part of these resource additions. We believe that a view of the future configuration of our system will help to demonstrate the prudence of adding the low-priced combined-cycle energy provided by the Mankato PPA at the time it is being made available by the vendor. While an ADP proceeding allows the Commission to focus on a particular resource addition, including developments from our Resource Plan can help the Commission make its decision in the larger context of the evolving NSP System.

When viewed in this larger context, the underlying merits of the Mankato PPA are clear: it is a low-cost, combined-cycle facility that is being made available only a few years earlier than our Loads and Resources calculations show a capacity deficit. The Mankato resource can, and will, provide significant benefits when it

goes into service to hedge against sudden variations in resource needs as well as to provide low-cost, combined-cycle capacity and energy as we move into an uncertain energy future. As we move to reduce the baseload energy provided by Sherco 1 & 2, obtaining the low priced combined-cycle energy made available by the Mankato PPA will help to provide dispatchable, low cost energy to the system as part of our overall replacement plan.

Q. WHY IS THE COMPANY CEASING OPERATIONS OF SHERCO UNITS 1 & 2 IN 2023 AND 2026 SO THAT IT MUST RELY ON THE MANKATO PPA?

A. In light of the increasing environmental requirements for older coal plants, the risk that these units may be required to install expensive Selective Catalytic Reduction (SCR) equipment in the mid-2020s, carbon regulation due to the EPA's Clean Power Plan, and the potential for future carbon reduction requirements, we concluded that it makes the most sense to plan now for the transition to cease coal operation at these units by the mid-2020's. This provides about 10 years to complete a smooth workforce transition and generation replacement while limiting customer cost impacts. The Minnesota Pollution Control Agency (MPCA), which regulates emissions in Minnesota where Sherco Units 1 & 2 are located, has an active role in implementing the regional haze regulations. We noted this possibility in our initial Resource Plan filing. Therefore, prudent long term resource planning requires us to weigh the significant capital upgrades that the SCRs could represent versus alternatives, along with these other factors.

The availability of the Mankato PPA helps us to make this transition smoothly and in a cost effective manner.

Q. WHAT IMPACT DOES THE PROPOSAL TO CEASE COAL OPERATIONS AT SHERCO UNITS 1 & 2 HAVE ON THE COMMISSION'S CONSIDERATION OF THE PRUDENCE OF THE MANKATO PPA PURCHASE BEGINNING IN 2019?

A. We recognize that the timing of the Mankato PPA is less than ideal given the new capacity need due to the cessation of coal operations at Sherco Unit 2 in 2023. However, obtaining this low cost combined-cycle generating resource on the timing that is being made available by the vendor is fundamentally prudent on the merits and we anticipate that securing this combined cycle generation now will be less costly than adding a similar combined-cycle unit in 2023. This is particularly true when balanced against the cost we would have to incur to add SCR equipment to the Sherco units and the current age of the plants.

In some respects, undertaking the Mankato PPA as it is being made available is similar to adding low cost wind resources to our system as Production Tax Credits (PTC) are available, regardless of need. Our initial Resource Plan filing demonstrated that under all circumstances, accelerating wind additions to secure available PTC benefits results in the least cost expansion plan. While the Mankato PPA will add costs to the system initially when it goes into service, securing its value now will likely result in lower system costs over the long term. In any event, adding this low cost resource to our system now will provide a reasonable hedge against future price fluctuations for combined cycle facilities.

Q. GIVEN THE OTHER RESOURCE ADDITIONS THE COMPANY IS CONTEMPLATING, IS THE MANKATO PPA NECESSARY TO ENSURE THAT THE COMPANY HAS SUFFICIENT RESOURCES IN THE EVENT OF THE CESSATION OF COAL OPERATIONS AT A SHERCO UNIT?

A. Yes. The Mankato PPA is the only combined-cycle addition contemplated by

our Resource Plan until a proposed combined cycle facility is constructed at the Sherco site in 2026. As discussed in more depth in our October 2, 2015 Resource Plan Update, adding generation at the Sherco site is necessary to support system stability and reliability when the two Sherco Units are not providing energy. Having the additional combined cycle capacity of the Mankato PPA will help us bridge this period.

Q. IF COAL GENERATION IS CEASED AT A SHERCO UNIT IN 2023, WHY DO YOU PROPOSE THE MANKATO PPA IN 2019?

A. As I describe in my Rebuttal Testimony, the 2019 in-service date was the result of the CAP/CON Proceeding and was a date that Calpine was willing and able to be in operation. We have no assurances or expectation that Calpine would hold open its offer of this capacity beyond 2019. Indeed, we have been advised by Calpine representatives that it would not be able to hold the offer open for an extended period of time. The bottom line is that the advantageous pricing of the Mankato PPA would not be available for a much later in-service date. We conclude that it is better to capture the benefits of this capacity as it become available in 2019 and have it in 2023 when we propose to cease coal operations at our first Sherco unit.

Q. DOES THE PROPOSAL TO CEASE COAL OPERATIONS AT SHERCO UNITS 1 & 2 IN 2023 AND 2026 RESPECTIVELY CHANGE YOUR RECOMMENDATION FOR THE COMMISSION?

A. No. I previously recommended that the Commission grant an ADP for the Mankato PPA beginning in 2019. That is still my recommendation.

However, ceasing coal operations at Sherco Units 1 & 2 adds further support to

that recommendation. I note that Staff has taken the position that the Commission should approve additional capacity *when it is needed* as demonstrated in the Company's Load and Resources Table. As shown in the October 2, 2015 Update, the Mankato PPA, along with Black Dog Unit 6 and additional solar generation, provide the necessary capacity for us to have sufficient resource available to our customers in 2023, when we plan to cease coal operations at Sherco Unit 2. In addition, we plan to install at least 200 MW of combustion turbine capacity in eastern North Dakota in the 2023 to 2025 timeframe as part of this plan as well. This further supports the prudence of this resource addition. Finally, all of the reasons supporting the Mankato PPA described in my Rebuttal Testimony and in the testimonies of the other NSP witnesses remain.

Q. HOW DOES THE MANKATO PPA FIT IN WITH OTHER RESOURCES RECENTLY CONSIDERED BY THE COMMISSION?

A. The Commission has recently granted an ADP for the Company's Black Dog Unit 6 expansion project but has rejected ADPs for recent solar power PPA acquisitions. We recognize that these solar resources represented resource additions to the NSP System that are incompatible with the commission's views, and we have found ways to manage the failure of the Commission to grant ADPs for them while maintaining their capacity available for the entire NSP System.

However, we believe that the Mankato PPA is compatible with North Dakota energy policies and believe that an ADP should be approved on that basis. It is a low-cost, combined-cycle resource addition that, while the timing is less than opportune, securing its comparatively low cost generation benefits while it is available is fundamentally prudent. The prudence of the resource addition is

even more certain when viewed in the larger context of the changing NSP System. Consequently, we believe that when analyzed on its merits, the Mankato PPA is a prudent resource addition.

III. CONCLUSION

Q. WHAT DO YOU RECOMMEND?

A. I recommend that the Commission accept the Mankato PPA beginning in 2019. The combination of benefits combined with the clear need for this resource that would result from ceasing coal operations at a Sherco unit in 2023 makes this a valuable system resource.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

STATE OF NORTH DAKOTA
BEFORE THE
PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF NORTHERN STATES POWER COMPANY FOR AN ADVANCE DETERMINATION OF PRUDENCE FOR A POWER PURCHASE AGREEMENT WITH MANKATO ENERGY CENTER, LLC FOR APPROXIMATELY 345 MW OF COMBINED-CYCLE NATURAL GAS GENERATION

Case No. PU-15-96

STATE OF MINNESOTA)
) ss.
COUNTY OF HENNEPIN)

Kurtis J. Haeger, being first duly sworn on oath, deposes and says that he is the Area Vice President of Resource Planning for Xcel Energy Services Inc., the service company subsidiary of Xcel Energy, in the above captioned matter, that he has read the supplemental rebuttal testimony and schedules submitted in the above captioned matter under his name, that they were prepared under his direction, that he knows the contents thereof, and that the same is true and correct to the best of his knowledge and belief.

Kurtis J. Haeger

Subscribed and sworn to before me this 1st day of October, 2015.

Yrene A. Nuñez
Notary Public
My Commission Expires: 9/28/16

YRENE A NUÑEZ
NOTARY PUBLIC
STATE OF COLORADO
NOTARY ID 19874149394
MY COMMISSION EXPIRES SEPTEMBER 28, 2016

414 Nicollet Mall
Minneapolis, Minnesota 55401

October 2, 2015 **—Via Electronic Filing—**

Daniel P. Wolf
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, Minnesota 55101-2147

RE: 2016-2030 UPPER MIDWEST RESOURCE PLAN
REPLY COMMENTS
DOCKET NO. E002/RP-15-21

Dear Mr. Wolf:

Northern States Power Company, doing business as Xcel Energy, submits to the Minnesota Public Utilities Commission this Reply to the July 2, 2015 Comments received on its 2016-2030 Upper Midwest Resource Plan in the above-referenced docket.

In this Reply, we bring to the Commission a proposal that outlines a bold energy vision that benefits our customers, communities, and the states we serve. We expect our proposal will stimulate discussion, and we look forward to engaging in a constructive dialogue with the Commission, the parties to this docket, and our stakeholders. In the Reply, we propose to work with the Commission Staff and parties on a procedural schedule that provides an opportunity to build the record and advance our Proposal.

We have electronically filed this document with the Commission, and copies have been served on the parties on the attached service lists. Please contact Aakash Chandarana at (612) 215-4663 or aakash.chandarana@xcelenergy.com if you have any questions regarding this filing.

/s/

CHRISTOPHER B. CLARK
PRESIDENT
NORTHERN STATES POWER COMPANY

Enclosures
cc: Service lists

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Beverly Jones Heydinger	Chair
Nancy Lange	Commissioner
Dan Lipschultz	Commissioner
John Tuma	Commissioner
Betsy Wergin	Commissioner

IN THE MATTER OF XCEL ENERGY'S 2016-2030 UPPER MIDWEST RESOURCE PLAN	DOCKET NO. E002/RP-15-21
	REPLY COMMENTS

INTRODUCTION

Northern States Power Company, doing business as Xcel Energy, submits to the Minnesota Public Utilities Commission this Reply to the July 2, 2015 Comments received on its 2016-2030 Upper Midwest Resource Plan in the above-referenced docket. In this Reply, we share a bold energy vision that transitions our system from coal generation, advances the acquisition of significant levels of renewable generation, recognizes nuclear energy as a critical carbon-free baseload resource, and confirms our commitment to energy efficiency efforts.

In our initial Resource Plan, we shared a vision of a 40 percent reduction of carbon dioxide emissions from 2005 levels by 2030. Since that time, other parties filed comments recommending different approaches, and the Environmental Protection Agency has issued its final Clean Power Plan (CPP). We have reviewed and analyzed the comments filed by our stakeholders. We have also conducted a preliminary analysis of the CPP, though we recognize much more will develop around this rule. In these Reply Comments, we present our analysis to-date, outline our proposed actions, and suggest a procedural framework that allows us to continue to move forward quickly, work collaboratively with other parties, and at the same time recognize the many other cases before the Commission.

In these Reply Comments, we outline our vision of the energy future for our customers, communities, and states. We believe our proposal benefits our customers by supporting a cost-effective transition to the future, allowing adequate time to transition our workforce, creating new jobs and investments for our communities in the states we serve, and continuing our renewable and carbon-free energy leadership. Our proposal would result in a 60 percent reduction of carbon emissions from 2005 levels by 2030. We recognize many pieces of a complex effort need to come together

to achieve these benefits. We outline this proposal to begin the necessary discussions and actions and to allow parties to consider how we may work together to achieve this outcome while weighing it against other alternatives. We look forward to a robust discussion around our proposal and welcome procedural guidance and input from the Commission and the Minnesota Pollution Control Agency (MPCA) on how best to coordinate between the agencies to further this important work.

Our proposal has four primary elements:

1. *Accelerate the transition from coal energy to renewables.* Our proposal includes:
    - Achieving 60 percent carbon emission reductions by 2030,
    - Ceasing coal generation at Sherco Unit 2 in 2023,
    - Ceasing coal generation at Sherco Unit 1 in 2026, and
    - Advancing the addition of substantial renewable generation (1,200 MW by 2020).

2. *Preserve regional system reliability.* We propose to continue operation of our nuclear units during the current resource planning period and construct sufficient gas fired generation and infrastructure to maintain reliability with an appreciation of regional, state, and local community economic and policy considerations. To that end, we envision:
    - Reaffirming our commitment to nuclear energy through the current licenses of our existing units,
    - Adding a combustion turbine in North Dakota by 2025,
    - Studying a Sherco Unit 2 boiler conversion or combustion turbine alternative,
    - Studying gas infrastructure and transmission expansion, and
    - Replacing Sherco generation with a combined cycle no later than 2026.

3. *Pursue energy efficiency gains and grid modernization.* We propose to continue our commitment to energy efficiency and new technologies, and we look to capitalize on these efforts rather than seeking to replace coal capacity megawatt for megawatt. We believe that modernizing the grid will further enable customer-driven solutions.

4. *Ensure customer benefits.* We propose to work with the Commission, the MPCA, and our stakeholders to ensure our customers get the full benefit of our proposal by:
    - Working with the MPCA, along with its counterpart environmental agencies in our other states, on the CPP State Plans to maximize the benefits of compliance for our customers and communities, and

- Pursuing rate plans and cost recovery mechanisms that smooth costs for our customers.

Our Preferred Plan in our initial filing achieved substantial progress toward federal and state energy goals at a reasonable cost. During the course of this proceeding, however, parties have asked us to consider alternative proposals. In evaluating those alternatives, we have concluded that we can propose a plan that achieves even greater carbon reductions, invests in our communities, and maintains the affordability of our rates while assuring reliable service. Three key factors drive our decision to advance this proposal now and underscore why we believe it the best course of action for our customers, communities, and company.

First, we believe there is great benefit to the certainty our proposal provides. While additional studies, rule analysis, and CPP State Plan development will be necessary, there is significant value for the Company and our customers if we shift our focus to the future. This forward-focus allows for the following to begin now:

- We will have a full ten years to transition our workforce to support our future generation resources.
- We can begin planning the redevelopment of the Sherco site to accommodate a combined cycle unit and solar energy, extend sufficient gas infrastructure to the site, finalize transmission studies, and fully understand the operational issues presented by the new infrastructure in conjunction with Sherco Unit 3 and Monticello.
- We can begin work on our North Dakota-sited combustion turbine, which will require building out sufficient natural gas and transmission infrastructure to support that generation.
- We can begin readying Request For Proposal (RFP) processes for additional wind and solar generation that we expect to be located throughout our service territories – and, with that, start identifying ways to maximize our CapX 2020 investments.
- We can work with the MPCA, along with its counterparts in our other states, to create a straw proposal for the CPP State Plans and explore a trading system that benefits all of the customers and states we serve.

We believe there are tangible benefits to moving now. For instance, we will have the opportunity to maximize the anticipated Production Tax Credit extensions in the acquisition of renewable energy. Additionally, addressing the future of Sherco Units 1 and 2 now helps us avoid the situation where we are replacing all of our baseload energy generation in the early 2030s.

Second, environmental regulations will continue to place pressure on the operations

of Sherco Units 1 and 2. The possibility that NOx reductions would require installation of Selective Catalytic Reduction (SCRs) at the Sherco Units in the mid-2020s was a factor that advanced this proposal. We do not believe committing significant amounts of capital to these Units represents a realistic view of our energy future. We have successfully operated Sherco Units 1 and 2 to produce cost-effective energy while exceeding environmental regulations; however, the environmental pressures on these Units will continue to build. Our vision for the future is cleaner, cost-effective energy, so – for us – moving forward now is the best choice and focus for our resources. We recognize that others in the region may not be able to make changes now due to recent investments in plants (for instance in South Dakota), higher percentages of coal energy (for instance in North Dakota), or the desire to see how various litigated issues are resolved. We believe our action here can help our region successfully make this transition, encourage the development of renewable energy in our states, and provide jobs and investments for our communities. Our plan will also help identify energy solutions and embrace new technologies, providing clear benefits for our customers from our energy leadership.

Third, our customers increasingly want cleaner energy. More of our customers are asking us to provide options for all renewable energy or are making individual or corporate commitments to sustainability and the environment. Likewise, our cities are making commitments to sustainability. Potential new customers deciding whether to locate their businesses in our states have asked for clean energy options. We believe the action we are taking here will position us well to serve customers into the future. At the same time, we are sensitive to the cost concerns of all our customers, and are aware that some of our customers compete in regional, state, national, and increasingly international markets. We believe we can deliver this proposal at a reasonable cost and do not believe cost concerns warrant delaying action. We prefer to implement a plan that provides cleaner energy and at the same time aggressively pursue actions to lower costs. For example, we will be ready to launch an RFP if the Production Tax Credit for wind generation is extended. In addition, we can focus on lowering costs of this plan through the development of a regional approach to the CPP and potential trading options. Finally, we believe longer-term rate plans are important as they can moderate any necessary rate increases over five-year periods and benefit customers by providing greater predictability. A longer-term rate compact has other benefits as it can free-up state regulatory, Company, and stakeholder resources to focus on issues other than ratemaking, such as the CPP State Plans and grid modernization. We have successfully entered into these longer-term compacts in North Dakota and South Dakota, and look forward to advancing proposals to do so in Minnesota based on legislation passed in the last legislative session.

With these factors in mind, over the past two months we developed alternative approaches to our Preferred Plan. The result is the proposal outlined in these Reply

Comments. While we have done the preliminary analysis to validate the plan, significant work is necessary to make it a reality. We recognize customers, communities in all of our states, and parties will want to react to this proposal and will want more details. We look forward to that exchange of information and further discussion. We intend to encourage additional public comment, but at the same time want to continue to work constructively and collaboratively with the parties to do the work that is necessary to move the plan forward. We want to move quickly, but deliberately, recognizing the need for input on the significant decisions that will be necessary. We believe that with the input and support of our stakeholders, we can begin the task of transitioning our fleet from baseload coal to cleaner energy resources.

For our part, a fleet transformation of this magnitude requires a diligent and thoughtful process to ensure our system remains safe, reliable, and cost-effective. We are at the beginning of the process to determine the best way to accomplish this transition, but much remains to be done. Among other things, we are currently studying how Sherco unit closures impact system reliability, how to efficiently deliver gas supply to a repowered Sherco site as well as a site in North Dakota, and how we can successfully transition our workforce and minimize the impacts on our current employees at the Sherco plant. These items and others need to be resolved to make the plan viable. If we are unable to reach resolution on these items, we would recommend the Department's proposed plan as an achievable fallback position. In that plan, we would convert one Sherco Unit to a gas boiler in 2025, and submit our next resource plan in January 2017 with additional detail on the impact of further actions at Sherco.

The last time we significantly transformed our fleet was in the early 2000s when we worked with the Commission and our stakeholders to repower Riverside and High Bridge plants, and make environmental improvements to our King plant. The Metro Emissions Reduction Project (MERP) construct effectively vetted generation alternatives and provided the Commission an opportunity to evaluate the costs and terms of the proposal.[1] We think the same approach could work here. A MERP-type construct would provide a forum for the Company to bring forward a definitive, thorough proposal for the Commission to consider and analyze. Prior to bringing the proposal forward, we would welcome the opportunity to work with parties to try and find areas of agreement and resolution, including working to align our proposal with the MPCA process.

In the balance of our Reply, we provide additional detail on our proposal, outline next steps, provide an initial analysis of the CPP, and respond to specific stakeholder

[1] Docket No. E002/M-02-633.

Comments.

Section I – *Our Proposal*
Section II – *Next Steps*

Attachment A – *Updated Load and Resources Information*
Attachment B – *Initial Analysis of the Clean Power Plan*
Attachment C – *Response to July 2, 2015 Comments*

I. OUR PROPOSAL

In our Resource Plan, we initially proposed to operate Sherco Units 1 and 2 to 2030 and to add a total of 1,800 MW of wind and 1,700 MW of large solar resources over the planning period. With our revised proposal, we can achieve a 60 percent carbon emissions reduction by 2030 (from 2005 levels). To achieve that goal, we propose three actions:

First, establish retirement dates for Sherco Units 1 and 2 that are technically feasible, allow for an orderly workforce transition, and align with our resource needs. To that end, we propose to cease coal operations at Sherco Unit 2 in 2023 and Sherco Unit 1 in 2026.

Second, accelerate the addition of wind and solar resources – a total of 800 MW of wind and 400 MW of solar in the pre-2020 timeframe. Advancing renewables benefits our customers in that we can capitalize on favorable market pricing and anticipated tax credits. The acceleration also brings replacement generation online to ensure reliable service for our customers during the Sherco transition.

Third, commit to the continued utilization of our carbon-free nuclear baseload resources through the existing plant licenses – and engage the Commission and our stakeholders in a multi-year study to better understand the evolving nuclear landscape, the expected costs to operate our units through their current licenses, and what the industry is considering for additional life extensions.

We outline below the four primary elements of our proposal.

A. Accelerate the Transition from Coal Energy to Renewables

1. Sherco Units 1 and 2

The first step in achieving a 60 percent reduction in our carbon emissions is to chart a certain path for Sherco Units 1 and 2. We considered the Clean Energy Organizations'

(CEO) recommendation to close the first Unit in 2021 and the second Unit in 2024, but moved those dates out to adjust for construction timelines, system reliability, workforce transition – and allow time for CPP State Plan development. We also considered the Department's recommendation to convert one Sherco Unit to a natural gas boiler in 2025. While the Department's recommendation sets forth a practical alternative, we believe that beginning a two-Unit transition effort now best positions our customers to benefit from favorable market pricing and a construction schedule for replacement generation in the early 2020s. This timing also demonstrates leadership on implementation of the CPP, provides an adequate planning horizon for our employees, and positions us for an orderly transition to the future.

In order to deliver an orderly transition, we will need to work aggressively to complete technical studies, create workforce transition plans, draft detailed construction plans, coordinate with the MPCA and other states on the CPP, and develop a thorough MERP-type proposal. Important to the success of our proposal will be the availability of tax credits, community and state outreach and support for generation and infrastructure investments, and longer-term cost recovery mechanisms to help smooth rates and facilitate the transition for customers.

2. Technical Feasibility

The technical feasibility of our proposal is still under study. In our March 16, 2015 Supplement, we noted that Sherco Units 1 and 2 are key components of our system, that the grid has grown up around them for nearly 40 years, and that the Units' size, location, and operating characteristics require detailed technical study to confirm that we fully understand the implications of their removal from the NSP and Midcontinent Independent System Operator (MISO) Systems.

To that end, we described the MISO Attachment Y2 and Xcel Energy Transmission Reliability studies we were initiating to examine the effects of phased retirement scenarios of one or both Sherco Units. We also explained that we would need to revisit our Black Start plan that currently relies on these Units to restore the system in the case of a catastrophic event. While we still need to complete our Transmission Study and Black Start analysis, we have received the MISO Y2 study results.

The MISO Y2 Study found that ceasing operations of one Sherco Unit will likely require some mitigation for expected reliability impacts. Ceasing operation of both Units, however, creates a significant voltage issue in the Monticello area. Importantly, MISO also declared Sherco Units 1 and 2 as System Stability Resources (SSR), which means that before we can cease operations of those Units, MISO must approve our plans to ensure we have sufficiently mitigated any anticipated impacts on the transmission system. The preliminary results from our Transmission Reliability Study

are consistent with the MISO Y2 findings with respect to system impacts of a one versus two Unit closure.

The most significant reliability issues that require additional study include: (1) ensuring the Monticello Nuclear Plant meets Nuclear Regulatory Commission (NRC) requirements related to voltage during all system conditions; and (2) ensuring we can reliably serve Twin Cities area load by providing sufficient generation and voltage support. In January 2016, we anticipate receiving the results of our Transmission Reliability Study that will provide further insight into system stability and reliability under various Sherco retirement scenarios; this study is also likely to identify topic areas for additional study.

An important consideration in assessing the technical feasibility of retiring generating units is the replacement plan. We believe the replacement generation we are proposing at Sherco and in North Dakota will fulfill our expected energy and capacity needs and provide critical reliability solutions in their respective locations. We discuss our proposed replacement generation more fully in Section B.

3. Policy Considerations

We share the same goal as many of our stakeholders – delivering clean, reliable, and affordable energy to our customers while supporting our service territory communities. We have helped to lead the way to this objective through our early action to:

- Add significant and competitively-priced amounts of wind to our system,
- Develop sophisticated wind forecasting systems that facilitate our ability to reliably integrate significant amounts of wind onto our system,
- Avoid building approximately 3,100 MW of generation capacity by helping our customers achieve energy efficiency through our programs,
- Initiate one of the largest solar programs in the country, and
- Achieve significant carbon emissions reductions in a cost-effective manner while preserving jobs and maintaining our commitment to our communities through our MERP.

Once again, early action will help deliver value to our customers. With respect to the impact of environmental regulations, however, we are dealing in the unknown. We recognize there are many details to work through with the CPP, and that the State Plan will need to align well with our proposal in order to ensure benefits for all of our customers. We look forward to working with the MPCA, and expect to offer ideas to support regional solutions and a surplus compliance market to motivate utilities to go beyond compliance, providing substantial benefits to our customers and offering

solutions to our neighboring states.

a. Evolving Environmental Regulations

In August 2015, the EPA issued its final CPP rules, which may prove to be the most significant environmental regulation affecting the electric power sector to-date. Our early efforts and environmental leadership will ease the remaining work we have to do to achieve our share of CPP compliance. However, we are just at the beginning of a significant effort that will require coordination and collaboration across many different stakeholder groups in Minnesota and across our Upper Midwest region.

Obtaining clarity on CPP State Plan requirements will take time. However, our preliminary understanding of the final rule is that this proposal will very likely exceed our requirements in the case of either a rate- or mass-based approach.

In the case of a mass-based CPP approach, we reasonably believe our proposal will generate a significant quantity of surplus allowances to facilitate interstate CPP solutions that would benefit our customers. Getting appropriate credit for our customers for the surplus compliance our plan generates is an essential part of this plan, and will help defray the costs our customers will incur as we transform our generation portfolio.

In Attachment B to this Reply, we provide a more detailed discussion of our initial analysis of the CPP. Additionally, in Attachment C, we address the National Ambient Air Quality Standards (NAAQS) and Regional Haze and Visibility regulations.

b. Socioeconomic Impacts

Charting a path certain for Sherco Units 1 and 2 is important for our employees, the City of Becker and surrounding area, and Liberty Paper, who relies on steam from the Units for its operations. With these stakeholders in mind, our proposal provides an eight to ten year transition period and proposes to replace generation onsite, which will preserve jobs, grow tax base, and reaffirm our commitment to Central Minnesota.

We have a successful history with transitions like this. Since 2007, we have closed six coal-fired generating units, including our High Bridge and Riverside plants, which we repowered on natural gas as part of our MERP. In terms of our employees, by working closely within the Company and our International Brotherhood of Electrical Workers union locals, we have successfully managed these transitions.

4. Renewable Generation

The second step in achieving our carbon emissions goal is advancing the addition of renewable resources. Technology is enabling a quicker and more cost-effective move toward a clean energy future. Solar costs have decreased by more than 60 percent in the last five years. The cost of wind generation energy is now on par with new natural gas combined cycle – and offers a great fuel hedge. We are also seeing storage technologies begin to come on the market and believe batteries will increasingly come down in cost, offering both new potential in transportation and also in providing reliability and support to renewable and Distributed Energy Resources (DER).

In recognition of these advancements, we believe we can add more renewable generation to our system earlier. Our proposal maintains the same total levels of renewable additions as our Preferred Plan proposed – 1,700 MW of large solar generation and 1,800 MW of wind generation – but proposes to add a total of 1,200 MW of renewable generation in the 2016-2020 timeframe. In advancing these additions, we are seeking to benefit our customers by capitalizing on favorable pricing and available tax incentives. Accordingly, our ability to advance the addition of early wind generation is dependent on an extension of the production tax credit.

We also see an opportunity to further our compliance with the CPP to obtain tradable surplus compliance credits that could serve to offset some of the costs of this plan for our customers. As the percentage of generation coming from renewables and DER continues to grow, it is important to understand how that growth impacts our grid. We recognize the Commission is already pursuing this knowledge with the Grid Modernization effort.

B. Preserve Regional System Reliability

The second element to our proposal is to preserve regional system reliability by constructing sufficient gas-fired generation infrastructure and committing to the continued utilization of our carbon-free nuclear baseload resources through the existing unit licenses.

1. Natural Gas Generation

The size, type, and timing of additional thermal generation involves multiple considerations, including system stability needs, resource needs, and regional, state, and local economic and policy considerations. While we do not propose to replace Sherco Unit 1 and 2 capacity megawatt for megawatt due to higher energy efficiency and the addition of renewable energy resources, we propose to add natural gas generation at both the Sherco site and in North Dakota to support system reliability.

With respect to Sherco, we are continuing to study the potential to convert one of the boilers to gas, as suggested by the Department; however, preliminary assessments suggest that refueling with natural gas poses significant operational challenges. Further study of this option, as well as combustion turbine alternatives is necessary.

When Sherco Units 1 and 2 are retired, we believe that a combined cycle generating unit at the Sherco location provides many needed benefits to the transmission system, including needed reactive power for voltage support and dynamic response for system stability. Replacing Sherco Units 1 and 2 with a combined cycle unit facility also reinforces our commitment to Central Minnesota generally, and Becker specifically. This would provide continued commitment through jobs, property taxes, and presence in the communities of Central Minnesota. We also believe the development of solar energy on the Sherco site further demonstrates our continued commitment to the community. Our customers will also benefit from replacement because the Company can capitalize on the existing infrastructure at the site, including transmission, land, water, and site services.

Replacing Sherco Units 1 and 2 with a combined cycle facility also benefits Liberty Paper, who relies on the steam output of Sherco Units 1 and 2 for their operations. A combined cycle onsite would enhance natural gas supply and provide options for continuing support of steam supply to Liberty Paper. Liberty Paper is a valued customer, an important employer in the Becker area, and a critical part of Minnesota's recycling industry.

We also propose to add a combustion turbine unit in North Dakota by 2025. Adding North Dakota-based generation is important from both a policy and reliability perspective. North Dakota is a growing part of our integrated system – and nearly all of the generation serving North Dakota customers is in Minnesota. Given that, North Dakota has requested that the Company commit to build generation resources in the state—and we agreed. From a reliability perspective, siting generation in North Dakota is preferable given its proximity to the growing load centers.[2] This proximity promotes system reliability and allows for a rapid and effective response in the event of a power outage due to an adverse weather event.

2. Our Nuclear Fleet

The second step to ensuring system stability – and achieving a 60 percent reduction in

[2] We have previously discussed the differing policy views between Minnesota and North Dakota with respect to the make-up of our generation portfolio, and note that the Agreement we filed with the North Dakota Commission on September 30, 2015 commits to site thermal generation in North Dakota before 2025.

carbon emissions – is committing to utilize our carbon-free nuclear baseload through the existing plant licenses. The nuclear industry is facing significant pressure and some companies are considering closing nuclear units. Our proposal calls for the continued operation of our nuclear units through the 2020s. The rationale to support our position is three-fold. First, our nuclear units are a critical baseload resource that ensures system reliability and stability—particularly as large coal units come off line. Second, in order to maintain system stability, promote an orderly workforce transition, and maintain affordable energy for our customers, we need to transition away from coal before taking on the issue of a nuclear transition. Third, our nuclear fleet is critical to meeting carbon emissions targets and provides a hedge against high gas prices.

As we prepare our system for the transition, we need to do so in light of what other resources will be on our system to assure we can provide reliable and affordable energy to our customers. Retaining nuclear generation provides our system with a baseload energy resource that helps ensure system stability. Although renewable technology has made significant strides, it is not yet capable of replacing baseload generation. Accordingly, one view of our system is that our nuclear units can act as a bridge—ensuring system reliability while allowing time for the development of storage technologies like batteries. This staged transition also provides time to understand and respond to system impacts as baseload generation shifts, allows for an orderly workforce transition, and spreads customer rate impacts over time. Another view is that nuclear should continue to be a resource beyond the current licenses of the units. To that end, the nuclear industry and the NRC are actively discussing the potential for additional license renewals (known as "life after 60").

Continuing to operate our nuclear fleet is also essential to achieving the emissions reductions contemplated by state and federal policies. Our nuclear units comprise more than half of the Company's carbon-free generation. Given the current limits of battery storage, nuclear units retired today would likely be replaced primarily by natural gas, which exposes our customers to gas price volatility and a significant increase in carbon emissions. For context, through 2030, our nuclear fleet is projected to generate about 14,000 GWh/year of clean energy. If all of that baseload generation were replaced with natural gas combined cycle generation emitting at 900 lbs CO_2/MWh, the resulting increase in carbon emissions would be 6.3 million short tons per year—equivalent to adding 1.2 million cars to the road.

Our proposal outlines a continued commitment to nuclear generation; however given the pressures in the nuclear industry and the higher costs many projects have encountered, we believe it is important to provide the Commission with a thorough assessment of what this commitment to nuclear could cost, what pressures the industry is facing and what alternatives could reasonably be explored.

Our most recent five-year capital forecast shows increased capital costs for Prairie Island over those used in our Changed Circumstances filing in 2012. As a result, we have undertaken a further review of life cycle costs for our Prairie Island Units. Unlike Monticello where most major equipment has been replaced, the Prairie Island life cycle management (LCM) program was scaled back to address immediate areas of concern; in particular, the electric generator and the generator step up transformer when the decision not to proceed with the Electric Power Uprate (EPU) was made. We have undertaken additional review of the likely costs we expect we would need to incur to run the Prairie Island nuclear units through their current life, and are continuing to assess and validate that information. We plan to undertake a similar review at Monticello, and would like to formalize a process to share and update our expectations about these expected costs and risks that those costs could be higher (for instance if the industry were to experience another significant rule change such as fire protection or cybersecurity.) To that end, we propose to engage the Commission and our stakeholders in a multi-year study to better understand the evolving nuclear landscape, including the expected costs to operate through the current life and beyond.

With respect to increased capital costs, at a high level, what we are seeing as the plant ages and we work to comply with regulatory requirements is that our projected capital spend at Prairie Island is outpacing some of the estimates included in the Changed Circumstance filing. That said, our fixed operating and maintenance (Fixed O&M) costs are lower than we modeled such that the increase in capital spend is offset by the Fixed O&M savings. While our costs from 2011-2015 tracked amounts anticipated in that filing, our review of future operations at Prairie Island indicates the need for substantially more capital. Our five-year capital expenditure forecast from 2016 to 2020 has increased by roughly $175 million above what was anticipated in 2012.

As a result, we also reviewed the capital that had been projected for the latter period of Prairie Island's license. We determined that operating the plant to the end of its current license would require substantial increases in capital for the period 2021 through 2034, primarily due to the reliability risks of aging equipment and anticipated costs for compliance with additional NRC requirements. While it is difficult to predict the specific investments that may be required in this timeframe, we believe that capital expenditures would likely need to increase by roughly $600 to $900 million over this fifteen-year period. Without a comprehensive LCM project as we completed for Monticello, we have increased the cost of planned equipment reliability investments to reflect that Prairie Island will continue to require more regular replacements on the non-reactor side of the plant. We have also created a larger contingency for anticipated capital expenditures for NRC-mandated compliance programs in the future.

Our capital expenditure forecast for 2011 to 2034 has increased between $650 and $950 million since our Changed Circumstance filing. Over the same period, however, we have not experienced the level of escalation that was modeled, and do not anticipate cost growth at the level we were previously modeling, so our Fixed O&M estimates have decreased by approximately $1 billion over the same period. Operations through the end of Prairie Island's licensed life compared to a natural gas combined cycle unit using the high end capital assumptions continues to produce Present Value of Societal Costs (PVSC) benefits in the neighborhood of approximately $500 to $1 billion. Notably, these results do not consider additional replacement variables, including transmission system costs, the timing and ability to deliver the significant amount of incremental natural gas to our system, the costs of accelerating funding of our decommissioning and associated worker retention costs.

For all of these reasons, we believe continuing to operate our nuclear Units makes sense for our customers. We also realize, however, that the costs of our nuclear fleet can change rapidly and are influenced by other events in the industry. As such, we believe this discussion would benefit from a formal review that could occur through a multi-year study to better understand the evolving nuclear landscape. In that process, we would propose to conduct a similar exercise on the costs of continued operations at Monticello. Such timing would allow the immediate actions related to Sherco to proceed, but position the Commission with substantially more information about nuclear in advance of our next Resource Plan.

C. Pursue Energy Efficiency Gains and Grid Modernization

The third element in our plan commits to pursue energy efficiency gains at the level recommended by the Department. We have seen tremendous advances in energy efficiency, and have discussed the challenges associated with our ability to continue to achieve significant levels of energy efficiency with our customers under the current regulatory construct, due largely to increasing codes and standards. Indeed, our position in this docket has been that we could not continue to achieve energy efficiency gains at the 1.5 percent level. However, we believe technology advancements may alter that future, and by leveraging technology to take advantage of the increasingly "smart" appliances and electronic devices, we may be able to unlock greater potential savings. Accordingly, we commit to maintain a goal of 1.5 percent Demand Side Management (DSM) through the planning period, and to find ways to stimulate greater demand response with our customers. Additionally, we are open to continued collaboration and discussion on the conservation incentive. We understand that the Department and stakeholders will be working through this issue in 2016, toward a goal of implementing solutions in 2017.

We believe that modernization of the distribution system will be an important step in

our ability to unlock greater DSM gains by enabling customer choice, savings, and control by creating a safe and efficient platform for new products, new services, and opportunities for accelerated adoption of new technologies. We know that some of our customers want more control of their energy choices and believe advancements in technology will help us deliver those consumer options.

For example, the Clean Energy Partnership with the City of Minneapolis represents our commitment to collaborate on innovative approaches and enhanced outcomes in energy efficiency and the use of renewable energy to help the city achieve its Climate Action Plan goals. We supported the approval of the Partnership's 2015-2016 work plan, incorporating a broad spectrum of concepts and ideas that have yet to be fully fleshed out to determine the level of impact this may have on a community focused concept such as the Clean Energy Partnership. Similarly, but on a smaller scale through our Partners in Energy program, we work with local stakeholders to develop custom action plans and provide implementation support services to help meet community energy objectives for delivering clean, affordable energy and achievement of their sustainability goals.

We are committed to be the preferred and trusted provider of the energy services our customers' need, which will require that we remain connected to our customers, think creatively to deliver solutions, and leverage the advancing technology. Our proposal sets us on a sustainable path to this future by committing to continue our strong achievement of DSM and Demand Response results.

D. Ensure Customer Benefits

We plan to work with the Commission, the MPCA, and our stakeholders to ensure our customers get the full benefit of our proposal. By working with the MPCA on the CPP State Plan, along with its counterpart environmental agencies in our other states, we hope to encourage adoption of a regional approach with trading options to maximize the benefits of compliance for our customers and communities. We also intend to work with the Commission and the Department to pursue longer-term rate compacts which will provide the runway we need to manage our business while smoothing the costs for our customers of this transition. Additionally, a longer-term rate compact will free-up Commission, stakeholder, and Company resources to focus on this proceeding, the State Plan, and other issues like Grid Modernization. We have successfully entered into these longer-term regulatory compacts in North Dakota and South Dakota, and look forward to advancing proposals to do so in Minnesota based on legislation passed in the last legislative session. Finally, we plan to develop a MERP-type proposal to provide predictable cost recovery and ensure an orderly transition to a cleaner energy future.

E. Customer Impacts

We have completed a preliminary analysis of our proposal and believe that we can begin the transformation of our generation fleet at a reasonable cost for our customers. We will complete a detailed customer impact analysis that will be filed with the Commission no later than January 29, 2016, but our initial analysis suggests that the plan can be implemented while keeping the overall cost impact through the planning period within an incremental two to three percent rate increase above our Reference Case. When we complete and submit our full resource planning analysis, it will include the same level of detail on estimated rate impacts that we submitted in our April 17, 2015 Reply Comments in this docket. In the interim, we provide a high level summary of expected cost impacts of our revised proposal as compared to our Preferred Plan:

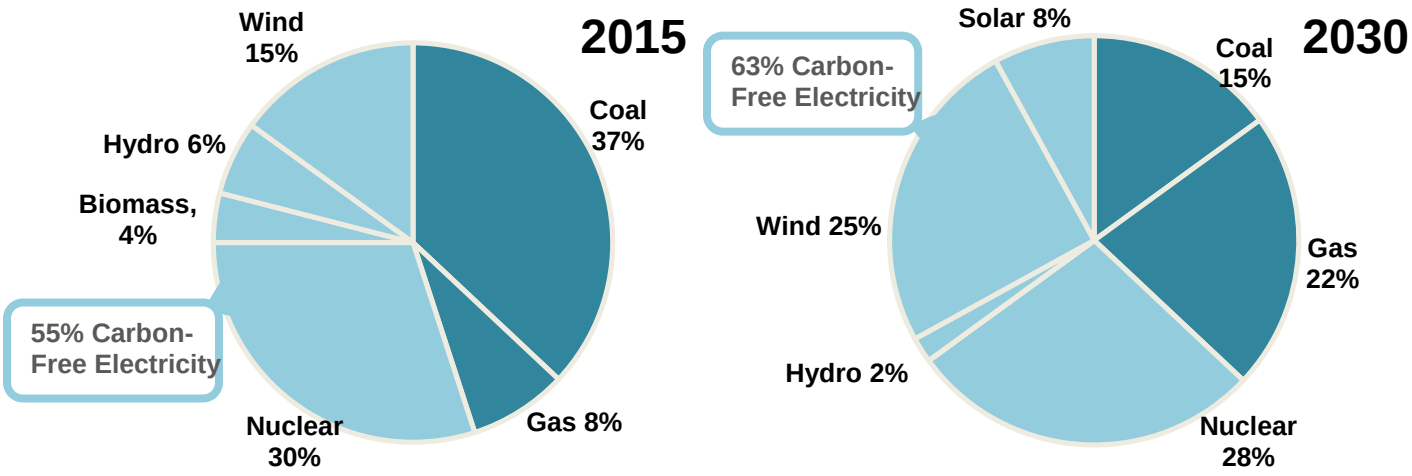
- Our Preferred Plan identified a one to two percent incremental rate impact above the Reference Plan for the period of 2016 to 2030; our revised proposal likely raises the incremental rate impact to two to three percent above the Reference Plan.
- Monetizing the value of the additional carbon emissions reduction of our revised proposal at the midpoint ($21.50) of the range of the Commission's regulatory cost of carbon, we show the incremental rate impact at the low-end of this range, and approximately two percent over the planning period.

We believe that there are opportunities to further offset the rate impact of our proposal by working with the MPCA and its counterparts in other states to develop a regional carbon market. We also believe there are regulatory tools, such as multi-year rate plans and the Emissions Reduction Rider statute (Minn. Stat. § 216B.1692) that can provide predictable cost recovery and help to smooth cost impacts for our customers.

F. Updated Metrics

Our proposal seeks to transform the energy supply for our Upper Midwest customers. Figure 1 below provides a side-by-side comparison of our energy mix today and how that energy mix changes as a result of our revised proposal. Overall, our carbon-free energy component increases to 63 percent.

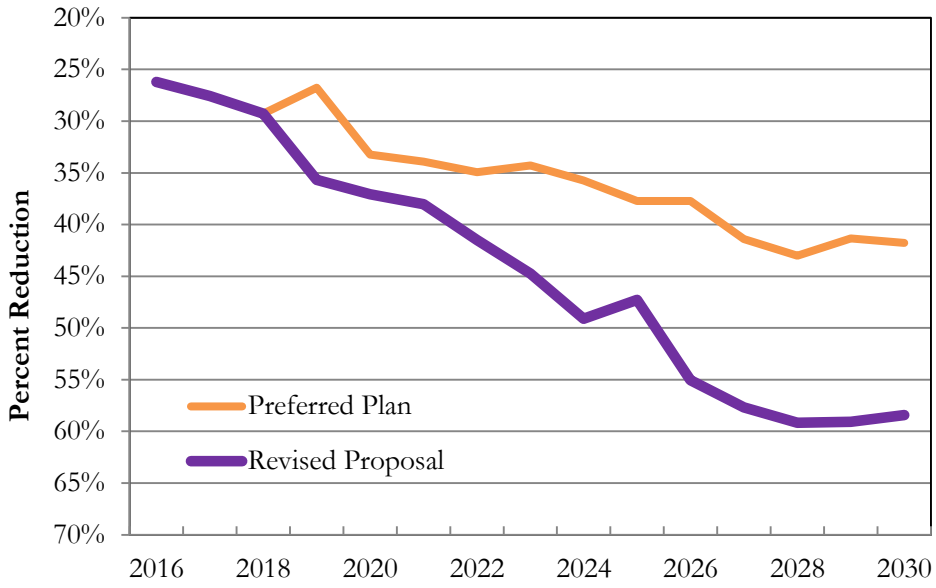
Figure 1: 2015 Energy Mix Compared to Revised Proposal in 2030



Key changes in our energy mix include a reduction to 15 percent for coal, and an increase in natural gas to 22 percent. With respect to renewables, solar increases to 8 percent, wind increases to 25 percent and—due to contract expirations—biomass and hydro drop to zero and two percent, respectively.

Figure 2 below demonstrates the projected carbon reduction of the revised proposal compared to the Preferred Plan. As shown, our revised proposal accelerates our reduction of carbon emissions and increases the level of reduction significantly – achieving nearly a 60 percent reduction from 2005 levels by 2030.

Figure 2: Projected Carbon Reduction from 2005 Revised Proposal Compared to Preferred Plan



As Attachment A to this Reply, we also provide an updated Load and Resources analysis that summarizes our capacity position through the planning period, and an Expansion Plan that outlines the generation additions we are considering to address the resource needs of our customers.

II. NEXT STEPS

We have outlined the Company's proposal for an energy future that is reliable, cost-effective, and cleaner. Our proposal optimizes the resource investments our customers have already made; provides the sustainability choices our customers want; creates the runway we need to successfully transition our workforce; creates the opportunity to reinvest in our communities; and motivates the Company to go beyond CPP compliance and generate valuable surplus allowances to the benefit of our customers.

We believe the level of collaboration that has ensued in this Resource Plan docket to-date has greatly improved stakeholder understanding of the evolving planning landscape and proposals that have been made. We have continued our outreach as we prepared these Comments and believe additional collaborative discussions will be beneficial. So that we can take advantage of the momentum of the current proceeding and continue our work with stakeholders to assemble the necessary support for and protections around our revised plan, we respectfully propose the following next steps:

- We propose to work with Commission Staff on a procedural schedule that continues to build the record for our revised proposal in this proceeding. With that in mind, we are open to supplementing the record incrementally as we complete various analyses and studies. We commit to supplement our revised proposal with a more detailed analysis and the results of our Transmission Reliability Study no later than January 29, 2016.
- Between now and January 2016, we propose to collaborate with parties to share our work, obtain valuable feedback (including in the form of filed Comments, if the Commission so orders), and identify areas of concern.
- Between now and January 2016, we propose to schedule additional stakeholder outreach meetings.
- We propose to immediately begin working with the Department and the MPCA on a schedule to accommodate the CPP State Plan, as well as collaborate regarding the scope of our nuclear study outlined above. Further, we look forward to similar collaboration with the Department and stakeholders regarding conservation potential and the associated financial incentives.
- We propose to develop a MERP-type proposal that we will be prepared to bring forward in the spring of 2016.

CONCLUSION

In these Reply Comments, we have outlined our vision for a cleaner energy future. We believe our proposal benefits our customers by supporting a cost-effective transition to a cleaner generation fleet, allows adequate time to transition our workforce, creates new jobs and investments for our communities, and continues our renewable and carbon-free energy leadership. There is much work to do be done, but we look forward working with the Commission, the Department, the MPCA, and our other stakeholders to bring our proposal forward.

Dated: October 2, 2015

Northern States Power Company

UPDATED LOAD AND RESOURCES INFORMATION

We provide below, an updated Load and Resources (L&R) analysis that summarizes our capacity position through the planning period, and an Expansion Plan that outlines the generation additions we are considering to address the resource needs of our customers. For clarity, we provide this resource summary in a format that builds on the L&R information included in our March 16, 2015 Supplement.

The final row of Table 1 below provides our updated capacity position before adding any of the new resources proposed in our revised proposal. More specifically, it shows we expect to have sufficient capacity to meet our customers' needs through 2023. However, starting in 2024 we have a capacity deficit that grows from 177 MW to over 3,500 MW by 2030.

Table 1: Updated Load and Resources (MW)

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Forecasted Load	9,442	9,525	9,597	9,649	9,674	9,694	9,754	9,748	9,766	9,798	9,868	9,962	10,136	10,151	10,251
MISO System Coincident	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%
Coincident Load	8,970	9,048	9,117	9,167	9,190	9,209	9,266	9,261	9,278	9,308	9,375	9,464	9,629	9,644	9,739
MISO Planning Reserve	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%
Obligation	9,607	9,691	9,764	9,818	9,843	9,863	9,924	9,919	9,937	9,969	10,041	10,136	10,313	10,328	10,430
Existing Resources	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Load Management	1,009	1,021	1,033	1,044	1,056	1,067	1,078	1,090	1,101	1,103	1,098	1,094	1,089	1,085	1,080
Coal	2,372	2,395	2,395	2,395	2,395	2,395	2,395	2,395	2,395	2,395	2,395	2,395	2,395	2,395	2,395
Nuclear	1,648	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643
Natural Gas	3,451	3,476	3,476	3,465	3,465	3,465	3,465	3,465	3,137	2,824	2,298	2,047	1,812	1,812	1,812
Biomass/RDF/Hydro/Wind	1,341	1,339	1,316	1,279	1,205	1,437	1,430	1,383	1,310	461	451	407	318	300	299
Solar*	25	33	137	143	149	156	164	174	187	202	220	242	268	300	338
Existing Resources	9,846	9,906	9,999	9,970	9,913	10,163	10,176	10,150	9,772	8,627	8,105	7,827	7,525	7,535	7,568
Position Jan 2, 2015 RP Initial Filing	**239**	**216**	**235**	**152**	**70**	**300**	**251**	**231**	**-165**	**-1,341**	**-1,936**	**-2,309**	**-2,788**	**-2,794**	**-2,862**
** Solar includes 2014 Solar RFP (Docket No. E002/M-14-162)*															
Planned Resource Additions	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Black Dog 6	0	0	0	208	208	208	208	208	208	208	208	208	208	208	208
Calpine MEC2	0	0	0	278	278	278	278	278	278	278	278	278	278	278	278
Geronimo	0	0	70	69	69	69	68	68	68	67	67	67	66	66	66
Community Solar Garden - Additions**	20	36	53	72	94	103	103	102	102	101	101	100	100	99	98
Additional Approved Resources	20	36	123	628	649	658	657	656	655	654	654	653	652	651	650
Position Mar 16, 2015 RP Supplement Filing	**260**	**251**	**358**	**779**	**719**	**958**	**909**	**887**	**490**	**-687**	**-1,282**	**-1,657**	**-2,136**	**-2,143**	**-2,212**
*** Solar Additions represent the revised solar implementation due to Community Solar Gardens.*															
Proposal	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Sherco 2 Cease Coal Operation	0	0	0	0	0	0	0	-667	-667	-667	-667	-667	-667	-667	-667
Sherco 1 Cease Coal Operation	0	0	0	0	0	0	0	0	0	0	-694	-694	-694	-694	-694
Proposed Coal Reductions	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**-667**	**-667**	**-667**	**-1,361**	**-1,361**	**-1,361**	**-1,361**	**-1,361**
Position Oct 2, 2015 RP Reply Comments Filing	**260**	**251**	**358**	**779**	**719**	**958**	**909**	**220**	**-177**	**-1,354**	**-2,643**	**-3,017**	**-3,497**	**-3,503**	**-3,573**

As shown in Table 2 below, our proposal adds thermal and renewable resources in an incremental manner to limit customer rate impacts while also supporting a smooth transition of our generation fleet through 2030.

Table 2: Revised Proposal Expansion Plan[1]
(MW Additions, Nameplate Ratings)
(Accredited capacity is less - see Table 3)

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
Large Solar	-	-	-	200	-	200	100	100	100	100	100	100	-	400	-	-	1,400
Wind	-	-	-	-	800	-	-	200	200	-	400	200	-	-	-	-	1,800
North Dakota CT	-	-	-	-	-	-	-	-	232	-	-	-	-	-	-	-	232
Sherco Gas Conversion/CT	-	-	-	-	-	-	-	-	-	-	562	-	-	-	-	-	562
Sherco CC	-	-	-	-	-	-	-	-	-	-	-	778	-	-	-	-	778
CT	-	-	-	-	-	-	-	-	-	-	-	464	-	-	-	-	464
CC	-	-	-	-	-	-	-	-	-	-	-	-	778	-	-	-	778

Note: The North Dakota CT is reflected in 2023 for planning purposes.

Relative to the Expansion Plan in our March 16 Supplement, we are proposing to accelerate the acquisition of 400 MW of large solar and an additional 200 MW of wind for a total acquisition of 800 MW of wind and 400 MW of large solar in the 2018 to 2020 timeframe. This timing will allow the opportunity to take advantage of possible cost-reducing incentives, while at the same time adding the energy resources necessary to allow Sherco Unit 2 to cease operations. Thermal resource additions, including a combined cycle at Sherco needed for system stability, a possible conversion of a Sherco Unit to use natural gas, and a combustion turbine in North Dakota are also staggered throughout the planning period to help manage costs and facilitate a smooth fleet transition.

To demonstrate how these proposed resources will meet the capacity needs of our customers through 2030, we provide a view of our net capacity position after these resources are added to the system as Table 3 below. Table 3 begins with the net capacity position from the final row of the L&R Table 1 above, and adds the MISO accredited capacity value of each of the proposed new resources. Table 3 concludes with our net capacity position.

[1] We clarify that with respect to Solar resource additions, we no longer show the expected 697 MW of Small Solar additions through 2030 or the 287 MW of Large Solar in 2017 already approved by the Minnesota Commission in the Expansion Plan. These resources are integrated into the L&R. Therefore, the total renewables additions we propose in this Reply are consistent with the total levels we proposed in our March 16 Supplement.

Table 3: Net Capacity Position after Resource Additions (MW Additions, UCAP Ratings)[2]

Position 10/02/2015 RP Reply Comments Filing	2016 260	2017 251	2018 358	2019 779	2020 719	2021 958	2022 909	2023 220	2024 -177	2025 -1,354	2026 -2,643	2027 -3,017	2028 -3,497	2029 -3,503	2030 -3,573
Revised Proposal Resources															
Large Solar	0	0	0	0	0	261	314	366	418	471	523	523	732	732	732
Wind	0	0	0	0	0	118	148	178	178	237	266	266	266	266	266
North Dakota CT	0	0	0	0	0	0	0	208	208	208	208	208	208	208	208
Sherco Unit Gas Conversion	0	0	0	0	0	0	0	0	0	514	514	514	514	514	514
Sherco CC	0	0	0	0	0	0	0	0	0	0	763	763	763	763	763
CT	0	0	0	0	0	0	0	0	0	0	417	417	417	417	417
CC	0	0	0	0	0	0	0	0	0	0	0	763	763	763	763
Total Plan Additions	***0***	***0***	***0***	***0***	***0***	***380***	***462***	***751***	***804***	***1,429***	***2,691***	***3,453***	***3,663***	***3,663***	***3,663***
Revised Proposal Position after Additions	**260**	**251**	**358**	**779**	**719**	**1,338**	**1,370**	**972**	**627**	**75**	**47**	**436**	**166**	**159**	**89**

Note: The North Dakota CT is reflected in 2023 for planning purposes.

[2] MISO Unforced Capacity (UCAP) values, which are equal to the amount of accredited capacity, by resource type, that MISO allows the Company to count towards meeting its capacity obligations. Please note that MISO accreditation is by MISO Planning Year, so the timing may not align with the resource addition dates reflected in the above Table 2: Revised Proposal Expansion Plan.

PRELIMINARY ASSESSMENT OF THE FINAL CLEAN POWER PLAN RULES

In August 2015, the Environmental Protection Agency (EPA) issued its final Clean Power Plan (CPP) rules, which may prove to be the most significant environmental regulation affecting the electric power sector to date. As we have noted, our early efforts and environmental leadership will ease the remaining work we have to do to achieve our share of CPP compliance. However, we are just at the beginning of an effort that will require coordination and collaboration across many different stakeholder groups both in Minnesota and across our Upper Midwest region. In this attachment, we discuss our preliminary understanding of the impact of the final rule on our NSP System.

The EPA's CPP for existing power plants under section 111(d) of the Clean Air Act was a proposed rule at the time of our January 2, 2015 filing and March 16, 2015 Supplement. It became a final rule on August 3, 2015.[1] Thus, EPA's final targets in both rate (lbs CO_2/MWh) and mass (tons CO_2) terms for the NSP System's five states are now known. While the final rule lowered the reduction target for Minnesota and South Dakota, it significantly raised the reduction target for North Dakota, with smaller increases for Wisconsin and Michigan. That said, only the Minnesota targets affect the Company directly, since we own and operate CPP-regulated units only in Minnesota.[2] Despite announcement of the final rule, much remains unknown about what CPP compliance will require of the Company. Many of the key decisions that will ultimately shape the 111(d) State Plans, due to EPA by September 2018, remain undecided.[3]

In our filings to date, we noted that the Preferred Plan we proposed would allow us to meet the Next Generation Energy Act (NGEA) Greenhouse Gas (GHG) goals and our renewable energy requirements and objectives – and put us on a path to address EPA CPP requirements, based on our analysis of the proposed rule. We still believe the Preferred Plan will exceed the NGEA goals and our renewable energy mandates. Our preliminary analysis of the final rule suggests it would also achieve CPP compliance in rate-based terms, in the event the Minnesota Pollution Control Agency

[1] Environmental Protection Agency. 40 CFR Part 60. *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units*. August 3, 2015. Posted at http://www2.epa.gov/cleanpowerplan/clean-power-plan-existing-power-plants.

[2] NSP owns no existing fossil units in North Dakota and Michigan, and our generating units in Wisconsin and South Dakota are exempt from the CPP definition of "affected electricity generating unit."

[3] States may file an "initial submittal" in September 2016, requesting an extension to September 2018 to file final plans. CPP final rule at pages 1475-1476.

(MPCA) designs a rate-based plan and assigns regulated utilities the same targets as EPA assigned to Minnesota.

Whether the Preferred Plan would achieve CPP compliance in mass-based terms is more difficult to say, since this requires assumptions about how MPCA might allocate the statewide allowance budget. Our preliminary analysis of the final CPP rule suggests that, based on conservative assumptions about allowance allocation, the Preferred Plan may not be sufficient to sustain carbon dioxide (CO_2) emissions below a possible allowance budget for NSP throughout the planning period.

Conversely, we believe that in either a rate-based or mass-based scenario, our revised proposal will likely exceed our CPP compliance obligation – generating valuable surplus reductions that would benefit our customers in an interstate collaboration scenario. We explain our reasoning below.

A. Proposed Rule

In the proposed CPP published June 18, 2014, Minnesota's and Xcel Energy's early efforts and environmental leadership were highlighted. However, the proposed rule did not give early action credit to the State of Minnesota, and generally assigned more stringent targets to states who had already achieved greater CO_2 reductions prior to the rule's baseline year of 2012. Minnesota's 2030 target in the proposed rule was 873 lbs CO_2/MWh. Under the Preferred Plan we initially proposed adding over 4 GW of wind and solar to reduce coal generation and bring the NSP System under the EPA's target for the state of 873 lbs. Thus, if MPCA assigned utilities a rate-based target equal to the state's target, the Preferred Plan we initially proposed would have been CPP-compliant in rate terms, without retiring coal units.

Mass-based compliance with the proposed CPP was more difficult to analyze, since the rule provided complex formulas for converting state rate goals into mass equivalents, and the mass goal for Minnesota appeared to be significantly more stringent than its rate equivalent, in part because of our Sherco Unit 3 having been offline for the entire baseline year of 2012. The MPCA, the Company, and others drew EPA's attention to these issues.

B. Final Rule

We worked with the MPCA and other stakeholders to advocate for revisions to the proposed rule that would make the final rule fairer to our Minnesota customers. In the final rule, Minnesota's 2030 target is 1,213 lbs CO_2/MWh in rate terms and 22.7

million short tons CO_2 in mass terms.[4] We note, however, that the target in the final rule is not comparable to the 873 lbs CO_2/MWh target in the proposed rule, since the formula significantly changed with the elimination of pre-2012 renewable energy, "at risk" nuclear, and energy efficiency from target-setting – as well as a regionalized rather than state-by-state approach to target-setting.

In any event, it is clear that Minnesota's interim and final targets are less stringent in the final rule than in the proposed rule. This is due to a different target-setting methodology that tended to bring all states' targets into a narrower band of values, as well as a technical correction the EPA made for Sherco Unit 3 having been offline for the entire baseline year of 2012. We believe the following discussion portrays a reasonable understanding of how the final CPP might apply to both our Preferred Plan and the revised proposal outlined in this Reply.

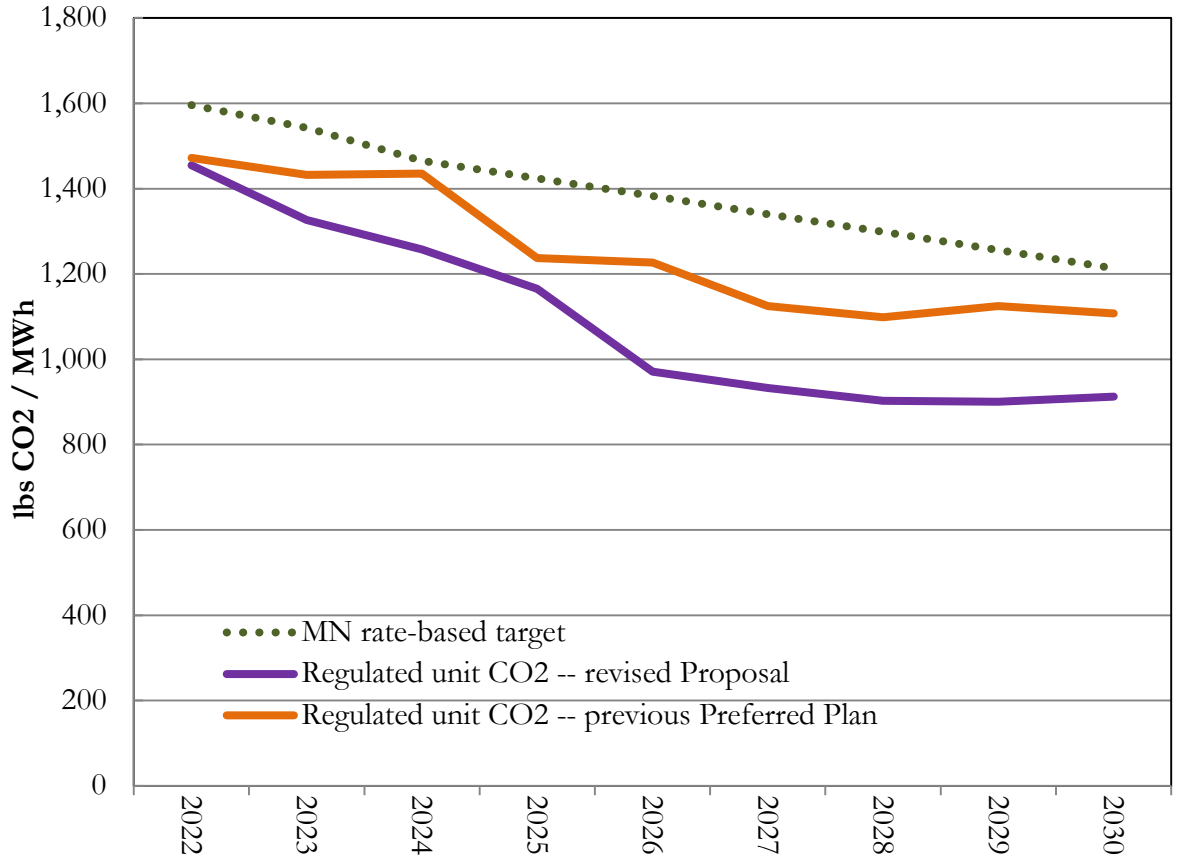
1. Rate-Based Compliance

Considering the new target of 1,213 lbs CO_2/MWh, the Preferred Plan continues to appear CPP-compliant in rate terms. The Preferred Plan would drive the NSP System to a CO_2 rate, under the final rule formula, of 1,107 lbs/MWh[5] in 2030 – below EPA's target for the state in that same year. Thus if MPCA assigns utilities a rate-based target equal to the state's target, the Preferred Plan would be CPP-compliant in rate terms without retiring coal units. Likewise, our revised Proposal would be CPP-compliant in rate terms, achieving a CO_2 rate under the CPP formula of 912 lbs/MWh in 2030, well below the state's 2030 target of 1,213 lbs/MWh. Figure 1 below demonstrates this rate-based compliance view; both the Preferred Plan (purple solid line) we initially proposed and our revised Proposal (orange solid line) would be below the MN rate-based budget (green dotted line) in all years.

[4] EPA target for total emissions from existing affected EGUs in Minnesota. The mass-based target for existing and new units (i.e. including the "new source complement") is slightly higher.

[5] This represents the NSP CO_2 rate according to EPA's formula in the final 111(d) rule, which is different from the NSP System's CO_2 rate under the more conventional metric of total emissions from owned and purchased power divided by total owned and purchased power. The NSP CO_2 rate under the latter metric would be 720 lbs/MWh in 2030 for the Preferred Plan.

Figure 1: Potential Final CPP Compliance Position in Rate Terms



2. Mass-Based Compliance

In mass terms, our previous Preferred Plan would reduce NSP's total CO_2 emissions from 111(d)-regulated units to 18.0 million short tons in 2030, while the revised Proposal would reduce total CO_2 emissions from 111(d)-regulated units to 9.8 million short tons in 2030.[6]

However, whether any plan achieves CPP compliance in mass-based terms is more difficult to assess than rate-based compliance. Mass-based compliance is determined by bringing total CO_2 emissions from the 111(d)-regulated units below a total budget of allowances allocated to NSP (plus any allowances purchased from others). Since MPCA has not yet made decisions about allowance allocation, any evaluation of mass-

[6] This represents total CO_2 emissions from 111(d)-regulated existing units, and does not include emissions from exempt units (simple-cycle CTs, biomass EGUs, etc.) or new units (units that commenced construction after January 8, 2014 and are thus regulated under section 111(b)).

based compliance is preliminary and depends on making reasonable assumptions about decisions MPCA has yet to make.

Under EPA's default method of allowance allocation in the proposed federal plan and model trading rules, allowances would be allocated among owners/operators of 111(d)-regulated units based on share of generation from those units in 2010-2012.[7] This would give NSP about 69 percent of the Minnesota budget. Our preliminary mass-based compliance evaluation assumes:

- MPCA creates a CPP plan for existing regulated units only, i.e. leaves new units outside its 111(d) plan,
- MPCA sets aside allowances, in the amounts suggested by EPA, for renewable energy, preventing emissions leakage from existing natural gas combined cycle (NGCC) units to new NGCCs, and the Clean Energy Incentive Program (CEIP), but does not set aside allowances for other purposes,[8]
- MPCA allocates the remaining mass budget to affected electrical generating units (EGU) on the basis of 2010-2012 generation, the default allocation in the proposed federal plan and model trading rules,
- NSP is able to win back a share of the allowance set-asides for renewable energy, existing NGCCs, and the CEIP, and
- MPCA does not adopt a provision in EPA's proposed federal plan that would only award allowances to a retiring unit for the remainder of a compliance period in which it retires, and award no allowances to units retiring more than two years prior to 2022.[9]

We note that states are not required to adopt this (or any other) allocation provision in the proposed federal plan or the model trading rules.

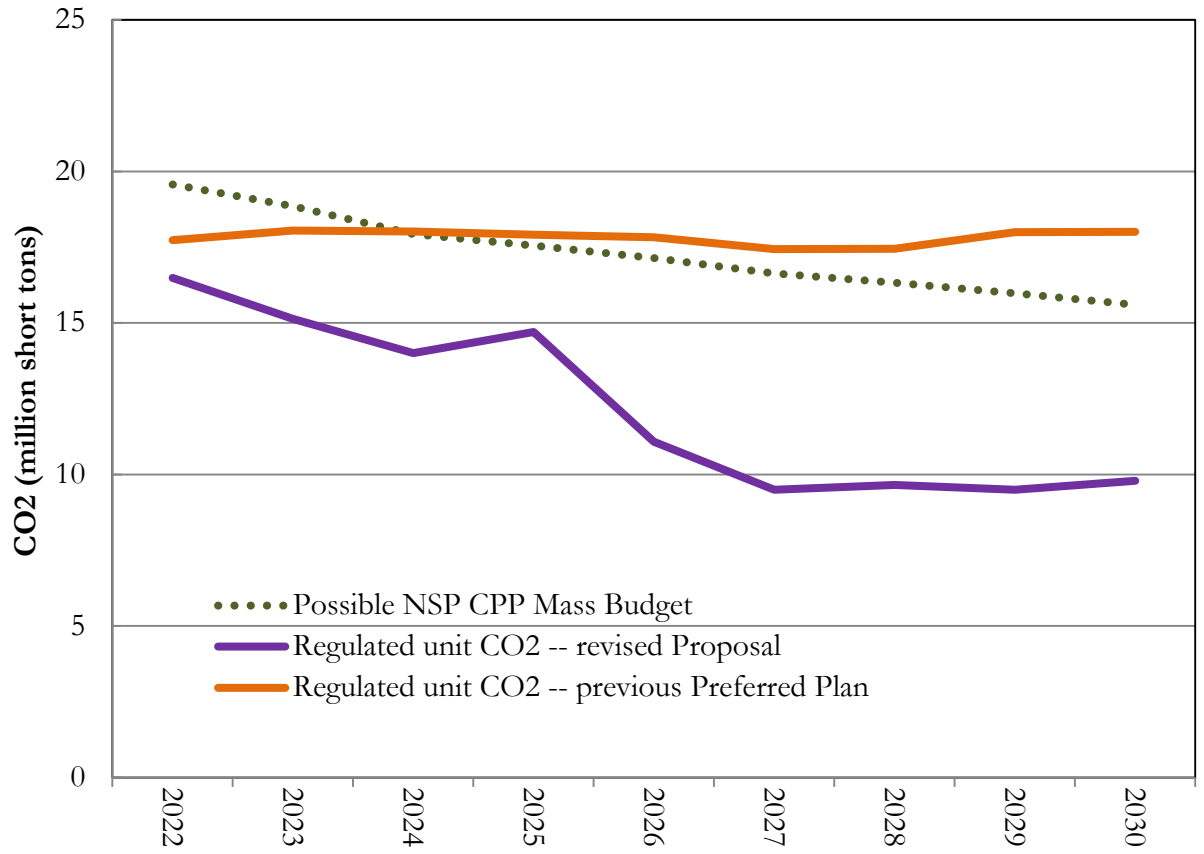
Under these assumptions, the CO_2 reductions associated with our Preferred Plan would exceed NSP's responsible share in the 2022-2024 compliance period, but would fall short in the 2025-2027 and 2028-2029 compliance periods. Under the rule, we would be allowed to "bank" allowances, or use surplus allowances from the first compliance period to make-up for some of the shortfall in the second and third periods. However, even with banking, we would be short allowances overall in the

[7] Environmental Protection Agency. 40 CFR Part 62. *Federal Plan Requirements for Greenhouse Gas Emissions from Electric Utility Generating Units Constructed on or Before January 8, 2014; Model Trading Rules; Amendments to Framework Regulations*. August 3, 2015. Page 252.
[8] EPA, Federal Plan Requirements and Model Trading Rules, pages 477-484.
[9] EPA, Federal Plan Requirements and Model Trading Rules, page 486.

2022-2029 interim period, requiring the Company to purchase allowances from others in order to achieve CPP mass-based compliance.

We demonstrate this mass-based compliance view in Figure 2 below. The CO_2 forecast for the Preferred Plan (purple solid line) we initially proposed lies below the allowance budget allocated to NSP (green dotted line) initially, but above it after 2024 – and surplus allowances banked in 2022-2024 are not sufficient to fill the shortfall after 2024.

Figure 2: Potential Final CPP Compliance Position in Mass Terms



In contrast, under our revised proposal, CO_2 emissions from the CPP-regulated units (orange solid line) would be well below the NSP mass budget (green dotted line) in all years. We would not be required to purchase allowances to achieve CPP compliance, and in fact we could generate a significant quantity of surplus allowances to facilitate interstate CPP solutions that would benefit NSP customers in all five NSP System states.

It is important to note that this analysis is preliminary. At present we do not know if MPCA will implement a rate-based or a mass-based approach to Minnesota's 111(d) plan; whether the plan will regulate EGUs only ("emission standards" plan) or other entities as well ("state measures" plan); and what share of the statewide CO_2 reductions will be assigned to NSP. There are more unknowns as well. If MPCA implements a mass-based approach, we do not know how MPCA will allocate allowances; whether intra- or interstate trading will be available; whether new (built after January 2014) units will be brought into or remain outside the plan; or whether MPCA will implement the allowance set-asides suggested by EPA and/or any other set-asides. Accordingly, we cannot definitively say whether the Preferred Plan would or would not be sufficient to achieve CPP compliance for NSP.

We can, however, say that our revised proposal appears to go beyond CPP compliance, and has the potential to generate value for our customers. Retiring Sherco Units 1 and 2 and accelerating the addition of solar and wind renewable generation, will create a surplus of allowances or Emission Rate Credits that can be used to the benefit of our Upper Midwest customers, including the possibility of using this value on a regional basis to smooth rate impacts for our customers.

RESPONSE TO COMMENTS

A. Background

We submitted our 2016-2030 Upper Midwest Resource Plan on January 2, 2015, as required by the Commission's May 23, 2014 Order in the Competitive Acquisition Process (CAP) proceeding.[1] The Commission made determinations in the CAP proceeding in December 2014; due to the timing, we were unable to incorporate the Commission's resource determinations into our Initial Filing. In January 2015, the Commission issued a Notice requiring the Company to supplement its Resource Plan to incorporate the resource decisions made in the CAP proceeding, which we did on March 16, 2015 (Supplement).

In our Supplement, we also provided information that responded to several stakeholder requests, including: (1) an expanded explanation of our modeling assumptions and those that were updated; (2) a more detailed approximation of rate impacts of our Preferred Plan by customer class; and (3) additional modeling and discussion regarding the costs and other implications of potential retirements of our Sherco Units 1 and/or 2 generating facilities in the early 2020s.

On February 10, 2015, we held our first in a series of stakeholder meetings where we discussed our Preferred Plan and its assumptions and impacts. We followed that meeting with three additional stakeholder meetings where we outlined the details and assumptions underlying our plan and addressed key areas of stakeholder interest including Strategist modeling, Demand Side Management, and evolving environmental regulations. We have also met with individual stakeholders to discuss aspects of our Preferred Plan and participated in the technical conferences held by the Department of Commerce and the Clean Energy Organizations (CEO).

We believe the level of collaboration that has ensued to-date has furthered a shared understanding of the evolving planning landscape and the proposals that have been made. These collaborative efforts and the diverse perspectives parties shared in their July 2, 2015 Comments informed our thinking about our future system and contributed to the revised Proposal we make in this Reply.
In terms of Comments, in addition to commenting on aspects of our Preferred Plan, the Department and CEO each proposed alternative plans that relied on Strategist modeling. The Minnesota Pollution Control Agency (MPCA) commended our commitment to reduce greenhouse gases (GHG), and concluded that it is reasonable

[1] Docket No. E002/M-12-1240.

to assume that the mid-2020s represents the likely timeframe when Selective Catalytic Reduction (SCR) could be required on Sherco Units 1 and 2. Liberty Paper highlighted the importance of Sherco Units 1 and 2 to their operation and the important benefits Liberty Paper provides to Minnesota. The City of Becker expressed appreciation for our leadership role in maintaining a balanced fuel source portfolio and aggressive pursuit of renewable energy, noted the need for continued baseload resources, and supported the addition of natural gas resources, potentially located in Becker.

Xcel Large Industrials acknowledged the significant regulatory uncertainty around environmental issues and expressed concern over our rates. Community Power requested that the Minneapolis Clean Energy Partnership work plan be formally included in the Company's Resource Plan. Minnesota Utility Investors noted the importance of the flexibility of the plan we proposed and supported continued reliance on our Sherco and nuclear units in the future. St. Paul Cogeneration recommended the Commission ensure that biomass and Combined Heat and Power (CHP) are part of the Company's future resource mix. Finally, International District Energy Association recommended that we incorporate CHP as a utility generation asset in our plan.

We appreciate the parties' thoughtful comments, and note again that they were taken into consideration when we created our revised proposal. We do not specifically address all of the Comments in this Response; rather, we respond to specific requests for information and provide clarifications in response to certain aspects of Comments by the Department and CEO.

B. Strategist Modeling and Greenhouse Gas Emissions Accounting

We appreciate the alternative plans proposed by the Department and CEO, and the constructive dialogue that has ensued as a result. While we are now advancing the revised proposal outlined in our Reply, in this section, we touch on modeling-related issues, including GHG accounting calculations that we believe require clarification.

1. GHG Emissions Accounting

In this section, we explain the methodology we employed to calculate our baseline and target-year carbon dioxide (CO_2) emissions under the Next Generation Energy Act (NGEA) GHG goals (Minn. Stat. § 216H.02, subd. 1), and note the importance of using consistent calculations in both baseline and projected CO_2 emissions forecasts. We agree with CEO that the methodology we use to calculate our NGEA

progress is different from the methodology MPCA employs to calculate NGEA progress at the statewide level. We note that while there is an established MPCA methodology for quantifying emissions and reporting on GHG reductions statewide, there is no approved MPCA methodology that applies to individual utilities.

MPCA itself acknowledges this difference:

> *In our reporting to the Legislature, we make no attempt to distribute total electric power sector emissions to individual utilities… It is the policy at MPCA that the Next Generation Energy Act goals are state-level goals covering, in aggregate, all economic sectors, and not targets that can be applied to specific economic sectors or any single firm.*[2]

MPCA's statewide methodology and the methodology we have used to calculate our emissions differ in several respects. First, MPCA's quantification for the electric power sector statewide includes GHG emissions from in-state power generating sources such as CO_2, methane (CH_4), and nitrous oxide (N_2O); emissions from area sources, such as sulfur hexafluoride (SF_6) emissions from the transmission and distribution (T&D) system; and a state-level term to account for emissions associated with the generation and transmission of net power imported across state borders, including T&D losses.[3] With respect to emissions from imported power, MPCA makes no attempt to allocate emissions to individual utilities.[4] So, while emissions from imported power are a portion of the 30.6 million short tons (MST) in our 2005 baseline, these would not be included in any MPCA estimate for the Company. Additionally, in MPCA's methodology, biogenic CO_2 emissions are estimated but reported separately, whereas they are included in our 2005 baseline.[5]

While MPCA does not generally apply its methodology to individual utilities, it did apply a version of this methodology to Xcel Energy in an October 2013 letter cited by the CEOs, but has since clarified that:

> *The estimate of emissions given in our letter to the MPUC is solely for fossil CO_2 from combustion at facilities owned or operated by Xcel Energy. No effort was made to allocate back to Xcel Energy emissions from net imports (or emissions from in-state area sources that, again, are calculated at a state-level) or to distribute emissions from*

[2] Peter Ciborowski, MPCA, e-mail of September 11, 2015.
[3] The NGEA requires MPCA to include in its estimates of statewide GHG emissions those emissions that result from out-of-state electricity generation that is consumed within Minnesota. Total electricity consumption in Minnesota, net electricity generation in the state and all associated transmission and distribution (T&D) line losses are estimated (Minn. Stat. § 216H.01, subd. 2).
[4] Peter Ciborowski, MPCA, e-mail of September 11, 2015.
[5] *Greenhouse Gas Emissions in Minnesota: 1970 – 2008,* pages 5, 12, 21, 93.

combustion sources across state lines on the basis of, say, retail sales or retail sales plus sales for resale.[6]

Applying this methodology, MPCA estimated 2005 emissions for Xcel Energy of 27.25 MST. In contrast, when quantifying our CO_2 emissions – both for the 2005 baseline year and for the NGEA target years of 2015 and 2025 – we included all CO_2 combustion emissions (but no non-CO_2 GHG emissions) from owned and purchased power used to serve customers in all five NSP System states, regardless of emission source location. Stated another way, our calculations include CO_2 from:

- Generating units we own in Minnesota;
- Owned units in other NSP states;[7]
- Biogenic CO_2 from biomass and RDF plants;
- Power we purchase under long-term PPA with fossil resources throughout our five-state area;
- Power purchased from MISO; and
- A very small amount of power purchases with unknown environmental attributes.[8]

Our methodology is more comprehensive than MPCA's October 2013 estimate and, as such, the total is larger both in the baseline year (30.6 MST) and in the target years of 2015 and 2025. Because it only accounts for a subset of our emissions, the 2005 baseline emissions portrayed in the "Goal" line in Figures 9 and 11 through 14 of CEO Comments are inaccurate. Although the Goal line may correctly represent a "trend line" to the NGEA goals, it cannot serve as an accurate point of comparison with the CO_2 forecast of our Preferred Plan.

2. Modeling Techniques and Assumptions

Strategist modeling results are highly dependent on the input assumptions used and, in some cases, the application of different modeling techniques. Discussion and debate surrounding the different assumptions and techniques constitute an important part of any resource planning proceeding, and we believe that some of the assumptions and techniques employed by CEO and, to a lesser extent the Department, may have produced results that are less reliable than our modeling results.

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[6] Peter Ciborowski, MPCA, e-mail of August 28, 2015.
[7] Gas peakers and biomass in Wisconsin; a gas peaker in South Dakota. The Company currently owns no fossil generation in North Dakota or Michigan.
[8] Assigned the MRO-W emission factor. See our response to Information Request No. DOC-56, question *b*.

a. Clean Energy Organizations

First, we appreciate the constructive dialogue we have had with CEO. We believe the dialogue has furthered a better understanding of each other's proposals and encouraged discussion about the future of our energy mix. We also applaud the efforts of CEO to develop Strategist modeling results in support of their recommendations in this proceeding. However, we believe CEO employed several assumptions and techniques in analyzing plan impacts that generated results that are imbalanced and lack a reasonable foundation.

Aside from citing differences from the MPCA statewide methodology and a different 2005 baseline, CEO cites three reasons why they believe our CO_2 emissions under the Preferred Plan will be higher than we forecasted:[9]

1) Adding 4 GW of wind and solar capacity to the NSP System will not necessarily result in reduced dispatch of and CO_2 emissions from NSP's own coal units,
2) The Company has underestimated emissions associated with MISO purchases,
3) The Company has overestimated emissions associated with "dump energy."

For each of these, CEO applies adjustments to "correct" the Strategist simulation results for a MISO/regional market-oriented regime, resulting in their conclusion that we will not achieve our "share" of the statewide NGEA goals. We discuss these *ex post facto* adjustments below:

Renewable Additions Impact Coal Operations. CEO "hard-wired" a level of coal generation into their modeling for the post-2020 period that was based on their model's forecasted coal operation data for 2017-2019. Fixing the operation of our coal fleet after 2020 at the same levels these Units operated in 2017-2019 (CEO Comments, footnote 24 at 20-21) is not a reasonable reflection of future coal dispatch and operation assumptions. We acknowledge that CEO disagrees with the amount of coal operation reduction that could occur in a MISO-controlled dispatch construct. However, suggesting that there will be *no* impact to our coal operations from the addition of significant levels of renewable generation is not reasonable. Strategist is a sophisticated tool that calculates changes in annual coal generation output levels based on key plan and system dispatch assumptions, which we believe forms a more reasonable basis than hard-wiring a flat level of operations based on a three-year

[9] CEO Comments at 19-28.

reference period.

Market Emission Rates. CEO also applied different emissions values to purchases and sales in the MISO market – using a higher market-wide rate for purchases and a lower NSP-specific system average rate for sales. This implies a carbon "arbitrage" between the market and a specific seller, which would most likely not materialize in a fully developed market that properly factors emission costs into prices and market design. We believe a more reasonable approach is to use the same emission values for MISO sales and purchases, since MISO purchases or sales need to reflect overall MISO system or MISO zonal emission levels. Employing this approach avoids any speculation of MISO purchase/sale emissions arbitrage. Additionally, our approach that used the artificially high emission factor of 1,624 lbs/MWh for both MISO purchases and sales will tend to conservatively overestimate our emissions, since (1) it does not reflect greening (decline in emission factor) from 2009 to present, and (2) our purchases from MISO have exceeded our sales in every year since 2005, as shown in our response to Information Request No. DOC-59.[10]

Purchase and Sales Volumes. For their "high" range of emissions projections for our Preferred Plan, CEO set purchase volumes to the highest level observed in the past five years, which was during the extended outage of Sherco Unit 3. It is not reasonable to expect that this abnormally high level of purchases will continue over time, and indeed recent purchase volumes since the return of Sherco Unit 3 have been well below these levels. Combined with the carbon arbitrage assumption, this makes the CEO projections of system carbon emissions much higher than would realistically be expected.

When combined, these "hard-wired" modifications to the Strategist modeling do not provide a reasonable basis to support the CEO conclusion that the Preferred Plan we proposed would not be compliant with the NGEA GHG goals.

We acknowledge that Strategist is limited to modeling a single utility system and cannot predict the interaction of proposed resources in the MISO market. Our

[10] The 1,624 lbs/MWh we used was based on the emission factor for the MRO region from EPA's Emissions & Generation Resource Integrated Database (eGRID). The latest eGRID emission factors available at the time of preparing our resource plan were for 2009 (EPA has since released data for 2010, where the MRO emission factor is 1,547 lbs/MWh). *See* eGRID 2012 Version 1.0, or the Eighth edition, for the MRO emission factor we used, and the Ninth edition for the later-released year 2010 data: http://epa.gov/cleanenergy/energy-resources/egrid/index.html. Because eGRID has a 3-4 year lag between the year reported and the year of release, the eGRID emission factors are always out-of-date and do not reflect recent declines in CO_2 intensity due to renewable energy additions, increased gas generation, reduced coal generation and coal retirements, etc.

decision to model our system with minimal MISO interaction has three primary advantages. First, by limiting the interaction with the MISO markets, our analysis provides the Commission valuable insight into the systems they regulate without complicating that analysis with hypothetical assumptions on how *other* utilities may modify or operate their systems over time. Second, it helps to determine what, if any, restrictions are necessary to ensure our fleet operates the governing framework. Third, it helps the Commission and other stakeholders understand the cost and profile of the NSP System without MISO interaction.

The incorporation of the NSP System into the MISO joint dispatch process should ultimately lower costs, yet still implement any operating or carbon restrictions that will be necessary to achieve the State's targets or compliance requirements. We, like other utilities and MISO, will have to figure out the process to incorporate the management of individual state carbon (or generation) targets into the dispatch process to ensure that all utilities can continue to achieve compliance with all of their individual states' Clean Power Plan (CPP) requirements. As a result, while the view we presented in our resource plan to-date does not simulate the exact operation of the system within the MISO construct, the Commission can use this view to establish cost and operating parameters to ensure the NSP System is positioned to achieve the State's carbon goals and CPP compliance obligations.

Development of the CPP State Plans remains in the early stages, with states just beginning to evaluate various compliance alternatives available under the rule. As the development progresses, we plan to evaluate the draft CPP State Plans, as well as any proposed MISO market changes, and use the most current information in developing our next Resource Plan.[11]

Financial Calculation Period. In addition to the concerns we have with the methodology CEO employed for CO_2 accounting, CEO's use of a 15-year calculation period for Present Value Revenue Requirements (PVRR)/ Present Value Societal Cost (PVSC) calculations do not account for the long-term impact planning decisions will have on customer costs.

Resource decisions, whether they are resource additions or retirements, are long-term decisions that have significant financial impacts well beyond the 15-year planning

[11] State plans under the CPP are due in September 2016 or, if states request an extension, September 2018. It is likely at least some of our states will request this extension, so will not have final plans submitted to EPA before the filing of our next Resource Plan. However, we believe we will have significantly more information on our states' CPP implementation strategies over the next year. In addition, EPA will release in summer 2016 the final version of its proposed model federal plan, for states that elect not to submit a state plan.

period of resource plans. Significant changes are projected to occur on the NSP System in the 2030's, including the possible retirement of our nuclear fleet as well as our remaining coal-fired baseload units. By not allowing Strategist to include the benefits or costs of these long-term significant changes, CEO oversimplifies the impact that planning decisions will have on customer costs.

b. Minnesota Department of Commerce

The most significant area of concern we have with the Department's modeling is their "end-effects" methodology. We have long differed on the appropriateness of using the Strategist end-effects methodology versus longer simulation periods. We raise it again here because, in this instance, use of the end-effects methodology may be driving inaccurate results. The other area we address is clarifying the extent to which we employed an iterative modeling technique.

End Effects. In Strategist, the end-effects modeling process employed by the Department holds "flat" the last year simulated, such that the same cost and benefits are repeated for a given number of years. As outlined above, holding the 2032 results constant skews the impact of the resource planning decisions being contemplated in this proceeding in that it ignores the significant changes projected to occur in the NSP fleet beyond the planning period

Iterative Modeling Technique. In explaining the development of their plan, the Department noted that it allowed economic consideration of renewable technologies in their simulations while we "forced" expansion alternatives in the model. As part of our resource planning discussions with the Department, it has become clear that we largely followed the same optimization process utilized by the Department.

We, like the Department, performed numerous simulations with renewable resources treated as "superfluous" units. Although these initial runs resulted in significant truncation of plans due to the number of states considered, it became clear that significant amounts of renewables were being considered as cost-effective energy-only resources. Through iterative processing, we identified and evaluated how much and at what times renewables were being added by the optimization engine, and sequentially added those repeatedly-chosen resources as "locked" resources in future runs to improve run time and reduce truncation.

Finally, as identified by both the Department and CEO, the treatment of excess or "dump energy" is a challenging issue from both a cost and CO_2 perspective. Fundamentally, the issues raised go to the best way to predict how both costs and

carbon accounting for purchases and sales will be treated in the MISO system once the CPP is in effect. We propose to work with the Department and CEO to arrive at an agreed-upon methodology, and we believe this task will become clearer as states begin to develop their State Plans.

C. Demand Side Management

We appreciate the Department and CEO comments regarding the appropriate DSM goal for the 2016-2030 planning period. We are committed to find new ways to elicit greater levels of energy efficiency and Demand Response (DR) that will benefit not only our customers, but the whole system. To this end, we accept the Department's recommendation and commit to a goal of 1.5 percent DSM through the planning period. This translates to 444 GWh of savings for the planning period, which we note does not impact any near-term resource decisions.

We make this commitment despite the challenges we face in our ability to continue to achieve significant levels of energy efficiency with our customers under the current regulatory construct. A step change in DSM and DR achievement will require technology advancements and regulatory recognition of types of savings that may not be contemplated today.

In the balance of this section, we discuss the challenges to achieving a 1.5 percent savings goal, respond to the CEO recommendation to increase the goal to 1.7 percent in years 2016 -2021, and respond to requests for explanation of certain aspects of our potential study by the Department and CEO.

1. History is not Always an Accurate Predictor of the Future

Through extraordinary efforts, we have cost-effectively met and exceeded our DSM goals. In 2014, we achieved over 481 GWh of electric savings, which equates to 1.66 percent of sales. We are proud of our success and are striving to continue this level of savings through 2015 and 2016, in which our goal is 435 GWh (1.5 percent of sales).

We have been providing our customers the opportunity to reduce their usage through a myriad of energy efficiency programs for more than 20 years. Our experience is that significant historical achievements reduce future potential, as fewer eligible participants remain with standard efficiency equipment. New technologies represent a small fraction of the energy savings potential lost to increasing codes and standards, especially with the implementation of aggressive lighting standards. The resulting decline in potential requires a greater pursuit of DSM to maintain historical levels.

More aggressive pursuit of DSM translates to more costly programs. In order to incent customers we must increase our outreach and rebate levels. This is further exacerbated by the fact that: (1) as creditable energy savings from each installed measure decreases due to increases in codes and standards, the number of installations must increase to maintain the same level of energy savings; and (2) the costs of new technologies, while declining, are still more expensive for customers to implement than historical technologies. We discuss these issues below.

2. Increased Codes and Standards are Eroding Creditable Savings

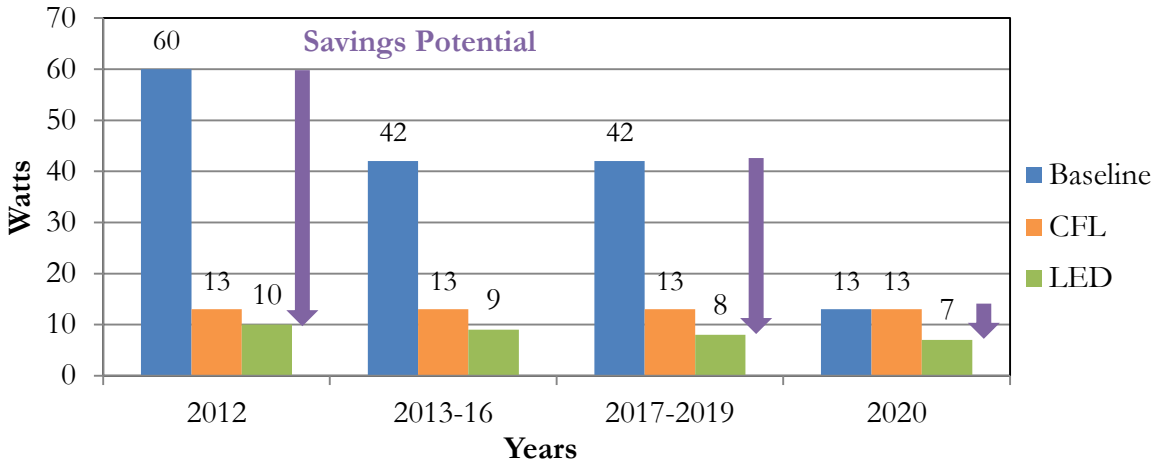
The greatest challenge to achieving future DSM program savings is the implementation of the codes and standards changes from the Energy Independence and Securities Act (EISA).[12] Since the EISA Standards were implemented in 2007, we have adjusted the baselines of more than a dozen savings measures and had to remove several lighting measures from our portfolio. These changes shrink the available pool of energy savings for which we can claim credit within our DSM programs, leaving the more expensive and complex savings opportunities for our customers. These savings opportunities require increased investment by our customers and higher incentives to motivate them to take action.

Residential lighting is the largest example of this phenomenon in practice. Light Emitting Diode (LED) technologies represent significant savings potential at the highest efficiency level. While the technology is becoming less expensive, allowing more customers to realize the benefits of the technology, *creditable* energy savings in utility DSM programs are measured as the difference between a baseline bulb as defined by the EISA Standards, and the efficient bulb. In the case of LEDs, the magnitude of the incremental efficiency creditable under utility DSM programs falls significantly short of the efficiency gains from codes and standards – eroding the energy savings potential we can claim.

We demonstrate the impact of the EISA Standards on baseline lighting technology for both Compact Fluorescents Lights (CFL) and LEDs in Figure 1 below.

[12] Public Law 110-140 (2007).

Figure 1: Residential Lighting Changes



In this graphic, the blue bars represent the EISA Standard, or baseline from which we can claim credit under our DSM program. As shown, our creditable potential was between 47-50 watts per installed CFL or LED bulb in 2012, which shrinks to 29-34 watts through 2019. In 2020, the EISA Standard will become a 13 watt CFL, so we will claim zero credit for installation of CFLs and only 6 watts of credit for installation of LEDs. This reduces our creditable potential by 88 percent when compared to the current savings, which is exacerbated by the fact that lighting programs have by far provided the majority of savings within our DSM Portfolio.

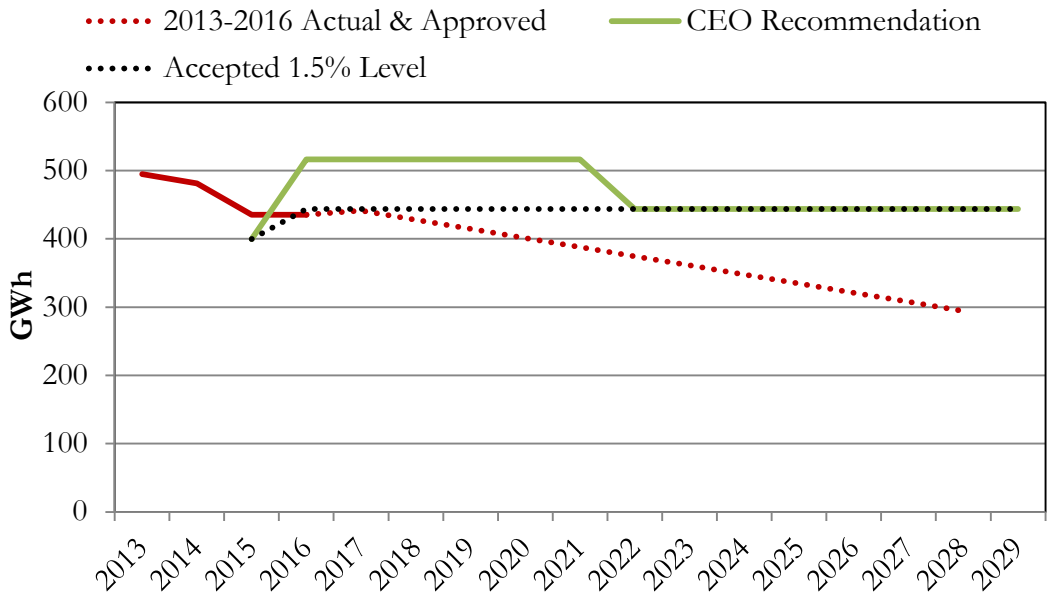
In Comments, CEO claims that despite the drop in savings attributable to utility DSM programs due to EISA lighting standards, we have still claimed an increase in energy savings. Figure 19 in the CEO Comments compares future DSM goals against historical DSM achievements from 2011-2014. However, it includes program years 2011-2012, which did not include the reduced savings from EISA standards, so the reference period is not representative of the impacts of EISA lighting standard changes.[13]

We provide as Figure 2 below, the impact of EISA lighting standards on our future potential by starting in 2013, which was the first year our creditable lighting potential ratcheted down due to the EISA Standards. We have included a comparison of the

[13] 2010/2011/2012 Triennial Plan (E,G002/CIP-09-198) p. 587 *Table 1 – Existing lighting wattage for residential lights* includes a 60 Watt baseline bulb for a 13-16 Watt CFL bulb. The same table in the 2013/2014/2015 Triennial Plan (E,G002/CIP-12-447) p. 454 includes a declining baseline wattage of 55.0 Watts (2013), 48.5 Watts (2014) and 43.0 Watts (2015) due to adoption of the EISA lighting standards.

forecasted impact based on our current 2013-2016 actual achievements and approved goals,[14] the CEO recommendation, and the 1.5 percent level we accept in this proceeding.

Figure 2: Actual and Projected Lighting Achievement – Impact of Increasing EISA Lighting Standards



This graphic demonstrates that:

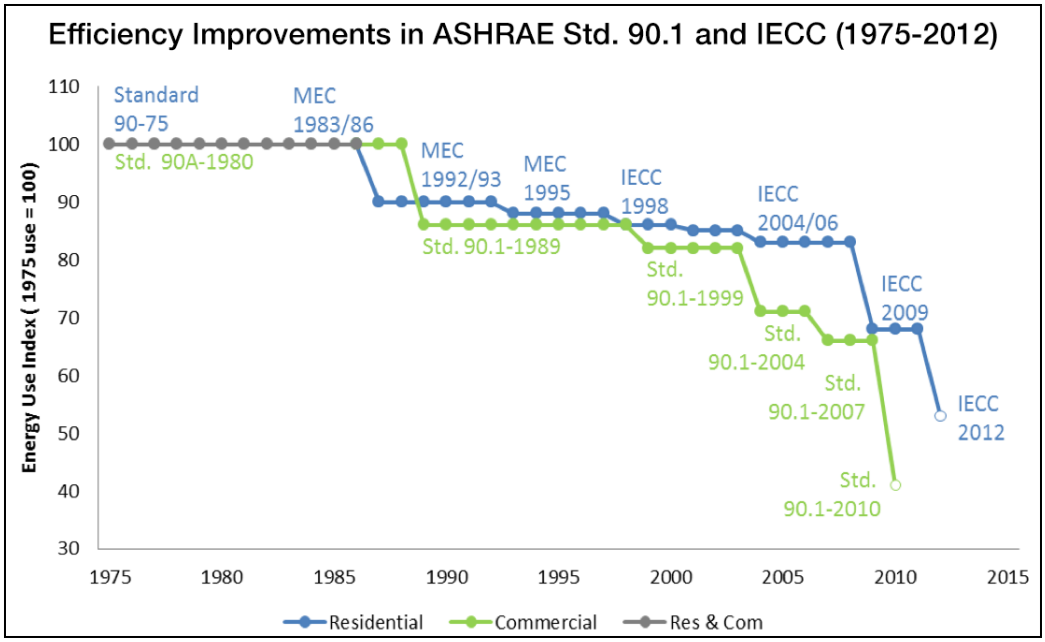
- CEO's proposed DSM 1.7 percent achievement in the early years of this resource plan significantly exceeds our historical performance, and
- The trajectory of our historical achievements, demonstrates that our commitment to 1.5 percent represents a significant increase in the pursuit of DSM.

We provide a graphic by the American Council for an Energy Efficient Economy (ACEEE) that illustrates the effect of declining potential from new technologies compared to the loss of creditable potential from increasing codes and standards in Figure 3 below. ACEEE's illustration of the efficiency improvements between the American Society of Heating, Refrigeration and Air-Conditioning Engineers (ASHRAE) Std. 90.1 over the last several decades in Figure 3 below shows how

[14] *See* 2015 and 2016 goals, which are identified in the Xcel Energy 2013-2015 Triennial Plan, the 2016 Extension, and actuals from Xcel Energy's 2013 and 2014 Status Reports (Docket No. E,G002/CIP-12-447).

various codes and standards have lowered the energy intensity of buildings (Energy Use Index) by increasing equipment codes and standards.

Figure 3: ACEEE Illustration of Efficiency Standard Increases on Building Efficiency



Source: http://sefaira.com/resources/us-energy-codes-could-surpass-leed/

As the baseline energy intensity against which energy efficiency achievements are measured decreases, creditable energy efficiency potential also decreases. Figure 3 shows a downward trend of the baseline energy intensity that could be considered representative for future energy savings potential across many technologies – and exemplifies the necessity to take trends like this into consideration, rather than relying only on past achievements.

3. Our Potential Study Considered Other Technologies

In Comments, CEO suggests that there are other savings opportunities that we did not address, such as Conservation Voltage Reduction (CVR). We note that this technology was not included in our most recent Potential Study; the Study defined only customer-side opportunity, and CVR is a utility infrastructure opportunity, which we note may be one of the grid modernization/technology-enabling types of efforts that will help us to unlock future savings opportunities for our customers.

With regard to CVR and CEO's assertion that we have potential for 5,200 GWh over a 20-year period, CEO fails to note that we developed these estimates as part of a preliminary analysis we conducted and are continuing to test through summer 2015 to approximate a more true potential for Minnesota.[15] While CVR may offer benefits such as reduced energy consumption to customers and the Company, the integration and implementation of these technologies are complex and capital-intense, and must consider impacts to utility sales.

While we are continuing to analyze impacts and costs, our preliminary analysis found that the addition of CVR will require capital investment over a five-year period for changes to the system such as:

- Voltage sensors added throughout the distribution system to maintain service voltages within required levels,
- Two-way controls installed on Regulators and Load Tap Changers (LTC') to control voltage levels,
- Capacitor Controls must be retrofitted with new two-way controls in order to maintain system power factor through capacitors,[16] and
- Substations must be updated with Feeder load monitoring and Supervisory Control and Data Acquisition (SCADA) to monitor load, power factor, voltage and control substation devices.

Additionally, implementation of CVR will require an ongoing O&M component to operate, maintain, and manage the CVR system.

Finally, while we believe CVR may provide a vehicle for energy efficiency savings in the future, its implementation involves upgrades to the utility distribution system rather than customer actions, like other DSM initiatives. These changes are also more consistent with modernization-type changes that utilities are making to their systems to ready them for greater customer choice and control in their energy preferences, such as distributed generation. For that reason, we believe initiatives such as this are better suited to proposal and cost recovery through other mechanisms such as base rates, or other regulatory mechanisms. For the reasons we have discussed, it is unlikely we will be ready to propose and implement a CVR program for Minnesota in the next year as indicated by CEO in their assumptions.

[15] Xcel Energy response to CEO IR No. 39 notes that preliminary analysis estimates that Distribution Voltage Optimization at a one percent voltage reduction would result in a reduction in MWh sales of 2.6 million.

[16] To-date, capacity controls have mostly been replaced through the SmartVAR program.

We note additionally that we actively monitor new technologies through our product development efforts, review other utility products, and conduct product research.[17] Some new technologies replace the traditional technologies, such as LED lighting, energy feedback programs, and holistic programs.[18] However, as we have discussed, the energy savings associated with these newer technologies and programs often have much less incremental savings potential than their predecessors – and there is also the potential that new codes and standards not yet contemplated may reduce the potential. Conversely, emerging technologies may develop that offer new potential that we and others have not yet fully contemplated in the context of the existing regulatory construct. We believe the Potential Study efforts we undertake examines and balances these trade-offs in how it treats potential associated with emerging technologies.

4. The Potential Study Relies on Reasonable Inputs

We rely on a Potential Study to help us identify future potential, which uses a cost analysis to determine the level of achievable savings. In Comments, CEO suggests that our Potential Study is not a reliable source for determining our future energy efficiency goals and future costs.[19] As we have discussed, we believe Potential Studies that consider the savings potential of currently available energy efficient equipment, the availability and cost of future energy efficient equipment, and the customer's likelihood of installing this equipment, provide a robust analysis and reasonable basis from which to identify sustainable, future potential.

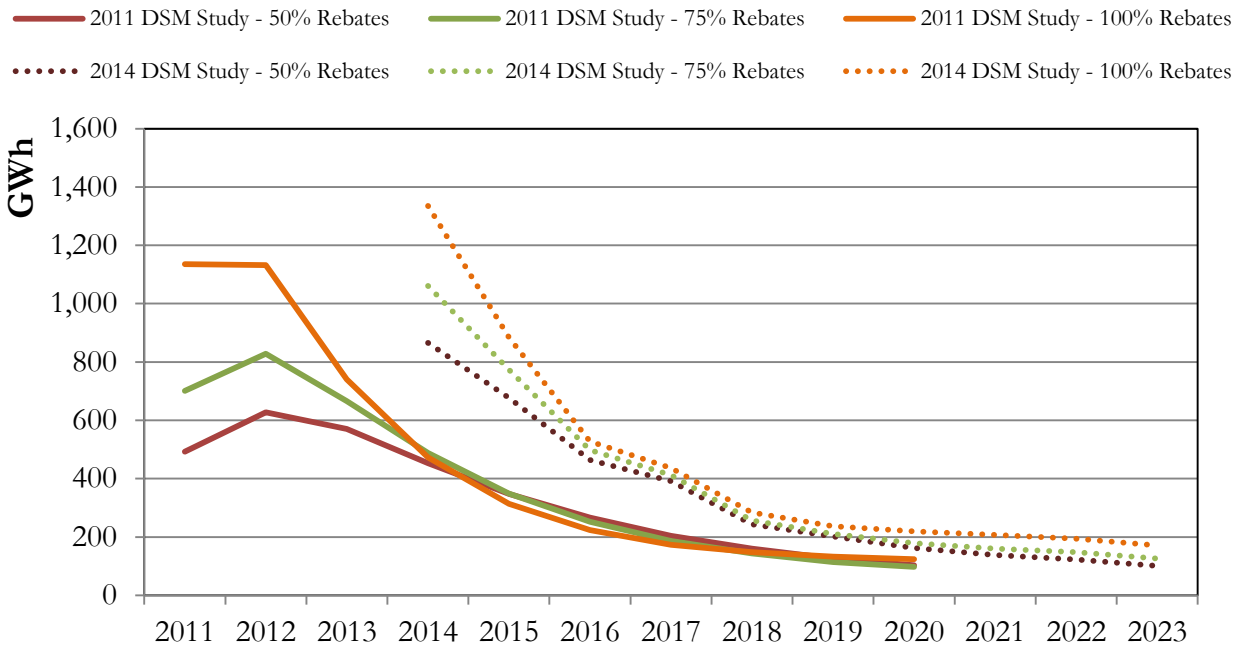
a. Study Results are Comparable

CEO appears to base their assumption on a comparison of results from our 2011 and 2014 Potential Studies, which CEO claims show significant differences in results.[20] However, this comparison does not take into consideration how the Potential Study estimates the annual pattern of achievable potential. The comparison must also include the first years of the 2011 Potential Study to accurately portray how the total

[17] We identify new products, technologies and measures through our Product Development group. We continue to participate and fund additional research through Conservation Applied Research and Development (CARD) grants. In the period of 2013 -2014, we made 48 program modifications, including adding additional programs and measures to existing programs.
[18] Holistic programs provide additional study and analysis to customers in order to make long-term energy adjustments to their facilities. Programs such as Process Efficiency and Energy Design Assistance are included in this category.
[19] The 2011 DSM Potential Study and 2014 Potential Study Update by KEMA were used for the Upper Midwest Resource Plan 2016 -2030 analysis.
[20] See CEO Comments at 29-30.

achievable potential over the ten-year period of the Studies compares. As demonstrated in Figure 4 below, the potential from the 2011 and 2014 Studies is very comparable.

Figure 4: 2011 and 2014 Study Results – Achievable Potential



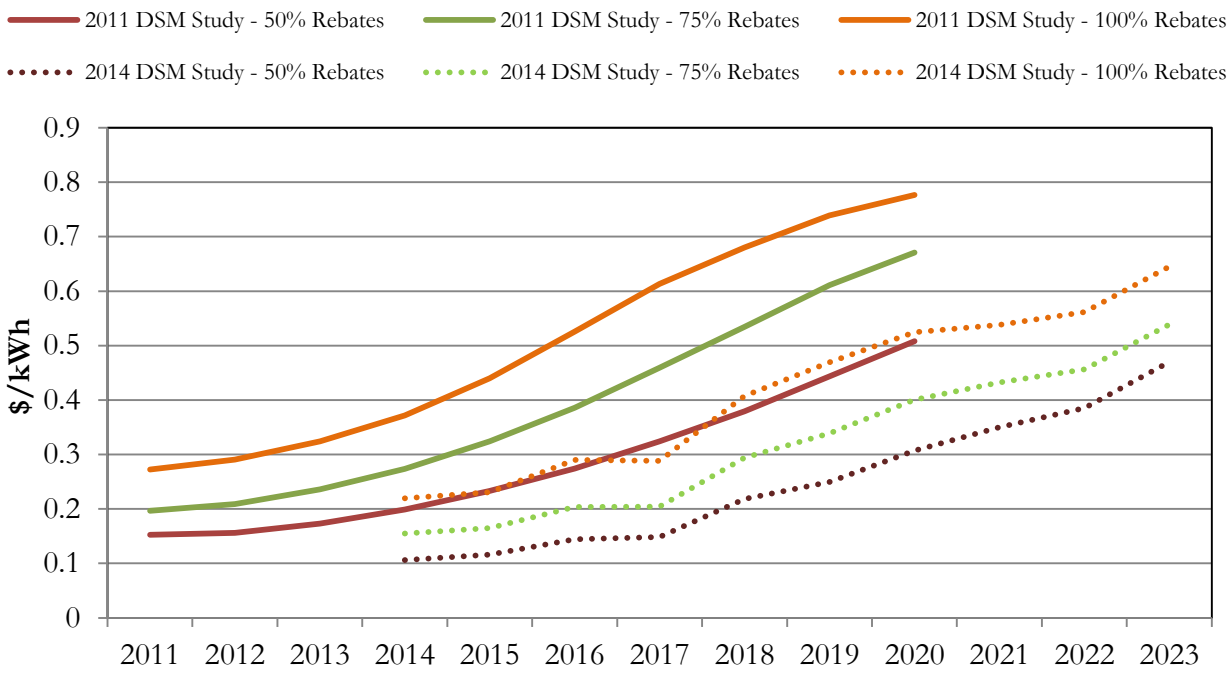
Another view of the comparability of the two most recent Potential Studies is to examine the average achievable potential over time, given the annual pattern of achievable potential. Again, the two Studies over their respective 10-year study periods are very similar as demonstrated in Table 1 below.

Table 1: 2011 and 2014 Study Results – Average Achievable Potential

	2011 Potential Study (Average kWh)	**2014 Potential Study** (Average kWh)
Study Period	***2011-2020***	***2014-2023***
50% Rebates	335,128,456	336,847,237
75% Rebates	382,514,195	382,330,087
100% Rebates	459,633,726	449,615,285

CEO also suggests that the 2014 Potential Study identified significant reductions in costs from the 2011 Study, relying on a view of annual achievable potential costs.[21] CEO Figure 16 shows costs increasing over the time period within each Study. However, a better measure of the difference in costs between the 2011 and 2014 Potential Studies is again a comparison of each Study's entire 10-year study period, which we provide below in Figure 5:

Figure 5: 2011 and 2014 Study Results – Costs Associated with Achievable Potential



As shown above, the 2014 Study identified price declines, but the declines are smaller when including the costs in the initial years (2011 vs. 2014) of each Study rather than by solely comparing the costs for each year (i.e., 2014 vs. 2014) in which the Studies overlap.

To determine the relative difference in costs between the two Studies, we averaged the cost estimates over the entire 10-year Study period and provide the results in Table 2 below. This demonstrates that the cost estimates from the 2014 Study were approximately $0.050/kWh lower than the 2011 Study, which is half the amount claimed by CEO in their Figure 16.

[21] *See* Figure 16, CEO Comments at 30.

Table 2: 2011 and 2014 Study Results – Average Costs Associated with Achievable Potential

	2011 Potential Study (Average $/kWh)	**2014 Potential Study** (Average $/kWh)
Study Period	***2011-2020***	***2014-2023***
50% Rebates	$0.224/kWh	$0.176/kWh
75% Rebates	$0.290/kWh	$0.235/kWh
100% Rebates	$0.372/kWh	$0.322/kWh

As these illustrations demonstrate, the costs used in the Potential Study are similar across the 2011 and 2014 Studies. We note however, the 2014 Potential Study includes a recent trend toward lower costs of various technologies, likely due to updated product costs in areas such as LED lighting. Our estimated achievable potential is based on these Potential Study scenarios and incorporates the trends in reduced product costs.

b. Rebate Levels Must Increase to Motivate Customer Action

The Department requested that we explain why the Potential Study calls for higher rebate levels to achieve lower levels of savings. In addition, CEO believes that we overestimated our costs to achieve various levels of potential. We explain below how we derived our estimates and why we believe they are reasonable.

Department of Commerce. In response to the Department, we note that the Study found that a rebate level of 50 percent results in only 1.3 percent of sales, in contrast to our achievements to-date, which have been *above* 1.5 percent of sales at rebate levels just above 30 percent. Figure 4 above (2011 and 2014 Study Results – Achievable Potential) shows that initially (2014-2016), the 50 percent rebate level results in achievement well-above 1.5 percent.[22]

So, as would be expected, higher rebate levels translate to higher potential. However, this potential greatly diminishes over time. Therefore, in order to determine a scenario that will provide a sustainable level of savings at a consistent level of percent-of-sales, we averaged the potential over a longer period (2014-2021) to estimate the rebate levels necessary to motivate customers to take creditable action. This resulted

[22] 2014 achievement in 2014 Potential Study equals 866 GWh of savings (nearly 3% of sales); 2015 of 677 GWh (approx. 2.3% of sales); 2016 of 464 GWh (approximately 1.6% of sales).

in our projection that it will require an average 50 percent rebate level to achieve 1.3 percent savings, and a 75 percent average rebate level to achieve 1.5 percent of sales, despite history.

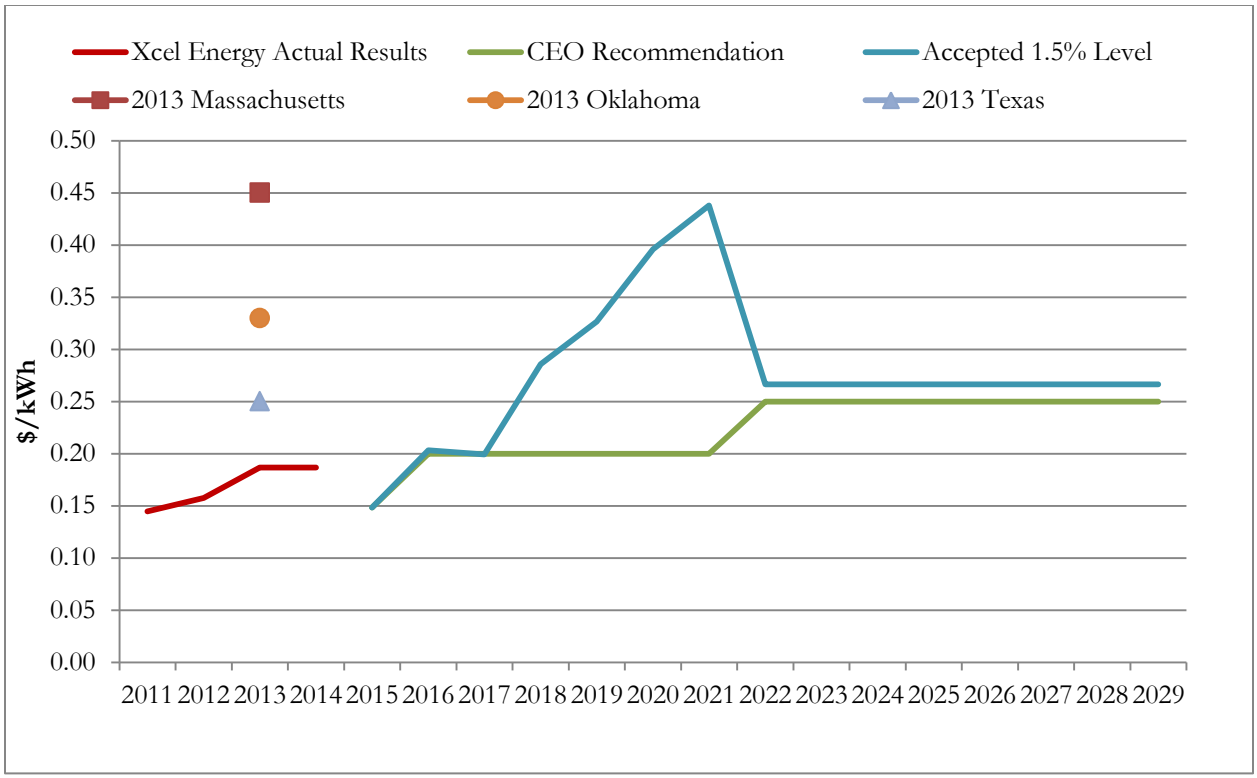
The cause of this significant increase in necessary rebate levels is attributable to the reduction in potential in the future for the reasons we have discussed. We have been able to maintain our 1.5 percent of sales achievements at lower rebate levels due in part to greater pursuit of programs that do not require rebates, such as Energy Feedback programs for Business and Residential customers, and the Home Energy Squad program. The reduction in potential worsens over the years, illustrated by the decline in achievable potential in Figure 3 above (ACEEE Illustration of Efficiency Standard Increases on Building Efficiency), requiring a continuing greater level pursuit of new DSM programs in the future. We believe this greater level of pursuit cannot be met with new programs alone; rather, rebate levels will also have to increase. The Potential Study serves as the best available projection of the expected achievement at these higher levels of creditable achievement.

Clean Energy Organizations. CEO used an illustration of actual costs of our lighting program compared to the initial ratcheting up of EISA lighting standards between 2012 and 2014 to support a claim that higher rebate levels are not necessary in the face of increasing codes and standards.[23] However, similar to what we explained previously, CEO Figure 20 also includes program years 2011-2012, which were not affected by a change in the EISA lighting standards. Therefore, the comparison of actual costs in light of increasing standards needs to begin in 2013 – the first year the EISA standards were implemented in the savings calculations.

By beginning in 2013, the costs per kWh to achieve savings increases significantly, as shown in Figure 6 below. To further illustrate the scope of these cost increases, we have also included the cost per kWh of other DSM programs as outlined in a May 2015 ACEEE report, including cost per kWh by Investor Owned Utilities in particular states with DSM portfolios.

[23] *See* Figure 20, CEO Comments at 34.

Figure 6: Historical Achievement and Plan Projections – Impact of Increasing Codes and Standards



Source: "Beyond Carrots for Utilities: A National Review of Performance Incentives for Energy Efficiency." ACEEE, May 2015
Note: State references (shapes) indicate point in time markers of cost, not a trend.

Our Potential Study demonstrates that significant increases in rebate levels and utility spending may be necessary to maintain historical energy savings levels, which corresponds to recent trends we and others have observed. Further, these costs are in line with those identified in other states with DSM portfolios, specifically those with comparably high energy standards such as Massachusetts.

c. New Technologies are Contemplated

CEO notes in Comments that the Potential Study did not consider most LED lighting measures in the commercial sector as either economic or achievable, with the implication that we are underestimating potential for technologies that are likely to be achievable during the planning period.[24] While it is true that we did not count specific achievements for these specific technologies, we did not directly take the achievable potential from the Study and make it our proposed DSM goal. Rather, we escalated

[24] CEO Comments at 36.

the potential the Study identified to account for savings such as these and other evolving technologies that we assume will be achievable at a future date.

Specifically, the Study concluded that achievable potential for the out-years of the planning period was less than one-half of one percent. Instead, we proposed a goal of nearly three-times larger – 1.3 percent – to account for evolving technologies and other cost efficiencies that are likely. Further, with this Reply, we now accept an even higher goal of 1.5 percent through the entire planning period.

We have delivered strong DSM program performance for more than 20 years and remain strongly committed to helping our customers continue to achieve savings.

D. Demand Response

We appreciate the Departments' analysis and recommendation that the Commission accept our proposed Demand Response (DR) growth of 76 MW over the planning period. We acknowledge the Department's comments regarding the importance of DR in a carbon-constrained future and repeat our commitment to leveraging technology to unlock additional potential for our customers. We also acknowledge and accept the Department's recommendation that we include in our next resource plan, a cost-effectiveness analysis taking into account possibilities for expanded and more dispatchable DR on our system.

In the balance of this section, we respond to the Department's request for information in the following aspects of our DR portfolio:

- Saver's Switch program usage,
- Dispatch process, including triggers for economic dispatch of load modifying resources,
- Impact from our 2015 Electric Rate Savings Program Waiver,
- Cost-effectiveness calculations, and
- DR Resource Value.

1. Saver's Switch Program Usage

The Department asked that we explain Saver's Switch's usage since 2007. As we noted in our 2014 Saver's Switch Annual Compliance Filing, we have had little need to control the program over the last several years.[25] Our Saver's Switch Tariff states

[25] *See* Saver's Switch Annual Compliance Filing, Docket Nos. E002/M-01-46 and E002/CI-01-1024 (Feb. 13, 2015).

that interruption will normally be based on meeting peak demands, system economic dispatch requirements and reliability concerns.[26] Our control history shows that these criteria have been met around ten times since 2007.

In terms of modeling our Saver's Switch program in this Resource Plan, the inputs are based on current program guidelines as defined by the Rider, and recent control history. Strategist is allowed to utilize the program up to the maximum amount of hours defined in the Rider. However, a minimum savings threshold was modeled based on the recent history of market conditions. Because the hourly savings of the program must exceed this threshold in order for the program to be dispatched in the Strategist simulation, this utilization only affects the energy savings value for the program, which is a very marginal component of the overall program economics. As with most DR programs, the vast majority of the economic benefit is realized in the avoided capacity value, i.e. avoidance of incremental resource additions in the expansion plan.[27]

2. Dispatch Process

As we explained in our response to Department Information Request No. 321 in our 2013 Electric Rate Case (Docket No. E002/GR-13-868), we have two DR procedures: (1) Peak Control Interrupt (PCI), and (2) Energy Control Interrupt (ECI). Saver's Switch customers can be controlled under both procedures. The two primary factors that contribute to the need to control are weather conditions and available generation resources. Over the last several years, customers and system operators have benefited from favorable weather conditions and the sufficient resources available on the NSP System to meet peak demand, resulting in fewer control events.

a. Peak Controlled Interrupt

PCI is used when reliability is at risk, and the NSP System is at risk of not being able to meet the peak demand of our customers. Saver's Switch is one of the programs that would be dispatched under our PCI procedure for system peaking conditions and reliability purposes during a system emergency. The PCI procedure may be activated to reduce customer demand that is associated with interruptible service tariffs when MISO's Reliability Coordinator (RC) instructs the NSP System to implement load management measures. Instructions from MISO's RC are given pursuant to MISO's Market Capacity Emergency Procedure for the protection of the overall system. NSP

[26] *See* NSP Electric Rate Book, Section 5, Tariff Sheet Nos. 97-99.1.
[27] For additional information, see DOC IR Nos. 19-24.

System Operations may also activate the PCI procedure if it in its opinion, the reliability of the NSP System is at risk.

These steps apply to all PCI customer classifications, including commercial and industrial, residential, retail, and wholesale under the Peak Controlled Tiers I and Tier II (1st Group, 2nd Group and 3rd Group), Peak Controlled Short Notice Rider, and Saver's Switch rates in the states of Minnesota, North Dakota, South Dakota, and Wisconsin.

NSP System Operations maintains the right to use the PCI procedure in the event of emergencies associated with the delivery system, as identified by NSP Transmission, NSP Distribution, or MISO. MISO will call on Load Modifying Resources (LMR) through their LMR automated process when system conditions warrant. An activation call identifies the total amount of LMR to be deployed; the call does not identify specific resources to be curtailed. NSP System Operations chooses which LMR to activate based on operational factors (i.e. constraints and locations).

b. Energy Control Interrupt (ECI)

The intent of the ECI procedure is to reduce the cost of service as compared to market/MISO energy prices. It is generally implemented when the cost to serve the energy needs of ECI customers exceeds certain thresholds as defined in the applicable rate schedule or as determined by the Company. These curtailments reduce the overall cost to supply total system load by requiring ECI customers to reduce load or by charging ECI customers a Control Period energy price if the ECI customer elects to buy through the interruption event.

For administration purposes, we have determined that we will call an ECI event only when the production cost is expected to exceed the applicable level for three consecutive, or five total hours in a day period. These conditions are likely any time that we are implementing PCI interrupts – and are expected at times to precede and/or follow a PCI event.

The steps above apply to all ECI customer classifications, including residential, retail, and wholesale. The majority of these customers are identified under the Tier 1 Energy Controlled Rider and the Energy Controlled Service (Non-Demand Metered) rate schedules. Saver's Switch for business and residential can also be controlled as an energy resource. As also explained in our 2014 Saver's Switch Compliance filing, we have not activated Saver's Switch for this purpose over the last several years, given favorable weather conditions and energy prices.

3. Anticipated 2015 Electric Rate Savings Program Waiver Impacts

In light of the increased expectation that MISO would begin calling emergency resources more frequently over the next several years as power supply resources become tighter, we believed it beneficial to have all customers participating in our rate savings programs verify their participation level and ability to comply with program requirements year-round. We requested a waiver from our Electric Rate Savings program tariff in order to work with customers throughout 2015 to help them determine their interest and ability to remain on the rate or to adjust their participation level to accurately reflect their current operations and capabilities.

Providing a one-time waiver allows customers the opportunity to adjust their participation without charge, essentially providing an incentive to make important adjustments prior to predicted change by MISO.

We have not yet conducted the necessary analysis to determine impacts from the waiver. In our Petition seeking the waiver, we noted that we believed this customer verification step would both help customers, and help the Company 'right-size' the current program and provide needed assurance that these resources will be available when called upon. In terms of reporting, we described in our Reply Comments that we complete an ongoing analysis of future control seasons through our load management forecast in the March/April timeframe, which is necessary to analyze the impacts of the waiver period. We accepted the Department's recommended reporting criteria and suggested certain modifications, one of which was extending the compliance reporting date to March 30, 2016 to incorporate the results of our load management analysis efforts – which the Department supported in its Response to our Reply Comments.[28] The Commission adopted the reporting criteria and timing into its May 22, 2015 Order approving the waiver.

Therefore, on or before March 30, 2016, we will submit a compliance filing in Docket No. E002/M-15-189 containing, at a minimum, the following:

- How many customers took advantage of the waiver,
- For customers that took advantage of the waiver, their annual and average monthly billed KW firm demand covered under the applicable or successor tariffs for years 2014, 2015, and estimated 2016,
- For customers that took advantage of the waiver, their annual and average

[28] *See* Response Comments of the Minnesota Department of Commerce, Division of Energy Resources, April 17, 2015, Docket No. E002/M-15-189.

monthly billed KW controllable demand covered under the applicable or successor tariffs for years 2014, 2015, and estimated 2016,

- The forecast MW of controllable demand for all customers covered under the applicable tariffs at the beginning of the waiver period (summer 2015),
- The forecast change in MW of controllable demand covered under the applicable tariffs following the waiver period (summer 2016) from customers that took advantage of the waiver,
- The final revenue impact of this tariff waiver, and
- A discussion on the overall results of this waiver and the Peak Controlled Services program reevaluation.

4. Cost Effectiveness Calculations

Minn. Stat. § 216B.241 defines DR, or load management, as referring to an action taken to change the timing or volume of a customer' use of energy use allowing the utility to respond to fluctuations in peak demand for the purposes of energy or capacity. Using this definition, noted by the Department[29], the Company refutes the premise that electric generation peaking resources change the timing or volume of a customer's use of energy.

There are many differences between the services and benefits of DR and those of electric generation peaking resources, which is why cost comparisons of the two sources is complex. We note that DR, unlike natural gas Combustion Turbine, can vary in predictability and reliability during peak load periods. Acknowledging this complexity, we compared DR to the economic carrying charge (ECC) of a generic CT for our cost-effectiveness calculations in the Resource Plan.

We performed cost-effective calculations in Strategist across the following four distinct scenarios: (1) low, (2) medium, (3) high, and (4) reference case. If the cost of the DR was higher than the comparative ECC of the generic CT, it was screened out and not modeled in Strategist. We created these portfolios from the programs, costs, and potentials from the Brattle Study (excluding Dynamic Pricing), provided as Appendix O to our initial Resource Plan filing. DR potential increases with incentive level; therefore, the high DR portfolio had the most programs, incentives, and potentials.

The cost-effectiveness calculations include the capacity obligation benefit of DR,

[29] See Comments of the Minnesota Department of Commerce, Division of Energy Resources, July 2, 2015. Docket No. E002/RP-15-21 page 48-49.

which is that it lowers the capacity obligation by an amount greater than the demand reduction it provides. The amount of DR reducing the capacity obligation is equal to the demand reduction multiplied by one plus the reserve margin. All else constant, this makes one DR unit of capacity worth more than one electric generation unit of capacity by a premium of the reserve margin. Since this is the only adjustment to the cost of the ECC of the CT, our cost-effectiveness calculations are giving a high-end value to the capacity of DR.

Table 3 below illustrates the comparison of the average costs of the Generic CT and the four scenarios we used in our Strategist modeling. We further note that these costs were derived using actual DR forecasts (Reference Case) and portfolios identified through our Demand Response Potential Study.

Table 3: Generic CT and the Low, Medium, and High DR Portfolio Costs used in the Strategist Modeling

($/kW per year)

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Generic CT ($/kW-yr)	57.72	59.04	60.36	61.68	63.12	64.44	66.00	67.44	68.88	70.44	72.00	73.68	75.36	77.04
Low Portfolio ($/kW-yr)	50.06	47.67	47.94	48.27	48.67	49.22	49.81	49.91	50.66	51.47	52.29	53.12	53.97	54.87
Medium Portfolio ($/kW-yr)	65.52	64.88	65.52	66.48	67.48	68.55	69.66	70.55	71.67	72.84	74.02	75.22	76.44	77.71
High Portfolio ($/kW-yr)	114.80	116.78	118.78	120.81	123.00	125.04	127.18	129.84	132.47	135.11	137.79	140.50	142.76	145.13
Reference Case ($/kW-yr)	105.01	107.03	109.04	111.08	113.11	115.11	117.14	119.20	121.27	123.16	124.91	126.68	128.48	130.33

The above table shows the $/kW per year costs used within the Strategist model to formulate the cost-effectiveness analysis as part of our review process. This information, along with Strategist sensitivities and the changing DR landscape were used in combination as we defined the DR goals outlined in the Resource Plan.

5. DR Resource Value

The Department requested we provide a comparison between the price assigned to DR resources in our modeling and the price of DR resources submitted to MISO. Interruptible loads can provide a lower cost way to meet reserve requirements compared to acquiring or building additional physical generation capacity, and are used to maintain an adequate reserve margin to fulfill our obligation to deliver adequate, reliable electric service to our customers – regardless of unforeseen factors impacting generation supply. As such, we register our DR resources under the MISO

Tariff[30] as emergency resources, which allows MISO to call a control event up to five times per Planning Year.[31] As an emergency resource, there is no price associated with the capacity provided. Within the Strategist model, we were consistent with how we register DR resources with MISO. Specifically, we placed no incremental cost hurdle in Strategist.

E. Potential Environmental Drivers Impacting Sherco Units 1 and 2

In this section, we provide additional discussion of National Ambient Air Quality Standards (NAAQS) as requested by the Department, and we respond to CEO Comments regarding future regulatory requirements that may impact the timeline for requiring SCRs on Sherco Units 1 and 2.

In summary, none of the regulations discussed by CEO currently requires emission controls beyond those already installed on Sherco Units 1 and 2, and the likely timeframe when SCRs could be required for Sherco Units 1 and 2 is the mid-2020s. The regulatory drivers that may drive SCR installation requirements are outlined below:

1. National Ambient Air Quality Standards (NAAQS)

The current status and expected revisions to each NAAQS are addressed in Appendix D, pages 12-18 of our January 2 filing. When Appendix D was prepared, only the then-pending Ozone (O_3) NAAQS revision represented a possible driver for further reductions in oxides of nitrogen (NO_x) from Sherco Units 1 and 2.[32]

EPA adopted the final ozone NAAQS of 70 parts per billion (ppb) on October 1, 2015. In Comments, CEO stated that a new standard of 65 ppb or lower could result in ozone non-attainment areas in several counties in Minnesota. While that was a possibility, with the standard at 70 ppb, Minnesota's air monitoring results currently comply with the new standard. Therefore, the MPCA will not need to require further

[30] Registering Demand Response resources with MISO allows the Company to obtain credit against our capacity requirements.
[31] The MISO Planning Year includes the 12-months period beginning June 1.
[32] As noted in Appendix D, page 14 of our January 2, 2015 filing, in December 2014, EPA finalized its area designations for $PM_{2.5}$ and did not classify any nonattainment areas in any state in which NSP operates. Therefore we do not anticipate a State Implementation Plan (SIP) process in Minnesota leading to additional NO_x and SO_2 control requirements for $PM_{2.5}$ purposes. EPA is not scheduled to review and potentially revise the $PM_{2.5}$ standard again for five years, until 2018-19. If needed, any future emission reduction requirements for such a standard issued in 2018-19 would be required in the 2025-2030 timeframe.

emission reductions to address the new standard. We note that EPA will next review the Ozone standard in 2020.

2. Regional Haze and Visibility

As described in Appendix D, pages 21-23 of our January 2 filing, SCR is not required for compliance with Minnesota's 2009 Regional Haze SIP. MPCA determined that the NO_x combustion controls currently in place at Sherco Units 1 and 2 constitute the "Best Available Retrofit Technology" (BART) for regional haze. EPA approved the State Implementation Plan (SIP) accepting these source-specific emission limits, as well as implementation of the Cross-State Air Pollution Rule (CSAPR) in Minnesota, as meeting the applicable requirements. Future developments in the regional haze program could require installation of SCRs, as described below.

a. Litigation of Minnesota's 2009 Regional Haze SIP

A lawsuit filed in August 2012 before the U.S. Court of Appeals for the Eighth Circuit (to which two members of the CEO are party) appealed EPA's approval of Minnesota's 2009 Regional Haze SIP. The parties to the proceeding disagree with MPCA's approval of the NO_x combustion controls at Sherco Units 1 and 2 as BART, and reliance on CSAPR. They believe EPA should not have approved Minnesota's 2009 SIP and should have required additional controls. In Comments, CEO states that if EPA's decision is reversed, we would almost certainly be required to install SCR at Sherco 1 & 2 to comply with BART.

A decision is expected from the Eighth Circuit in 2016. If the court finds fault with EPA's approval of Minnesota's 2009 Regional Haze SIP, the matter would be remanded to EPA, and likely the state, for further evaluation. That evaluation would first re-evaluate whether or not the adoption of CSAPR as BART is appropriate for Minnesota. If not, it would then consider the current emissions from the Units, the progress that has occurred in emission reductions for the 2009-2018 planning period beyond what the MPCA anticipated, and whether or not SCRs should nevertheless be found to be BART.

Thus, whether the Regional Haze litigation ultimately leads to a requirement for SCR will not be known for some time.

b. 2018 Regional Haze SIP

The CEOs also assert that Minnesota's 2018 Regional Haze SIP is likely to require

SCRs for Sherco 1 Units and 2, "because with current emissions the state will not achieve the rate of process necessary to achieve natural visibility by 2064."[33] This proceeding has not yet started, thus any conclusions about the likely outcome of the SIP are speculative at this time.

c. Reasonably Attributable Visibility Impairment (RAVI)

Since our January 2 initial filing, we have reached agreement with EPA and six environmental advocacy organizations, including three of the CEOs, to resolve litigation related to RAVI claims by agreeing to additional emission limitations at Sherco. As part of the settlement agreement, SCRs for NOx will not be required under RAVI.

3. The Externalities Docket[34]

The CEOs state that we should have assigned higher externality values to CO_2 and three criteria pollutants (NO_x, SO_2 and particulate matter) than the Commission's currently approved values, in anticipation of these values being set higher in the current Externalities Docket (No. E999/CI-14-643), in which a Commission decision is expected in 2016.[35]

Our base assumptions for Strategist modeling include the following:

- The high end of the Commission's current externality ranges for NO_x, PM_{10}, SO_2, CO and lead;
- The $21.50/ton midpoint of the Commission's regulatory cost range for CO_2 starting in 2019, as specified by the Commission; and
- The high end of the Commission's currently approved CO_2 externality range in any year where the CO_2 regulatory value is not applied.[36]

We are required by Minn. Stat. § 216B.2422, subd. 3 to use the values established by the Commission in resource planning proceedings. Accordingly, when the Commission establishes new values, we will apply those values in future resource proceedings.

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[33] CEO Comments at 48.
[34] Also referred to by the CEOs as the "true cost of pollution" docket.
[35] State of Minnesota Office of Administrative Hearings. Second Prehearing Order. *In the Matter of the Further Investigation into Environmental and Socioeconomic Costs under Minn. Stat. 216B.2422, subd. 3*. MPUC Docket No. E999/CI-14-643, OAH Docket No. 80-2500-31888.
[36] *See* Xcel Energy January 2, 2015 filing, Appendix J at 8; Appendix D at pages 40-41; and the March 16, 2015 Supplement – Appendix at 2-3.

CERTIFICATE OF SERVICE

I, SaGonna Thompson, hereby certify that I have this day served copies or summaries of the foregoing document on the attached lists of persons.

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

xx by electronic filing.

Docket No. E002/RP-15-21

Resource Plan Interested Parties

Dated this 2nd day of October 2015

/s/

SaGonna Thompson

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First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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Leigh	Currie	lcurrie@mncenter.org	Minnesota Center for Environmental Advocacy	26 E. Exchange St., Suite 206 St. Paul, Minnesota 55101	Electronic Service	No	GEN_SL_Xcel Energy_Xcel Energy RP Interested Parties
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First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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Randall	Doneen	randall.doneen@state.mn.us	Department of Natural Resources	500 Lafayette Rd, PO Box 25 Saint Paul, MN 55155	Electronic Service	No	GEN_SL_Xcel Energy_Xcel Energy RP Interested Parties
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First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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