414 Nicollet Mall
Minneapolis, Minnesota 55401-1993

August 13, 2012

Burl W. Haar
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101

—Via Electronic Filing—

RE: REPLY COMMENTS
2010 RESOURCE PLAN
DOCKET NO. E002/RP-10-825

Dear Dr. Haar:

Northern States Power Company, doing business as Xcel Energy, submits the enclosed Reply to Comments received by parties on our 2010 Resource Plan. We appreciate the thoughtful, productive discussions and welcome the opportunity to respond.

We have electronically filed this document with the Commission, which also constitutes service on the Department of Commerce and the Office of the Attorney General. A copy of this filing has been served on all parties on the official service list in this docket.

Please contact me at (612) 330-6732 or james.r.alders@xcelenergy.com if you have any questions regarding this filing.

Sincerely,

/s/

JAMES R. ALDERS
STRATEGY CONSULTANT
REGULATORY AFFAIRS

Enclosures

c: Service List
Richard J. Savelkoul

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Beverly Jones Heydinger	Chair
Phyllis A. Reha	Commissioner
David C. Boyd	Commissioner
J. Dennis O'Brien	Commissioner
Betsy Wergin	Commissioner

IN THE MATTER OF THE APPLICATION OF NORTHERN STATES POWER COMPANY FOR APPROVAL OF OUR 2011-2025 INTEGRATED RESOURCE PLAN	DOCKET NO. E002/RP-10-825
	REPLY COMMENTS

OVERVIEW

Northern States Power Company, a Minnesota corporation, submits to the Minnesota Public Utilities Commission this Reply to Comments received on our 2011-2025 Resource Plan. Several parties submitted Comments in response to our Plan, including the Minnesota Department of Commerce, Division of Energy Resources; Environmental Intervenors;[1] Minnesota Chamber of Commerce; Xcel Large Industrials (XLI);[2] Calpine Corporation; and Prairie Island Indian Community. We also received several Comments from customers and interested individuals. We appreciate the Comments provided and are in agreement with several of the parties on the following key topics:

- *Forecasts.* We agree with the Department's recommendation to accept our energy forecast and peak demand forecast, with a proposed adjustment, for resource planning purposes.
- *Resource need.* We agree with the Department that the addition of 400 to 600 MW of capacity is a reasonable target for resource acquisition beginning in 2017.
- *Demand-side management.* We agree with the Department's assessment of the appropriate DSM goal for the planning period.
- *Environmental issues.* We agree to work with the Environmental Intervenors on a study evaluating the retirement and replacement of the Company's coal

[1] Includes Izaak Walton League of America-Midwest Office, Fresh Energy, Sierra Club, and the Minnesota Center for Environmental Advocacy.
[2] Includes Gerdau Ameristeel Corporation, Flint Hills Resources, LP, and USG Corporation.

resources and agree with the Department's suggestion that we provide updates regarding the Cross-State Air Pollution Rule (CSAPR) in future resource plans.

- *Rate impact.* We provide examples of more detailed rate impact analyses as requested by the Chamber and XLI and agree to work with them to develop the analyses for inclusion in future resource plans.

A few parties commented that we did not provide information necessary for a full evaluation of our Plan. Our objective in this proceeding is to provide the Commission, stakeholders and our customers with greater visibility into our Resource Plan, including the assumptions underlying our resource decisions. Upon receiving Comments, we engaged the parties to better understand what specific information was requested. We supplied the requested information to parties or developed a plan for providing the information, and will continue working with our stakeholders and customers to improve in areas where we fell short of expectations.

We believe our Resource Plan, as revised by the December Update and this Reply, is in the public interest and fulfills the requirements set forth under Minnesota law. We respectfully request that the Commission approve the following recommendations:

- Approve the Company's base energy and peak demand forecast, with a proposed adjustment, as adequate for resource planning purposes;
- Procure 400 to 600 MW of natural gas capacity in the 2017 to 2019 timeframe;
- Revise the scope of the Black Dog Repowering Proceeding (Docket E002/CN-11-184) to identify the best plan to meet the resource need of 400 to 600 MW over the years of 2017 to 2019;
- Direct the Administrative Law Judge for the Black Dog Repowering Proceeding to protect the disclosure of confidential information related to bids from competing parties;
- Retire Black Dog Units 3 and 4 in 2015;
- Reassess acquiring new wind generation for the 2015 to 2016 timeframe, except if unique, high-valued opportunities arise before then;
- Submit a study by July 1, 2013 that examines the feasibility and cost-effectiveness of continuing to operate Sherco Units 1 and 2, as well as the feasibility and cost effectiveness of non-coal-based alternatives;
- Continue to work with interested parties to identify useful measures of rate impacts associated with the Company's resource plans and incorporate them into the next resource plan filing; and
- Procure the 1.3 percent DSM scenario.

We respectfully request that the Commission decline to require the following recommendations put forth by parties:

- Fully address forecasting issues prior to the submission of any certificate of need or rate case filing;
- Fund a solar resource study prior to submission of our next resource plan; and
- Immediately issue an RFP for a 20-year fixed price gas contract.

We propose to submit our next resource plan in late 2013 to allow the results of the resource acquisition process to be incorporated into our reassessment of resource needs.

We have organized our Reply in the following sections:

A. Standard of Review
B. Energy and Peak Demand Forecasts
C. Resource Need and Acquisition Process
D. Future of Sherco 1 and 2
E. Rate Impact
F. Demand-side Management

REPLY

A. Standard of Review

The Company is required to file a resource plan under Minn. Stat. § 216B.2422. To be approved by the Commission, the plan must contain the required information and be in the public interest. Minnesota R. 7843.0500 provides several factors to be considered by the Commission when determining whether a resource plan or individual proposed resource option is in the public interest, including the plan's ability to:

- Maintain or improve the adequacy and reliability of utility service;
- Keep the customers' bills and the utility's rates as low as practicable, given regulatory and other constraints;
- Minimize adverse socioeconomic effects and adverse effects upon the environment;
- Enhance the utility's ability to respond to changes in the financial, social, and technological factors affecting its operations; and

- Limit the risk of adverse effects on the utility and its customers from financial, social, and technological factors that the utility cannot control.

We believe our Plan is complete and accomplishes the criteria listed above for affirming public interest.

B. Energy and Peak Demand Forecasts

We appreciate the Department's recommendation to accept our base energy and peak demand forecast, with a minor peak adjustment, as adequate for resource planning purposes.[3] We believe the similarity of the forecasts prepared by the Department and the Company affirms that the forecasts form a reasonable basis for examining resource needs in the planning setting.

In making the recommendation to approve the adjusted forecast, the Department raised two concerns with our forecasting methodology. The principal concern is the trend of the Company's forecasts to lower predictions of future sales relative to past sales. The Department's other concern is the validity of certain statistical parameters in the Company's forecast model. We have discussed both issues with the Department. We believe this exchange was helpful, giving us a better understanding of the nature of the Department's concerns and how to address them, which we discuss below.

1. Downward Trend of Energy Forecasts

In the December Update, the Company provided revised energy and peak demand forecasts using the same key demand and energy forecast variables and forecasting methodology as in the Resource Plan. The updated forecasts projected lower energy sales and peak demand, which the Company attributed to the loss of municipal customers and setbacks in the national and regional economic recovery. While the Department accepts we had a noticeable reduction in municipal customers, they are concerned that our forecasts started to trend lower before the recession of 2008, suggesting the weaker sales growth trend may not be the result of the economy, but rather possible problems with our econometric model.[4]

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[3] The Department adjusted the Company's peak demand forecast by removing two variables from the peak demand model. DER Comments at 6. The Department's adjusted peak demand forecast is 42 MW (0.4%) higher in 2020 than the Company's.

[4] The Company and Department have discussed this particular concern. DER Comments at 5 and note 9. The Company's lower forecasts prior to the 2008 recession were the result of the actual economic variables for 2006 and 2007 coming in lower than projected. The lower actual economic variables for 2006 and 2007

As the Department notes, they spent a considerable amount of time trying to assess the sensitivity of the econometric model before filing Comments, but were not able to do so as a result of not receiving certain information requested from the Company. Through recent discussions, we understand the Department needs the following to complete its assessment: 1) the current values for all variables that have appeared at any time in previous forecast modeling but were not included in the Company's current modeling; and 2) a map that tracks the changes in acronym for each modeling variable in previous modeling to identify and eliminate any error arising from changes in a variable's acronym. We provided this data to the Department concurrent with this Reply.

2. Specific Modeling Issues

The Department identified the following five issues in the Company's forecasting methodology that they believe need to be resolved prior to the submission of any certificate of need or rate case filing:

- Inconsistent application of statistical diagnostic test;
- Inconsistent use of weather variables;
- Inconsistent use of certain binary variables;
- Unclear documentation of the source of weather data; and
- Overuse of variables.

We recently discussed these issues with the Department and believe we have reached consensus on the last two issues listed above.[5] The other three issues are complex and raise different concerns subject to different resolutions depending on the scope and purpose of the forecast being modeled. For instance, the principal considerations in developing a 15-year forecast for a resource plan are not the same as those for a forecast developed for a single historical or projected test year for ratemaking purposes, which will not be subject to corrective forecasting in subsequent proceedings. Further, forecasting, as highlighted by the three outstanding issues, can

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thus impacted forecasting from 2007 onward, which has resulted in the Company's lower annual sales projections that have, to date, not under-estimated actual sales.

[5] The Company agrees with the Department's decision to drop two variables out of concern that they were insignificant and resulted in an over-identified model, which resulted in the Department's forecast adjustment noted above. The Company also agrees with the Department that when weather data is obtained from sources that gather the data from weather stations that the National Oceanic and Atmospheric Administration (NOAA) also uses, the Company should not identify the weather data source as "NOAA weather stations" because that mistakenly implies the weather data was collected, scrubbed, and published by NOAA when that is not the case.

be debated on theoretical or academic bases, making it difficult and unnecessary to reach consensus on a single approach.

Due to the theoretical nature of the differences in approach and the differences in application between resource planning and ratemaking purposes, we do not believe that complete resolution of these issues should be a prerequisite for filing a rate case or certificate of need. Nonetheless, we pledge to continue discussions with Department on the forecasting issues raised. We provide a brief discussion of the remaining forecasting issues in Attachment A.

C. Resource Need and Acquisition Process

In this section, we discuss the projected need of 400 to 600 MW in new capacity recommended by the Department. We believe the 400 to 600 MW range identified by the Department represents a reasonable target for resource additions. We recommend the Commission, in its Resource Plan Order, direct the resource acquisition process initiated in the Black Dog Repowering Certificate of Need docket to be resumed with the appropriate adjustments in scope to reflect the Department's recommendation. While we introduce several size, type and timing considerations in our Reply, we believe the resource acquisition process is best suited to develop a record from which the Commission can select a specific resource or combination of resources. In this section, we also respond to comments concerning our plans for Black Dog Units 3 and 4 and renewable resource needs, which are separate and distinct from the resources needed to meet the projected 400 to 600 MW in new capacity.

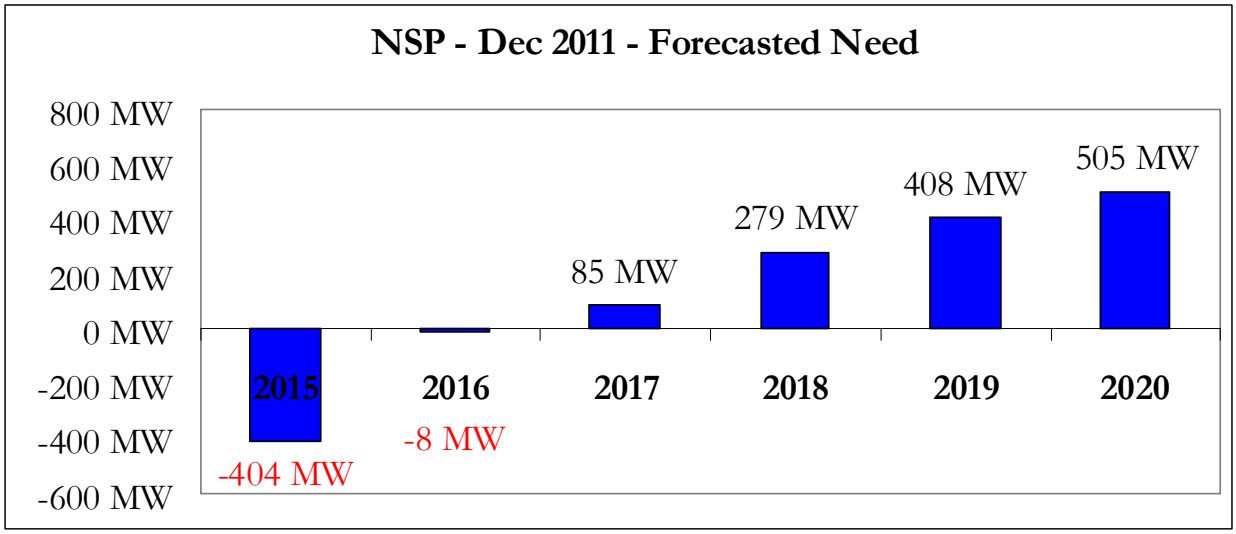
1. Resource Need

The Department recommends the Company obtain 400 to 600 MW of natural gas capacity in 2017-18 and concludes at least half the acquisition should be combined-cycle generation. We appreciate the extensive evaluation the Department performed in this docket and agree that new capacity is expected to be needed in 2017. We also agree with the Department that 400 to 600 MW is a reasonable target for the Company's resource acquisition process.

a. Size and Timing

Examining the resource need requires the comparison of forecasted peak demand plus reserve margin requirements against available generating capacity. The chart below presents the net surplus and deficiency by year as was modeled in our

December Update.[6] At that time we forecasted an 85 MW capacity need in 2017 that grows to 408 MW in 2019.



Our current need assessment has not changed significantly from the Update. We believe the load forecast presented in our Update is still the most appropriate to use for resource planning purposes. However, we note that we developed a new load forecast this spring, which was included in the annual Electric Utility Information Report submitted on June 29, 2012. This spring forecast was lower than the one used in December; however, given our observations of peak loads this summer, we believe the 2011 forecast is the best estimate for future peak loads.

Our current assessment incorporates the Department's recommended adjustment, which increases peak demand by an additional 30 to 40 MW per year. We also made some additional adjustments to reflect current estimates of retirements at older peaking plants. The adjusted need assessment reflects retirement of Black Dog Units 3 and 4 in the spring of 2015, as discussed later in our Reply. We have included the continued operation of peaking units at Key City in Mankato and at Granite City near St. Cloud for another five years, for a total of approximately 100 MW of production capacity, as an uncertain factor that may impact future resource needs.

Another factor impacting the expected resource need is the application of the two MISO capacity accreditation standards. MISO's installed capacity or ICAP standard is based on a unit's tested maximum capacity, while unforced capacity or UCAP

[6] In our December Update, Figure 3.11 contained inaccurate information that did not reflect the data used in Strategist modeling. Table 3.11 included an incorrect 224 MW in 2015 and 2016. Also, the data used for the figure included an assumed wind expansion plan that added approximately 950 MW of wind between 2013 and 2020. This wind expansion was not assumed in the final modeling.

includes an adjustment for recent forced outage factors. We have used the ICAP standard, as we believe it is a more stable measure of system resources and more appropriate for use in long term planning. However, the use of UCAP may also be appropriate. Due to the relatively high reliability of the NSP fleet when the UCAP standard is applied to our forecast, the expected need is reduced by 75 MW to 116 MW in the 2017-19 timeframe.

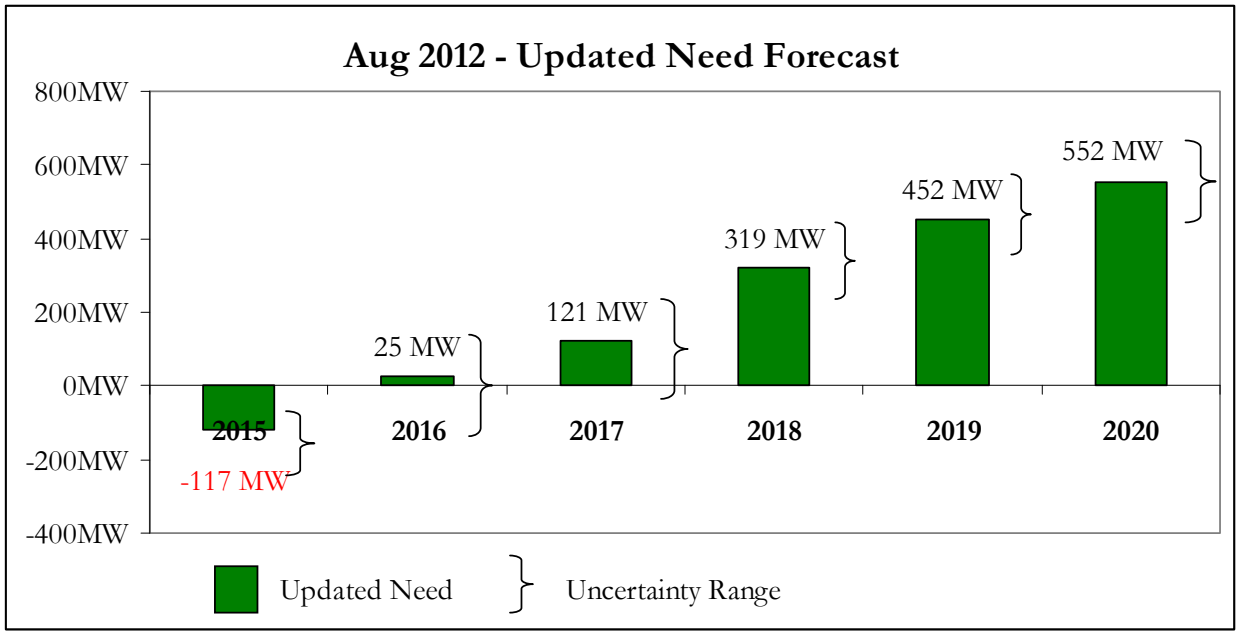
In addition to these adjustments, we include provisions to reflect the uncertainty surrounding the extended power uprate program at the Prairie Island plant. As part of our December Update, we advised the Commission we could move forward with the uprate program if the Commission believed the project still to be in the public interest in light of significant changes that can affect expected benefits. We filed our Notice of Changed Circumstances and Petition on March 30, 2012 to advise the Commission and interested stakeholders of these potential risks.[7] Specifically, we identified changes that are ongoing or could reasonably arise before the program is placed into service, such as further changes to project size, cost and timing; declining load forecasts; declining natural gas prices; and timing uncertainties in the federal licensing process. We presented this information to ensure the Commission was informed of these risks and the potential impacts of circumstances on expected benefits of the extended power uprate program, before deciding whether we should proceed with the uprate project. The Commission may consider our Changed Circumstances Petition before the resource acquisition process is fully engaged. If it is determined that the EPU project should not proceed, the potential resource need increases by approximately 55 MW starting in 2016 and another 55 MW starting in 2017.

The following table and chart illustrate our updated capacity need forecast. We start with the need from December 2011 and add the Department's recommended peak adjustment and the revised Black Dog 3 and 4 retirement date. We then list the capacity from the Prairie Island EPU, Key City and Granite City, and the impact from the UCAP separately to reflect the uncertainty regarding these issues. The data illustrates that between 2017 and 2019 the expected need could range anywhere from zero to 562 MW.

[7] *See* Docket No. 08-509.

Updated Need Assessment	2015	2016	2017	2018	2019	2020
Dec 2011	(404)	(8)	85	279	408	505
DOC Peak Adj*	29	32	36	40	44	47
Black Dog	257	-	-	-	-	-
Updated Need	(117)	25	121	319	452	552
Need Uncertainty						
Key & Granite City	(97)	(97)	(97)			
PI EPU	55	110	110	110	110	110
UCAP	(36)	(68)	(75)	(107)	(116)	(127)
Need Uncertainty Range						
Low	(250)	(140)	(51)	212	336	425
High	(62)	135	231	429	562	662

* Includes 12% reserve margin



Thus, after further exploring some uncertainty factors, our analysis suggests the potential for a capacity deficit in the range of roughly 120 to 450 MW in the 2017-19 timeframe and potentially growing to over 550 MW in 2019. Therefore, we believe the Department's recommendation to add 400 to 600 MW of new capacity is a reasonable target, but recommend broadening the timeframe slightly to include the possibility of 2019 in-service dates to meet part of the resource need.

b. Type

The Department recommends that at least half of the 400 to 600 MW of new natural gas capacity come from combined-cycle plant additions. We agree that it is appropriate to limit consideration to natural gas-fired resources. We do not believe, however, that the Strategist modeling conducted by the Department or the Company in this proceeding is sufficient to definitively identify the appropriate combination of peaking and intermediate resources.

As reported in our December Update, our Strategist model work did not clearly favor a combustion turbine or combined-cycle addition. Through the MERP program, we have added substantial amounts of natural gas combined-cycle capacity in recent years, and capacity factors at High Bridge and Riverside have been relatively low to date, with significant unused generation capability at those plants. If the anticipated new capacity is needed primarily to meet peak demand, additional intermediate generating capability may not be as cost-effective as other options.

Further, the Department's modeling results were significantly influenced by the addition of a carbon dioxide (CO_2) price of $21.50 starting in 2012 and the removal of the MISO market from the model. The Department also, by necessity, made some simplifying assumptions about the cost of smaller increments of combined-cycle generation. The Department's cost assumptions, as well as ours, may not accurately reflect an actual combined-cycle proposal. These assumptions are conservative approaches and help identify the size and timing of the resource need. However, they also have a significant influence on the type of resource the model selects.

Instead of relying on generic cost estimates and other embedded assumptions to identify the proper mix of peaking and intermediate resources, we believe the Commission should continue with the process it established for competitive acquisition when the Company's self-build option is involved. We agree that the acquisition process need not wait for the next cycle of planning, but instead should proceed expeditiously so that the potential for an in-service date as early as 2017 can be preserved.

The first step in the competitive acquisition process is for the Commission to include parameters around the size, type, and timing of the resource need to be acquired in its Order. Here, we believe the Commission should identify the need for approximately 400 to 600 MW of natural gas-fired intermediate and/or peaking generation in the 2017-19 timeframe. The process then moves to the examination of actual proposals to meet the identified resource need. Much more informed decisions can then be made based on actual proposals as opposed to assumptions.

2. Resource Acquisition Process

We believe the process the Commission already authorized in connection with the currently pending Black Dog Repowering Proceeding (Docket E002/CN-11-184) is the appropriate process for selecting proposals to meet the need discussed by the Department and in our Reply. We believe this process is designed to ensure that the resources selected provide the most cost-effective generation for our customers. The necessary regulatory framework is generally in place, since this is an ongoing proceeding. Further, Calpine's participation in the process provides competition to our proposal.

When we asked to withdraw our application for a Certificate of Need in the Black Dog proceeding, we concluded many relevant circumstances had changed.[8] Revising our Certificate of Need application would represent our best proposal for meeting the identified need of 400 to 600 MW over the 2017-19 timeframe. Additionally, the filing would contain information sufficient to evaluate the proposal. Should the Commission agree with the continued use of this process, we suggest Calpine and the Company be afforded the opportunity to revise our proposals before the proceeding. We request the Commission to direct the Administrative Law Judge to establish a procedural schedule that establishes the date by which the revised applications must be submitted. We note expeditious preparation is important to keep open the possibility of beginning to acquire resources in 2017.

a. Confidential Information

While the current Black Dog proceeding generally was working well, a debate developed regarding protecting confidential data while ensuring fair access to the information parties need to make their case in a contested case proceeding. We respectfully request the Commission provide specific guidance to the Administrative Law Judge on this matter.[9] By doing so, the process of discovery and hearing can

[8] We recognized we no longer could meet the burden of proof to support the original proposal. Withdrawal was the formal mechanism available to us to get the matter back to the Commission to address changing circumstances.

[9] The Company respectfully suggests the Commission include an ordering point which requires the hearing officer to provide a protective order. By way of example, the Commission could require the protective order include the following language: "The Company shall not be required to disclose to Calpine Corporation any information designated Confidential, Highly-Confidential or Trade Secret by the Company; likewise, Calpine Corporation shall not be required to disclose to the Company, except to the Company's resource planning employees, any information designated Confidential, Highly-Confidential or Trade Secret by Calpine Corporation. Both the Company and Calpine Corporation shall be required to disclose any information related to their respective proposals, including Confidential, Highly Confidential and Trade Secret information, to the Department of Commerce – Division of Energy Resources."

move more quickly, and important information that could influence independent power proposals in the future can be protected to the benefit of customers. Specifically, Calpine and the Company share a legitimate interest in preserving the confidentiality of proposals. We suggest that the Commission impose a requirement that competitors not be allowed to review each others' confidential proposals. This means Calpine should not be provided access to the confidential details underlying our proposal. Similarly, the Company's Energy Supply unit and Business Development function will be screened from reviewing Calpine's confidential data. This process will ensure that highly-sensitive data is not used to corrupt the process and customers are protected. The Company's Resource Planning and other support functions need to be given access to all proposals in order to conduct the modeling and other work necessary to make resource selections and propose them for approval.

Of course, the Department would have to complete evaluations of the revised proposals from Calpine and the Company. Accordingly, the Department must be allowed full access to non-public proposals as they are the objective evaluator of resource proposals.

3. Black Dog Units 3 and 4

In their Comments, the Chamber recommended the Company consider continuing coal operation of these units beyond 2014. As we have indicated in prior filings, our analysis has shown that ceasing coal operations will avoid incurring major capital expenses to comply with pending environmental regulations.

To comply with the Mercury and Air Toxics Standards (MATS) for coal-fired operation at Black Dog Units 3 and 4, a fabric filter baghouse, spray dryer absorber, and sorbent injection would likely be required to reduce particulate matter, non-mercury hazardous air pollutant metals, hydrogen chloride, sulfur dioxide (SO_2), and mercury emissions. Both units currently have electrostatic precipitators for particulate control, which the Company has identified as insufficient for MATS compliance. The electrostatic precipitators would have to be removed and replaced with different control equipment in order for Black Dog 3 and 4 to continue operation. Additionally, the design and limited space at the plant site would make the addition of fabric filters and flue gas scrubbers (i.e., spray dryer absorber) to control SO_2 very complicated. Finally, we also have determined that in addition to MATS, there are other upcoming environmental regulations that would require additional control equipment upgrades and construction.

CSAPR[10] or replacement regulation may require additional reduction in nitrogen oxide (NO_X) emissions. Black Dog 3 and 4 are wall-fired boilers without low NO_X burner technology. This configuration results in a higher rate of NO_X production than other boiler firing configurations. Additionally, the plant design does not allow sufficient space for a typical "high dust" selective catalytic reduction (SCR) system design to be installed for the reduction of NO_X emissions. The configuration of Black Dog 3 and 4 requires that a "low dust" or "tail end" SCR design be utilized. This equipment would require reheat of the flue gas to optimum SCR temperatures with duct firing and regenerative heating.

Based on our current understanding, Units 3 and 4 would have to comply with MATS requirements by the spring of 2015. Since the initial capital investment to comply with MATS alone (and potentially CSAPR) is so high, we were not able to identify a compliance strategy that would allow the plant to operate cost-effectively on coal as a bridge until the next set of changes in air quality requirements occur. Therefore, our assessment of resource needs reflects the retirement of Units 3 and 4 in the spring of 2015.

In our December Update we had indicated that running Black Dog 3 and 4 on natural gas in 2015 was an option that would provide a capacity bridge until the next resource was acquired. After more careful study of the potential costs and operating limitations associated with running these units on natural gas, we no longer believe that this strategy is appropriate. In addition to the cost of staffing the facility, there is a potential for significant repair costs should the unit encounter major failures. Similarly, the time it would take to bring the unit online after a period where it was not operating reduces the ability of these units to reliably contribute to meeting system demand. Additionally, based on our updated need forecast we do not expect that Black Dog 3 and 4 will be needed in 2015 to meet system needs. Should capacity be needed in 2015, we believe that low-cost capacity will be available in the MISO market.

4. Fuel Acquisition and Risk Management Strategy

The Chamber also recommended the Company submit a risk management plan for fuel acquisition and issue an RFP for a 20-year gas contract to provide support for the assumptions we used in our resource plan modeling.

[10] As part of the Department's review, they suggested our next resource plan include an update on the impact the CSAPR may have on our generating facilities. We agree and will provide such an update with our next resource plan filing.

a. Risk Management Plan

While not specifically a risk management plan, we submitted an annual electric generation natural gas supply plan on March 30, 2012 in Docket No. E002/M-02-633. Our objective is to obtain a reliable and flexible supply of gas at a competitive market price to meet the dynamic requirements of our gas-fired generating fleet. In the plan we outline our contracted firm storage, and note that we will not be using any financial instruments, in order to avoid being hedged in excess of actual gas consumption during the winter and summer seasons and acknowledging that storage serves as a hedge against price volatility.

We are willing to consider expanding our current natural gas supply plan to include a risk management plan addressing natural gas price volatility over a longer time horizon; however, it should be noted that the time horizon of the plan would most likely be limited to ten years, as compared to the 20-year horizon suggested by the Chamber. The objectives and the details of this plan would need to be agreed upon by the interested parties, and the Company would need adequate regulatory certainty surrounding the recovery of any costs it may incur in implementing such a plan.

b. RFP for 20-year Contract

We disagree with the Chamber's suggestion to immediately issue an RFP for a 20-year supply contract to provide support of assumptions used in the resource plan modeling. We believe that issuing an RFP with the sole intent of soliciting price information from the market would not be in good faith. Also, this recommendation is not practical, as 20-year natural gas contracts are extremely uncommon if not non-existent. We believe that the current four-source blend that the Company currently uses in its modeling is a fair representation of future prices, as it blends the independent work of three forecasting consultants and the current forward market.

5. Renewable Generation

Distinct from the projected need of an additional 400 to 600 MW of new capacity is our need to add new renewable generation to comply with the renewable energy standard and the renewable generation policies of the other states we serve. Below we address our plans regarding wind, solar and cogeneration generation resources.

a. Wind

The Department recommends we pursue 100 to 200 MW of additional wind in the 2015-16 timeframe if the price of the energy is $50 per MWh or less. The Chamber advocates that no more wind power be added to the system out of concern that it is not a cost-effective resource. We believe our proposal is consistent with these recommendations. We are not proposing any specific additions as part of our action plan, but believe 2015-16 is an appropriate timeframe for potential wind additions.

We note, however, that the price target suggested by the Department could be significantly higher than our recent experience with wind generation. The Department's price is predicated on the use of the Commission's $21.50 per ton CO_2 cost estimate. While the Department correctly applies the $21.50 cost in their Strategist runs, it is also necessary to present the results without CO_2 prices to demonstrate the impact that CO_2 prices have on cost-effectiveness. Upon reviewing the Department's Strategist results, it appears that of the benefits created by the $50 per MWh wind in 2014, about 29 percent is associated with CO_2 costs. The implication is that without the CO_2 costs, wind would need to be closer to $35.50 per MWh to be cost-effective.

We acknowledge that federal production tax credits are set to expire at the end of this year. We generally expect that if the tax credit is allowed to expire permanently, it will result in significant restructuring in the marketplace, impacting cost-effectiveness of new wind for a period of time. However, we remain open to the possibility that wind may be a cost-effective resource in the future and suggest that the 2015-16 timeframe gives adequate time to revisit the issue in the next resource planning cycle. Additionally, we have previously stated that we remain open to the idea of pursuing unique wind generation opportunities if they arise. There is always the potential that a unique resource, such as an existing generator, may become available at an attractive price. We believe it is appropriate that the Company be allowed to explore those opportunities if they arise.

b. Solar

Xcel Energy has been recognized by the Solar Energy Industries Association as one of the top solar utilities in the nation and is committed to the installation of solar technologies where reasonable for our ratepayers and where the regulatory framework for solar photovoltaic (PV) is appropriate and sustainable. In 2011, Xcel Energy

ranked fifth in the nation for total solar installed capacity.[11] In addition, Xcel Energy is one of the original founding members of the Solar Technologies Acceleration Center.[12]

The majority of the solar we have installed on the Xcel Energy system is in Colorado and New Mexico, where the solar resource is better than in the Upper Midwest. As we described in our Plan, our solar strategy in the Upper Midwest is to build on our experience with solar generation in the Southwest with targeted installations and programs here in Minnesota. Through grants funded by Xcel Energy customers through the Renewable Development Fund, and rebates funded by our customers through the Minnesota Solar*Rewards program in our Conservation Improvement Program (CIP), Xcel Energy has increased the amount of solar capacity in Minnesota from very little in 2007 to 1 MW in 2010 and over 4 MW today. To our knowledge, this amount surpasses the solar capacity of any utility in the Upper Midwest.

Our decision to phase out Solar*Rewards from CIP by the end of 2013 was based on several factors, including the high cost of solar compared to other resources; rebate levels and cost-effectiveness results that are out of line with other CIP programs; and lack of an effective regulatory framework. We remain committed to working with policy makers, customers and other interested stakeholders, including the Environmental Intervenors, on a path forward for solar DG that is consistent with our resource needs; supportive of continued development of Minnesota's solar industry; reflective of the financial impacts of solar on the Company; and, most importantly, protective of our ratepayers and their continued need for affordable, reliable electric service.

A solar resource study may support development of that path, but the need for such a study should be discussed and designed within the broader scope of a solar DG design effort. While we are open to further discussions on this topic, we request that the Commission decline to require the Company to fund a solar study prior to submission of our next resource plan.

c. Cogeneration

The Chamber recommended that we examine the potential for combined heat and power (CHP) for distributed baseload generation, including specific sites, barriers and

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[11] http://www.solarelectricpower.org/media/257582/final%202011%20utility%20solar%20rankings%20report.pdf, page 13.

[12] The mission of Solar TAC is "to increase the efficiency of solar energy products and rapidly deploy them to the commercial market." http://www.solartac.org/About/Default.aspx.

opportunities, and economic feasibility. We agree that CHP and, more broadly, distributed generation, is a timely topic, particularly given the new opportunities presented by low natural gas prices. We are interested in continuing a constructive dialogue with stakeholders regarding the design of an appropriate regulatory structure that addresses the value of distributed generation, while maintaining a financially sustainable regulatory model for utilities. Although a site-specific approach to this issue would be challenging, we would be able to outline the economics, environment and industries for which it may provide the greatest value, as well as the risks, opportunities, and policy implications for both customers and the Company.

D. Future of Sherco Units 1 and 2

The December Update continued to assume that Sherco Units 1 and 2 would operate beyond the end of their book lives in 2023, subject to the results of a life extension study that the Company is conducting on the units. The Department tested the validity of this assumption by modeling a number of resource plan scenarios that retired the units before the end of their current lives. Their analysis supports their conclusion that an early shutdown of Sherco 1 and 2 "would impose significant costs on Xcel Energy's system and require immediate acquisition of significant resources" and their recommendation that no action be taken at this time to retire Sherco Units 1 and 2. We appreciate the recognition of the significant role Sherco plays in our resource mix and support this recommendation.

That said, the future of Sherco Units 1 and 2 beyond 2023 is still being evaluated. The Company has begun a comprehensive Life Cycle Management Study for Sherco Units 1 and 2 to facilitate an understanding of the plants' future. Similarly, as part of this proceeding, the Environmental Intervenors are requesting the Company complete a study evaluating the retirement and replacement of the Company's coal resources, similar to what a number of other Minnesota electric utilities have been ordered to undertake. They ask that the Commission order this study to be completed within six months.

With the retirement of Black Dog Units 3 and 4, the two Sherco units comprise more than 50 percent of the coal generation left on the NSP system. The remaining coal-based generating facilities on our system have been subject to significant capital upgrade projects. Therefore, we believe it makes sense to focus evaluations on the future of coal on the Sherco facilities, using the Life Cycle Management Study as a starting point. We are willing to work with parties to develop a scope for a study that would leverage the work currently being done and address other concerns related to the use of coal, such as our coal price assumptions and least-cost options for meeting

50 percent and 75 percent of new and refurbished capacity with renewables and conservation.

We are willing to commit to file the study by July 1, 2013. At that time, after seeing the status of our work, the Commission can better determine the best procedural course, either to establish a new, issue-specific docket or fold the issue into a future resource plan proceeding.

Below we provide an update on our Life Cycle Management Study and initial comments on our coal price assumptions and compliance with the least-cost analysis requirement.

1. Life Cycle Management Study

The Life Cycle Management Study is evaluating the costs and benefits of continuing to operate Sherco Units 1 and 2 beyond their initial book life, including the investments needed to extend the units' operating lives, as compared with the costs of replacing the units with alternative generating facilities. Thus far, the life cycle management team has reviewed the current operating condition of the units and environmental controls installed. The team's initial findings determined that the current operating condition of the units is very good, and with some investment they could be maintained and operated well beyond this date. As for environmental controls, Sherco Units 1 and 2 both have wet scrubbers, which use an alkaline spray to capture sulfur dioxide and ash. The plant also installed wet electrostatic precipitator (ESP) technology on these units to reduce particulate emissions. To control nitrogen oxide, low NO_X burners, overfire air, and combustion controls have been installed.

Looking ahead to key near-term compliance requirements,[13] it appears that three projects will be needed:

- Activated Carbon Injection Project to control mercury emissions;
- Wet Electrostatic Precipitator Project to further reduce fine particulate emissions; and
- Sparger Installation Project to improve SO_2 emissions controls.

It is our expectation that these projects, when added to the existing emissions controls, will likely be adequate to meet near-future mercury, SO_2 and particulate

[13] Primarily the Regional Haze Best Available Retrofit Technology milestone, the Cross-State Air Pollution Rule, the Mercury and Air Toxics Standard rule, and the Minnesota Mercury Emissions Reduction Act.

matter requirements as they are promulgated today, but there may be additional regulations that may require further emission reductions. We will continue to evaluate the spargers as they are installed to determine whether they are adequate to meet SO_2 requirements. Thus, we believe the key question pending for future criteria pollutant controls is whether and when additional NO_X controls will be needed, i.e., SCRs. Thus, the timing of SCRs installation became a significant component of the options developed by our Sherco Unit 1 and 2 study team, along with the timing of unit retirement.

2. Price of Coal

The Company believes the study scoping process is the appropriate forum to address the study conditions proposed by Environmental Intervenors, including the future price of coal. We agree with the Environmental Intervenors that coal prices are critical inputs in resource planning analysis and are willing to work with parties in the future to ensure that our analyses fully address a broad range of future fuel prices.

Based on their review of the Power River Basin Coal Resource and Cost Study, the Environmental Intervenors believe that our Plan makes an unjustified assumption that price increases for coal will be less than actual historic price escalations. While we appreciate the Environmental Intervenors careful review of the study, it was not the basis for our coal price forecast. We believe that our coal price assumptions are reasonable because they are based on actual contracted prices and volumes in the near-term, as well as forecasted values from consulting agencies. Additionally, we note that the long-term escalation for coal is almost identical to that for natural gas. Using volumetrically weighted average prices from the base case used in the December Update, the average growth rate from 2025-50 in the model was 2.02 percent for coal and 2.03 percent for natural gas.

3. Least-Cost Analysis

We believe that the scoping process can also address the Environmental Intervenors' concerns regarding how the least-cost options for meeting 50 percent and 75 percent of Company's new and refurbished capacity with renewables and conservation should be determined.

The Environmental Intervenors suggest that our Plan does not include a least-cost scenario that supplies 50 and 75 percent of new and refurbished capacity needs with renewables and conservation as required by the Minnesota resource planning statute, Minn. Stat. § 216B.2422, subd. 2. Specifically, the Environmental Intervenors claim that the Company did not analyze future refurbishments to Sherco Units 1 and 2. In

initial Comments, the Department concluded that we applied the 50 and 75 percent analysis rule properly.

We believe the Resource Plan fulfills the resource planning statutes and rules, which is to analyze *known* new and refurbished capacity needs. There is no current certainty around the need to refurbish Sherco 1 and 2. The Company stated in our December Update that we continue to analyze options for the two units in light of the remaining life and environmental regulations. Therefore, there is no need to currently include them in a least-cost analysis. Should we definitively determine to continue the lives of Sherco Units 1 and 2 beyond their current expected life (2023), we will include a least-cost analysis for them in a future resource plan.

E. Rate Impact

The Chamber and XLI expressed concern that our Plan lacks detailed rate impact analyses and information. The Chamber's concerns are directed at resource choices made to fulfill policy considerations, such as DSM and the acquisition of renewables; XLI's are focused on resource choices identified in our Five-Year Action Plan. We appreciate their interest in having a deeper understanding of the potential financial impacts to our customers from resource choices made as part of this proceeding. We had what we believe to be constructive discussions that have helped us understand the information we might be able to provide that will respond to these concerns.

Since there are no specific resource acquisitions proposed in our Action Plan, we do not believe further rate impact analysis is necessary in this docket. However, we offer examples of additional information that could be included in future resource planning and acquisition dockets to better inform the rate impacts of proposed actions. We believe an order point, similar to those in other recent resource planning orders, that directs the Company to provide additional rate impact information in its next resource plan, would be appropriate. Regardless, we intend to continue our discussions with interested parties in an effort to best meet their information needs going forward.

1. Measuring Specific Rate Impacts

Resource planning, by its nature, takes a high-level or long-range view of resources required to meet the needs of our customers. Strategist is the analytical tool that furthers our understanding of size, type, and timing considerations. By including factors such as capital costs of major generation additions into account, Strategist helps us understand the present value of financial benefit our customers can receive from a given resource choice.

Ratemaking, in contrast, typically concentrates on a single test year, essentially representing the present or very near-term, to understand the overall revenue requirements needed for us to continue providing safe, reliable service to our customers. Short-range budgeted data, with support from actual data, construct the test year, which factors in all capital and O&M to run the business.

In terms of supply resources, capital-related costs go into rate base when Company assets such as Company-owned generators are put into service. Other supply resources for which we have PPAs, once executed, are liabilities factored into determining any revenue deficiencies. Thus, ratemaking and the tools used to support it are much more detailed and inclusive, making it not comparable or suited for long-range planning efforts.

Since the focus of resource planning and ratemaking are different, a bridge is needed to quantify the impacts one has on the other. There is no perfect bridge to cross this divide, but we have worked diligently with parties to construct analyses that illustrate potential rate impacts based on planning data. While discussions with the Chamber and XLI have clarified their requests,[14] for the reasons we stated above, it is important to note that the results we present below are approximations. We look forward to continuing our constructive dialogue in an effort to better understand and meet their needs in future resource plan proceedings.

We provide as Attachment B more detailed discussion and analysis of rate impacts related to renewable generation and DSM, and the five-year action plan.

2. Rate Comparison

The Chamber also requested a comparison of our electric rates to other utilities in the state and surrounding areas. Like rate impact analyses, rate comparisons have limitations that prevent an apple-to-apple comparison of general utility rates, let alone rates by customer class.

Rates charged to customers are affected by the capital investments made by utilities. By their nature, capital investments are cyclical; at times when some utilities are making significant capital investments, other utilities in a state, region or nation may not be, or vice versa. Rates are likely to increase when significant capital investments are made. On the other hand, rates may not change much during periods of nominal

[14] For example, the Chamber clarified that they are seeking the ratepayer impacts in early years of the planning horizon.

to no capital investment. Rate comparisons, which look at a static time period such as a year, cannot capture this difference in stages of the capital investment cycle.

Additionally, rate comparisons use broad customer classes that do not correlate to the more specific customer classes we use. For example, SNL Energy's rate comparison illustration uses the Federal Energy Regulatory Commission defined residential, commercial and industrial customer classes. The Company, by comparison, has six customer classes. Our five non-residential classes are squeezed into the two non-residential classes used by SNL. We believe that for reasons such as this, as well as including non-investor owned utilities, rate comparisons are not very reliable.

We understand, however, that this type of information may be helpful to the Chamber. We use SNL Energy as a reference. SNL Energy is an energy publication that, among other things, provides annual rate comparisons. We provide the results of their 2010 and 2011 rate comparison, which looked at electric rates nationally and in the upper-Midwest, as Attachment C. Because these results represent large class averages, customers in individual segments within those classes may not be reflected in these results. We recognize the limitations of these analyses and look forward to working with interested stakeholders to provide better information in future resource plans.

F. Demand-Side Management

We appreciate the Department's consideration of the appropriate DSM goal for the planning period and agree with their assessment that the difference in savings between the 1.3 percent DSM scenario and the 1.5 percent scenario is not enough to impact any near-term resource decisions. Therefore, there are no resource implications associated with choosing one DSM scenario over the other.

In 2011, we achieved the 1.5 percent of sales goal and are on track to sustain this level of savings throughout our upcoming 2013-15 CIP Triennial Plan. While we are proud of our recent successes, we believe that there are challenges to sustaining the 1.5 percent goal over the planning period. This was confirmed by a DSM market potential study recently completed for our electric service territory, which estimates the achievable potential for additional energy efficiency assuming various rebate levels.[15] The study does not support a long-term goal over 0.7 percent of sales, even with rebates equal to 100 percent of incremental cost. However, we will continue to assess the long-term feasibility and cost-effectiveness of the 1.5 percent goal in

[15] The study, including the demand response assessment, is available on our website at: http://www.xcelenergy.com/About_Us/Rates_&_Regulations/Regulatory_Filings/MN_DSM

subsequent resource plans, as we gain more experience at high levels of savings and evaluate market changes.

The Chamber recommended that we examine issues related to our load profile, including efforts to improve system load factor by providing more relevant pricing signals and improved compensation for demand reduction or displacement. We are willing to provide additional information in our next resource plan and offer these initial comments.

We are projecting a slight decline in load factor over the 2012-20 time period, with the annual system load factor decreasing by about one percent based on peak demand growing at a faster rate than energy. One factor causing this forecasted decline in load factor is the loss of our firm wholesale contracts. Because the firm wholesale load had a 65-70 percent load factor compared to the historical system average load factor of 58-59 percent, the loss of these contracts results in a lower system average load factor. Also, some energy efficiency gains, such as lighting, reduce energy use without commensurate peak demand impacts, resulting in a lower load factor. Therefore, there are reasons independent of pricing signals for this trend.

CONCLUSION

We appreciate the Comments submitted by parties on our Resource Plan. We agree with several of the recommendations put forth and will continue to work with parties on ongoing issues.

We believe our Resource Plan, as revised by the December Update and this Reply, is in the public interest and fulfills the requirements set forth under Minnesota law. We respectfully request that the Commission approve the following recommendations:

- Approve the Company's base energy and peak demand forecast, with a proposed adjustment, as adequate for resource planning purposes;
- Procure 400 to 600 MW of natural gas capacity in the 2017 to 2019 timeframe;
- Revise the scope of the Black Dog Repowering Proceeding (Docket E002/CN-11-184) to identify the best plan to meet the resource need of 400 to 600 MW over the years of 2017 to 2019;
- Direct the Administrative Law Judge for the Black Dog Repowering Proceeding to protect the disclosure of confidential information related to bids from competing parties;
- Retire Black Dog Units 3 and 4 in 2015;

- Reassess acquiring new wind generation for the 2015 to 2016 timeframe, except if unique, high-valued opportunities arise before then;
- Submit a study by July 1, 2013 that examines the feasibility and cost-effectiveness of continuing to operate Sherco Units 1 and 2, as well as the feasibility and cost effectiveness of non-coal-based alternatives;
- Continue to work with interested parties to identify useful measures of rate impacts associated with the Company's resource plans and incorporate them into the next resource plan filing; and
- Procure the 1.3 percent DSM scenario.

Dated: August 13, 2012

Northern States Power Company

Respectfully submitted by:

/s/

JAMES R. ALDERS
STRATEGY CONSULTANT
REGULATORY AFFAIRS

Specific Modeling Issues

The Department identified the following five issues in the Company's forecasting methodology:

- Inconsistent application of statistical diagnostic test;
- Inconsistent use of weather variables;
- Inconsistent use of certain binary variables;
- Unclear documentation of the source of weather data; and
- Overuse of variables.

We believe we have reached consensus on the last two issues listed above and provide brief discussion of the other issues below, with the inconsistent use of weather and binary variables discussed together.

A. Inconsistent Application of Statistical Diagnostic Test

The Department's concern with the Company's "inconsistent application of [its] statistical diagnostic test" is an example of where it is appropriate to deviate from a general guideline to produce a more reliable result for planning purposes. Their concern refers to the Company including a variable in the econometric modeling that is significant at the 90 percent level rather than at the higher 95 percent level. While the Company generally adheres to the higher significance level to ensure that the impact of the variable is meaningful, this is a guideline rather than a hard and fast rule. Including a variable with a lower level of significance (referred to as an "explanatory" variable) is statistically acceptable, and its inclusion does not necessarily make the model invalid, resulting in an unreliable forecast. There are cases, such as this, where an explanatory variable is the best or even the only way to reflect a factor that impacts the forecast period and, thus, its inclusion will improve the overall soundness of the forecast.

For example, the North Dakota Gross State Product is used as a measure of overall economic activity and its impact on sales to the North Dakota Small Commercial and Industrial class. The Gross State Product variable is not significant at the 95 percent level, but it is significant at the 90 percent level. The Company has found that even though this variable does not meet the 95 percent level of significance, including it to reflect expected changes in the economy provides a sounder sales forecast.

B. Inconsistent Use of Weather and Binary Variables

The Company may also vary its use of binary variables and weather variables from forecast to forecast, when appropriate, to improve a forecast. A binary variable is a variable that is included to help the model account for outliers or step changes in the historical data associated with another variable. Generally, a forecast is initially developed without any binary variables; they are added later as deemed advisable to improve the overall model fit or monthly pattern of the forecast. While it is common for the same binary variables to be used from forecast to forecast, it is also common for them to be modified for a particular forecast because of a change in that forecast's historical data points or some other variable.

The Company's use of weather variables is driven by the relationship between sales and weather by month, class, and geography. It is important to identify these weather and sales relationships because they are not only used in the development of sales forecasts but also to determine unbilled sales each month and weather-normalize historical sales. In the course of developing a forecast, there may be some months where a weather response theoretically should be present but the modeled relationship is weak or the weather response seems unreasonable relative to the surrounding months. To address this issue, adjacent months that demonstrate a common relationship between weather and sales are grouped together. These groups can differ from forecast to forecast, however, because the weather and sales relationship can differ between classes and across geography.

Rate Impact Analysis

A. Policy-Related Rate Impacts

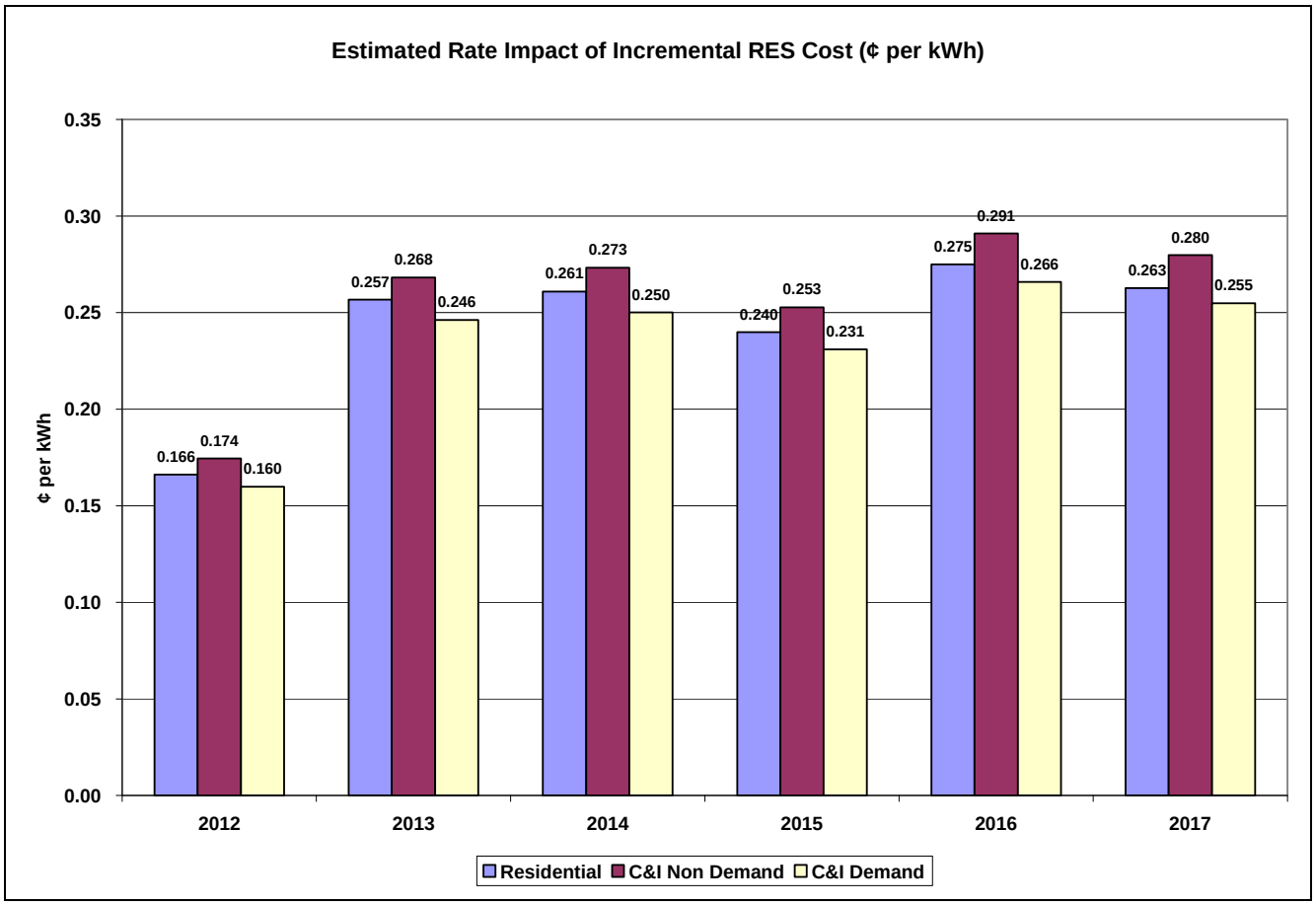
To address the Chamber's request for rate impacts associated with various state policies, we identified renewable generation and DSM as two areas where we could provide further rate impact analysis. To approximate the rate impacts associated with renewable generation procured to satisfy policy initiatives, we compared a Strategist model in which increments of various renewables are added to our system with a scenario in which no additional renewables are added to our system. The difference between the two represents the cost, on a present value basis, of adding more renewables. An example from our Renewable Energy Standard (RES) Rate Impact Report of the difference in PVRR between the two scenarios is shown below:[1]

System Cost Differential
Net Present Value 2010-2025 ($000)

Scenario	No RES	RES	% Change
Base Case	$50,142,085	$50,842,891	1.40%
PTC Extended	$50,142,085	$50,514,235	0.74%
CO_2 Cost	$53,753,421	$53,975,089	0.41%
High Gas	$50,822,706	$51,318,994	0.98%

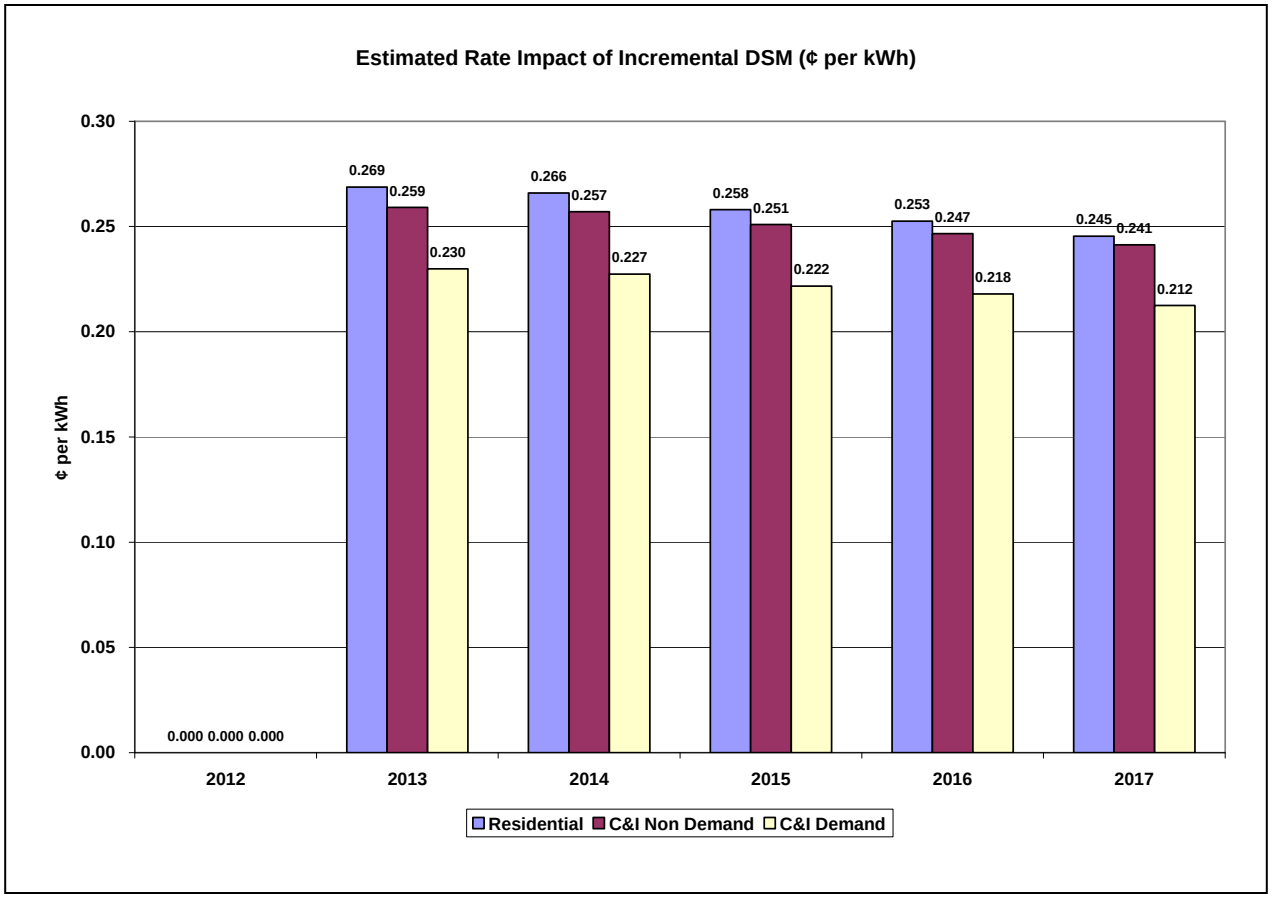
Strategist calculates the PVRR difference scenarios in revenue requirements between the two. We then attempt to translate the net revenue requirement into potential rate implications by class. The table below summarizes the results of one such attempt.

[1] IN THE MATTER OF UTILITY RENEWABLE ENERGY COST IMPACT REPORTS, Docket No. E999/CI-11-852, October 25, 2011.



We used a similar approach for the DSM analysis, looking at the estimates of incremental cost of achieving the 1.5 percent of sales savings goal instead of our achievement of 1.3 percent.

For the 2013-17 period, we anticipate spending an average of approximately $130 million per year on DSM, which includes expenditures and incentives to achieve the 1.3 percent of sales savings goal. We then forecasted total costs associated with achieving the 1.5 percent target and modeled the incremental cost associated with achieving the 1.5 percent sales saving target to approximate the potential rate implications by class, as summarized below.



B. Five-Year Action Plan Rate Impacts

XLI also stated that our Plan does not satisfy state law because it is too ambiguous and omitted a definitive cost impact for the five-year action plan. The Commission's rules require us to file a proposed plan for meeting the needs of our customers over the forecast period.[2] We must show the "resource options the utility believes it might use to meet those needs."[3] Resource options only have to be identified on a generic basis unless a commitment to a specific resource exists at the time of the filing.[4] A resource plan must include a five-year action plan with a schedule of key activities, including construction and regulatory filings.[5]

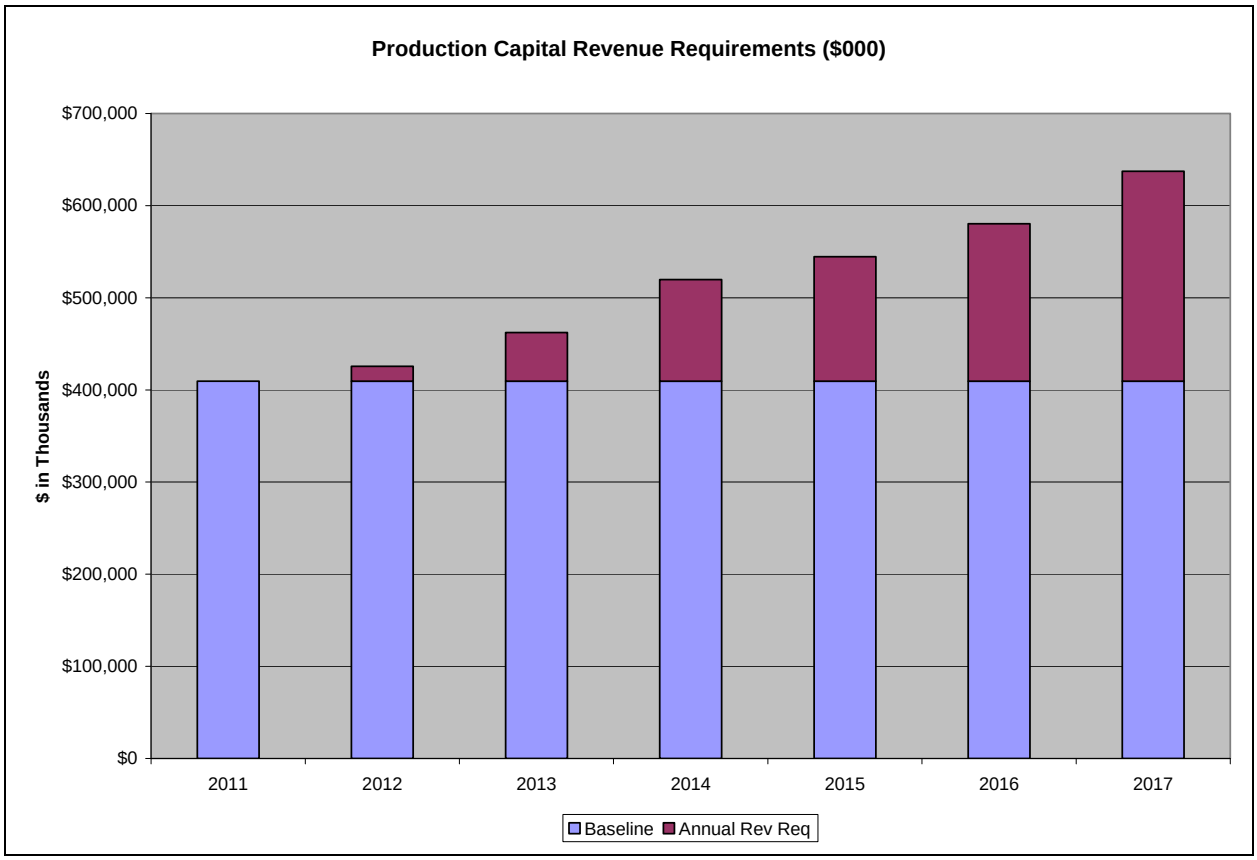
[2] See Minn. R. 7843.0400, subp. 2.
[3] *Id.*
[4] *Id.*
[5] *Id.*, at subp. 3.

We believe our Plan satisfies the Commission's rules. Our Plan provides our five-year action plan, as well as our long-term vision for meeting the needs of our customers in a safe, reliable and cost-effective manner. For resource acquisitions beyond 2016, we identified the resource options we believe will and might be used to meet the needs of our customers. As of our December Update, only the Prairie Island EPU program and DSM efforts remain under the five-year action plan. The primary regulatory filings for the EPU program, a certificate of need and route permit, were resolved before our Resource Plan was filed. As for DSM, we provided our plan for achieving savings of 1.5 percent of sales in our 2013-2015 CIP Triennial Plan, filed with the Department on June 1, 2012.

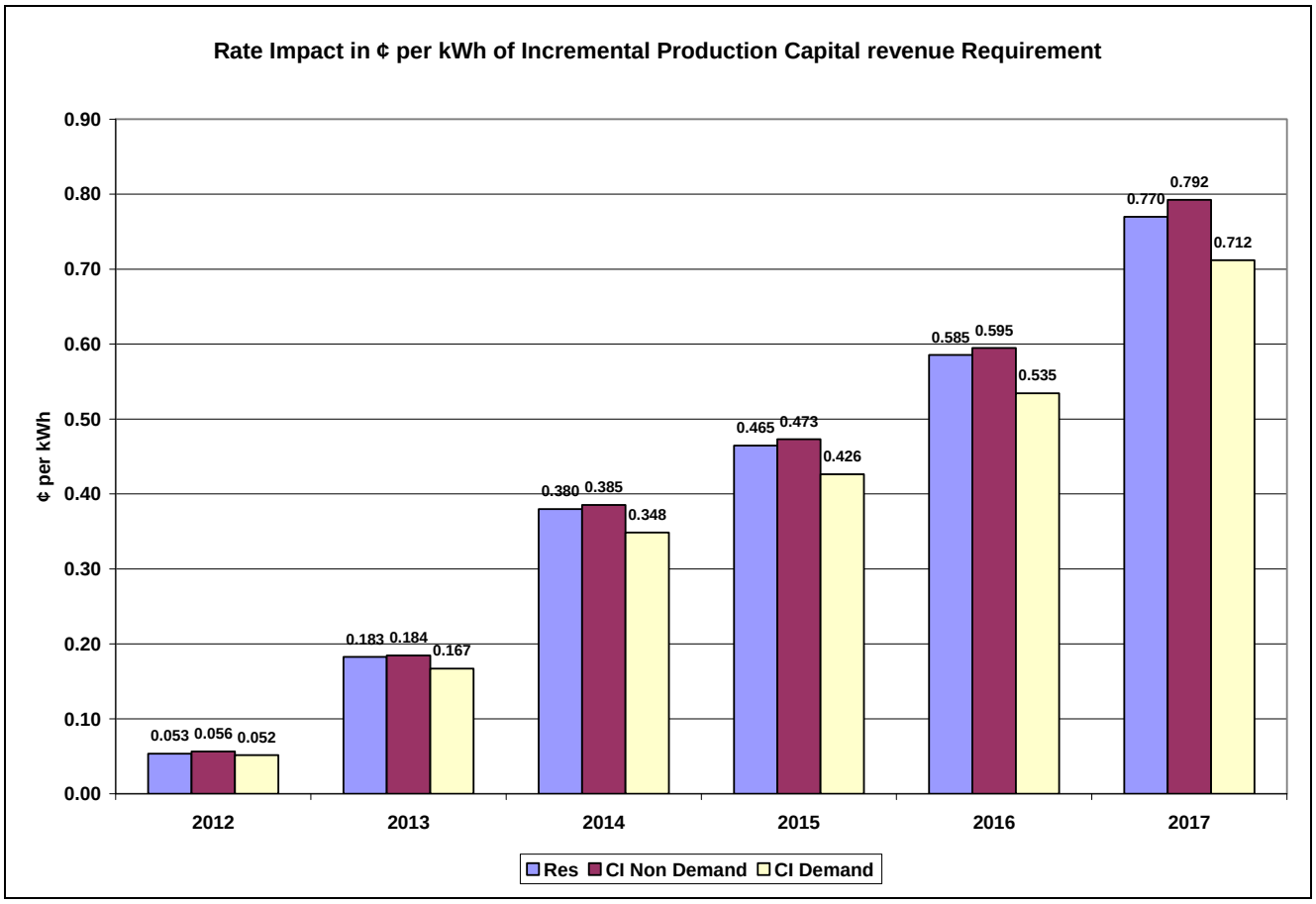
Regarding the lack of a detailed rate impact analysis of our five-year action plan, the rate impacts provided in our Plan are of similar substance and content as in previous plans accepted by the Commission. Further, the detailed analysis sought by XLI is difficult to produce due to changes in our rates and resource needs that will occur over time.

Despite these challenges, we developed a high-level illustrative analysis that conceptualizes potential rate impacts by customer class resulting from implementing our revised five-year action plan. Our general approach is to "net" current production resources, in-process resource changes, and the resource changes identified in our revised five-year action.

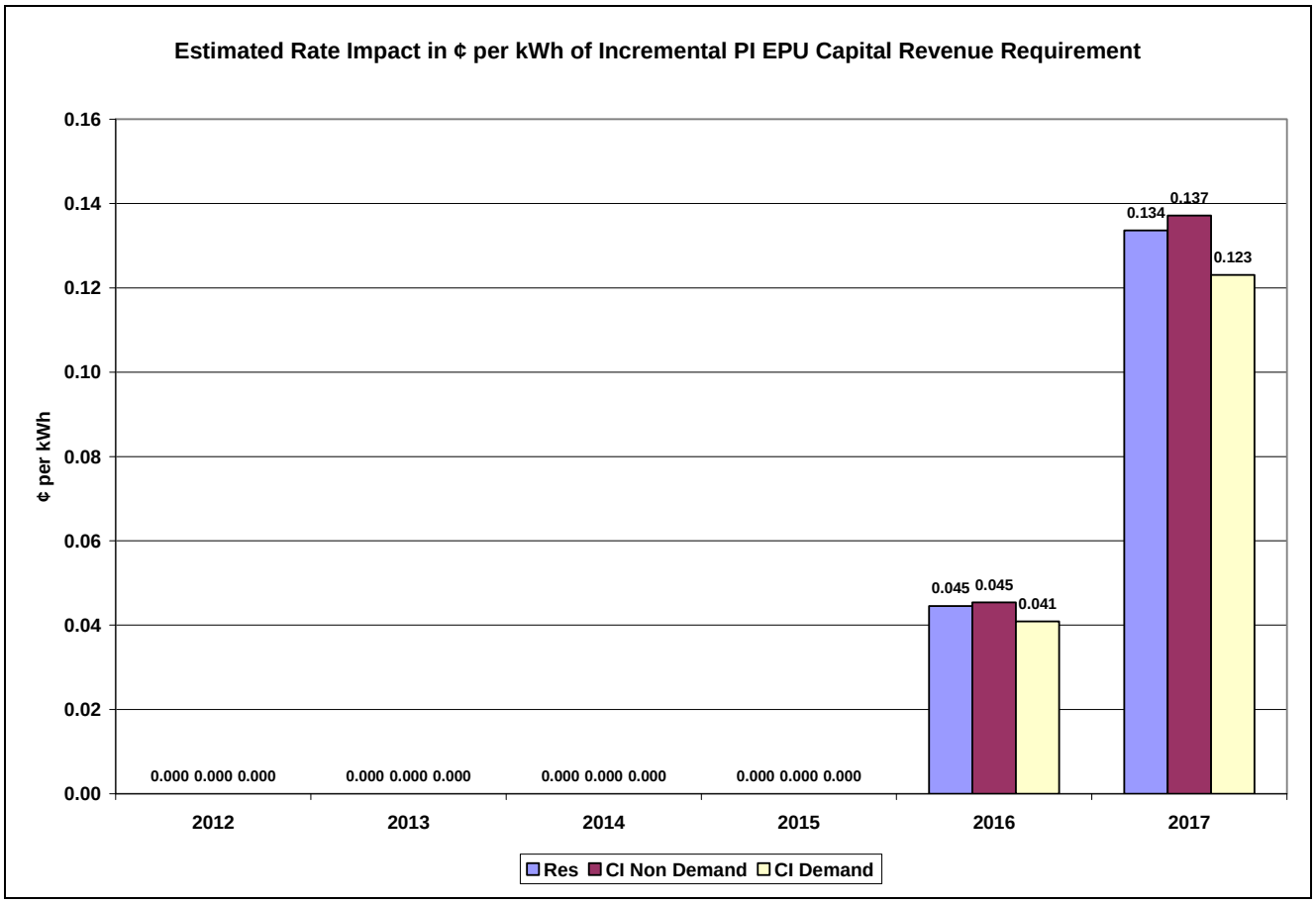
The impact on revenue requirements associated with our estimates of all generation-related capital expenditures during the next five years is shown below. The capital investment we anticipate in the next five years creates significant new revenue requirements above the level reflected in current rates. This fact was discussed in broad percentage terms in our Resource Plan filing.



As in the case of the policy issues outlined above, we have also attempted to approximate these estimates of revenue requirements into rate impacts by customer class, as illustrated below.

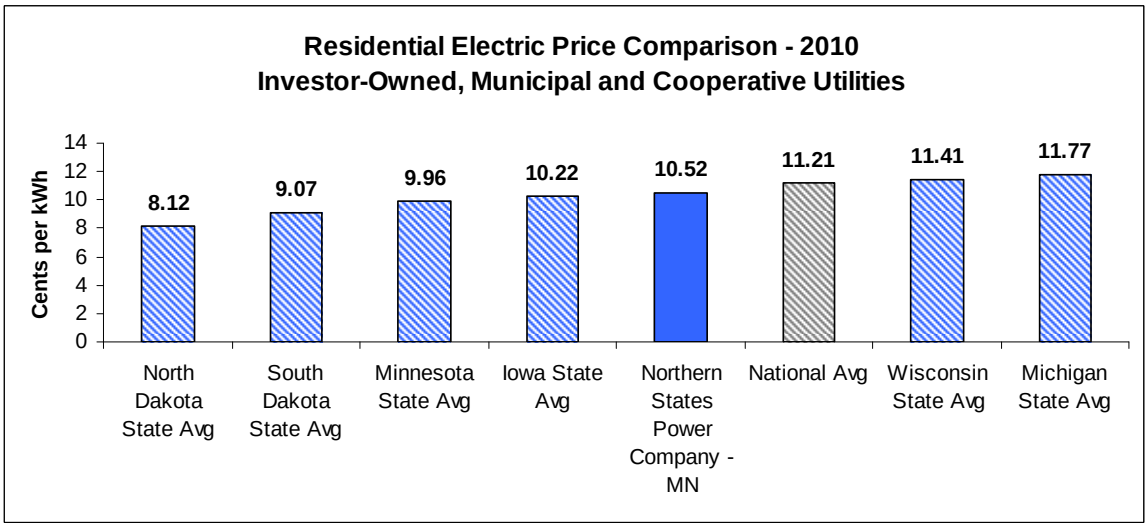


The only element of the five-year action plan that has a direct capital impact is the Prairie Island extended power uprate (EPU). We estimate our capital expenditures could be reduced by approximately $237 million if the project is not pursued. That translates into a potential reduction in revenue requirements of $13 million in 2016 and $39 million in 2017, compared to the above. The chart below approximates the class impact.



To approximate the class rate impacts, we split the forecasted 2012-17 production-related resources into "peaking" and "baseload" components for each year, using our plant stratification approach. We allocated peaking-related revenue requirements to each customer class using the Production Capacity allocator (D10C) used in our most recent rate case; for baseload-related revenue requirements, we used the Energy allocator (E8760).

We then "net" these total class revenue requirements against the 2011 rate case settlement baseline to approximate the incremental impacts, ultimately dividing the results by forecasted kWh sales levels to determine a per kWh impact.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Investor-Owned, Municipal and Cooperative Utilities
Cents per kWh
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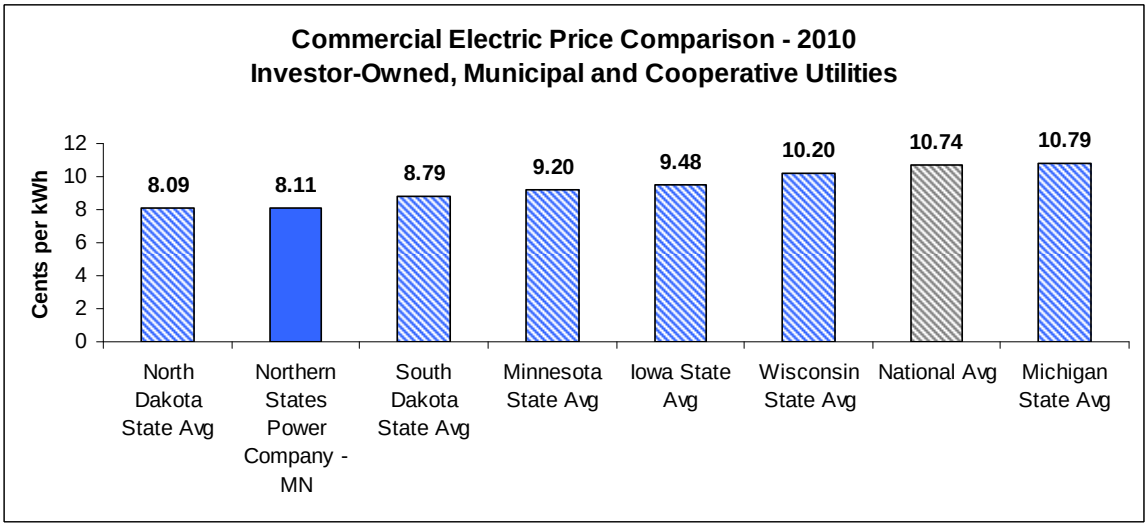
Iowa State Avg
Northern States Power Company - MN
National Avg
Wisconsin State Avg
Michigan State Avg


Commercial Electric Price Comparison - 2010
Investor-Owned, Municipal and Cooperative Utilities
Cents per kWh
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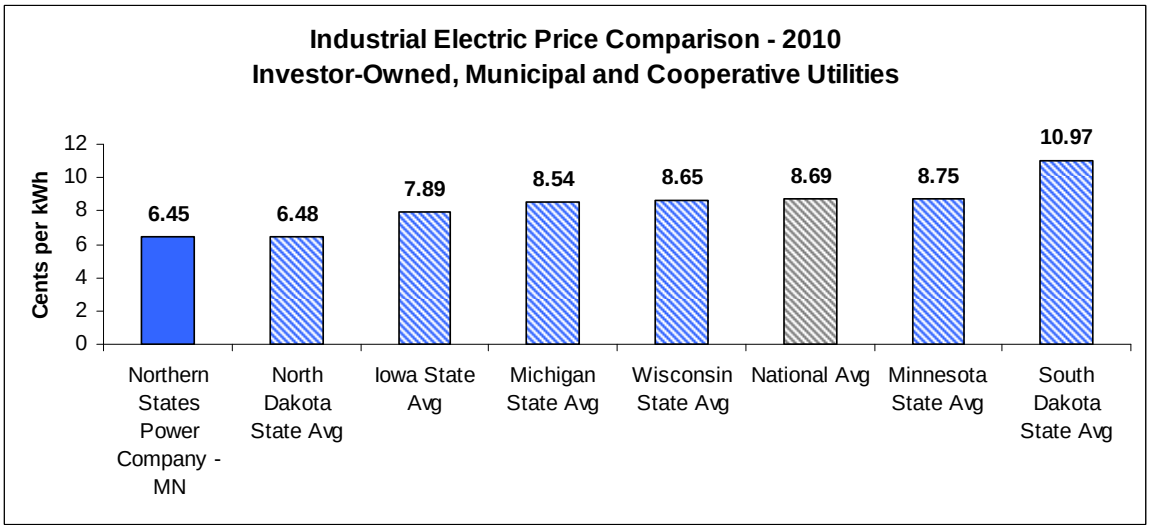
Minnesota State Avg
Iowa State Avg
Wisconsin State Avg
National Avg
Michigan State Avg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National Avg
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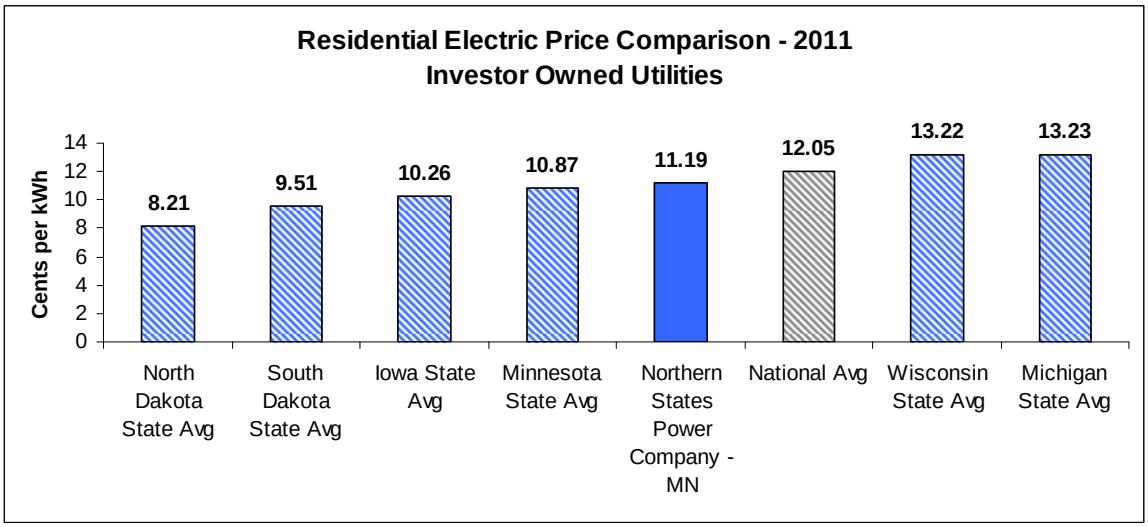
South Dakota State Avg


Residential Electric Price Comparison - 2011
Investor Owned Utilities
Cents per kWh
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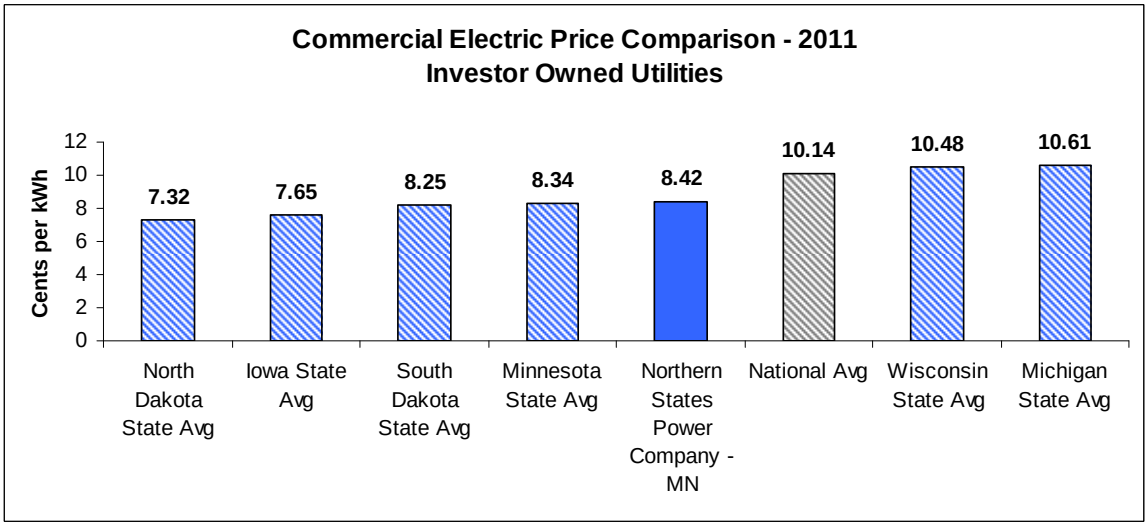
Northern States Power Company - MN
National Avg
Wisconsin State Avg
Michigan State Avg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Investor Owned Utilities
Cents per kWh
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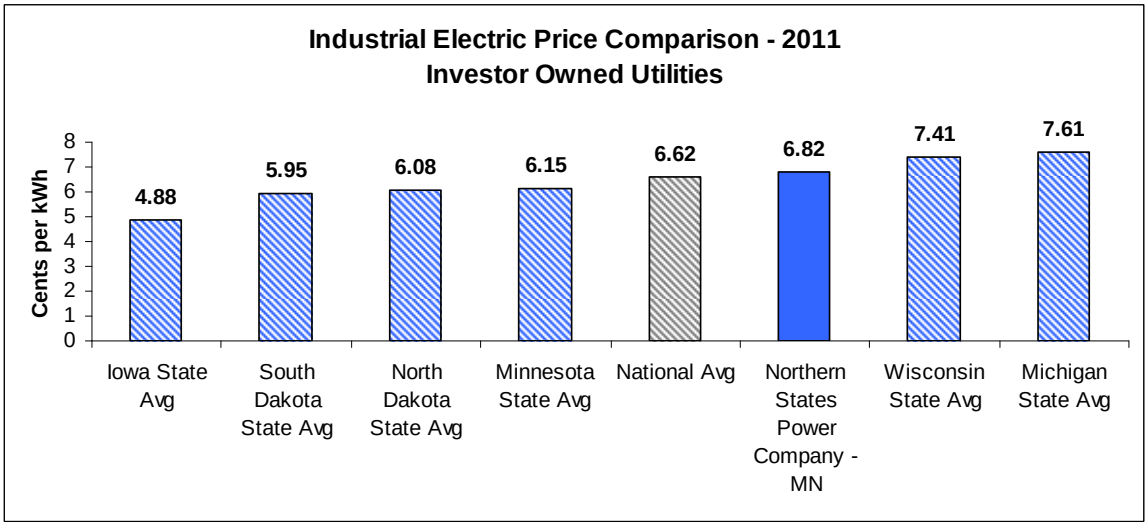
Industrial Electric Price Comparison - 2011
Investor Owned Utilities
Cents per kWh
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South Dakota State Avg
North Dakota State Avg
Minnesota State Avg
National Avg
Northern States Power Company - MN
Wisconsin State Avg
Michigan State Avg

CERTIFICATE OF SERVICE

I, Lindsey L. Didion, hereby certify that I have this day served copies or summaries of the foregoing document on the attached list of persons.

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

xx electronic filing

DOCKET NO. E002/RP-10-825

Dated this 13th day of August 2012

/s/

Lindsey L. Didion

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
David	Aafedt	daafedt@winthrop.com	Winthrop & Weinstine, P.A.	Suite 3500, 225 South Sixth Street Minneapolis, MN 554024629	Paper Service	No	OFF_SL_10-825_RP-10-825
Christopher	Anderson	canderson@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022191	Electronic Service	No	OFF_SL_10-825_RP-10-825
Julia	Anderson	Julia.Anderson@ag.state.mn.us	Office of the Attorney General-DOC	1800 BRM Tower 445 Minnesota St St. Paul, MN 551012134	Electronic Service	Yes	OFF_SL_10-825_RP-10-825
Jon	Brekke	jbrekke@grenergy.com	Great River Energy	12300 Elm Creek Boulevard Maple Grove, MN 553694718	Paper Service	No	OFF_SL_10-825_RP-10-825
B. Andrew	Brown	brown.andrew@dorsey.com	Dorsey & Whitney LLP	Suite 1500 50 South Sixth Street Minneapolis, MN 554021498	Paper Service	No	OFF_SL_10-825_RP-10-825
Jeffrey A.	Daugherty	jeffrey.daugherty@centerpointenergy.com	CenterPoint Energy	800 LaSalle Ave Minneapolis, MN 55402	Electronic Service	No	OFF_SL_10-825_RP-10-825
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce	85 7th Place E Ste 500 Saint Paul, MN 551012198	Electronic Service	No	OFF_SL_10-825_RP-10-825
Edward	Garvey	garveyed@aol.com		32 Lawton Street St. Paul, MN 55102	Paper Service	No	OFF_SL_10-825_RP-10-825
Elizabeth	Goodpaster	bgoodpaster@mncenter.org	MN Center for Environmental Advocacy	Suite 206 26 East Exchange Street St. Paul, MN 551011667	Paper Service	Yes	OFF_SL_10-825_RP-10-825
Todd J.	Guerrero	tguerrero@fredlaw.com	Fredrikson & Byron, P.A.	Suite 4000 200 South Sixth Street Minneapolis, MN 554021425	Electronic Service	No	OFF_SL_10-825_RP-10-825

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Burl W.	Haar	burl.haar@state.mn.us	Public Utilities Commission	Suite 350 121 7th Place East St. Paul, MN 551012147	Electronic Service	Yes	OFF_SL_10-825_RP-10-825
Eric	Jensen	ejensen@iwla.org	Izaak Walton League of America	Suite 202 1619 Dayton Avenue St. Paul, MN 55104	Electronic Service	No	OFF_SL_10-825_RP-10-825
Hank	Koegel	N/A	enXco	10 Second St., NE, Ste 107 Minneapolis, MN 55413	Paper Service	No	OFF_SL_10-825_RP-10-825
Douglas	Larson	dlarson@dakotaelectric.com	Dakota Electric Association	4300 220th St W Farmington, MN 55024	Electronic Service	No	OFF_SL_10-825_RP-10-825
John	Lindell	agorud.ecf@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012130	Electronic Service	Yes	OFF_SL_10-825_RP-10-825
Mark	Lindquist		The Minnesota Project	1026 North Washington Street New Ulm, MN 56073	Paper Service	No	OFF_SL_10-825_RP-10-825
Pam	Marshall	pam@energycents.org	Energy CENTS Coalition	823 7th St E St. Paul, MN 55106	Paper Service	No	OFF_SL_10-825_RP-10-825
Daryl	Maxwell	dmaxwell@hydro.mb.ca	Manitoba Hydro	360 Portage Ave FL 16 PO Box 815, Station Main Winnipeg, Manitoba R3C 2P4 Canada	Paper Service	No	OFF_SL_10-825_RP-10-825
Brian	Meloy	brian.meloy@leonard.com	Leonard, Street & Deinard	150 S 5th St Ste 2300 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_10-825_RP-10-825

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David	Moeller	dmoeller@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022093	Electronic Service	No	OFF_SL_10-825_RP-10-825
Andrew	Moratzka	apm@mcmlaw.com	Mackall, Crounse and Moore	1400 AT&T Tower 901 Marquette Ave Minneapolis, MN 55402	Paper Service	No	OFF_SL_10-825_RP-10-825
Carl	Nelson	cnelson@mncee.org	Center for Energy and Environment	212 3rd Ave N Ste 560 Minneapolis, MN 55401	Electronic Service	No	OFF_SL_10-825_RP-10-825
Thomas L.	Osteraas	tomosteraas@excelsiorenergy.com	Excelsior Energy	225 S 6th St Ste 1730 Minneapolis, MN 55402	Paper Service	No	OFF_SL_10-825_RP-10-825
Joshua	Pearson	N/A	enXco, Inc.	15445 Innovation Drive San Diego, CA 92128	Paper Service	No	OFF_SL_10-825_RP-10-825
Kent	Ragsdale	kentragsdale@alliantenergy.com	Alliant Energy-Interstate Power and Light Company	P.O. Box 351 200 First Street, SE Cedar Rapids, IA 524060351	Paper Service	No	OFF_SL_10-825_RP-10-825
Kevin	Reuther		MN Center for Environmental Advocacy	Suite 206 26 East Exchange Street St. Paul, MN 551011667	Paper Service	Yes	OFF_SL_10-825_RP-10-825
Matthew J.	Schuerger P.E.		Energy Systems Consulting Services, LLC	P.O. Box 16129 St. Paul, MN 55116	Paper Service	No	OFF_SL_10-825_RP-10-825
Robert H.	Schulte	rhs@schulteassociates.com	Schulte Associates LLC	15347 Boulder Pointe Road Eden Prairie, MN 55347	Paper Service	No	OFF_SL_10-825_RP-10-825
James M.	Strommen	jstrommen@kennedy-graven.com	Kennedy & Graven, Chartered	470 U.S. Bank Plaza 200 South Sixth Street Minneapolis, MN 55402	Paper Service	No	OFF_SL_10-825_RP-10-825

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Eric	Swanson	eswanson@winthrop.com	Winthrop Weinstine	225 S 6th St Ste 3500 Capella Tower Minneapolis, MN 554024629	Electronic Service	No	OFF_SL_10-825_RP-10-825
SaGonna	Thompson	Regulatory.Records@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 7 Minneapolis, MN 554011993	Electronic Service	Yes	OFF_SL_10-825_RP-10-825
Douglas	Tiffany	tiffa002@umn.edu	University of Minnesota	316d Ruttan Hall 1994 Buford Avenue St. Paul, MN 55108	Paper Service	No	OFF_SL_10-825_RP-10-825