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March 4, 2016

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

Re: In the Matter of Minnesota Power's Application for
Approval of its 2015-2029 Resource Plan
Docket No. E015/RP-15-690

Dear Mr. Wolf:

Minnesota Power hereby electronically submits its Reply Comments in the above-referenced Docket.

Please contact me at the number or the email address provided if you have any questions.

Yours truly,

Lori Hoyum

Lori Hoyum

LH:sr
Attach.
cc: Service List

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

In the Matter of Minnesota Power's Application for Approval of its 2015-2029 Resource Plan	Docket No. E015/RP-15-690 **MINNESOTA POWER'S REPLY COMMENTS**

I. Overview

Minnesota Power submits these Reply Comments to the Minnesota Public Utilities Commission ("Commission") in response to the Department of Commerce – Division of Energy Resources ("Department"), the Large Power Intervenors Group ("LPI"), and Clean Energy Organizations ("CEOs") who each filed Initial Comments on January 4, 2016. On September 1, 2015, Minnesota Power filed its 2015 Integrated Resource Plan ("2015 Plan" or "Plan") for the 2015-2029 timeframe. On November 9, 2015, the Department issued Comments on the completeness of the Plan. In its Comments, the Department stated it had reviewed the 2015 Plan for completeness pursuant to Minnesota Stat. § 216B.2422, that statute's reference to Minnesota Statutes 216C.17, subd. 2., Minn. R.7843.0400, subp. 1-4, the requirements set forth in the Commission's November 12, 2013 Order approving the 2013 integrated resource plan ("2013 Plan"), and the Commissions August 5, 2013 Notice of Information in Future Resource Plan Filings, and "MP's filing can be considered complete."

Minnesota Power's 2015 Plan is the next chapter in the Company's *Energy**Forward*** resource strategy. Minnesota Power's *Energy**Forward*** strategy is reshaping the Company's power supply from a predominantly coal-based energy mix to one that is more diverse, while maintaining low cost, reliable electricity for customers. The Plan is designed to supply Minnesota Power customers with a safe, reliable, and affordable power supply while improving environmental performance, reducing emissions, sustaining the Company's high-quality energy conservation program and adding renewables in the near-term and natural gas in the long-term. The short- and long-term strategies identified in the Plan position the Company well to successfully adapt to a range of economic and environmental futures while maintaining service to its customers at a competitive cost.

The Plan fully satisfies the five factors the Commission is to consider in its evaluation of a resource plan. Per Minn. Rules 7843.055, subp. 3., the Commission is to evaluate the resource plan's "ability to:

A. maintain or improve the adequacy and reliability of utility service;

B. keep the customers' bills and the utility's rates as low as practicable, given regulatory and other constraints;

C. minimize adverse socioeconomic effects and adverse effects upon the environment;

D. enhance the utility's ability to respond to changes in the financial, social, and technological factors affecting its operations; and

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

Minnesota Power appreciates the time and work by the Department, LPI and CEOs to develop Initial Comments that convey their respective viewpoints of the Company's short– and long-term action plans. Through these Reply Comments, Minnesota Power provides additional information, insight and clarification in response to Initial Comments, questions and points raised by stakeholders, including the Commission Staff, through the information request process, regarding the Company's 2015 Plan.

II. Reply Comments

As with the 2013 Plan, Minnesota Power is again addressing two key long-term planning questions in its 2015 Plan. First, what environmental compliance strategies will be used to ensure the Company's generation system meets pending Clean Power Plan ("CPP") regulations and the developing state implementation plan ("SIP") requirements; and second, how will it position and augment its power supply to meet the load growth potential that is emerging in its service territory. The Preferred Plan, identified through extensive evaluation of resource alternatives as the least cost and most reasonable for customers in the 2015-2029 planning period, takes into consideration the Company's expected range of additional environmental regulations and projected customer power supply needs.

The Preferred Plan continues the transition of Minnesota Power's fleet and broader power supply to one that is more diverse, efficient and flexible with fewer emissions per unit of energy produced, while preserving system reliability and protecting customer affordability. Specifically, Minnesota Power's Preferred Plan includes these primary actions:

- Idling Taconite Harbor Energy Center's ("THEC") units 1 & 2 ("THEC1&2") in 2016 and ceasing coal-fired operations by 2020, consistent with the Minnesota Next Generation Act, and well ahead of proposed CPP compliance targets;
- Reducing the emission profile of Boswell Energy Center ("BEC") units 1 and 2 ("BEC1&2") (130 MW) by leveraging the environmental infrastructure of the BEC facility;
- Implementing 33 MW of solar resources by 2020, complying with the state's solar energy standard ("SES"); and
- Beginning the competitive procurement process to secure 200 MW – 300 MW of efficient natural gas combined cycle ("CC") generation supply for implementation by 2024.

The Company was encouraged to see stakeholders relatively aligned on its Preferred Plan: further transformation of its small coal resources, adding natural gas in the long-term, and continuing to advance its energy conservation programs. Minnesota Power continues to prioritize the importance of having a transparent and iterative process with its stakeholders as it considers future resource alternatives and factors for state and federal regulation compliance, and the need to maintain low cost, reliable electricity for customers. The Company, in part, attributes this open and on-going dialogue with its stakeholders to the fact that the Comments in this proceeding were generally supportive of Minnesota Power's Preferred Plan objectives.

Four primary areas of focus emerged from the comments provided by the Department, LPI and CEOs on January 4, 2016, regarding Minnesota Power's 2015 Plan and elements of its Preferred Plan: load forecasting, power supply, plan cost, and conservation. Minnesota Power's Reply Comments address these four areas, supplementing information already submitted in the Docket through the initial 2015 Plan filing and responses to multiple information requests. Additionally, Minnesota Power provides, as requested by Commission Staff in its January 27, 2016 information request No. 7, its 1) discussion on "how the EPA, for Clean Power Plan (CPP) compliance, could treat emissions reduction differently depending on whether the Boswell1&2 units are retired, refueled with natural gas, or replaced with a new natural gas combined cycle unit[;]" and 2) "the Company's perspective on its position to comply with the <u>interim</u> CPP requirements when they begin in 2022." These Reply Comments also provide clarification and further context to help stakeholders gain a greater understanding of the Company's 2015 Plan evaluation process.

A. Load Forecasting

Minnesota Power utilized its 2014 Annual Electric Utility Forecast Report ("AFR2014"), the latest load outlook available for use, as the foundation of its 2015 Plan due to the need to begin its resource planning analysis in early 2015. The 2015 Annual Electric Utility Forecast Report ("AFR2015") filing was made to the Department on July 1, 2015, and was incorporated into the analysis as a sensitivity to ensure the short- and long-term action plans were not impacted by the update in projection (See Appendix K of the 2015 Plan).

Minnesota Power recognizes that subsequent to submitting its 2015 Plan, near-term operations of several of its taconite customers have been curtailed, consistent with their long-term cyclical business profile; however, these customers have not indicated that they intend to permanently end their need for electric service. Therefore, for longer-term planning purposes, Minnesota Power must remain prepared with a reliable and economic power supply plan to serve these customers.

The annual forecast is created through a robust methodology that leverages the latest national and regional economic outlooks to project Minnesota Power's energy and peak demand. Minnesota Power's load forecasting process has been refined over the last several years through a collaborative stakeholder process to reflect commonly-agreed upon best practices in econometric load forecasting. During this time, the Company has been working closely with the Department on methodology and their econometric preferences for Minnesota utility forecasting. Through this iterative process and ongoing dialogue, additional perspectives have been shared and adjustments have been made to further enhance the quality and transferability of Minnesota Power's forecast data and method.

The scope of the Company's Annual Electric Utility Forecast Report ("AFR") has also been expanded to increase transparency in data development processes, analytical techniques, and assumptions. Forecast model development has become more comprehensive as well; from under 1,000 models generated in the AFR submitted in 2012, to over 10 million generated and rigorously-tested as part of AFR2015 development. To ensure a highly defensible forecast, the Company has:

- Archived all models developed for the AFR to support final model selection decisions
- Clearly identified its model selection process, and applied statistical criteria consistently in accordance with this model selection process
- Expanded statistical testing capabilities to ensure final models are free from the potentially negative effects of multicollinearity and heteroscedasticity, and contain only unbiased and statistically-significant indicators
- Documented any/all year-to-year changes in its input-variables
- Clearly identified and justified adjustments to any/all raw data
- Provided advanced insight and data to ensure efficient review during the integrated resource planning process

Minnesota Power's on-going commitment to refining its load forecast is acknowledged by the Department on page 16 of their Initial Comments. In the Department's recommendations specific to its analysis of the Company's energy and demand forecasts, the Department states, "Minnesota Power has continued to work on improving its sales and peak demand forecast since it previous IRP filing. In the resource plan, the Department's analytical approach is typically geared more towards range estimates and risk analysis as opposed to point estimates, which is the primary tool in a proceeding such as a general rate case. As a result, the Department concludes that MP's forecasts are satisfactory for IRP planning purposes and recommends their approval." LPI did not comment on Minnesota Power's load forecast.

The CEOs took issue with the Company's load forecast in Initial Comments, although Minnesota Power did not find any material critique of the load forecast process. The CEOs did not identify specific deficiencies in the forecast development process and prescribe alternative methods, nor did the CEOs rebut the quality of the regression models on the basis of any statistical metric. The focus of the CEOs Initial Comments are on a perceived inadequacy of Minnesota Power's forecast models that is discussed on page 12, section 2.D., titled "Minnesota Power's Regression Models Cannot Be Relied Upon for Long-Term Projections of Sales." The sole basis for this assertion provided by the CEOs is that "Shifts in key drivers […] suggest […] that the Company's regression models cannot be relied upon for long-term projections of sales." The CEOs do not develop or expand on this argument.

Minnesota Power does not agree with the CEOs' inference that "shifts in key drivers" impact the validity of the forecast. There is no justifiable reason that models, and the key drivers included in those models, should remain unchanged over time. As stated previously, the Company uses commonly-agreed upon best practices in econometric load forecasting that include:

- Avoiding use of insignificant variables (indicated by a P-value > 0.1) in load forecast modeling;

  > *E.g. If a Utility reconstructs the previous year's model (2014), adds 12-months of new historical data to the regression, and finds that one key driver is now insignificant as a predictor, the 2014 model is eliminated from consideration for use in the 2015 forecast.*

- Using only the demonstrably superior model to forecast load;

  > *E.g. If a Utility manages to identify an alternative to the previous year's model (the 2014 model) that is objectively better by all statistical measures, the Utility uses the statistically-superior alternative model in a 2015 forecast.*

- Evaluating models based on statistical quality and reasonableness of the outlook, as opposed to keeping the models unchanged from year to year.

> *E.g. If a Utility reconstructs the previous year's model (2014), adds 12-months of new historical data to the regression, and finds that this model now produces an unbelievable forecast (e.g. 7% per year growth in residential usage), the Utility eliminates the 2014 model from consideration for use in the 2015 forecast.*

The recommendation by the Department to approve Minnesota Power's forecast as presented in the 2015 Plan, and the absence of strong, statistical justification to substantiate the CEOs' position as to why the AFR2014 models and AFR2015 models must contain identical inputs or else be considered unreliable, provides support for the validity and reliability of the Company's load forecast. The Company remains open to continued evaluation of other statistical methods that can be proved as best practice for econometric forecasting and will continue to enhance its processes as new practices are demonstrated that increase performance of its outlooks.

B. Power Supply

Through Minnesota Power's *Energy**Forward*** strategy, the Company is planning for and making progress towards achieving an energy mix of approximately one-third renewable resources such as wind, wood, water and solar, one-third natural gas/other and one-third coal for its long-term position. Diversification of the Company's fleet is already well underway, with much of the progress attributed to the smooth evolution away from coal at its small coal plants, concurrently with the successful implementation of its cost-effective renewable plans, including contracting for, constructing and placing into operation over 600 MW of wind, and securing 383 MW of hydroelectricity from Manitoba Hydro. Additionally, Minnesota Power has developed a portfolio-based solar strategy that will position the Company to be in compliance with the SES in 2020. To replace the reliable, non-intermittent coal-fired generation available to serve customers, Minnesota Power has been evolving the timing and need to incorporate a natural gas CC resource into its power supply portfolio.

For the 2015 Plan, Minnesota Power again strived to create a Preferred Plan that contains robust power supply actions to position its customers for the industry transformation ahead, while shielding them from unnecessary reliability and cost risk. The Company's planning process evaluates and compares various outcomes with a series of sensitivity impacts. A four-step planning evaluation was used to arrive at the operational strategy for each generating facility, and to find the best resource alternatives to augment the Company's power supply for long term customer requirements.

There are many industry changes that are underway and the integrated resource planning process in Minnesota gives stakeholders an opportunity to learn more about the drivers and impacts to Minnesota electric customers of the evolving power supply. Minnesota Power's resource portfolio has been under a significant transformation as communicated and approved through its last three integrated resource plan filings. Based on review of the Initial Comments, Minnesota Power provides additional information and clarification on the following energy resources: small coal, wind, natural gas, and solar.

Small Coal

THEC1&2 Operation & Environmental Compliance

In Initial Comments the Department and CEOs recommended that THEC1&2 be shut down earlier than 2020. Additionally, the CEOs made several statements regarding THEC1&2's ability to comply with environmental standards and permit requirements over the next five-year period during idle status. In the following section Minnesota Power will reinforce the benefits economic idling of THEC1&2 brings to customers, clarify how operations at THEC1&2 will change once the facility is idled in October 2016, and respond to the statements made regarding environmental compliance.

Planning for a smooth evolution away from coal at its small coal facilities is an important part of the Company's *Energy**Forward*** strategy. By optimizing the timing and opportunities at each of its facilities, Minnesota Power is taking its next steps in this transition. As part of this transition, the Company plans to idle THEC1&2 in the near term, take advantage of trends in lower cost replacement energy supplies from wholesale markets, and cease coal-fired operations at the facility by the end of 2020. Minnesota Power's 2015 Plan analysis identified that allowing THEC[1] to be a flexible resource as it transitions off coal is the most economical plan for

[1] Specifically units 1 and 2 of THEC. Unit 3 ceased coal-fired generation as of June 2015.

customers.[2] Further, the CPP, prior to the Supreme Court stay, has identified that the first regulatory compliance period would start as early as 2022, giving support for Minnesota Power's evaluation that in the near term THEC can continue to provide benefits to customers and the rest of the region as a viable, environmentally compliant generation facility. The optimization of the resource and near-term idle will begin in October 2016, and reduce facility output and emissions, while at the same time allowing it to remain available to regional markets on a seasonal basis for reliability to generate electricity.[3] The Company's recommendation to cease coal-fired operation at the facility by the end of 2020 will be well in advance of regulatory compliance targets being set by the CPP, providing additional reductions in the carbon profile for Minnesota Power customers and allowing the transition to more permanent power supply replacement with the Manitoba Hydro power purchase and new natural gas resource.

Under the economic idling, Minnesota Power will offer THEC into the annual Midcontinent Independent System Operator ("MISO") Capacity Auction for the 2016/2017 planning year in March 2016. The Company will continue to offer THEC into each subsequent Annual Capacity Auction for planning years 2017/2018, 2018/2019 and 2019/2020. If THEC is selected as economical in the capacity auction, Minnesota Power will offer THEC into the energy and ancillary market if the units clear MISO's Annual Capacity Auction for that planning year. If THEC is not selected, the facility will be placed in long-term cold and dry lay-up status. A modest fuel supply will be preserved on site in the event that Unit 1 and/or Unit 2 are restarted to address reliability or system emergency needs. Additional fuel can be delivered to the site if necessary based on the anticipated period Unit 1 and/or Unit 2 are expected to operate. With appropriate notice from MISO, trained staff will temporarily transition from their current assignments back to THEC and prepare the unit(s) for operation.

It is difficult to predict if the units will be required to restart to address reliability or emergency needs on the transmission system. Outside of a system emergency need, Minnesota Power anticipates the greatest potential for the units(s) to be called upon to support system reliability is during the summer peak demand period.

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[2] See Section IV, pages 49-54, of the 2015 Plan (Docket No. E015/RP-15-690).
[3] Facility staffing will be reduced and call back and start up procedures will be in place to accommodate the need for plant operations.

When called upon to provide system reliability or respond to emergency needs, THEC1&2 will operate with emissions well-controlled. The Company completed significant environmental upgrades on THEC1&2 to control oxides of nitrogen (“NO_x”), sulfur dioxide (“SO_2”), particulate matter (“PM”) and mercury emissions as a part of Minnesota Power’s Arrowhead Regional Emissions Abatement (“AREA”) environmental retrofit project. The AREA environmental retrofit at THEC1&2 resulted in NO_x emissions reduction of approximately 60 percent, SO_2 reductions of approximately 45 percent (from controls and new low-sulfur coal supply), and mercury reductions of up to 90 percent. In 2014, a Direct Sorbent Injection system (“DSI”) was also installed on THEC1&2 to meet the Mercury and Air Toxic Standards Rule. The system injects sodium bicarbonate into the flue gas stream ahead of the electrostatic precipitator to further reduce SO_2 emissions and hydrochloric acid emissions. The DSI is working effectively; final design sodium bicarbonate injection rates are now stabilized and producing the desired emission reductions.

Minnesota Power is compliant with its current Title V operating permit and is working with the Minnesota Pollution Control Agency (“MPCA”) toward issuance of a revised permit which will include an updated permit limit consistent with the Environmental Protection Agency’s (“EPA”) 2010 1-hour SO_2 National Ambient Air Quality Standard (“NAAQS”). Once issued, the Company will comply with the limit. Official modeling approved by the MPCA demonstrates that THEC models compliance for the 1-hour SO_2 NAAQS. Minnesota Power conducts the required monitoring of SO_2 emissions at THEC1&2, an Acid Rain Program electric generating unit, through the use of SO_2 continuous emissions monitors. Stack testing for SO_2 emissions is not typically required for units continuously monitoring SO_2. Based on past investments in emission control technology on THEC1&2, current compliance with existing standards and permit requirements, and on-going dialogue with the MPCA on pending permit updates, the Company is confident that when called upon to provide system reliability or respond to emergency needs, THEC1&2 will operate in compliance with all regulations and permits, including the 1-hour NAAQS.

Although the Department states in Initial Comments “that the overall best plan clearly involves shutting down Taconite Harbor units 1 and 2 early” [2017], Minnesota Power is confident that the decision to idle THEC1&2 while preserving its energy and capacity availability will provide optionality for Minnesota Power's customer portfolio in 2017 through 2019, as the region continues to transform its power supply and regional reserve margins decline. Idling THEC1&2 allows the flexibility to leverage the low regional energy market pricing, resulting in projected power supply cost savings for customers ranging from $29 to $43 million. Being able to call back THEC1&2 into service will maintain the capability to respond to regional reliability requirements, recognizes the new carbon emission compliance targets in place, and allows consideration of a refuel or remission opportunity in 2020 which the Department's recommendation to shut down the facility in 2017 doesn't address. This idling action could provide a valuable resource option, considering the substantial energy transformation underway across North America. Minnesota Power considered various options at the facility as part of its 2015 Plan analysis, including refueling with compressed natural gas or torrefied wood. Future refueling and remission opportunities will be considered in planning and optimization of the facility for Minnesota Power's next resource plan.

Through the shutdown alternative comparison performed as part of the 2015 Plan analysis, Minnesota Power identified that there are significant consequences with a near-term shutdown of THEC including community and regional impacts of losing a key industrial facility, and additional transmission requirements to maintain reliable electric service. The Company provided as part of its 2010 and 2013 integrated resource plans[4] insight that clarified the complexity of implementing a shutdown at a baseload generation facility. A three to five year timeframe has been identified as reasonable for generator shutdown to allow for necessary coordination with the associated processes of each entity.[5]

The transmission and distribution evaluation determined the impacts of having THEC1&2 removed from the bulk electric system near Schroeder, Minn., where the facility is located.[6] The results indicated a THEC1&2 shutdown scenario would create transmission reliability concerns in the area, and require two sets of transmission projects to ensure the electric service to Minnesota Power customers is maintained. Set one would be required at the time of shutdown with the Company's current system configuration, and set two is related to new load

[4] Docket No. E015/RP-09-1088 and Docket No. E015/RP-13-53.
[5] See page 18 of Appendix J in the 2015 Plan.
[6] The results of this study are available in Appendix F of the 2015 Plan.

growth being projected in the region.[7] The estimated costs for the transmission projects are **[TRADE SECRET DATA EXCISED]**. These transmission requirements require adequate time for planning, coordination with load additions and implementation. Should these transmission projects be delayed, the ability to restart THEC Units 1 and/or 2 may be required for reliability purposes. The transmission costs and implementation were included in the Company's analysis.

The socioeconomic impact of a closure of THEC1&2, while not included as a direct cost to the THEC1&2 shutdown alternative, is a significant consideration when evaluating the future of these facilities. The valuation study[8] conducted by Minnesota Power for the 2015 Plan emphasized that these generating facilities provide significant benefit to the communities and surrounding region through tax payments, employment and vendor utilization. The valuation study found that closure of the THEC facility (economic idling and/or permanent shutdown) results in the loss of nearly 40 jobs and the associated support roles throughout the local region and creates a three percentage point increase in unemployment almost immediately for the area. The resulting loss of revenue and wages contributes to $36 million in loss each year for the area after the closure. The Company will continue to consider future refueling and remission opportunities for the facility to produce electricity that are in the best interests of Minnesota Power customers, and also economically benefit the communities and surrounding region.

In summary, THEC1&2 and the broader THEC facility benefits Minnesota Power customers and the region in which it is located. Idling THEC1&2 allows the flexibility to thoughtfully transition the facility away from coal, while at the same time reducing overall emissions and customer costs and assuring bulk system reliability, and position Minnesota Power to address the CPP compliance target of 2022.

[7] Appendix F outlines the transmission mitigation identified for the region. Minnesota Power will be entering into the MISO Attachment Y2 process to gain additional confirmation about reliability impacts of a potential shutdown of the facility by 2020. However, additional remission and refuel evaluation will be done during Minnesota Power's next resource plan to confirm final facility transition plans.
[8] The valuation study is included in Appendix M.

Wind

The Department recommends Minnesota Power add 300 MW of new wind generation around 2018, along with an additional 100 MW of new wind generation at the end of the useful life of the BEC1&2 in 2023. With its current wind portfolio at 600 MW which has led to 25 percent renewables ten years ahead of the RES (renewable energy standard) requirement, Minnesota Power's Preferred Plan did not recommend wind additions in this timeframe and through its analysis identified there are two primary factors that influence the economics of adding wind to the Company's power supply: 1) inclusion and timing of a carbon dioxide ("CO_2") regulation penalty, and 2) estimated wind project cost. In general, among all the sensitivities ran wind was shown economical more often for customers when there was a mid-CO_2 regulation penalty or greater or at the lower range of wind cost considered.

In December 2015, nearly three months after Minnesota Power filed its 2015 Plan, the United States Congress passed an omnibus spending bill that included a provision to extend the expired Federal Production Tax Credit ("PTC") for five years, creating additional economic incentives to consider more wind. Stakeholders communicated that the extension of the PTC should create an additional push to add wind onto the power system, with near-term pricing reductions that may not be available later. Minnesota Power recognizes that there are certain conditions where additional wind generation shows an economical benefit for customers and does not dispute the near-term industry trends. For Minnesota Power, the near-term concern for adding 300 MW of wind to its customer's power supply is that the additional wind energy is not required to meet customer requirements in the near-term and additions prior to 2022 would result in a large excess of energy in the supply portfolio, and create large annual energy liquidation resulting in additional customer power supply costs.

New wind additions typically create value for customers by reducing the need for market purchases and higher-cost generation. There may be some excess energy created during a wind addition, however, when the majority of the wind is going to serve a customer requirement the excess energy plays a smaller role and does not impact the resource decision. The potential for a 300 MW wind addition to create an excess of energy for Minnesota Power customers in the near-term is demonstrated in Figure 1 and Figure 2. Figure 1 is the energy position that is created with Minnesota Power's Preferred Plan as presented in the 2015 Plan, and Figure 2 is the energy position for the Preferred Plan with 300 MW of wind added in 2018. The MISO market purchases decrease from 6 percent in the Preferred Plan to 4 percent when 300 MW or 1.2 million MWh of new wind is added in 2018, however, the 2 percent decrease in market purchases represents only 350,000 MWh of new wind energy being used to meet customer requirements and the remaining 850,000 MWh is excess energy in the portfolio. In essence, if Minnesota Power added 300 MW of wind, about 70 percent of the energy would be liquidated at times when customers could not use it, creating a large, unnecessary cost risk for customers.

The presence of excess energy on the system from large amounts of wind is viewed positively as long as the excess energy can generate adequate revenue to offset the cost of building the new resource and deliver benefit to customers in the near-term. This is the premise of the 300 MW modeling exercise and where the revenue generated from the excess energy drives the value of the resource for customers.

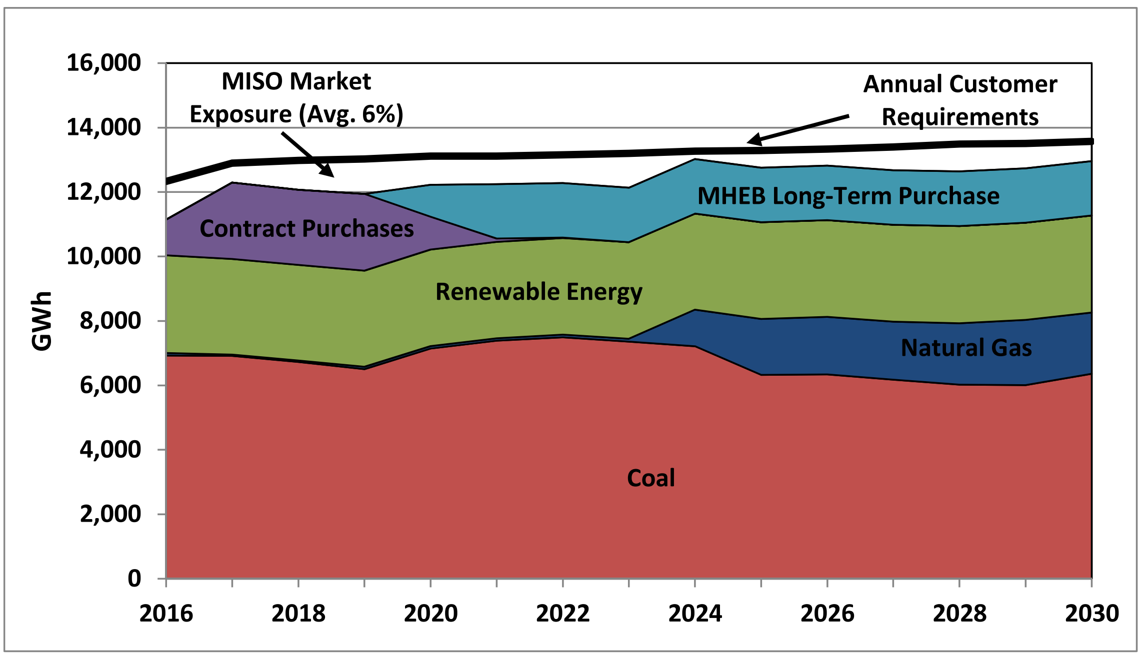

Figure 1 - Preferred Plan Energy Position Outlook

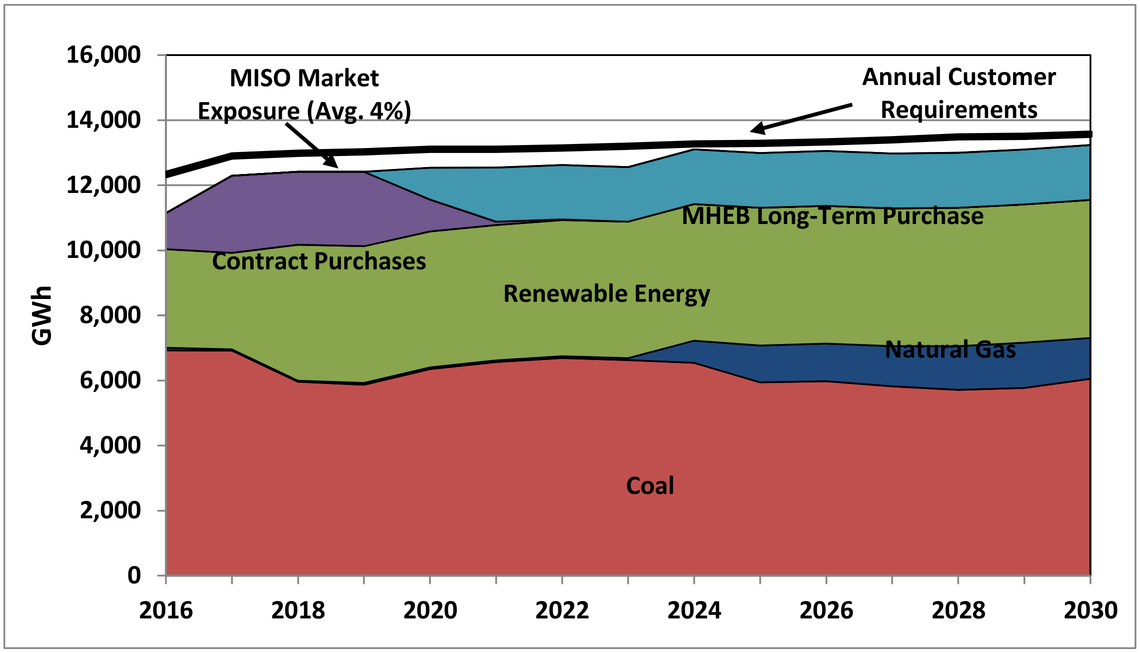

Figure 2- Preferred Plan with 300 MW Additional Wind Energy Position Outlook

If the excess energy is unable to generate enough revenue in the energy markets, customer costs will increase due to the wind additions, especially if natural gas and energy market prices remain suppressed. As demonstrated in Table 1, when wholesale market energy prices remain around \$20/MWh to \$30/MWh (Low and Lower Wholesale Market sensitivity from Minnesota Power's analysis) adding additional wind is a cost to customers. Based on current outlooks, the near-term markets are not elevated to support enough revenue generation from the excess energy created from 300 MW of wind, and the carbon regulation penalty may or may not be present depending on the outcome of the Minnesota SIP for the CPP.

Table 1 - 2015 NPV of Preferred Plan Cost with Additional 300 NW Wind

		2015 NPV of Power Supply Cost From 2018-2022	
Strategist Sensitivity Number	Sensitivities	Preferred Plan	Preferred Plan w/ 300MW Wind 2018 @ \$35/MWh
0	Base	\$ 2,304	\$ 2,306
0	CO2 Penalty in 2019 \$21.50/ton	\$ 2,694	\$ 2,654
17	Lower Wholesale Market	\$ 2,207	\$ 2,244
18	Low Wholesale Market	\$ 2,266	\$ 2,284

Excess energy in the Company's energy portfolio aside, the renewed competiveness of wind generation due to the extension of the PTC is generating a limited time opportunity for access to very low-cost wind resources. These wind resources could provide an energy hedge for customers in the future when the resource may be needed for customer requirements due to CPP compliance, continued transformation of power supply, over forecasted energy conservation program performance, and potential for new load growth on the system.

Minnesota Power recognizes the uncertainty of the energy industry at the time of filing these Reply Comments, and the planning analysis referenced above identified approximately 350,000 MWh of wind would match with customer requirements without large amounts of excess energy being generated. As part of a balanced supply that includes backing a growing reliance on intermittent generation with flexible and efficient natural gas in its long-term plan, the Company agrees that investigating 100 MW of new wind power supply could be beneficial as part of its short-term action plan to capture the benefits of the current low-cost wind pricing. Utilizing its Preferred Plan and updating it to add 100 MW of new wind in 2018, there is a potential benefit for customers with and without a carbon regulation penalty.

Table 2 - 2015 NPV of Preferred Plan Cost with Additional 100 NW Wind

		2015 NPV of Power Supply Cost From 2018-2022	
Strategist Sensitivity Number	**Sensitivities**	**Preferred Plan**	**Preferred Plan w/ 100MW Wind 2018 @ $35/MWh**
0	Base	$ 2,510	$ 2,506
0	CO2 Penalty in 2019 $21.50/ton	$ 2,954	$ 2,933
17	Lower Wholesale Market	$ 2,400	$ 2,410
18	Low Wholesale Market	$ 2,467	$ 2,470

Minnesota Power will continue to evaluate the customer impacts of adding additional wind above 100 MW in the 2018-2022 timeframe as part of its ongoing power supply planning. The timing and size of subsequent wind farms will be dependent of the State's plan for complying with the CPP and the EPA's approval of the SIP.

Natural Gas

Minnesota Power's Baseload Diversification Study, 2013 Plan and the 2015 Plan, along with the Department's own analysis, consistently show that natural gas CC generation has a place in the Company's long-term power supply to serve its customers. The benefits to customers of diversifying the power supply with natural gas generation are clear. Through its evaluation, Minnesota Power and the Department identified up to 400 MW of natural gas additions in the post-2022 time period to replace retiring small coal generation (BEC1&2), and augment a growing customer base and renewable portfolio.

Natural gas fits well with Minnesota Power's growing mix of intermittent generation like wind and solar. Natural gas is a flexible, fast-acting resource that can be present to deliver energy when wind and solar are not available. As Minnesota Power has incorporated significant wind resources into its portfolio (over 600 MW in total) and is growing its solar portfolio, the addition of this more flexible technology is sensible and timely.

The prevalence of the CC technology over the range of expansion plans evaluated solidified the resource selection for Minnesota Power's long-term action plan. In order to prepare for the implementation of a resource of this magnitude, specifically when considering a partial participation in a larger, more efficient facility for the 2024 time period, initial exploration of available CC resource options needed to begin. The resource investigation began in October 2015 with the issuance of a Request for Proposal ("RFP") for up to 400 MW of CC natural gas generation, commensurate with its short-term action plan outlined in the 2015 Plan.[9] The RFP process was widely communicated and advertised thru industry forums[10] and will identify CC power supply options available for the 2024 time period to ensure adequate time for identification, selection and development.

To add a new natural gas resource to the power system is a lengthy process; the planning, design, contracting, environmental, transmission additions and regulatory approval quickly add up to a six to eight year process. With the transformation taking place in the industry, Minnesota Power determined it was necessary to begin its natural gas investigation to ensure it could gain access to a new larger CC facility by 2024. Actual resource additions will vary based on continued updates to customer load outlooks and availability of competitive opportunities. The

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[9] The expected implementation time frame for a large efficient CC facility is five to seven years. Permitting, and coming to agreement on a partial ownership share of a facility also adds time to the procurement process.

[10] Minnesota Power employed the following best practices for communicating power supply RFP: sequential advertisement in Platts Megawatt Daily , submitted to exploders for North American Electric Marketing Association (NAEMA) and over 400 industry development entities, as well posted the RFP on Minnesota Power's company website.

addition of a natural gas supply to Minnesota Power's energy supply portfolio will be subject to further Commission approval once a specific resource has been identified.

Solar

Minnesota Power outlined a broad solar strategy utilizing its customer, community and utility focus through which the Company will leverage multiple sizes and types of solar energy to meet the projected requirements. This approach was supported in the Department's Initial Comments and is designed to meet the estimated SES requirement in 2020.[11] In 2016, Minnesota Power will embark upon its first utility scale solar opportunity and begin installation of its Commission approved 10 MW solar array at Camp Ripley, near Little Falls, Minn.[12] The Company has also brought forward for Commission consideration a unique community solar garden pilot program[13] to augment its successful individual customer solar incentive programs already in operation. In total, Minnesota Power is estimating 33 MW of solar resource additions, as part of its strategy to meet and sustain the 2020 requirement.

Minnesota Power recognizes that solar technology is continuing to become more efficient, and costs are declining. At the right cost level, additional solar could begin to show a benefit to customers in the expansion planning process. Minnesota Power will continue to evaluate new solar technology trends in future resource plans to identify when it will augment its power supply with additional solar.

In implementing the next phase of Minnesota Power's solar energy strategy to continue progress towards meeting the Minnesota Solar Energy Standard in 2020, the Company will initiate an open, non-site specific competitive acquisition process for additional utility scale solar to serve its customers. Also, as the Company's proposed community solar garden subscriptions sell out, additional solar gardens will be developed and offered to customers. Minnesota Power will continue to monitor available solar technology and resource options as part of its least cost supply planning, and reflect its findings in the Company's next integrated resource plan.

[11] Docket No. E999/M-15-462.
[12] Docket No. E015/M-15-773 approved on February 24, 2016.
[13] Docket No. E015/M-15-825.

C. Clean Power Plan Compliance (Commission Staff Information Request No. 7)

Commission Staff requested in its January 27, 2016 information request No. 7 that Minnesota Power provide in its Reply Comments 1) discussion on "how the EPA, for Clean Power Plan (CPP) compliance, could treat emissions reduction differently depending on whether the Boswell1&2 units are retired, refueled with natural gas, or replaced with a new natural gas combined cycle unit[;]" and 2) "the Company's perspective on its position to comply with the interim CPP requirements when they begin in 2022."

Of note, on February 9, 2016, the Supreme Court issued a stay, halting implementation of the CPP, subject to further judicial review. While the implications of this unprecedented action are yet to be determined, Minnesota Power's *Energy**Forward*** resource strategy positions the Company well for whatever ultimate regulations are promulgated at the federal level and implemented in Minnesota.

CPP compliance for affected electrical generating units ("EGUs") is based on several factors and processes which are currently being defined, specifically the development of Minnesota's SIP. The SIP will encompass the program and guidelines for Minnesota that will ultimately meet the state specific requirements starting sometime in 2022 or beyond. While the CPP provides a framework for how states might achieve carbon reduction measures, and includes different options for potential treatment of units, it ultimately relies upon state action for implementation and affords each state broad latitude in how they might choose to implement carbon reductions. States can use the framework within the CPP, and the EPA associated model trading rules and Federal Implementation Plan ("FIP"), when constructing a SIP. At this point, Minnesota has not announced any definitive plans for how it might construct a SIP, but has announced its intention to develop a SIP.

Minnesota's final SIP, due in September 2018 (or later, pending the recent Supreme Court stay and associated legal proceedings at the D.C. Circuit Court of Appeals) is anticipated to contain the treatment options for all EGUs, including THEC1&2, BEC1&2, BEC Unit 3 and BEC Unit 4 ("BEC4"). Therefore, the following scenarios are based solely on the Company's current understanding of the federal rules and that the rule could change significantly as a result of court action. It is important to note that the state has yet to indicate whether it intends to regulate carbon under the CPP via a mass-based approach (total tons per year) or a rate-based approach (pounds of carbon per megawatt-hour). It is also possible that Minnesota could choose not to submit a SIP, or could submit a SIP deemed wholly or partially unacceptable by the EPA, and subsequently be subject to a FIP.

Retirement:

Should BEC1&2 and THEC1&2 be retired, the carbon allowances (mass-based system) could be retained by Minnesota Power and banked, sold, or used for compliance purposes within its system. The length of time those allowances would remain in Minnesota Power's possession is currently unknown and will remain so until the SIP process is complete. Those allowances might also be surrendered to the state. In either scenario, the carbon emission reductions associated with retirement would likely be subtracted from Minnesota's overall annual emission budget.

Under a rate-based system, the amount of carbon generated from these units would be subtracted from numerator of the overall pounds in the CO_2/MWhr rate-based equation.

Refueling with Natural Gas

Assuming the refueling action would not require modification to the facility that would classify the boilers as new units; the refueling option would likely see the continued inclusion of BEC1&2 in the current affected EGU category under section 111(d). Carbon emissions would be counted against the current mass-based budget, or factored into the numerator in the CO_2/MWhr formula for determining statewide carbon emission rates. As a natural gas unit the emission profile would be far less carbon intensive and Minnesota would see an overall reduction in CO_2.

Replacement with new Natural Gas-fired Combined Cycle ("NGCC") unit

Replacing the current BEC1&2 boilers with a new NGCC unit could be treated several ways, depending on the final regulatory structure of Minnesota's SIP. Since new units are typically regulated under 111(b), which contains specific New Source Performance Standards ("NSPS") for new gas units, including carbon emissions, the new NGCC could be regulated as a 111(b) unit and is exempt from the CPP. In that scenario, it would need to meet the NSPS standards for carbon emissions, which typically achievable with today's NGCC technology.

However unlikely, the SIP could elect to include new units in the 111(d) carbon emission budget under a "new source complement". The primary purpose behind including new units (111(b)) with existing (111(d)) units would be to address "leakage"; i.e., using this inclusion as a mechanism to discourage incentivizing power producers to switch from existing sources to new gas sources. Should Minnesota choose to include new units in 111(d) regulation under a new source complement, emission from that unit(s) would be counted against the annual tonnage limit.

Minnesota Power's long-term action plan includes a new natural gas power supply by 2024, and it is assumed the federal plan should regulate these sources under 111(b), and exclude new units from the CPP/111(d) regulation.

Position to Comply in 2022 and Beyond

Minnesota Power has made significant strides to reduce its carbon emissions in the past decade (Section IV, Page 75) including addition of the Bison and Taconite Ridge wind farms, large turbine efficiency upgrades at BEC, the conversion of Laskin Energy Center to a natural gas unit, and the retirement of Taconite Harbor Energy Center Unit 3. The Company also continues to reduce its off-take from Milton R. Young 2 ("Young 2") lignite coal generating station in North Dakota from over 400 MW originally to 227.5 MW in 2009, and by 2026 Minnesota Power will no longer take any of the Young 2 output for its customers. Additionally, Minnesota Power's plan to idle THEC's coal operations in 2016 and cease coal operations by 2020 at the facility, and the planned delivery of carbon-free hydropower via the Great Northern Transmission Line ("GNTL"), are further reducing carbon emissions. Minnesota Power has taken action to timely address environmental regulations and strongly position its customers for compliance with the EPA's CPP.[14] The Company expects a 90 percent reduction in air emissions and 30 percent reduction in greenhouse gas emissions by 2025, from 2005 levels, with the 2015 Plan short- and long-term action plans proposed.

At this time, the Company's ultimate compliance position will be dependent on the compliance framework within the SIP. Decisions on rate vs. mass programs, treatment of new units, renewable set-asides, credit for renewable and efficiency actions between 2005 and 2012,

[14] See http://www2.epa.gov/cleanpowerplan/clean-power-plan-final-rule.

and allocation methodology can all fundamentally affect compliance for generation resources, and at this time are unknown. Minnesota Power has been actively involved in the MPCA's CPP stakeholder process, and has clearly communicated the need for the SIP to reflect the considerable investments by customers in reducing carbon intensity since 2005, both with achieved and planned actions.

Ultimately, the CPP compliance may require additional carbon reductions prior to the first compliance period, during the first, second or third compliance periods, or it may not require additional actions at all. Minnesota Power will actively participate on behalf of its customers in the Minnesota SIP development and stakeholder process to help ensure that the customer investments to date are not lost and are accounted for in order to help remove the need to "redouble its investment" and increase customer costs.

D. Plan Costs

As explained in the 2015 Plan, the rate estimates provided in Appendix L: Cost Impact Analysis By Customer Class should be used as guideposts on cost and rate impact rather than viewed or used as ultimately determinative calculations on customer rates. The estimated rates may not correspond with actual rates that the Commission sets for various rate classes. In developing the estimates, numerous simplifying assumptions have been made in both the calculation methodology and the input variables, and these assumptions naturally cause imprecision in the estimates. Long-term resource planning is inherently uncertain and, therefore, causes additional uncertainty in the resulting rate impacts. As a planning tool, the 2015 Plan is not necessarily meant to provide accurate rate projections for a specific year, but rather an overall magnitude of rate changes over a longer time period. In comparing the projected compounded rate increase over the planning period between the 2013 Plan and 2015 Plan, the overall trend for the large power class is consistent.

As requested, Minnesota Power is clarifying why the 2017 rates for the large power class increased by $2.65/MWh when compared to the rates shown in the 2013 Plan. As can be seen below, the 2017 rates have two components – the average current rate and the 2015 Plan rate increase. Comparing the components from the 2015 Plan and 2013 Plan, it can be seen that the 2015 average current rate increased by $5.21/MWh and the resource plan component decreased by $2.56/MWh, for a total increase of $2.65/MWh. The $5.21/MWh increase in the average current rate is explained by the change in the rider rates and the change in the Fuel & Purchase Energy ("FPE") adjustment that are added to the base rates to estimate the current average rate. The rider rates include Minnesota Power's current cost recovery riders (Renewable Resources Rider, Transmission Cost Recovery Rider and the BEC4 Emission Reduction Rider). In the 2013 Plan rate impact analysis, the rider rates were based on calendar year revenue requirements. The rider rates in the 2015 Plan were refined to reflect what the large power customers would likely pay on a cash basis on their bills in 2015. Because the anticipated cost recovery rider factor increases did not occur in 2013 and 2014, this resulted in higher increases in 2015 and thus higher average current rates. In addition to the change in rider rates, there was a small increase in the FPE Adjustment that is estimated by comparing the total average cost of fuel and purchased energy that was included in Minnesota Power's last rate case to the current year budgeted costs.

As the Company explained in its Reply Comments in the 2013 Plan (page 28),[15] while the preliminary cost estimate for the GNTL was included in the 2013 Plan evaluation and as part of its expansion plan estimates, it was not included in the detailed rate impact analysis due to the fact that the detailed cash flow estimate for the Project was too preliminary at the time the 2013 Plan was developed, and the Company anticipated the vast majority of these costs would occur later than the five-year rate impact (2013-2017) provided in the 2013 Plan. As explained in Appendix L (page 2) in the 2015 Plan, the Plan power supply costs include the revenue requirements associated with GNTL, and the Company also included an adjustment in the rate impact analysis to include the revenue requirements of all other projects in the Transmission Cost Recovery rider that were known at the time of Minnesota Power's 2015 Plan filing. It is also important to note that the change in the current rider rates described above was not impacted by GNTL in either 2013 or 2015.

As can be seen, there was a decrease in 2017 of $2.56/MWh in the 2015 Plan power supply costs when comparing the 2013 Plan and 2015 Plan. There are several factors for the decrease in total power supply cost between the 2013 Plan and 2015 Plan, which can be divided into three categories: market outlooks, thermal fleet transition and capital project cost. In general, the market outlooks for fuel have decreased slightly from the 2013 Plan resulting in

[15] Docket No. E015/RP-13-53.

lower power supply cost. The recommendation of idling THEC1&2 results in a decrease in power supply cost. Lastly, the projected capital cost for Minnesota Power's existing thermal generation decreased due to taking into consideration the expected life of each unit when projecting the projects required for continuing to operate these facilities reliably in the future. In addition, there was a significant decrease in the expected capital costs of the BEC4 Environmental Retrofit Project.

Table 3 - 2017 Rate Increase Comparison

		2017
2015 IRP	Large Power (2015 average current rate, $/MWh)	59.95
	2017 IRP Increase ($/MWh)	8.34
	Total 2017 Rate	68.29
2013 IRP	Large Power (2013 average current rate, $/MWh)	54.75
	2017 IRP Increase ($/MWh)	10.90
	Total 2017 Rate	65.64
	2015 IRP - 2013 IRP	
	Change in Large Power Average Current Rate, $/MWh)	5.21
	Change in 2017 IRP Increase ($/MWh)	-2.56
	Total Change ($/MWh)	2.65
	Change in Average Current Rates	
	2015 Rider Rates ($/MWh) - Cash basis	9.291
	2013 Rider Rates ($/MWh) - Revenue requirements basis	4.165
	Change in Rider Rates ($/MWh)	5.13
	2015 FPE Adjustment ($/MWh)	-0.450
	2013 FPE Adjustment ($/MWh)	-0.530
	Change in FPE Adjustment ($/MWh)	0.08
	Total Change	5.21

E. Conservation

Minnesota Power presented multiple scenarios regarding energy-savings as part of its 2015 Plan and provided cost assumptions for achieving every 0.1 percent of savings above 1.5

percent of non-CIP-exempt retails sales.[16] In arriving at these scenarios and cost assumptions, careful consideration was given to historical performance, contributory success factors, potential for future energy-savings, and rate impact. In addition, program cost trends were considered on both a national and state level.[17] As part of its Preferred Plan, Minnesota Power included an energy-savings assumption well above the energy-savings goal of 1.5% established in CIP statute.[18] This will require additional investment in CIP and the Company will take the recommendation into consideration in the creation of its upcoming 2017 – 2019 Triennial Plan. As will be communicated further in this section, Minnesota Power is not comfortable with a long term resource planning assumption of 76 GWh of energy savings being present. Programs need to further demonstrate their sustainability without the aid of large projects that have been elevating savings levels in recent years. The costs presented by Minnesota Power in the scenarios are indicative of those seen for residential and small to mid-sized commercial sector projects. In order to achieve higher savings levels, more savings from these sectors will be needed, particularly the small to mid-sized commercial sector. This involves increased outreach, program administration, and likely higher incentive levels to encourage program participation.

Minnesota Power is in the midst of preparing its 2017-2019 Triennial Plan. While many of its existing programs are anticipated to continue in some form, Minnesota Power projects that more commercial and industrial program elements that target smaller scale prescriptive projects than have been experienced in prior program years will be needed to achieve energy-saving targets. To augment program design, a Demand Side Management ("DSM") alternative potential study has been commissioned. This segment level analysis will explore savings potential by eligible customer segment and program/measure to help identify effective delivery strategies from both a savings and cost perspective. Another important planning consideration involves the energy efficiency measures to include. To that end, Minnesota Power appreciates the continued efforts of the Department's technical staff to establish and update a Technical Reference Manual

[16] Order Point 12d of November 12, 2013 Commission Order Approving Resource Plan, Required Filings, and Setting Date for Next Resource Plan, Docket No. E015-/RP-13-53.

[17] Multiple sources including - E-Source: DSM Achievements and Expenditures 2013 Research Results; LBNL. 2014. The Program Administrator Cost of Energy Saved for Utility Customer-Funded Energy Efficiency Programs; EIA data for 2013; 2013-2015 Massachusetts Joint Statewide Three-Year Electric and Gas Efficiency Plan; ESP Reporting tool, Minnesota Department of Commerce.

[18] Minn. Stat. §216B.241, Subd. 1c(b), "Each individual utility and association shall have an annual energy-savings goal equivalent to 1.5 percent of gross annual retail energy sales unless modified by the commissioner under paragraph (d). The savings goal must be calculated based on the most recent three-year weather normalized average."

(TRM) that can be used for program design and planning. As Minnesota Power strives to meet the energy-savings goal in the years ahead, it is helpful to have a robust resource that provides guidance regarding standards for measuring, evaluating, and reporting energy savings and cost-effectiveness; allows utilities to leverage third-party engineering expertise; and provides a guidebook and "menu" of savings opportunities that have been vetted through a Department-led process. As Minnesota Power has stated, portfolio design will evolve as programs mature. Factors such as technology mix, comprehensiveness, target markets, and new program/product introduction, in addition to regulatory or industry factors such as measurement and verification standards, accepted measure lives for different technologies, and codes and standards are all changing and evolving faster than ever in today's energy-efficiency environment.

The Company recognizes that the costs in the presented scenarios, which range from \$0.17/kWh to \$0.23/kWh for first year savings, are a departure from its experienced historical costs on a per kWh basis, which have ranged from \$0.08/kWh to \$0.11/kWh for first year savings. They are, however, well within range, and still lower than, the costs and trending seen in other utility portfolios, which can range as high as \$0.40/kWh or greater.[19] As a more recent reference, according to the E-Source: DSM Achievements and Expenditures 2014 Research Results, "utilities spent an average of \$0.26 per annual kWh saved. The cost of reducing electric energy consumption varies widely, but nearly all utilities spent less than \$0.50 per annual kWh….The median expenditure, \$0.23, is close to the average, which means that most utilities spent considerably less than the maximum value."

While Minnesota Power appreciates the optimism expressed by parties in terms of continued performance at the high levels demonstrated in recent years, it remains Minnesota Power's view that those savings levels, and the related costs per kWh for first year savings, are not indicative of achievable planning goals. The Department's recommendation of 76.5 GWh is aggressive and significantly beyond the energy-savings goal established for utility CIPs. To that point, in its Comments, the Department "concedes that it is difficult to project whether MP will be able to sustain high energy savings levels." Minnesota Power agrees. Historical performance does not assure future results. While savings at or near the Department's recommendation have been achieved, this has been an exception and not a year over year performance trend. Actual

[19] According to E-Source: DSM Achievements and Expenditures 2013 Research Results, per kWh costs range from \$0.07 to \$1.27 per annual kWh saved.

program results are contingent on customer actions and their decisions to participate in conservation program offerings. The Department notes that the Commission will be re-evaluating Minnesota Power's energy-savings goal in its next resource plan approximately two years from now. In the meantime, Minnesota Power will be putting forth its 2017-2019 CIP Triennial Plan. As Minnesota Power is already including energy-savings above the established goal for CIP, it is the Company's recommendation that any furtherance of that goal from a planning perspective be revisited as part of the next resource plan review. Insights in the interim regarding program design, costs and participation will help to further inform that review.

As referenced in Appendix B, Figure 1, program results for Minnesota Power have had a particularly heavy weighting toward large customer projects. As an illustrative example, approximately five large projects represented 40% of claimed savings in Minnesota Power's highest energy-savings achievement year. These projects have significant economies of scale compared to other energy-savings opportunities included in Minnesota Power's broader CIP portfolio. Savings contributions from these projects unduly skew results and should be normalized to some degree for planning purposes, particularly given the limited number of eligible customers large enough to have projects of this scale or magnitude.[20] It is true that, in large part due to these projects, Minnesota Power has achieved energy savings at costs below state and national electric utility industry averages. As the Department correctly notes in its Comments, "it is evident that the large projects allow MP to realize a much better cost per kWh when they are factored into the cost analysis. The Department concludes that it would be reasonable to start with a range of historical costs that both includes and excludes these large projects."[21] While backing out these projects will provide some insight, it does not fully address the question of what it would cost to deliver similar savings levels without large projects.

As part of its planning for conservation programs, Minnesota Power conducts benefit/cost analysis of programs from multiple perspectives, including but not limited to societal, utility and ratepayer impact. Minnesota Power appreciates the Department's comments about rate impacts and acknowledgement of analysis indicating that most energy savings projects don't pass the ratepayer impact test. In addition to this broader analysis, consideration of current cost recovery

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[20] Exemptions from CIP were approved during the historical reference period, meaning additional projects with these customers are not eligible under CIP statute, Minn. Stat. §216B.241.

[21] Comments of the Minnesota Department of Commerce, page 47; Docket No. E015/RP-15-690, January 4, 2016.

is also important as program portfolios and related budgets are established. Cost recovery for CIP occurs through a conservation cost recovery charge (CCRC), as established during a retail rate case, and conservation program adjustment (CPA) factor, as proposed and approved during annual CIP reporting. As a point of reference, for the current portfolio, the combined cost recovery factors would equate to \$0.0024/kWh.[22] Using the expanded conservation program scenarios, from a current cost recovery perspective, this could equate to as much as \$0.0059/kWh. While the benefits of CIP over the long term arguably outweigh the costs, these metrics remain important considerations for effective program design.

Minnesota Power has demonstrated its commitment to energy efficiency, exceeding the 1.5% goal since 2010 with increased investments, resources and proven program delivery strategies. Sustaining savings level at or above the 1.5% target will be even more challenging in the years ahead. Thoughtful inclusion of long-term conservation savings increases in resource planning, as recommended in its Preferred Plan, will allow the resource planning process to maintain a balance of encouraging conservation and maintaining a reliable resource supply. Minnesota Power looks forward to working with the Department and others on how best to meet that challenge while balancing intended objectives with both customer costs and value.

[22] This is not inclusive of the DSM shared savings financial incentive, which is currently undergoing review in Docket No. E,G999/CI-08-133. This performance-based incentive is in reference to Minn. Stat. §216B.241, subd. 2c and Minn. Stat. §216B.16, subd. 6c, as most recently approved on December 20, 2012. Minnesota Power has expressed the importance of balancing intended objectives of the financial incentive with both customer costs and value. The merits and rationale for the financial incentive mechanism are best addressed by the Commission in the financial incentive review.

III. Summary

Minnesota Power's 2015 Plan, the next chapter in the Company's *Energy**Forward*** resource strategy, continues to transform the Company's power supply from a predominantly coal-based energy mix to one that is more diverse, while maintaining low cost, reliable electricity for customers. The 2015 Plan is designed to supply Minnesota Power customers with a safe, reliable, and affordable power supply while improving environmental performance, reducing emissions, sustaining the Company's high-quality energy conservation program and adding renewables in the near-term and natural gas in the long-term. Minnesota Power will continue on with the core foundation of the 2015 Plan in its next integrated resource plan which the Company recommends the Commission require be submitted December 1, 2018. Minnesota Power appreciates the opportunity to provide reply comments and looks forward to working with Commission Staff, the Department, LPI, CEOs and other stakeholders throughout the remainder of the regulatory review process.

Dated: March 4, 2016

Respectfully Submitted,

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STATE OF MINNESOTA	)	AFFIDAVIT OF SERVICE VIA
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COUNTY OF ST. LOUIS	)	FIRST CLASS MAIL

Susan Romans, of the City of Duluth, County of St. Louis, State of Minnesota, says that on the **4th day of March**, **2016**, she filed Minnesota Power's Reply Comments in Docket No. E015/RP-15-690 on the Minnesota Public Utilities Commission and the Minnesota Department of Commerce via electronic filing. The remaining parties on the attached Official Service List were served as indicated.

Susan Romans

Susan Romans

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