Direct Testimony
David H. Sederquist

Before the North Dakota Public Service Commission
State of North Dakota

Northern States Power Company — Case No. PU-12-813
2013 Electric Rate Increase Application

Northern States Power Company — Case No. PU-13-706
Advanced Determination of Prudence – Courtenay Wind Project Application

Northern States Power Company — Case No. PU-13-707
Advanced Determination of Prudence – Odell Wind Project Application

Northern States Power Company — Case No. PU-13-708
Advanced Determination of Prudence – Pleasant Valley Wind Project Application

Northern States Power Company — Case No. PU-13-742
Advanced Determination of Prudence – Border Winds Project Application

Northern States Power Company — Case No. PU-13-743
150 MW Border Winds Project – Rolette County
Public Convenience and Necessity

Northern States Power Company — Case No. PU-13-194
Advanced Determination of Prudence – NG Generators Application

Northern States Power Company — Case No. PU-13-195
Red River Valley NG Units 1 & 2 – Hankinson, ND
Public Convenience and Necessity

Northern States Power Company — Case No. PU-15-96
Advance Determination of Prudence – 345 Mankato Energy Center Application

Negotiated Agreement

Exhibit__ (DHS-1)
November 30, 2015

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I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND OCCUPATION.

A. My name is David Sederquist. I am a Senior Regulatory Consultant with Northern States Power Company (Xcel Energy or NSP) in Fargo, North Dakota. I am responsible for NSP's regulatory affairs in the State of North Dakota. I have held positions relating to NSP's North Dakota operations for 22 years.

Q. HAVE YOU PREVIOUSLY PROVIDED TESTIMONY IN THIS PROCEEDING?

A. Yes, I provided testimony in support of the Comprehensive Agreement filed on December 13, 2013. The Comprehensive Agreement set forth guiding principles and a timeline for future generation resource recovery negotiations that would lead, ultimately, to the submittal of this Negotiated Agreement.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. I describe the terms of and provide support for the Negotiated Agreement (Agreement) reached between NSP and Advocacy Staff of the North Dakota Public Service Commission. I will describe the key provisions of the Agreement and provide perspective on how we landed on these provisions. I will also explain why the Agreement provides value for our customers in North Dakota and addresses some of the Commission's important policy concerns.

Q. DO YOU HAVE ANY PRELIMINARY COMMENTS YOU WANT TO MAKE ABOUT THE AGREEMENT?

A. Yes I do. I'd like to start by saying that back in December of 2013 when the Staff and NSP committed to the effort of developing a regulatory framework that would result in electric generation costs being reflective of the Commission's policy preferences, we had a very ambitious vision. Today, we remain committed to such a resource framework, but we have become much more attuned to the difficulties in balancing the requirements – and benefits – of an integrated system with meeting the policy requirements of the states in which we operate.

That said, we submitted an Agreement on September 30th that maintains our momentum toward what we are referring to as a long-term Resource Treatment Framework (RTF). In doing so, the Agreement focuses primarily on a solution for treating *existing* generation resources that the Staff flagged during our last rate case as not being consistent with North Dakota energy policies. As a result, this Agreement resolves some of the longstanding Commission concerns about the prudence of legacy wind and solar resources that came about through policy objectives in Minnesota but were recovered in North Dakota to date, and it also creates the path and commitment for the Company's first investment in thermal generation in North Dakota in many decades.

Developing an approach to selecting future energy resources that is responsive to differing state energy policies has been – and will continue to be – a complex and measured effort. In that regard, I'd like to acknowledge the patience, flexibility, and constructive approach demonstrated by

Advocacy Staff throughout this process of reinventing a different framework to jurisdictional resource planning and cost recovery. They have been receptive to the weighty challenges we have come up against, but have continued to be engaged and offer ideas while remaining true to their and the Commission's original objectives.

II. PROVISIONS OF THE AGREEMENT

Q. WHAT ARE THE KEY ELEMENTS OF THIS AGREEMENT?

A. If approved by the Commission, this Agreement will result in the following:

- *By the end of 2025, Xcel Energy will build or have located in North Dakota a natural gas-fired electric generation facility with a capacity of at least 200 MW:* The Company commits to accelerate by 11 years its Comprehensive Settlement (Case No. PU-12-813) commitment to construct, by 2036, an NSP System thermal generating plant in North Dakota. Our revised 2015 Resource Plan points to the need in the early to mid-2020's for additional capacity, and our preliminary analysis shows that a plant in eastern North Dakota could be reasonably cost-effective and enhance the reliability of the NSP System and more specifically, its North Dakota service territory.
- *The additional costs of 17 existing power purchase agreements (PPAs) will no longer be recovered in North Dakota:* In recognition that the energy policies in other states in which Xcel Energy operates have and may continue to diverge from the energy priorities of North Dakota, the Negotiated Agreement provides for the exclusion of certain Community-Based Energy Development (CBED) and small solar PPAs from the Company's North Dakota Fuel Cost Rider (FCR). This provision recognizes that

these resources were planned and selected to meet commitments and requirements established in and for the state of Minnesota. This provision also acknowledges that, while the Commission initially allowed the costs of these relatively small projects to be recovered in NSP's North Dakota rates, over time the number and impact of these projects on North Dakota rates has grown to a material level and, given that the aggregate effect conflicts with North Dakota's energy policies, the premium costs (approximately $1.6 million beginning in 2016 and a total of approximately $19 million through 2030) will be removed from rates.

- *The costs of six key biomass energy contracts will continue to be recovered in North Dakota:* In the Comprehensive Settlement, six baseload-type biomass resources from which NSP purchases energy and capacity were identified as potential PPAs for exclusion. Given the close ties these resources have with the approval of additional nuclear fuel storage – and the continued operation of the Company's low-cost Prairie Island units – Staff has agreed to allow the continued recovery until the terms of these PPAs expire.
- *The Company's current rate case moratorium will be extended an additional year:* In the Comprehensive Settlement, a four year rate plan was approved which included annual base rate increases of 4.9 percent in 2013, 2014, and 2015, and a rate freeze in 2016. If approved, this agreement will extend the freeze through 2017. As a result, NSP will not be allowed to increase base electric rates (on an interim or final level) before January 1, 2018.
- *Commission Staff will support NSP's continued use of a 12 Coincident-Peak system allocator through 2025 for the purpose of assigning production and transmission costs to its three NSP operating company jurisdictions:* This Comprehensive Settlement called for an in-depth study of the method alternatives for

allocating the costs of the integrated NSP System (generation and transmission) costs to its state jurisdictions. The study was conducted by a third-party consultant (the Brattle Group) under the direction of both Parties to the Settlement, and submitted to the Commission on April 27, 2015. This Agreement applies the results and recommendations of the study to the positions taken by Advocacy Staff and NSP in any applicable electric rate proceedings initiated prior to December 31, 2025.

- *Development of a Resource Treatment Framework*: Recognizing that the other terms of the Negotiated Agreement do not fully resolve the issue of divergent state energy policies on a going-forward basis, we are obligated to file with the Commission a RTF that will propose how to address this issue into the future.

Q. WHAT WILL BE THE IMPACT OF THIS AGREEMENT ON NORTH DAKOTA ELECTRIC RATES?

A. The immediate effect of the Agreement will be to decrease overall electric rates by approximately $1.6 million in 2016. It will also prohibit an electric base rate increase until at least 2018. Finally, the Agreement requires that the combustion turbine we committed to be located in the state be treated as an NSP System resource; this means the costs are to be allocated to all states and customers served by the NSP System, as is customary. As a result, approximately 5 percent of the project costs will be assigned to North Dakota customers (subject, of course, to any provisions of a future approved RTF that may modify this arrangement).

Q. SINCE THIS AGREEMENT FOCUSES PRIMARILY ON HOW TO TREAT CERTAIN *EXISTING* GENERATION RESOURCES THAT STAFF IDENTIFIED AS NOT REFLECTIVE OF A LEAST-COST, NEED-BASED PLANNING APPROACH DOES THE AGREEMENT ADDRESS THE TREATMENT OF *FUTURE* RESOURCE ADDITIONS IN ANY WAY?

A. Yes it does, and mainly in two ways. First it identifies the reasons why the Parties to this Agreement believed it prudent to first address the treatment of existing resources and provide additional time for the more difficult task of developing an overall, long-term RTF. Second, it identifies a potential timeline for the RTF; a due date for filing the proposal of January 1, 2017, 8 to 10 months in 2017 for the Commission to conduct their review, and a proposed implementation date of January 1, 2018.

Q. WHY DIDN'T THE PARTIES INCLUDE AN RTF, OR LONG-TERM SOLUTION, IN THIS AGREEMENT?

A. There are primarily two reasons why. First, there is considerable future uncertainty in the energy industry. This stems mainly from the evolving utility landscape we are facing and emerging Federal environmental requirements such as the Environmental Protection Agency's (EPA) Clean Power Plan. In addition, there are – or may be – differing state environmental regulations as well. Moreover, NSP's baseload generation fleet will be changing dramatically in the next 10-20 years. Even the Midcontinent Independent System Operator (MISO) is contemplating changes to how it defines its load zones and determines its adequacy requirements. There are many moving parts and they all give us good reason to pause as we consider how to construct a new regulatory paradigm for approving resources in the future.

Second, in the many months we have been working on this issue we have learned much about the significant complexity in designing a framework to meet the unique energy policy preferences of the various states we serve while maintaining a multi-state, integrated system. Though it was our goal from the start, it became more and more evident that it was simply not feasible to adequately address the myriad of issues in time to meet the filing deadline for this Agreement. More time to analyze different options and assess the cost/benefit ratios of those options was, and is, clearly needed.

III. THE PATH TO THE AGREEMENT

Q. PLEASE DESCRIBE THE PROCESS THAT RESULTED IN THIS AGREEMENT.

A. Once the Commission approved the Comprehensive Settlement in Case No. PU-12-813, we, along with Staff, began in earnest to explore options for addressing the impact of divergent state energy policies, wherever they may occur, on electric rates in our system footprint. A team was commissioned to draw upon various areas of Company and outside expertise to brainstorm various framework alternatives, what steps would need to be taken and in what timeframe, and what potential obstacles there would be to implement each scenario.

Q. WHAT FRAMEWORKS WERE CONSIDERED?

A. The most serious consideration was given to the following ideas:

1. *States ensure full cost recovery for resources that they direct Xcel Energy to acquire and/or otherwise approve.* This would entail a process whereby there is assurance at the front end of the resource approval process that the full capacity, energy, any environmental attributes, and related cost recovery of prospective

resources being approved or directed in certain states be assigned and accepted only in those approving states for planning, accounting, and ratemaking purposes.

2. *Uneconomic resources are repriced in those states relying on least-cost selection criteria.* In this approach, NSP would use a "least cost proxy" to reprice, for ratemaking, future resource additions whose selection is not approved by the reviewing state commission.
3. *Employ a Pricing Zone concept.* This would entail establishing separate pricing zones for North Dakota and the remainder of the integrated NSP System. This would allow for our North Dakota customers to be served by generation resources that were consistent with the Commission's policy preferences, our North Dakota customers would no longer be directly served by the integrated NSP System.
4. *Restructure Xcel Energy to facilitate more state autonomy in selecting resources.* With this approach, a separate operating company subsidiary of Xcel Energy would be established to serve our North Dakota loads and better facilitate separate regulatory processes and power contracting that would comply with each states' energy preferences. This approach would take the pricing zone concept one step further to legally separate our North Dakota operations from the NSP-Minnesota company and the integrated NSP System..

None of these outcomes have advanced much past the conceptual stages, but the discussions that ensued over many months regarding how to address the impact of divergent state energy policy on each states' rates also involved Xcel Energy's senior management team. It has been an important and strategic issue at the highest levels of our company.

Q. WHY WASN'T NSP ABLE TO DEVELOP A FRAMEWORK OUT OF THE FIRST APPROACH THAT YOU MENTION?

A. Establishing a process for this "front end" understanding would be very difficult without additional time. Our review of the regulatory processes in place today in each state, and the complexity of trying to coordinate them in a way to achieve full accord - or even understanding of the impact on customers - among the affected states on each and every resource decision led us to see that such a process really requires a "regional" regulatory approach to resource selection and approval. The various forms of regulatory approval needed in each NSP state would have to be closely aligned so as to ensure commission procedures were fairly consistent and made on a similar timeframe. There would also need to be an ability for states or Xcel Energy to reopen dockets to consider the subsequent decisions made by the other state commissions. Even if it were feasible for us to bring about a more consistent set of state approval processes (which would involve various regulatory rule reforms and passage of new legislation), this approach has the potential to create long regulatory delays, more litigation, and increased costs.

In summary, while this path shows some promise over the long term, there is significant interjurisdictional coordination that would be required as well as the need to address the appropriate approval procedures in each state going forward.

Q. WHY HASN'T NSP BEEN ABLE TO FURTHER DEVELOP THE REPRICING APPROACH?

A. At first blush, this method does appear to be quite feasible and actually formed the basis of the Comprehensive Settlement's "Restack" concept. But as with many things, the devil is in the details. The first complication is getting agreement about how to reprice the capacity and energy components of the resource. To determine a least-cost proxy price, does one use existing generation assets, rely on some MISO benchmark, or construct a theoretical generation resource? Should the proxy be updated every year to reflect new technical developments or economic realities? These are only two questions of many that need to be answered and agreed upon.

And, again, what about the administration and accounting needed to track each and every repriced PPA and/or generation addition that comes down the road? You can imagine the complexity and detail in tracking the various fixed and variable costs throughout the operating or contract lives of the affected resources, to say nothing of the impacts to the ratemaking process.

These illustrate some of the technical challenges, but ultimately there is another over-arching problem with this approach: Xcel Energy would rarely, if ever, be able to fully recover its cost of service without full inter-jurisdictional coordination to ensure costs not recovered through a repricing approach are recovered in the cost-causative jurisdiction.

Q. WHAT IS THE "PRICING ZONE" ALTERNATIVE, AND WHY HASN'T THAT BEEN MORE FULLY DEVELOPED?

A. This concept would essentially remove the generation component of our service to North Dakota customers from the integrated NSP System. Under this approach, our North Dakota customers would be served by resources selected only for North Dakota and approved by the Commission. These resources would be appropriately sized for a 500-600 MW utility. As older units on our NSP System are gradually retired and replaced, our North Dakota customers would not participate in their replacement but instead a North Dakota-specific resource would be acquired to replace the North Dakota share of the retired capacity.

The Parties spent considerable time discussing, at a high level, this concept. We intend to continue analyzing this concept as we work through developing an RTF. However, we are concerned that this approach could be detrimental to North Dakota customers as they lose the benefits inherent in the integrated NSP System.

Q. FINALLY, PLEASE COMMENT ON THE ALTERNATIVE OF RESTRUCTURING XCEL ENERGY.

A. Generally speaking, establishing a separate operating company (OpCo) for the Xcel Energy's North Dakota operations would, in fact, help to resolve a number of regional regulatory coordination issues that a multi-state utility like NSP must deal with. It would also facilitate the negotiation of separate power supply contracts and arrangements for our North Dakota operations, much like a wholesale supply contract to a municipality or another utility company. However, the process for establishing a North Dakota OpCo is expensive and very time-consuming as it involves a number of federal and state approvals, the renegotiation of many supplier and affiliate contracts and agreements, certificate transfers, and other significant transactions. I think it would be fair to characterize this option as a "last resort" given the magnitude of effort and cost, and its "finality". The Company has hopes that a simpler and more flexible framework can be developed. However, as we work through the RTF we want to keep this option available.

Q. IF XCEL ENERGY REALIZED LAST SUMMER THAT THIS AGREEMENT WOULD NOT INCLUDE A MORE COMPLEX LONG-TERM RTF PROPOSAL, WHY DID YOU NEED TO REQUEST A THREE MONTH EXTENSION OF TIME TO FILE WITH THE COMMISSION?

A. In early June of this year, negotiations between the parties led to a very promising verbal agreement that would resolve, in a fairly efficient manner, how to treat the existing renewable PPAs listed in the Comprehensive Settlement identified by Staff as "uneconomic" resources needing to be repriced. The key to this verbal "agreement in principle" was Xcel Energy's offer to consider accelerating its 2036 commitment to build a North Dakota thermal generating plant to as early as 2020.

Up to this point in time, much of the discussions had focused on proxy pricing concepts and ways in which Xcel Energy could migrate its North Dakota system to be more "stand alone" in terms of the Commission being able to influence the types of future energy resources added to meet North Dakota load growth and replace retired plants. But the verbal agreement reached in June narrowed the focus to the ratemaking treatment of the existing renewable PPAs listed in the Settlement and how to frame the commitment to locate a plant in North Dakota. Even so, it was evident that more time would be needed for us to explore various thermal plant options. It was the need for due diligence on this effort that prompted our request for more time to file the Agreement.

Q. WHY DID THE GENERATION COMMITMENT CHANGE FROM 2020 IN YOUR JUNE VERBAL AGREEMENT TO 2025 IN THE FILED AGREEMENT?

A. There were two primary reasons for this change. First, the Company's concerted efforts in July and August to investigate potential generation investments and structures in North Dakota soon revealed that the logistics of determining an investment structure, siting the plant, arranging for its fuel supply and interconnection, and completing construction simply could not be accomplished by the end of 2020. Second, during the summer we had already begun to make sizeable investments toward the 200 MW combustion turbine planned and approved for our Black Dog site and that we would move ahead on the installation of the Black Dog unit first as the most cost effective resource available to meet needs prior to 2025. Staff was amenable to 2025 as the "outside" target date so we agreed to that. Mr. Haeger discusses the need drivers around the 2025 date.

Q. ARE ANY OF THE LONG-TERM ALTERNATIVES YOU'VE DISCUSSED HERE CONSIDERED TO BE "OFF THE TABLE" AS FAR AS FUTURE DISCUSSIONS AROUND AN RTF GO?

A. No, I don't think so. Mr. Clark discusses the Company's openness to all solutions for an RTF. But the challenges posed by each of them – as well as the uncertainties of the evolving utility landscape, including environmental regulations and generation technologies – provide good justification for not rushing to include a framework for long-term, forward looking proposals in this Agreement. The Negotiated Agreement requires us to continue to work on developing an RTF in 2016 and file a future-looking proposal with the Commission by January 1, 2017. I might add that, until and unless an RTF has been approved, the Commission retains its ability to review (and reject) resources proposed by NSP. We acknowledge that the current status quo may be unsustainable and, therefore, moving away from the current status quo provides incentive for Xcel Energy to develop and propose an appealing long-term solution through the RTF.

IV. BENEFITS OF THE NEGOTIATED AGREEMENT

A. Commitment to Build Generation in North Dakota

Q. WHAT IS THE VALUE OF NSP'S COMMITMENT TO ADD DISPATCHABLE GENERATION IN NORTH DAKOTA?

A. I see our commitment to locate dispatchable thermal generation in the state as a door-opener for future investment by the Company in the state's robust energy industry. Depending on the ultimate size and scope of the plant, once it is built Xcel Energy will have invested nearly $1 billion in low-cost North Dakota generation and transmission assets during the most recent fifteen years, including almost $600 million in new wind generation.

Infrastructure build-out can lead to more economic activity and more infrastructure build-out. I can envision that a plant or large energy park in eastern North Dakota could act as a catalyst for one or more natural gas supply lines from the west to the east, which of course could help the economic development efforts of a number of small communities along the route. Such a new pipeline would have a favorable impact on the economics of converting the plant at some point in the future to a larger and more efficient combined-cycle facility.

We have seen how a generating plant of this type and the enhanced reliability it brings is an enticement to national businesses looking to locate new and large manufacturing, data processing, or food processing facilities in North Dakota. I can envision that such a plant could be expanded in the future as a competitive, brown-field resource option similar to the advantageous economics of Calpine's Mankato Energy Center. And of course, all of these possibilities bring to North Dakota additional jobs, economic growth, and new tax revenues.

Q. IS NSP'S COMMITMENT TO CONSTRUCT THERMAL GENERATION IN EASTERN NORTH DAKOTA CONDITIONED?

A. To an extent, yes. As with any generation development, we must obtain all necessary permits and approvals to construct the plant. And even if we assume that all North Dakota regulatory and local zoning approvals will be granted, our other state jurisdictions, in particular Minnesota, have regulatory processes that require us to obtain their approval prior to adding resources to our system.

Q. HOW WILL THE COMMISSION HAVE ASSURANCE THAT XCEL ENERGY WILL FOLLOW THROUGH WITH THIS COMMITMENT IF THESE CONDITIONS ARE NOT MET?

A. Staff was concerned about this and proposed, and we agreed, to subject to refund half of the revenues associated with the continued cost recovery of six biomass PPAs from 2016 through 2025. The refund is triggered if the plant is not in-service by December 31, 2025 without qualification (provided that we can always petition the Commission for an extension, or modification, if necessary).

B. Exclusion of Certain Renewable PPAs from Rate Recovery

Q. WHAT IS THE VALUE OF EXCLUDING 15 CBED PROJECTS AND 2 SMALL SOLAR PPAS FROM THE NORTH DAKOTA FCR?

A. We estimate that excluding these 17 PPAs from the monthly North Dakota Fuel Cost Rider (FCR) charge will reduce North Dakota customer energy costs starting at about $1.6 million in 2016.

Q. HOW ARE THE SIX BIOMASS PPAS LISTED ON ATTACHMENT E IN THE COMPREHENSIVE SETTLEMENT BEING TREATED?

A. The Company will continue to include these costs in its FCR as they have been since these resources went into production on various dates from 1994 to 2009. As such, there will be no future incremental increase in North Dakota electric rates as a result of these PPAs.

Q. WHAT IS THE RATIONALE FOR HAVING NORTH DAKOTA CUSTOMERS CONTINUE TO PAY FOR THE BIOMASS RESOURCES?

A. These resources represent approximately 145 MW's of baseload-like power that have been a part of the NSP System, and recovered in North Dakota retail rates, for many years. The projects were developed and the power sold to Xcel Energy so NSP could comply with legislation passed in Minnesota in the early 1990's that also allowed us to temporarily store spent nuclear fuel at our 1,100 MW Prairie Island nuclear plant. Obtaining the certificate to store spent fuel at the site meant that we could continue to operate these units for an additional 20 years. The Commission has always supported our nuclear plants as they have been reliable, low-cost, and clean sources of power, and these PPAs are tied to our ability to continue to provide nuclear energy now and many years into the future.

C. Additional Year of Rate Moratorium

Q. WHAT IS THE VALUE OF ADDING ANOTHER YEAR TO THE CURRENT 2016 RATE MORATORIUM?

A. In Case PU-12-813 the Commission approved NSP's first 4 year "multi-year plan" (MYP) which established fixed percentage rate changes for each of 2013, 2014, and 2015, (4.9 percent, or about $10 million annually) and a rate "freeze" in 2016. It is somewhat difficult to be specific with respect to the financial impacts of adding another year to the moratorium given that we do not have a "rate case quality" forecast for 2017. However, it would seem reasonable to say that extending the freeze another year has the potential to save North Dakota customers millions of dollars in interim and/or final rate increases, not to mention the costs to conduct another rate proceeding in 2017. When the Comprehensive Settlement was submitted in 2013, we felt there was a reasonably good chance that we would need to prepare another rate case to file in late 2016 using a 2017 test year. With this agreement, however, NSP would defer such a filing another year.

D. Demand Allocator

Q. WHY IS THERE A PROVISION IN THE AGREEMENT THAT STAFF WILL SUPPORT USE OF THE 12CP DEMAND ALLOCATOR THROUGH 2025?

A. I believe Staff was comfortable with the findings and recommendations of the Allocation Study we filed with the Commission on April 27, 2015. The Study thoroughly evaluated a number of methodologies based on their representation of costs, stability, forecastability, simplicity, and overall system cost recoverability and we were both satisfied that the current methodology in place – that of the 12 coincident peak – was reasonably adequate for ensuring that North Dakota customers were paying their fair share of NSP's system generation and transmission costs.

In addition, both Parties agreed that establishing some regulatory certainty would help to mitigate the number of issues that the Commission and Company will need to address in the next 5-10 years.

Q. DOES THIS MEAN THAT THE COMMISSION IS PROHIBITED FROM ADDRESSING THE JURISDICTIONAL ALLOCATION ISSUE UNTIL 2026?

A. No, I don't believe that is what the Agreement calls for. Rather, the Parties are agreeing to both support use of the 12 CP method in any future rate filings through 2025. That doesn't preclude the Commission or other interested parties from reviewing or challenging its use in a future rate application.

E. Resource Treatment Framework

Q. HOW WILL AN RTF PROVIDE BENEFITS TO NORTH DAKOTA?

A. As I discussed earlier, the Negotiated Agreement provides needed time for the Parties to develop a workable RTF proposal, and requires NSP to file it by January 1, 2017. I am hopeful that an RTF will provide an equitable approach to resource selection for our state Commissions, Xcel Energy, and all of our customers.

V. CONCLUSION

Q. DOES THIS AGREEMENT PRECLUDE THE COMMISSION FROM DENYING FUTURE RESOURCES THAT IT DOESN'T CONSIDER TO BE LEAST-COST OR IN NEED?

A. No, there is nothing in the Agreement that binds the Commission from approving or rejecting future resources proposed in a request for an Advanced Determination of Prudence or included in a rate case test year.

Q. ARE THERE ANY CIRCUMSTANCES THAT WOULD RENDER THIS AGREEMENT NO LONGER IN FORCE?

A. The only circumstance would be the approval of a subsequent long-term RTF that re-addresses treatment of the existing PPAs referenced in this Agreement or over-lay other terms and conditions, such as the timing and treatment of the North Dakota thermal generation plant.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. This Agreement is beneficial to our customers, the state of North Dakota, and Xcel Energy as it 1) lowers our North Dakota customers' bills, 2) extends the current NSP electric rate freeze another year, 3) commits NSP to make a significant investment in a North Dakota generating plant to help meet its future system capacity needs, and 4) sets the timing for the establishment of a long-term Resource Treatment Framework to address in a more comprehensive manner the future rate and regulatory impacts of divergent state energy preferences and policies. For these reasons, I recommend the Agreement be adopted and approved.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes, it does.

STATE OF NORTH DAKOTA
BEFORE THE
PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF NORTHERN STATES POWER COMPANY FOR APPROVAL OF A NEGOTIATED AGREEMENT RELATING TO NORTH DAKOTA GENERATION RESOURCE POLICY

Case No. PU-12-813

STATE OF MINNESOTA)
) ss.
COUNTY OF HENNEPIN)

David H. Sederquist, being first duly sworn on oath, deposes and says that he is the Senior Consultant, Regulation and Finance for Northern States Power Company, a Minnesota corporation, in the above captioned matter, that he has read the testimony and schedules submitted in the above captioned matter under his name, that they were prepared under his direction, that he knows the contents thereof, and that the same is true and correct to the best of his knowledge and belief.

David H Sederquist
David H. Sederquist

Subscribed and sworn to before me this 20th day of November, 2015.

Janie Hogan
Notary Public
My Commission Expires: July 14, 2020

JANIE HOGAN
Notary Public
State of North Dakota
My Commission Expires July 14, 2020