Minnesota Public Utilities Commission

Staff Briefing Papers

Meeting Date: **March 10, 2016** .... Agenda Item # 2**

Company:	Xcel Energy
Docket No.	E002/M-15-330
	In the Matter of the Petition of Northern States Power Company for Approval of Cost Recovery of the North Dakota Share of the Aurora Distributed Solar Project
Issue(s):	Should the Commission grant Xcel's Petition, and approve recovery from Xcel's Minnesota-jurisdictional customers, the North Dakota jurisdictional share of the costs of the Aurora Distributed Solar Power Purchase Agreement?
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Background Documents

Xcel – Energy Petition for Cost Recovery.. October 20, 2015
Aurora Distributed Solar, LLC – Comments .... December 4, 2015
DOC DER – Comments .... December 4, 2015
DOC DER – Addendum to Comments .... December 8, 2015
Aurora Distributed Solar – Reply Comments .... January 8, 2016
Xcel Energy – Reply Comments.. January 8, 2016

Xcel's January 15, 2016 - Proposed Order in ND PSC (12-813) .... Attached

The attached materials are work papers of the Minnesota Public Utilities Commission staff. They are intended for use by the Commission and are based upon information already in the record unless noted otherwise.

I. Statement of the Issue

Should the Commission grant Xcel's Petition to approve cost recovery from Minnesota ratepayers of the (incremental) North Dakota jurisdictional share of the costs of the Aurora Distributed Solar Power Purchase Agreement?

II. Procedural History

On February 5, 2015, at the conclusion of the competitive resource acquisition process (CAP) docket, the Commission approved three proposals selected to fill the demonstrated capacity need on Xcel's system:[1,2,3]

1. the power purchase agreement (PPA) between Xcel Energy and Aurora Distributed Solar, LLC for 100 MW of distributed solar generation,
2. the PPA between Xcel Energy and Calpine Corporation for a 345 MW natural-gas-fired, combined-cycle generation, and,
3. price terms for Xcel Energy's Black Dog 6 proposal, 215 MW natural-gas-fired, combustion turbine generation.

Each of the PPAs contained standard contract language that if any state rejects advanced approval for cost recovery of the project (by dates certain), Xcel could terminate the contract. For purposes of discussion regarding the Aurora PPA, staff refers to the Aurora term as Condition Precedent 6.1.

Following the resource selection process, Xcel petitioned the Commission to approve cost recovery of the Minnesota-jurisdictional portion of the Aurora Solar Project from its customers under Minn. Stat. § 216B.1645, Subp. 1. This statute authorizes Xcel to seek from the Commission, first, a determination that an investment or expenditure is reasonable and prudent way to meet the state's Renewable Energy Standard (RES) or Solar Energy Standard (SES), and second, if determined reasonable, a determination that those costs can be recoverable through the fuel clause rider. Essentially, Xcel is able to obtain a favorable recovery mechanism for projects that are reasonable methods for meeting the RES or SES. The Commission found the Aurora project was a reasonable way to meet the State SES and approved Xcel's petition to recover MN-jurisdictional portion of the Aurora Solar project through the fuel clause rider.[4,5]

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[1] See the October 4, 2013 Commission Order Approving Plan, Finding Need, Establishing Filing Requirements and Closing Docket in Docket No. RP-10-825.

[2] See the May 23, 2014 Commission Order Directing Xcel to Negotiate Draft Agreements with Selected Parties in Docket CN-12-1240.

[3] Staff has included as an appendix, an overview on how need was determined in this docket, and is generally determined, to provide background on the status of need on Xcel's system.

[4] See the August 20, 2015 Commission Order Approving Power Purchase Agreement in this docket, M-15-330.

[5] At the time of Xcel's Petition for cost recovery of the MN portion, Aurora submitted a request for the Commission to also preemptively approve the ND-jurisdictional portion of the project.

At the time of the Commission's approval of the MN-jurisdictional portion of the PPA, Xcel's Advanced Determination of Prudence (ADP) for the Aurora project from the North Dakota Public Service Commission (ND PSC) was pending.

In light of the unique jurisdictional circumstances and the Condition Precedent 6.1, Xcel and Aurora (and its new parent company, Enel Green Power NA)[6] came to an agreement (Letter Agreement) that allowed the project to proceed to construction. In the Letter Agreement, dated August 12, 2015 – and attached to Xcel's Petition - Aurora agreed to reimburse Xcel for the North Dakota's jurisdictional share of the incremental project costs if the Minnesota Commission declines the Petition. Aurora argued the Letter Agreement was necessary to ensure the project could progress to construction (to meet a December 2016 in-service date) and meet other timelines. As a result of the Letter Agreement, Xcel Energy waived its right under Condition Precedent 6.1 of the PPA to terminate the agreement.

On September 16, 2015 the NDPSC determined that Xcel had *not* shown that the Aurora Solar PPA merits an ADP and therefore denied Xcel the advanced assurance of rate recovery and denied Xcel the ability to recover costs of the Aurora Project through its North Dakota Fuel Cost Rider. The ND PSC Aurora ADP Denial Order is attached to the DOC DER's Addendum Comments dated December 8, 2015, which is included as a relevant document to this brief.[7]

Following ND PSC's denial, on October 20, 2015, Xcel Energy filed with the Commission its Petition to recover the incremental North Dakota-jurisdictional costs from Minnesota ratepayers via Minnesota Fuel Clause Rider. In its Petition, Xcel outlines an incremental cost calculation method based on each jurisdiction's MWh sales. While each jurisdiction has a different fuel cost recovery mechanism, the jurisdictional shares are all based on the same monthly per unit system fuel cost.. The Petition is discussed in further detail in Section III. below.

Initial and reply comments were filed by Aurora Distributed Solar, LLC and replies from Xcel Energy requesting the Commission approve the Petition. Initial comments were filed by the Department of Commerce recommending the Commission deny the Petition (discussed further below).

III. Xcel's Petition for Cost Recovery of the ND-Jurisdictional Portion

On October 20, 2015, Xcel filed its Petition to recover (pursuant to Minn. Stat. § 216B.1645, Subd. 1) from Minnesota ratepayers the North Dakota share of the incremental cost for the Aurora Project. Incremental costs which parties believe are attributable to Minnesota policy.

[6] Enel Green Power North America purchased the project from Geronimo Energy. The Aurora Distributed Solar, LLC is now a wholly owned subsidiary of Enel Green Power North America.
[7] An ADP ensures Xcel that it will receive cost recovery from North Dakota rate payers; an ADP denial does not restrict the ND PSC from determining that the resource was a prudent acquisition in a future rate case.

Xcel's main points in its Petition were:

1) That (MN and ND) state energy policies are continuing to diverge which puts Xcel in a challenging position to move forward with resource additions without the assurance of cost recovery.
2) It is appropriate to deviate from traditional jurisdiction allocation methods when different states have divergent policy objectives. The Minnesota Commission has established past Commission precedent (2011 RDF Rate Factor Filing) that when Minnesota specific policies drive incremental costs, Minnesota ratepayers should bear those costs. [8]
3) The Aurora project was selected, in part, to meet Xcel's Minnesota mandated RES or SES and therefore 100% recovery from Minnesota is reasonable.
4) North Dakota in its Aurora ADP denial reinforced its position that it will not ask its ratepayers to pay for resource additions that are not consistent with North Dakota's (least cost) approach to resource planning.
5) The denial of the ND PSC's ADP and the Aurora project is not likely to be an isolated incident for resource needs identified in Xcel's 2011 Resource Plan (IRP) or its pending 2016 IRP as Xcel intends to add over 2,800 MW of thermal and 3,200 MW of renewable projects by 2030.
6) Aurora/Enel NA will reimburse Xcel for the North Dakota jurisdictional share of the incremental project costs if the Minnesota Commission denies this Petition.
7) Xcel believes that a project developer should not be required to cover costs of a project that is being developed to meet an identified resource need or to support Xcel's compliance with a Minnesota policy and agreements of this sort are not a sustainable solution to the issue of diverging energy policies.

Xcel outlined in its Petition its proposed calculation to determine the incremental cost of the Aurora Project. Xcel proposed to substitute a generic, ND PSC-approved resource in the place of the Aurora costs in the fuel clause rider calculation. The difference between the costs of the Aurora Project and the generic resource would be the costs reallocated to Minnesota ratepayers. As explained by Xcel in its Petition:

> If the Commission approves this proposal, we have a process to determine the monthly amount Minnesota would assume for North Dakota's share of the Aurora project. Currently fuel and purchased energy costs under the NSP System are shared by Minnesota, North Dakota, South Dakota, and the NSP-Wisconsin Company, based on each jurisdiction's MWh sales. While each jurisdiction has a different fuel cost recovery mechanism, the jurisdictional shares are all based on the same monthly per unit system fuel cost. This system platform ensures that the process of transferring costs from one jurisdiction to another is fair and transparent.

[8] See Commission's June 6, 2011 Order After Reconsideration Modifying March 17, 2011 Order and Reallocating Expenses in Commission Docket M-10-1054.

> The system fuel cost is calculated including all jurisdictions. After determining the baseline, another system cost is calculated by removing the generation resources disallowed by North Dakota and adding back replacement costs. The difference between these two systems costs, multiplied by North Dakota's MWh sales weighted as a percent of total system sales, constitutes the allocated fuel cost to be removed from the North Dakota monthly fuel clause recovery calculation. If the Company's proposal in this filing is approved, this amount will be recovered from the Minnesota fuel clause as a surcharge in the monthly true-up filed with the Commission.[9]

IV. Comments

Department of Commerce – Division of Energy Resources

The Department provided initial comments on the Petition and recommended the Commission reject Xcel's Petition. In support of their conclusion, the Department argued that the record which supported the Aurora project (the CAP docket) analyzed Xcel's system as a whole, not as a separate MN-only system, and therefore, there is no evidence that the Aurora project would (or would not) be a cost effective resource to meet the energy and capacity needs of only Xcel's Minnesota ratepayers.

The Department argued that since Enel NA already agreed to pay the incremental ND-portion of the project, a market based solution exists, and it would not be reasonable to require Minnesota ratepayers to bear those costs.

Additionally, the Department provided its analysis of the extent in which it views the Aurora Project as contributing to both Xcel's SES and its RES requirements and concluded that the Aurora Project has a minimal impact to Xcel's compliance with both Minnesota policies.

Aurora Distributed Solar, LLC

Aurora Solar provided comment noting the project's history, cited Commission's orders providing support for the project and recapped how Aurora had tried to address the cost recovery issue through the CAP docket and the Commission's subsequent Aurora PPA approval.

Aurora argued that the Commission's 2011 RDF allocation decision provided a sufficient basis to allocate ND's costs to Minnesota ratepayers as it was a Minnesota-based policy decision. Aurora provided that S-RECs that would have been used by ND could be used by MN and would further assist MN in meeting their SES goals. Additionally, Aurora argued that denial of the Petition would set precedent that could be detrimental to meeting the state's renewable energy goals and the Commission's competitive resource acquisition process in that it would increase uncertainty to developers.

[9] Xcel Energy, Petition Request for Approval of Costs, Docket No. E002/M-15-330, p. 8.

Last Aurora argued that it has taken extraordinary measures to preserve its contractual obligations in that it agreed to cover the costs of the ND portion if denied in MN. Aurora agreed with Xcel's statement that this arrangement would be likely never occur before the Commission.

Aurora asks that the Commission hold to the terms of the competitive resource acquisition process in that bidders are held to the estimates provided, and the Commission do the same.

Xcel Energy Reply

Xcel reiterated their Petition arguments in their reply comments.

In response to the Department's arguments about the CAP bidding process and the analysis conducted in that docket (conducted on a system-wide basis) Xcel argued that requiring a different bidding process based only on the energy and capacity needs of *Minnesota* ratepayers would be impracticable. Xcel argued that its integrated system planning approach is based on economies of scale and a well-balanced fuel source mix.

In response to a topic for comment listed in the Commission's October 27, 2015 Notice in this docket, requesting Xcel discuss the relevance of costs for generation sold into the wholesale market, Xcel noted that the Aurora PPA will be a retail asset and be treated as such for cost allocation. The energy from the Aurora PPA will serve the overall retail system, while the incremental cost of the North Dakota share that was disallowed by the ND PSC will be shifted to Minnesota. Because the incremental generation from the Aurora PPA could impact the aggregate wholesale purchases and sales revenues the Company makes and receives through the MISO market, Xcel believes the existing jurisdictional treatment of MISO purchases and revenues continues to be appropriate.

Xcel requested that the Commission grant its Petition as to not introduce additional risk to developers for cost recovery of renewable energy projects on Xcel's system. Xcel believes rejection would discourage future bids or incent developers to drive up their prices in order to cover the additional risk.

Aurora Reply

Aurora responded to the Department's main points. First, Aurora argued that there is no legal basis to support the conclusion that the Commission is not allowed to approve Xcel's Petition. However, in the inverse, there is precedent in the Renewable Development Fund docket which supports Xcel's proposed cost recovery method.

Second, the Commission's selection of the Aurora project clearly relied on factors other than the Department's Strategist and cost benefit analysis; therefore, the Department's argument that the CAP docket analysis only supports the selection of a system-wide resource is not supported. If the Department's argument would prevail, Aurora argued the CAP docket would be "undone by another state commission's decision to deny cost recovery." Aurora argued that Minnesota's system load is approximately 75% of the Xcel's total Midwest system, and a denial of Xcel's Petition would allow another state to essentially veto Minnesota Commission decisions.

Third, Aurora provided that its agreement with Xcel to cover the costs in the instance of a MN-denial of ND's incremental portion is not cause to deny the Petition. Aurora argued, among other points, that other market solutions exist, in that Xcel could have struck the Condition Precedent 6.1 of the PPA and not terminated the Aurora PPA, despite the denial by the ND PSC. Aurora provided that this issue is not unique to Aurora, as Calpine's Mankato Expansion project and the three solar PPAs approved by the Commission in March 2015 all contain the same provisions, but they have not yet been terminated by Xcel.[10]

Fourth, Aurora argued that the Aurora PPA will contribute to Xcel's compliance with the SES (and all solar projects have an incremental impact to the SES compliance, which is not unique to Aurora). Therefore the Department's argument that Aurora would not have a significant impact to Xcel's SES compliance is unfounded.

Fifth, Aurora argued that the Commission should take a broad look at this issue and the impacts its decision may have on Minnesota's competitive process – if unanticipated regulatory costs arising through no fault of the parties are shifted to the utility or developer.

V. Staff Discussion

Staff believes considerable weight should be given to the Department's recommendation, in part because ratepayers will be minimally impacted if the Commission denies Xcel's Petition as Enel has agreed to pay for the North Dakota share. Aurora and Xcel negotiated the Letter Agreement and proceeded with the project knowing the risk and cost associated with a potential Minnesota denial. As a matter of course and principle, staff supports all reasonable means to minimize ratepayer impacts.

To the argument that future competitive bidding processes will be permanently compromised if the Commission denies Xcel's Request, one could argue this claim is speculative and unsupported, and that the certainty of increased costs to Minnesota ratepayers outweighs the uncertainty of the effect on future acquisition proceedings. On the other hand, one could also reasonably argue that future competitive acquisition processes could be harmed if developers factor into their bids and terms the possibility that costs from various jurisdictions could ultimately be incurred.

[10] As Aurora noted, the Solar RFP has received a final-ADP denial by the ND PSC however the Calpine decision is pending and a final ND PSC vote is expected on March 9, 2016. During the ND PSC Work Session on the Calpine matter (Case File 15-096) in February 2016, ND PSC asked staff to draft an Order denying the facility (as not needed) for a final vote in March 2016.

However, staff agrees with Aurora and Xcel that the Letter Agreement is not in any manner a long-term solution. Staff is sympathetic to Aurora as the current state of the generation resource market in the Midwest has additional uncertainty that it has not had historically. All parties in this situation are in a difficult position in that:

1) North Dakota and Minnesota clearly have not only diverging state policies generally, but specifically, diverging policies on the procurement of new generation resources and on resource planning,
2) Xcel's NSP-MN system covers several states, and also interacts with its NSP-WI system,
3) Xcel established the Condition Precedent 6.1 (or similar) into its PPA contracts terms in which Xcel may terminate the PPAs if an individual state denies an advanced determination of prudence (or equivalent)[11],
4) the ND PSC has denied (or will likely be denying) ADPs on the basis of MN-policies and uncertainty (need, environmental regulations, among other reasons.), and,
5) Xcel's 2016-2030 Resource Plan (and its renewable-energy focus) amplifies the need to find a workable path through these jurisdictional issues.

Aurora preemptively asked the Commission to address Condition Precedent 6.1 at the time of the PPA approval and MN-jurisdictional cost approval, and the Commission did not address that request. Additionally, while Condition Precedent 6.1 was agreed to by both parties in PPA negotiations, the PPA negotiations could have likely stalled without agreement by Aurora to the Condition Precedent 6.1.

What would the Commission do absent a Letter Agreement? Does the Commission find that paying for Minnesota-based policy costs of a resource is reasonable?

Staff considered how the Commission might have addressed this situation absent the Aurora-Xcel Letter Agreement. Staff believes in that scenario, Xcel's petition could have been denied as insufficient.

First, staff believes that the proxy resource cost allocation method to replace the disallowed ND-resources in each state's fuel clause riders was not sufficiently explained or quantified in Xcel's Petition for several reasons.

The Department's position, essentially, is that there is no evidence to support the economics of the Aurora project with an incremental cost adder for Minnesota ratepayers. Staff agrees it is a problem that there is no quantitative analysis identifying the magnitude of the Minnesota ratepayer impact. While Xcel outlines a calculation method, neither the dollar amount nor its influence on whether there is a more beneficial alternative to Minnesota ratepayers is provided.

[11] While these condition precedents are not new, and have been used for some time, previously, they had not had an effect.

Xcel and Aurora have argued that the Commission's 2011 decision to assign all costs related to RDF grants to Minnesota customers serves as precedent for the decision in the instant docket. Grants awarded to projects form the RDF are for research and development and for demonstration and near-commercial renewable generation projects, a very different purpose and type of review than for system resources. In contrast, the Aurora project and other generation projects coming out of the CAP proceeding were thoroughly reviewed and determined to be least-cost system resources.

In its June 6, 2011 Order After Reconsideration, Modifying March 17, 2011 Order and Reallocating Expenses, in the Xcel RDF Factor Docket, E-002/M-10-1054, the Commission limited its decision to the specific facts of the case:

> The Company correctly points out that these costs – unlike most system-wide utility costs – have a unique connection with Minnesota. They are incurred under Minnesota statutory mandates to promote state energy policies, and may not have been incurred without those mandates. <u>There is therefore no danger that allocating the full 2011 costs to Minnesota ratepayers would create a worrisome precedent of allocating to Minnesota ratepayers costs disallowed in other jurisdictions, especially since the approval granted today is limited specifically to the facts underlying the record related to the 2011 rate rider</u>.
>
> In the Company' s reallocation request and its request for reconsideration, the Company has emphasized that it is not seeking rate recovery of any past RDF costs, and that this request for rate recovery is limited to its 2011 RDF rate rider. The Company has emphasized that it remains open to exploring -- with the Department and any other interested parties -- alternative approaches to recovery of these costs in the future.
>
> Given these unique circumstances, and on this record, the Commission concurs with the Company that it is appropriate to allocate to Minnesota ratepayers Xcel's 2011 RDF rate rider costs, and will so order. The Commission appreciates the parties' agreement to work together to explore alternative approaches to recovering the costs of this important policy initiative for the future.
>
> [Emphasis added]

In addition, in that RDF docket, the incremental amount of money to be recovered from Minnesota ratepayers was known, unlike in the instant case, where the level of costs that could potentially be allocated to Minnesota customers is not known and is likely to grow over time if used as precedent for other projects potentially disallowed by North Dakota.

Second, the Petition only allocates the incremental *costs* of the Aurora project to Minnesota ratepayers without the assurance of retaining the corresponding (potential or future) benefits. Benefits - such as avoided generation, displaced market energy, reduced line losses, among others - would be realized across Xcel's entire NSP-M system (ND, SD, and MN) without some metric to retain them for Minnesota ratepayers. Without parameters in place to ensure the benefits are allocated to the 'cost-causer' is not in Minnesota ratepayers' best interest. While staff acknowledges this task to ensure benefits are retained by Minnesota is challenging, they should nevertheless be retained.[12]

Third, as noted in Xcel's reply comments, "the addition of the Aurora project may impact the aggregate wholesale purchases and sales revenues the Company makes and receives through the MISO market, ..." Because Aurora will serve the overall retail system, staff believes further development is required to clarify how shifting jurisdictional costs will account for impacts in the MISO energy market.

Additional Options for the Commission

Staff notes that the Letter Agreement between Aurora and Xcel allows until December 31, 2016 for a Commission final decision. Thus, if the Commission believes the Letter Agreement is not an acceptable solution, the Commission could reject the Petition without prejudice while allowing for Xcel to file a better proposal to protect MN-ratepayer interests.

Further Evaluation Needed on Jurisdiction Cost Allocation Issues

Staff believes a larger problem of diverging jurisdictional policies is appropriately raised in the context of this docket; however, staff does not believe this issue can be resolved here. While Aurora and Xcel argue that the Commission should approve this instant Petition to ensure a clear path forward for developers (and Xcel) – staff does not believe that can be done without a more comprehensive evaluation of options available to appropriately jurisdictionally allocate costs (and benefits) of resource additions.

Additional Unknowns Regarding Jurisdictional Allocation Changes

While Xcel and Aurora argued that allowing these (Aurora) costs to be recovered by Minnesota ratepayers would provide clarity and precedent for future cases, staff is uncertain in light of on-going changes to historic jurisdictional allocation methods on Xcel's system. It is staff's understanding that Xcel and the ND PSC have been working on a Negotiated Agreement as a result of their 2012 North Dakota Rate Case. Initially, the plan was that North Dakota would determine which resources it would approve as consistent with their state policies (via the "Restack" of resources on Xcel's system) and therefore would allow automatic recovery while disallowing other resources. While this situation was potentially not optimal for Minnesota, the anticipated Restack Agreement provided an allocation method which was thought to be 'final' method. A method the Commission could grapple with and

[12] Staff notes similar discussions surrounding the quantification of solar benefits occurred in the recent Minnesota Power Camp Ripley Solar Proposal Docket M-15-773.

react to – and expect moving forward. However, in the most recent versions of the Negotiated Agreement, it is staff's understanding that the discussion has turned to a yet-to-be-developed Resource Treatment Framework (RTF), in lieu of the Restack proposal. It was noted that the resource 'Restacking' may no longer be the optimal solution for Xcel and North Dakota and therefore further negotiation was necessary. Per the September 30, 2015 (first) Negotiated Agreement (and restated in its February 22 Revised Agreement) Xcel and the ND PSC staff agreed that:

> "…additional information not available when the Rate Settlement was entered into (…the Company's 2015 Resource Plan…, additional proposed resource additions and the Clean Power Plan) have led the Parties to slow down and reassess how to viably approach the very complex issue of divergent state energy policies.
>
> The Parties concur that varying state energy policies within the NSP System footprint have led to differences in each state's approach to generation resource development. Given this, and the Company's plans to add significant generation resources to its system over the next twenty years to address load requirements replace aging infrastructure, and comply with new environmental regulations, the Parties have determined that the repricing approach contemplated in the Rate Settlement (and referred to as the "Restack") may not be sufficiently robust to address concerns regarding differing state energy policies while allowing the Company a reasonable opportunity to earn its authorized rate of return.
>
> Therefore, the Parties have determined that the development of an effective long-term framework to resolve these issues is imperative. By this Agreement, the Company binds itself to devise and implement a regulatory framework to: 1) address the impact of divergent state energy policy on NSP's customers; 2) increase the geographic diversity of NSP System generation while maintaining system reliability; and 3) provide monetary value to North Dakota customers in the event the Company is unable to make good on this Agreement.
>
> The Parties intend this Agreement to provide a "bridge period" for the Company to propose and implement, in collaboration with the Commission and Staff, a long-term "Resource Treatment Framework," or RTF. This Agreement binds the Company to file an RTF proposal with the Commission no later than January 1, 2017, with the intention to implement it no later than January 1, 2018. This Agreement also requires the Company to accelerate, from 2036 to 2025, its commitment to construct and install an integrated NSP System thermal generating resource in eastern North Dakota, preferably near the city of Fargo.

Additionally, in Xcel's proposed Order (attached) for the ND PSC filed in the same docket on January 15, 2016, Xcel outlined the additional option posed to North Dakota PSC staff to attempt to deal with the jurisdictional allocation issues. While these are noted as rejected by ND PSC staff, Minnesota may want to consider these concepts as options to pursue. From page 9 of the filing (filing also attached):

16. As explained by NSP witness Mr. David Sederquist, the options that were given the most serious consideration were the following:

> (a) States ensure full cost recovery for resources that they direct NSP 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;
>
> (b) 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;
>
> (c) Employ a Pricing Zone concept. This would entail establishing separate pricing zones for North Dakota and the remainder of the integrated NSP System;
>
> (d) Restructure NSP to facilitate more state autonomy in selecting resources. Under this approach, a separate operating company subsidiary of Xcel Energy would be established to serve North Dakota loads and better facilitate separate regulatory processes and power contracting that would comply with each state's energy preferences.

17. Mr. Sederquist explained that none of these approaches advanced much past the conceptual stages during negotiations with Advocacy Staff.

Further Discussion on Policy Mandates, Need and Resource Acquisition

In Xcel's reply comments, the Company argues that, "in order to allow the Company to fulfill Minnesota state energy policy, we believe it is appropriate for the Commission to approve recovery of the incremental costs that would otherwise be allocated to the Company's North Dakota customers." Xcel goes on to argue that "state policy favoring energy from renewable sources and the state goal of reducing greenhouse gases added to the value of Aurora's proposal and was a factor in its selection."

Certainly the Commission's selection of the Aurora project took into account state energy policy, in part because it is required to do so by law. Among other laws, Minn. Stat. § 216H.06, requires that CO_2 values established by the Commission "must be used in all electricity generation resource acquisition proceedings." Moreover, according to the resource planning statute, Minn. Stat. § 216B.2422, "A utility shall use the [environment cost] values established by the commission in conjunction with other external factors, including socioeconomic costs, when evaluating and selecting resource options in all proceedings before the commission, including resource plan and certificate of need proceedings."

It could be argued that, under Xcel's line of reasoning, any Minnesota resource plan or resource acquisition that accounts for environmental costs would be subject to the same treatment as the Aurora Project. For example, the ND PSC also denied an ADP for Xcel's 187 MW, and appears likely to deny the Calpine ADP.

Setting aside whether the resource in question is generated from renewable energy or not, there is a parallel question of whether the Minnesota resource planning and resource acquisition processes could be considered a matter of policy themselves. It bears repeating that the Aurora project was selected out of a Minnesota resource acquisition process, which evolved from a capacity need identified in the Company's resource plan. In the resource acquisition process from which Aurora was selected, the Commission found that "Xcel's revised 2013 forecast, with further adjustments for the Solar Energy Standard and revised capacity ratings for Xcel's generators and demand-side management programs, demonstrates a need for more than 300 MW by 2019." On the other hand, in Xcel's ADP Petition, the ND PSC found that "the capacity to be provided by the resource addition is in excess of what is necessary to ensure reliability and meet customer load, and therefore the Geronimo Solar PPA will cause increased costs to North Dakota customers without corresponding benefits."

As the Commission reviews the materials in this docket, staff believes two threshold questions are relevant to its decision:

- What qualifies as Minnesota energy policy? (Is it to mean state law? Is it based on environmental assumptions used in regulatory processes? Does it mean Minnesota regulatory processes themselves?)
- If the Commission agrees with Xcel that the Aurora project was made, in part, to fulfill Minnesota state energy policy, the Commission could further ask to what end those principles which guided policy-related decision-making should extend to jurisdictional cost allocation.

Last, staff notes that Xcel, in its pending Integrated Resource Plan, is proposing what it refers to as a fleet transformation, in which the Company can position itself a national leader in clean energy. It appears that Xcel's business plan may be separating from its North Dakota regulatory environment. As the Commission answers the question of "Who pays?"—both in this docket and for those forthcoming—the Commission may want to discuss how "Minnesota policy" is distinct from Xcel's business plan.

Commission Decision Options

A. Xcel's Petition

1. Approve the Petition and allow cost recovery of the incremental ND-jurisdictional portion of the Aurora Project.
2. Deny the Petition with prejudice.
3. Deny the Petition without prejudice.
4. Table the issue and request additional information from Xcel.

STATE NORTH DAKOTA
PUBLIC SERVICE COMMISSION

Northern States Power Company 2013 Electric Rate Increase Application	Case No. PU-12-813
Northern States Power Company Advanced Determination of Prudence — Courtenay Wind Project Application	Case No. PU-13-706
Northern States Power Company Advanced Determination of Prudence — Odell Wind Project Application	Case No. PU-13-707
Northern States Power Company Advanced Determination of Prudence — Pleasant Valley Wind Project Application	Case No. PU-13-708
Northern States Power Company Advanced Determination of Prudence — Border Winds Project Application	Case No. PU-13-742
Northern States Power Company 150 MW Border Winds Project — Rolette County Public Convenience And Necessity	Case No. PU-13-743
Northern States Power Company Advance Determination of Prudence — NG Generators Application	Case No. PU-13-194
Northern States Power Company Red River Valley NG Units 1 & 2 — Hankinson, ND Public Convenience And Necessity	Case No. PU-13-195
Northern States Power Company Advance Determination of Prudence — 345 Mankato Energy Center Application	Case No. PU-15-96

APPLICANT'S PROPOSED FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER

104 PU-15-96 Filed 01/15/2016 Pages: 15
Proposed Findings of Fact, Conclusions of Law, and Order
Northern States Power Company

147 PU-13-195 Filed 01/15/2016 Pages: 15
Proposed Findings of Fact, Conclusions of Law, and Order

130 PU-13-194 Filed 01/15/2016 Pages: 15
Proposed Findings of Fact, Conclusions of Law, and Order

140 PU-13-743 Filed 01/15/2016 Pages: 15
Proposed Findings of Fact, Conclusions of Law, and Order

132 PU-13-742 Filed 01/15/2016 Pages: 15
Proposed Findings of Fact, Conclusions of Law, and Order

128 PU-13-708 Filed 01/15/2016 Pages: 15
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Appearances

Commissioners Julie Fedorchak, Brian P. Kalk, and Randy Christmann.

Alison C. Archer, Xcel Energy Services Inc., 414 Nicollet Mall, 5th Floor, Minneapolis, Minnesota 55401-1993, and Zeviel T. Simpser, Briggs and Morgan, P.A., 2200 IDS Center, 80 South Eighth Street, Minneapolis, Minnesota 55402-2157, appearing on behalf of Northern States Power Company.

John Schuh, Legal Counsel, North Dakota Public Service Commission, State Capitol, 600 E. Boulevard Ave., Bismarck, North Dakota 58505, on behalf of the Public Service Commission Advocacy Staff.

Illona Jeffcoat-Sacco, General Counsel, North Dakota Public Service Commission, State Capitol, 600 E. Boulevard Ave., Bismarck, North Dakota 58505, on behalf of the Public Service Commission Advisory Staff.

Wade C. Mann, Administrative Law Judge, Office of Administrative Hearings, 2911 North 14th Street - Suite 303, Bismarck, North Dakota 58507.

Preliminary Statement

On December 18, 2012, Northern States Power Company (NSP) filed a Notice of Change in Rates for Electric Service to increase electric rates by $16.9 million or 9.25 percent. Along with the Notice, the Company filed an Alternative Petition for interim rate relief of $14.7 million or 8.05 percent, to be effective February 16, 2013. This application is Case No. PU-12-813.

On December 21, 2012, the Commission suspended NSP's general rate increase application.

On January 30, 2013, the Commission ordered that NSP's interim rate schedules be effective for service rendered on or after February 16, 2013.

On February 13, 2013, the Commission issued a Notice of Hearing, Notice of Intervention Deadline, and Notice of Public Input Sessions in Case No. PU-12-813, scheduling the formal hearing to begin August 27, 2013 in the Commission Hearing Room, 12th Floor, State Capitol, Bismarck, North Dakota. The Notice set forth the following issues to be considered:

1. What is the value of NSP's property, used and useful, for the service and convenience of the public in North Dakota?

2. What is NSP's rate of return on its property, used and useful, for the service and convenience of the public in North Dakota?

3. What is the just and reasonable rate of return on NSP's property, used and useful, for the service and convenience of the public in North Dakota?

4. What rates and charges are necessary to provide a just and reasonable rate of return on NSP's property, used and useful, for the service and convenience of the public in North Dakota?

5. Are NSP's rate schedules designed in such a manner that they result in a basis of charge to its customers that is just and reasonable without discrimination?

6. Other relevant information or proposals concerning the proceeding.

The Notice also scheduled two public input sessions to be held on April 15 and 16, 2013, via interactive television at locations in Fargo, Grand Forks and Minot, North Dakota.

The hearing and public input sessions were held as noticed.

On April 26, 2013, NSP filed an Application seeking an advance determination of prudence (ADP) for its proposal to add three 215 MW natural gas fired, simple cycle, combustion turbine generators to its system; one at the Company's existing Black Dog generating site (Black Dog Unit 6) and two at a site near Hankinson, North Dakota (Red River Valley Units 1 and 2). This application is Case No. PU-13-194.

Also on April 26, 2013, NSP filed an Application for a Certificate of Public Convenience and Necessity (PC&N) for the construction of Red River Valley Units 1 and 2. This application is Case No. PU-13-195.

On July 26, 2013, NSP filed an application seeking an ADP for three wind generation projects: a proposed power purchase agreement (PPA) for the 200 MW Courtenay Wind Project (Courtenay Project), to be located in Stutsman County, North Dakota; a proposed PPA for the 200 MW Odell Wind Project (Odell Project) to be located near Mountain Lake, Minnesota; and the proposed 200 MW Pleasant Valley Wind Project (Pleasant Valley Project) to be located in southeastern Minnesota and owned by NSP. The applications for these projects are Case No. PU-13-706, Case No. PU-13-707, and Case No. PU-13-708, respectively.

On August 13, 2013, NSP filed an application seeking an ADP for the proposed 150 MW Border Winds Project (Border Winds) to be located in Rolette County North Dakota and owned by NSP. This application is Case No. PU-13-742.

Also on August 13, 2013, NSP filed an application for a PC&N for its ownership of the Border Winds Project. This application is Case No. PU-13-743.

On September 25, 2013, the Commission issued a Notice of Consolidated Hearing for Case No. PU-13-706, Case No. PU-13-707, Case No. PU-13-708, Case No. PU-13-

742, and Case No. PU-13-743 scheduling a hearing on all five cases to begin October 31, 2013 in the Commission Hearing Room, 12th Floor, State Capital, Bismarck, North Dakota. The Notice specified the issues to be considered were:

1. Are the PPAs reasonable and prudent and in the best interests of customers?

2. Is NSP's proposed investment in the Pleasant Valley Wind Project and the Border Winds Project prudent?

3. Whether the public convenience and necessity will be served by the purchase and operation of the facilities.

4. Whether the applicant is fit, willing, and able to provide service.

The hearing was held as noticed.

On October 9, 2013, the Commission issued a Notice of Consolidated Hearing for Case No. PU-13-194 and Case No. PU-13-195, scheduling a hearing on these two cases for November 26, 2013, in the Commission Hearing Room, 12th Floor, State Capitol, Bismarck, North Dakota. The Notice specified the issues to be considered:

1. Whether NSP's proposed investment in the three CTs is prudent.

2. Whether the public convenience and necessity will be served by NSP's construction and operation of the three CTs.

3. Whether NSP is fit, willing and able to provide service.

The hearing was held as noticed.

On December 13, 2013, the Company and Advocacy Staff entered into and filed with the Commission a Comprehensive Settlement Agreement resolving all open issues in all the captioned cases.

On December 16, 2013, the Commission issued a Notice of Hearing in all the captioned cases scheduling a hearing for January 23, 2014, in the Commission Hearing Room, 12th Floor, State Capitol, Bismarck, North Dakota. The Notice of Hearing provided that the issue to be considered is whether the settlement is reasonable and should be adopted by the Commission. The hearing was held as noticed.

On February 3, 2014, NSP and Advocacy Staff filed an Amended Settlement Agreement. The Amended Settlement Agreement modified the original Comprehensive Settlement Agreement by providing additional terms and conditions with respect to the conduct of the demand allocator study.

On February 18, 2014, NSP and Advocacy Staff filed the Second Amended Settlement Agreement. The Second Amended Settlement Agreement modified the multi-year rate plan provided for in the Comprehensive Settlement Agreement by lowering the five percent base rate increases in 2013, 2014, and 2015 to a 4.9 percent base rate increase in each of those years.

On February 25, 2014, NSP and Advocacy Staff filed a Revised Second Amended Settlement Agreement to revise terms in the Second Amended Settlement and to correct typographical errors.

The Revised Second Amended Settlement Agreement provides for, among other things:

- A multi-year rate plan with 4.9 percent rate increases in each of 2013, 2014 and 2015 and a base rate increase moratorium in 2016.
- Authorized return on equity of 9.75 percent, 10.0 percent, 10.0 percent, and 10.25 percent in 2013, 2014, 2015, and 2016, respectively.
- An earnings sharing mechanism through which NSP will refund to customers fifty percent of any earnings above the authorized ROE during the term of the rate plan.
- Reforms to NSP's Fuel Cost Rider (FCR).
- Implementation of Transmission Cost Rider (TCR) and Renewable Energy Rider (RER) tariffs.
- A negotiating framework for the virtual modification or "restack" of NSP's electric supply resources serving North Dakota. Through this restack NSP will adjust rates in North Dakota to reflect a resource mix more consistent with North Dakota energy priorities. If such a framework cannot be developed to suitably address existing and future resources, the Settlement Agreement will provide financial penalties for NSP.
- A commitment by NSP to build up to 400 MW of thermal generation in the Red River Valley of North Dakota by 2036, consistent with prudent resource planning principles.
- The performance of a study to analyze the contribution of NSP's North Dakota jurisdiction toward NSP's overall system-wide production and transmission costs, and the available demand allocation methodologies which may be implemented to reflect such cost causation.
- Finding that NSP's proposal in Case Nos. PU-13-194 is reasonable and prudent.
- NSP's proposals in Case Nos. PU-13-706, PU-13-742 and PU-13-743 have a rebuttable presumption of prudence as resource additions located within the State of North Dakota and are prudent resource additions to NSP's integrated system.
- The disposition of NSP's requests in Case Nos. PU-13-707 and PU-13-708 will be addressed as part of the "restack" or the penalty provisions thereof.
- Acceptance by NSP of all proposed test year adjustments in Case No PU-12-813 specifically related to: pension loss amortization, annual

incentive plan, charitable donations and economic development contributions, and asset-based margins on wholesale sales.

- NSP will retain remaining Department of Energy (DOE) proceeds to offset the need for additional revenues in 2013 and 2014.
- Rate Design:
  - o Implementation of the multi-year rate plan consistent with NSP's originally proposed class apportionment;
  - o Instituting single customer charges for several rate classes;
  - o Elimination of account history charge; and
  - o Performance of a study with respect to Time-of-Day rates.
- NSP will return one hundred percent of all proceeds from the sale of renewable energy credits to customers.
- Amounts over collected through interim rates will be refunded to customers.
- Additional reliability improvement commitments.

On February 26, 2014, the Commission issued an Order approving the Revised Second Amended Settlement Agreement. This February 26, 2014 Order also took no action on NSP’s requests for ADPs in Case No. PU-13-707 and Case No. PU-13-708 and those applications were dismissed without prejudice. The February 26, 2014 Order granted NSP’s applications for ADP in Case No. PU-13-194, Case No. PU-13-706, and Case No. PU-13-742 consistent with the Revised Second Amended Settlement.

On June 6, 2014, NSP filed a request with the Commission to dismiss its application for a PC&N for Red River Valley Units 1 and 2 without prejudice in Case No. PU-13-195.

On August 20, 2014, the Commission issued an Order dismissing without prejudice NSP’s application for a PC&N for Red River Valley Units 1 and 2 in Case No. PU-13-195.

On February 13, 2015, NSP filed an Application for an ADP for 345 MW of capacity and associated energy through a 20-year power purchase agreement with Mankato Energy, LLC, an affiliate of Calpine Corporation. This application is Case No. PU-15-96.

On May 11, 2015, NSP filed an Application for an ADP for a determination of prudence to discontinue the power purchase agreement for the 200 MW Courtenay Project. This application is Case No. PU-15-183. The Commission had granted NSP’s requested ADP for purchasing the output of the Courtenay Project through a power purchase agreement in Case No. PU-13-706 on February 26, 2014. NSP sought to discontinue the power purchase agreement due to changed circumstances since approval of this ADP which resulted in NSP proposing to develop, construct, own, and operate the Courtenay Project. NSP also sought an ADP for its ownership and operation of the Courtenay Project, a transfer of the Site Certificate Siting Application, and a PC&N from the Commission in Case Nos. PU-15-174, PU-15-175, and PU-15-181.

On June 17, 2015, the Commission granted NSP’s request for a 90-day extension from June 30, 2015 to September 30, 2015 for the filing date of a North Dakota policy based generation mix required under section II. A. of the Revised Second Amended Comprehensive Settlement Agreement adopted by the Commission’s February 26, 2014 Order Adopting Settlement in Case Nos. PU-12-813, PU-13-194, PU-13-195, PU-13-706, PU-13-707, PU-13-708, PU-13-742, and PU-13-743.

On July 8, 2015, the Commission issued a Notice of Hearing in Case No. PU-15-96 scheduling a hearing for October 15, 2015, in the Commission Hearing Room, 12th Floor, State Capitol, Bismarck, North Dakota. The Notice of Hearing provided that the issue to be considered is whether NSP’s power purchase agreement with Mankato Energy, LLC should receive an ADP from the Commission. The hearing was held as noticed.

On August 24, 2015, the Commission issued an Order granting NSP’s request to discontinue the ADP related to the power purchase agreement for the output of the Courtenay Project granted by the Commission’s February 26, 2014 Order in Case No. PU-13-706.

On September 30, 2015, NSP and Public Service Commission Advocacy Staff filed a Negotiated Agreement to address electric generation resource policy differences that exist between NSP's North Dakota and Minnesota jurisdictions.

The Negotiated Agreement provides an opportunity to address North Dakota's energy policy goals and other matters, such as:

- Accelerating NSP's commitment to locate thermal electric generation in North Dakota from 2036 to 2025, subject to a potential refund of an estimated $25 million if NSP fails to achieve its generation commitment by the end of 2025.

- Excluding the costs and volumes of 17 existing Community Based Energy Development and small solar purchased power agreements from the calculation of the North Dakota Fuel Cost Rider (FCR).

- Extending the current electric rate moratorium through 2017.

- Allowing cost recovery for NSP's existing biomass purchase power agreements.

- Continuing to use the 12 coincident peaks method for assigning generation and transmission costs among the states served by NSP through 2025.

- Development of a Resource Treatment Framework (RTF) due on or before January 1, 2017 to address the issue of divergent state energy policies.

On November 4, 2015, the Commission issued a Notice of Consolidated Hearing for the Negotiated Agreement filed on September 30, 2015 and nine captioned cases, Case Nos. PU-12-813, PU-13-706, PU-13-707, PU-13-708, PU-13-742, PU-13-743, PU-13-194, PU-13-195, and PU-15-96, to begin on December 15, 2015 in the Commission Hearing Room, 12th Floor, State Capital, Bismarck, North Dakota. The Notice specified the issue to be considered is whether the Negotiated Agreement is reasonable and should be adopted by the Commission.

The hearing was held as noticed.

On January 15, 2016, NSP filed late-filed exhibits and its brief.

Findings of Fact

Background

1. NSP is an investor-owned electric utility authorized to provide public utility service in North Dakota subject to the jurisdiction of the Commission.

2. NSP, along with its affiliate Northern States Power Company, a Wisconsin corporation (NSPW), plan for and operate an integrated generation and transmission system serving the states of North Dakota, South Dakota, Minnesota Wisconsin, and Michigan (the NSP System).

3. NSP provides retail electric service in North Dakota, South Dakota, and Minnesota, and NSPW provides retail electric service in Wisconsin and Michigan. In North Dakota, NSP serves retail electric customers in and around Fargo, West Fargo, Grand Forks, and Minot, North Dakota.

4. The integrated NSP System has nearly 10,000 MW of load that is served through the Company's nuclear, large fossil, hydroelectric, and renewable generation resources. NSP's North Dakota load is approximately 500 MW.

5. NSP System costs are incurred by NSP and NSPW to ensure power is supplied reliably across the system and customers in each state benefit from the economies of scale provided by the large shared generation and transmission assets and operations located in all five states.

6. To allocate costs between NSP and NSPW, NSP and NSPW entered into an Interchange Agreement for the sharing of all production and transmission costs incurred and revenues received to support the system, including capital costs such as the costs of building power plants and transmission infrastructure as well as for PPAs to procure generation to serve the system. The Interchange Agreement is a FERC-filed tariff and all generation and transmission costs incurred and revenues received to support the integrated NSP System is accounted for through this agreement.

7. Allocations between the states served by NSP and NSPW, as well as the rates and terms and conditions of service for customers are regulated by the utility commissions in each of the states. For purposes of establishing those rates, the costs of the integrated system that are incurred are generally allocated to each state in a manner that reflects the share of each states' use of the integrated system. The

costs of the integrated NSP System are generally allocated to the states served by NSP utilizing a 12 coincident peak demand allocation methodology.

8. The record reflects that in the event that a state agrees to absorb a specific cost that is historically allocated through the Interchange Agreement, NSP and NSPW have filed an amendment to the Interchange Agreement at FERC to reflect this agreement. However, this change is subject to ratification by FERC. The record also reflects that a decision to not recover the costs of a resource in a specific jurisdiction is difficult to address in the same manner without the full agreement of all five states.

9. While the integrated nature of the NSP System provides benefits to customers in all five states, it also requires management of the NSP System in a way that complies with all mandates and requirements of each of the five states served by the NSP System.

10. NSP has been able to manage the NSP System in a way that meets the needs of all of the states it serves for many years, however, in recent years the divergent state energy policies of the states servcied by the integrated NSP System have begun to result in the disallowance of the cost of certain generating resources in North Dakota that were acquired by NSP to meet the policy goals and requirements of other states served by the integrated NSP System.

11. In light of this, NSP and Advocacy Staff have entered into the Negotiated Agreement to address the impact of these energy policy differences.

Rate Settlement

12. The Negotiated Agreement stems from NSP's and Commission Advocacy Staff's agreement reflected in the Revised Second Amended Comprehensive Settlement Agreement (Rate Settlement) in Case Nos. PU-12-813, PU-13-706, PU-707, PU-13-708, PU-13-742, PU-13-743, PU-13-194, and PU-13-195 adopted by the Commission on February 26, 2014.

13. The Rate Settlement sought to address divergent state energy policies in the states within the NSP System by repricing in North Dakota certain generation resources that were selected primarily on the basis of meeting Minnesota requirements or commitments.

14. Specifically, the Rate Settlement set a June 30, 2015 deadline for the development of the repricing scheme (often referred to as the "Restack") so that existing resources deemed inconsistent with North Dakota energy policies would be repriced based with "like" replacements using real or proxy pricing and that any future resources would be priced to reflect marginal pricing for a similar resource. The Rate Settlement also required Commission Staff to consider the financial impact to NSP of the Restack including reasonable and mutually agreeable implementation schedules and deadlines. Finally, the Rate Settlement included a commitment by

NSP to build “up to 400 MW” of thermal generation in North Dakota no later than 2036.

15. Once the Commission approved the Rate Settlement, NSP and Commission Staff worked in earnest to explore options for the Restack to address the impact of divergent state energy policies.

16. As explained by NSP witness Mr. David Sederquist, the options that were given the most serious consideration were the following:

    (a) States ensure full cost recovery for resources that they direct NSP 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;

    (b) 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;

    (c) Employ a Pricing Zone concept. This would entail establishing separate pricing zones for North Dakota and the remainder of the integrated NSP System;

    (d) Restructure NSP to facilitate more state autonomy in selecting resources. Under this approach, a separate operating company subsidiary of Xcel Energy would be established to serve North Dakota loads and better facilitate separate regulatory processes and power contracting that would comply with each state’s energy preferences.

17. Mr. Sederquist explained that none of these approaches advanced much past the conceptual stages during negotiations with Advocacy Staff.

<u>Negotiated Agreement</u>

18. Given the difficulties in developing and implementing these options, NSP and Advocacy Staff agreed to the current terms of the Negotiated Agreement which, in part, allowed additional time for development of these concepts by NSP, in collaboration with the Commission and Staff, of potential solutions to the issue of divergence energy policies through the development of a RTF.

19. The Negotiated Agreement has six key terms:

    a. By the end of 2025, NSP will build or have located in eastern North Dakota a natural gas-fired electric generation facility with a capacity of at least 200 MW. The combustion turbine will be treated as an NSP System resource and its costs will be allocated to all states and customers served by the NSP System. If the combustion turbine is not in-service by December 31, 2025, NSP will refund to its North Dakota customers 50 percent of the excess costs of the six biomass PPAs identified in the Negotiated Agreement;

b. The costs and volumes of 15 Community-Based Energy Development (C-BED) and two small solar PPAs will be excluded from the calculation of NSP's North Dakota Fuel Cost Recovery (FCR) Rider;

c. The costs of six key biomass PPAs and the Odell and Pleasant Valley wind projects will be recovered in North Dakota. The biomass resources provide approximately 145 MW of baseload-type capacity and energy for the entire NSP System and allow for continued fuel storage for NSP's nuclear fleet. The two wind projects provide low cost energy to the NSP System thereby reducing overall system costs;

d. NSP's current rate case moratorium will be extended an additional year, or through 2017. In the Revised Second Amended Comprehensive Settlement Agreement, 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. The Negotiated Agreement extends this rate freeze through 2017. NSP will not be allowed to increase base electric rates (on an interim or final level) before January 1, 2018;

e. 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;

f. Development of an RTF due on or before January 1, 2017 to address the issue of divergent state energy policies. The Commission will conduct review of this RTF for 8 to 10 months in 2017 and the RTF is proposed to be implemented on January 1, 2018.

20. The Negotiated Agreement represents a reasonable exchange of value to address the impacts of past resource decisions, further a key Commission policy goal, and provide a path to address the impact of divergent energy policies on NSP's future resource decisions.

21. The effect of the Negotiated Agreement will be to decrease overall electric rates by approximately $1.6 million in 2016. The Negotiated Agreement will also prohibit an electric base rate increase until at least 2018.

22. The terms of the Negotiated Agreement are reasonable and will provide benefits to North Dakota.

23. Developing thermal generation in eastern North Dakota is a key policy goal of the Commission.

24. As Advocacy Staff witness, Mike Diller, testified, NSP's commitment to add at least 200 MW of thermal generation in eastern North Dakota by 2025 combined with NSP's future ownership of 350 MW of North Dakota wind generation, is a "reasonable start towards providing local generation." Mr. Diller further noted that the thermal generation addition "will continue to promote local grid stability and reliability and provide a platform for future generation development in North Dakota." Moreover, as explained by NSP witness, Mr. Sederquist, "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."

25. The exclusion of 15 C-BED projects and two smaller solar PPAs from the monthly North Dakota FCR reflects NSP's recognition that these projects were selected primarily to fulfill obligations in Minnesota and, in the case of C-BED projects, were required to be located in Minnesota. As described by NSP witness Mr. Kurtis Haeger, excluding the costs and volumes of these 17 PPAs will reduce North Dakota customer energy costs starting at approximately $1.6 million in 2016 and a total of approximately $19 million through 2030.

26. The continued recovery of the six biomass PPAs through the North Dakota FCR will not result in future incremental increase in North Dakota electric rates as these costs are already included in the FCR given that these resources went into production on various dates between 1994 and 2009. As explained by NSP's witness, Mr. Sederquist, these resources represent approximately 145 MW of baseload power and were developed so that NSP could comply with legislation enacted in Minnesota in the early 1990s that also allowed the Company to continue to operate its nuclear facilities in Minnesota. The Commission has supported NSP's nuclear plants as they provide reliable, low-cost, and clean sources of power for the NSP System. NSP witness Mr. Haeger explained that forgoing recovery of these six biomass PPAs is not sustainable as it results in lost revenue of $5.6 million in 2016 and a total of approximately $50 million through 2025.

27. As explained by Advocacy Staff witness, Mr. Diller, the inclusion of the Pleasant Valley and Odell wind farms in North Dakota rates are a benefit to North Dakota ratepayers and will result in lower total system costs. Consequently, inclusion of these resources in NSP's North Dakota rates will help to mitigate the financial impacts of the biomass PPAs while allowing NSP the ability to recover the full costs of those resource additions.

28. While it is difficult to value the addition of one year to the rate moratorium, Advocacy Staff witness Mr. Diller testified that "a $10 million value is not unrealistic given NSP's recent multi-year rate increases" and that "it gives ratepayers assurance, outside of some unforeseen or extraordinary event, that NSP's base rates will remain stable through 2017."

29. The Negotiated Agreement provides that Commission Advocacy Staff and NSP will support use of the 12 CP method in any future rate filings through 2025. The Allocation Study filed by NSP on April 27, 2015 in Case No. PU-12-813 evaluated 12 jurisdictional allocation methods and the current 12 CP method was determined by Commission Staff and NSP to be reasonably adequate for ensuring that North Dakota customers were paying their fair share of NSP's system generation and transmission costs. The Commission notes that this provision of the Negotiated Agreement does not bind the Commission with respect to demand allocation methodologies to be utilized in setting NSP's North Dakota rates.

30. The Negotiated Agreement requires NSP, in collaboration and consultation with the Commission and its staff, to develop an RTF in 2016 and file a future-looking proposal with the Commission by January 1, 2017. This additional time is necessary given the complex issues involved with an RTF and to provide parties with time to achieve additional clarity with respect to uncertainty in the utility industry, especially the uncertainty related to the Clean Power Plan.

31. As explained by NSP witness Mr. Christopher Clark, an RTF is necessary because the current status quo is not a workable long-term solution given the divergent state energy policies within the NSP System. The accounting mechanisms and regulatory structures that are in place under the status quo do not provide for a simple way for NSP to separate the North Dakota portion of a specific resource from the rest of the system. Instead, under the current regulatory mechanisms of the integrated NSP System it is assumed that all jurisdictions will enjoy the benefits and pay the costs of all resources that are used to serve the integrated system. An RTF is necessary so that there is a long-term solution in place to adjust the regulatory mechanisms for resource additions that are not fully shared by each jurisdiction within the NSP System.

32. Without an RTF, there is a reasonable likelihood Xcel Energy's North Dakota rates could become unjust and unreasonable.

33. Importantly, the Negotiated Agreement leaves the current status quo in place unless and until the Commission adopts an RTF. Thus, NSP has the incentive to develop an RTF that meets with Commission approval. Should the Commission not adopt a proposed RTF, the current status quo will remain in place.

Based on the foregoing Findings of Fact, the Commission makes the following:

Conclusions of Law

1. The Commission is a constitutionally established body with its powers delegated to it by the legislature.[1]

2. A key power delegated to the Commission by the legislature is the authority to ensure that the rates charged by a public utility are just and reasonable.[2]

3. The Commission has jurisdiction in this matter.

4. The Commission has authority to adopt the Negotiated Agreement.

5. The Commission finds that the Negotiated Agreement is reasonable and provides a reasonable resolution to all of the pending issues in all the captioned Cases.

6. The Commission finds that the Negotiated Agreement achieves outcomes which provide greater benefits to NSP's North Dakota customers than those possible merely by Commission Order.

7. The Commission finds that NSP's commitment to build at least 200 MW of thermal generation in North Dakota by December 31, 2025 and the provision for refund for non-compliance provided for in the Negotiated Agreement is reasonable, meets a key Commission policy goal, promotes local grid stability and reliability, and provides a platform for future generation development in North Dakota.

8. The Commission finds that the Negotiated Agreement's exclusion of the costs and volumes of 15 C-BED and two small solar PPAs from the calculation of NSP's North Dakota FCR is reasonable.

9. The Commission finds that the Negotiated Agreement's provision allowing continued recovery of the six biomass PPAs in the FCR is reasonable and that the exchange of value related to continued recovery of these generating resources and the development of North Dakota based generation provides greater benefits than merely disallowing these costs from NSP's FCR.

10. The Commission finds that the Negotiated Agreement's provision requiring Advocacy Staff to support the use of the 12 CP jurisdictional allocation method for purposes of allocating generation and transmission costs through December 31, 2025 is reasonable and does not bind the Commission.

[1] N.D. Cent. Code Ch. 49-01 (2014) (providing the general rules concerning the Public Service Commission); see generally N.D. Cent. Code title 49 (providing the general rules concerning public utilities).
[2] N.D. Cent. Code 49-02-03 (2014) ("The commission shall supervise the rates of all public utilities . . . [T]he commission by order shall fix reasonable rates . . . ").

11. The Commission finds that the moratorium on base rate increases through the end of 2017 provided for in the Negotiated Agreement is reasonable.

12. The Commission finds that the additional time to develop a long-term RTF to address energy policy differences among the states served by the NSP System provided for in the Negotiated Agreement is reasonable.

Based on the foregoing Findings of Fact and Conclusions of Law, the Commission issues the following:

Order

The Commission Orders:

1. The September 30, 2015 Negotiated Agreement, a copy of which is attached to this Order and made a part of this Order, is APPROVED.

2. NSP shall file the RTF for the Commission's consideration no later than January 1, 2017.

3. NSP shall make all necessary filings in consultation with Commission Advocacy Staff and Advisory Staff as required by this Order and the Negotiated Agreement.

4. The Advanced Determination of Prudence requested by NSP in Case No. PU-13-708 for the Pleasant Valley Wind Farm is GRANTED.

5. The Advanced Determination of Prudence requested by NSP in Case No. PU-13-707 for the Odell Wind Farm is GRANTED.

PUBLIC SERVICE COMMISSION

Randy Christmann **Commissioner**	**Julie Fedorchak** **Chairman**	**Brian P. Kalk** **Commissioner**

Xcel Energy®

February 22, 2016

Darrell Nitschke, Executive Secretary
North Dakota Public Service Commission
Dept. 408
600 East Boulevard Avenue
Bismarck, ND 58505-0480

RE: FIRST REVISED NEGOTIATED AGREEMENT
CASE NOS. PU-12-813, *ET. AL.*

Dear Mr. Nitschke:

Enclosed for filing in the above referenced Cases, please find the executed version of the First Revised Negotiated Agreement (Revised Agreement) between Northern States Power Company (NSP) and Commission Advocacy Staff. The unexecuted version of the agreement was filed on Friday, February 19, 2016.

Thank you.

Sincerely,

DAVID SEDERQUIST
SR. REGULATORY CONSULTANT

cc: Mitch Armstrong
Illona Jeffcoat-Sacco
Pat Fahn
Jerry Lein
Mike Diller
Jack Schuh
Blaine Johnson
ALJ Timothy Dawson - OAH File Nos. 20150578, 20150579, 20150580, 20150581, 20150582, 20150583, 20150584 and 20160685

STATE OF NORTH DAKOTA
BEFORE THE
PUBLIC SERVICE COMMISSION

NORTHERN STATES POWER COMPANY 2013 ELECTRIC RATE INCREASE APPLICATION	CASE NO. PU-12-813

FIRST REVISED NEGOTIATED AGREEMENT

RELATING TO
NORTH DAKOTA GENERATION RESOURCE POLICY

I. INTRODUCTION

This First Revised Negotiated Agreement (Agreement) is entered into by Northern States Power Company, a Minnesota corporation (NSP or the Company) and the North Dakota Public Service Commission (Commission) Advocacy Staff (Staff) as of February 22, 2016. NSP and Staff may each be referred to as a "Party" and may be collectively referred to as the "Parties." This Agreement revises and supersedes the Negotiated Agreement Relating to North Dakota Generation Resource Policy executed by the Parties and filed with the Commission on September 30, 2015 (Original Negotiated Agreement) by incorporating revisions to the Original Negotiated Agreement consistent with the Commission's direction provided at the February 3, 2016 work session in this Case.

This Agreement stems from the Parties' commitments contained in the Revised Second Amended Comprehensive Settlement Agreement (Rate Settlement) in Case Nos. PU-12-813, PU-13-706, PU-13-707, PU-13-708, PU-13-742, PU-13-743, PU-13-194, PU-13-195 (collectively, the Rate Case) adopted by the North Dakota Public Service Commission (Commission) on February 26, 2014. As required by the Rate Settlement, the Parties have negotiated in good faith to obtain this Agreement utilizing the guiding principles in Section II.A of the Rate Settlement as a basis for their negotiations (which are provided for reference as Schedule 1 to this Agreement). However, additional information not available when the Rate Settlement was entered into (*e.g.*, the Company's 2015 Resource Plan (Case No. PU-15-19), additional proposed resource additions and the Clean Power Plan) have led the Parties to slow down and reassess how to viably approach the very complex issue of divergent state energy policies.

The Parties concur that varying state energy policies within the NSP System footprint have led to differences in each state's approach to generation resource development. Given this, and the Company's plans to add significant generation resources to its system over the next twenty years to address load requirements, replace aging infrastructure, and comply with new environmental regulations, the Parties have determined that the repricing approach contemplated in the Rate Settlement (and referred to as the "Restack") may not be sufficiently robust to address concerns regarding differing state energy policies while allowing the Company a reasonable opportunity to earn its authorized rate of return.

Therefore, the Parties have determined that the development of an effective long-term framework to resolve these issues is imperative. By this Agreement, the Company binds itself to devise and implement a regulatory framework to: 1) address the impact of divergent state energy policy on NSP's customers; 2) increase the geographic diversity of NSP System generation while maintaining system reliability; and 3) provide monetary value to North Dakota customers in the event the Company is unable to make good on this Agreement.

The Parties intend this Agreement to provide a "bridge period" for the Company to propose and implement, in collaboration with the Commission and Staff, a long-term "Resource Treatment Framework," or RTF. This Agreement binds the Company to file an RTF proposal with the Commission no later than January 1, 2017, with the intention to implement it no later than January 1, 2018. This Agreement also requires the Company to accelerate, from 2036 to 2025, its commitment to construct and install an integrated NSP System thermal generating resource in eastern North Dakota, preferably near the city of Fargo.

II. INVESTMENT IN NORTH DAKOTA THERMAL GENERATION

The Parties agree that the Commission has long encouraged the Company to invest dispatchable, thermal system generation in eastern North Dakota. The Parties also agree that there are local reliability and system benefits in locating thermal generation within or near its North Dakota service territory. In light of this, the Company agreed as part of the Rate Settlement to develop up to 400 MW of dispatchable, thermal generation in eastern North Dakota by 2036 (the 2036 Commitment) consistent with least cost planning and prudent ratemaking principles.

Since making the 2036 Commitment, the Company has completed its 2016-2030 Resource Plan and has identified a capacity need arising in 2025. To fulfill this need with thermal generation in North Dakota, and to reciprocate the cost recovery provisions agreed to by Staff in Section III of this Agreement, the Company agrees to develop, own, and operate (or alternatively, cause to be developed and operated on its behalf through a power purchase agreement or other contractual arrangement) a combustion turbine with a capacity of at least 200 MW in eastern North Dakota, no later than December 31, 2025. The costs of the generating facility will be allocated to all state jurisdictions served by the Company in a manner consistent with other NSP System resources.

Attainment of this commitment is contingent on the Company's receipt of all necessary and appropriate permits and regulatory approvals. Further, except as modified by this Section II, all provisions of the 2036 Commitment remain in place, including without limitation, the requirements that the combustion turbine agreed to in this paragraph reasonably: 1) address a system capacity need, and 2) represent a least-cost resource when also considering the local reliability and system benefits of developing thermal generation in North Dakota.

If for any reason the Company does not place in service the combustion turbine contemplated by this Section II by December 31, 2025, the Company will provide a refund to North Dakota customers in 2026 equal to fifty percent of the revenues collected from North Dakota customers during the ten year period of 2016-2025 that represents the difference between the actual revenues received by the Company for the biomass power purchase agreements (identified below) and the amount North Dakota customers would have paid for these resources had they been disallowed for recovery by the Commission; recognizing that – if disallowed – North Dakota customers would have paid an adjusted system average cost of fuel for the energy (and associated capacity) from these resources. The biomass contracts subject to this paragraph are: 1) KODA Energy LLC; 2) WM Renewable Energy (MN Methane); 3) Pine Bend; 4) FibroMinn; 5) Laurentian Energy Authority I; and 6) St. Paul Cogeneration.

III. RECOVERY OF SELECTED GENERATION RESOURCES

A. *Existing System Resources*. In recognition of the Company's accelerated commitment to construct thermal generation in North Dakota, and the interest of the Parties to achieve a long-term RTF, the Parties agree that the resources listed in Attachment A to this Agreement are to be excluded from the calculation of the Company's North Dakota Fuel Cost Rider beginning the later of January 1, 2016 or the date this Agreement is adopted by the Commission. The North Dakota portion of the capacity and energy costs of all other NSP System resources (including Company-owned facilities and Power Purchase Agreements) in-service as of February 26, 2014 are to be recovered by the Company through its base rates, Fuel Cost Rider (FCR), and/or Renewable Energy Rider (RER), as may be applicable, during the term of this Agreement. The Parties further agree that the costs of the Border Winds, Pleasant Valley, and Odell wind resource additions currently being constructed are to be included in the Company's rate base, Fuel Cost Rider (FCR), and/or Renewable Energy Rider (RER), as applicable. The Commission's recent Orders in Case Nos. PU-15-95 and PU-14-810 (Aurora Solar and Solar Portfolio) denying Advance Determination of Prudence are unaffected by this Agreement.

B. *Pending Resource Additions.* The Parties agree that the proposed Calpine Mankato Combined Cycle PPA currently pending before the Commission in Case No. PU-15-96 is not subject to this Agreement.

C. *Future Pre-RTF Resource Additions.* In the event that the Company proposes other resource additions between the date this Agreement is executed by the Parties and the date an RTF is implemented by the Commission, the Company will bring these resources for approval before the Commission consistent with its obligations under the Rate Settlement, Case No. PU-12-59 and Case No. PU-07-776.

IV. RESOURCE TREATMENT FRAMEWORK

The Parties recognize that the Company, and the utility industry as a whole, is entering a period of significant uncertainty. This uncertainty includes the potential for new federal environmental regulations regulating carbon dioxide emissions and their impact on the utility industry. Further, the Company is entering a 20 year period in which it anticipates significant portions of its generating fleet will be retired and replaced.

In light of this, the Parties have entered into this Agreement to address short-term treatment of resources (*i.e.,* existing and certain pending resources) and provide time for careful consideration as to how the Company should best proceed to ensure future generation resources are in place – and the costs properly assigned – to meet the energy and capacity needs of its customers.

To that end, the Parties agree that the Company, in consultation and collaboration with the Commission and its Staff, will propose a long-term RTF which shall address the Company's long-term plans for addressing divergent state energy policies. The Company must file the proposed RTF with the Commission no later than January 1, 2017 with the expectation that the RTF, if approved by the Commission, will be implemented on January 1, 2018. Mutual agreement between the Company and Staff is desired but not a prerequisite to the Company making the filing contemplated by this paragraph.

V. OTHER MATTERS

A. *Extension of Rate Case Moratorium.* In the Rate Settlement the Company agreed to a moratorium for further rate adjustments until 2017. To provide sufficient time for the Commission to consider the Company's RTF during 2017, the Company commits to extend this rate case moratorium one additional year. To that end, the Company may not increase base rates – on an interim or permanent basis – prior to January 1, 2018. To ensure that rates remain just and reasonable during 2017, in the event that the Company's annual weather-normalized earnings exceed a 10.25 percent return on equity during 2017, the Company will refund to customers one hundred percent (100%) of any weather-normalized revenue associated with the excess earnings.

B. *Other Commitments of the Company.* To facilitate successful implementation of this Agreement, the Company agrees to waive: a) any claims regarding the enforceability of this Agreement; and b) any claims against the Commission with respect to the adequacy of rates set by the Commission resulting strictly from this Agreement. The waiver in this paragraph is effective as of the date this Agreement is executed by the Company and terminates on January 1, 2018. Further, the waiver in this paragraph does not limit or prohibit NSP's right to request rehearing or appeal of any Commission order with respect to either the prudence of a particular resource or the adequacy of rates set by the Commission.

C. *Commitment of Advocacy Staff*. To facilitate successful implementation of this Agreement, Staff agrees to cooperate with the Company consistent with negotiating principle 7 of the Rate Settlement.

D. *Demand Allocator*. The Parties agree that the conclusions of the Allocator Study filed with the Commission on April 27, 2015 support the continued use of the 12 CP jurisdictional allocation method. To that end, this Agreement establishes a rebuttable presumption that the 12 CP jurisdictional allocation method is appropriate for allocating applicable system costs between North Dakota, South Dakota and Minnesota. In the event that circumstances have sufficiently changed such that Staff believes it is appropriate to rebut the rebuttable presumption established in this paragraph: 1) Staff will notify NSP of its intentions as early as possible; and 2) Staff will work in good faith with NSP to reach agreement on an appropriate allocation methodology in light of the rebuttable presumption established in this paragraph. The provisions of this paragraph expire on December 31, 2025.

VI. OTHER TERMS AND CONDITIONS

A. *Environmental Attributes*. "Environmental Attributes" are those credits, allowances, offsets and other similar rights associated with renewable electric generation that can be used to (i) satisfy the Company's renewable energy requirements in any of the states it operates in, and/or (ii) claim responsibility for, ownership of, avoidance of, or reduction of legally-recognized emissions or pollutants. The Company and Staff agree to establish the principle that it would be inequitable to allocate Environmental Attributes to the Company's North Dakota jurisdiction from a generation resource in the event that 1) the Commission rejects an Advanced Determination of Prudence for such resource, unless and until full recovery of the allocable North Dakota costs is approved in a later proceeding, or 2) costs of the generation resource are disallowed in a rate case or other proceeding.

In the event that new regulations promulgated by the federal government under the Federal Clean Power Act, 42 U.S.C. §§ 7401, *et. seq.*, known as the Clean Power Plan, 80 Fed. Reg. 64661 (Oct. 23, 2015) (to be codified at 40 C.F.R. pt. 60), or any Clean Power Plan successor regulations, state or federal implementation plans, or related court orders conflict with the provisions of this Section VI.A., then these regulations, plans, or court orders shall control.

B. *Special Accounting.* The Company may petition the Commission for special accounting treatment for any disallowances that result from this Agreement.

C. *Basis of Negotiated Agreement.* This Agreement is subject to the approval of the Commission.

D. *Negotiations Privileged.* All offers, discussions and information exchanged related to the negotiation of this Agreement are considered privileged by the Parties and may not be used in any manner in connection with any regulatory proceedings or otherwise, except as provided by law. In the event that the Commission does not approve this Agreement, it shall not constitute part of the record in Case No. PU-12-813 and no part thereof may be used by any Party for any purpose in any other proceeding.

E. *Applicability and Scope.* This Agreement is binding on the Parties, and their successors, assigns, agents, and representatives for the specified term.

F. *Effect on Rate Settlement.* This Agreement is a product of the Rate Settlement. It will control over the terms of the Rate Settlement with respect to the subject matter contained herein.

G. *Ongoing Support.* The Parties will jointly support the approval of this Agreement, without amendment or modification, by the Commission.

H. *Complete Agreement.* This Agreement and any Attachments and Schedules attached hereto will constitute the entire agreement between the Parties relating to the subject matter herein and will supersede all prior contracts and understandings between them relating to such matters.

I. *Counterparts.* This Agreement may be executed in any number of counterparts by the Parties, each of which when so executed will be an original, but all of which together will constitute one and the same instrument.

J. *Effective Date.* This Agreement shall be effective upon the Commission issuing a final, non-appealable order adopting this Agreement. The Company will make all necessary compliance filings to reflect this Agreement in a timely manner and guided by a schedule established jointly by the Parties.

K. *Termination for Commission Modification.* This Agreement is subject to approval by the Commission who retains continuing oversight pursuant to N.D.C.C. § 49-05-09. If the Commission order initially approving this Agreement modifies or conditions this Agreement it will be considered terminated if either Party files a letter with the Commission within thirty (30) calendar days of the order date stating that the modification is unacceptable.

L. *Petition for Modification or Termination.* The Company may petition the Commission for modification or termination of this Agreement for good cause shown.

VII. CONCLUSION

The Parties agree that the provisions of this Agreement will support the Commission's interest in advancing North Dakota's energy policy priorities and lead to a just and reasonable outcome.

[SIGNATURE PAGE FOLLOWS]

Dated this 22nd day of February, 2016.

Northern States Power Company,
A Minnesota corporation

By: ____________________

Christopher B. Clark
President
Northern States Power Company (MN)

Dated this 22nd day of February, 2016.

Northern Dakota Public Service Commission Staff

By: s/John M. Schuh

John M. Schuh, Advocacy Staff
Counsel to the Commission

[SIGNATURE PAGE TO FIRST REVISED NEGOTIATED AGREEMENT]