NDPSC Case Nos. PU-12-813, *et al.*
MPUC Docket No. E-002/M-16-223
APPENDIX D

REVISED SECOND AMENDED COMPREHENSIVE SETTLEMENT AGREEMENT

NDPSC 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

STATE OF 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**

ORDER ADOPTING SETTLEMENT

February 26, 2014

Appearances

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

Kari L. Valley, Assistant General Counsel, Xcel Energy Services Inc., 414 Nicollet Mall, Fifth Floor, Minneapolis, Minnesota 55401, representing Northern States Power Company.

Zeviel Simpser, Briggs and Morgan, P.A., 2200 IDS Center, 80 South 8th Street, Minneapolis, Minnesota, 55402, representing Northern States Power Company.

Ryan Norrell, Legal Counsel, North Dakota Public Service Commission, State Capitol, 600 East Boulevard Avenue, Bismarck, North Dakota 58505, representing Commission Advocacy Staff.

Illona A. Jeffcoat-Sacco, General Counsel, North Dakota Public Service Commission, 600 E. Boulevard Ave, Bismarck, North Dakota 58505, representing the Commission.

Mitchell D. Armstrong, Special Assistant Attorney General representing the Public Service Commission.

Bonnie Fetch, Office of Administrative Hearings, 2911 North 14th Street, Suite 303, Bismarck, ND 58503, Administrative Law Judge .

Patrick Ward, Zuger, Kirimis & Smith, 316 North Fifth Street Bismarck, ND 58502-1695, Administrative Law Judge.

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), to be located in Stutsman County, North Dakota; a proposed PPA for the 200 MW Odell Wind Project (Odell) to be located near Mountain Lake, Minnesota; and the proposed 200 MW Pleasant Valley Wind Project (Pleasant Valley) 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.

Summary of Settlement

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:
  - Implementation of the multi-year rate plan consistent with NSP's originally proposed class apportionment;
  - Instituting single customer charges for several rate classes;
  - Elimination of account history charge; and
  - 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.

Discussion

NSP explained that its need for increased rates is driven by NSP's current investments to upgrade and refresh its system to safely and reliably serve customers, as well as additional costs to comply with new regulatory requirements, and cost increases due to general economic trends. NSP identified significant investments in its nuclear fleet, thermal generation fleet, transmission and distribution systems as the key drivers of its investment cycle. NSP stated that its system investments are expected to decrease in 2016.

The Commission finds that the multi-year rate plan provides fixed, predictable increases that will provide NSP the opportunity to earn a reasonable return on equity of 9.75 percent in 2013, 10.0 percent in 2014 and 2015, and 10.25% in 2016.

The Commission finds that the earnings sharing mechanism provided for in the Revised Second Amended Settlement provides reasonable customer protections in the event NSP earns above its authorized return on equity on a weather normalized basis.

The Commission finds the moratorium on base rate increases in 2016 provided for in the Revised Second Amended Settlement is reasonable.

The Commission finds that the Fuel Cost Rider reforms provided for in the Revised Second Amended Settlement are reasonable and responsive to the Commission's interests in providing for more transparency for this cost recovery mechanism.

The Commission finds that the implementation of the Transmission Cost Recovery Rider and Renewable Energy Rider are reasonable and consistent with Commission precedent.

The Commission finds that the "restack" proposal provided for in the Revised Second Amended Settlement provides an opportunity to address concerns regarding the impact of the energy policies of other state jurisdictions on the rates of NSP's North Dakota customers.

The Commission finds that the jurisdictional allocation study provided for in the Revised Second Amended Settlement is reasonable.

The Commission finds that the rate design provided for in the Revised Second Amended Settlement is reasonable.

The Commission finds that NSP's commitment to build up to 400 MW of thermal generation in the Red River Valley by 2036 consistent with prudent resource planning principles as provided for in the Revised Second Amended Settlement is reasonable.

The Commission finds that NSP's commitments to increase reliability investments provided for in the Revised Second Amended Settlement are reasonable.

The Commission finds that the Border Winds Project is a prudent resource acquisition and the ADP requested in Case No. PU-13-742 should be granted as provided for in the Revised Second Amended Settlement.

The Commission finds that the Red River Valley turbine generators are prudent resource acquisitions and the ADP requested in Case No. PU-13-194 should be granted as provided for in the Revised Second Amended Settlement.

The Commission finds that the Revised Second Amended Settlement is reasonable and provides a reasonable resolution to all of the pending issues in all the captioned cases.

Having considered this matter, the Commission issues the following:

Order

1. The Revised Second Amended Settlement Agreement, a copy of which is attached to this Order and made a part of this Order, is APPROVED.

2. NSP shall file compliance tariffs consistent with this Order and the Revised Second Amended Settlement Agreement within 10 days after the date of this Order.

3. Within 90 days from the effective date of rates filed in compliance with this Order, NSP shall issue to customers a refund consistent with the Revised Second Amended Settlement.

4. NSP shall make all necessary filings as required by this Order.

5. No action is taken on NSP's requests for ADPs in Case No. PU-13-707 and Case No. PU-13-708 and those applications are dismissed without prejudice.

6. NSP's applications for ADP in Case No. PU-13-194, Case No. PU-13-706 and Case No. PU-13-742 are granted consistent with the Revised Second Amended Settlement.

PUBLIC SERVICE COMMISSION

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

STATE OF NORTH DAKOTA
BEFORE THE
PUBLIC SERVICE COMMISSION

Brian Kalk	Chairman
Randy Christmann	Commissioner
Julie Fedorchak	Commissioner

APPLICATION OF NORTHERN STATES POWER COMPANY, A MINNESOTA CORPORATION, FOR AUTHORITY TO INCREASE RATES FOR ELECTRIC SERVICE IN NORTH DAKOTA	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 ADVANCE DETERMINATION OF PRUDENCE – ODELL WIND PROJECT APPLICATION	CASE NO. PU-13-707
NORTHERN STATES POWER COMPANY ADVANCE DETERMINATION OF PRUDENCE – PLEASANT VALLEY WIND PROJECT APPLICATION	CASE NO. PU-13-708
NORTHERN STATE POWER COMPANY ADVANCE DETERMINATION OF PRUDENCE – BORDER WINDS PROJECT APPLICATION	CASE NO. PU-13-742
NORTHERN STATE 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 GENERATOR APPLICATION	CASE NO. PU-13-194
NORTHERN STATES POWER COMPANY RED RIVER VALLEY NG UNITS 1 & 2 – HANKINSON, ND PUBLIC CONVENIENCE & NECESSITY	CASE NO. PU-13-195

REVISED SECOND AMENDED COMPREHENSIVE SETTLEMENT AGREEMENT

This Revised Second Amended Settlement Agreement ("Revised Second Amended Settlement") is entered into this 25th day of February 2014, by and between the North Dakota Public Service Commission Advocacy Staff ("Staff") and Northern States Power Company ("Xcel Energy" or the "Company") (collectively, the "Parties") and supersedes the Second Amended Settlement dated February 18th. This Revised Second Amended Settlement will (a) result in just and reasonable rates for the Company's retail electric operations in North Dakota for a four-year period beginning January 1, 2013 and ending December 31, 2016 and (b) implement a framework to reflect North Dakota's energy policy priorities as expressed by the Commission. The Second Amended Settlement reflected additional discussion and agreement of the Parties with respect to the annual percent increase in rates necessary to address increased costs of service during the term of the multi-year plan. This Revised Second Amended Settlement revises terms used in the Second Amended Settlement and corrects typographical errors. Through this Revised Second Amended Settlement the Parties have resolved all issues in the above captioned proceedings.

PRELIMINARY STATEMENT

The above captioned Cases address the Company's requested 9.25 percent retail revenue increases (Case No. PU-12-813; the Rate Case); the Company's request for advanced determinations of prudence (ADP) for 750 MW of additional wind resources and a certificate of public convenience and necessity (PC&N) for a 150 MW wind project (Case Nos. PU-13-706, PU-13-707, PU-13-708, PU-13-742, PU-13-743; the Wind Cases); and the Company's request for ADP and PC&N for the construction of three gas combustion turbines to meet an identified capacity need in the 2017-2019 time frame (Case Nos. PU-13-194, PU-13-195; the Gas CT Cases). Attachment A contains a summary of the procedural history of the Rate Case, the Wind Cases, and the Gas CT Cases (collectively, the Proceedings).

The Proceedings have raised a number of rate and policy issues related to the Company's ongoing provision of service in North Dakota. In light of these issues, and in an effort to achieve mutually agreeable long-term solutions, the Parties have entered into this Revised Second Amended Settlement to develop a multi-year rate plan and address North Dakota energy policy goals. Specifically, this Revised Second Amended Settlement establishes:

- A four-year rate plan that results in just and reasonable rates to match the Company's current investment cycle while balancing our customers' need for predictable and competitive rates;

- A framework to ensure that the Company's North Dakota customers will be served by a resource mix consistent with North Dakota's energy policies. The framework provides hard deadlines and financial impacts to the Company if the framework is not sufficiently developed; and

- A path toward development of North Dakota based generation nearer to the Company's existing loads.

Just and Reasonable Rates

The rate plan agreed to in this Revised Second Amended Settlement reflects efforts to minimize the impacts on customer energy bills during the Company's current investment cycle while providing the Company a reasonable opportunity to recover its investments and operating costs and earn a fair rate of return. The rate plan agreed to in this Revised Second Amended Settlement also provides a base rate increase moratorium for Xcel Energy's North Dakota customers in the final year of the plan.

Recognizing that a long-term rate plan requires reliance on forecasted costs and sales, this Revised Second Amended Settlement establishes a mechanism to ensure that the rates set in the rate plan are just and reasonable. This mechanism provides for revenue sharing with our customers for weather-normalized earnings in excess of the authorized returns on equity (ROE) established in this Revised Second Amended Settlement. The Parties believe that this mechanism creates reasonable safeguards for Xcel Energy's customers.

Even with the rate increases contemplated in this Agreement, the Company's average rates in North Dakota are projected to remain among the lowest in the Midwest and approximately 15 percent lower than the national average through 2016. Moreover, in 2016 the Company's North Dakota rates will have increased, on average, only about 2.6 percent per year over the past twenty-five years. This is similar to the average annual rate of inflation expected during the same period.[1]

<u>Serving Customers Consistent With North Dakota Energy Policy</u>

In addition to the multi-year rate solution presented in this Revised Second Amended Settlement, the Parties are also proposing to undertake actions intended to address the long-term interest of the Commission in exerting more control over the energy resource mix serving the Company's North Dakota customers. This Revised Second Amended Settlement creates a negotiating framework through which the Parties will

[1] Source: U. S. Dept. of Labor (Consumer Price Index).

seek to adjust the resource mix to be more consistent with the North Dakota energy policy now and in the future.

That said, the Parties also recognize the immense complexity of implementing this plan. Therefore, our proposal implements a hard deadline by which such a mechanism must be developed and filed with this Commission for its approval. If the Parties are unable to meet this deadline, this Revised Second Amended Settlement will result in adverse financial impacts on the Company, as described in Section II.A.

The Parties believe that this policy-based framework is a novel and bold approach to provide a long-term solution to long-standing North Dakota concerns and is a significant benefit of this Revised Second Amended Settlement.

Development of North Dakota Generation

Consistent with the efforts of the Parties to provide solutions to the Commission's stated policy interests, as part of this Revised Second Amended Settlement, the Company is committing to develop North Dakota based generation consistent with prudent resource planning principles and the concepts of orderly development. The Company's commitment is consistent with the timing and parameters of Advocacy Staff's recommendations to the Commission in the Gas CT Cases and demonstrates the Company's commitment to provide a reasonable framework for meeting the energy policy goals of North Dakota.

In addition, this Revised Second Amended Settlement is intended to address other matters affecting the Company that are currently before the Commission. Through a negotiated process, the Parties are seeking to address the Commission's concerns and have documented the outcome of these negotiations in this Revised Second Amended Settlement.

REVISED SECOND AMENDED SETTLEMENT TERMS

The Parties agree to the provisions as defined below and supported by Attachment B, which is a summary of the Revised Second Amended Settlement Agreement adjustments and their revenue impact.

I. REVENUE MATTERS

A. Rate Plan

1. *Multi-Year Solution*

The Parties acknowledge that the Company's rate request is driven largely by its current investment cycle which includes efforts to extend the lives and increase the capacity of its nuclear fleet, significantly invest in its transmission system, and to refresh and automate its distribution system. These investments not only create a revenue deficiency in the 2013 test year, but are forecasted to drive revenue shortfalls in 2014 and 2015 as well.

The Rate Plan agreed to by the Parties in this Revised Second Amended Settlement allows the Company to implement annual electric base rate increases for three years in lieu of filing additional and separate rate cases to address the forecasted deficiencies in those years due to the Company's on-going investment cycle. The Rate Plan then imposes a rate moratorium for the final year to match with the close of the Company's investment cycle. As part of the Rate Plan, the Company would be precluded from filing another general rate application prior to November 1, 2016 (and increasing base rates before 2017). The agreed-to Rate Plan is derived from a consideration of the Company's longer-range financial forecasts and a common desire to lessen bill impacts.

The proposed retail revenue increase percentages and corresponding base revenue increase estimates are shown in Table 1 below:

Table 1

Plan Year	Retail Increase %	Est. Base Revenue Increase
2013	4.9 %	$7,378,000[2]
2014	4.9%	$9,368,000
2015	4.9%	$10,072,000
2016	0%	$0

The methodology for implementing the proposed increase percentages is provided in Attachment C.

2. *Ensuring Just and Reasonable Rates*

To ensure rates are appropriately set under the Rate Plan, the Parties agree to establish an earning sharing mechanism to share with customers any weather-normalized earnings above the ROE agreed to in this Revised Second Amended Settlement. The earnings sharing mechanism requires that in the event the Company's annual weather-normalized earnings exceed the agreed to ROE in this Revised Second Amended

[2] Reflects February 16, 2013 effective date of Revised Second Amended Settlement 2013 rate increase and corresponding 10.5 months of recovery for an estimated annualized increase of $8,953,000.

Settlement described in Section I.A.3, the Company will refund to customers 50 percent of any weather-normalized revenue earned in excess of its authorized ROE for a particular year of the Rate Plan.

The earnings sharing framework is asymmetrical; customers will not be charged for earnings below the authorized level. The Parties further agree that, in 2016, the calculation of weather-normalized earnings for the purposes of the revenue sharing mechanism shall account for the impact to the Company's overall earnings of the costs of any power purchase agreement for which the Company has agreed, or which the Commission has ordered, be excluded from the calculation of the Company's Fuel Cost Rider mechanism (FCR), either in whole or in part and such costs are not recovered in another jurisdiction.

3. *Return on Equity and Capital Structure*

To ensure a balance between rate affordability, system reliability, and the utility's financial health, the Parties agree for settlement purposes to an authorized ROE of 9.75 percent for 2013. The approved ROE will increase in 2014 and again in 2016 in acknowledgment of the longer-term nature of the Rate Plan as provided in Table 2 below:

Table 2

Plan Year	Authorized ROE
2013	9.75 %
2014	10.00 %
2015	10.00 %
2016	10.25 %

The Parties also agree that a 10.00 percent ROE will be used for purposes of determining interim rates in the Company's next electric rate application.

For future rate rider calculations, the capital structure and cost of debt listed in Attachment D would be used, specifically the test year amounts, and the ROE would be updated per this Revised Second Amended Settlement. For annual reporting, the actual capital structure and cost of debt would be used in addition to the specified ROE.

B. Rider Implementation and Reform

In addition to the Rate Plan agreed to in this Revised Second Amended Settlement, the Parties have agreed to implement transparency reforms to the Company's Fuel Cost Rider (FCR) and to implement a Transmission Cost Recovery Rider (TCR) and a North Dakota Renewable Energy Rider.

1. Fuel Cost Rider Reforms

In addition to the cost of fuel, the Company currently recovers the costs of its power purchase agreements (PPA) through the FCR, consistent with the Commission's rules. N.D. Admin. Code § 69-09-02-39. However, the Parties recognize that a stronger "gatekeeping" mechanism is necessary to ensure that the Commission has been fully notified of PPA costs to be recovered through the FCR to determine if they are prudent. To that end, the Parties have agreed to reform the procedures through which the Company may include the costs of PPAs in the FCR.

For projects less than 50 MW in size, the Company will make an annual filing providing notification of any new PPAs that have been included in the FCR in that year. Such annual filing will include a description of the project, a summary of the justification for the contract or investment, the expected annual costs over the life of the contract, and the initial estimated monthly bill impact to residential customers. Such notification will provide clear and transparent notice to the Commission of the new PPA(s) under 50 MW being included in the Company's FCR calculation and allow the Commission to decide if it wants to review the PPA(s) in more detail to determine its prudence, consistent with the Commission's current Automatic Adjustment Clause Rules. The Parties agree that in the event the Commission does not commence review of the PPA(s) identified in the annual FCR notice filing within six months of the filing, the PPA(s) identified in the annual FCR notification filing will be deemed prudent for ratemaking purposes for the life of the PPA(s). In addition to the annual FCR notification filing, the Company will also provide similar information for new PPA(s) in the Company's regular monthly FCR filing in which the costs and volumes of that PPA are being included in the FCR calculation for the first time. The Parties further agree that the foregoing FCR reform is not applicable to any of the Company's energy purchases from the MISO market.

The Parties agree that Commission granting an ADP of all future PPAs over 50 MW is required before such costs are included in the Company's FCR for recovery. The Parties further agree that the foregoing FCR reform is not applicable to any of the Company's energy purchases from the MISO market.

The Company will file compliance tariff sheets implementing the above-mentioned FCR reforms within 90 days of the date of an Order adopting this Revised Second Amended Settlement.

2. *Transmission Cost Rider*

A significant component of the Company's investment cycle is the substantial investment in transmission infrastructure to support the Company's integrated system. Key among these investments is the Company's development of the CapX2020 Group 1 Projects for which the Commission granted an ADP in Case No. PU-09-678. As part of the Rate Case, the Company requested that the Commission approve the Company's implementation of a Transmission Cost Rider (TCR) to allow for rider recovery of these investments. To that end, the Parties agree to implement the Company's request to establish a TCR, consistent with N.D.C.C. § 49-05-04.3. The Company will file compliance tariff sheets implementing the TCR within 90 days of the date of an Order adopting this Revised Second Amended Settlement.

Consistent with the Company's request in the Rate Case, and to ensure transparency to the Commission and our customers of the costs included in the TCR, this Revised Second Amended Settlement only establishes the TCR tariff. The Company must file with the Commission a request to include specific costs for recovery through the TCR in a separate proceeding.

3. *North Dakota Based Renewable Energy Rider*

North Dakota law encourages the development of renewable resources in the State. Specifically, N.D.C.C. § 49-05-16 provides a rebuttable presumption that generation resource to be developed in North Dakota are prudent. Further, N.D.C.C. Chs. 49-02, 49-05 and 49-06 and Commission precedent in Case No. PU-06-466 allows for the recovery of costs of renewable resources developed in North Dakota. To that end, the Parties agree to implement a North Dakota Renewable Energy Rider as part of the Company's rate structure. To ensure transparency of the costs to be recovered through this rider, the Company may only include the costs of renewable projects that are located in North Dakota and for which the Commission has granted an ADP. As of the date of this Revised Second Amended Settlement, the Parties contemplate that the Company will recover the costs of the Border Winds Project (the subject of Case No. PU-13-742) through the Renewable Energy Rider, consistent with the agreed to terms of this Revised Second Amended Settlement concerning the Company's requested ADP in that Case.

The Company will file compliance tariff sheets implementing its Renewable Energy Rider within 90 days of the Commission's Order adopting this Revised Second Amended Settlement.

II. IMPLEMENTATION OF NORTH DAKOTA ENERGY POLICY

The Parties recognize that it has been the interest of North Dakota to exert more control over its energy resource future for a number of years. The Company and Staff began substantially addressing this interest in the Settlement Agreement adopted by the Commission in Case No. PU-07-776. In that settlement, the Company and Staff agreed to implement processes to keep the Commission informed of the Company's resource planning efforts through the then relatively new ADP law (N.D.C.C. § 49-05-16) to provide the Commission an opportunity to provide early input into the Company's resource decisions. A clear outcome of the Proceedings is the realization by both the Company and Staff that, while they improved awareness and enhanced dialogue regarding the Company's resource decisions, the processes implemented in Case No. PU-07-776 have been insufficient to address the Commission's needs.

In light of this, the Parties agree to make a fundamental and unprecedented shift in the way the Company serves its North Dakota customers by proposing to adjust rates to effectively change the resource mix serving its North Dakota customers so that it is more consistent with North Dakota's energy policies. The Parties believe that a comprehensive framework may be a better way to address the Company's resource decisions than on a case-by-case basis.

The Parties also recognize that an undertaking of this nature is extremely complex. To allow for a timely settlement of the Proceedings, this Revised Second Amended Settlement is intended to provide a framework for the Parties to further develop and implement such a mechanism. Through this framework, the Parties intend to cooperatively develop a mechanism through which the Company will serve its North Dakota customers with a resource mix consistent with North Dakota energy policies. However, due to the complexity of the undertaking, the likely involvement of other state Commissions, and the potential that the Parties may not reach ultimate agreement on the appropriate mechanism to implement the proposal, the Parties have agreed to a deadline by which they will bring a negotiated agreement to implement such a mechanism (Negotiated Agreement) to the Commission for approval. Should the Negotiated Agreement not be filed with the Commission by that deadline, the Parties have agreed on a remedial action that will disallow certain renewable energy costs identified in the Rate Case and the Wind Cases on a prospective basis. The Parties believe that such a negotiating structure will induce both the Company and Staff to obtain a timely and successful outcome of negotiations as well as provide for a default result consistent with the Commission's current policies and authority should no agreement be reached.

As part of this Revised Second Amended Settlement, the Company and Staff have also settled the outstanding issues in the Wind Cases and the Gas CT Cases as well as other outstanding renewable energy related issues that arose in the Rate Case. Further, this Revised Second Amended Settlement includes a commitment by the Company to develop North Dakota based thermal generation consistent with prudent resource planning principles as described in detail below.

A. North Dakota Policy Based Generation Mix – Negotiating Framework

As described above, the Parties have agreed to negotiate in good faith to develop a mechanism whereby the Company will serve its North Dakota customers with resources (either real or proxy) consistent with North Dakota's energy policies. The Parties have entered into preliminary discussions to explore the feasibility of such mechanism and agree that such an outcome is feasible. To that end, the Parties have agreed to the following general principles as a framework to guide such good faith negotiations to result in a Negotiated Agreement.

1. All policy choices come with benefits and drawbacks and that the ultimate outcome of the Company's proposal is to allow its North Dakota customers to obtain the benefits and bear the burdens of North Dakota's energy policy choices. Benefits may include immediately lower pricing while burdens may include increased exposure to commodity and regulatory risk. Consistent with this principle, the Parties agree that any cost savings or cost increases, now and in the future, that result from any Negotiated Agreement shall be allocated to the Company's North Dakota jurisdiction.

2. North Dakota energy policies are considered to be those expressed by the legislature through the enactment of laws, including the Renewable Energy Objective (N.D.C.C. § 49-02-28), and the Commission as expressed in its rules and orders.

3. The North Dakota historically allocated share of the Company's existing thermal resources provides an appropriate base upon which to meet a significant percentage (likely over 75 percent) of the Company's North Dakota resource needs. The North Dakota Renewable Energy Objective represents a reasonable amount of renewable resources to be included in the ultimate resource mix.

4. Any resources (real or proxy) utilized to replace existing Company resources that are deemed inconsistent with North Dakota energy policies should be "like" replacements taking into account the nature of the existing Company resource to be replaced (*i.e.* baseload, intermediate, peaking, *etc.*) and the contribution of the replaced resource to the integrated system (*i.e.* capacity and energy).

5. Proxy pricing (for either energy or capacity) for any future resource addition should reflect marginal pricing for the type of resource for which the proxy price is being utilized as a replacement.

6. Resource choices should be guided by the concept of reasonableness so that the ultimate North Dakota resource mix would be a reasonable approximation of what would have occurred had the Company historically developed its overall resource mix consistent with North Dakota policy so as not to result in only the lowest cost resources available making up the total agreed to North Dakota resource mix.

7. The Parties will consider the financial impact to the Company of the agreed upon resource mix in developing the Negotiated Agreement which includes but is not limited to providing for reasonable and mutually agreeable implementation schedules and deadlines.

8. The Negotiated Agreement must address how future resource additions will be treated if the Commission does not approve such future resource addition. Such future scenarios must account for both the energy and capacity value of such resources.

9. To provide certainty, the Negotiated Agreement is intended to be final for the purposes of developing a baseline resource mix (real or proxy) to serve the Company's North Dakota customers.

10. The Negotiated Agreement shall be subject to approval by the Commission.

The Parties agree to use their best efforts to negotiate in good faith, obtain agreement, document such agreement in the Negotiated Agreement, and file the Negotiated Agreement for approval with the Commission no later than June 30, 2015, unless the Parties mutually agree to request an extension from the Commission.

In the event the Parties do not (a) file an agreement with the Commission by June 30, 2015, or (b) request from the Commission an extension of time to file an agreement by June 30, 2015, then beginning January 1, 2016 the Company shall (i) remove from its calculation of its FCR the costs and volumes of the 21 PPAs identified on Attachment E, page 1; (ii) remove the costs of the three PPAs listed in Attachment E, page 2 from its FCR calculation and replace those costs as part of its FCR calculation with proxy costs representing the capacity and energy from the Company's Allen S. King Plant; and (iii) the Pleasant Valley Wind Project shall be disallowed from recovery in base rates in North Dakota and the volumes representing the energy production of the Pleasant Valley Project will be removed from the Company's calculation of its FCR. The Parties agree that this provides a penalty to the Company to induce the Company to use its best efforts to reach agreement in accordance with the negotiating framework.

B. Development of North Dakota Based Generation

As part of the Gas CT Cases, the Company proposed to construct two gas combustion turbines (CT) near Hankinson, North Dakota known as Red River Valley Unit 1 and Red River Valley Unit 2 to meet an identified capacity resource need in the 2017-2019 time frame. The record in the Gas CT Cases also reflects the fact that the Company may choose some alternative resource to meet that need instead of one or both of the proposed North Dakota based CTs. In light of the record in the Gas Cases, the Parties acknowledge that the Gas Cases identified the interest of the Commission in ensuring that the Company develops generation closer to its loads in North Dakota. The Parties further acknowledge that the record in the Gas CT Cases reflects the fact that diversifying the location of the Company's generation mix and locating generation closer to the Company's North Dakota loads provides some benefits to the Company's North Dakota customers as well as all of the other customers served by the Company.

In recognition of the fact that the Company's proposal to construct and own North Dakota based generation to meet its 2017-2019 resource need may not be implemented, but to obtain the benefits of North Dakota based generation identified in the Gas CT Cases, the Company hereby commits to develop up to 400 MW of thermal generation resources in North Dakota no later than 2036, consistent with the principles of orderly development of resources, the principle of least-cost development as provided in N.D. Admin. Code § 69-09-02-33, and general concepts of prudent resource planning to meet incremental additional resource needs that may arise in that timeframe. In furtherance of the foregoing sentence, and not in limitation thereof, development of North Dakota based generation must be cost effective taking into account the benefits of locating generation nearer to North Dakota loads and the benefits of geographic diversity of generation when compared to other alternatives.

Additionally, the Company's North Dakota based generation must be developed to meet an identified resource need. The Company shall continue to inform the Commission of its resource needs through the filing of its Ten-Year Plan and Midwest Resource Plan consistent with North Dakota law and the Company's commitments. The Company and Advocacy Staff shall meet and confer with respect to resource needs as they deem appropriate. When performing its resource planning, the Company shall incorporate its commitment into its planning efforts. Further, the Company agrees to advocate for the development of North Dakota based generation in other affected jurisdictions to the extent such North Dakota based generation is both cost effective and needed, as discussed in this Section II.B.

C. Jurisdictional Demand Allocator

In light of the issues raised in the Rate Case related to the appropriate demand allocation methodology to be used for the purposes of setting the Company's North

Dakota rates, the Parties agree that a study shall be performed to analyze the contribution of the Company's North Dakota jurisdiction toward the Company's overall system-wide production and transmission costs, and the available demand allocation methodologies which may be implemented to reflect such cost causation (the Study).

The Parties intend the Study to be unbiased and thorough. To that end:

1. Scope. The Parties will determine, after consulting and seeking the input of the Commission, the appropriate scope of the Study, consistent with the terms of this Revised Second Amended Settlement. The scope of the Study will be to analyze a number of demand allocator methodologies and propose recommendations for the methodology or methodologies that most reasonably represent the cost causation of the North Dakota jurisdiction on the Company's overall system-wide production and transmission costs. Secondary consideration will be given to maintaining consistency among jurisdictions and administrative feasibility.

2. Independent Third-Party. The Parties will utilize the services of an independent third-party to assist in directing, monitoring, and evaluating the results of the Study. The Parties and the Commission must agree on the third-party to be used. Both Parties will fully cooperate with the third-party. Either Party may supplement the Study as appropriate to assure that the Commission has a full and complete record for its use.

3. Costs. The costs of using an independent third-party will be paid by the Company. The Parties agree to use deferred accounting to recover these costs as a rate case expense in the Company's next rate case

4. Submittal. In light of the intent of the Parties to provide an unbiased and thorough Study and allow for the Commission to review the results, the Parties will submit the Study to the Commission no later than one-year after the Commission issues an order adopting this Revised Second Amended Settlement. The Commission may direct that additional analysis be done regarding the Study after the initial submission. The Parties shall also consult and seek input from the Commission prior to initiating the Study as provided in Paragraph 1 above.

5. Use as Evidence. The results of the Study may be used by the Parties as evidence in the Company's next North Dakota rate case to support a particular demand allocation methodology.

6. Implementation of the Settlement. For purposes of this Revised Second Amended Settlement, the Parties agree to the continued use of the average 12-month Coincident Peak (12CP) demand methodology. Further, the jurisdictional allocations used in rate rider calculations during the term of the Revised Second Amended Settlement will be made using 12CP with the specific allocation factors updated to reflect the current circumstances and information.

D. Prairie Rose PPA

The Parties agree that, while the Company was not timely in filing its ADP application, (ultimately leading to Commission rejection of the ADP) the costs of the Company's Prairie Rose PPA are recoverable. In recognition of the Company's late-filed ADP and the Staff's concern that this resource exceeds what is needed to meet North Dakota's Renewable Energy Objective, the Parties agree that only the Prairie

Rose energy costs incurred on and after the date the Commission adopts this Revised Second Amended Settlement will be included in the FCR calculation and the Company will forego any unrecovered portion of the Prairie Rose PPA incurred prior to that time.

E. Settlement of the Gas CT Cases

The Parties agree that the Company's proposal to construct Black Dog Unit 6 and Red River Valley Units 1 and 2 under the flexible, phased in approach described in the Company's Application is a cost-effective and prudent approach to meet forecasted capacity needs of the Company in the 2017 to 2019 time-frame.

While acknowledging the prudence of the Company's proposal to construct and own Black Dog Unit 6 and Red River Valley Unit 1 and 2, this Revised Second Amended Settlement shall in no way be construed to foreclose upon the possibility and prudence of some other approach to meet the Company's proposed 2017-2019 capacity needs, such as any proposal that may be selected as part of the Minnesota Competitive Acquisition Process described in the record of the Gas CT Cases. In the event the Company chooses to move forward with a resource acquisition other than Black Dog Unit 6 or Red River Valley Unit 1 or Red River Valley Unit 2 to meet its 2017-2019 capacity need, it shall file an application for an Advanced Determination of Prudence for such other resource acquisition(s).

In the event that the Company constructs and owns Red River Valley Unit 1 or Red River Valley Unit 2 to meet its identified 2017-2019 resource needs, the Company's commitment in Section II.B of this Revised Second Amended Settlement shall be deemed to have been satisfied.

F. Settlement of the Wind Cases

The Parties agree that the Company's proposal to construct and own the Border Winds Project and to purchase the output of the Courtenay Project as described in the Wind Cases enjoy a rebuttable presumption of prudence as resource additions located within the State of North Dakota pursuant to N.D.C.C. § 49-05-16. The Parties further agree that the record in the Wind Cases does not support a rebuttal to the presumption of prudence. Therefore, the Parties agree that the Border Winds Project and the Courtenay Project are prudent resource additions to the Company's integrated system and meet the standards for advanced determinations of prudence from the Commission. The disposition of the Odell and Pleasant Valley Projects are intended by the Parties to be addressed in the Negotiated Agreement or as provided for in Section II.A of this Revised Second Amended Settlement.

III. RATE CASE ADJUSTMENTS

A. Pension Loss Amortization

The Parties agree to extend the Company's amortization period for unrecognized pension costs reflecting, among other things, costs associated with the 2008 market downturn.

The Company's pension costs are determined under the Aggregate Cost Method, a pension funding method based on guidelines provided by the Internal Revenue Service. The method does not comply with SFAS 87, but is allowed as a permitted exception under SFAS 71 since it has received regulatory approval. The Parties agree that the Company will move from the current "percent of compensation" based amortization period of approximately 10 years to a 20 year amortization period. The appropriate ratemaking treatment will include a return on the unamortized balance. The extension of the amortization period will delay recovery for the Company but will reduce test year revenue requirements by approximately $447,000.

B. Annual Incentive Plan

The Parties agree that for purposes of determining the overall test year revenue requirement and future regulatory reporting, Annual Incentive Plan costs above 15 percent of base pay will be excluded. This reduces the test year revenue requirement by $209,000.

C. Charitable Contributions and Economic Development Donations

The Parties agree that for purposes of determining the overall revenue requirement and annual regulatory reporting during the 2013-2016 term of the Agreement, donations to state and local economic development entities and charitable contributions will be excluded. This reduces the test year revenue requirement by $171,000 and $157,000, respectively.

D. Asset-based Margins on Wholesale Sales

In the Settlement Agreement resolving a previous rate application (Case No. PU-07-776), the Parties agreed that the Company would pass to customers 85 percent of the margins realized from wholesale electricity sales from Company-owned (asset-based) generation. The Company currently passes 100 percent of the jurisdictional allocation of these margins to its Minnesota and South Dakota customers.

The Parties agree that the Company will, beginning January 1, 2014, pass through 100 percent of wholesale asset-based margins to North Dakota customers as well. This change does not impact base rate revenue requirements, but it will benefit customers by reducing their fuel costs approximately $56,000 (asset-based margins are flowed to customers through the Fuel Cost Rider).

E. Amortized Expenses

The Parties agree to increase the amortization period for various non-recurring expense items from the Company's initially filed three year period to a four year period. This is consistent with the four-year term of the Rate Plan. The items included in this amortization treatment include rate case expenses from the previous and pending dockets, private fuel storage costs, deferred demand side management expenses, and SO_2 emission credits. The longer amortization period will result in a test year decrease in revenue requirements of approximately $92,000.

F. Department of Energy Nuclear Fuel Proceeds

In 2012, $4,668,000 in Department of Energy ("DOE") proceeds were credited to customer bills through a one-time bill credit as part of the interim rate refund in Case No. PU-10-657. These payments are a result of the Company's successful litigation against the DOE for its failure to take spent nuclear fuel during the period 1998 to 2013, net of legal costs. This Revised Second Amended Settlement Agreement provides for the disposition of an estimated $5,200,000 in additional payments received since then or yet to be received from the DOE.

The Parties agree that by having the Company retain the DOE payments received since the first payment and recording these proceeds as income in 2013 and 2014 allows a lower base rate increase to be implemented in these two years. The proceeds would be applied as follows under the Rate Plan:

2013: $3.9 million (from payments received in 2012 and 2013)
2014: $1.3 million (from payments received in 2013 and expected in 2014)

The Parties recognize that, while this approach provides only temporary revenue relief for 2013 and 2014, it helps to reduce revenue requirements and customer base rate impacts and provides for an efficient disposition of the DOE payments.

IV. RATE DESIGN

A. Class Apportionment

The Parties agree to a customer class revenue increase apportionment reflecting rate percentage changes (by customer class) that are consistent with the Company's originally proposed class revenue increases, as shown on Attachment F. This apportionment reflects rate percentage changes by customer class that are consistent with the Company's originally proposed class revenue allocation, as shown on the attachment.

The Parties agree to the miscellaneous tariff changes proposed in the Company's initial filing and not otherwise addressed in this Revised Second Amended Settlement. The Parties agree to use the Company's proposed rate design principles in developing final rates to implement the approved revenue requirement contained in this Revised Second Amended Settlement Agreement.

The Company shall file compliance tariff pages setting forth the revised electric rates and tariffs provided by this Revised Second Amended Settlement Agreement at least thirty (30) days after the date of approval of this Settlement.

B. Monthly Customer Charge

The Parties believe it would be prudent to make significant steps toward better matching of the fixed costs of providing electric service with fixed rates. Assigning fixed electric customer service costs (costs that are not driven by electric usage, such as metering and billing) to the fixed monthly Customer Charge is consistent with the bills that customers are familiar with when paying for other services. The Parties agree, therefore, to replace the four distinct Customer Charges for non-time of day residential electric service (regular overhead, overhead space heating, regular underground, and underground space heating) with a single, common Customer Charge of $14.00. The Small General Service Customer Charge will be set at $16.00. This will reduce the amounts of customer-related fixed costs recovered through the Energy Charge. The Energy Charges for the various residential and small general service rate codes will be reduced accordingly, such that the overall class increase is appropriately derived.

C. Account History Charge

The Parties agree to eliminate the $5 charge for responding to customer requests for account history.

D. Time of Day Rate

Currently, few of the Company's customers in North Dakota have opted for Time-of-Day (TOD) service. However, TOD offerings are becoming increasingly popular throughout the industry as customers seek ways to manage energy costs and utility companies implement smart metering technology and new billing systems. The Parties agree to investigate the feasibility of redesigning the Company's TOD rate in a manner that will provide accurate and clear pricing signals to customers, help reduce North Dakota's contribution to the Company's peak periods, and minimize the incremental costs to administrate the TOD rate. By December 31, 2014, the Company commits to submitting to the Commission either a pilot TOD tariff or a recommendation regarding an appropriate path for improving a residential TOD offering in North Dakota.

V. ADDITIONAL MATTERS

A. Renewable Energy Credit (REC) Sales

Currently, the Company passes to North Dakota customers 90 percent of the net proceeds from the sale of North Dakota-allocated RECs, as approved in Case No. PU-10-19. To date, North Dakota customers have been credited $1.1 million for their portion of REC sale proceeds. As a condition of this Revised Second Amended

Settlement, the Parties agree that the Company will pass 100 percent of North Dakota jurisdictional net REC proceeds to North Dakota customers for all sales on and after January 1, 2014.

Historically, the Commission's intentions have been for the Company to sell all North Dakota-allocated RECs not needed to meet the 2015 renewable objective of 10 percent. Given that the current market for hydro and biomass RECs is minimal since these types of RECs are not as viable for voluntary purchasers, the Company will investigate the potential for establishing a framework for transacting "inter-jurisdictional" REC sales whereby non-marketable RECs allocated to North Dakota could be transferred – or "sold" – to the Company's NSP REC portfolio for purposes of meeting the renewable energy standards or objectives of other jurisdictions served by the Company, subject to approval of the relevant jurisdictions. The proceeds from these transactions would be passed on to North Dakota customers like any other REC sale. The Company commits, as a condition of this Settlement, to file a report with the Commission no later than December 31, 2014 detailing its findings and recommendations for such a process.

VI. CUSTOMER REFUNDS

A. Interim Rates

Since the base rate increase for 2013 is lower than the current interim increase percent, this Revised Second Amended Settlement will result in a lower overall revenue increase for 2013 than the level currently being collected in interim rates. An estimated interim rate refund of approximately $3.45 million (plus interest) is expected to be issued to customers beginning approximately 1 month from the implementation of final rates.

The Parties agree the interim rates that went into effect on February 16, 2013 will remain in effect until final rates are implemented. An interim rate refund will be issued to customers within ninety (90) days of the implementation of final rates for the difference between total interim revenues collected since February 16, 2013 as reflected and calculated in Attachment G.

To determine the interim refund the Company will utilize the same practices it has used in the past and include monies for the St. Paul Cogeneration refund as agreed to by the Company in the Rate Case record.

At the time of this Revised Second Amended Settlement Agreement, the final amount of interim revenues collected is not available, so an estimate is made using a similar prorating of the annualized interim rate increase as described above resulting in a total customer refund of approximately $19.00 per residential customer, to be issued during the Revised Second quarter of 2014. Attachment G provides further information with respect to the interim rate refund.

VII. RELIABILITY AND REPORTING COMMITMENTS

A. Reliability Improvement Commitments

The Parties agree to expand the Company's current initiatives agreed to in its previous rate Settlement Agreement (Case No. PU-10-657) to improve reliability in North Dakota with the following actions:

1. Expansion of the Company's efforts to proactively locate and replace an older type of underground cable, referred to as 500 MCM cable, used in the Company's North Dakota electric distribution system. The original commitment was to incur $750,000 over three years (2012-2014) to find and remove this cable. Remaining funding from the Company's 2012 Intelliteam roll-out will be re-purposed to extend the 500 MCM removal project one additional year and expand the scope to approximately $400,000 per year from 2013-2015. No additional adjustment to test year revenue requirements is needed for this program expansion.

2. The current "Reliability Performance Plan" (RPP) in place for 2013, 2014, and 2015 will be extended through 2016 consistent with the general term of this Revised Second Amended Settlement. The RPP provides $50 credits to customers who experience more than 3 sustained outages in a given year, provides a financial incentive for the Company to achieve a 57 minute System Average Interruption Duration Index (SAIDI) threshold, and requires expanded outage reporting to the Commission. There is no additional adjustment to test year revenue requirements for the RPP term extension.

3. Suspension of the current practice of providing feeder outage notifications as they occur, and quarterly underground cable failure summary reports, until further Commission notice. The Company will continue to provide the Commission notice of major outages and other events as appropriate.

B. Removal Costs in Depreciation Rates

The Parties agree that the Company will footnote the North Dakota portion of its

Asset Retirement Obligation in its annual report of regulated earnings. It will also notify the Commission of any new depreciable life studies or revisions that have been completed and filed with the Minnesota Public Utilities Commission. The Parties agree that the depreciation lives and rates presented in the Rate Case will be the ones in effect upon approval of this Revised Second Amended Settlement.

C. Tariff Book Improvements

The Parties agree that the Company will submit to the Commission, no later than the date of its next general rate application, an updated and improved North Dakota Electric Rate Book. The new revision will include a thorough review of all tariffs and general rules of service and reflect language and/or format enhancements that will improve readability, remove unnecessary phrases or sections, and ensure the terminology is up-to-date and understandable. The Company will work with Staff throughout the project to ensure the revisions meet the needs of North Dakota customers, the Company, developers, and regulators.

D. Jurisdictional Financial and Budget Variance Reporting

During the Rate Case, Staff and the Commission expressed concerns about the Company's difficulty in producing North Dakota jurisdictional financial data on a monthly or year-to-date basis. The Parties recognize the need to be able to timely produce and review updates of actual expenses, test year expenses, rate base, and overall revenue requirements, particularly during discovery process. Thus, the Parties agree that, prior to the next general rate application, the Company will develop a jurisdictional financial system that can be used to update test year forecasts with actual data and/or revised revenue, expense, and capital expenditure forecasts. The tool will also be able to accommodate assumption changes for purposes of modeling different test year input scenarios.

VIII. OTHER TERMS AND CONDITIONS

A. Basis of Revised Second Amended Settlement

It is agreed that this Revised Second Amended Settlement is a negotiated settlement agreement subject to approval by the Commission. This Revised Second Amended Settlement does not establish any principle or precedent, or adopt or recommend any specific type or amount of expense or rate base, for this or any future proceeding.

B. Effect of the Settlement Negotiations

It is understood and agreed that all offers of settlement and discussions related to this Revised Second Amended Settlement are privileged and may not be used in any manner in connection with proceedings in this case or otherwise, except as provided by law. In the event the Commission does not approve this Revised Second Amended Settlement, it shall not constitute part of the record in this proceeding and no part thereof may be used by any party for any purpose in this case or in any other.

C. Applicability and Scope

This Revised Second Amended Settlement shall be binding on the Parties, and their successors, assigns, agents, and representatives. Consistent with the Commission's settlement guidelines, this Revised Second Amended Settlement does not set policy or overturn precedent. This Revised Second Amended Settlement shall not in any respect constitute an agreement, admission or determination by any of the Parties as to the merits of any specific allegation or contention made by the Parties in this proceeding.

D. Effective Date

This Revised Second Amended Settlement shall be effective on the date of the Commission Order approving the Revised Second Amended Settlement. The revised rates and tariff agreed to by this Revised Second Amended Settlement Agreement shall be effective on the dates specified herein.

E. Modification

If a Commission Order modifies or conditions approval of this Revised Second Amended Settlement, it shall be deemed terminated if either Party files a letter with the Commission within three (3) business days of the date of such Order stating that a condition or modification to the Revised Second Amended Settlement is unacceptable to such party.

F. Force Majeure

The Parties agree that certain material changes in the Company's forecasted expenses during the term of the Rate Plan that are beyond the Company's control and may require adjustment to the Company's rates then in effect or may be appropriate for deferral or recovery through a new rider, provided that the change is reasonably expected to increase or decrease the Company's North Dakota jurisdictional revenue requirement for its electric business by at least $1.5 million in that year.

The Parties agree that the Company may petition to the Commission to provide for a mechanism to address these additional costs as they arise during the effectiveness of the Rate Plan. The types of cost changes that would qualify for an adjustment pursuant to this section include changes in Generally Accepted Accounting Principles that are appropriately reflected in rate regulation; changes in tax laws (both federal and state in any jurisdiction that may affect the Company's cost of service in North Dakota); changes in the Company's obligations stemming from changes in federal or North Dakota state or municipal laws, or regulations issued or actions taken by federal or North Dakota state or local governmental bodies, including but not limited to the Environmental Protection Agency, the Federal Energy Regulatory Commission, the North American Electric Reliability Corporation, the Commission, and the Nuclear Regulatory Commission; and natural disasters or catastrophic events, net of any insurance proceeds.

CONCLUSION

The Parties have agreed to the forgoing terms to resolve all outstanding issues in the above-captioned proceeding. These terms are a result of negotiations between the Parties, are in the public interest, and will result in reasonable electric rates through 2016. For these reasons, the Parties urge the Commission to approve this Revised Second Amended Settlement.

[SIGNATURE PAGE FOLLOWS]

Dated this 25th day of February 2014.

Northern States Power Company,
A Minnesota corporation

By: ______________________________
David M. Sparby
President and Chief Executive Officer

Dated this 25th day of February 2014.

Northern Dakota Public Service Commission Staff

By: ______________________________
Ryan Norrell
Counsel to the Commission

[SIGNATURE PAGE TO REVISED SECOND AMENDED SETTLEMENT]

PROCEDURAL HISTORY
Case No. PU-12-813

On December 18, 2012, Northern States Power Company ("NSP" or "Xcel Energy") filed a Notice of Change in Rates for Electric Service ("Notice") with the North Dakota Public Service Commission (the "Commission") to increase its rates for electric utility service to provide additional 2013 test year annual revenue of $16,900,000 or a 9.25 percent increase over current rates effective for electric service on and after January 17, 2013. The Company filed testimony by eight witnesses in support of the Notice, along with revised tariffs, exhibits, and supporting statements.

Xcel Energy proposed to increase residential base rates by $6,312,000 or 8.95 percent and commercial service revenues by $10,380,000 or 9.47 percent. The 2013 proposed monthly increase for a residential customer using 750 kilowatt-hours in a winter month is $6.40 and in a summer month is $6.64. Rates for public authorities were proposed to increase by $92,000 or 8.29 percent.

Concurrent with the Notice, Xcel Energy submitted an Alternate Petition for Interim Rates. The proposed interim increase, which impacted only base rates, was for $14,704,000 or 8.05 percent, to be effective February 16, 2013 (60 days from filing) in the event the Commission suspended the proposed general increase. The proposed interim increase and rate design were submitted pursuant to the criteria set forth in N.D.C.C. 49-05-06.

On December 21, 2012, the Commission issued an order suspending Xcel Energy's general rate increase application and set the matter for investigation and hearing.

On January 30, 2013, the Commission issued an order authorizing Xcel Energy to implement an interim electric rate increase of $14,704,000 effective February 16, 2013 and subject to refund.

On February 4, 2013, Xcel Energy filed compliance tariffs reflecting the Commissions interim rate Order.

On February 13, 2013 the Commission issued a Notice of Hearing, Intervention Deadline, and Public Input Session. The Notice announced that a Public Hearing would be held beginning August 27-29, 2013 at 9:00 a.m. central time, setting forth the following issues to be considered in this case:

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 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?

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 of Hearing also announced Public Input Sessions to be held via interactive television on April 15, 2013, at 7:00 p.m. and April 16, 2013, at 12:00 p.m. central time at various locations in Fargo, Grand Forks, Minot, and Bismarck. Members of the public were invited to appear and participate in the informal discussion. Finally, the Notice set forth a deadline of May 1, 2013 for parties to indicate their interest in participating in the case. No parties intervened.

On April 3, 2013, Xcel Energy filed supplemental direct testimony in regards to cost recovery of the Prairie Rose wind power purchase agreement. In the Company's Prairie Rose ADP docket, the Commission had recently ordered that recovery of Prairie Rose costs be considered in a "separate proceeding".

On April 15 and 16, 2013, the Commission conducted two public input sessions. The sessions utilized interactive video-conferencing capabilities to include participants in Fargo, Grand Forks, Minot, and Bismarck. Outside of local media, only one person from the public attended.

On July 17, 2013, Advocacy Staff consultants Snavely, King, Majoros, and Associates, Inc. filed Direct Testimony. The testimony recommended a rate decrease in the amount of $2,088,000 based on an authorized ROE of 9.0 percent.

On July 22, 2013, Advocacy Staff analyst Sara Cardwell filed Direct Testimony.

On August 12, 2013 Xcel Energy filed rebuttal testimony and exhibits. The testimony reduced the amount of the rate increase request to $14,884,000 or 8.15 percent.

On August 22, 2013 Advocacy Staff filed supplemental testimony and exhibits. The testimony revised the recommended rate decrease to $10,018,000.

On August 26, 2013 the NDPSC held its initial Work Session in this proceeding.

On August 27, 28, and 29, 2013 Evidentiary Hearings were held in the Commission Hearing Room, 12th Floor, State Capitol Building.

During the months of September, October, and November, various settlement discussions were held between Staff and the Company to resolve the issues in the case.

On September 24, 2013, the NDPSC held its second Work Session in this proceeding.

On October 30, 2013, the NDPSC held its third Work Session in this proceeding.

On December 5, 2013 the Commission held its fourth Work Session in this proceeding.

On December 5, 2013, Advisory Staff issued a letter to NSP indicating that two late-filed exhibits remained outstanding, and that the Commission was interested in getting a status update on Settlement discussions in this case. The requested information was to be filed by December 11, 2013.

On December 6, 2013 NSP sent a letter to the Commission indicating that Settlement discussions were in progress but had been delayed by the Company's efforts to complete an updated five year forecast of its regulated earnings in North Dakota. The

Company informed the Commission that it and Advocacy staff would attempt to complete negotiations and file a Settlement Agreement by December 13, 2013.

On December 9, 2013 NSP filed the final late-filed exhibit requested during the Evidentiary Hearings with the Commission.

During the week of December 9 – 13, 2013, representatives met with Advocacy Staff to negotiate the final terms of a multi-year Settlement Agreement.

At a special meeting on December 10, 2013, the Commission took official notice in the rate case of the records of six other ADP filings and two Resource Plan dockets in North Dakota.

On December 13, 2013 this Settlement Agreement was entered into by Advocacy Staff and Xcel Energy, and filed with the Commission.

On December 20, 2013, Advocacy Staff filed testimony in support of the Settlement Agreement. Also on this day, NSP responded to the December 10, 2013 Notice recognizing the records of multiple open cases before the NDPSC to clarify certain statements made by a witness in the Gas CT cases (Case Nos. PU-13-194 and PU-13-195) should be evaluated in their entirety.

On January 7, 2014 the Commission held an Informal Hearing on the Settlement Agreement.

On January 15, 2014, NSP filed testimony supporting the Settlement Agreement.

On January 17, 2014, Advocacy Staff submitted additional testimony documenting

Staff's presentation of the Settlement Agreement to the Commission at its January 7th Informal Hearing.

On January 23, 2014, the Commission conducted a Formal Hearing on the Settlement Agreement.

On January 24, 2014, the Commission held its fifth Work Session in this proceeding.

On January 28, 2014, NSP filed the first of two hearing exhibits requested during the January 23rd Formal Hearing.

On February 3, 2014 the Amended Settlement Agreement and final hearing exhibit requested during the January 23rd Formal Hearing was filed.

On February 12, 2014, the Commission held its sixth Work Session in this proceeding.

On February 18, 2014, the Second Amended Settlement Agreement was filed.

On February 25, 2014, the Revised Second Amended Settlement Agreement was filed.

The administrative record in this proceeding supports the Revised Second Amended Settlement Agreement, and the Parties jointly recommend the Commission approve this Revised Second Amended Settlement Agreement without further modifications.

Case Nos. PU-13-706, PU-13-707, PU-13-708, PU-13-742, PU-13-743

On July 26, 2013, Northern States Power Company (NSP or Company) filed an application with the North Dakota Public Service Commission (Commission) seeking an advance determination of prudence (ADP) under North Dakota Century Code Section 49-05-16 for NSP's undertaking of three wind projects:

- a proposed power purchase agreement (PPA) for the 200 megawatt (MW) Courtenay Wind Project (Courtenay) to be located in Stutsman County, North Dakota in Case No. PU-13-706;
- a proposed PPA for the 200 MW Odell Wind Project (Odell) to be located near Mountain Lake, Minnesota in Case No. PU-13-707; and
- a proposed purchase of the 200 MW Pleasant Valley Wind Project (Pleasant Valley) to be located near NSP's existing Grand Meadow Wind Farm in southeastern Minnesota in Case No. PU-13-708.

On August 13, 2013, NSP filed an application for an ADP for the proposed purchase of the 150 MW Border Winds Project (Border Winds and collectively with Courtenay, Pleasant Valley and Odell, the Resource Additions) to be located in Rolette County, North Dakota in Case No. PU-13-742. Also on August 13, 2013, NSP filed an application for a Certificate of Public Convenience and Necessity for Border Winds in Case No. PU-13-743.

On September 25, 2013, the Commission issued a Notice of Consolidated Hearing consolidating for hearing Case Nos. PU-13-706, PU-13-707, PU-13-708, PU-13-742, and PU-13- 743 and scheduling a hearing for October 31, 2013 in the Commission Hearing Room, Twelfth Floor, State Capitol, 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.

On October 2, 2013, NSP filed corrections to the ADP applications in the instant Cases.

On October 31, 2013, a public hearing was held as scheduled.

On November 5, 2013 the Commission held its first work session on these Cases.

On December 2, 2013 the Commission held its second work session on these Cases.

During the week of December 9 – 13, 2013, representatives met with Advocacy Staff to negotiate the final terms of a multi-year Settlement Agreement.

On December 13, 2013 this Settlement Agreement was entered into by Advocacy Staff and Xcel Energy, and filed with the Commission.

On December 20, 2013, Advocacy Staff filed testimony in support of the Settlement Agreement. Also on this day, NSP responded to the December 10, 2013 Notice recognizing the records of multiple open cases before the NDPSC to clarify certain statements made by a witness in the Gas CT cases (Case Nos. PU-13-194 and PU-13-195) should be evaluated in their entirety.

On January 7, 2014 the Commission held an Informal Hearing on the Settlement Agreement.

On January 15, 2014, NSP filed testimony supporting the Settlement Agreement.

On January 17, 2014, Advocacy Staff submitted additional testimony documenting Staff's presentation of the Settlement Agreement to the Commission at its January 7th Informal Hearing.

On January 23, 2014, the Commission conducted a Formal Hearing on the Settlement Agreement.

On January 24, 2014, the Commission held its fifth Work Session in this proceeding.

On January 28, 2014, NSP filed the first of two hearing exhibits requested during the January 23rd Formal Hearing.

On February 3, 2014 the Amended Settlement Agreement and final hearing exhibit requested during the January 23rd Formal Hearing was filed.

On February 12, 2014, the Commission held an additional Work Session in this proceeding.

On February 18, 2014, the Second Amended Settlement Agreement was filed.

On February 25, 2014, the Revised Second Amended Settlement Agreement was filed.

The administrative record in this proceeding supports the Revised Second Amended Settlement Agreement, and the Parties jointly recommend the Commission approve this Revised Second Amended Settlement Agreement without further modifications.

Case Nos. PU-13-194, PU-13-195

On April 26, 2013, Northern States Power Company (NSP or Company) filed an application with the North Dakota Public Service Commission (Commission) seeking an advance determination of prudence (ADP) under North Dakota Century Code Section 49-05-16 for its proposal to add three 215 MW natural-gas-fired, simple cycle, combustion turbine (CT) generators to its system (Case No. PU-13-194):

- The first CT will be constructed at Xcel Energy's Black Dog generation plant in Burnsville, Minnesota (Black Dog Unit 6) for service beginning in 2017;
- The second and third CTs will be constructed at a new plant site to be located in the Red River Valley near Hankinson, North Dakota (Red River Valley Units 1 and 2) for service beginning in 2018 and 2019.

The Company also requested the Commission grant a Certificate of Public Convenience and Necessity for Red River Valley Units 1 and 2, pursuant to North Dakota Century Code Chapter 49-03 (Case No. PU-13-195).

On October 9, 2013, the Commission issued a Notice of Consolidated Hearing consolidating for hearing Case Nos. PU-13-194 and PU-13-195, and scheduled a hearing for November 26, 2013, in the Commission Hearing Room, Twelfth Floor, State Capitol, Bismarck, North Dakota. The Notice specified the issues to be considered were:

1. Whether NSP's proposed investment in the three CTs is prudent;
2. Whether the public convenience and necessity will be served by the NSP's construction and operation of the three CTs; and
3. Whether NSP is fit, willing, and able to provide service.

On November 26, 2013, a public hearing was held as scheduled.

On December 2, 2013 the Commission held its first work session on these Cases.

During the week of December 9 – 13, 2013, representatives met with Advocacy Staff to negotiate the final terms of a multi-year Settlement Agreement.

On December 13, 2013 this Settlement Agreement was entered into by Advocacy Staff and Xcel Energy, and filed with the Commission.

On December 20, 2013, Advocacy Staff filed testimony in support of the Settlement Agreement. Also on this day, NSP responded to the December 10, 2013 Notice recognizing the records of multiple open cases before the NDPSC to clarify certain statements made by a witness in the Gas CT cases (Case Nos. PU-13-194 and PU-13-195) should be evaluated in their entirety.

On January 7, 2014 the Commission held an Informal Hearing on the Settlement Agreement.

On January 15, 2014, NSP filed testimony supporting the Settlement Agreement.

On January 17, 2014, Advocacy Staff submitted additional testimony documenting Staff's presentation of the Settlement Agreement to the Commission at its January 7th Informal Hearing.

On January 23, 2014, the Commission conducted a Formal Hearing on the Settlement Agreement.

On January 24, 2014, the Commission held its fifth Work Session in this proceeding.

On January 28, 2014, NSP filed the first of two hearing exhibits requested during the January 23rd Formal Hearing.

On February 3, 2014 the Amended Settlement Agreement and final hearing exhibit requested during the January 23rd Formal Hearing was filed.

On February 12, 2014, the Commission held an additional Work Session in this proceeding.

On February 18, 2014, the Second Amended Settlement Agreement was filed.

On February 25, 2014, the Revised Second Amended Settlement Agreement was filed.

The administrative record in this proceeding supports the Revised Second Amended Settlement Agreement, and the Parties jointly recommend the Commission approve this Revised Second Amended Settlement Agreement without further modifications.

Xcel Energy
Electric Utility - State of North Dakota
Second Amended Settlement Agreement - 2013 Test Year Revenue Requirement
Dollars in 000's

Item	Amoun	Notes
2013 Test Year Deficiency as Filed (Dec. 18, 2012)	$16,900	
Rebuttal Testimony Corrections, Updates, and Adjustment	($2,016)	
Revised Test Year Deficiency	$14,884	8.1%
Settlement Adjustments		
Return on Equity (from 10.25% to 9.75%)	($1,690)	
Unrecognized Pension Costs - extend amortization	($447)	a
Incentive Plan/ Nuclear Restricted Stock adjustments	($209)	b
Economic Develop Contributions	($171)	
Charitable Contributions	($157)	
Extend 3 Yr amortization of non-recurring items by 1 Yr	($92)	c
Total Adjustments	($2,766)	
Settlement 2013 Test Year Deficiency	$12,118	
Reduce Deficiency by DOE Proceeds	($3,937)	
Adjusted 2013 Test Year Settlement Deficiency	$8,181	
4.9% Settlement Increase for 2013	$7,378	d

Notes:

a) Reflects replacement of the current "percent of compensation" based amortization period of approximately 10 years to a 20 year amortization.
b) Limits AIP costs to 15 percent of base pay; removes all nuclear restricted stock costs.
c) see Exh. AEH-1, Schedule 20 of Application for amortized items
d) reflects partial annual recovery, effective Feb. 16, 2013

Xcel Energy
Electric Utility – State of North Dakota
Revised Second Amended Settlement Agreement Rate Change Procedures

1. The overall annual rate increase percent for 2013, 2014, and 2015 is 4.9 percent.

2. The Company's budget or updated forecast of the upcoming test year base revenues and fuel cost rider revenues will be used as the baseline for applying the annual 4.9 percent increase. Any Transmission Cost Recovery and/or Renewable Cost Recovery Rider revenues forecasted for the corresponding year will not be included in the baseline amount.

3. The annual base rate increase amount is determined by multiplying the Company's total projected base and fuel revenues for the upcoming forecast (test) year by 4.9 percent. The result is the allowable base rate increase amount for that forecast year.

   Annual Base Revenue Increase = Sum of (Projected Base and Fuel Revenues) x .049

4. The 2013 increase will be apportioned to classes based on the Company's apportionment proposal in Case No. PU-12-813. The Company is authorized to implement an across-the-board 4.9 percent increase to all classes in 2014 and 2015.

5. The compliance tariffs to effectuate the qualifying revenue increases proposed for each customer class will be filed with the Commission at least 60 days prior to their effective date (generally January 1 of the test year). Staff will review the filings for completeness and accuracy. No additional Commission action will be required.

6. The tariffs supporting the proposed 2013 and 2014 increases will be filed within 10 days of Commission approval of this Revised Second Amended Settlement Agreement. The 2013 and 2014 increases will go into effect May 1, 2014, or within 60 days of the order approving the compliance tariffs. Because those increases will be less than the interim rates currently in effect, they will result in interim rate refunds. The interim refunds will be issued within 90 days of the effective date of the new rates. The 2015 increase will be filed October 31, 2014 for rates to be effective January 1, 2015.

Case No. PU-12-813
Attachment D

Xcel Energy
Electric Utility - State of North Dakota
Settlement Agreement - Capital Structure

	2013			2014			2015			2016		
	%	Cost	Wtg.%	%	Cost	Wtg.%	%	Cost	Wtg.%	%	Cost	Wtg.%
Long Term Debt	44.96%	5.14%	2.31%	44.96%	5.14%	2.31%	44.96%	5.14%	2.31%	44.96%	5.14%	2.31%
Short Term Debt	2.48%	0.75%	0.02%	2.48%	0.75%	0.02%	2.48%	0.75%	0.02%	2.48%	0.75%	0.02%
Shareholders' Equity	52.56%	9.75%	5.12%	52.56%	10.00%	5.26%	52.56%	10.00%	5.26%	52.56%	10.25%	5.39%
Total	100.00%		7.45%	100.00%		7.59%	100.00%		7.59%	100.00%		7.72%

Case No. PU-12-813
Attachment E
Page 1 of 2

Xcel Energy – State of North Dakota
Electric Rate Case Settlement

IDENTIFIED RENEWABLE PPAS

BioMass
1. KODA Energy LLC (12 MW)
2. WM Renewable Energy (MN Methane) (12 MW)
3. Pine Bend (4.7 MW)

Community Based Energy Development (CBED) Wind
1. Jeffers Wind 20, LLC (50 MW)
2. Big Blue (36 MW)
3. Community Wind South (Zephyr) (30 MW)
4. Ridgewind Power Partners LLC (25 MW)
5. Adams Wind Generations (20 MW)
6. Danielson Wind Farms (20 MW)
7. Ewington Energy Systems LLC (20 MW)
8. Grant County Wind, LLC (20 MW)
9. North Community Turbines (15 MW)
10. North Wind Turbines (15 MW)
11. Valley View Transmission (10 MW)
12. Uilk Wind Farm (4.5 MW)
13. Hilltop Power (2 MW)
14. Winona County Wind (1.5 MW)
15. Woodstock Municipal Wind, LLC (0.8 MW)

Other Wind
1. Odell (200 MW)

Solar Contracts
1. Outland Solar (2 MW)
2. Best Power (St. Johns) (0.4 MW)

Xcel Energy – State of North Dakota
Electric Rate Case Settlement

IDENTIFIED BIOMASS PPAS

1. FibroMinn (55 MW)
2. Laurentian Energy Authority I (35 MW)
3. St. Paul Cogeneration (25 MW)

Case No. PU-12-813
Second Amended Settlement Agreement
Attachment F
Page 1 of 1

Northern States Power Company
Electric Utility - North Dakota Retail Jurisdiction
Test Year Ending December 31, 2013
Settlement Rate Revenue Apportionment
Dollars in 000's

	Residential	Non-Dmd	Demand	Lighting	Retail	Other[1]	Total
Original Application							
Present	$70,465	$11,575	$98,825	$1,860	$182,724	$0	$182,724
Proposed	$76,777	$12,537	$108,334	$1,948	$199,597	$27	$199,624
Increase	$6,312	$963	$9,509	$89	$16,873	$27	$16,900
Percent change	8.96%	8.32%	9.62%	4.77%	9.23%		9.25%
Class Allocation	38.47%	6.28%	54.28%	0.98%	100.00%		
Settlement Agreement							
Test Year 2013							
Present Revenue	$70,465	$11,575	$98,825	$1,860	$182,724	$0	$182,724
Increase	$3,344	$510	$5,038	$47	$8,939	$14	$8,953
Percent change	4.75%	4.41%	5.10%	2.52%	4.89%		4.90%
Total Revenue	$73,809	$12,085	$103,863	$1,907	$191,663	$14	$191,677
Class Allocation	38.51%	6.31%	54.19%	0.99%	100.00%		
Year 2014							
Present Revenue	$73,620	$12,054	$103,597	$1,902	$191,172	$14	$191,186
Increase	$3,602	$590	$5,068	$93	$9,353	$15	$9,368
Percent change	4.89%	4.89%	4.89%	4.89%	4.89%		4.90%
Total Revenue	$77,222	$12,643	$108,665	$1,995	$200,525	$29	$200,554
Class Allocation	38.51%	6.31%	54.19%	0.99%	100.00%		
Year 2015[2]							
Present Revenue	$79,144	$12,958	$111,369	$2,044	$205,515	$30	$205,545
Increase	$3,873	$634	$5,449	$100	$10,056	$16	$10,072
Percent change	4.89%	4.89%	4.89%	4.89%	4.89%		4.90%
Total Revenue	$83,016	$13,592	$116,819	$2,144	$215,571	$46	$215,617
Class Allocation	38.51%	6.31%	54.19%	0.99%	100.00%		

[1] Other: Increases in Non-Retail Operating Revenues: Late Payment Fees

[2] Year 2015 is an example based on current estimated revenue; updated 2015 figures will be filed with the Commission prior to the implementation of the 2015 increase.

Northern States Power Company — **Case No. PU-12-813**
Electric Utility - State of North Dakota — **Attachment G**
Summary of Interim Refund — **Schedule 1**
Second Amended Settlement

		2013 TY	2014 TY	Total
	Interim Refund Factor Calculation			
1	Authorized Annual Interim Rate Increase	$14,704,000	$14,704,000	
2	Approved Annual Base Rate Increase	$8,953,000	$18,321,000	
3	Annualized Excess Interim Recovery (line 1- line 2)	$5,751,000	-$3,617,000	
4	% Refundable (line 3 / line 1)	39.1118%	-24.5987%	
5	Actual Interim Revenue Increase Collected[1]	$12,115,262	$5,256,467	$17,371,729
6	Interim Refund Excluding Interest (line 4 x line 5)	$4,738,497	-$1,293,022	$3,445,475
7	Interest on Interim Refund Balance (Schedule 3)	$63,804	$44,248	$108,051
8	Interim Refund Including Interest (line 6 + line 7)	$4,802,301	-$1,248,775	$3,553,526
9	St Paul Co-Gen PPA Refund			$89,000
10	Net Interim Refund Including Interest (line 8 + line 9)			**$3,642,526**
11	**Interim Refund Factor (line 10 / line 5)**			**20.9681%**
	Est. Average Residential Customer Interim & DOE Settlement Refunds			
12	Interim Revenues for Residential Customers			$7,209,620
13	Average Residential Customers Feb. 2013 - Nov. 2013			78,909
14	Average Interim Revenues per Customer (line 12 / line 13)			$91
15	Est. Average **Interim Refund** per Residential Customer (line 11 x line 14)			**$19.16**

[1] 2013 interim revenues collected from Feb. 16, 2013 through Dec. 31, 2013. 2014 interim revenues collected from Jan. 1, 2014 through April 30, 2014. Revenues for February through April 2014 are estimates. See Schedule 2.

Northern States Power Company — **Case No. PU-12-813**
Electric Utility - State of North Dakota — **Attachment G**
Interim Rate Refund by Month — **Schedule 2**
Second Amended Settlement

	Interim Revenue Collected	% Refundable[1]	Interim Refund (excl. Interest)
Feb-13	$110,174	39.1118%	$43,091
Mar-13	$929,205	39.1118%	$363,429
Apr-13	$1,189,781	39.1118%	$465,345
May-13	$1,094,524	39.1118%	$428,088
Jun-13	$1,055,081	39.1118%	$412,661
Jul-13	$1,485,768	39.1118%	$581,111
Aug-13	$1,371,588	39.1118%	$536,453
Sep-13	$1,361,855	39.1118%	$532,646
Oct-13	$1,241,161	39.1118%	$485,440
Nov-13	$1,026,980	39.1118%	$401,670
Dec-13	$1,249,146	39.1118%	$488,563
2013 Total	$12,115,262		$4,738,497
Jan-14	$1,506,467	-24.5987%	-$370,571
Feb-14 Est.	$1,300,000	-24.5987%	-$319,783
Mar-14 Est.	$1,250,000	-24.5987%	-$307,484
Apr-14 Est.	$1,200,000	-24.5987%	-$295,184
2014 Total	$5,256,467		-$1,293,022
Grand Total	$17,371,729		$3,445,475

[1] Schedule 1, Line 4

Northern States Power Company
Electric Utility - State of North Dakota
Interim Refund Interest Calculation
Second Amended Settlement

Case No. PU-12-813
Attachment G
Schedule 3

Revenue Month	Beginning Balance	Curr Mo Int Rev Refund	Ending Balance	Average Balance	Days	Annual Interest[1]	Monthly Interest
Feb-13 [2]	$0	$43,091	$43,091	$21,545	13	3.25%	$25
Mar-13	$43,116	$363,429	$406,545	$224,830	31	3.25%	$621
Apr-13	$407,165	$465,345	$872,510	$639,838	30	3.25%	$1,709
May-13	$874,219	$428,088	$1,302,307	$1,088,263	30	3.25%	$2,907
Jun-13	$1,305,214	$412,661	$1,717,875	$1,511,545	30	3.25%	$4,038
Jul-13	$1,721,913	$581,111	$2,303,024	$2,012,468	31	3.25%	$5,555
Aug-13	$2,308,579	$536,453	$2,845,031	$2,576,805	31	3.25%	$7,113
Sep-13	$2,852,144	$532,646	$3,384,790	$3,118,467	30	3.25%	$8,330
Oct-13	$3,393,120	$485,440	$3,878,561	$3,635,840	31	3.25%	$10,036
Nov-13	$3,888,597	$401,670	$4,290,267	$4,089,432	30	3.25%	$10,924
Dec-14	$4,301,191	$488,563	$4,789,754	$4,545,472	31	3.25%	$12,547
2013 Total							$63,804
Jan-14	$4,802,301	($370,571)	$4,431,730	$4,617,015	31	3.25%	$12,744
Feb-14 Est.	$4,444,474	($319,783)	$4,124,691	$4,284,582	28	3.25%	$10,653
Mar-14 Est.	$4,135,344	($307,484)	$3,827,860	$3,981,602	31	3.25%	$10,990
Apr-14 Est.	$3,838,850	($295,184)	$3,543,666	$3,691,258	30	3.25%	$9,860
2014 Total							$44,248
Grand Total							$108,051

[1] Prime interest rates are from Federal Reserve Statistical Release H15 - Bank Prime Loan - Monthly
http://www.federalreserve.gov/releases/h15/data/Monthly/H15_PRIME_NA.txt

[2] Interim rates effective February 16, 2013 through April 30, 2014

NDPSC Case Nos. PU-12-813, *et al.*
MPUC Docket No. E-002/M-16-223
APPENDIX E

SETTLEMENT AGREEMENT

NDPSC Case No. PU-07-776

STATE OF NORTH DAKOTA
PUBLIC SERVICE COMMISSION

Northern States Power Company
Electric Rate Increase
Application

Case No. PU-07-776

ORDER ADOPTING SETTLEMENT

December 31, 2008

Appearances

Commissioners Susan E. Wefald, Kevin Cramer, and Tony Clark.

Megan J. Hertzler, Assistant General Counsel, Xcel Energy, 414 Nicollet Mall, Fifth Floor, Minneapolis, Minnesota 55402, and Michael J. Bradley, Attorney at Law, Moss & Barnett, 4800 Wells Fargo Center, 90 South Seventh Street, Minneapolis, Minnesota 55402, attorneys for Northern States Power Company.

Douglas A. Bahr, Solicitor General, Office of the Attorney General, 500 North Ninth Street, Bismarck, North Dakota 58501, attorney for the Advocacy Staff.

Illona A. Jeffcoat-Sacco, General Counsel, Public Service Commission, 600 E. Boulevard Avenue, Department 408, Bismarck, North Dakota 59505-0480, attorney for the Public Service Commission.

Al Wahl, Administrative Law Judge, Office of Administrative Hearings, 1701 North Ninth Street, Bismarck, North Dakota 58501-1882, appearing as hearing officer.

Preliminary Statement

On December 7, 2007, Northern States Power Company (NSP) filed its application and direct testimony seeking a general revenue increase of $17,950,000 or 12.15 percent of total revenues with the North Dakota Public Service Commission (Commission).

On December 21, 2007, the Commission suspended NSP's general rate increase application.

On January 16, 2008, the Commission issued a Notice of Public Input Session and Intervention Deadline.

On January 30, 2008, the Commission issued its Order on Interim Rates authorizing the Company to collect interim rates.

On March 23, 2008, the Commission issued its Notice of Hearing setting the dates for hearing and specifying the 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 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?

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 proposed 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 of Public Input Session and Intervention Deadline provided that any person wishing to intervene as a party in this proceeding must file a petition for intervention by March 28, 2008. No one petitioned to intervene as a party in the proceeding.

On May 14, 2008, a public input session was held via interactive television in Fargo, Grand Forks, Minot, and Bismarck, North Dakota.

On May 21, 2008, the Commission Advocacy Staff filed direct testimony.

On June 13, 2008, NSP filed rebuttal testimony.

On June 23 through June 25, 2008, the hearing was held in the Commission Hearing Room at the State Capitol in Bismarck, North Dakota.

On December 17, 2008, NSP filed a partially executed settlement agreement. On December 19, 2008, NSP filed a partially executed amendment to the settlement agreement filed on December 17th. On December 29, 2008, NSP filed a fully executed Settlement Agreement providing among other things for:

(a) a rate increase to provide additional annual revenue of approximately $10,855,000 or 7.4% effective for service rendered on or after March 1, 2009;

(b) a moratorium prohibiting further electric rate increases from becoming effective prior to January 1, 2011;

(c) an earnings sharing mechanism if net income exceeds 10.75% return on equity; and

(d) accounting treatment for Midwest ISO Day-2 Energy Market costs.

Having considered this matter, the Commission finds the December 29, 2008Settlement Agreement is reasonable and should be approved. Therefore, the Commission issues the following:

Order

1. The Settlement Agreement filed December 29, 2008, a copy of which is attached to this Order and made a part of this Order, is APPROVED.

2. NSP shall file compliance tariffs consistent with this Order and Settlement Agreement to implement final rates for service rendered on or after March 1, 2009, to yield an annual revenue increase of not more than $12,785,000, which is expected to yield a net annual revenue increase of approximately $10,855,000 when combined with projected fuel cost adjustment decreases resulting from off-system sales margin sharing.

3. Interim rates approved by the Commission will remain in effect for all customer classes thru February 28, 2009. Refunds, in the form of one-time bill credits, must be issued to customers within 90 days of the implementation of final rates for the difference between the interim revenue level and the approved March 1, 2009 revenue requirement. NSP shall file a final refund report with the Commission upon completion of the refunding.

4. This Order supersedes the interim accounting treatment ordered in Case No. PU-05-147 for Midwest ISO Day 2 Energy Market costs and Case No. PU-05-147 shall be closed.

PUBLIC SERVICE COMMISSION

Tony Clark **Commissioner**	**Susan E. Wefald** **President**	**Kevin Cramer** **Commissioner**

Xcel Energy®

RECEIVED

DEC 29 2008

PUBLIC SERVICE COMMISSION

VIA ELECTRONIC FILING AND U.S. MAIL

December 22, 2008

Darrell Nitschke
Executive Secretary and Director of Administration
North Dakota Public Service Commission
State Capital
600 East Boulevard
Bismarck, ND 58505-0480

Re: IN THE MATTER OR THE APPLICATION OF NORTHERN STATES POWER COMPANY, A MINNESOTA CORPORATION, FOR AUTHORITY TO INCREASE RATES FOR ELECTRIC SERVICE IN NORTH DAKOTA
Case No. PU-07-776

Dear Mr. Nitschke:

Attached is a Settlement Agreement dated December 22, 2008 between Northern States Power Company, a Minnesota corporation operating in North Dakota and the Advocacy Staff of the North Dakota Public Service Commission ("Commission") in the above referenced matter. It replaces entirely the Settlement Agreement dated December 17, 2008 and the Amendment to Settlement Agreement dated December 19, 2008, which have been combined into this replacement Settlement Agreement.

We have also included a legislative version of the Settlement Agreement so that the Commission can readily determine the changes made to the December 17th Settlement Agreement. To avoid confusion, we note that we have not provided legislative-format versions of the schedules, but rather are providing schedules that simply match the terms of this combined Agreement.

The Parties respectfully request the Commission to approve the Settlement Agreement and are available to provide any additional information the Commission may require.

Please contact us with any questions.

110 PU-07-776 Filed: 12/29/2008 Pages: 29
Fully Executed Settlement Agreement

Northern States Power Company

Very truly yours,

David H Sederquist Mu G Diller

David Sederquist	Michael Diller
Sr. Regulatory Consultant	Director, Economic Regulation

Encls.

cc: Service List

STATE OF NORTH DAKOTA
BEFORE THE
PUBLIC SERVICE COMMISSION

Susan E. Wefald	President
Kevin Cramer	Commissioner
Tony Clark	Commissioner

APPLICATION OF NORTHERN STATES POWER COMPANY, A MINNESOTA CORPORATION, FOR AUTHORITY TO INCREASE RATES FOR ELECTRIC SERVICE IN NORTH DAKOTA

CASE NO. PU-07-776

SETTLEMENT AGREEMENT

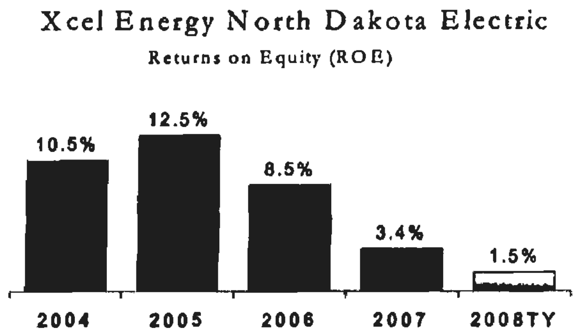
This Settlement Agreement is entered into this 22nd day of December 2008, by and between the North Dakota Public Service Commission Advocacy Staff ("Staff") and Northern States Power Company ("Xcel Energy" or the "Company"), a Minnesota corporation operating in North Dakota (collectively, the "Parties"). It replaces entirely the Settlement Agreement dated December 17, 2008 and the Amendment to Settlement Agreement dated December 19, 2008, which have been combined into this replacement Settlement Agreement. This Settlement Agreement resolves all outstanding issues in the above-captioned proceeding in a manner consistent with the public interest and will result in just and reasonable rates for the Company's retail electric operations in North Dakota.

BACKGROUND

Xcel Energy's electric operations in North Dakota were revenue deficient in 2006 and 2007, earning substantially below the authorized return on equity ("ROE") of 11.5

percent, as shown in Figure 1 below. Projected ROE for the 2008 test year, absent rate relief, was 1.54 percent.

Figure 1



Prior to this rate application, the Company had not filed a general electric rate increase application since November 1992 (Case No. PU-400-92-399). During this period, Xcel Energy did implement two modest performance-based rate increases under the provisions of the "PLUS Plan." authorized in Case No. PU -400-00-195. Those increases were triggered by above-target operating and rate performance, and below-authorized earnings.

In 2007, Xcel Energy's average residential electric rate was ranked as the lowest among investor-owned utilities in the states of North Dakota, Iowa, Minnesota, Montana, South Dakota, Wisconsin and Wyoming. This was the fourth year since 2001 in which the Company's North Dakota residential electric rates were the lowest in the region. With the increase contemplated in this Settlement Agreement, Xcel Energy's North Dakota residential rates are expected to remain within the top six of the thirty service territories comprising this regional comparison group. Moreover, even with the agreed-to increase, the Company's North Dakota rates will have averaged an annual increase of less than one percent since 1993, well under half the rate of inflation over the same period.

See Attachment A for a summary of the procedural history of this case, leading to the Settlement Agreement.

TERMS

The Parties agree to the provisions as defined below and supported by Attachments B, C, D, and E to this Settlement Agreement.

ENERGY POLICY

In this case, the Company determined its revenue requirement in part based on the costs of operating a single, multistate, and integrated system of generation and transmission facilities, with a corresponding allocation of those costs to the North Dakota jurisdiction.

Staff challenged whether North Dakota customers should pay for a portion of the integrated system costs incurred by the Company to satisfy environmental and renewable requirements imposed or facilitated by Minnesota law. During this proceeding, this issue became central to this rate case.

To eliminate or minimize conflicts surrounding energy resource decisions and the associated costs in future general rate proceedings, the Parties agree to adhere to the following regulatory procedures to ensure appropriate Commission involvement and oversight of the Company's future resource plans and selection of future generation and transmission projects to be added to the system serving North Dakota.

A. North Dakota Resource Planning Process

The Parties to this Agreement recognize that Xcel Energy, with its multi-state utility system, seeks to provide its customers the benefits of operating an integrated system while at the same time complying with the energy goals and policies of the states it serves. Currently, these states have different and/or conflicting energy priorities. The intent of the Energy Policy provisions of this Settlement Agreement is to provide a framework for identifying future plans and investments and, to the extent applicable, state-specific energy goals and policies and their implications for serving North Dakota customers. Using input provided by the Commission, the Company will be able to determine how best to proceed to both meet the needs of its North Dakota customers and recover its system-wide cost of providing service.

Xcel Energy agrees to provide to the Commission its Minnesota-filed Resource Plans ("RPs") for the integrated NSP System (Minnesota, Michigan, North Dakota, South Dakota and Wisconsin) as it has in the past. In addition to these overall RPs, the Company agrees to provide an alternative system-wide resource plan (the "North Dakota version") that strictly meets both Federal and North Dakota environmental and renewable requirements for the same time period addressed by the Minnesota Resource Plan.

While no formal action by the Commission on these RP scenarios would be required, the Parties envision that the Commission would consider the submissions on an informal basis and provide input to the Company's planning process. The intent of this provision is to seek and obtain such input prior to Company investments in resources for which it intends to seek recovery from North Dakota customers.

The Company also agrees to file with its annual Ten Year Plan required by N.D.C.C. § 49-22-04 and N.D.A.R. § 69-06-02-01 a summary of the key generating and transmission investments or purchase agreements that it intends to construct or enter into within the next five years. This summary will provide an anticipated schedule of future applications for Advance Determination of Prudence ("ADP") pursuant to N.D.C.C. § 49-05-16 that the Company would commit to filing with the Commission (see Section B of this Settlement Agreement).

Finally, the Company agrees to meet with the Commission and Staff as necessary to conduct updates on its resource planning efforts and decisions, and discuss the Ten Year Plan filed in that year. Such updates would include, but not be limited to, details regarding the above described alternative planning analyses, the specific projects identified in the five-year horizon, key management decisions being considered or made regarding the generation fleet and transmission systems, issues or trends in the energy industry impacting generation and transmission, the status of energy policies or laws approved or under consideration across the integrated NSP-System, as well as other pertinent planning topics of interest to the Commission. The Company commits to keeping the Commission and its Staff informed on a timely basis of any major changes in its Resource Plan or significant legislative initiatives under consideration in another jurisdiction.

Xcel Energy will file its next Ten Year Plan report on or before July 1, 2009. In the report, the Company will provide the results of its North Dakota version of the Resource Plan (based on the current 2008-2022 RP) outlined in this Settlement Agreement. Thereafter, Xcel Energy agrees to file the complete RP and updated North Dakota version on a schedule that corresponds to its overall Resource Planning cycle. In this first and all future Ten Year Plans, the Company will include and describe the current five-year action plan for generation and transmission facilities and its anticipated schedule for filings under the ADP statute.

B. Advanced Determination of Prudence

In accordance with N.D.C.C. § 49-05-16 the Company agrees to file for an ADP finding from the Commission for all proposed new construction, rehabilitation, or acquisition of an energy conversion facility, renewable energy facility, transmission facility or proposed energy purchase in which:

1. The Company proposes to allocate all or part of the related costs to the North Dakota jurisdiction for recovery in electric rates; and
2. The capacity of the generation facility or purchase is at least 50 MW; and/or the length of the transmission facility is at least 50 miles long.

The Company will identify its proposed cost-allocation methodology in the ADP petition as an item for which a determination of prudence by the Commission is requested.

The Parties anticipate that RP and ADP processes will provide a sound basis for Commission decision-making and substantially reduce the likelihood that the disputes of this case will occur in future rate proceedings. To the extent that these new processes reveal continued concern with individual resource decisions or cost assignments to jurisdictions, the Parties agree to work together on alternative approaches that might be employed while still allowing the Company to recover its costs of service and earn a reasonable return. Such efforts will include advocacy by the Company for cost recovery statutes to directly assign costs and benefits of mandated expenditures to the jurisdiction imposing the mandate when appropriate.

C. North Dakota Depreciation Study

The Company's proposed depreciation expense in this case was based on a uniform depreciation expense for use in all jurisdictions. In its testimony and post-hearing briefs, Staff challenged the reasonableness of the Company's methodologies in several respects.

In response, the Parties agree to the following process for establishing depreciation expenses:

- The Company will use the principles adopted in this Settlement Agreement in establishing depreciation rates for use in North Dakota. The Company will reflect its North Dakota depreciation rates in its annual North Dakota earnings reports and will file depreciation rates consistent with these principles as part of the Company's next electric rate case.

- For informational purposes, the Company will submit to the Commission the various depreciation studies and related documents that are periodically filed with the Minnesota Public Utilities Commission. Such filings include: Annual Review of Remaining Lives, Average Service Life and Vintage Group Filing (every five years), Triennial Review of Nuclear Decommissioning

- Ninety days before filing its next electric rate case, the Company will report to the Commission on whether it intends to propose North Dakota specific depreciable lives for distribution facilities, and the reasons for its proposal.

- Both Parties agree that, unless directed otherwise by the Commission, rate recovery -- past, present, and future -- for the removal and retirement of Company utility property will be used solely for the retirement of the Company's utility property and recognized as a regulatory liability.

REVENUE REQUIREMENTS

As a result of the adjustments agreed to herein and described below, the Parties agree to an increase in Xcel Energy's electric rates for retail customers in North Dakota to ultimately yield an annual retail sales and miscellaneous revenue increase of approximately $10,855,000 or 7.4 percent. As shown in Table 1 below and on Attachment B, the rates implemented on March 1, 2009 will reflect an increase in base rates of $12,785,000 offset by projected fuel clause reductions as a result of customer credits from wholesale margins of $1,930,000.

Table 1

Implementation	Base Rates	Fuel Rates	Overall Revenue
March 1, 2009	$12,785,000	($1,930,000)	$10,855,000

An interim rate refund will be issued to customers for the difference between the interim rate increase placed into effect on February 5, 2008 and the Settlement Agreement amount. The interim rate refund will reflect the fact that wholesale margins were credited to the interim revenue requirement. However, such margins will be credited to the fuel clause adjustment on a prospective basis, coinciding with final rates. See Attachment C for the calculation of the annualized interim rate refund.

Following is a description of the specific test year adjustments agreed to in this Settlement Agreement. (See also Attachment B):

D. Return on Equity

The Parties agree to a return on equity of 10.75 percent as outlined in the previous settlement with Staff. The adjustment reduces the original revenue request by $1,562,000 and agrees to share any earnings above 10.75% with customers (see other Terms and Conditions for a full discussion of this sharing mechanism).

The Parties also agree that a 10.75% ROE will be used for purposes of determining interim rates in the Company's next electric rate case.

E. Generating Plant Service Lives

For purposes of determining the overall revenue requirement, the Parties agree to:

- Extend the service lives of the Sherco Generating Station, and five other combustion plants (Angus C. Anson, Granite City, High Bridge, Inver Hills, and Key City) as proposed by Staff. The Company will reflect the longer service lives in final rates implemented in this docket. The adjustment reduces the revenue requirement by $1,362,000.
- Reduce the depreciation rates for its transmission and distribution assets to effect an adjustment in the reserve balance, thereby recalibrating the balance to be more in line with theoretically calculated levels. This adjustment reduces the revenue requirement by $1,180,000.
- Recover removal costs in depreciation rates for transmission and distribution based on a net present value methodology rather than on a future cost methodology (using Staff's alternative five year historical average for the purposes of this case). This adjustment reduces the revenue requirementby $437,000.
- The Parties recognize that the life extension has already been approved for the Monticello nuclear generating plant and that this fact eliminates the need for continued accruals to the existing escrow account, as reflected in the revenue requirement in this rate case. The Parties also agree to return, effective beginning March 1, 2009 and completed by the end of 2010, the amounts that North Dakota customers contributed to the decommissioning escrow account for the Monticello plant. This provision reduces the revenue deficiency for final rates by $212,000. Because this provision applies only to final rates (effective after March 1,

2009), it results in no change to the interim rate refund in this proceeding.

In addition, the Parties agree to determine final rates using a remaining life for the Prairie Island nuclear generating plant that assumes approval of the requested life extension for this facility. This adjustment results in a $2,162,000 decrease to the test year revenue requirement.

The Company has sought the necessary approvals for life extension and spent fuel storage from the Nuclear Regulatory Commission (NRC) and the Minnesota Public Utilities Commission (MPUC) for the Prairie Island nuclear generating plan, but those petitions are pending.[1] Final approvals from the NRC and MPUC are not expected prior to 2010. In recognition of the possibility that life extension and fuel storage may not be obtained, the Parties further agree that the Company will track the rate benefit provided by this provision. The rate benefit being tracked is the revenue requirement difference due to depreciation recognized using the longer remaining life versus the depreciation calculated using the current license life. In the event the needed regulatory approvals for life extension and fuel storage are not received, the amount in the tracker account shall become a regulatory asset, with an appropriate offset to accumulated depreciation, that will be recoverable from customers in a manner to be determined by the Commission in the Company's next electric rate case. In addition, within 60 days of the determination that life extension or the necessary additional fuel storage has been denied, the Company shall file a petition with the Commission to adjust North Dakota rates to recover the remaining investment in the Prairie Island

[1] The Prairie Island life extension requires approval of a new operating license from the Nuclear Regulatory Commission and a Certificate of Need ("CON") from the Minnesota Public Utilities Commission. Pursuant to Minn. Stat. § 216B.242, the Minnesota Public Utilities Commission's approval of a CON for additional nuclear storage will take effect after the close of the next legislative session after approval of the CON.

nuclear generating plant over the remaining life as determined by the operating license.

The Parties also agree that in no event is this provision intended to limit or deny the Company the opportunity to recover all prudent costs associated with the Prairie Island nuclear generating plant. Instead, this provision is intended to respond to the Commission's expectation that life extension for this plant will be approved and its expressed desire to provide the benefits of such extension at this time.

In all other respects, the Parties recommend that the Commission approve the methodologies used by the Company in this proceeding.

The service life extensions and other depreciation-related and escrow fund refunds reduce the revenue increase request by $6,335,000.

F. Generation and Transmission Investments

The Parties agree to allow recovery of the Company's proposed costs of its investments in the King and High Bridge power plants and the Grand Meadows wind farm and associated transmission investments. The Parties recognize that these investments were primary issues of dispute in this proceeding. The Parties reached agreement on this issue as a whole, and believe that the RP, ADP, earnings sharing, and rate moratorium provisions all facilitate the resolution of this issue and result in reasonable rates. Further, the Parties agree that the Company's refurbishment and repowering of two of its aging coal-fired power plants were prudent and economic investments, especially considering the strategic location of these plants. Moreover, Staff acknowledges that the Grand Meadow Wind Farm is able to take advantage of existing production tax credits to produce low and stable-priced energy that will contribute to Xcel Energy's efforts to meet North Dakota's renewable energy objective of supplying 10 percent of its retail energy needs with renewable resources. For these reasons, this Settlement Agreement provides for recovery of Company's costs associated with the King, High Bridge, and Grand Meadow generating facilities.

G. Wholesale Margins

For purposes of determining the overall revenue requirement, the Parties agree to provide to ratepayers 85 percent of all asset-based and 50 percent of non-asset-based margins achieved by the Company through the fuel clause. Passing these credits directly to customers through the fuel clause as they are realized ensures that neither customers nor the Company are disadvantaged by a non-representative margin forecast in the test year. By sharing the gains on asset-based sales, the Parties recognize that the Company is incented to maximize the benefit from these sales. Further, the non-asset sharing at 50 percent is more than adequate to assure that any costs imposed on customers as a result of this activity is fully credited.

H. Amortization of Nuclear Refueling Expenses

For purposes of determining the overall revenue requirement, the Parties agree to an annual amortization expense level of $2,492,407, which approximates the levelized annual amortization after refueling outages have occurred for all three of the nuclear units at the Prairie Island and Monticello nuclear generating plants. This provision results in no change to the revenue requirement initially filed in the rate case. Given that other provisions of this Settlement Agreement provide for the accelerated life extension for Prairie Island, earnings sharing and a rate moratorium, the Parties believe this approach is reasonable. Attachment D shows these costs.

I. Renewable Development Fund

For purposes of determining the overall revenue requirement, the Parties agree to remove the test year expenses related to Renewable Development Fund research and development grants and disbursements. The adjustment reduces the rate increase request by $170,000.

J. Charitable Contributions

For purposes of determining the overall revenue requirement, the Parties agree to remove the Company's costs associated with 50 percent of its charitable contributions. The adjustment reduces the rate increase request by $86,000.

K. Incentive Compensation Cap

For purposes of determining the overall revenue requirement, the Parties agree to a reduction in the cap on incentive compensation from the Company's proposed level of 25 percent to 15 percent of base salary. Accordingly, costs associated with the incentive compensation of the employee's total compensation is capped at 15 percent of an individual's base salary, and costs for incentive compensation in excess of 15 percent of the employee's base salary will not be included in rates. The adjustment reduces the rate increase request by $35,000.

L. Mercury Emissions Control

For purposes of determining the overall revenue requirement, the Parties agree to a reduction in costs related to monitoring mercury emissions reduction efforts at its King and Sherco generating plants to meet Minnesota mercury emissions requirements. The adjustment reduces the revenue increase request by $12,335.

M. MISO Schedule 16 and 17 Costs

For purposes of determining the overall revenue requirement, the Parties agree to recovery of Midwest Independent Systems Operator ("MISO") Schedule 16 and 17 costs in the fuel clause. Fuel clause treatment is appropriate given that, like all other MISO Day 2 charge types which are also recovered through the fuel clause, they are non-discretionary charges billed out by the MISO, and they have been recovered through the fuel clause in North Dakota for the past three years. Fuel clause treatment is also consistent with the present treatment of these costs in South Dakota. This adjustment does not impact the overall revenue increase, since the recovery of these costs is just being shifted from base rates to fuel clause rates. This adjustment does, however, reduce the base rate revenue requirement by $532,000.

N. Private Fuel Storage

The Parties clarify that the rate increase contained in this Settlement Agreement provides for recovery of the Company's costs associated with Private Fuel Storage. The Parties agree that the Company's effort in securing such a facility was prudent and appropriate in light of delays in the development of a Federal repository for spent nuclear fuel. This provision results in no change in the Company's proposed test year revenue requirement.

RATE DESIGN

The Parties agree to the following revenue requirement apportionment among customer classes for the March 1, 2009 rate increase:

1. Residential service: $5,157,000 or 8.9 percent;
2. Commercial (non-demand metered) service: $972,000 or 9.3 percent; and
3. Commercial (demand metered) service: $6,656,000 or 8.6 percent.

These changes are further shown on Attachment E to the Settlement Agreement. This apportionment reflects base rate percentage changes by customer class that are consistent with the Company's originally proposed class revenue allocation, as shown on the attachment.

The Parties agree to the filed tariff changes proposed in the Company's initial filing, as amended to reflect the change in revenue requirement contained in this Settlement Agreement. In amending the tariffs, the Parties agree to using the Company's proposed rate design principles in the development of final rates to implement the approved revenue requirement contained in this Settlement Agreement.

The Company shall file compliance tariff pages setting forth the revised electric rates and tariffs provided by this Settlement Agreement at least thirty (30) days prior to the effective date of final rates.

INTERIM RATES

The Parties agree the interim rates will remain in effect for all customer classes until February 28, 2009. Refunds will be issued to customers within ninety (90) days of the implementation of final rates for the difference between the interim revenue level and the March 1, 2009 revenue level agreed to in this Settlement. Based on current information, the Parties estimate that customers will receive $6,328,000 in base rate refunds (see Attachment C).

OTHER TERMS AND CONDITIONS

O. Customer Refunds for Earnings Above Authorized ROE

The Parties agree to an earnings-sharing mechanism that will result in customer refunds if the Company's net income exceeds a 10.75 percent ROE for its North Dakota electric operations.

If the Company earns in excess of 10.75 percent ROE during the 2009 or 2010 calendar years, the Company will refund to customers revenues corresponding to earnings as shown below:

- 50% of earnings above 10.75% up to and including 11.25%; and
- 75% of earnings above 11.25%.

Earnings sharing refunds would be applied to customer accounts as a one-time bill credit as soon as practical on or after July 1st of the following calendar year.

P. Rate Moratorium

The Parties agree to a moratorium on an electric rate increases until 2011 for Xcel Energy's North Dakota operations. This moratorium does not preclude the Company from submitting a rate application for electric rates prior to 2011, but no change in customer rates would be implemented before January 1, 2011.

Q. Basis of Settlement Agreement

It is agreed this Settlement Agreement is a negotiated settlement agreement subject to approval by the Commission. Except for the purpose of setting interim rates and depreciation expenses in the Company's next electric rate case, the Settlement Agreement does not establish any principle or precedent, nor adopt or recommend any specific type or amount of expense or rate base, for this or any future proceeding.

R. Effect of the Settlement Negotiations

It is understood and agreed that all offers of settlement and discussions related to this Settlement Agreement are privileged and may not be used in any manner in connection with proceedings in this case or otherwise, except as provided by law. In the event the Commission does not approve this Settlement Agreement, it shall not constitute part of the record in this proceeding and no part thereof may be used by any party for any purpose in this case or in any other.

S. Applicability and Scope

This Settlement Agreement shall be binding on the Parties, and their successors, assigns, agents, and representatives. Consistent with the Commission's settlement guidelines, this Settlement Agreement does not set policy or overturn precedent. This Settlement Agreement shall not in any respect constitute an agreement, admission or determination by any of the Parties as to the merits of any specific allegation or contention made by the Parties in this proceeding.

T. Effective Date

This Settlement Agreement shall be effective on the date of the Commission Order approving the Settlement Agreement. The revised rates and tariff agreed to by this Settlement Agreement shall be effective on the dates specified in the Revenue Requirements Section of this Settlement Agreement.

V. Modification

If the Commission Order modifies or conditions approval of this Settlement Agreement, it shall be deemed terminated if either Party files a letter with the Commission within three (3) business days of the date of such Order stating that a condition or modification to the Settlement Agreement is unacceptable to such party.

CONCLUSION

The Parties have agreed to the forgoing terms to resolve the contested issues in the electric rate case proceeding. These terms are a result of negotiations between the Parties, are in the public interest and will result in reasonable electric rates. For these reasons, the Parties urge the Commission to approve the Settlement Agreement.

Dated this 22nd day of December 2008.

Northern States Power Company,
A Minnesota corporation

By: ______________________
Judy M. Poferl
Regional Vice President

Dated this 23rd day of Dec. 2008.

Northern Dakota Public Service Commission Staff

By: ______________________
Doug Bahr
Counsel to the Commission

PROCEDURAL HISTORY

Case No. PU-07-776

On December 7, 2007, Xcel Energy filed a Notice of Change in Rates for Electric Service ("Notice") with the North Dakota Public Service Commission (the "Commission"), based on a 2008 test year, with interim rates to become effective February 5, 2008. The Notice proposed an increase in electric retail and miscellaneous base rates of $20,535,000 and a decrease in fuel clause rates of $2,371,000, or about a 12.3 percent overall increase in revenues. The Company filed testimony by eleven witnesses in support of the Notice.

Xcel Energy proposed to increase residential base rates by $8,228,000 or 14.3 percent and commercial service revenues by $12,056,000 or 13.9 percent. Filed with the Notice were revised tariffs, direct testimony, exhibits, and supporting statements.

Concurrent with the Notice, Xcel Energy submitted an Alternate Petition for Interim Rates. The proposed interim increase, which impacted only base rates, was for $17,183,000 or 11.5 percent, to be effective February 5, 2007 (60 days from filing) in the event the Commission suspended the proposed general increase. The proposed interim increase and rate design were submitted pursuant to the criteria set forth in N.D.C.C 49-05-06.

On December 31, 2007, the Commission issued an order suspending Xcel Energy's general rate increase application and set the matter for investigation and hearing.

On January 16, 2008, the Commission issued a Notice of Public Input Session and Intervention Deadline announcing a Public Input Session to be held via interactive television on March 14, 2008, at 11:30 a.m. central time at various locations in Fargo, Grand Forks, Minot, and Bismarck. Members of the public were invited to appear and participate in the informal discussion. The notice also set forth a deadline of March 28, 2008 for parties to indicate their interest in participating in the case. No parties intervened.

On March 26, 2008, the Commission issued a Notice of Hearing that set forth the following issues to be considered in this case:

> What is the value of NSP's property, used and useful, for the service and convenience of the public in North Dakota?
>
> What is NSP's rate of return on its property, used and useful, for the service and convenience of the public in North Dakota?
>
> What is 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?
>
> 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?
>
> 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?
>
> Other relevant information or proposals concerning the proceeding.

On January 30, 2008, the Commission issued an order allowing an interim base rate increase of $17,183,000, to be placed into effect February 5, 2008, subject to refund.

On March 14, 2008, the Commission conducted a public input session. The session utilized interactive video-conferencing capabilities to include participants in Fargo, Grand Forks, Minot, and Bismarck.

On May 16, 2008, Advisory Staff filed Direct Testimony prepared by two consultants from Snavely King & Majoros.

On June 13, 2008, Xcel Energy filed Rebuttal Testimony prepared by seven witnesses.

On June 23 and 24, evidentiary hearings were held in the Commission Hearing Room at the state capitol building in Bismarck, North Dakota. Fourteen Xcel Energy witnesses provided testimony on the Company's need for rate relief. Two consultants from Snavely King & Majoros provided testimony on behalf of Commission Advocacy Staff.

On August 22, post-hearing briefs were filed by both Xcel Energy and the Commission Advocacy Staff.

From November 9th through December 12th of 2008 the Commission held three working sessions with its Advisory Staff during which the issues raised by Advocacy Staff and the Company were considered and discussed.

On December 22nd this Settlement Agreement was entered into by Advocacy Staff and the Company, and filed with the Commission.

The administrative record in this proceeding supports the Settlement Agreement. Accordingly, the Parties jointly recommend the Commission issue an Order approving this Settlement Agreement, and the earlier settlement on ROR, without further conditions or modifications.

Northern States Power Company, a Minnesota corporation
Electric Utility- State of North Dakota
2008 Summary of Settlement Agreement Impacts

		Base Rates	Fuel Rates		Total Revenue	
1	**12/7/07 Rate Application**	**$20,535**	**($2,371)**	[1]	**$18,164**	
2	Stipulate to ROE of 10.75%	($1,562)	$0		($1,562)	
3	Depr - life adj. - Prairie Island*	($2,162)	$0		($2,162)	
4	Depr - life adj. - Steam & Other Production	($1,362)	$0		($1,362)	
5	Depr - T&D reserve recalibration	($1,180)	$0		($1,180)	
6	Depr - Net PV method for removal in T&D	($437)	$0		($437)	
5	King, High Bridge, Gr Meadow Generation	$0	$0		$0	
7	Monti Decommissioning escrow refund amort	($212)	$0		($212)	
5	Levelized nuclear fuel reload amortization	$0	$0		$0	
5	Amortization of private nuclear fuel storage	$0	$0		$0	
8	Disallow Renewable Development Fund	($170)	$0		($170)	
9	Add'l 35% of non-asset margins to cust (50/50 shar	$0	($91)		($91)	
10	Disallow all charitable contributions	($86)	$0		($86)	
11	Decrease incentive comp cap from 25% to 15%	($35)	$0		($35)	
12	Disallow mercury emissions costs	($12)	$0		($12)	
13	Recover MISO 16/17 costs in fuel rates	($532)	$532		$0	
14	**Settlement Outcome (Implemented 3/1/09)**	**$12,785**	**($1,930)**		**$10,855**	7.4%

Notes:
[1] Fuel Clause Impact of 12/7/07 Application

Pass 85% Asset-Based margins to customers	($1,800)
Pass 15% Non-Asset Based margins to cust.	($39)
Move MISO 16/17 costs to Base Rates	($532)
	($2,371)

Northern States Power Company, a Minnesota corporation
Electric Utility- State of North Dakota
Calculation of 2008 Test Year Annualized Refund
Dollars in 000's

	Amount
Interim Revenue Increase (annual)	$17,183
Amended Settlement Agreement Increase	$10,855
Estimated refund [1]	$6,328

Notes:
[1] This refund amount is an estimate based on a 12 month interim rate period. Assuming final rates are implemented on March 1, 2009, the refund will include a 13 month period and wil include interest.

Attachment D
Page 1 of 1

Northern States Power Company, a Minnesota corporation
Electric Utility - State of North Dakota
Amortization of Nuclear Fuel Outage Costs

	NSPM Co.	North Dakota Jurisdiction	
2008 Actual Outage Expense	$50,759,000	$\boxed{\$2,492,407}$	*
2008 Amortization	$16,535,421	$811,935	
2009 Actual Outage Expense	$58,821,000	$2,888,274	
2009 Amortization	$44,282,980	$2,174,417	
2010 Actual Outage Expense	$35,000,000	$1,718,597	
2010 Amortization	$52,307,202	$2,568,428	

* Test year and amended settlement level

Notes:

2008 amortization reflects 10 months of PI 1 and 3 months of PI 2.

2010 amortization reflects 12 months at all three units.

There are 2 fuel reloading outages (PI1 and PI2) scheduled to occur in 2008; 2 reloading outages (Monti and PI1) are scheduled in 2009, and 1 outage (PI2) is scheduled in 2010.

Northern States Power Company, a Minnesota corporation
Electric Utility - State of North Dakota
Settlement Base Rate Revenue Apportionment
Dollars in 000's

Original Application	Residential	Non-Dem	Demand	Street Ltg	Total	
Present revenues	$57,723	$10,436	$77,139	$1,881	$147,179	
Proposed revenues	$66,006	$11,997	$87,830	$1,881	$167,714	
Base rate deficiency	$8,283	$1,561	$10,691	$0	$20,535	
Percent change	14.3%	15.0%	13.9%	0.0%	14.0%	
March 1, 2009 Increase						
Base rate increase	$5,157	$972	$6,656	$0	$12,785	[1]
Percent change	8.9%	9.3%	8.6%	0.0%	8.7%	

Notes:
[1] Revenue impacts do not include credits for wholesale margins, which will be passed directly to customers through the Fuel Clause.

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June 17, 2016

- Via Email and U.S. Mail -

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

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

Dear Mr. Nitschke:

Enclosed for filing with the North Dakota Public Service Commission in the above-referenced dockets is a courtesy copy of the Aurora Compliance Filing on Jurisdictional Cost Issues that was filed with the Minnesota Public Utilities Commission on June 13, 2016 (MPUC Docket Nos. E002/M-15-330; E002/M-16-223). The filing contains information that relates directly to the Company's efforts to develop a Resource Treatment Framework that can accommodate differing state energy policies and priorities.

Please contact me if you have any questions regarding this filing at dave.sederquist@xcelenergy.com or 701-241-8632.

Sincerely,

David H Sederquist

DAVID H. SEDERQUIST
Sr. Regulatory/Financial Consultant
Northern States Power Company

Enclosures
cc: Jack Shuh
Mike Diller
Illona Jeffcoat-Sacco
Jerry Lein

414 Nicollet Mall
Minneapolis, Minnesota 55401

June 13, 2016

ɣVIA ELECTRONIC FILINGɣ

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

RE: COMPLIANCE FILING ON JURISDICTIONAL COST ISSUES
DOCKET NOS. E002/M-15-330 AND E002/M-16-223

Dear Mr. Wolf:

Northern States Power Company, doing business as Xcel Energy, submits this Compliance Filing in the above-referenced dockets. This filing responds to the Commission's April 13, 2016 Order in Docket No. E002/M-15-330, and provides information related to coordination of resource selections in states served by the Northern States Power Company integrated system (NSP System).

Pursuant to Minn. Stat. § 216.17, subd. 3, we have electronically filed this document, and served copies on all parties on the attached service list.

Please contact me at (612) 215-4663 if you have any questions regarding this filing.

Sincerely,

/s/

AAKASH H. CHANDARANA
REGIONAL VICE-PRESIDENT
RATES AND REGULATORY AFFAIRS

Enclosures
c: Service List

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Beverly Jones Heydinger	Chair
Nancy Lange	Commissioner
Dan Lipschultz	Commissioner
Matthew Schuerger	Commissioner
John Tuma	Commissioner

IN THE MATTER OF THE PETITION OF NORTHERN STATES POWER COMPANY D/B/A XCEL ENERGY FOR APPROVAL OF COST RECOVERY OF THE AURORA POWER PURCHASE AGREEMENT

DOCKET NO. E002/M-15-330

IN THE MATTER OF XCEL ENERGY'S FILING ON JURISDICTIONAL COST ISSUES

DOCKET NO. E002/M-16-223

COMPLIANCE FILING

Northern States Power Company, doing business as Xcel Energy, submits to the Minnesota Public Utilities Commission this Compliance Filing in the above-referenced docket.

INTRODUCTION

We provide service to our customers through an integrated generation and transmission system known as the NSP System. The NSP System has been successfully managed on an integrated basis for almost 100 years, and during that time our customers have benefited from the efficiencies and cost savings that come with a large and diverse system. Throughout this period the Company has been governed by three underlying principles and they are the principles that continue to guide us today. They are:

- Retaining the integrated nature of the NSP System for the benefit of all of our customers;
- Respecting the sovereign nature of each of the states we serve, while ensuring that they understand and bear the costs and risks associated with their decisions; and

- Ensuring the Company has an opportunity to remain whole by fully recovering its cost of service in each state served by the NSP System.

These principles often work together—though not always. At times they are in direct tension with one another. That said, we believe the core value that is shared by all of our states—the provision of safe and reliable service at an affordable cost—has been well served by the integrated system. That has allowed us to reach consensus on the vast majority of our existing generation fleet, and this agreement on resources continues as we expand our generation fleet, most recently with the Black Dog Unit 6 expansion and our purchase of the Courtenay Wind Farm.

In achieving that consensus while still respecting the sovereignty of the states we serve, we have had to employ different approaches in different states. In North Dakota that includes the use of settlements, as is the jurisdictional norm. These settlements have served the integrated system well, allowing us to move forward with key resource additions supported by Minnesota and other NSP states while preserving the integrated nature of the NSP System and recovering our full cost of service. These settlements have also allowed us to address these concerns in North Dakota through that state's own processes

While we have successfully managed the integrated system to date, the addition of significant generation resources continues to put pressure on that model. Recently, we have been unable to reach settlement in North Dakota on certain proposed generating resources. Instead, we developed resource-by-resource solutions in a way that keeps our three core principles intact.[1] It is our belief that this type of piecemeal approach is unsustainable, and we have therefore begun to examine our options for – managing the NSP System going forward.

For several reasons, now is the right time for this discussion. First, our fleet is aging and will turn over, almost completely, in the next two decades. Second, the mix of resources coming onto our system continues to evolve with the maturation of wind, solar, and distributed generation as well as historically low gas prices. Third, we are likely to see new environmental regulations at both the state and federal level, including the Clean Power Plan, that drive resource decisions.

[1] Examples of these solutions include proposing to include the North Dakota portion of some of the 187 MW Solar Portfolio projects in our Renewable*Connect Tariff and obtaining agreement from the developer of the Aurora Solar Project to support the Company for the unrecovered North Dakota costs of the project.

Accordingly, we proposed to the North Dakota Public Service Commission (NDPSC) that we perform detailed analyses to support development of a long-term plan that addresses the future of the NSP System. The NDPSC agreed to our proposal and we will be submitting our plan by January 1, 2017. We will make a concurrent filing with the Minnesota Public Utilities Commission.

While we will ultimately bring forward a recommendation, today finds us in the middle of our detailed analyses. Indeed, it is too early in the process to know the size and shape of our ultimate proposal. What is certain is that our proposal cannot interfere with either the sovereignty of the states in which we provide service or the need for the Company to remain whole on cost recovery. Accordingly, our analysis centers around our first principle—retaining (or not) an integrated system.

On that front, we are considering all options. On one end of the spectrum, we are investigating structures that would retain the integrated nature of the NSP System through modest changes to the way we manage the system today. On the other end of the spectrum, we are analyzing whether and how to separate some or all of the states served by the Company from the NSP System. Our analysis also includes identifying and developing the many options that fall somewhere in between those bookends.

In anticipation of filing our long-term proposal, this Compliance Filing is intended to provide history and context for the principles underlying our management of the NSP System as well as our work to date. To that end, we first discuss the NSP System, its historical development and its current structure. Next, we compare and contrast the regulatory and analytical frameworks in Minnesota and North Dakota to provide perspective on past outcomes and how they may relate to future resource additions. We then discuss our efforts in North Dakota since 2007 for contextual support of our efforts to date. Finally, we identify our analytical framework and potential structures we may propose at year's end.

This filing is only one step in what the Company hopes will be an ongoing dialogue with the Commission on these issues. Therefore, we respectfully request a planning meeting be held in the third quarter of this year where we can further discuss the information presented in this filing and answer any questions the Commission and our stakeholders may have.

I. DEVELOPMENT AND OPERATION OF THE INTEGRATED NSP SYSTEM

The NSP System is comprised of the generation and transmission assets of Northern States Power Company – Minnesota (NSPM), which serves customers in Minnesota, North Dakota, and South Dakota, and the generation and transmission assets of our sister operating company, Northern States Company – Wisconsin (NSPW), which serves customers in Wisconsin and Michigan. Although these two separate companies own separate assets and serve customers in different states, we plan for and operate all of the generation and transmission resources on an integrated basis.

To better understand the issues with respect to managing the NSP System as an integrated whole, it is useful to understand how and why the NSP System developed the way it did, how it looks today, and how it is operated. At base, the development of the NSP System mirrors the overall development of the utility industry and its continual search for economies of scale and diversity.

Economies of scale are generally sought to efficiently manage and economically develop and dispatch generation and utilize transmission systems to meet the needs of customers in the most cost-effective manner possible. By aggregating load and sharing resources across a larger geographical area, utilities are able to build larger and more diverse generating facilities capable of efficiently meeting the energy needs of customers, while also providing resource diversity and scale to manage plant outages and fuel price volatility. Seeking these economies of scale has been a goal throughout the utility industry as it has developed over the past century.

Diversity was, and continues to be, a key factor in balancing capacity and demand. Utilities sought diversity in several different ways. The utility holding company structure helped to achieve diversity by operating utilities in several different regions of the country, which spread risk across the holding company system. The effects of a poor wheat crop in Kansas could therefore be offset with an oil boom in Texas. The industry views diversity as a system of efficient generating stations tied together by a high-voltage transmission grid which is better able to offset risk than isolated generating stations that serviced individual communities.

Today's integrated NSP System, and the structure of Xcel Energy Inc., is a product of 100 years of utility industry development using benefits of scale and diversity across all our states.

A. Development of the NSP System

The formation of the modern Northern States Power Company resulted from the activities of the Consumers Power Company, a collection of small-town electric companies in what would become the Twin Cities area, which was part of the Standard Gas and Electric Company's holding company system. From 1909 to 1916, the year Consumers Power Company became Northern States Power Company; the company consolidated its Minnesota operations and began acquiring properties in other states. In 1911, North Dakota operations began through the purchase of the Fargo, Grand Forks, and Minot utilities. In 1914, operations began in South Dakota through the acquisition of the local Sioux Falls utility. In 1915, the Company expanded into Wisconsin through the purchase of several hydroelectric facilities and the service territory of the communities they served. However, because Wisconsin law then (and now)[2] requires that utilities operating in that state be incorporated as Wisconsin companies, Northern States Power Company, a Wisconsin corporation (NSPW), was established. From 1923 to 1925 the Company consolidated its St. Cloud and Twin Cities holdings through the acquisition of additional local utilities in Minneapolis, St. Paul, and St. Cloud. By the late 1920s, the Northern States Power Company that ultimately emerged from this industry-wide wave of consolidation was mostly contiguous and tied together by a web of 66 kV transmission lines. By 1929, Northern States Power Company served approximately 270,000 electric meters in five states.

Consistent with the move toward capturing the economies of central station power, NSP constructed the Riverside plant to meet the load-serving needs of the Minneapolis flour/grain mills and the surrounding areas. Construction began in 1915 and expansion of the plant continued through the mid-1920s. In addition to this generation development, parts of the emerging NSP transmission system were upgraded from 66 kV to 110 kV. The system continued to grow until the Great Depression and World War II.

In the post-war boom, NSP more than doubled its generating capacity. During this time, the Company built or upgraded ten new steam electric generating plants, including the Black Dog plant, additions to the High Bridge and Riverside plants, and new units in Mankato, Red Wind, St. Cloud, Granite Falls, Sioux Falls, Minot, and Grand Forks.

The Company's post-war load growth was met with generation additions that were increasingly lower cost per kilowatt of new capacity. These economies of scale spurred the need for more load growth, so that the Company could install more generation at a lower cost-per-kilowatt. Rates could then be reduced correspondingly, which would promote more load growth. The effectiveness of these economies of scale was so pronounced that rates were reduced in 1946, and after increases in 1948 and 1952, the Company began an unbroken succession of rate reductions extending through the rest of the 1950s and into the late 1960s.

[2] Wis. Stat. § 196.53.

Throughout the 1960s, NSP embarked on an aggressive construction program to meet customer demand, obtain better economies of scale, and modernize the system. The 1960s saw the development of the 345 kV transmission loop around the Twin Cities and the further development of the Black Dog plant, additions to the Riverside plant, and construction of the Allen S. King plant. In the 1970s, the first two units of the Sherburne County generating station were developed, continuing the central station economies of scale that first began with the Riverside plant.

The Company has also been a leader in developing emerging technologies that complement existing elements of the system and offer new ways to most efficiently provide service. The Company has been an active participant in nuclear development, culminating with our Monticello and Prairie Island units in the early 1970s. Additionally, we have retained our historic plants at High Bridge and Riverside through their repowering (along with retrofitting the Allen S. King plant) as part of the Metropolitan Emissions Reduction Program (MERP). More recently, the Company has become a leader in the development of wind power, fostering this technology with a demonstration facility in the 1980s and supporting its emergence in the mid to late 1990s through its maturity in today's landscape.

Transmission development remains a crucial component of the NSP System and ensures economies of scale and reliable service to all states throughout the region. The Company was one of the first utilities to upgrade its facilities to the then-new 345 kV technology. We also installed the region's first 500 kV transmission line connecting the Twin Cities in Minnesota to Winnipeg, Canada in the early 1980s, to take advantage of extreme geographic and seasonal diversity through power purchase exchanges with the Manitoba Hydro Energy Board. Recently, the CapX2020 Group 1 Projects provide new, strong links between our customers in North Dakota through the Fargo Line, South Dakota through the Brookings Line, Wisconsin through the Rochester to La Crosse Line, and the generation in and around our largest load center in the Twin Cities area of Minnesota.

The historic development of the NSP System through today continues to provide many of the benefits that initiated its development almost a century ago.

B. The Current NSP System

Today, NSPM and its sister corporation, NSPW, continue to provide electric service to customers across a five-state area in the upper Midwest through an integrated generation and transmission system. Although these two companies serve customers in five different states, the integrated nature of the NSP System means that generation and transmission planning and operation has been conducted on a system-wide, rather than a state-specific, basis for the benefit of all customers.

The current NSP System is comprised of a diverse electric generating fleet with an installed capacity of over 10,000 megawatts (MW) meeting the energy needs of over 1.6 million electric customers. NSPM serves electric customers totaling approximately 1.2 million in Minnesota, 92,000 in North Dakota, and 90,000 in South Dakota, making NSPM the largest utility in each of those states. NSPW serves approximately 245,000 electric customers in Wisconsin and 9,000 electric customers in Michigan.

Our generation portfolio currently includes the High Bridge, Riverside, and Angus Anson natural gas plants in Minnesota and South Dakota, the Monticello and Prairie Island nuclear facilities in Minnesota, and the Sherco and Allen S. King coal plants in Minnesota. The NSP System also includes peaking plants located in both Minnesota and Wisconsin, as well as approximately 2,500 MW of renewable energy capacity including wind, hydro, biomass, refuse derived fuel, and solar resources. The renewable generation portfolio includes 19 hydro facilities in Wisconsin and one hydro facility in Minnesota, the Nobles, Pleasant Valley, and Grand Meadows wind farms in Minnesota, and the Border and Courtenay wind farms in North Dakota. The NSP System also transmits electricity via approximately 7,700 miles of transmission lines that stretch across the five-state NSP System.

NSPM and NSPW continue to own all levels of the electric supply chain, *i.e.* generation, transmission, and distribution, and are regulated by each of the states served by the NSP System (and the Federal Energy Regulatory Commission) as vertically integrated utilities. The integrated nature of the NSP System continues to allow NSPM and NSPW to construct, plan, and operate generation and transmission facilities across the five-state area to provide economic and reliable supply of electricity to meet the needs of our customers. This integrated NSP System supports our customers by providing opportunities to leverage economies of scale, access diverse and numerous generation resources, take advantage of load diversity, and construct a robust and resilient transmission system.

The continuing purpose of operating as an integrated NSP System is highlighted in the planning agreement between NSPM and NSPW:

> *[I]ntegrated system planning and operation provides benefits to the [Company] and their respective customers, including opportunities for:*

A. The construction of new generation and transmission facilities of optimum size to produce maximum economies of scale for the [Companyǒs] combined electric system as a whole;

B. The economical use of capacity and energy available from variations in load patterns resulting from the diversity of loads imposed by the [Companyǒs diverse load];

C. The utilization of the seasonal and diversity patterns of other utilities not contiguous to [the Company] for the outlet of surplus capacity and energy which may be available from time to time, together with the opportunity, because of such variation in seasons and diversity of loads, to acquire capacity and energy from other utilities and thus avoid or defer the construction of generating capacity to meet seasonal loads;

D. The pooling of reserves to reduce the magnitude of reserve capacity required by the [Company] in order to assure reliable service to [its] customers;

E. Improvement in the reliability of electric service through the use of transmission interconnections which provide the [Company] with the opportunity to call upon [other resources] as well as other utilities with which they, or any of them, are interconnected to provide backup service in case of emergencies or breakdowns in excess of the reserves carried by the [Company]; and

F. The provision of the most economical energy for the customers of the [Company] by use of a centralized economic dispatch system.[3]

The NSP System provides a strong, reliable platform as we continue to evolve in the modern utility landscape. As noted in our most recent Upper Midwest Resource Plan (Docket No. E002/RP-15-21), much of the existing NSP generating fleet will be retiring over the next twenty years, which make this an appropriate time for a review of the NSP System.

[3] *Xcel Energy Operating Cos.*, FERC Docket No. ER01-1014, Restated Agreement to Coordinate Planning and Operations and Interchange Power and Energy between Northern States Power Company (Minnesota) and Northern States Power Company (Wisconsin) (Jan. 19, 2001); *Xcel Energy Operating Cos.*, FERC Docket No. ER01-1014, Letter Order (Mar. 20, 2001); *see also N. States Power Co., a Minn. Corp.*, FERC Docket No. ER15-1575, Letter Order (June 22, 2015) (unpublished letter order of Xcel Energy's most recent update to the Interchange Agreement).

C. Coordination of the Integrated NSP System

The fact that the NSP system is supported by two separate corporate entities that serve customers in more than one state impacts the way in which the integrated NSP System is managed and regulated. To that end, NSPM and NSPW must have in place mechanisms to appropriately share and assign cost responsibility to the customers of each of these states for constructing, operating, and maintaining the integrated NSP System. This is done both on an inter-corporate basis (between NSPM and NSPW) and on an inter-jurisdictional basis amongst the states served by each of the corporate entities.

1. Inter-corporate Coordination

In general, all production and transmission costs incurred on behalf of NSPM and NSPW are allocated under the terms of an agreement that has been approved by FERC. This agreement is formally titled "Restated Agreement to Coordinate Planning and Operations and Interchange Power and Energy between Northern State Power Company (Minnesota) and Northern States Power Company (Wisconsin)" and is commonly referred to as the Interchange Agreement (IA).

Cost sharing agreements between NSPM and NSPW date back to at least the 1970s,[4] and the 1984 version of the IA was restated in 2001 to provide more specificity in the formula rates and cost of service procedures. The IA establishes the method for determining charges from each company to the other for the sharing of power, energy, and transmission costs. Each operating company shares in the NSP System's production and transmission costs by billing the other according to the methodologies authorized by FERC in the IA. While only one operating company has title to, or contracts for, any given generation or transmission asset, both NSPM and NSPW share the cost of developing, operating, and maintaining all generation and transmission facilities that comprise the NSP System.

In general, the IA formula utilizes an allocation methodology involving the highest monthly system demand and the corresponding coincident operating company peak demand for a 36-month period—referred to as the 36 Coincident Peak or 36CP method. Under this method, cost share is determined by each operating company's ratio of peak demand to the system total using 18 months historic and 18 months

[4] The modern day version of the IA was established in 1984; its predecessor, The Coordinating Agreement, was approved by the (then) Federal Power Commission in 1971.

forecasted peak load data, resulting in approximately 15 percent of the costs of the NSP System being allocated to NSPW, and approximately 85 percent of the NSP System costs being allocated to the NSPM. The exact allocation percentages are determined by the allocation factors updated, filed, and approved at FERC annually.

The relationship between NSPM and NSPW as two separate contracting parties is governed by the IA and, because the IA is a FERC jurisdictional federal tariff, it is overseen and regulated by FERC. This creates a different legal and regulatory structure governing the relationship between NSPM and NSPW (and therefore between the Minnesota and Wisconsin jurisdictions of the NSP System) than between different jurisdictions served by the same corporate entity such as the Minnesota, North Dakota, and South Dakota jurisdictions served by NSPM or the Wisconsin and Michigan jurisdictions served by NSPW.

2. *Inter-jurisdictional Coordination*

In contrast to the inter-corporate relationships managed through FERC jurisdictional tariffs and contracts, the inter-jurisdictional relationships within a single corporate entity are generally managed through state regulatory approval of ratemaking factors, which allocate system costs across the jurisdictions served by a particular corporate entity. Therefore, there is no FERC oversight of the inter-jurisdictional coordination of states served by the same corporate entity such as the Minnesota and North Dakota jurisdictions served by NSPM. Rather, the applicable state regulatory commissions have direct oversight over the inter-jurisdictional coordination of a single corporate entity.

NSPM allocates the fixed production and transmission costs among Minnesota, North Dakota, and South Dakota customers through the use of "The Sum of 12 Monthly Coincident Peak" (12CP) Method. Through the use of this methodology, the fixed production and transmission costs of the NSP System are allocated to each of the states served by NSPM based on their respective impact on total NSPM system peak.[5] By design, this method will allocate 100 percent of system costs to the individual state jurisdictions served, allowing the Company to fully recover its cost of service across those states. The state regulatory commissions of all three NSPM jurisdictions have approved this allocation method.[6]

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[5] *See Compliance Filing ð Jurisdictional Allocation Study*, Case. No. PU-12-813, REVIEW OF JURISDICTIONAL ALLOCATION METHODS FOR PRODUCTION AND TRANSMISSION COSTS (N.D. P.S.C. Apr. 27, 2015).

[6] *See In the Matter of N. States Power Co. for Authority to Increase its Rates for Elec. Serv. in Minn.*, Docket No. E-002/GR-87-670, ORDER AFTER RECONSIDERATION (Minn. P.U.C. Oct. 20, 1988); *N. States Power Co. Elec. Rate Case*, Case No. PU 400-87-6, ORDER APPROVING SETTLEMENT (N.D. P.S.C. Dec. 13, 1988); *In the*

Under the 12CP Method, NSPM first determines each jurisdiction's peak, measured in kilowatts (kW), coincident with the NSP System peak for each of the 12 months of the year. The monthly NSP System peaks for each state are then summed and each state's allocation is determined by dividing the state's 12 month total by the NSPM 12 month total. The 12CP Method ensures that the cost of generating capacity and transmission capability is allocated to each jurisdiction according to the capacity necessary to generate energy and provide transmission service to the jurisdiction. The fact that all three states utilize the same 12CP Method ensures uniform treatment of costs amongst the jurisdictions. By allocating fixed costs in relation to the impact of monthly system peaks, the cost allocations methods used by NSPM also provides states with an incentive to implement energy efficiency and demand-side management programs as these programs can decrease a state's contribution to the monthly system peak and result in fewer system costs being allocated to the conserving state. The allocation of NSPW's fixed production and transmission costs between Wisconsin and Michigan utilizes the same method.

D. Regional Transmission, Power Pooling, and RTOs

In addition to seeking economies of scale through large integrated systems such as the NSP System, utilities also benefit from inter-utility regional cooperation. Strengthening ties between utilities in a region can provide additional support to the NSP System through the use of generation in other locations, support of the transmission system, and the pooling of power to meet reserve needs and more economic dispatch across a wider grouping of generators. The Company has been coordinating with other utilities in the region for half a century. By 1953, NSP had interconnected with five of its utility neighbors; 10 years later the Company had interconnected with 75 investor-owned and public power electric suppliers.

Coordinating with regional utilities has been an important part of the Company's development. The Company was a leader in the formation of the Upper Mississippi Valley Power Pool, the predecessor to the Mid-Continent Area Power Pool (MAPP). Additionally, NSP was a leader in the creation of MAPP and its ability to improve service to a wide swath of the Midwest. As the backbone utility of MAPP, NSP presided over the construction of an interconnected transmission network that linked the Twin Cities with utilities as far south as St. Louis, Kansas City, Chicago, and

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Matter of the Application of N. States Power Co., Docket No. EL12-046, ORDER GRANTING JOINT MOTION FOR APPROVAL OF SETTLEMENT STIPULATION; ORDER APPROVING REFUND PLAN (S.D. P.S.C. Apr. 18, 2013) (approving a revenue requirement using the 12-CP methodology for allocation of production and transmission costs).

Omaha and as far west as western North Dakota. During a ten-year period in the late 1960s and early 1970s, NSP, along with other MAPP members and affiliated utilities, built 5,400 miles of transmission lines, most of it operating at high voltages of 230 kV and 345 kV.

This interregional cooperation was part of larger efforts throughout the industry. In 1997, FERC issued Order No. 888 which provided for non-discriminatory access to the transmission system for all industry participants. Shortly thereafter, FERC issued Order No. 2000 providing the regulatory framework for Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs). In 2007, FERC issued Order No. 890 which required regional transmission planning to help ensure efficient large-scale regional transmission development and further expanded these efforts more recently through the issuance of Order No. 1000.

In 1998, the Midcontinent Independent System Operator (MISO) was formed as the nation's first RTO.[7] Today, MISO is an independent and member-based non-profit organization and its members include 51 transmission owners, including NSPM and NSPW. MISO operates the transmission system across 15 states and one Canadian province and operates one of the world's largest real-time energy markets.

While MISO's initial focus was on providing regional transmission services, in 2005 MISO launched its energy markets and began centrally dispatching generating units throughout much of the central United States based on bids and offers. With the introduction of its Ancillary Services Market (ASM) in 2009, MISO also became the region's Balancing Authority, instructing local balancing authorities on operation of resources. Integration of ASM into market operations made possible the central dispatch of regulated reserves, spinning reserves, and supplemental reserves based on bids and offers cleared.

The formation of MISO, its centralized transmission planning, and its organized energy, ancillary services, and spinning reserve markets continue the evolution of utility development to capture economies of scale and diversity. MISO uses a centralized economic dispatch of generation resources across the MISO footprint to optimize the use of these resources. This central, economic dispatch increases the economies of scale available to all MISO members by increasing the scope and diversity of resources available for dispatch, better mitigates the impact of plant outages by making more resources available to a larger pool of utilities, and increases

[7] MISO was originally named the "Midwest Independent Transmission System Operator."

fuel diversity available to all MISO members. Also, MISO's large footprint allows lower planning reserves due to the load diversity across its 15-state region.

While the Company's participation in MISO expands the economies of scale and diversity provided by the integrated NSP System, the operation of the integrated NSP System still supports efficient provision of service to our customers. For instance, the MISO markets by definition utilize market mechanisms to function. Therefore, while participation in the MISO market provides greater resource diversity and a larger pool of resources available for economic dispatch, reliance on the market also subjects its participants to greater market exposure and the attendant market risks. The large integrated nature and size of the NSP System provides the opportunity to hedge this market exposure through system-dedicated large and diverse generation facilities.

Further, participation in MISO is still not a substitute for NSP System planning and generation development. While capacity is transacted within MISO through its annual capacity auction mechanisms, each utility participating in MISO must still ensure that it can meet its load serving and reserve margin obligations. This means that MISO can provide support for utilities to help meet their short-term capacity needs at the then-market cost, but purchasing capacity on an annual basis is not a replacement for the development of actual generation or long-term bilateral contracts.

Therefore, states, and each individual utility, must plan for and develop sufficient generation resources so that utilities can meet their load serving obligations. Because the need to procure sufficient generation capacity rests with the utilities, the need for the states' participation in resource planning is paramount. Through the NSP System, we can continue to provide all of our customers in the states we serve with material economies of scale notwithstanding the increased dispatch economies provided by MISO.

The NSP System within the MISO market also continues to provide load diversity associated with having customers located in five different states, by smoothing load spikes and slumps that may occur in one area across a broader geographic region. This load diversity also provides a hedge against temporary spikes in market energy prices.

II. ENERGY POLICIES OF STATES IN THE NSP SYSTEM

This section addresses some of the legal, regulatory and statutory schemes governing the Minnesota and North Dakota Commissions, as well as the regulatory processes and traditions that frame considerations of resource decisions. We believe that understanding these requirements, processes, and outlooks will help to illustrate how

Commissions may reach different resource selection outcomes. Although there are differences in the approaches of the NSP System states, they share foundational priorities for resource selection including reliability, affordability, and diversity. While we focus on Minnesota and North Dakota here, we note that all of the states served by the NSP System utilize their own legal, regulatory, and policy structures.

A. Statutory Structures

Both the Minnesota and North Dakota Commissions are creatures of statute and have those powers granted to them by their respective state legislatures.[8] While the regulatory regimes of both states support and govern vertically integrated utilities, the statutory schemes empowering both commissions are significantly different. In North Dakota, the governing statutes are still fundamentally based on North Dakota's Public Utilities Act of 1919.[9] In Minnesota, the Public Utilities Act of 1974 governs.[10] This results in different statutory requirements governing each commission, with the North Dakota structure rooted in the traditional valuation methodology of ratemaking, and the Minnesota view reflecting ratemaking standards from the 1970s.

1. Ratemaking and Oversight Paradigms

A comparison of the statutory ratemaking standards of both Minnesota and North Dakota law is instructive. Minnesota statute provides the following guidance to the Commission:

> *The commission, in the exercise of its powers under this chapter to determine just and reasonable rates for public utilities, shall give due consideration to the public need for adequate, efficient, and reasonable service and to the need of the public utility for revenue sufficient to enable it to meet the cost of furnishing the service, including adequate provision for depreciation of its utility property used and useful in rendering service to the public, and to earn a fair and reasonable return upon the investment in such property. In determining the rate base upon which the utility is to be allowed to earn a fair rate of return, the commission shall give due consideration to evidence of the cost of the property when first devoted to public use, to prudent acquisition cost to the public utility less appropriate depreciation on each, to construction work in progress, to*

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[8] *See Minnegasco, a Div. of NorAm Energy Corp. v. Minn. Pub. Utils. Comm'n*, 549 N.W.2d 904, 907 (Minn. 1996) ("The MPUC, as a creature of statute, only has the authority given it by the legislature."); *Capital Elec. Co-op., Inc. v. Pub. Serv. Comm'n of State of N.D.*, 534 N.W.2d 587, 589 (N.D. 1995) ("The PSC has only the powers and duties conferred upon it by the legislature.").

[9] *See* 1919 N.D. Sess. Law ch. 192; *see generally* N.D.C.C ch. 49. Much of current N.D.C.C. ch. 49 originates from the Public Utilities Act passed in 1919.

[10] 1974 Minn. Sess. Law ch. 429 (codified at Minn. Stat. ch. 216B).

> *offsets in the nature of capital provided by sources other than the investors, and to other expenses of a capital nature. For purposes of determining rate base, the commission shall consider the original cost of utility property included in the base and shall make no allowance for its estimated current replacement value. If the commission orders a generating facility to terminate its operations before the end of the facility's physical life in order to comply with a specific state or federal energy statute or policy, the commission may allow the public utility to recover any positive net book value of the facility as determined by the commission.*[11]

North Dakota statute imposes the following requirements on the NDPSC:

> *The commission, for the purpose of ascertaining just and reasonable rates and charges of public utilities, or for any other purpose authorized by law, shall investigate and determine the value of the property of every public utility, except railroads and motor carriers, used and useful for the service and convenience of the public, excluding therefrom the value of any franchise or right to own, operate, or enjoy the same in excess of the amount, exclusive of any tax or annual charge, actually paid to any political subdivision of the state as a consideration for the grant of the franchise or right, and exclusive of any value of the right by reason of a monopoly or merger. The commission shall prescribe the details of the inventory of the property of each public utility to be valued.*[12]
>
> ***
>
> *The value of the property of a public utility, as determined by the commission for ratemaking purposes, is the money honestly and prudently invested therein by the utility including construction work in progress for new facilities that use lignite mined in this state to generate electricity, as well as additions or modifications to existing lignite facilities, less accrued depreciation.*[13]

In Minnesota, the Commission may consider a range of factors in establishing just and reasonable rates. North Dakota law tends to be more prescriptive and based on valuation of rate base.[14]

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[11] Minn. Stat. § 216B.16, subd. 4.
[12] N.D.C.C. § 49-06-01.
[13] N.D.C.C. § 49-06-02.
[14] Illustrating these differences is the fact that the North Dakota statutory structures are silent with respect to utility expenses. North Dakota courts have had to read into the various public utility statutes the requirement that a utility be allowed to recover its reasonable cost of providing service as a necessary prerequisite to a utility being able to earn a reasonable rate of return on its rate base. *See N. States Power Co. v. Hagen*, 314 N.W.2d 32, 37 (N.D. 1981).

Another example is related to resource planning. Minnesota has a well-defined statute[15] and associated rules.[16] Many intervenors generally participate in this process and a robust record is built. Additionally, the Commission reviews and approves a five-year action plan under Minnesota's requirements. North Dakota's planning statutes require that utilities submit a ten-year plan to the Commission.[17] This ten-year plan is filed for informational purposes but there is no requirement that the Commission act on it. The NDPSC has not acted on any of the Company's ten-year plans to date.

Additionally, since 2008, the Company has been required to file its Upper Midwest Resource Plan, prepared pursuant to the Minnesota requirements, in North Dakota, including a planning scenario that "strictly meets both Federal and North Dakota environmental and renewable requirements for the same time period addressed by the Minnesota Resource Plan."[18] These filings are for informational purposes, and the NDPSC has not acted on any of the Company's resource plan submissions to date.

These are just two examples of broad statutory mandates imposed on the Minnesota and North Dakota Commissions by their respective legislatures that inform the type and degree of oversight that each Commission undertakes. In addition to these statutory mandates, we also provide examples of more specific requirements below.

2. *Treatment of Externality Values*

Minnesota and North Dakota have conflicting mandates with respect to valuating externalities in resource decisions. Minnesota requires their use;[19] North Dakota requires that they not be used.[20] In fact, North Dakota statute bars the NDPSC from increasing rates to recover the cost of a resource if it is selected by other states due to the consideration of externality values:

> *The Commission may not increase electric rates as a result of actions taken by other states requiring higher cost resources to be built, purchased, or otherwise acquired as a result of the application of quantified environmental externality values, as defined in Section 49-02-23, as part of any resource selection process.*[21]

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[15] Minn. Stat. § 216B.2422.
[16] Minn. R. ch. 7843.
[17] N.D.C.C. § 49-22-04.
[18] *Application of N. States Power Co., a Minn. Corp., for Auth. to Increase Rates for Elec. Serv. in N.D.*, Case No. PU-07-776, SETTLEMENT AGREEMENT at 4 (N.D. P.S.C. Dec. 31, 2008) (hereinafter "2008 Settlement").
[19] Minn. Stat. § 216B.2422, subd. 3.
[20] N.D.C.C. § 49-02-23.
[21] N.D.C.C. § 49-06-24.

The states' respective treatment of externality values can impact results. An example is the different modelling outcomes that the Company's 187 MW of Solar Portfolio produced in Minnesota and North Dakota as a result of externality values being applied and omitted, respectively, from the analysis in each state.[22] In Minnesota, the relevant analysis indicated that on a present value of societal cost basis (*i.e.,* utilizing externality values in the analysis, including imputed CO_2 costs), the projects showed cost savings of approximately $47 million in our reference case and continued savings for the system in almost every scenario, including $56 million in savings in a "markets off" sensitivity. The North Dakota analysis, on the other hand, showed that excluding externalities results in increased system costs of $14 million in our reference case and further increased system costs in almost every scenario, including $43 million in added system costs in the "low gas" price sensitivity.

3. *Renewable Energy Mandates and Objectives*

Minnesota has several mandates that require public utilities to provide customers with certain varying percentages of renewable energy.[23] These mandates are firm requirements that must be met unless the Commission explicitly approves a deviation. For example, the Minnesota Renewable Energy Standard requires that the Company generate 30 percent of total retail electric sales from eligible renewable energy technologies by 2020:[24]

North Dakota has only one state renewable energy statute and that is the achievement of a ten percent renewable and recycled energy objective.[25] "This objective is voluntary and there is no penalty or sanction for a retail provider of electricity that fails to meet this objective."[26] In practice, the NDPSC has made clear that achievement of this objective should not result in any increases in costs to North Dakota electric customers.[27]

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[22] *In the Matter of Xcel Energy's Petition for Approval of a Solar Portfolio to Meet Initial Solar Energy Standard*, Docket No. E-002/M-14-164, PETITION at 20 (Minn. P.U.C. Oct. 24, 2014); *N. States Power Co. Advance Prudence – 187 NW Solar Energy Portfolio*, Case No. PU-14-810, APPLICATION FOR ADVANCE DETERMINATION OF PRUDENCE at 10 (N.D. P.S.C. Nov. 7, 2014).
[23] *See* Minn. Stat. § 216B.1691, subd. 2a(a)-(b).
[24] *See* Minn. Stat. § 216B.1691, subd. 2b.
[25] N.D.C.C. § 49-02-28.
[26] *Id.*
[27] *See Comments on Retiring Renewable Energy Credits to Meet N.D.'s Renewable Energy Objective*, Case No. PU-15-094, LETTER REGARDING RENEWABLE ENERGY CREDITS (N.D. P.S.C. May 6, 2016).

The contrast between a mandatory, renewable energy regime in Minnesota and the voluntary objective in North Dakota in particular[28] can result in different resource planning and resource selection decisions. For instance, requiring mandate-driven resource additions in advance of demonstrated system load-serving needs has created concerns in North Dakota with respect to the cost of carrying the excess capacity. This is notwithstanding the fact that the NDPSC has considered qualitative benefits, such as fuel hedging, when evaluating resources.[29]

4. *Statutory Goals*

Minnesota statutes provide policy direction to the Commission and state utilities about the energy goals of the state.[30] Even though these goals are voluntary, based on input from the Commission and other stakeholders, the Company incorporates them into its planning considerations. For example, our Current Preferred Plan, as presented in our 2016-2030 Upper Midwest Resource Plan, makes strides toward the statutory goal of an 80 percent carbon reduction by 2050[31] by advancing a plan that achieves nearly 60 percent carbon emissions reduction from 2005 levels by 2030. [32] Also, the solar resource additions proposed in our Current Preferred Plan put us on a path toward meeting the 10 percent by 2030 goal set forth in Minnesota's Solar Energy Standard.[33]

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[28] The other states served by the NSP System have also implemented renewable energy standards, with electric service providers in Wisconsin and Michigan having to achieve a retail supply portfolio that includes at least ten percent renewable energy. *See, e.g.*, Wis. Stat. § 196.378 (requiring all Wisconsin electric providers to provide their retail electricity customers with ten percent of electricity from renewable resources); Mich. Comp. Laws § 460.1001 *et seq.* (requiring Michigan electric providers to achieve a retail supply portfolio that includes at least ten percent renewable energy by 2015). South Dakota has established a state renewable recycled, and conserved energy objective that ten percent of all electricity sold at retail within the state by the year 2015 be obtained from renewable, recycled, and conserved energy sources. Like North Dakota, however, this objective is voluntary. *See* S.D. Codified Laws § 49-34A-101.

[29] *N. States Power Co. Advance Determination of Prudence – 210 MW Nobles Wind Project Application*, Case No. PU-08-907, ORDER ON APPLICATION FOR ADVANCE DETERMINATION OF PRUDENCE at 2-3 (N.D. P.S.C. Aug. 12, 2009); *Otter Tail Corporation Advance Determination of Prudence Application*, Case. No. PU-06-481, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER at 16 (N.D. P.S.C. Aug. 27, 2008).

[30] *See, e.g.*, Minn. Stat. § 216B.241 (requiring each public utility to spend and invest certain percentages for energy conservation improvements); Minn. Stat. § 216B.2422, subd. 2 (requiring utilities to include the least-cost plan for meeting 50 to75 percent of all new and refurbished capacity needs through a combination of conservation and renewable energy resources in their resource plan filings); Minn. Stat. § 216B.2423 (providing for wind power mandates); Minn. Stat. § 216B.2424 (providing for biomass power mandates); Minn. Stat. 216B.1691 (providing for numerous renewable energy objectives).

[31] Minn. Stat. § 216H.02, subd. 1.

[32] *Current Preferred Plan 2016-2030 Upper Midwest Resource Plan*, Docket No. E002/RP-15-21, SUPPLEMENT at 10 (Jan. 29, 2016).

[33] *Current Preferred Plan 2016-2030 Upper Midwest Resource Plan*, Docket No. E002/RP-15-21, SUPPLEMENT at Attachment C, p. 3 (Jan 29, 2016).

Rather than set out specific policy goals, North Dakota statutes provide incentives to further its policy priorities for development of lignite based resources, as well as for investment in the state, including a rebuttable presumption of prudence for North Dakota based resources and North Dakota income tax credit for certain generation types.[34] The NDPSC has also articulated its policy objectives, including ensuring that: (1) North Dakota electric rates remain as low as possible; (2) resource additions are generally made when they are needed to serve load and are the least-cost option available at the time; (3) system resources that lower the overall cost to the system may be acceptable in certain instances without an identified need; and (4) system additions to achieve policy mandates or goals of other states that increase costs will not be acceptable.

B. Resource Evaluation Outlooks

Minnesota and North Dakota also have specific resource planning and selection outlooks which inform their evaluation of resource options. These specific outlooks utilize state specific processes, assumptions and views of risk, and impact resource assessments related to the size, type, and timing of resource additions.

Specifically, each Commission evaluates how to assess the risks and impacts of reliance on MISO's energy markets, future gas price volatility, the likelihood of future environmental costs, and the timing of resource additions relative to an identified need.

1. MISO Markets

Reviewing the varying perspectives on the MISO's energy markets is instructive. The Company has, and continues, to analyze its resource selection proposals with both a "Markets Off" view, which models the NSP System in isolation, and a "Markets On" view, which models the NSP System as part of the broader MISO market. In Minnesota, our reference case generally presents system cost impacts in a Markets Off view. In North Dakota, however, the NDPSC and its staff have expressed a preference that our reference case be presented with a Markets On view. Each respective approach tends to emphasize or deemphasize the potential value of accessing the MISO energy markets and the particular resource's impacts on the Company's participation in those markets.

[34] N.D.C.C. § 49-06-02, N.D.C.C. § 49-05-16, and N.D.C.C. § 57-38-01.8.

2. Fuel Hedge Value

Accounting for a resource's fuel hedge value (or not) may also impact the evaluation of a resource. The Company's resource selection analyses generally present modeling sensitivities with high and low gas price assumptions, but the usefulness of this analysis is mitigated if the jurisdiction does not recognize future fuel price volatility or otherwise discounts the resource's hedge value.

3. Environmental Regulation Hedge Value

Likewise, the value of a hedge against environmental regulation is informed by a particular state's view of the potential for regulation. In Minnesota, the Company presents a range of costs associated with the potential for future carbon regulation as required by the Commission. In addition, we assess the risk of future environmental control equipment, such as Selective Catalytic Reduction (SCR) systems, when considering resource options.[35] Similarly, while the NDPSC is prohibited by statute from quantifying environmental externalities, it may evaluate the risks of future environmental regulation on a qualitative basis and thus the value of a hedge against such regulation. Assessing the likelihood and magnitude of future environmental regulations requires judgment, and different states may make different judgments that can impact resource selection outcomes.

4. Resource Need

Guidance from states on system capacity and resource timing can also impact resource selection analyses. North Dakota requires that the timing of resource additions be aligned as closely as possible with the most recently identified resource need. If an updated forecast indicates a mismatch of resource addition to timing of need, our experience has been that the NDPSC would expect that resource additions be delayed in light of those updated forecasts.[36] In Minnesota, the Commission has recently held that the lumpiness of significant resource additions is acceptable and that material system length is a conservative approach that errs on the side of sufficient capacity, and is a reasonable method to hedge against potential shortfalls

[35] As noted above, the Company also includes externality costs associated with criteria pollutants.
[36] North Dakota precedent indicates that if a utility adds too much length to its system that the system length may not be considered used and useful. *See Pub. Serv. Comm'n v. Montana-Dakota Utils. Co.*, 100 N.W.2d 140, 150 (N.D. 1959); *In re Otter Tail Power Co.*, 44 P.U.R.4th 219, 225 (N.D. P.S.C. July 20, 1981).

due to the inherent variability of forecasting and the risk that delaying the additions of cost-effective resources may result in additional costs over a longer planning period. [37]

III. RECENT NORTH DAKOTA PROCEEDINGS

This section offers a chronological overview of eleven of the key resource-related regulatory proceedings in North Dakota and their outcomes. We believe this background provides the historical foundation for our current work and reflects the Company's efforts to advance our guiding principles with respect to specific resource additions. This section also illustrates the tension that has emerged with respect to our guiding principles, and shows a growing desire from North Dakota to protect its sovereignty which has placed pressure on the two remaining principles. The Company has found ways to respond with individualized solutions that have preserved the integrated system with its attendant benefits. However, those solutions have often required us to advance proposals that have made full cost recovery impossible. After providing the historical context, we advance to a discussion of the alternatives we have evaluated thus far.

A. North Dakota 2008 Test Year Rate Case (2007)

On December 7, 2007, the Company filed its 2008 test year rate case with the NDPSC in Case No. PU-07-776. The core issue in the rate case proceeding was "whether North Dakota customers should pay for a portion of the integrated system costs incurred by the Company to satisfy environmental and renewable requirements imposed or facilitated by Minnesota law."[38] Concerns arose due to the Company's request to recover the costs of its MERP-related investments in its King, High Bridge, and Riverside power plants and the Grand Meadows wind farm. Consistent with North Dakota norms, the 2008 test year rate case was settled through the 2008 Settlement.

The 2008 Settlement facilitated the resolution of these issues by attempting to "eliminate or minimize conflicts surrounding energy resource decisions and the associated costs in future general rate proceedings"[39] through the implementation of certain regulatory procedures that would help to "ensure appropriate [North Dakota] Commission involvement and oversight of the Company's future resource plans and

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[37] *In the Matter of the Petition of N. States Power Co. d/b/a Xcel Energy for Approval of Competitive Resource. Acquisition Proposal and Certificate of Need*, Docket No. E-002/CN-12-1240, ORDER APPROVING POWER PURCHASE AGREEMENT WITH CALPINE, APPROVING POWER PURCHASE AGREEMENT WITH GERONIMO, AND APPROVING PRICE TERMS WITH XCEL at 8-9 (Minn. P.U.C. Feb. 5, 2015).

[38] 2008 Settlement at 3.

[39] *Id.* at 3

selection of future generation and transmission projects to be added to the system serving North Dakota."[40] The procedural changes had two components: resource planning and pre-approvals.

1. Resource Planning

The 2008 Settlement recognized that the Company sought to provide its customers with the benefits of operating a multi-state integrated system, while also complying with the energy priorities of the states it serves. By involving the NDPSC more directly in the Company's resource planning and selection process, the 2008 Settlement intended to provide a framework to both meet the needs of the Company's North Dakota customers and for the Company to fully recover its system-wide cost of service. To facilitate this framework, the 2008 Settlement required the Company to:

- Provide the NDPSC with its Upper Midwest Resource Plans—filed with the MPUC—for the Company's integrated system.

- Provide "an alternative system-wide resource plan (the 'North Dakota version') that strictly meets both Federal and North Dakota environmental and renewable requirements for the same time period addressed by the [Upper] Midwest Resource Plan."[41]

- File a summary of its key generation and transmission investments or purchase agreements that the Company intended to construct or procure within five years and that may require an Advance Determination of Prudence (ADP) application.

- Meet with the NDPSC and Advocacy Staff as necessary to conduct resource planning updates and discuss the most recently filed Ten Year Plan, and commit to "keeping the Commission and its Staff informed on a timely basis of any major changes in its [Upper] Midwest Resource Plan or significant legislative initiatives under consideration in another jurisdiction."[42]

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[40] *Id.* at 3-4.
[41] *Id.* at 4.
[42] *Id.* at 4.

2. *Resource Addition Pre-Approvals*

The 2008 Settlement also contained provisions related to ADP filings with the NDPSC to further solidify a framework to meet need and cost requirements. Specifically, the Company, in accordance with North Dakota Century Code (N.D.C.C.) § 49-05-16, agreed to file an ADP application with the NDPSC for:

> *all proposed new construction, rehabilitation, or acquisition of an energy conversion facility, renewable energy facility, transmission facility or proposed energy purchase in which:*
>
> 1. *The Company proposes to allocate all or part of the related costs to the North Dakota jurisdiction for recovery in electric rates; and*
>
> 2. *The capacity of the generation facility or purchase is at least 50 MW; and/or length of the transmission facility is at least 50 miles long.*[43]

The 2008 Settlement anticipated that the resource planning and ADP provisions would "provide a sound basis for Commission decision-making and substantially reduce the likelihood that the disputes of [the 2008 test year rate case] will occur in future rate proceedings."[44] In the event that the issues identified in the 2008 test year rate case persisted, the 2008 Settlement required the consideration of alternative approaches to address cost assignment and resource planning concerns while still allowing the Company to recover its full cost of service and earn a reasonable rate of return. These efforts included the potential for the Company to advocate for cost recovery legislation to "directly assign costs and benefits of mandated expenditures to the jurisdiction imposing the mandate when appropriate."[45]

B. Nobles and Merricourt ADPs (2008)

On December 3, 2008, the Company filed ADP applications for its proposed Nobles Wind Project in Southwest Minnesota and Merricourt Wind Project in Southeast North Dakota in Case Nos. PU-08-907 and PU-08-908. On August 12, 2009, the NDPSC issued simultaneous orders in both cases granting the Nobles and Merricourt ADPs, finding that the projects were consistent with North Dakota principles.[46]

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[43] *Id.* at 6.
[44] *Id.* at 7.
[45] *Id.* at 7.
[46] *N. States Power Co. Advance Determination of Prudence – 201 MW Nobles Wind Project Application*, Case No. PU-08-907, ORDER ON APPLICATION FOR ADVANCE DETERMINATION OF PRUDENCE (N.D. P.S.C. Aug. 12,

The NDPSC observed that while the proposed projects were somewhat more expensive than a comparable gas generator,[47] they would "provide a hedge against the volatility of natural gas prices; provide a greater degree of diversity in its fleet of generation facilities; [and] provide a hedge against potential carbon dioxide regulation."[48]

C. Prairie Rose Wind (2012)

On January 31, 2012, the Company filed an application with the NDPSC seeking an ADP for the Prairie Rose Project in Case No. PU-12-59.[49] The Company's application, however, was dismissed with prejudice on December 21, 2012, after the NDPSC determined that the application was untimely in that it was filed after the Company committed to the resource addition.[50] More specifically, the PPA included termination provisions allowing Xcel Energy to terminate the agreement if it was not approved by the Minnesota Commission—which it was on December 28, 2011. The agreement did not, however, contain a parallel provision subjecting the project to NDPSC approval.

In light of this, the NDPSC found that the Company "did not fulfill the commitment [it] made when settling its rate case proceeding in Case No. PU-07-776 by applying for an ADP finding from the Commission when the energy purchase was proposed, but rather [the Company] waited to apply until after the transaction was fully effective and committed."[51] The NDPSC thus refused recovery of any costs of the project until further proceedings to establish a record regarding the appropriate ratemaking treatment for the PPA costs.[52]

2009); *N. States Power Co. Advance Determination of Prudence – 150 MW Merricourt Wind Project Application*, Case No. PU-08-908, ORDER ON APPLICATION FOR ADVANCE DETERMINATION OF PRUDENCE AND CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY (N.D. P.S.C. Aug. 12, 2009).

47 *See N. States Power Co. Advance Determination of Prudence – 201 MW Nobles Wind Project Application*, , Case No. PU-08-907, APPLICATION at 9-13 (N.D. P.S.C. Dec. 3, 2008); *N. States Power Co. Advance Determination of Prudence – 150 MW Merricourt Wind Project Application* , Case No. PU-08-908, APPLICATION at 11-14 (N.D. P.S.C. Dec. 3, 2008).

48 *N. States Power Co. Advance Determination of Prudence – 210 MW Nobles Wind Project Application*, Case No. PU-08-907, ORDER ON APPLICATION FOR ADVANCE DETERMINATION OF PRUDENCE at 3 (N.D. P.S.C. Aug. 12, 2009)

49 *N. States Power Co. Advance Determination of Prudence – Geronimo Wind Application*, Case No. PU-12-59, APPLICATION (N.D. P.S.C. Jan. 31, 2012).

50 *N. States Power Co. Advance Determination of Prudence – Geronimo Wind Application*, Case No. PU-12-59, FINDINGS OF FACT, CONCLUSIONS OF LAW AND ORDER at 3 (N.D. P.S.C. Dec. 21, 2012).

51 *Id.*

52 *Id.* at 4.

In addition to creating the precedent for the filing of ADPs[53], the Prairie Rose Wind docket established the ratemaking treatment for disallowed energy-only priced PPAs in North Dakota. This ratemaking treatment accounts for the disallowed resource but, through the structure of the Company's North Dakota Fuel Cost Recovery Rider (FCR)[54] itself, defaults to a "modified system average cost of fuel" proxy pricing for these types of resources. This is accomplished by effectively zeroing out both the costs and volumes of the Prairie Rose PPA in the average system cost of fuel calculation in the North Dakota FCR.

At a high level, the North Dakota FCR is structured as recovering a system average cost of fuel, which includes purchased power.[55] To calculate this system average cost of fuel, total NSP System fuel costs, including purchased power, for a particular month are divided by the total volumes of generation of the NSP System for that month. The result of this calculation is the average cost of fuel and purchased power per kWh of generation in that month. This per kWh average system cost of fuel is then applied as a rider to each customer's bill for each kWh of energy they consume.

The method developed to address the disallowance of the Prairie Rose project accounted for the disallowance by making Prairie Rose Wind a nullity in the calculation of the FCR's system average cost of fuel. This was accomplished by reflecting the project costs as a zero in calculating the numerator and excluding the associated volumes in the calculation of the denominator in developing the system average cost of fuel calculation. The exclusion of the costs and volumes of the disallowed project results in a "modified system average" cost of fuel.[56]

Notably, because the North Dakota FCR is structured as a rider to each kWh consumed by each customer, we still collect some revenue from customers for the project because each customer pays the modified system average cost of fuel for each kWh they consume. This results in a "proxy price" type outcome that is purely a result of the structure of the North Dakota FCR rather than a reflection of affirmative decisions with respect to the appropriate proxy pricing of a particular resource. The

[53] In a letter to the North Dakota Commission dated November 5, 2012, the Company further defined its previous commitment to file ADP applications for significant resource acquisitions with the North Dakota Commission by providing that it will make the necessary ADP filings within 14 days of making similar filings in Minnesota

[54] N.D. Admin. Code § 69-09-02-39.

[55] The North Dakota FCR also contains complex forecasting and true-up mechanisms.

[56] In practice, we reflect the disallowed project in the system average cost of fuel calculation at the cost of the "modified system average cost of fuel" and reflect the associated volumes in the calculation to ensure proper accounting. The mathematical results of doing so are identical to the ratemaking outcome described.

modified system average cost of fuel has become the default method for treating disallowed energy-only priced PPAs in North Dakota.[57]

The NDPSC ultimately allowed recovery of the costs of the Prairie Rose PPA in the 2014 Settlement Agreement for our 2013 test year rate case (2014 Settlement) discussed below.[58] Due to the procedural challenges outlined above as well as concerns about whether there was a resource need, the parties agreed that Prairie Rose Wind's energy costs would be recovered on a going forward basis only.[59] Prairie Rose, then, is an example where the Company reached a negotiated resolution that achieved the principles of system integration and respect for sovereignty, but it came at a cost to the Company who will not have an opportunity to fully recover the cost of that resource.

D. North Dakota 2013 Test Year Rate Case (2012)

On December 18, 2012, the Company filed its 2013 test year rate case in Case No. PU-12-813. The rate case proceeding raised a number of issues related to the Company's ongoing provision of service in North Dakota, the role of North Dakota in the NSP System, the Company's need for generation resources, and the most efficient and least-cost way of filling that need. To address these issues, Xcel Energy and Advocacy Staff entered into the 2014 Settlement to develop a multi-year rate plan and address North Dakota energy policy goals.

The principal issue contested in the rate case involved the jurisdictional demand allocator. As discussed above, the demand allocator measures the impact of North Dakota, South Dakota, and Minnesota on the integrated NSP System and allocates costs consistent with that impact. By raising the issue of the demand allocator, the NDPSC was questioning North Dakota's role in the NSP System including its relative impact and the fairness of the current status quo. In other words, North Dakota sought to ensure that its allocated share of fixed NSP System costs were an accurate reflection of its system impact.

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[57] This result is only applicable to energy-only priced PPAs because they are wholly recovered through the FCR. If a resource that was recovered through base rates was disallowed, we would not achieve the same outcome since a disallowance for such a resource would result in our base rates reflecting no recovery for a particular resource. We also note that this outcome only accounts for energy and does not account for any capacity benefits accruing from a particular energy-only priced PPA resource.

[58] *See N. States Power Co. 2013 Elec. Rate Increase Application et al.*, 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, REVISED SECOND AMENDED COMPREHENSIVE SETTLEMENT AGREEMENT at 20 (N.D. P.S.C. Feb. 26, 2014) (hereinafter "2014 Settlement").

[59] *See Id.*

To analyze the particular contribution of the Company's North Dakota jurisdiction to its overall costs, the 2014 Agreement required that a jurisdictional demand allocation study be performed.[60] The specific scope of the study was "to analyze a number of demand allocator methodologies and propose recommendations for the methodology or methodologies that most reasonably represent the cost causation of the North Dakota jurisdiction on the Company's overall system-wide production and transmission costs."[61] Secondary consideration was given to "maintaining consistency among jurisdictions and administrative feasibility."[62] Pending results of the study, Xcel Energy and Advocacy Staff agreed to the continued use of the 12CP demand allocation methodology, and agreed that the jurisdictional allocations used in rate rider calculations during the term of the Settlement would be made using the 12CP allocator with the specific allocation factors updated to reflect current circumstances and information.[63]

The rate case also triggered an examination of 23 of the Company's existing renewable energy PPAs related to Community-Based Energy Development (C-BED) wind, solar funded by the Renewable Development Fund, and PPAs related to the Minnesota biomass mandate.[64] These projects were included in the Company's portfolio due, in part, to Minnesota regulatory policy mandates, and costs associated with the PPAs were recovered through the Company's North Dakota FCR.[65] The disposition of these PPAs and other resources became a subject of the proxy pricing or "Restack" efforts required under the 2014 Settlement. At bottom, the Restack effort—a resource-by-resource negotiation—demonstrates the Company's commitment to the principle of retaining the benefits of system integration for our customers while recognizing the different policy objectives of the states we serve.

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[60] *Id.* at 18-19.
[61] *Id.* at 19.
[62] *Id.*
[63] *Id.* at 20.
[64] *Id.* at 17-18. The identified policy driven resources were: KODA Energy LLC (12MW); WM Renewable Energy (MN Methane) (12 MW); Pine Bend (4.7 MW); Jeffers Wind 20, LLC (50 MW); Big Blue (36 MW); Community Wind South (Zephyr) (30 MW); Ridgewind Power Partners LLC (25 MW); Adams Wind Generations (20 MW); Danielson Wind Farms (20 MW); Ewington Energy Systems LLC (20 MW); Grant County Wind, LLC (20 MW); North Community Turbines (15 MW); North Wind Turbines (15 MW); Valley View Transmission (10 MW); Uilk Wind Farm (4.5 MW); Hilltop Power (2MW); Winona County Wild (1.5 MW); Woodstock Municipal Wind, LLC (0.8 MW); Odell Wind (200 MW); Outland Solar (2MW); Best Power (St. Johns) (0.4 MW); FibroMinn (55 MW); Laurentian Energy Authority I (35 MW); and St. Paul Cogeneration (25 MW). *See* 2014 Settlement at Attachment E.
[65] The way that the ND FCR rules are structured allows for the recovery of purchased power costs without initial NDPSC review. However, the rules also allow the NDPSC to review and disallow on a prospective basis should it find that any costs included in the FCR lead to unjust and unreasonable rates. N.D. Admin. Code § 69-09-02-39.

We note that in North Dakota, it is appropriate for a comprehensive review of the FCR to be conducted as part of a rate case proceeding. North Dakota rules do not provide for an annual audit of the FCR, and while the NDPSC may initiate a review of the FCR if issues arise, rate case proceedings provide an opportunity for full evaluation of fuel costs at the same time all of a company's costs are under review. This is a different procedure that in Minnesota, where a full review of fuel costs is conducted in a separate proceeding on an annual basis rather than as part of rate cases.

The 2008 test year rate case also raised the issue that North Dakota's FCR rules allow for the recovery of fuel costs, including purchased power, without prior NDPSC review but reserves to the NDPSC the ability to review the prudence of costs once they are being recovered in the future, on a prospective basis. To avoid future review of PPAs many years after recovery had begun, the 2014 Settlement created a "stronger 'gatekeeping' mechanism necessary to ensure that the Commission has been fully notified of PPA costs to be recovered through the FCR to determine if they are prudent."[66] The Company and Advocacy Staff agreed to reform the procedures through which the Company could include PPA costs in the FCR.[67]

E. Natural Gas Portfolio (2013)

On April 26, 2013, the Company filed an Application seeking an ADP for its proposal to add three 215 MW natural gas-fired, simple-cycle, combustion-turbine generators to the NSP System – one at NSP'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) – in Case No. PU-13-194.[68] Consistent with North Dakota norms, parties agreed to a settlement which concluded that the construction of Black Dog Unit 6 and Red River Valley Units 1 and 2 were cost-effective and prudent approaches to meet the Company's then forecasted capacity needs in the 2017-2019 time-period.[69] The NDPSC granted the ADP application on February 26, 2014 in its Order adopting the 2014 Settlement.[70]

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66 2014 Settlement at 9.
67 *Id.*
68 *In the Matter of the Application of N. States Power Co. for an Advance Determination of Prudence for Three Natural Gas Combustion Turbine Generators*, Case No. PU-13-194, APPLICATION FOR ADVANCE DETERMINATION OF PRUDENCE AND CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY (N.D. P.S.C. Apr. 26, 2013).
69 2014 Settlement at 21.
70 *N. States Power Co. 2013 Elec. Rate Increase Application et al.*, 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, ORDER ADOPTING SETTLEMENT (N.D. P.S.C. Feb. 26, 2014).

Three primary issues drove the NDPSC's decisions: first, the absence of thermal generation in eastern North Dakota; second, the phased in approach advanced by the Company was consistent with the North Dakota resource need framework; and third, installation of the Red River Valley Units was flexible and could be shifted to match North Dakota generation needs.

In the 2014 Settlement Agreement that followed, the Company committed to developing North Dakota-based thermal generation, "consistent with prudent resource planning principles and the concepts of orderly development."[71] Specifically, the 2014 Settlement committed the Company to "develop up to 400 MW of thermal generation resources in North Dakota no later than 2036."[72] The Company also agreed to "advocate for the development of North Dakota based generation in other affected jurisdictions to the extent such North Dakota based generation is both cost effective and needed."[73]

In its ADP application, the Company noted that it had filed a similar application in the MPUC's Competitive Acquisition Process (CAP) proceeding, Docket No. E002/CN-12-1240, and acknowledged that the outcome of the CAP proceeding could result in the Company pursuing an alternative approach to meet its then forecasted 2017-2019 capacity needs. The 2014 Settlement also accounted for both the potential that the 2017-2019 need could be less than forecasted and that the Minnesota CAP proceeding could result in a different outcome:

> *The Parties agree that the Company's proposal to construct Black Dog Unit 6 and Red River Valley Units 1 and 2 <u>under the flexible, phased in approach</u> described in the Company's application is a cost-effective and prudent approach to meet forecasted capacity needs of the Company in the 2017 to 2019 time-frame.*
>
> *While acknowledging the prudence of the Company's proposal to construct and own Black Dog Unit 6 and Red River Valley Unit 1 and 2, this Revised Second Amended Settlement <u>shall in no way be construed to foreclose upon the possibility and prudence of some other approach to meet the Company's proposed 2017-2019 capacity needs</u>, such as any proposal that may be selected as part of the Minnesota Competitive Acquisition Process described in the record of the Gas CT Cases. In the event the Company chooses to move forward with a resource acquisition other than Black Dog Unit 6 or Red River Valley Unit 1 or Red River Valley Unit 2 to meet*

71 2014 Settlement at 5.
72 *Id.* at 17.
73 *Id.* at 18.

> *its 2017-2019 capacity need, it shall file an application for an Advanced Determination of Prudence for such other resource acquisition(s).*[74]

Specific to Red River Valley Units, the NDPSC found the generators to be a prudent resource addition.[75] The Commission's ADP for the Red River Valley Units was supported by the rebuttable presumption of prudence provided for in North Dakota's ADP statute because these generators were located in North Dakota. Further, the record in the Case reflected that the Company's proposed three combustion turbine package was cost-competitive with the absolute least-cost option. The NDPSC's ADP was therefore supported by the fact that "the top 5 portfolios [were] separated by less than $10 million."[76]

The NDPSC also supported the Red River Valley Units because it placed generation in an area where there is no native generation and which is supported almost exclusively through transmission. It was also acknowledged that "diversifying the location of the Company's generation mix and locating generation closer to the Company's North Dakota loads provide[d] some benefits to the Company's North Dakota customers as well as all of the other customers served by the Company"[77] including enhancing "the local reliability of the power grid."[78]

Along with the ADP, the Company also requested a Certificate of Public Convenience and Necessity ("CPCN") for the Red River Valley Units.[79] After adopting the 2014 Settlement and finding the Red River Valley Units to be a prudent investment, the NDPSC issued an order dismissing the Company's CPCN Application.[80] In its order, the NDPSC acknowledged that the Red River Valley Units may not be implemented.[81] The NDPSC, therefore, did not make a need

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74 *Id.* at 21.

75 *Application of N. States Power Co., a Minn. Corp., for Authority to Increase Rates for Elec. Serv. in North Dakota et al.*, Case Nos. PU-12-813, PU-13-7036, PU-13-707, PU-13-708, PU-13-742, PU-13-743, PU-13-194, PU-13-195, ORDER ADOPTING SETTLEMENT at 8 (N.D. P.S.C. Feb. 26, 2014).

76 *N. States Power Co. Advance Determination of Prudence – NG Generator Application*, Case No. PU-13-194, ALDERS SUPPLEMENTAL DIRECT EXHIBIT NSP-5 at 10:15-17 (Nov. 26, 2013).

77 2014 Settlement at 17.

78 *N. States Power Co. Advance Determination of Prudence – NG Generator Application*, Case No. PU-13-194, ALDERS SUPPLEMENTAL DIRECT EXHIBIT NSP-5 at Schedule 2, 32:9-16 (Nov. 26, 2013).

79 *See In the Matter of the Application of N. States Power Co. for a Certificate of Public Convenience and Necessity for Three Natural Gas Combustion Turbine Generators*, Case No. PU-13-195, APPLICATION at 1 (N.D. P.S.C. Apr. 26, 2013).

80 *N. States Power Co. Red River Valley NG Units 1 & 2 – Hankinson, ND Public Convenience and Necessity*, Case No. PU-13-195, ORDER DISMISSING APPLICATION at 1 (N.D. P.S.C. Aug. 20, 2014).

81 *N. States Power Co. Red River Valley NG Units 1 & 2 – Hankinson, ND Public Convenience and Necessity*, Case No. PU-13-195, ORDER DISMISSING APPLICATION at 1 (N.D. P.S.C. Aug. 20, 2014); *see also N. States Power*

determination regarding the Red River Valley Units, but rather, determined that they were a prudent way to meet potential future need when it arose.[82]

The NDPSC also granted the ADP for the Black Dog Unit 6, noting that the unit was supported by the need and least-cost planning paradigm.

F. 750 MW Wind Portfolio (2013)

On July 26, 2013, the Company filed an application seeking an ADP for three wind generation projects: (1) a proposed PPA for the 200 MW Courtenay Wind Project, to be located in Stutsman County, North Dakota, in Case No. PU-13-706; (2) a proposed PPA for the 200 MW Odell Wind Project to be located near Mountain Lake, Minnesota, in Case No. PU-13-707; and (3) the proposed 200 MW Pleasant Valley Wind Project to be located in southeastern Minnesota and owned by Xcel Energy, in Case No. PU-13-708. On August 13, 2013, the Company filed an application seeking an ADP for the proposed 150 MW Border Winds Project to be located in Rolette County, North Dakota and owned by Xcel Energy, in Case No. PU-13-742. The cases were subsequently consolidated and settled in the 2014 Settlement.

The Company proposed a large wind portfolio to take advantage of the historically low pricing that these projects provided.[83] The Company's analysis – using both the Minnesota and North Dakota analytical frameworks – indicated that the addition of these generation resources would significantly lower overall system costs by offsetting more expensive native system generation and market purchases.[84]

While the pricing of the projects would ultimately decrease the overall cost of the integrated system, the NDPSC supported only a portion of the Company's wind portfolio. ADPs for Border Winds and Courtenay were granted because they enjoyed a rebuttable presumption of prudence as resource additions located within the State of North Dakota pursuant to N.D.C.C. § 49-05-16,[85] but no decision was made on the

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Co. Advance Determination of Prudence – NG Generators Application, Case No. PU-13-194, ORDER ADOPTING SETTLEMENT at 8 (N.D. P.S.C. Feb. 26, 2014).

[82] *N. States Power Co. Advance Determination of Prudence – NG Generators Application*, Case No. PU-13-194, ORDER ADOPTING SETTLEMENT at 8 (N.D. P.S.C. Feb. 26, 2014).

[83] *See N. States Power Co. Advance Determination of Prudence – Pleasant Valley Application*, Case No. PU-13-708, APPLICATION FOR ADVANCE DETERMINATION OF PRUDENCE at 2-3 (July 26, 2013).

[84] *See Id.* at 13-21 (providing that the wind projects would result in a conservative estimate of at least $180 million in cost savings to customers).

[85] 2014 Settlement at 22.

Minnesota-based Odell and Pleasant Valley projects as they were left to be addressed in future proceedings. [86]

G. Comprehensive Settlement (2014)

As outlined above, the 2014 Settlement Agreement resolved numerous open issues then before the NDPSC.[87] The agreement was subsequently amended on February 3, 2014, February 18, 2014, and February 25, 2014 receiving NDPSC approval on February 26, 2014.[88]

The 2014 Settlement attempted to find a way for the Company's North Dakota rates to reflect a resource mix considered more consistent with North Dakota energy priorities. We describe these efforts as attempting to "Restack" the Company's electric supply resources that serve North Dakota. The 2014 Settlement listed ten general principles as a guide for good faith negotiations between the Company and Advocacy Staff to achieve the Restack. These principles were implemented to develop "a mechanism whereby the Company will serve its North Dakota customers with resources (either real or proxy) consistent with North Dakota's energy policies."[89]

At the forefront of issues addressed by the framework were the costs and benefits of Xcel Energy's integrated system:

1. *All policy choices come with benefits and drawbacks and that the ultimate outcome of the Company's proposal is to allow its North Dakota customers to obtain*

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[86] *See N. States Power Co. 2013 Elec. Rate Increase Application et al.*, 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, FIRST REVISED NEGOTIATED AGREEMENT at 5 (N.D. P.S.C. Mar. 9, 2016) (hereinafter "Negotiated Agreement").

[87] The 2014 Settlement addressed the following cases: (1) Northern States Power Company 2013 Electric Rate Increase Application (Case No. PU-12-813); (2) Northern States Power Company Advanced Determination of Prudence – Courtenay Wind Project Application (Case No. PU-13-706); (3) Northern States Power Company Advanced Determination of Prudence – Odell Wind Project Application (Case No. PU-13-707); (4) Northern States Power Company Advanced Determination of Prudence – Pleasant Valley Wind Project Application (Case No. PU-13-708); (5) Northern States Power Company Advanced Determination of Prudence – Border Winds Project Application (Case No. PU-13-742); (6) Northern States Power Company 150 MW Border Winds Project – Rolette County Public Convenience and Necessity (Case No. PU-13-743); (7) Northern States Power Company Advance Determination of Prudence – NG Generators Application (Case No. PU-13-194); and (8) Northern States Power Company Red River Valley NG Units 1 & 2 – Hankinson, ND Public Convenience and Necessity (Case No. PU-13-195).

[88] In response to work session discussions, amendments to the 2014 Settlement reflected feedback from the North Dakota Commissioners and included third-party involvement in demand allocation study, reduction of annual base rate increase percentages for the 2013-2015 period, and several non-financial wording changes.

[89] 2014 Settlement at 14.

> *the benefits and bear the burdens of North Dakota's energy policy choices. Benefits may include immediately lower pricing while burdens may include increased exposure to commodity and regulatory risk. Consistent with this principle, the Parties agree that any cost savings or cost increases, now and in the future, that result from any Negotiated Agreement shall be allocated to the Company's North Dakota jurisdiction.*[90]

In addition to addressing the "benefits and burdens" of the Company's integrated system on North Dakota, the "Restack" negotiating framework provided the following principles:

> *2. North Dakota energy policies are considered to be those expressed by the legislature through the enactment of laws, including the Renewable Energy Objective (N.D.C.C. § 49-02-28), and the Commission as expressed in its rules and orders.*[91]
>
> *3. The North Dakota historically allocated share of the Company's existing thermal resources provides an appropriate base upon which to meet a significant percentage (likely over 75 percent) of the Company's North Dakota resource needs. The North Dakota Renewable Energy Objective represents a reasonable amount of renewable resources to be included in the ultimate resource mix.*[92]
>
> *4. Any resources (real or proxy) utilized to replace existing Company resources that are deemed inconsistent with North Dakota energy policies should be "like" replacements taking into account the nature of the existing Company resource to be replaced (i.e. baseload, intermediate, peaking, etc.) and the contribution of the replaced resource to the integrated system (i.e. capacity and energy).*[93]
>
> *5. Proxy pricing (for either energy or capacity) for any future resource addition should reflect marginal pricing for the type of resource for which the proxy price is being utilized as a replacement.*[94]
>
> *6. Resource choices should be guided by the concept of reasonableness so that the ultimate North Dakota resource mix would be a reasonable approximation of what would have occurred had the Company historically developed its overall resource mix*

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[90] *Id.* (emphasis added).
[91] *Id.* at 15.
[92] *Id.*
[93] *Id.*
[94] *Id.*

> *consistent with North Dakota policy so as not to result in only the lowest cost resources available making up the total agreed to North Dakota resource mix.*[95]
>
> *7. The Parties will consider the financial impact to the Company of the agreed upon resource mix in developing the Negotiated Agreement which includes but is not limited to providing for reasonable and mutually agreeable implementation schedules and deadlines.*[96]
>
> *8. The Negotiated Agreement must address how future resource additions will be treated if the Commission does not approve such future resource addition. Such future scenarios must account for both the energy and capacity value of such resources.*[97]
>
> *9. To provide certainty, the Negotiated Agreement is intended to be final for the purposes of developing a baseline resource mix (real or proxy) to serve the Company's North Dakota customers.*[98]
>
> *10. The Negotiated Agreement shall be subject to approval by the Commission.*[99]

The Company's intention in "restacking" its electric supply resources that serve North Dakota was to acknowledge current and future resources on the integrated system that do not align with North Dakota energy policies, and at the same time develop a method to ensure North Dakota customers pay an equitable portion of system costs. In applying our three guiding principles for management of the NSP System, through the "Restack," we sought to secure a beneficial solution that would maintain the integrated system for the benefit of our customers, respect the NDPSC's sovereign authority, and provide an acceptable outcome with respect to costs recovery. The Company did this, in part, by focusing on the implementation of a fair and equitable proxy pricing framework.

In essence, the Restack efforts were an attempt to identify a proxy pricing regime that would appropriately identify and value a "policy premium" resulting from certain resource selections. By valuing this policy premium, it was thought that North Dakota would pay a least-cost based proxy price for the associated capacity and energy, while the cost-causative jurisdiction would make a decision about whether it would absorb the premium and move ahead with the project or cancel it. As we were developing these mechanisms, we concluded that over time they would not be

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[95] *Id.*
[96] *Id.* at 16.
[97] *Id.*
[98] *Id.*
[99] *Id.*

sufficiently robust to both respect the sovereign decision-making of each jurisdiction and ensure the Company can collect its full cost of service. Additionally, the framework did not sufficiently address problems associated with the timing—as opposed to pricing—of resource additions.

Overall, the 2014 Settlement strived to meet our management principles by maintaining the integrated nature of the NSP System, providing North Dakota with more control over its energy resource future and ensure that we could recover our cost of service over the NSP System. The 2014 Settlement accomplished this in several ways: (1) by seeking to adjust rates to change the North Dakota resource mix to better suit North Dakota's energy policies; (2) provide a negotiating framework to "restack" the Company's electric supply resources serving North Dakota; (3) settle the outstanding issues in the wind and gas combined-turbine cases, as well as other outstanding renewable energy-related issues that arose in the 2013 test year rate case, as discussed above; and (4) commit to the development of North Dakota-based thermal generation consistent under prudent resource planning principles.

H. 187 MW Solar Portfolio (2014) and Aurora PPA (2015)

On November 7, 2014, Xcel Energy filed its first solar ADP in North Dakota for its 187 MW Solar Portfolio in Case No. PU-14-810.[100] Soon after, Xcel Energy filed a second solar ADP on February 13, 2015, in its Application for an ADP for a PPA with Aurora Solar, LLC (Aurora PPA) in Case No. PU-15-095.[101]

In its 187 MW Solar Portfolio Application, the Company stated that the resource additions "represent a prudent opportunity for the Company to cost effectively meet its Minnesota Solar Energy Standard (SES) requirements."[102] The 187 MW Solar Portfolio ADP was also pursued in an effort to "produce clean energy, reduce [the Company's] annual carbon emissions and thereby provide a hedge against future environmental regulation" by displacing fossil fuel resource generation.[103]

The NDPSC Advocacy Staff raised concerns that the Company's solar PPAs were undertaken to meet Minnesota requirements and were not selected as cost-effective resource additions; and that alternative, lower-cost resource additions were available

[100] *N. States Power Co. Request for Approval of an Advance Determination of Prudence for a 187 MW Solar Portfolio*, Case No. PU-14-810, APPLICATION (N.D. P.S.C. Nov. 7, 2014).
[101] *N. States Power Co. Advance Prudence – 100 MW Aurora Solar, LLC Application* , Case No. PU-15-095, APPLICATION (N.D. P.S.C. Feb. 13, 2015).
[102] *N. States Power Co. Request for Approval of an Advance Determination of Prudence for a 187 MW Solar Portfolio*, Case No. PU-14-810, APPLICATION at 1-2 (N.D. P.S.C. Nov. 7, 2014).
[103] *Id.* at 18.

to hedge against future environmental regulations and natural gas prices. Staff further concluded that the capacity to be provided by the resource additions was in excess of what was necessary to ensure reliability and meet customer load, causing increased costs to North Dakota customers without corresponding benefits.[104] "Given that [the Company] entertain[ed] the [solar projects] to meet Minnesota requirements, and [they were] not a least-cost option, Advocacy Staff recommend[ed] the costs and benefits of the [solar projects] not be allocated to the North Dakota jurisdiction."[105] For all of these reasons, the NDPSC determined that the Company did not show that its proposed solar projects were prudent and ultimately denied both ADP applications.[106]

I. Courtenay Wind Farm Purchase (2015)

On May 6, 2015, the Company filed an application with the NDPSC seeking an ADP to construct, own, and operate the 200 MW Courtenay Wind Farm Project in Case No. PU-15-181.[107] In its application, the Company explained that it had previously been granted an ADP for purchasing the output of the Courtenay Project through a PPA in Case No. PU-13-706.[108] Due to changed circumstances surrounding the Courtenay Project, namely that the developer of the project was unable to secure financing or a third-party equity investor for the project, the Company proposed ownership of the Courtenay Project.[109] The Company estimated that, with the 200 MW addition, system costs would be lower by approximately $97 million over time on a present value of revenue requirements (PVRR) basis than if the Courtenay Project was abandoned.[110]

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[104] *See N. States Power Co. Advance Prudence – 187 MW Solar Energy Portfolio Application* , Case No. PU-14-810, FINDINGS OF FACT, CONCLUSIONS OF LAW AND ORDER at 3 (N.D. P.S.C. June 17, 2015); *N. States Power Co. Advance Prudence – 100 MW Aurora Solar, LLC Application*, Case No. PU-15-095, FINDINGS OF FACT, CONCLUSIONS OF LAW AND ORDER at 3 (N.D. P.S.C. Sept. 16, 2015).
[105] *See N. States Power Co. Advance Prudence – 187 MW Solar Energy Portfolio Application* , Case No. PU-14-810, FINDINGS OF FACT, CONCLUSIONS OF LAW AND ORDER at 3 (N.D. P.S.C. June 17, 2015); *N. States Power Co. Advance Prudence – 100 MW Aurora Solar, LLC Application*, Case No. PU-15-095, FINDINGS OF FACT, CONCLUSIONS OF LAW AND ORDER at 3 (N.D. P.S.C. Sept. 16, 2015).
[106] *N. States Power Co. Advance Prudence – 187 MW Solar Energy Portfolio Application* , Case No. PU-14-810, FINDINGS OF FACT, CONCLUSIONS OF LAW AND ORDER at 3-4 (N.D. P.S.C. June 17, 2015); *N. States Power Co. Advance Prudence – 100 MW Aurora Solar, LLC Application*, Case No. PU-15-095, FINDINGS OF FACT, CONCLUSIONS OF LAW AND ORDER at 3-4 (N.D. P.S.C. Sept. 16, 2015).
[107] *N. States Power Co. Advance Prudence – 200 MW Courtenay Wind Farm Application*, Case No. PU-15-181, APPLICATION FOR ADVANCE DETERMINATION OF PRUDENCE (N.D. P.S.C. May 6, 2015).
[108] *N. States Power Co. Advance Prudence – 200 MW Courtenay Wind Farm Application*, Case No. PU-15-181, APPLICATION FOR ADVANCE DETERMINATION OF PRUDENCE at 1 (N.D. P.S.C. May 6, 2015).
[109] *Id.* at 2.
[110] *Id.* at 3.

The NDPSC granted the Company's request for an ADP for acquisition and development of the Courtenay Project on August 24, 2015.[111] In making this determination, the NDPSC considered the Company's sensitivity analyses that indicated that, even in a worst case scenario, "the Courtenay Project would still provide customers with approximately $20 million in net cost savings on a PVRR basis over the next 20 years" and provided that the Company's "proposal to own the resource is a lower net present value cost than the original PPA."[112] The NDPSC also considered Advocacy Staff's reasoning that Xcel Energy's ownership of the Courtenay Project represented a least-cost option to meet the Company's future energy needs.[113]

J. Mankato Energy Center II (2015)

Through Minnesota's Competitive Acquisition Process, selection of a proposal made by the Calpine Corporation for the expansion of the Mankato Energy Center was approved by this Commission in Docket No. E002/CN-12-1240 on February 5, 2015. On February 13, 2015, the Company filed an application with the NDPSC seeking an ADP under N.D.C.C. § 49-05-16 for 345 MW of capacity and associated energy to be added to the NSP System through a 20-year PPA with Mankato Energy Center, LLC, an affiliate of Calpine Corporation (Calpine PPA) in Case No. PU-15-96.[114]

In its application, the Company stated that the Calpine PPA would help it meet a potential need of 150 to 500 MW on its system in the 2017-2019 time period as identified in its 2010 Resource Plan.[115] To meet the need, the Company proposed to add the Calpine PPA, in combination with Black Dog Unit 6 and the up-to-100MW (nameplate) distributed solar generation PPA proposed by an affiliate of Geronimo Energy, in lieu of the Company's initial Red River Valley proposal.[116]

Due to timing of this proceeding, the record, an updated load forecast which showed that the timeframe of potential need was not expected until at least 2023 or 2024 and potentially in 2025. The Company asserted that, despite the changed timeframe for anticipated need, the Calpine PPA remained a prudent resource addition due to

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[111] *N. States Power Co. Advance Prudence – 200 MW Courtenay Wind Farm Application*, Case No. PU-15-181, FINDINGS OF FACT, CONCLUSIONS OF LAW AND ORDER at 6 (N.D. P.S.C. Aug. 24, 2015).
[112] *N. States Power Co. Advance Prudence – 200 MW Courtenay Wind Farm Application*, Case No. PU-15-181, FINDINGS OF FACT, CONCLUSIONS OF LAW AND ORDER at 4-5 (N.D. P.S.C. Aug. 24, 2015).
[113] *Id.* at 5.
[114] *N. States Power Co. Advance Prudence – 345 MW Mankato Energy Center Application* , Case No. 15-96, APPLICATION (N.D. P.S.C. Feb. 13, 2015).
[115] *Id.* at 1.
[116] *Id.* at 1-2.

advantageous pricing and its flexibility for evolving circumstances.[117] Advocacy Staff disagreed and testified that, while the Calpine PPA offered advantageous pricing, it was not a prudent investment given that the anticipated need was not until 2024 or 2025. The ADP proceeding therefore became a choice for the NDPSC to capture the advantageous pricing or, to determine that since no load serving need was identified for the first quarter of the PPA term, to decline to capture the advantageous pricing.[118]

On March 23, 2016, the NDPSC issued its Findings of Fact, Conclusions of Law and Order in the Case dismissing our application without prejudice.[119] This provides the Company additional opportunities to seek cost recovery for this project in the future.

K. Negotiated Agreement (2015)

Throughout 2014 and into 2015, the Company and NDPSC Staff negotiated the terms of the agreement contemplated by the 2014 Settlement. This work was intended to develop a proxy pricing framework applicable to existing resources previously identified by the NDPSC in the 2013 test year rate case; as well as develop a framework to create a proxy pricing approach to apply to future NSP System generation resources that may not be approved by the NDPSC. While these discussions were fruitful, they were ultimately unsuccessful in developing a mutually agreeable proxy pricing framework.

The Restack negotiations were focused on three primary issues: (1) how to address the capacity component of resource additions that were not driven by an identified load serving need; (2) how to structure a proxy pricing application that could address past as well as future resources; and (3) the recognition that any proxy pricing outcome cannot be implemented without the consent and agreement of the other states in the NSP System to allow for the recovery of the "policy premium" in the cost-causative jurisdiction.

The Company approached these negotiations with the same three guiding principles in mind—retaining the benefits of the integrated system, respecting the sovereignty of our states and preserving the opportunity for full cost recovery. Although ultimately

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[117] *See N. States Power Co. Advance Prudence – 345 MW Mankato Energy Center Application*, Case No. PU-15-96, FINDINGS OF FACT, CONCLUSIONS OF LAW AND ORDER (N.D. P.S.C. Mar. 23, 2016) (discussing Xcel Energy's testimony in findings of fact).

[119] *N. States Power Co. Advance Prudence – 345 MW Mankato Energy Center Application*, Case No. PU-15-96, FINDINGS OF FACT, CONCLUSIONS OF LAW AND ORDER (N.D. P.S.C. Mar. 23, 2016).

[119] *N. States Power Co. Advance Prudence – 345 MW Mankato Energy Center Application*, Case No. PU-15-96, FINDINGS OF FACT, CONCLUSIONS OF LAW AND ORDER (N.D. P.S.C. Mar. 23, 2016).

unsuccessful, these negotiations did help improve our understanding of the structures and oversight issues related to managing the NSP System. Based on our work on a proxy pricing agreement, it was decided that it was necessary to first address the historic resources raised by the NDPSC in order to shift the focus to forward-looking solutions. Accordingly, we worked with the NDPSC to negotiate and develop the Negotiated Agreement, which addresses existing generation resources.

On September 30, 2015, the Company and Advocacy Staff filed the Negotiated Agreement, and on February 22, 2016, Xcel Energy and Advocacy Staff filed a First Revised Negotiated Agreement, clarifying certain provisions of the Negotiated Agreement. The key terms of the Negotiated Agreement were as follows:

- *By the end of 2025, [the Company] 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 [Xcel Energy] System resource and its costs will be allocated to all states and customers served by the [Xcel Energy] System. If the combustion turbine is not in-service by December 31, 2025, [the Company] will refund to its North Dakota customers 50 percent of the revenues collected from North Dakota customers that exceed the revenues that would have been collected from January 1, 2016 through December 31, 2025 if North Dakota customers had paid an adjusted system average cost for fuel, and energy and associated capacity, for the six biomass PPAs identified in the Negotiated Agreement;*

- *The costs and volumes of fifteen C-BED and two small solar PPAs will be excluded from the calculation of [the Company]'s North Dakota Fuel Cost Recovery (FCR) Rider;*

- *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 [Xcel Energy] System and allow for continued fuel storage for [the Company]'s nuclear fleet. The two wind projects provide low cost energy to the [Xcel Energy] System thereby reducing overall system costs;*

- *[The Company] will extend its current rate case moratorium an additional year through 2017. In the Revised Second Amended Settlement Agreement, a four year rate plan was approved that 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. [The Company] will not file for an increase in base electric rates (on an interim or final level) to be effective before January 1, 2018;*

- *Commission Staff and [Xcel Energy] agree to a rebuttable presumption that the 12-Coincident Peak jurisdictional allocation method is appropriate for allocating applicable system costs between North Dakota, South Dakota, and Minnesota through the year 2025;*

- *Development of a Resource Treatment Framework (RTF) to be filed on or before January 1, 2017 to address the issue of divergent state energy policies. The parties propose the RTF be implemented on January 1, 2018;*

- *[The Company] and Commission Advocacy Staff agree to establish a principal that it would be inequitable to allocate environmental attributes to the North Dakota jurisdiction from a generation resource where costs are not recoverable from the North Dakota jurisdiction.*[120]

On March 9, 2016, the NDPSC approved the Negotiated Agreement, finding that the agreement represented a "reasonable path" forward. The order also granted the Company's ADPs for the Pleasant Valley Wind Farm and the Odell Wind Farm, and[121] outlined the need for a long-term RTF which the Company is required to file with the NDPSC by January 1, 2017.

IV. THE RESOURCE TREATMENT FRAMEWORK – A PATH FORWARD

We have been working diligently to develop a RTF, but there is no simple solution. Although the Company has not yet determined a firm path for moving forward, we continue to weigh the available options and present discussion of these options here.

Our current work is informed by the many months of planning and negotiating a proxy pricing agreement, but a more permanent solution would address not only resource allocation but the terms of resource additions as well.

Foundationally, a successful RTF will appropriately balance the three principles by which we manage the NSP System. It will look to retain integration of the system, respect state sovereignty by allowing each state to plan for and implement a resource mix that meets its objectives while ensuring the benefits and burdens of each state's

[120] *N. States Power Co. 2013 Elec. Rate Increase Application et al.*, 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, ORDER APPROVING SETTLEMENT at 4 (N.D. P.S.C. Mar. 9, 2016).
[121] *Id.* at 5.

choices flow to that state's customers, and ensure that the Company has the opportunity to fully recover our cost of service.

In this section, we first describe the current spectrum of options that we have contemplated as potential RTF models. We then identify the specific frameworks that we focused on through the Restack negotiations and their benefits and drawbacks, also highlighting how each structure values the three principles to varying degrees. Last, we describe the work in progress to develop the tools necessary to track and assign both the costs and the benefits of any particular resource addition.

A. Spectrum of Options

The Negotiated Agreement provides broad parameters for what a RTF may contain, stating simply that "the Company, in consultation and collaboration with the [North Dakota] 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."[122] Given this, we envision a RTF that would form somewhere within a broad spectrum of potential outcomes set forth by NSPM President, Mr. Christopher Clark, in his Direct Testimony supporting the Negotiated Agreement before the NDPSC:

> *We see three potential paths: (1) a solution that allows our North Dakota customers to continue to participate in the integrated NSP System while accounting for some divergence in state energy policy; (2) a solution that ultimately separates our North Dakota jurisdiction from the integrated NSP System so that our North Dakota customers pay for energy and capacity consistent with North Dakota's policy goals while no longer participating in the integrated NSP System; and (3) some hybrid solution that will emerge while we engage in discussion with the Commission as to an RTF.*[123]

One end of the RTF spectrum, we would retain a mostly integrated view of the NSP System and, at the other end, a more fully separated system would emerge. This spectrum of options recognizes that while maintaining the economies of scale inherent in our integrated system will benefit all our customers as it has for many years, continued integration may not be possible. Consequently, we may need to provide greater ability for states to more directly influence the size, type, and timing of resource additions consistent with their own objectives and constraints.

122 Negotiated Agreement at 6.
123 *N. States Power Co. 2013 Elec. Rate Increase Application et al.*, 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, CLARK DIRECT at 15:22- 16:2. (Nov. 30, 2015).

With respect to maintaining a highly integrated system in the future, Mr. Clark also identified some key principles:[124]

- *Defining Which Resources are Due to Divergent Energy Policies.* It may be possible to identify with greater specificity the types of resource additions and/or conditions that present conflicting value among the states and work with the cost-causative jurisdictions on absorbing those. This principle played a key role in resolving energy policy differences between the New Mexico and Texas jurisdictions served by Xcel Energy subsidiary, Southwestern Public Service.

- *Identifying Constructive Solutions to Non-Policy Driven Dissimilar Outcomes.* Differing views of the energy future may lead to different assessments regarding a resource addition, such as timing or hedge value, which are not related to explicit energy policies.[125] In these instances, we would expect to find constructive solutions to reach agreement amongst the states we serve with respect to the disposition of a proposed resource addition. Without finding constructive outcomes, under the current integrated approach, the Company will be faced with the difficult choice of cancelling projects or failing to recover its full costs of providing service.

- *Locating System Investments Throughout the System Footprint.* Retaining an integrated approach will require us to approach our investment decisions with an eye toward all of the states we serve. This means that investment decisions should take into account the benefits of geographical and resource diversity by locating new resources in the many states we serve. Further, siting decisions should also acknowledge the reliability benefits of siting generation nearer to load centers throughout the system.

On the other end of the spectrum, a RTF could ultimately result in beginning the process of some of our states exiting the integrated NSP System. This might be the eventual outcome if it is determined that the differences between our states have become too big to bridge or if it has become infeasible for the various states to work together to achieve constructive outcomes. System separation can take many forms and we are analyzing potential structures to facilitate such an approach, if it were to be needed.

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[124] *Id.* at 17:1-18:20.

[125] An example of this is the Calpine Mankato Energy Center expansion PPA. Different regulatory outcomes in Minnesota and North Dakota with respect to this resource are mainly driven by the timing of the resource addition and not a particular policy preference for one type of generation over another.

We do not want to prejudge the outcome of our work in developing a RTF. We could, potentially, identify a hybrid or other approach that could provide a more workable path forward. The bookends of the spectrum, however, provide the range of outcomes.

Whatever the outcome of our RTF, we acknowledge the importance of engaging our regulators and stakeholders, and advancing a solution that all states can support. Although developing an effective RTF presents challenges, we are also in a timeframe that presents opportunities. Our current Resource Plan describes how our aging fleet is requiring us to take a holistic view of how to address the challenges of the future. The future retirements of our existing generation resources provide opportunities for us to address future needs of each state with a less integrated system should it be determined that this is the most beneficial outcome.

Developing and operating an integrated system for a century means that all of our states are reliant on each other to serve all of our customers' needs while achieving efficiencies and cost savings. As we work to achieve a framework that is acceptable to all of our NSP System states, we must identify the appropriate structures through which to implement it and have sufficient flexibility to address any unforeseen issues.

B. Structures for Implementing an RTF

The Company has been analyzing different structures and frameworks for accommodating state energy preferences on a going forward basis. These structures have formed the basis for how we conceive of implementing a RTF within the spectrum of outcomes.

Mr. David Sederquist described four of these structures at a high level in his Direct Testimony supporting the Negotiated Agreement before the NDPSC in November 2015:

1. *States ensure full cost recovery for resources 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, and 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 a 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, or 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 state's 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.*[126]

These structures were being analyzed as logical extensions of the work we were undertaking while negotiating the Restack portion of the 2014 Agreement. At the time, our analysis of these structures did not advance past the planning stages. However, these initial concepts form the basis for the potential RTF structures. We note that we have not yet considered the fundamentally different nature of the relationship between NSPM and NSPW and if and how these concepts would operate within the context of the Interchange Agreement.

1. Full Recovery from the Cost-Causative and Approving Jurisdiction(s)

Under this structure, we would maintain the integrated system resource planning approach and if a particular system resource was not approved by all jurisdictions served by the NSP System, the costs of the proposed resources would either be assigned to the causative jurisdiction and other approving states or the Company would not move forward with the proposed project.

While this approach may seem straightforward, there are challenges to achieving this kind of framework. First, there are differences in the resource selection and/or approval processes in the various states we serve, and the complexity of trying to coordinate them requires strong "regional" coordination in the selection and approval

[126] *N. States Power Co. 2013 Elec. Rate Increase Application et al.*, 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, SEDERQUIST DIRECT at 7:22-8:20 (Nov. 30, 2015).

of resources. At a minimum, we would need to align the regulatory approvals of our states to enable consistent treatment and timing.

Additionally, under this approach, all states would enjoy the capacity and energy of a particular resource, but not all states would be paying the costs of that resource if it is not approved by all states. Therefore, we may encounter free rider issues and first-mover disadvantages by giving other states the ability to take a "free option" on the integrated NSP System.

However, to the extent that we can better define resources that may be subject to policy-driven needs and identify constructive outcomes, the process adjustments to align resource decisions could be an appropriate solution

2. Proxy Pricing

This concept also retains the integrated nature of the NSP System and integrated resource planning. It differs from the "full recovery" method above in that there is no "up-front" understanding among all state commissions that only the approving states will participate – and pay for – a proposed resource. Rather, states that reject a resource will pay an alternative "proxy price" for the energy and capacity that would presumably protect that state's customers from paying a "policy premium" for the resource. Additionally, this framework will generally not erode the integrated nature of the NSP System since all states continue to pay for all energy and capacity in some form.

In its most basic form, this structure recognizes that since the integrated NSP System is planned for and managed as an integrated whole, each state should pay something for the capacity and energy that they receive from every resource on the system. By instituting a proxy price for that capacity and energy, equities would be retained and the "policy premium" presumably inherent in certain resource selections would be recovered in the cost-causative jurisdiction. This concept was the underlying foundation of our negotiation of the Restack component of the 2014 Settlement in North Dakota.

While conceptually simple, the pricing proxy structure presents some challenges. First, we will need to develop an energy and capacity proxy pricing framework that is equitable and can be accepted by all states. There are many potential proxies, and each have their benefits and drawbacks—none of them perfectly capturing the true cost of a particular resource.

As we were negotiating the Restack, we discovered that there are many potential proxies for energy. Because MISO has a mandatory, organized, and utilized energy market – which all NSP generation participates in – energy market pricing is an attractive, though not the only, available proxy. This is especially the case since MISO's Locational Marginal Price (LMP) represents the cost of the next unit of energy available. However, identifying the appropriate LMP node is challenging. There are at least three potential LMP pricing nodes that would serve as a fair proxy: (1) the generator's pricing node; (2) the main system load node; and (3) a particular state's main load node. Each of these three pricing nodes would result in a different proxy price being paid and each would have a different policy rationale supporting their use. Additionally, the state paying the "policy premium" must agree in principle with the proxy energy price being paid by the jurisdiction that decline to approve the resource or the Company will not be kept whole.[127]

The many different proxies available, and the need for states to agree to an energy proxy, make the use of proxy pricing difficult. However, the challenges with proxy pricing for capacity further complicate the development of this structure.

In contrast to energy pricing, MISO has no organized, mandatory capacity market that can provide a value like LMP. Rather, MISO has its annual capacity auctions and also publishes its Cost of New Entry (CONE). Both of these values reflect different conditions and potential capacity prices. The auction price is for a very limited duration and generally reflects the amount of excess capacity available within MISO; in recent years this has had very low value. CONE, on the other hand, reflects MISO's best estimate of the cost of a new combustion turbine and has a relatively high value, which MISO uses to determine any penalties it will levy upon utilities who fail to meet their capacity obligations. In addition to these capacity values published by MISO, the Company also uses a generic combustion turbine cost in its resource planning efforts and the United States Energy Information Agency publishes its own capacity values. All of these values are derived using different methodologies and for

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[127] Identifying an agreeable proxy energy price is further complicated by the fact that the structure of the North Dakota FCR is charged on a per kWh of usage basis, which means that all North Dakota customers pay something for each and every kWh of usage. Because the North Dakota FCR is structured as recovering a system average cost of fuel, should the NDPSC disallow a particular resource, it merely gets entered as a zero in both the costs and volumes of the purchased power portion of the cost of fuel resulting in a default proxy price of a modified system average cost of fuel. In other words, the default ratemaking outcomes in North Dakota already mitigate issues of "free energy" by resulting in this modified system average cost of fuel merely through the calculation of the FCR, creating yet another reasonable energy proxy price. This was the "proxy price" that resulted in the disallowance of recovery of the North Dakota share of the Aurora Solar PPA from Minnesota customers.

different purposes; there are significant benefits and drawbacks to using these (or some other) value as the appropriate capacity proxy.

In addition to the challenge of identifying a reasonable proxy pricing mechanism, utilizing a proxy capacity price for one type of unit, like a combustion turbine, would not recognize the energy value that a more efficient unit, such as a combined cycle plant, would provide to the system. The same is likely true in the reverse where a proxy price could overvalue the capacity added to the system if it were merely excess capacity that could only be sold into the market at a lower value, if at all. Therefore, a proxy capacity price could significantly undervalue (or overvalue) the actual benefits of a capacity addition to the NSP System. This does not account for any of the additional value which distributed generation resources may provide to the system by interconnecting to the distribution system.

The difficulties in valuing capacity to the system leads to another challenge of the proxy pricing approach: how each state's particular resource selection outlook impacts their view of the timing of resource additions. Traditional resource planning would try to time resource additions consistent with an identified resource need. While that paradigm is consistent amongst all of our states, emphasis on different factors (such as the appropriate use of short-term capacity purchases through the MISO capacity auction) can sometimes lead to resource planning results indicating a resource need or type at different times. Further, renewable energy mandates can also lead to the need to add resource for compliance purposes when no load need may exist. Accordingly, different jurisdictions may disagree as to the appropriate size, type, and timing of particular resource additions.

3. Pricing Zone Concept

This concept is similar to what occurs in the natural gas industry, where different pricing zones are sometimes used for gas utilities that provide service in different areas with mismatched infrastructure costs. Under this concept, the Company would plan and select resources for each state or groupings of state jurisdictions developed as a separate pricing zone within the NSP System. In essence, the North Dakota jurisdiction would remain part of NSPM, and thus part of the NSP System, but might eventually be served by resources not serving the remainder of the system. Therefore, the generation component of the cost of service would vary by pricing zone to reflect the different mix of resources.

Under this concept, a methodology would be developed to allocate not only costs but also the benefits of particular resources to particular states. Said another way, we would allocate the capacity, energy and ancillary benefits of a particular resource to particular states. This would help to ensure that the benefits of a particular resource only accrue to the supporting state.

Rather than merely pricing the "policy premium," the pricing zone concept would directly allocate not only the costs but also the entire bundle of output of the resource to the participating states. To do this requires a complex series of management, market, accounting, operations, and other processes to be developed and tested. Additionally, as resources are added to the system that may not be shared among all of the NSP System's states, we will increasingly have to plan for and meet the capacity needs of each jurisdiction on a potentially stand-alone basis in addition to the integrated planning we currently do. Over time, this may irretrievably separate various jurisdictions from the integrated whole of the NSP System.

The pricing zone concept can allow for economies of scale for those resources where there is agreement, continues the current sharing of the transmission system, and eliminates many of the difficulties of the corporate separation approach discussed below. Further, the flexibility of a pricing zone concept, in that it can apply to one, some, or all of a particular jurisdiction's resources, can make this a useful framework to manage the impact of divergent energy policies. This concept, however, may result in the separation of the integrated NSP System and will require full agreement between the affected jurisdictions as to its implementation. This option also involves the need for complex accounting decisions to be made that can have significant ratemaking impacts and which continue to place the Company's recovery at risk.

4. Separate Operating Companies

Under this concept, the Company would restructure to organize itself with its North Dakota operations (perhaps in addition to or in combination with its South Dakota operations) as a new operating company separate from the Company that would serve Minnesota customers. We started to explore this concept in earnest while proxy pricing framework negotiations were ongoing. To that end, we explored separation to determine if it would provide a vehicle for the Company to serve the NSP System states in a manner consistent with its preferences, while mitigating the need to coordinate between each of the jurisdictions.

We determined that corporate restructuring may best resolve the differences amongst the NSP System states if we envision an energy future where there is more disagreement than agreement on resource selection and choices. Corporate restructuring can provide finality to the issue of divergent energy policies, allow each of our states to develop consistent with their own priorities, and significantly mitigate any need for agreement amongst the states into the future. Additionally, creating separate operating companies may allow us to capture opportunities for our customers, and our shareholders, that may not be possible if we were required to seek agreement and approval from all of the states served by the NSP System.

Creating new operating companies, however, is a lengthy and costly process. Further, a new relationship between the operating companies would need to be structured and approved by the state Commissions as well as FERC. New operating companies could also require renegotiation of existing supply contracts, affiliate relationship contracts, and other significant transactions. It would likely also require an analysis and potential reallocation of the existing generation resources, many of which all of our jurisdictions have been supporting for many decades. This could result in cost shifts amongst the states and losing some of the system efficiency achieved by the economies of scale of the integrated system. Last, restructuring the Company also adds significant corporate complications related to credit access and other financing issues.

C. Development of an RTF

Consistent with our obligations under the Negotiated Agreement, we continue to work toward developing a RTF, which we expect to file in North Dakota and Minnesota by the end of the year. Currently, we anticipate that it will contain a set of regulatory processes and procedures to manage preferences in our various states. We are still in the development stage and do not want to prejudge the outcome of what a RTF may contain. However, our work has been informed by the various concepts described above and we continue pursuing a path that we hope can support a viable RTF. To achieve this, we are currently developing the necessary tools to ensure the benefits and costs of any resource selection or rejection are appropriately borne by the appropriate state. Once these tools are developed, we can then determine the appropriate regulatory matters that need to be addressed to efficiently and equitably deploy these tools.

We believe that a successful RTF will acknowledge that there is fundamental agreement between states on the vast majority of the existing generation fleet, a fleet that has been supported by all of our states for decades. Further, we believe that there will be continued benefits of leveraging the economies of scale provided by the integrated NSP System for all of our customers and therefore will need to develop a RTF that allows for the sharing of resources in the future as well. This means that a successful RTF is likely to:

(1) be forward looking to address future policy divergence between the states, should it occur;

(2) find opportunities to continue an integrated approach to serving all of our customers, where possible; and
(3) continue to keep the existing, or legacy, generating fleet available to all of our customers in all of the states we serve.

We are currently in the process of determining the accounting, market, management, and other internal processes necessary to implement either a Full Recovery or Pricing Zone Concept within the NSPM operating company. By doing so, we hope to develop the necessary tools that allow us not only to assign the costs of a particular resource to a particular jurisdiction but also the capacity, energy, Renewable Energy Credits (RECs), and other ancillary benefits (such as the value of solar) of that resource to that particular jurisdiction. By doing so, we can ensure that the jurisdiction paying the costs of a resource can obtain all of the benefits of that resource. We believe that this will be an effective methodology to ensure that all of our states are served by a resource mix consistent with their policy priorities.

Our initial efforts have demonstrated that it is likely feasible to develop the needed internal process changes to support each state's policies. We currently have the ability to allocate RECs on a jurisdictional basis. We are currently working on the details for ways the Company can participate in the MISO markets as an integrated whole while allocating the costs and revenues of MISO market transactions on a generator basis, rather than on an integrated basis. This would help align the capacity and energy impacts of particular resources with those participating jurisdictions. We are also exploring opportunities to address the secondary benefits of Minnesota's current focus on distributed generation through different accounting methodologies similar to the way we account for the benefits of Minnesota energy efficiency programs. Work continues on development of these procedures, and myriad determinations still have to be made. We hope to work with all of our affected states as we develop this concept to help ensure that it results in an equitable outcome that can be acceptable to, and align with the policies of, all of the states we serve.

That said, new processes that accommodate policy divergence will impact the current regulatory structures in all of the states we serve. We will need to determine new ways to plan and select resources for each jurisdiction separately, as well as for the integrated whole. We will need to find ways to seek agreement amongst our jurisdictions for shared resources in the future as well as to determine when particular resources will be proposed for only a single jurisdiction. How to manage the implementation of the internal processes we are developing will be a key component of the RTF. A successful RTF will be challenging, but aims to provide the Company, our regulators, and other stakeholders an opportunity to find common ground as well as make independent decisions.

CONCLUSION

The Company appreciates the opportunity to provide additional context to the Commission about the planning and operation of the integrated NSP System and the regulatory and analytical frameworks in Minnesota and North Dakota that impact resource decisions. The Company is working toward development of a RTF that provides the necessary framework to manage outcomes in the states we serve. The Company will file this RTF with the Minnesota and North Dakota Commissions by January 1, 2017. We look forward to continued dialogue with the MPUC on these issues and next steps. To that end, we respectfully request a planning meeting held in the third quarter of this year where we can further discuss the information presented in this filing and answer any questions the Commission and our stakeholders may have.

CERTIFICATE OF SERVICE

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

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

xx electronic filing

Docket Nos. E002/M-15-330 and E002/M-16-223

Dated this 13th day of June 2016

/s/

____
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Regulatory Administrator

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http://www.utilitydive.com/news/steel-for-fuel-xcel-ceo-ben-fowke-on-his-utilitys-move-to-a-renewable-c/446791/

'Steel for fuel': Xcel CEO Ben Fowke on his utility's move to a renewable-centric grid

By 2021, Xcel expects wind to be its single largest energy resource - and that means big changes to grid operations. Fowke sat down with Utility Dive to discuss what the transition entails.

By
Gavin Bade @GavinBade

July 11, 2017

Even for veterans of the power sector, the pace of the energy transformation can astound.

"If I were talking to you 10 years ago, I don't think I'd be telling you that I think solar is competing with fossil," said Ben Fowke, CEO of Xcel Energy. "I wouldn't tell you that wind is beating fossil. I am telling you that now."

Fowke’s utility company serves more than 3 million electricity customers across eight states from Michigan to New Mexico. Last week, Minnesota regulators approved a portion of Xcel’s wind energy expansion in the upper Midwest — a total investment of 1.55 GW of wind that also includes Iowa and the Dakotas.

That plan is part of a larger Xcel initiative to add more than 3 GW of wind across its service areas in the coming years. Back in March, Fowke framed Xcel’s power mix evolution as a shift away from its traditional focus on coal-fired generation and toward wind, solar and natural gas.

“We already provide 6,700 MW [of wind],” Fowke told Utility Dive in an interview at the Energy Thought Summit in Austin, Texas. “This will be 3.4 GW ... and that's going to have us at 35% of our energy mix with wind.”

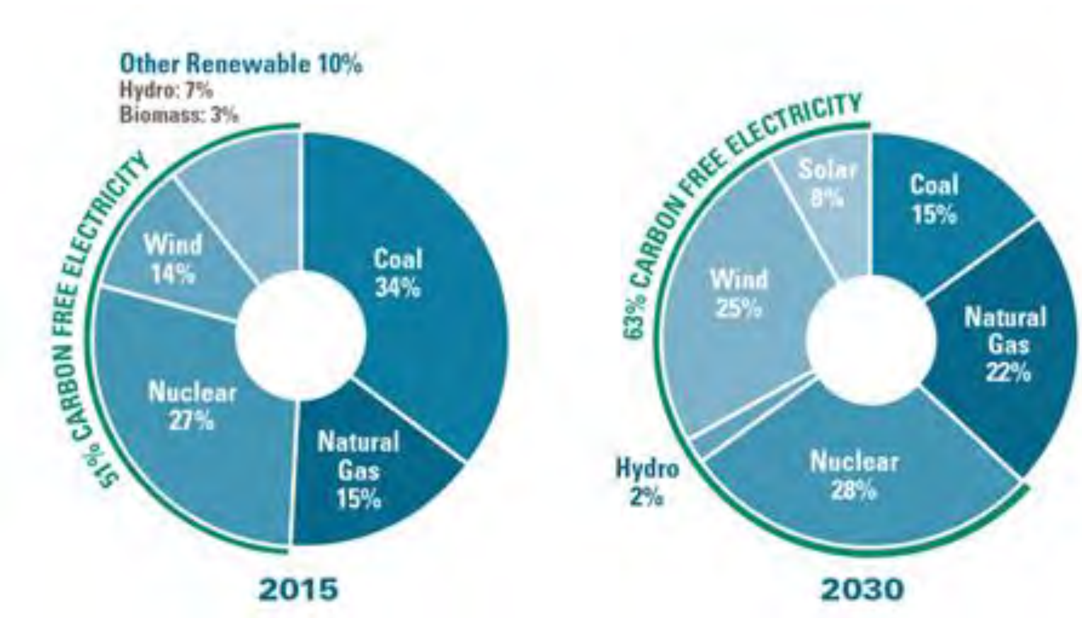
“[Wind] beats gas, even at today’s prices. I like to say we backed up the truck because the fuel of tomorrow was on sale today.”

Ben Fowke
Xcel Energy CEO

By 2021, the utility expects wind will be its largest energy source — not in terms of capacity, but actual generation.

“What's even more amazing is the prices,” Fowke said. “We're looking at [prices] in the low teens to low 20s [in dollars/MWh] — not starting prices, but levelized across the 25-year life of the project.”

“That beats gas, even at today’s prices,” he added. “I like to say we backed up the truck because the fuel of tomorrow was on sale today.”



By 2030, Xcel expects wind generation to top 35% of its total energy mix, including 25% of its Upper Midwest capacity, as depicted above. *Credit:* Xcel Energy Upper Midwest Plan

Xcel calls it “steel for fuel” — swapping out fossil generation for fuel-free wind and solar. At today’s prices, “everybody benefits,” Fowke said. Consumers get lower-cost energy and Xcel can earn a rate of return for building wind projects. Xcel plans to own 1,150 MW of its latest 1,550 MW wind expansion.

“None of it would work if you didn't focus on the technologies that are adding value today,” Fowke said. "That's what's really important.”

Wind is Xcel’s current focus, as the production tax credit for the resource will phase out over the next few years. After that, the next resource to add value to Xcel’s grid will likely be another renewable — solar.

“We wanted to capture the production tax credits … Then I think you start to pivot to what's next,” Fowke said. “I think what's next will be taking advantage of the steady improvements of solar technology, particularly large universal solar. The tax credits will still be there in 2020, and perhaps it's an opportunity for us to lock in again tremendous prices for our customers as we continue to transition to this carbon-light world."

Those investments will help Xcel make good on its pledge to cut carbon emissions 60% by 2030, but getting there will require the transformation of the rest of its resource mix as well.

From baseload to flexible

To get to the point where wind can be a power grid’s largest energy source, “you need to make sure that your entire generation portfolio works in sequence with that,” Fowke said. That means Xcel plans to add more natural gas peaking plants, and “the baseload coal will probably be replaced with combined cycle [gas plants].”

“You keep hearing me say wind is fuel, and that's how we look at it. You still have to have the capacity to back it up,” Fowke said. “Everybody knows wind doesn't blow all the time. When it does blow, it's displacing natural gas or coal that you'd be using in your fossil plants. That's where we get the savings from.”

In addition to those physical assets, the utility expects to continue development of its renewable energy software and data analytics capabilities. By understanding how wind farms operate “at a micro level,” Fowke said Xcel has been able to save customers “tens of millions of dollars a year.”

“We think we've been far more efficient with harnessing the wind that's on our system, not being overly conservative, having to curtail it often,” he said.

The Xcel CEO expects the energy transition to continue regardless of the policy environment in Washington, D.C. President Trump's administration is in the process of rolling back a number of Obama-era environmental and energy regulations, including the Clean Power Plan, which governed carbon pollution from power plants.

"Steel for fuel would make sense with or without a Clean Power Plan."

Ben Fowke
Xcel Energy CEO

"I think what we're doing, it makes sense regardless of whatever federal overlays there," he said. "Steel for fuel would make sense with or without a Clean Power Plan. In fact, we did it not to comply with the Clean Power Plan, but to drive the economics of the environmental benefits.”

Like other U.S. utilities, Fowke does not expect his companies to add new coal generation, but he said some companies could end up running old plants longer in the absence of carbon or other pollution regulations.

“The only thing you might see ... is if you were going to shut down a plant rather than put hundreds of millions of dollars into some pollution control equipment, you might run the old car a little bit longer,” he said. “The short answer is I could see it having some effect on the margins, but right now I still think that economics are driving what's happening in the industry.”

Toward deeper decarbonization

The energy transition hasn’t been all happy headlines for Xcel. Earlier this year, environmentalists and consumer advocates slammed the utility for its plan to repower the 1.3 GW Sherco coal generator with 786 MW of new gas-fired generation.

Xcel announced the retirement of the two Sherco units in its 2016 integrated resource plan, and regulators ordered a study on renewable energy alternatives to replacing the coal capacity with gas.

Then, in January, the legislature stepped in with a bill that would authorize Xcel to bypass the regulatory process and build the gas plant without approval from the Public Utilities Commission. Environmentalists howled, calling it a “power play” by Xcel, but Gov. Mark Dayton (D) signed the measure in February.

From Fowke’s perspective, the bill was not a utility ploy to circumvent its regulators, but rather an attempt by local legislators to ensure some power industry jobs at the Sherco site would be saved after the coal retirements.

“The commission didn't say no [to the gas plant], but they said, 'Let's study it some more.' They thought it was a decent idea,” Fowke said. “The local legislators wanted an answer quicker than that. We're supportive of that. The legislation was passed.”

Fowke stressed that he thinks about decarbonization “continuously,” including how to contribute to the electrification of transportation and industrial processes. Despite regulatory rollbacks, he expects Xcel will be able to do its part to uphold the goals of the Paris climate agreement, which roughly translate to an 80% economywide decarbonization by 2050 — but he also knows it will likely take more innovation.

“I think we can do it, but [with] the technologies today, to be 100% renewable, it doesn't work. That doesn't mean it won't be possible in the decades to come."

Ben Fowke
Xcel Energy CEO

“I already mentioned that I think we're going to have 60% less carbon emissions by 2030. I think to go from 2030 to 2050, we'll have to see additional technologies, the battery technologies that I'm talking about,” he said. "I'd like to see the next generation of nuclear fleet get going because in 2033, 2034, our nuclear plants are scheduled at this point to retire. That's a tremendous amount of carbon reduction that goes away unless we replace it with something else.”

At present, Fowke says Xcel continues to study the lowest-cost pathways to get to deep decarbonization.

“I think we can do it, but [with] the technologies today, to be 100% renewable, it doesn't work,” he said. “That doesn't mean it won't be possible in the decades to come. Combine that with nuclear — I know it's possible. That I know today.”

Correction: Ben Fowke's quote was updated to reflect that Xcel currently provides 6,700 MW of wind, not 8,000MW. The wind pricing quote was updated to reflect that he was referring to dollars per megawatt-hour, not cents per kilowatt-hour.

*Follow Gavin Bade on **Twitter***

STATE OF NORTH DAKOTA
BEFORE THE
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 Application	**Case No. PU-13-706**
Northern States Power Company Advanced Determination of Prudence – Odell Wind Application	**Case No. PU-13-707**
Northern States Power Company Advanced Determination of Prudence – Pleasant Valley Application	**Case No. PU-13-708**
Northern States Power Company Advanced Determination of Prudence – Border Winds Application	**Case No. PU-13-742**
Northern States Power Company 150 MW Border Winds Project – Rolette County, ND Public Convenience & Necessity	**Case No. PU-13-743**
Northern States Power Company Advanced Determination of Prudence – NG Generators Application	**Case No. PU-13-194**
Northern States Power Company Red River Valley NG Unites 1&2 – Hankinson, ND Public Convenience &Necessity	**Case No. PU-13-195**

VERIFICATION

STATE OF MINNESOTA)
) ss.
COUNTY OF HENNEPIN)

Aakash H. Chandarana, being first duly sworn on oath, deposes and says that he is the Regional Vice-President of Rates and Regulatory Affairs for Xcel Energy Services Inc. on behalf of Applicant Northern States Power Company, a Minnesota corporation, in the above-captioned matter, that the testimony and schedules submitted in the above-captioned matters under his name 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.

Aakash H. Chandarana

Subscribed and sworn to before me this 11th day of July, 2017.

CYNTHIA D. HARRINGTON
Notary Public, State of Minnesota
My Commission Expires
January 31, 2020

Notary Public
My commission expires: 1-31-2020