TRANSMISSION SERVICE IMPLICATIONS OF SEPARATING THE NORTH DAKOTA JURISDICTION

As noted in the accompanying Application, a number of alternative approaches exist for addressing the future energy needs of the North Dakota electric customers of Northern States Power Company, a Minnesota corporation (NSPM). These approaches range from full regulatory alignment to pseudo separation of the North Dakota portion of the five-state integrated NSP System,[1] to full legal separation through a separate North Dakota operating company (NSPD). The two structures we have identified as being able to support our proposed Resource Treatment Framework (RTF) are the Pseudo Separation structure and Legal Separation structure. For simplicity, this Schedule refers to the implementation of either of these structures as a "separation scenario."

From a transmission perspective, currently the North Dakota jurisdiction is responsible for about 5.3 percent of all transmission costs incurred on the integrated NSP System and correspondingly receives about 5.3 percent of all benefits from the delivery capability of that overall integrated NSP System. Analyzing the RTF impacts on the Company's North Dakota operations and the overall NSP System requires consideration of how transmission service would be provided in a separation scenario. Depending upon the chosen RTF structure and implementation, there are a number of possible outcomes. The purpose of this Schedule 8 is to provide a high-level description of the transmission service implications to our North Dakota and Minnesota customers. The Company estimates a range of costs and risks to North Dakota and Minnesota of separating the Company's North Dakota operations from the integrated NSP System if Legal Separation is ultimately selected as the appropriate structure to support our RTF.

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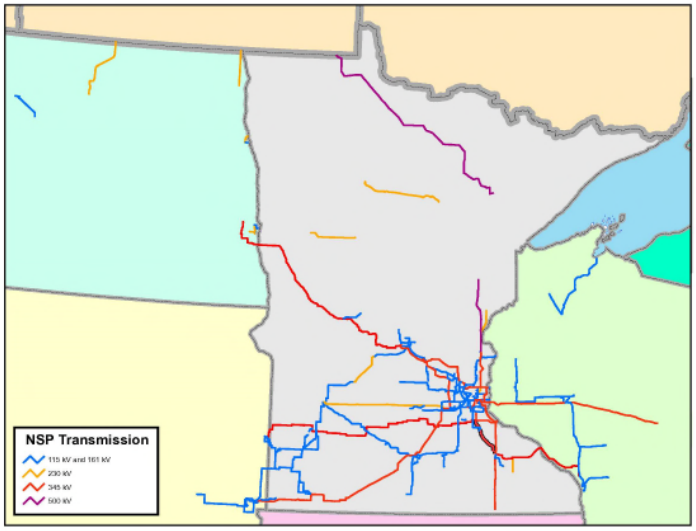
[1] NSPM's electric production and transmission system in Minnesota, North Dakota, and South Dakota is currently planned, built, and operated on an integrated basis with the production and transmission system of Northern States Power Company, a Wisconsin corporation (NSPW). Collectively, NSPM and NSPW integrate their operations facilities, known as the "NSP System," through a Federal Energy Regulatory Commission (FERC)-jurisdictional wholesale Interchange Agreement that allows the two companies to utilize all generation and transmission facilities on an integrated basis to effect the most economical and reliable supply to meet their combined electric load. *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); *see also N. States Power Co., a Minn. Corp.*, FERC Docket No. ER15-1575, LETTER ORDER (June 22, 2015) (unpublished letter order of the most recent update to the Interchange Agreement).

A. Transmission System in the Region

NSPM is currently the largest retail electric provider in the State of North Dakota, providing service to three urban areas in the state: (i) Minot, (ii) the Grand Forks/East Grand Forks area, and (iii) the Fargo/Moorhead area. These three load centers are not contiguous themselves or contiguous with the remainder of the NSP System via transmission facilities owned by NSPM, and are thus considered "load pockets." NSPM currently serves the transmission needs for these load pockets through network transmission service reservations obtained under the Midcontinent Independent System Operator, Inc. (MISO) open access transmission, energy, and reserve markets tariff (MISO Tariff) and through individually negotiated pre-MISO transmission agreements, known as "grandfathered agreements" (GFAs) under the MISO Tariff.

In order to assess how transmission service could be provided to the Company's North Dakota load pockets in a separation scenario, it is important to understand the configuration of the system in North Dakota and the MISO Tariff and contractual arrangements that exist among neighboring utilities and the regional transmission organizations (RTOs)[2] that operate in the region. This, in turn, will inform how this configuration could affect future transmission service under evolving circumstances. Figure 1, below, depicts the NSP System transmission facilities (115 kV and above).

Figure 1: NSP System Transmission Facilities (115 kV and above)

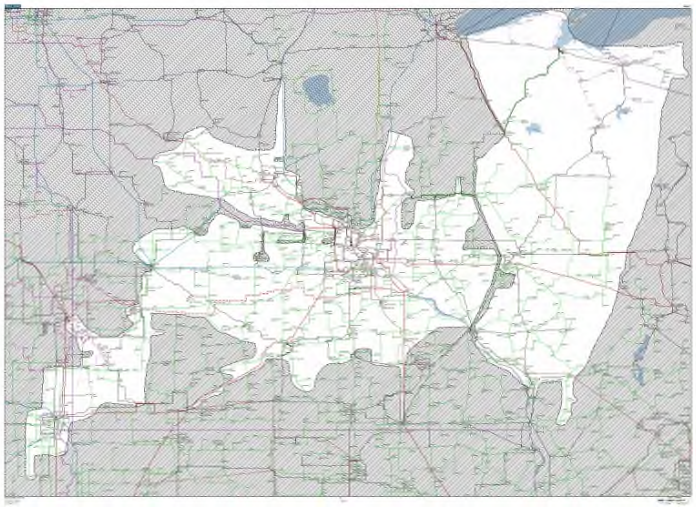


[2] Specifically, MISO and the Southwest Power Pool, Inc. (SPP) are RTOs as established pursuant to FERC Order No. 2000.

The electric delivery service for NSPM customers (including in Minnesota and North Dakota) is procured through the MISO Tariff. In all separation scenarios described herein, NSPM anticipates that it will continue to procure network transmission service through the MISO Tariff.

To serve the three load pockets, NSPM must rely upon both its own transmission facilities as well as other regional transmission infrastructure owned by other utilities. As depicted in Figure 1, the Company does not have contiguous transmission facilities in and around the three North Dakota load pockets that it serves. Indeed, as shown by Figure 2, below, the three North Dakota load pockets are not located within NSP's Local Balancing Authority (LBA).

Figure 2: NSP Local Balancing Authority (White area)



As can be seen, NSPM transmission facilities do not directly serve the Minot and Grand Forks areas, and each of these load pockets are located adjacent to transmission facilities of other utilities: Minot (adjacent to Great River Energy (GRE)); Grand Forks (adjacent to Minnkota Power Cooperative (Minnkota)); and Fargo (adjacent to Otter Tail Power Company (OTP)). The location of the Company's North Dakota load adjacent to the facilities of other utilities presents an important feature that could have significant implications in a separation scenario, as will be described in more detail below.

In addition, two of the load pockets (Grand Forks/East Grand Forks and Fargo/Moorhead) include loads on both sides of the North Dakota/Minnesota

border served from common transmission facilities. Finally, while the Minot load pocket is served under the MISO Tariff, it is also interconnected to transmission facilities owned by utilities who are members of SPP, a separate RTO. These conditions specific to the transmission system in and around North Dakota may impact service to North Dakota customers in a separation scenario. They could create challenges for providing transmission service to one or more of these load pockets in the event the Company's North Dakota jurisdiction is separated from the integrated NSP System, as will be discussed in this Schedule 8.

1. MISO, SPP, Minnkota, and Seams

Other transmission-owning members of MISO have facilities that interconnect with the Company's transmission facilities in and around North Dakota. These third-party facilities are important to ensuring sufficient transmission capacity is available to serve the Company's North Dakota customers. The adjacent interconnected MISO transmission owners include GRE, OTP, Minnesota Power, and Montana-Dakota Utilities. All of these transmission-owning members of MISO are subject to the MISO Tariff as well.

The Company's North Dakota service territory is in the western part of the MISO footprint. In this area, MISO-controlled facilities are interconnected to other utilities and regional organizations that are not governed by the MISO Tariff. The situation is complicated by the fact that the transmission network in North Dakota is under the functional control of two separate RTOs (MISO and SPP), and other facilities (Minnkota) are interconnected with NSPM but not a member of any RTO. The presence of non-MISO facilities in the area raises implications of separating NSPM's North Dakota customers or transmission facilities from the larger NSP System.[3]

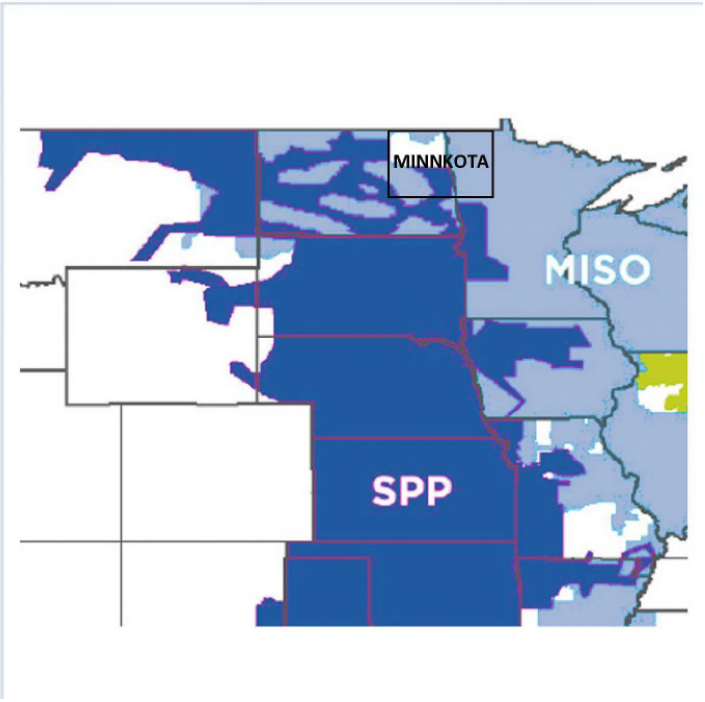
For example, Basin Electric Cooperative (Basin) and the Western Area Power Association (WAPA) have facilities that interconnect to the MISO footprint in the region. These two utilities are transmission-owning members of SPP. Members of SPP, such as WAPA and Basin, are subject to the SPP Tariff and have granted functional control of their transmission facilities to SPP.

Further, Minnkota has transmission facilities in northeastern North Dakota and northwestern Minnesota that are interconnected to NSPM's facilities. These facilities

[3] *See Sw Power Pool, Inc.*, 153 FERC ¶ 61,367 (2015)(addressing ongoing seams issues between SPP and MISO related to the Central Power Electric Cooperative system).

are important to ensure adequate service to our North Dakota customers, particularly in Grand Forks/East Grand Forks. Minnkota is not a member of either MISO or SPP; Minnkota is an independent generation and transmission cooperative that operates pursuant to its own tariffs and cooperation agreements with neighboring utilities, MISO, and SPP.

Figure 3: SPP/Minnkota/MISO System Boundaries (approximate and illustrative)



The confluence of MISO, SPP, and Minnkota within the borders of North Dakota creates the need to coordinate planning and operations to ensure the overall electric grid operates safely and efficiently. MISO, SPP, and Minnkota each operate under separate tariffs and agreements, with sometimes divergent operational requirements, conditions, and rate structures. The divergence of tariffs and operational requirements, even with the interconnection of their respective facilities and electrical flows, creates what are known as "seams." It is necessary for utilities to manage and plan around the seams to ensure proper operations and cost allocation, and to minimize costs to customers.

Seams are managed through a series of agreements among RTOs. MISO and SPP are parties to a FERC-approved Joint Operating Agreement (JOA) that is intended to

coordinate interregional planning and operations at the seams between their respective systems, including within North Dakota.

The JOA between MISO and SPP stipulates each region must maintain sufficient contract paths to serve its own generation and load obligations, and establishes procedures between the regions to allocate transmission capacity when necessary. The JOA sets a process for coordinating operations and setting consequences if the contract path has been exceeded. Section 5.2 of the JOA provides that if there is insufficient transmission capacity to support the contract path, the party responsible for the shortfall is required to pay. While the application of the JOA to the MISO/SPP seam in the MISO South region has been the subject of substantial litigation at FERC, with the issues largely being resolved,[4] seams issues arose between MISO and SPP in the north as well with the integration of the WAPA/Basin Integrated System (WAPA/Basin System) into SPP, and, as yet, those seams issues have not been comprehensively addressed.

Similarly, Minnkota has a series of legacy coordination agreements with its neighboring utilities (including NSPM). These GFAs predate FERC's Order Nos. 888 and 2000 requirements for comparably-provided open access transmission service under regional tariffs. The GFAs with Minnkota remain necessary to coordinate seams, particularly since Minnkota is not a member of any RTO. These agreements[5] date back to the 1960s and the Mid-Continent Area Power Pool, and provide a mechanism for neighboring utilities with non-contiguous transmission systems to interchange power and transmission service to each other's noncontiguous loads.

When FERC approved implementation of day-ahead and real-time markets in the MISO Tariff in 2005, FERC authorized a mechanism that allowed these legacy GFAs to continue in place, i.e., allowed the pre-MISO transmission service arrangements to remain in effect despite more recent delivery arrangements being superseded by the

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[4] *See Sw Power Pool, Inc.*, 154 FERC ¶ 61,021 (2016) (approving settlement between MISO and SPP regarding flows between MISO South and MISO North regions).

[5] As discussed herein, prior to FERC Order No. 888 and Order No. 2000 requirements for transmission owners to provide open access service and the subsequent MISO Tariff, these individually negotiated agreements were the typical way for neighboring utilities to grant a contract path for transmission delivery service to remote customers or loads. NSPM entered into a series of these legacy agreements to facilitate service to its noncontiguous North Dakota load pockets.

implementation of individual system or regional tariffs.[6] This prevented the disruption of the effectiveness of agreements already approved by FERC so as not to upset the long-standing arrangements of the parties. Further, since utilities such as Minnkota are not subject to FERC jurisdiction it was necessary to allow contractual arrangements with such entities to continue, thereby ensuring a smoother transition to the operation of the regional market and to help ensure utilities could continue efficient operations, even if they were not members of MISO or subject to FERC jurisdiction.[7]

A key GFA that has historically played a significant role in providing service to NSPM customers in North Dakota is a 1964 energy delivery swap agreement with GRE known as the "Stanton Agreement."[8] This agreement predates MISO and the advent of open access.[9] Although both NSPM and GRE are now transmission-owning

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[6] *See Midwest Indep. Transmission Sys. Operator, Inc.*, 107 FERC ¶ 61,191 (2004); *Midwest Indep. Transmission Sys. Operator, Inc.*, 108 FERC ¶ 61,163 (2004), *order on reh'g*, 109 FERC ¶ 61,157 (2004), *order on reh'g*, 111 FERC ¶ 61,043 (2005); *Midwest Indep. Transmission Sys. Operator, Inc., et al.*, 111 FERC ¶ 61,176 (2005).

[7] There are over 100 GFAs that are recognized under the MISO Tariff. The complete list of those agreements can be found in Attachment P to the MISO Tariff, available at https://www.misoenergy.org/Library/Repository/Tariff/FERC%20Filings/2013-03-27%20Docket%20No.%20ER13-1170-000.pdf. The GFAs that are relevant to the Company's service in North Dakota include:

- *Winnipeg – Grand Forks 230 kV Interconnection Coordinating Agreement*, among Manitoba Hydro, Minnkota Power Cooperative and Northern States Power Company, January 16, 1969, as amended (Attachment P No. 309);
- *North Dakota – Western Minnesota 230 kV Facilities Coordinating Agreement* among Minnkota Power Cooperative, Inc., Minnesota Power and Light Company, and Northern States Power Company, July 29, 1966, as amended (Attachment P No. 317); and
- *Transmission Service Agreement* among Great River Energy (formerly Northern Minnesota Power Association, Rural Cooperative Power Association, and United Power Association) and Northern States Power Company, August 17, 1964, as amended (Attachment P Nos. 323 and 390).

In addition, the Company is a party to GFAs allowing municipal utilities to use NSPM facilities for deliveries of WAPA preference power allocations to loads near the WAPA/NSPM boundary. *See, e.g.*, *Municipal Interconnection Agreement*, between Northern States Power Company and the City of Ada, MN, November 30 1992 (Attachment P No. 352); *Transmission Facilities Agreement* between Northern States Power Company and Water, Light, Power & Building Commission for the City of East Grand Forks, Minnesota, December 10, 1992 (Attachment P No. 431).

[8] *Transmission Service Agreement* among Great River Energy (formerly Northern Minnesota Power Association, Rural Cooperative Power Association, and United Power Association) and Northern States Power Company, August 17, 1964, as amended (Attachment P Nos. 323 and 390).

[9] The Stanton Agreement established an energy delivery "swap" or displacement using the generation resources and transmission of one utility to serve the nearby loads of the other utility on an equivalent basis. GRE owns and operates generation in North Dakota near Minot, but its largest load centers are near

members of MISO subject to the MISO Tariff and GRE has announced plans to retire the Stanton generating station, the transmission rights designated under the Stanton Agreement will continue and will provide some energy delivery hedge value to the parties in the future and the principles of this GFA remain a valuable part of the NSP System.

If a Legal Separation scenario is chosen, the Company believes it would likely be appropriate to assign the relevant GFAs to the North Dakota jurisdiction to allow North Dakota customers to retain the benefits of those agreements. For example, the Company anticipates that, if the North Dakota jurisdiction is separated from the NSP System, the Company would attempt to work with GRE and MISO to ensure that the value of the Stanton Agreement remains available to North Dakota customers. However, that outcome would ultimately be determined by negotiations with these other parties and would require FERC approval, and cannot be guaranteed.

2. Current Transmission Service

Under current circumstances, NSPM procures network transmission service for all of its customers throughout the integrated NSP System by making reservations for service under the MISO Tariff. This includes obtaining network transmission service for the customers in North Dakota. It is not necessary for NSPM to schedule deliveries separately using transmission service established through any of its GFAs. But the presence of these GFAs supports the Company's ability to take network service through MISO without incurring any additional charge for crossing separate transmission systems or for using transmission capacity enabled by the separate systems.[10]

Transmission service is charged through mechanisms contained in the MISO Tariff. Network transmission service is priced through a formula that applies a charge reflecting the embedded cost of transmission facilities included in the applicable "pricing zone" plus an amount reimbursing a variety of charges imposed by MISO.

Minneapolis, Minnesota. By contrast, NSPM serves three load centers in North Dakota (Minot, Fargo, and Grand Forks) while its generation fleet is predominantly located in central and southern Minnesota. The Stanton Agreement allowed NSPM to electrically exchange GRE resources generated in western North Dakota to physically serve Minot area loads, and GRE received NSPM resources generated in Minnesota to serve GRE loads in Minnesota.

[10] As discussed below, however, the existence of the GFAs remains important and termination of the grandfathered rights could present downstream cost and operating impacts that would need to be taken into account.

Pricing zones are financial concepts intended to ensure transmission costs are levied to loads commensurate with the firm demands on the system and the utility is reimbursed for its necessary transmission investment.

A pricing zone may include facilities or loads that are electrically non-contiguous. In the case of NSPM's North Dakota operations, customers in Fargo/Moorhead and Grand Forks/East Grand Forks and various transmission facilities in North Dakota are included in the NSP pricing zone for transmission pricing purposes even though the facilities and loads are adjacent to transmission facilities of OTP or Minnkota respectively. The Minot area load, however, is presently included in a joint NSP/GRE pricing zone to address GRE's significant transmission infrastructure in that area.[11]

Charges for network transmission service include (i) the applicable zonal rate applied to the load served, plus (ii) a variety of MISO administrative and other charges, including regionally-allocated transmission costs (e.g., MISO Schedule 26 and 26A). The zonal rate is based on a revenue requirement for the zonal transmission plant and the loads assigned to the pricing zone. The NSP pricing zone facilities and loads include both NSP System loads and facilities and third-party loads and facilities.

The NSP pricing zone net charges and MISO administrative and other regionally-allocated charges are spread to all customers in the NSP System on a load-ratio-share basis. Included in the net amount and similarly allocated are revenue credits the Company receives from MISO under the Tariff. This generally means that our Minnesota customers bear approximately 75 percent of the overall NSP System transmission cost and our North Dakota customers bear about 5.3 percent of the overall NSP System transmission costs. This establishes a revenue requirement split that reflects North Dakota's load-ratio share of the overall NSP System.[12]

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[11] In a joint pricing zone (JPZ), participants such as NSPM and GRE have negotiated a transmission revenue-sharing agreement to reflect their respective transmission investment used to serve customers in that area. The NSP System is also a participant in a JPZ for the NSP System pricing zone that includes the costs of certain facilities used for the provision of transmission service to the Fargo and Grand Forks load pockets.

[12] However, it should be noted that the amount of NSP System transmission plant in service located in North Dakota is less than five percent of the NSP System total. Five percent of the transmission plant in service on the NSP System in year ending 2016 equals about $161.5 million on a net book value basis. Transmission facilities located in North Dakota currently have a net book value of about $102.9 million. This disparity could be meaningful in a separation scenario, depending upon how the separation is effectuated because loads in North Dakota would continue to need to use NSP System facilities from outside North Dakota to receive reliable service.

B. Future Transmission Issues Presented

This section discusses ways transmission service could be provided to serve North Dakota customers in a separation scenario. While transmission service would continue to be procured through network transmission reservations under the MISO Tariff, each scenario creates specific issues that may change the costs and risks associated with transmission service.

Several separation scenarios exist, which are largely dependent upon whether the NSP System can be retained in some form or if full disaggregation through Legal Separation is the desired outcome. These scenarios are identified here and described in the next section.

1. Separation Scenarios if NSP System is Retained

The Company has identified three scenarios that could occur if the integrated NSP System is retained in some form. They are:

Regulatory Alignment: As described in the Application, if the Company's jurisdictions can reach consensus on resource selection sufficiently to keep the NSP System operating in its present form, then there would be no need to change the way transmission service is provided to all customers. In short, the North Dakota jurisdiction would continue to receive and benefit from its load-ratio share of the integrated NSP System, i.e., currently about 5.3 percent of the NSP System.

Proxy Pricing: Under this scenario, the structure of the NSP System stays in place but the energy component is priced differently for each jurisdiction, reflecting the jurisdiction's policy preferences. In this scenario, it is likely (though not assured) that transmission could continue to be served on an integrated basis as it is today. As described in the next section, this scenario could present variable outcomes depending upon how the proxy pricing is structured and how the NSP System evolves.

Pseudo-Separation: NSPM could retain all of the transmission assets (including those located in North Dakota) and provide transmission service to North Dakota customers on the same basis as today. Once again, it is possible that transmission service could continue to be provided on an integrated basis,

although this raises a policy question of the fairness of a state participating in transmission service on an integrated basis if that state also requires a separate pricing zone for its energy, creating an asymmetrical cost and risk structure.

2. Separation Scenarios if Legal Separation is Chosen

The Company has identified three separation scenarios that could occur if the Commissions choose to have NSPM legally separate its North Dakota jurisdiction into a separate operating company. These scenarios vary depending upon how NSPD is structured and what assets it owns. They are:

NSPD as a Transmission-Dependent Utility Purchasing Transmission Through MISO: In this separation scenario, North Dakota electric distribution and generation facilities are legally separated from the NSP System but NSPM retains the transmission assets. NSPD would become a transmission-dependent utility and would take transmission service under the MISO Tariff in a way that is similar to how other transmission-dependent utilities take service. This avoids separation of the NSP System transmission assets and somewhat mitigates the costs and risks identified below with scenarios where NSPD becomes a transmission owner, needing to operate under the MISO Tariff and become a party to the GFAs that facilitate transmission service into the state. This scenario changes the cost profile to the North Dakota jurisdiction since NSPD would not own transmission and would, therefore, not receive any offsetting revenue credits from MISO.

NSPD as a Transmission-Owner Operating Within the Existing NSPM Load Zones: Ownership of the North Dakota transmission assets could be transferred to NSPD, with NSPD loads acting as a transmission owner within the larger NSP pricing zone separate from NSPM and NSPW. This scenario raises a number of cost and risk issues as described below. Further, this scenario would require renegotiation of a number of agreements and may be challenging to the extent that it results in cost shifting to other utilities or other states.

NSPD as a Transmission-Owner Operating Within a New NSPD Load Zone: Ownership of the North Dakota transmission assets could be transferred to NSPD with development of a separate North Dakota pricing zone under the MISO Tariff to charge North Dakota customers (including wholesale loads) accordingly. This scenario may not be feasible. At a minimum it would require MISO concurrence. In addition there are potential complications with GFA

assignment to NSPD and transmission pricing zone negotiations with other MISO pricing zone participants.

C. Scenarios Discussion

Each of the scenarios described summarily above and in more detail below present a unique profile. The Company notes that each scenario carries individual issues and potential complications. While the Company has not comprehensively studied all of the scenarios, issues that have already been identified may include:

- Transmission cost shifting from one state jurisdiction to another among customers throughout the integrated NSP System;
- potential cost shifting among affected transmission owners;
- changes in the contractual and operational relationships with and among neighboring utilities;
- potential seams issues/costs/risks with SPP and Minnkota;
- MISO Tariff changes;
- rate design changes;
- changes to load metering requirements for transmission invoice settlements;
- allocation of costs for residual system support services between companies; and
- a variety of other potential changes necessary to effectuate ongoing transmission service to North Dakota customers.

Further, each scenario other than regulatory alignment could present risk of changes to seams costs. And some of the scenarios will require acceptance by a variety of stakeholders (MISO, FERC, the states, neighboring utilities) each of which may have its own interests that may not be aligned with the Company's interests.

At this time, the Company has not fully estimated all of the costs and risks under each scenario, except at an order-of-magnitude level for discussion. If a separation scenario is considered, the Company will undertake a more granular analysis of the costs and risks of providing transmission service post-separation.

1. Scenarios That Retain the NSP System in Some Form

a. Regulatory Alignment

In the event that the Company's jurisdictions are able to achieve sufficient compromise that the integrated NSP System can be retained, no change to the current transmission service function would be required. The North Dakota jurisdiction will continue to take its load-ratio share of service on the system and will reap a corresponding amount of the benefits of that system. Under current circumstances, this means that North Dakota customers will continue to pay about 5.3 percent of all NSP System transmission costs. Because NSPM is a transmission owner in MISO, this also means that NSPM receives credits and offsetting revenues from MISO. Under current circumstances, the North Dakota jurisdiction reaps its pro rata (5.3 percent) share of those credits and offsetting revenues. In a Regulatory Alignment scenario, this status quo would be maintained.

b. Proxy Pricing

Similar to the Regulatory Alignment scenario, if the jurisdictions are able to come to agreement on a way to more closely align resource cost responsibility through the current NSP System, it is likely that transmission service could continue to be procured and allocated to the jurisdictions on a pro rata basis as it is today. In this situation, NSPM (and NSPW, coordinated through the Interchange Agreement) would continue to be the transmission owner for the entire NSP System, including North Dakota, and would continue to make transmission service reservations and payments applicable to the entire system. In this type of voluntary scenario where the jurisdictions agree to adjust resource pricing in a manner that is fair to all jurisdictions, it would likely be fair for transmission to be procured on a pro rata basis, similar to current circumstances. North Dakota customers would remain in the current NSP and NSP/GRE pricing zones and would be allocated a share of the costs of transmission commensurate with already-established practices.

The Company could retain the current system-wide allocator that results in the current 5.3 percent allocation to North Dakota, hence a relatively unchanged transmission system cost allocation. The current use of the NSPM system-wide retail cost allocator actually benefits North Dakota customers due to the diversity of peak demand allocation with the rest of the NSP System when compared with MISO transmission cost allocation in the other scenarios.

There may be nuances in this scenario depending upon how proxy pricing is determined and which resources may be included or excluded. Further, as legacy generation resources are retired and new resources are added to the system, the transmission delivery arrangements from such resources may need to be adjusted to reflect those evolving circumstances. And to the extent proxy pricing results in inter-jurisdictional subsidization or unrecovered costs, a policy question would be raised as to the fairness of a state participating fully in the integrated NSP System's transmission assets while not participating fully in the generation component of the integrated NSP System.

c. Pseudo Separation

In a Pseudo Separation scenario, NSPM functionally separates its North Dakota jurisdiction from the integrated NSP System but does not legally separate into a North Dakota operating company. The impacts on the provision of network transmission service to customers in North Dakota would be minimal. In this situation, NSPM (and NSPW, coordinated through the Interchange Agreement) would continue to be the transmission owner for the entire NSP System, including North Dakota, and would continue to make transmission service reservations and payments applicable to the entire system.

In this scenario, it is possible that, from a transmission perspective, North Dakota customers could continue to be charged a load-ratio share of the transmission costs attributable to the overall system as they are today. The cost of transmission service could largely reflect the embedded cost calculated using North Dakota retail cost of service principles, plus the costs billed to the NSP System for MISO regional services. North Dakota customers would remain in the current NSP and NSP/GRE pricing zones as established in the normal course of business and would be allocated a share of the costs of transmission commensurate with already-established practices.

The Company could retain the current system-wide allocator that results in the current 5.3 percent allocation to North Dakota, hence a relatively unchanged transmission system cost allocation. The current use of the NSPM system-wide retail cost allocator actually benefits North Dakota customers due to the diversity peak demand allocation with the rest of the NSP System when compared with MISO transmission cost allocation in the other scenarios, though generation costs would be allocated as discussed in the Application.

This scenario, similarly raises a policy question of the fairness of a jurisdiction participating equally with the overall NSP System for transmission delivery while not participating equally from a generation perspective. Depending upon the potential inter-jurisdictional subsidization that could occur, it may be necessary to functionally separate the transmission delivery function in a way that better aligns the benefits of transmission delivery with the chosen generation portfolio. The details of this type of approach have not been studied and the implications of such a structure are not yet fully understood.

2. Legal Separation Scenarios

a. Transmission Dependent Utility Service

In this Legal Separation scenario, there is a legal separation of a North Dakota operating company but NSPM would retain the transmission facilities located in North Dakota (as today) and NSPM would operate NSPD as a transmission-dependent utility (TDU) with no owned transmission assets and taking service under the MISO Tariff. This transaction structure would result in NSPD operating as a distribution-only utility.

In this scenario, NSPD would take tariffed MISO network transmission service for each of the three load pockets.[13] The transmission charges to NSPD would be based on the NSP System transmission formula rate (and the formula rates of the other entities in the NSP pricing zone) using FERC ratemaking principles rather than the traditional retail cost of service model. NSPD would be charged the zonal rate for the NSP pricing zone and would be responsible for MISO administrative and other fees (e.g., MISO Schedule 26/26A regional charges) in proportion to its use.

Because NSPD would not be a transmission owner in this scenario, NSPD would not incur the costs of transmission asset investments and likewise would not participate in transmission revenue distribution under the MISO Tariff. The retail electric rate in NSPD would therefore have no direct transmission revenue requirement or credits

[13] The Company would endeavor to assign the relevant GFAs to NSPD in order to preserve the benefits of those legacy agreements to the extent possible. It should be noted that FERC policy is generally to encourage utilities to take transmission service pursuant to the relevant RTO tariff and to phase out use of GFAs. While the Company believes that it should be able to assign the GFAs to NSPD, this is not entirely free from doubt and would need to be investigated in detail prior to separation.

for service sold, but instead would simply reflect the costs of transmission invoice settlements under the MISO Tariff.

The Company recognizes that NSPD taking transmission as a transmission-dependent utility would result in transmission costs being incurred somewhat differently. The Company estimates that this would result in a net transmission cost increase to NSPD compared to today's paradigm in the range of $2 to $4 million per year, largely as a result of a shift in the retail rate design necessitated by the way a TDU is billed for transmission services under the MISO Tariff.

b. NSPD Owns Transmission in the NSP Joint Pricing Zone

In this Legal Separation scenario, there is a legal separation of a North Dakota operating company, with ownership by NSPD of transmission assets. This would change the way transmission costs are allocated. Several steps would be necessary to implement this scenario:

- NSPD would become a transmission-owning member of MISO;
- the transmission assets physically located in North Dakota would be transferred to NSPD;
- the Company and other members of the JPZ agreement for the NSP pricing zone would add NSPD to the JPZ agreement and treat the NSPD facilities and loads separately from the NSPM and NSPW facilities and loads.[14]

NSPD would also need to replace NSPM as the party to the GRE JPZ agreement, which would require both agreement by GRE and FERC approval. In addition, NSPD and NSPM would need to enter into coordinating agreements to ensure that costs and responsibilities for residual or contracted service functions are allocated appropriately.[15]

[14] Note that all parties to the JPZ agreement would need to unanimously consent to this change. In the event that this scenario could result in costs being shifted from one transmission owner to others, obtaining consent to make this change would be challenging.

[15] Note that FERC approval would be required for the transfer of facilities to NSPD, the modifications of the NSP pricing zone JPZ and GRE/NSP pricing zone JPZ agreements, and any coordinating agreements between NSPD and NSPM.

Under this separation scenario, NSPD would be a party to the JPZ agreement and be eligible for the bundled load exemption under the MISO Tariff.[16] The NSPD MISO transmission formula revenue requirement would be calculated separately from that for NSPM and NSPW. The North Dakota transmission revenue adjustment charges would be based on the overall NSP and GRE/NSP pricing zones loads and revenue requirements using FERC ratemaking principles, with the net charges to NSPD determined pursuant to the bundled load exemption.

As previously noted, the physical transmission assets located in North Dakota do not reflect the pro rata share of transmission assets based on a load-ratio share of the overall System. In 2016, the transmission assets in North Dakota were valued at $102.9 million. However, 5.3 percent of the NSP System transmission assets (North Dakota's load-ratio share) would be $161.5 million for 2016, or a difference of about $60 million. The Company's projections are that the same differential order of magnitude would continue to exist in 2020 when a separate operating company could be established.

The allocation of NSP pricing zone costs would therefore reflect the under-investment by NSPD relative to its loads to ensure that North Dakota customers pay a sufficient amount to compensate the other JPZ member utilities for their overall investment in transmission. In this scenario, the North Dakota jurisdiction transmission revenue adjustment net of MISO would be on the order of $3 to $6 million per year, plus assignment of certain costs from NSPM for residual or contracted service functions.

c. Separate NSPD Pricing Zone

Finally, there is a possibility of completely separating North Dakota and creating its own MISO pricing zone. In this Legal Separation scenario, a North Dakota operating company owns North Dakota transmission assets, but NSPD is not a party to the

[16] The MISO bundled load exemption is a Tariff mechanism that exempts transmission owners who serve bundled load from paying certain charges under the Tariff. This exemption is found at Section 37.3a of the MISO Tariff and is designed to ensure that transmission owners serving bundled load do not collect revenues from MISO that are proportionately greater than the utility's revenue requirement. Without the bundled load exemption, "[t]his windfall would be at the expense of other [MISO] TOs without bundled retail load … who would receive aggregate revenues that are proportionately less than their revenue requirements." *Midwest Indep. Transmission Sys. Operator, Inc. and the Transmission Owners of the Midwest Indep. Transmission Sys. Operator, Inc.*, 122 FERC ¶ 61,090 at P 46 (2008), *reh'g denied*, 136 FERC ¶ 61,099 (2011).

NSP JPZ agreement. This would significantly change the way transmission costs are allocated.

In this scenario, NSPD would become a member of MISO separate from the remainder of the NSP System. The transmission assets physically located in North Dakota would be transferred to NSPD. NSPD, in its new capacity as a transmission owner in MISO, would have to develop a separate North Dakota pricing zone applicable to the North Dakota facilities and loads, with the new zone approved by FERC for inclusion in the MISO Tariff.[17] NSPD would also need to be designated as a party to the GRE JPZ agreement.[18] In addition, NSPD and NSPM would need to enter into coordinating agreements to ensure that costs and responsibilities for residual or contracted service functions are allocated appropriately.[19]

As previously noted in Scenario 3 above, the physical assets located in North Dakota ($102.9 million) do not reflect the pro rata share of transmission assets based on a load-ratio share of the overall system ($161.5 million), and this same delta range is expected to continue to exist in 2020 when a new operating company could be established.

To effectuate a separate NSPD transmission pricing zone, the Company would require reallocating a portion of the existing NSP System (or NSP pricing zone) costs to ensure that North Dakota customers receive an appropriate and fair allocation of the overall transmission system investment. Additionally, other MISO utilities could require NSPD to share in the costs of facilities in their pricing zones.

In addition, as noted above, the Company's Fargo and Grand Forks load pockets are largely adjacent to OTP and Minnkota's transmission facilities respectively. In the scenario where a North Dakota-specific pricing zone is implemented, there is a risk that OTP or Minnkota may take the position NSPD cannot serve these load pockets

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[17] Note that the MISO Tariff has specific requirements for developing pricing zones, including the necessity of the utility creating an LBA as a condition of joining MISO. This could be challenging for NSPD since the three load pockets all currently reside within the LBA of other utilities. As a result, the feasibility of this scenario would need to be carefully investigated prior to implementation.

[18] Similar to Scenario 3, above, replacing NSPD on the GRE JPZ agreement would require consent of all parties thereto and to the extent this scenario results in cost shifts, it may be challenging to obtain the required consents.

[19] Note that FERC approval would be required for the transfer of facilities to NSPD, the creation of an NSPD pricing zone under the MISO Tariff, and any coordinating agreements between NSPD and NSPM.

using NSPD's own zonal facilities and claim NSPD is dependent upon OTP or Minnkota's facilities in those areas. OTP could argue that NSPD should be required to join the OTP pricing zone or seek to create an OTP/NSPD JPZ reflecting OTP's greater transmission investment in these areas, rather than remain part of the NSP pricing zone. We have no estimate at this time for the magnitude of the potential cost shift associated with this risk.

Another issue with this scenario is that the basis upon which MISO charges are allocated would change. In the current circumstances, MISO administrative and other charges are allocated across the integrated NSP System based on the jurisdictional load-ratio share of the System with North Dakota customers responsible for about five percent of those charges.

In this Legal Separation scenario, however, North Dakota customers will be responsible for 100 percent of the costs attributable to providing service to North Dakota. These include certain costs subsumed by the NSP System today related to support for the sub-regional network in North Dakota. Further, to the extent that unusual or unforeseen charges are attributed to the North Dakota jurisdiction, such costs would not be shared across the larger NSP System. Thus, if a network reservation to serve the new North Dakota jurisdiction created a seams cost with SPP or Minnkota, such a cost would be attributable only to NSPD and would not be spread to the larger NSP System. Alternatively, if NSPD were required to install new network transmission facilities because of load growth or new generation interconnections, the costs would not be shared in the manner they are today.

Given the number of potential impacts to development of this scenario and the range of costs associated with certain risks of this scenario, we have not attempted a specific cost evaluation. In our judgment, we anticipate a minimum transmission cost increase for NSPD of $5 million annually compared with regulatory alignment in order to effectuate the arrangements that would support this scenario. In addition, this scenario would be dependent upon rearranging transmission contracts throughout the region and obtaining numerous third-party consents and approvals, none of which could be assured.

D. Additional Costs and Risks in Separation Scenarios

Legal Separation of North Dakota from the integrated NSP System may have additional impacts relating to the allocation of transmission-related costs. While these issues may not apply in all scenarios, there is the potential for unexpected results.

1. Example 1: Risk of SPP Seams Cost

A utility located at the seam between MISO and SPP may have two transmission sources to support a network transmission reservation – one source interconnecting to MISO and one interconnecting to SPP. If the MISO source experiences an outage, service would be provided solely through the SPP source for the duration of the outage. Such use of the SPP interconnection source could result in temporarily "leaning on" the SPP system, a layman's term for an insufficient contract path as contemplated in the MISO/SPP JOA.

Generally, MISO has taken the position that a scenario like this is not grounds for contract path insufficiency and that the RTOs can and should provide mutual aid to each other during such contingencies without compensation for such transmission usage. SPP, however, has taken the position that the JOA does not require providing mutual aid of this type. Rather, SPP generally takes the position that the contingent outage scenario can create contract path insufficiency and hence an obligation for the load serving utility to purchase SPP transmission service. SPP has maintained in the past that if this scenario occurs there must be a payment for transmission service to establish contract path, pursuant to Section 5.2 of the JOA. SPP maintains that the concept of mutual aid encourages free riding and should be discouraged.

This divergent view of seams management could create a situation where the utility (i.e., NSPD) is required either to pay SPP for transmission service (pancaked rates), or penalties (under the JOA) when the contract path is exceeded, or invest in new transmission facilities to reinforce the system to ensure that the system is adequate to obviate the need for mutual aid. All three options would come at a currently-unknown cost to NSPD that would not be shared with the remainder of the NSP System.

The issue of pancaked rates between MISO and SPP is currently being reviewed in a FERC proceeding involving OTP. In *Southwest Power Pool, Inc.*, FERC Docket No. ER16-209, SPP filed a transmission rate for a new SPP transmission-owning member,

Central Power Electric Cooperative, Inc. (Central). Central's transmission facilities are interconnected with OTP's facilities at the seam between SPP and MISO.

OTP protested, arguing the arrangement would undermine OTP's existing rights and cause pancaked rates for transmission uses where OTP had not borne pancaked rates previously. Both the MPUC and NDPSC intervened in the case.[20]

FERC accepted the SPP filing but recognized the potential for pancaked rates and set the matter for settlement judge procedures to address this and other issues. In its December 30, 2015, *Order Accepting Tariff Revisions Implementing Formula Rates and Establishing Hearing and Settlement Judge Procedures*,[21] FERC accepted SPP's proposed tariff, subject to refund, and required the parties to attempt to resolve their differences through FERC's established settlement procedures. As it pertains to OTP's protest, FERC ruled that:

> to the extent that Otter Tail has facilities that are highly integrated with facilities in the expanded SPP transmission system as a result of joint planning and ownership, and is concerned that the integration of Central Power into SPP will introduce duplicative or pancaked rates that did not previously exist for use of such jointly planned and owned facilities, Otter Tail may address in the hearing and settlement judge procedures whether any provision is needed in its service agreement with SPP to mitigate such impacts in order to ensure just and reasonable rates.[22]

This FERC matter is ongoing and remains unresolved. Regardless of the outcome, it raises important questions for consideration applicable to NSPD in a separation scenario, as the risk of incurring pancaked transmission rates in the future would impose costs on NSPD's customers.[23]

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[20] The MPUC intervened, opposing Central's proposal and expressing concerns about the cost impacts to OTP ratepayers. The NDPSC intervened and commented on the filing.

[21] *Sw Power Pool, Inc.*, 153 FERC ¶ 61,367 (2015).

[22] 153 FERC ¶ 61,367 at P 47 (2015).

[23] FERC has stated that seams charges from one regional transmission organization (SPP) to another (MISO) are permitted and are consistent with FERC precedent and that pancaking of transmission rates is permitted where the utility is using the transmission facilities within both regional organizations. *Sw Power Pool, Inc.*, 155 FERC ¶ 61,259 at P 29 (June 16, 2016) (citing *Sw Power Pool, Inc.*, 153 FERC ¶ 61,051 at P 52 ("[T]hese separate 'inter-RTO' transmission charges are consistent with Commission precedent, which allows RTOs to

Under current circumstances, any seams costs incurred affecting delivery to loads in North Dakota are allocated to the entire NSP System, meaning that the North Dakota jurisdiction is allocated about 5.3 percent of the cost. If the Company's North Dakota transmission system is separated into a distinct NSPD operating company, such costs incurred to support transmission to North Dakota customers would be assessed only to NSPD.

2. Example 2: Minnkota Costs

NSP's load pocket in the Grand Forks/East Grand Forks area is supported by transmission assets owned by Minnkota via the GFA NSPM has with Minnkota. Power is transmitted from Fargo across the Minnkota system contract path to customers in the Grand Forks area pursuant to a GFA.[24] This area of northeastern North Dakota (and far northwestern Minnesota) lies predominantly within Minnkota's retail service territory.

As Minnkota is not a member of MISO, it is not bound by the MISO Tariff; and as a cooperative, Minnkota is not subject to FERC jurisdiction. As a result, maintaining this GFA and contract path to serve the Grand Forks area is an important factor in providing transmission delivery to our customers in North Dakota. If this GFA is terminated or is found to be inapplicable to future circumstances in a Legal Separation scenario, NSPD would potentially need to obtain alternative transmission capacity. While it is likely NSPD could obtain a transmission reservation under the MISO Tariff to serve this load pocket, MISO could determine that network upgrades are required to provide the service. The cost and schedule for system upgrades necessary to support such a reservation are currently unknown.

Because of the presence of GFAs with Minnkota, NSPM is able to obtain transmission service for these customers under the MISO Tariff and GFA without incurring any additional charges for using Minnkota's facilities. In the future, if the GFA with Minnkota is terminated or found to no longer be applicable in a separation scenario, additional payments may be demanded by Minnkota for use of its

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collect transmission charges from a load-serving entity for every transmission system that the load-serving entity uses.")) (citing *Cal. Indep. Sys. Operator Corp.*, 147 FERC ¶ 61,231 at P 155 (2014)("As a matter of policy, the Commission generally has not required the elimination of inter-RTO rate pancaking, but has required the elimination of intra-RTO rate pancaking.")).

[24] *North Dakota – Western Minnesota 230 kV Facilities Coordinating Agreement* (MISO Attachment P No. 317).

transmission facilities. If this scenario occurred today affecting delivery to loads in North Dakota, any cost imposed by Minnkota would be allocated to the entire NSP System, meaning that the North Dakota jurisdiction would be allocated about 5.3 percent of the cost. If North Dakota transmission is separated into a distinct NSPD operating company, such costs incurred to support transmission to North Dakota customers would be assessed only to NSPD and its customers.

As noted, in a transmission separation scenario, the Company believes it should be allowed to assign the relevant GFAs to NSPD to allow the North Dakota operating company to retain the benefits of those agreements, including the GFAs with Minnkota. However, that outcome would ultimately be determined by negotiations with Minnkota and be subject to FERC approval, and cannot be guaranteed.

E. Conclusion

Separating the Company's North Dakota operations from the overall NSP System in some form raises issues for consideration regarding how transmission service will be provided. Different scenarios raise different issues, costs, and risks. If separation is ultimately the desired outcome, how separation impacts transmission service will need to be taken into account.

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MPUC Docket No. E-002/M-16-223
SCHEDULE 9
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RTF High-Level Revenue Requirement Impact-North Dakota

Revenue Requirement Impact ($ in millions) **2020 Test Period**

	Alloc	ND Jur	Res	Commercial Non Demand	C&I Demand	Ltg
Pseudo-Separation Differences						
Biomass	E8760	(6.6)	(2.3)	(0.4)	(3.9)	(0.0)
CBED Wind	E8760	(2.3)	(0.8)	(0.1)	(1.4)	(0.0)
Solar	E8760 & D10C	(1.2)	(0.4)	(0.1)	(0.7)	(0.0)
Replacement cost for Biomass, CBED Wind, Solar	E8760 & D10C	3.1	1.0	0.2	1.8	0.0
New wind net of fuel savings	E8760 & D10C	4.1	1.4	0.2	2.4	0.0
Sherco 1 & 2 Retirements	E8760 & D10C	(1.3)	(0.5)	(0.1)	(0.8)	(0.0)
Additional Acctg & IT	A&G	0.1	0.0	0.0	0.0	0.0
Total-Pseudo-Separation		(4.1)	(1.4)	(0.2)	(2.4)	(0.0)
Legal Separation Differences						
Pseudo-Separation Differences except A&G		(4.2)	(1.5)	(0.2)	(2.5)	(0.0)
Additional A&G	A&G	2.0	0.8	0.1	1.1	0.0
Financing difference	Labor	1.0	0.4	0.1	0.5	0.0
Service Co Allocations	A&G	3.0	1.0	0.2	1.8	0.0
Transmission	D10T	5.0	1.7	0.3	3.0	0.0
Transaction Costs	A&G	1.0	0.4	0.1	0.5	0.0
Total-Legal Seperation		7.8	2.8	0.5	4.4	0.1
Estimated Bill Impacts						
Pseudo-Seperation						
Annual kHh Sales		2,309,682,896	812,242,938	122,259,235	1,356,166,305	19,014,418
Impact per kWh			-$0.0017711	-$0.0019191	-$0.0017924	-$0.0014408
Average Annual kWh per Month per Customer			842	1,137	28,784	783
Average Monthly Bill Impact			**-$1.49**	**-$2.18**	**-$51.59**	**-$1.13**
Legal Seperation						
Annual kHh Sales		2,309,682,896	812,242,938	122,259,235	1,356,166,305	19,014,418
Impact per kWh			$0.0034523	$0.0040549	$0.0032808	$0.0033888
Average Annual kWh per Month per Customer			842	1,137	28,784	783
Average Monthly Bill Impact			**$2.91**	**$4.61**	**$94.44**	**$2.65**

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SCHEDULE 9
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RTF High-Level Revenue Requirement Impact-Minnesota

Revenue Requirement Impact ($ in millions)		**2020 Test Period**				
				Commercial		
	Alloc	MN Jur	Res	Non Demand	C&I Demand	Ltg
Main RTF Differences						
Biomass	E8760	5.1	1.5	0.2	3.4	0.0
CBED Wind	E8760	1.8	0.5	0.1	1.2	0.0
Solar	E8760 & D10S	0.9	0.3	0.0	0.6	0.0
Replacement cost for Biomass, CBED Wind, Solar	E8760	(2.4)	(0.7)	(0.1)	(1.6)	(0.0)
New wind net of fuel savings	E8760 & D10S	(3.2)	(0.9)	(0.1)	(2.1)	(0.0)
Sherco 1 & 2 Retirements	E8760 & D10S	1.0	0.3	0.0	0.7	0.0
Additional Acctg & IT	A&G	0.7	0.3	0.0	0.4	0.0
Total-Pseudo-Separation		4.0	1.2	0.1	2.6	0.0
Legal Separation Differences						
Pseudo-Separation Differences except A&G		3.2	1.0	0.1	2.1	0.0
Additional A&G	A&G	0.0	0.0	0.0	0.0	0.0
Financing difference	Labor	0.0	0.0	0.0	0.0	0.0
Service Co Allocations	A&G	(2.3)	(0.7)	(0.1)	(1.5)	(0.0)
Transmission	D10S	(3.9)	(1.3)	(0.1)	(2.4)	0.0
Transaction Costs	A&G	1.0	0.3	0.0	0.7	0.0
Total		(1.9)	(0.8)	(0.1)	(1.1)	0.0
Estimated Bill Impacts						
Pseudo-Seperation						
Annual kHh Sales		30,680,751,285	8,558,594,266	930,970,250	21,013,565,407	177,621,362
Impact per kWh			$0.000144	$0.000148	$0.000123	$0.000099
Average kWh per Month per Customer			630	893	37,099	545
Average Monthly Bill Impact			**$0.09**	**$0.13**	**$4.55**	**$0.05**
Legal Seperation						
Annual kHh Sales		30,680,751,285	8,558,594,266	930,970,250	21,013,565,407	177,621,362
Impact per kWh			-$0.000096	-$0.000089	-$0.000050	$0.000062
Average kWh per Month per Customer			630	893	37,099	545
Average Monthly Bill Impact			**-$0.06**	**-$0.08**	**-$1.86**	**$0.03**

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, that the Application filed in the above captioned matters on December 31, 2016 was prepared under his direction, that he has read said Application, 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 22nd day of December, 2016.

Theresa Ann Senart
Notary Public
My commission expires: Jan. 31, 2020

THERESA ANN SENART
Notary Public
Minnesota
My Commission Expires January 31, 2020

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

NEGOTIATED 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 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 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 & Necessity	Case No. PU-13-195

ORDER APPROVING SETTLEMENT

March 9, 2016

Appearances

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

Alison C. Archer, Xcel Energy Services Inc., 414 Nicollet Mall, 5th Floor, Minneapolis, Minnesota 55401-1993, and Zeviel T. Simpser, Briggs and Morgan, P.A.,

2200 IDS Center, 80 South Eighth Street, Minneapolis, Minnesota 55402-2157, appearing on behalf of Northern States Power Company.

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

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

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

Preliminary Statement

On February 26, 2014, the Commission issued an Order approving a Revised Second Amended Settlement Agreement in the captioned Northern States Power Company (NSP) cases. The Order dismissed without prejudice NSP's applications for an Advanced Determination of Prudence (ADP) in Case No. PU-13-707 and Case No. PU-13-708, and granted NSP's applications for ADP in Case No. PU-13-194, Case No. PU-13-706, and Case No. PU-13-742, consistent with the Revised Second Amended Settlement.

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

- Reforms to NSP's Fuel Cost Rider (FCR).
- 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.
- NSP will pass 100 percent of North Dakota jurisdictional net renewable energy credit proceeds, for North Dakota allocated renewable energy credits, to North Dakota customers for all sales on and after January 1, 2014.

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

On June 17, 2015, the Commission granted NSP's request for a 90-day extension from June 30, 2015 to September 30, 2015 for the filing date of a North Dakota policy based generation mix required under the Revised Second Amended Settlement Agreement adopted by the Commission's February 26, 2014 Order Adopting Settlement in the captioned eight cases.

On August 24, 2015, the Commission issued an Order in Case No. PU-15-174, Case No. PU-15-175, Case No. PU-15-181 and Case No. PU-15-183, which, among other provisions, granted NSP's request to discontinue the ADP related to the power purchase agreement for the output of the Courtenay Project granted by the Commission's February 26, 2014 Order in Case No. PU-13-706.

On September 30, 2015, NSP and Public Service Commission Advocacy Staff filed a Negotiated Agreement to comply with the 90-day extension granted by the Commission on June 17, 2015. The Negotiated Agreement addressed electric generation resource policy differences that exist between NSP's North Dakota and Minnesota jurisdictions with an opportunity to address North Dakota's energy policy goals and other matters.

On November 4, 2015, the Commission issued a Notice of Consolidated Hearing on the Negotiated Agreement filed on September 30, 2015 in the eight captioned cases and Case No. PU-15-96 to begin on December 15, 2015 in the Commission Hearing Room, 12th Floor, State Capital, Bismarck, North Dakota. The Notice specified the issue to be considered is whether the Negotiated Agreement is reasonable and should be adopted by the Commission. The consolidated hearing was held as noticed.

On February 22, 2016 NSP and Advocacy Staff filed a First Revised Negotiated Agreement, clarifying certain provisions of the Negotiated Agreement. The First Revised Negotiated Agreement includes the following key terms:

- By the end of 2025, NSP will build or have located in eastern North Dakota a natural gas-fired electric generation facility with a capacity of at least 200 MW. The combustion turbine will be treated as an NSP System resource and its costs will be allocated to all states and customers served by the NSP System. If the combustion turbine is not in-service by December 31, 2025, NSP will refund to its North Dakota customers 50 percent of the revenues collected from North Dakota customers that exceed the revenues that would have been collected 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 Community-Based Energy Development (C-BED) and two small solar PPAs will be excluded from the calculation of NSP's North Dakota Fuel Cost Recovery (FCR) Rider;
- The costs of six key biomass PPAs and the Odell and Pleasant Valley wind projects will be recovered in North Dakota. The biomass resources provide approximately 145 MW of baseload-type capacity and energy for the entire NSP System and allow for continued fuel storage for NSP's nuclear fleet. The two wind projects provide low cost energy to the NSP System thereby reducing overall system costs;
- NSP's 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. NSP 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 NSP 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.
- NSP 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.

Discussion

The First Revised Negotiated Agreement represents a reasonable path towards addressing the impacts of divergent energy policies on NSP's resource decisions.

The exclusion of 15 C-BED projects and two small solar Power Purchase Agreements under the First Revised Negotiated Agreement will decrease overall electric revenues by approximately $1.6 million in 2016 and a total of approximately $19 million through 2030.

The First Revised Negotiated Agreement will provide a moratorium against electric base rate increase until at least 2018.

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

Order

The Commission Orders:

1. The First Revised Negotiated Agreement filed February 22, 2016, a copy of which is attached to this Order and made a part of this Order, is APPROVED.

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

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

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

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

PUBLIC SERVICE COMMISSION

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

Xcel Energy®

February 22, 2016

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

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

Dear Mr. Nitschke:

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

Thank you.

Sincerely,

DAVID SEDERQUIST
SR. REGULATORY CONSULTANT

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

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First Revised Negotiated Agreement
Northern States Power Company / Public Service Commission Advocacy Staff
Christopher Clark / John Schuh

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First Revised Negotiated Agreement

STATE OF NORTH DAKOTA
BEFORE THE
PUBLIC SERVICE COMMISSION

NORTHERN STATES POWER COMPANY
2013 ELECTRIC RATE INCREASE
APPLICATION

CASE NO. PU-12-813

FIRST REVISED NEGOTIATED AGREEMENT

RELATING TO
NORTH DAKOTA GENERATION RESOURCE POLICY

I. INTRODUCTION

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

This Agreement stems from the Parties' commitments contained in the Revised Second Amended Comprehensive Settlement Agreement (Rate Settlement) in Case Nos. PU-12-813, PU-13-706, PU-13-707, PU-13-708, PU-13-742, PU-13-743, PU-13-194, PU-13-195 (collectively, the Rate Case) adopted by the North Dakota Public Service Commission (Commission) on February 26, 2014. As required by the Rate Settlement, the Parties have negotiated in good faith to obtain this Agreement

utilizing the guiding principles in Section II.A of the Rate Settlement as a basis for their negotiations (which are provided for reference as Schedule 1 to this Agreement). However, additional information not available when the Rate Settlement was entered into (*e.g.*, the Company's 2015 Resource Plan (Case No. PU-15-19), additional proposed resource additions and the Clean Power Plan) have led the Parties to slow down and reassess how to viably approach the very complex issue of divergent state energy policies.

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

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

The Parties intend this Agreement to provide a "bridge period" for the Company to propose and implement, in collaboration with the Commission and Staff, a long-term "Resource Treatment Framework," or RTF. This Agreement binds the Company to file an RTF proposal with the Commission no later than January 1, 2017,

with the intention to implement it no later than January 1, 2018. This Agreement also requires the Company to accelerate, from 2036 to 2025, its commitment to construct and install an integrated NSP System thermal generating resource in eastern North Dakota, preferably near the city of Fargo.

II. INVESTMENT IN NORTH DAKOTA THERMAL GENERATION

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

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

Attainment of this commitment is contingent on the Company's receipt of all necessary and appropriate permits and regulatory approvals. Further, except as modified by this Section II, all provisions of the 2036 Commitment remain in place, including without limitation, the requirements that the combustion turbine agreed to

in this paragraph reasonably: 1) address a system capacity need, and 2) represent a least-cost resource when also considering the local reliability and system benefits of developing thermal generation in North Dakota.

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

III. RECOVERY OF SELECTED GENERATION RESOURCES

A. *Existing System Resources.* In recognition of the Company's accelerated commitment to construct thermal generation in North Dakota, and the interest of the Parties to achieve a long-term RTF, the Parties agree that the resources listed in Attachment A to this Agreement are to be excluded from the calculation of the Company's North Dakota Fuel Cost Rider beginning the later of January 1, 2016 or the date this Agreement is adopted by the Commission. The North Dakota portion of the capacity and energy costs of all other NSP System resources (including Company-owned facilities and Power Purchase Agreements) in-service as of February 26, 2014 are to be recovered by the Company through its base rates,

Fuel Cost Rider (FCR), and/or Renewable Energy Rider (RER), as may be applicable, during the term of this Agreement. The Parties further agree that the costs of the Border Winds, Pleasant Valley, and Odell wind resource additions currently being constructed are to be included in the Company's rate base, Fuel Cost Rider (FCR), and/or Renewable Energy Rider (RER), as applicable. The Commission's recent Orders in Case Nos. PU-15-95 and PU-14-810 (Aurora Solar and Solar Portfolio) denying Advance Determination of Prudence are unaffected by this Agreement.

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

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

IV. RESOURCE TREATMENT FRAMEWORK

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

In light of this, the Parties have entered into this Agreement to address short-term treatment of resources (*i.e.,* existing and certain pending resources) and provide time for careful consideration as to how the Company should best proceed to ensure

future generation resources are in place – and the costs properly assigned – to meet the energy and capacity needs of its customers.

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

V. OTHER MATTERS

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

B. *Other Commitments of the Company.* To facilitate successful implementation of this Agreement, the Company agrees to waive: a) any claims regarding the enforceability of this Agreement; and b) any claims against the Commission with respect to the adequacy of rates set by the Commission resulting strictly from this Agreement. The waiver in this paragraph is effective as of the date this Agreement is

executed by the Company and terminates on January 1, 2018. Further, the waiver in this paragraph does not limit or prohibit NSP's right to request rehearing or appeal of any Commission order with respect to either the prudence of a particular resource or the adequacy of rates set by the Commission.

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

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

VI. OTHER TERMS AND CONDITIONS

A. *Environmental Attributes.* "Environmental Attributes" are those credits, allowances, offsets and other similar rights associated with renewable electric generation that can be used to (i) satisfy the Company's renewable energy requirements in any of the states it operates in, and/or (ii) claim responsibility for, ownership of, avoidance of, or reduction of legally-recognized emissions or pollutants. The Company and Staff agree to establish the principle that it would be inequitable to allocate Environmental Attributes to the Company's North Dakota

jurisdiction from a generation resource in the event that 1) the Commission rejects an Advanced Determination of Prudence for such resource, unless and until full recovery of the allocable North Dakota costs is approved in a later proceeding, or 2) costs of the generation resource are disallowed in a rate case or other proceeding.

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

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

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

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

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

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

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

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

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

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

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

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

VII. CONCLUSION

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

[SIGNATURE PAGE FOLLOWS]

Dated this 22nd day of February, 2016.

Northern States Power Company,
A Minnesota corporation

By: _____

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

Dated this 22nd day of February, 2016.

Northern Dakota Public Service Commission Staff

By: s/John M. Schuh

John M. Schuh, Advocacy Staff
Counsel to the Commission

[SIGNATURE PAGE TO FIRST REVISED NEGOTIATED AGREEMENT]

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

COMPLIANCE FILING ON JURISDICTIONAL COST ISSUES

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

414 Nicollet Mall
Minneapolis, Minnesota 55401

June 13, 2016

—VIA ELECTRONIC FILING—

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 [Company's] 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 [Company's 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 – 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*

[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]
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> *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

[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]

[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 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*

[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*

[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*

[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.

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[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

[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/

SaGonna Thompson
Regulatory Administrator

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

COMPLIANCE FILING ON JURISDICTIONAL COST ISSUES LETTER – GUIDING PRINCIPLES FOR FUTURE COST ALLOCATION PROPOSALS

MPUC Docket No. E002/M-16-223

Minnesota Public Utilities Commission

September 15, 2016

Aakash H. Chandarana
Northern States Power Company, d/b/a Xcel Energy
414 Nicollet Mall
Minneapolis, MN 55401

RE: Compliance Filing on Jurisdictional Cost Issues (PUC Docket: E002/M-16-223)
Letter – Guiding Principles for Future Cost Allocation Proposals

Dear Mr. Chandarana,

I am responding on behalf of the Minnesota Public Utilities Commission (Commission) to Xcel Energy's June 13, 2016 Compliance Filing on Jurisdictional Cost Issues (Compliance Filing), filed in Commission Docket E002/M-16-223. The Compliance Filing was in response to the Commission's Order issued on April 13, 2016 concerning the cost allocation issues raised in the Aurora Power Purchase Agreement (PPA) Docket (Commission Docket No. E002/M-15-330).

In the Compliance Filing, Xcel indicated its intent to file its Resource Treatment Framework (RTF) filing with the Minnesota Commission and the North Dakota Public Service Commission (NDPSC) on January 1, 2017. The RTF filing was the agreed upon outcome of a negotiated settlement made as part of Xcel's last rate case before the NDPSC.[1] Xcel also indicated in the filing that the Company would like to address issues associated with the filing at a Commission planning meeting this fall.

The Commission believes that it would be helpful for the Company to discuss issues associated with jurisdictional cost analyses it will be filing with the Commission at a planning meeting. In particular, the Commission would like the Company's perspective on how the following principles could serve as a guide:

1. Recognition that an integrated NSP system has benefits for customers in all states served by that system.

2. Least-cost planning consistent with all applicable Minnesota laws and regulations must continue to drive the Minnesota Commission's resource-related decisions notwithstanding decisions of other states in the NSP system.

[1] NDPSC Case No. PU-12-813, *Order Approving Settlement*, dated March 9, 2016

3. Jurisdictional shares of costs must incorporate all attributes, costs and benefits of the type and timing of resource acquisition, including but not limited to: energy, capacity, grid services including reliability, and the associated short-term and long-term risk, among others.

4. Minnesota ratepayers should only pay their jurisdictional share of costs associated with a resource that serves multiple jurisdictions in NSP's system. If a state declines to bear its share of those costs, that state's ratepayers should not receive the related system benefits.

5. Xcel Energy's communications to each state commission in its NSP system should consistently and accurately characterize the basis for each of the Company's resource decisions.

6. Each proposed alternative for resolving the interjurisdictional issue between Minnesota and North Dakota (or any other states in NSP's system) must include a full cost and rate analysis of the proposal and alternatives. Any filing proposing alternatives to resolve the interjurisdictional issue should include the costs and rate impacts associated with establishing separate operating companies.

Discussion of the above principles would allow the Company to identify any with which it disagrees and explain why, as well as identify any of the above information that it does not anticipate providing in its January 2017 jurisdictional cost filing with the Commission and why.

To set up a time to address these and any other Minnesota cost jurisdictional issues at a Commission planning meeting, please contact Sean Stalpes at sean.stalpes@state.mn.us or 651-201-2252, or Tricia DeBleeckere at tricia.debleeckere@state.mn.us or 651-201-2254.

Sincerely,

Daniel P. Wolf

Daniel P. Wolf
Executive Secretary