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DIRECT TESTIMONY AND SCHEDULES
STEPHEN J. BEUNING

Before the North Dakota Public Service Commission
State of North Dakota

In the Matter of Northern States Power Company,
a Minnesota corporation d/b/a Xcel Energy
Jurisdictional Cost Allocation Matters

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
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I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Stephen Beuning, and my business address is Xcel Energy Services Inc., 1800 Larimer, Suite 1000, Denver, Colorado.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by Xcel Energy Services Inc., the service company for four Xcel Energy Inc. operating companies, including Northern States Power Company, a Minnesota corporation (NSPM or the Company) and Northern States Power Company, a Wisconsin corporation (NSPW). I have been employed by Xcel Energy Services Inc. and its predecessors for more than 33 years. My current job is Director of Market Operations, which I have held since 2004.

Q. PLEASE DESCRIBE YOUR QUALIFICATIONS AND EXPERIENCE.

A. In my current role, I am responsible for procurement of transmission service for the NSP System[1] as well as regional energy market design. As a result, my experience is directly related to the subject matter of my testimony here

[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 Corp.*, FERC Docket No. ER15-1575, LETTER ORDER (June 22, 2015) (unpublished letter order update to the Interchange Agreement).

regarding how transmission service is and may in the future be obtained for the Company's North Dakota jurisdiction. My Statement of Qualifications is attached as Schedule 1.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to provide a summary of the electric transmission service issues and potential costs and risks associated with serving the future energy needs of the North Dakota electric customers in various scenarios. I also support Schedule 8 (the transmission appendix) of the Application and am available to answer questions about it.

Q. PLEASE PROVIDE A SUMMARY OF YOUR TESTIMONY.

A. I provide a high-level description of the transmission system that currently serves the Company's North Dakota customers. From a transmission perspective, the North Dakota jurisdiction is currently responsible for about 5.3 percent of all transmission costs incurred on the NSP System and correspondingly receives about 5.3 percent of all benefits derived from the NSP delivery system.

I discuss some of the complexities in the region related to the number and type of transmission providers who serve in and around North Dakota. These complexities could be important as changing current and settled practices could result in changed relationships and shifts in cost and risk.

I then identify and describe the types of "separation scenarios" that may be available to serve our North Dakota customers in the future and provide a high-level discussion of the potential costs and risks associated with the various scenarios.

Q. WHAT CONCLUSIONS DO YOU DRAW FROM YOUR TESTIMONY?

A. Separating the Company's North Dakota operations from the integrated NSP System will result in both known and unknown costs and risks. Depending upon the separation scenario chosen, a broad range of cost impacts could occur. Recognizing that additional and unforeseen cost and risk impacts could arise during actual implementation, the Company estimates that separating North Dakota customers from the remainder of the NSP System could potentially result in incremental cost shifts between North Dakota customers and the remainder of the system in potentially significant amounts, depending upon the scenario.

Separating the North Dakota jurisdiction will also have a cost impact on customers in other jurisdictions within the larger NSP System. Cost impacts on those customers are not necessarily equal and opposite nor proportionate with respect to relative load share served by the delivery system. While it may seem logical that a cost increase to North Dakota customers would translate into a comparable cost decrease elsewhere, depending upon the nature of the separation, the cost changes may not line up directly.

Q. WHY ARE THE COST IMPACTS ON CUSTOMERS NOT PROPORTIONAL TO THE RELATIVE LOADS?

A. Redesigning the cost allocation of a significant element of the cost of service (transmission) is not as simple as shifting costs in a linear fashion. Redesigning the rate structure to accommodate separation of North Dakota from the remainder of the NSP System will be a complex endeavor that requires multiple changes. It requires redesigning both state and federal rate structures. It requires addressing issues under the MISO Tariff and may require creation of new transmission tariff rate zones. It may require adjusting the retail ratemaking structures and developing an independent North Dakota rate base (*i.e.*, no allocation of system assets located outside of the state) used to develop North Dakota rates.

It will certainly require renegotiation of legacy grandfathered agreements with other industry participants, the results of which cannot be precisely predicted.

All of these types of items will interact with each other and impact on the net cost to customers. While Xcel Energy will endeavor to minimize the net cost impact to all of its customers, we will be required to follow the obligations imposed by tariffs and agreements in allocating costs among various jurisdictions.

II. TRANSMISSION SERVICE

A. Regional Transmission System

Q. PLEASE PROVIDE AN OVERVIEW OF THE REGIONAL TRANSMISSION SYSTEM, FOCUSING ON THE ATTRIBUTES SIGNIFICANT TO A POTENTIAL SEPARATION OF NSP'S NORTH DAKOTA JURISDICTION FROM THE LARGER NSP SYSTEM.

A. NSPM is currently the largest retail electric provider in North Dakota, providing service to three urban areas in the state: (i) Minot, (ii) the Grand

Forks area, and (iii) the Fargo area. These load centers are not contiguous with each other or contiguous with the remainder of the NSP System via transmission facilities owned by NSPM, and are thus considered "load pockets."

NSPM is a transmission-owning member of the Midcontinent Independent System Operator, Inc. (MISO), a FERC-jurisdictional Regional Transmission Organization (RTO). NSPM currently serves the transmission needs for its three North Dakota load pockets through network transmission service obtained under MISO's open access transmission, energy, and operating reserve markets tariff (MISO Tariff). Other individually negotiated pre-MISO transmission agreements, known as "grandfathered agreements" (GFAs), also play a role in the provision of transmission service to our North Dakota customers.

Q. IS THERE ANOTHER RTO IN THE NORTH DAKOTA REGION THAT IS SIGNIFICANT TO THE PROVISION OF TRANSMISSION SERVICE TO NSPM'S NORTH DAKOTA CUSTOMERS?

A. Yes. In addition to MISO, the Southwest Power Pool, Inc. (SPP) is also an RTO established pursuant to FERC Order No. 2000 and administers a transmission tariff and regional energy market in and around North Dakota. As described later in my testimony, the presence of multiple RTOs (MISO and SPP) complicates the transmission service situation in North Dakota.

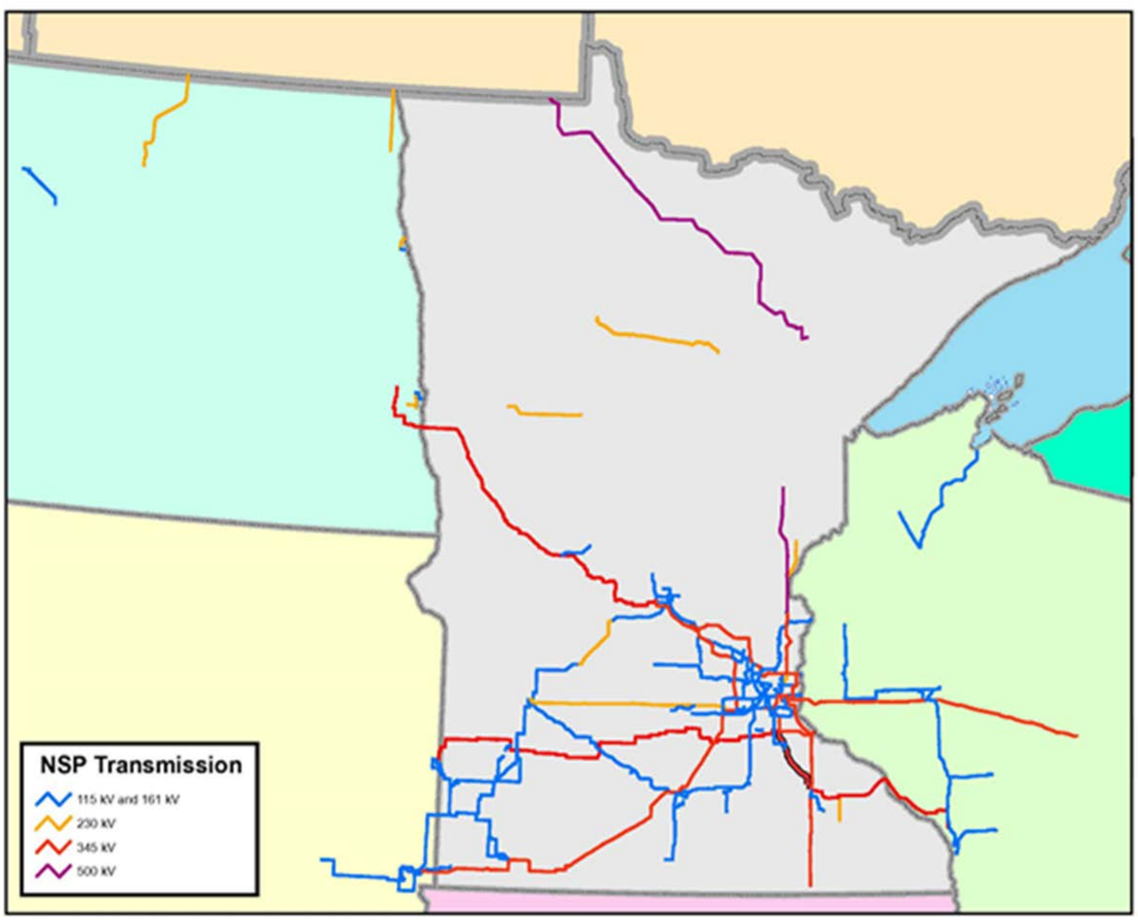
In addition to MISO and SPP, Minnkota Power Cooperative (Minnkota or MPC) has its own independent and unaffiliated transmission system that provides transmission service in areas of Minnesota and North Dakota that are contiguous with NSP's facilities. MPC is not a member of MISO or SPP but instead, operates separately in the region. As described later in my testimony, the presence of Minnkota transmission facilities creates a complication that must be taken into account in assessing the cost and risk of various separation scenarios.

1. *Description of NSP System Transmission*

Q. CAN YOU PROVIDE A HIGH-LEVEL DESCRIPTION OF THE NSP SYSTEM'S TRANSMISSION FACILITIES?

A. Yes. Figure 1, below, depicts the NSP System transmission facilities (115 kV and above).

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



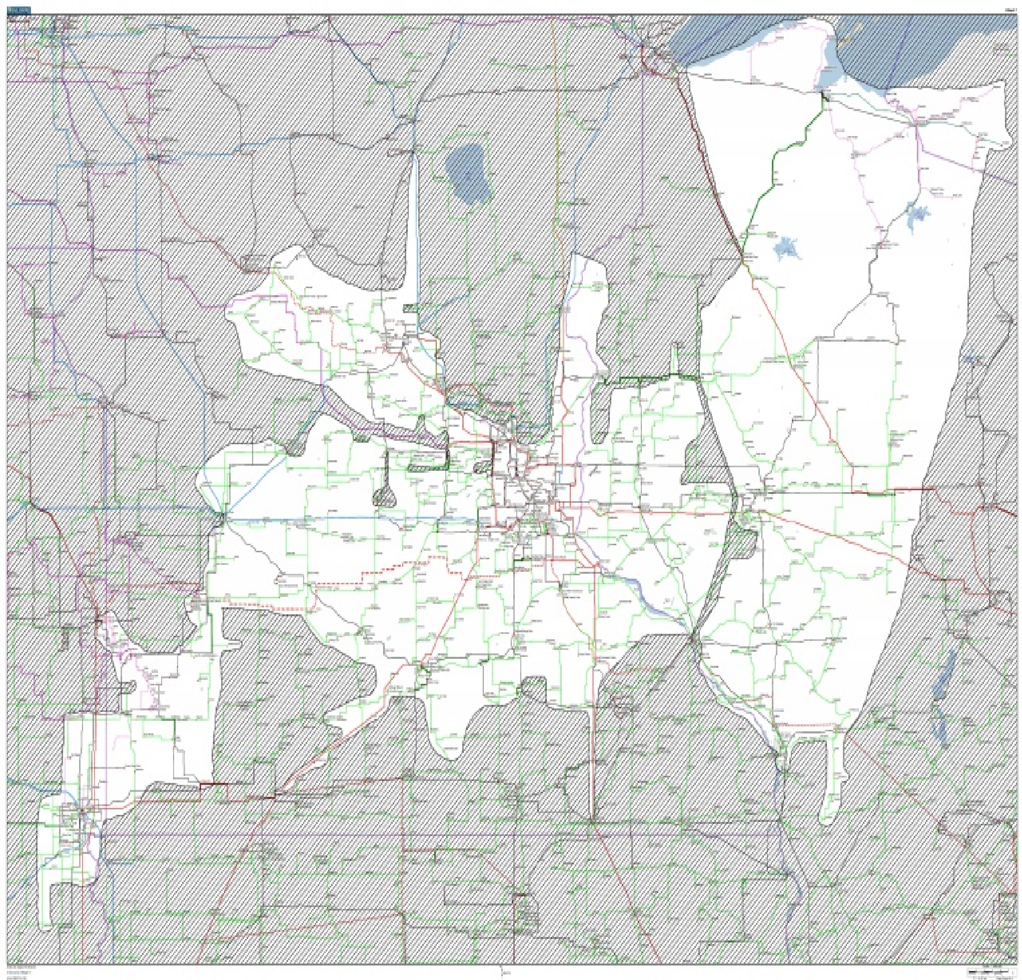
Q. HOW DO NSPM'S NORTH DAKOTA FACILITIES INTERCONNECT WITH OTHER FACILITIES IN THE REGION?

A. The NSP load pockets in North Dakota are geographically distant from the remainder of the NSP System. 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 and controlled by MISO, SPP, or Minnkota under their separate tariffs and regulations, pursuant to distinct contractual mechanism for each entity.

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)[2].

[2] A LBA is a metered boundary on the grid that approximates the historical footprint of utility supply obligations pre-dating the establishment of RTOs. It is used to assign certain operational obligations on the various utilities with facilities in the RTO region.

Figure 2: NSP Local Balancing Authority
(White area)



Q. WHAT IS THE SIGNIFICANCE OF THE FACT THAT THE NSPM LOAD POCKETS ARE NOT LOCATED WITHIN NSPM'S LBA?

A. NSPM transmission facilities do not directly serve the Minot and Grand Forks areas. Each of the three North Dakota load pockets are located adjacent to transmission facilities of other utilities: Minot (adjacent to Great River Energy (GRE), Western Area Power Administration (WAPA), and Basin Electric Power Cooperative (Basin)); Grand Forks (adjacent to Minnkota and WAPA); and Fargo (adjacent to Otter Tail Power Company (OTP), Minnkota, and WAPA). 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 and Fargo areas) include loads on both sides of the North Dakota/Minnesota border served from common transmission facilities. Finally, while these load pockets are served under the MISO Tariff, they are also interconnected to transmission facilities owned by utilities who are members of SPP, a separate RTO. These interconnections with SPP entities do not result in SPP "serving" the delivery needs, but the separate RTO organization brings its own tariff and business practices which can impact NSP as a bordering utility. These conditions specific to the transmission system in and around North Dakota may impact service to North Dakota customers in a separation scenario.

Q. DO THESE IMPACTS CREATE CHALLENGES?

A. Yes. The challenges are complex and may create unforeseen cost impacts and other consequences. As members of MISO, transmission service can be provided to all of our North Dakota load pockets on a non-discriminatory basis. Doing so under changed business structures may, however, require altering how we provide that service.

2. Seams and GFAs

Q. WHAT IS THE SIGNIFICANCE OF NSPM'S TRANSMISSION FACILITIES BEING LOCATED ADJACENT TO DIFFERENT TRANSMISSION OWNING UTILITIES?

A. 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 has implications for providing transmission service to our North Dakota customers.[3]

For example, Basin and 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.

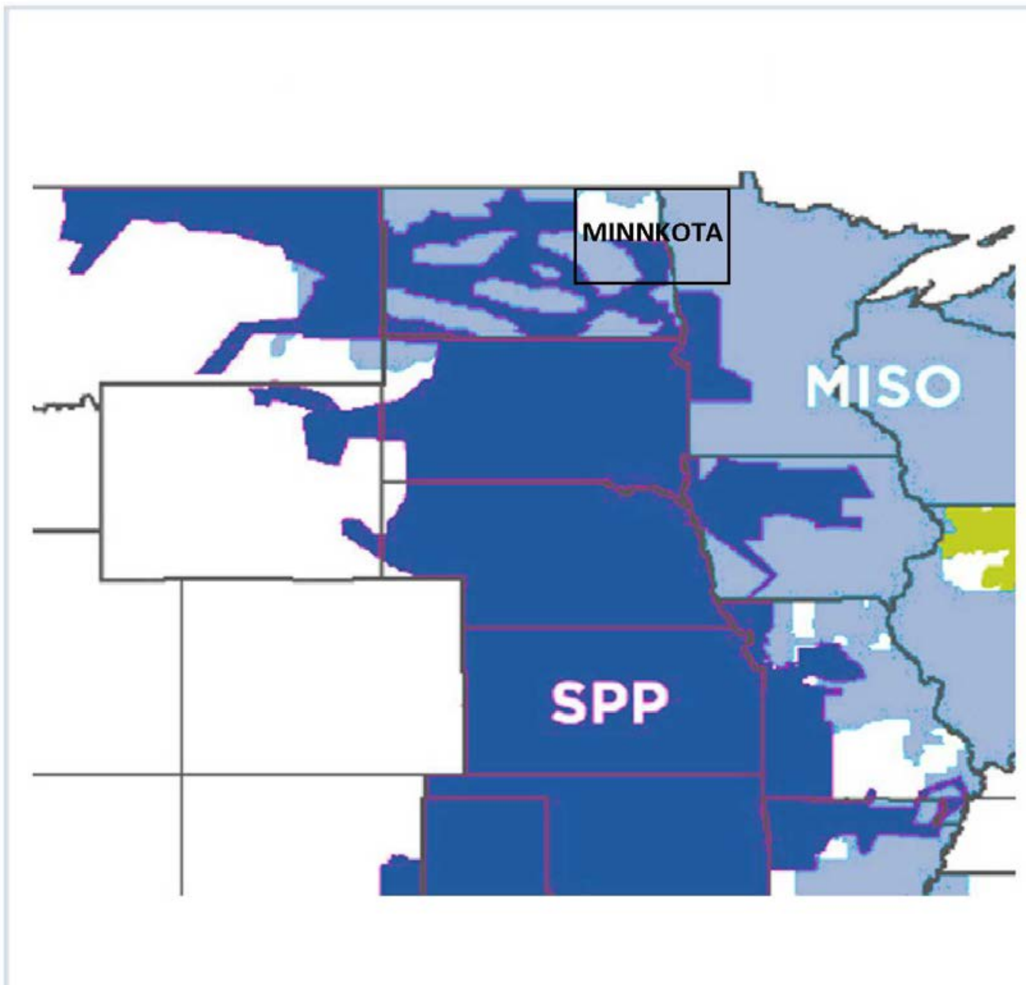
Further, Minnkota has transmission facilities in northeastern North Dakota and northwestern Minnesota that are interconnected to NSPM's facilities. These facilities are important to ensure adequate service to our North Dakota customers, particularly in the Grand Forks area. Minnkota is not a member of 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 depicts the relative relationship of SPP/Minnkota/MISO facilities. The boundaries between these three independent authorities have to be

[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).

managed, introducing potential complications particularly if current relationships are changed.

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



Q. YOU MENTIONED THE PRESENCE OF GFAS UNDER THE MISO TARIFF; ARE THESE GFAS NECESSARY TO SECURE NETWORK SERVICE FOR NORTH DAKOTA CUSTOMERS?

A. The electric delivery service for NSPM customers (including in Minnesota and North Dakota) is procured through the MISO Tariff. It is not necessary for NSPM to schedule energy deliveries separately using transmission service established through any of its GFAs. In all separation scenarios described herein, NSPM anticipates that it will continue to procure network transmission service through the MISO Tariff.

Q. IF TRANSMISSION SERVICE IS PROCURED UNDER THE MISO TARIFF, THEN WHAT RELEVANCE DO THE GFAS HAVE FOR CURRENT AND POTENTIAL FUTURE TRANSMISSION COSTS?

A. 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, 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.

The presence of GFAs, as well as Seams Agreements, (as described later in my testimony) supports the Company's ability to take network service through MISO without incurring pancaked rates for the use of different transmission systems.

Q. HOW ARE SEAMS MANAGED?

A. 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.

Q. DOES NSPM HAVE ANY SEAMS AGREEMENTS WITH MINNKOTA?

A. Minnkota has a series of legacy coordination agreements with its neighboring utilities (including NSPM) that provide rules and protocols for the interface between Minnkota's transmission facilities and those of its neighbors. These GFAs predate FERC's Order Nos. 888 and 2000 requirements for comparably-provided open access transmission service under regional tariffs. Further, Minnkota is not a FERC-jurisdictional investor-owned public utility.

[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).

Q. ARE THE GFAS WITH MINNKOTA STILL NECESSARY UNDER THE MISO TARIFF?

A. Yes. The GFAs with Minnkota remain necessary to coordinate seams, particularly since Minnkota is not a member of any RTO. These agreements date back to the 1960s and provide a mechanism for neighboring utilities with non-contiguous transmission systems to interchange power and transmission service to each other's noncontiguous loads to avoid the need for duplicate transmission facilities.

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 although more recent tariff-based delivery arrangements were superseded by the implementation of individual system or regional tariffs.[5] 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. This ensured a smoother transition to the operation of the regional market and to help ensure utilities could continue efficient

[5] *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).

operations, even if they were not members of MISO or subject to FERC jurisdiction.

Q. WHAT GFAS ARE IMPORTANT TO THE OPERATION OF NSP'S TRANSMISSION FACILITIES SERVING ITS NORTH DAKOTA CUSTOMERS?

A. MISO recognizes close to 500 GFAs, of which NSP is a party to about 50 under the Tariff.[6] 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, Otter Tail Power Company, 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., Otter Tail Power Company, Minnesota Power and Light Company, and Northern States Power Company, July 29, 1966, as amended (Attachment P No. 317);
- *Transmission and Transformation Agreement* between University of North Dakota and Northern States Power Company-Minnesota and Northern States Power Company-Wisconsin, March 20, 1985 (Attachment P No. 364); and
- *Transmission Service Agreement* among Great River Energy (formerly Northern Minnesota Power Association, Rural Cooperative Power Association, and United Power Association), Otter Tail Power Company,

[6] The complete list of those agreements that remain active can be found in Attachment P to the MISO Tariff, available at https://www.misoenergy.org/_layouts/MISO/ECM/Download.aspx?ID=19293 .

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 served from North Dakota's transmission system. *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).

Q. DOES NSPM HAVE OTHER AGREEMENTS WITH UTILITIES AND PROVIDERS IN THE REGION THAT ARE ALSO IMPORTANT TO THE INTEGRATED OPERATION OF THE REGIONAL TRANSMISSION SYSTEM?

A. Yes. The transmission system in and around North Dakota is essentially a patchwork of facilities owned and controlled by a variety of entities. This part of the system developed over time and required contractual arrangements between NSPM and its neighbors to facilitate coordinated operation of the overall electric system in the region. These include coordination agreements with WAPA and Manitoba Hydro, transmission interconnection agreements with neighboring utilities such as OTP, GRE, MPC and others, and transmission service agreements with a variety of entities throughout the region.

Q. PLEASE GIVE AN EXAMPLE OF ONE OF THESE GFA'S THAT REMAINS IMPORTANT TO THE OPERATION OF THE REGIONAL TRANSMISSION SYSTEM.

A. One good example of the importance the GFAs play on the system in North Dakota is GFA 317 listed above. This is the North Dakota – Western Minnesota 230 kV Facilities Coordinating Agreement, which avoids duplication of facilities by allowing several utilities to use the same set of facilities to serve their respective loads. Without this GFA in place, all of the utilities subject to that agreement would risk being required to develop duplicative facilities in the same area.

Another 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."[7] 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.[8] The Stanton Agreement is in the process of being terminated because GRE has announced plans to retire the Stanton generating station. Nevertheless, the congestion hedging entitlements and transmission rights designated under the Stanton

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

[8] GRE owns and operates generation in North Dakota near Minot, but its largest load centers are near 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. This agreement predates MISO and the advent of open access.

Agreement will continue in effect under current MISO policy and will still be available to the parties to assist in serving each other's non-contiguous loads.

B. Transmission Service

1. Current Transmission Service

Q. HOW IS TRANSMISSION SERVICE OBTAINED TO SERVE NSPM'S NORTH DAKOTA CUSTOMERS TODAY?

A. Today, NSPM procures network transmission service for all of its customers throughout the integrated NSP System (including North Dakota customers) by making reservations for service under the MISO Tariff[9].

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

MISO 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) and ancillary transmission services. The zonal rate is based on a revenue requirement for the zonal transmission plant and the loads assigned to the pricing zone. The MISO transmission

[9] And NSP arranges for load delivery under the SPP Tariff for a very small network delivery to NSPM's Berthold, ND customers.

settlements applicable to the NSP pricing zone facilities and loads include both NSP System loads and facilities and third-party loads and facilities.[10]

a. Load Ratio Share

Q. HOW ARE TRANSMISSION COSTS SPREAD AMONG CUSTOMERS GENERALLY?

A. 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.[11] 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.

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[10] The NSP System is also a participant in a NSP Joint Pricing Zone (the NSP JPZ) that includes the costs of certain facilities used for the provision of transmission service to the Fargo and Grand Forks load pockets. In addition, some NSP customer loads take transmission service in pricing zones of other transmission providers. The aggregate of these costs are included in the overall transmission cost of service for the NSP System.

[11] Load-ratio-share means the share of a particular customer group or region compared to the overall NSP System.

Q. IS THE 5.3 PERCENT COST INCURRED BY NORTH DAKOTA CUSTOMERS INDICATIVE OF THE AMOUNT OF TRANSMISSION INVESTMENT IN NORTH DAKOTA?

A. No. The 5.3 percent cost assessed to the North Dakota jurisdiction is based on the jurisdiction's load-ratio share of the overall NSP System. It is not based on actual investment in North Dakota.

The amount of NSP System transmission plant in service located in North Dakota is actually 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 and pay for NSP System facilities from outside North Dakota to receive reliable service. However, the allocation of transmission costs in such a scenario would be under a modified basis to reflect NSPD as a transmission customer under the MISO Tariff, rather than an allocated cost share of the NSP System. This will be discussed in greater detail in this testimony.

b. Pricing Zones Generally

Q. WHAT ARE PRICING ZONES AND HOW DO THEY IMPACT THE COST OF TRANSMISSION TO PARTICULAR CATEGORIES OF CUSTOMERS?

A. Pricing zones are financial concepts intended to ensure transmission costs are levied to loads commensurate with their firm demands on the system and the host utility is reimbursed for its necessary transmission investment. A pricing zone may include facilities or loads that are electrically non-contiguous. A pricing zone may include the loads of multiple utilities' customers. Also, when a pricing zone is established that includes the transmission revenue requirement of multiple transmission providers, it is termed a "Joint Pricing Zone" (JPZ) as the revenue requirement of the providers is pooled for allocation to customer loads within the zone.

Q. HOW DO PRICING ZONES WORK FOR XCEL ENERGY'S NORTH DAKOTA CUSTOMERS?

A. In the case of NSPM's North Dakota operations, customers in Fargo and 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 the GRE pricing zone to address GRE's significant transmission infrastructure in that area.

In a JPZ, participants such as NSPM and GRE have a transmission revenue-sharing arrangement to reflect their respective transmission investment used to serve customers in that area. This simply means that NSPM's customers in the Minot area are charged a transmission rate that includes reimbursement for GRE's transmission investment in the area, as well as the investments of other transmission owners in that area, since those investments are important to the delivery service provided to those customers.

2. *Potential Future Transmission Service*

Q. HAS THE COMPANY CONSIDERED HOW TRANSMISSION SERVICE WOULD WORK IN POTENTIAL SEPARATION SCENARIOS?

A. At a high level, yes. However, there are sufficient unknowns and variables in the operation of the transmission system that it is not possible to state definitively how a given separation scenario would impact particular customer groups.

Q. WHAT DO YOU MEAN?

A. 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, including the seams and GFAs identified earlier in my testimony. The presence and interaction of NSPM's transmission facilities with other MISO facilities, SPP facilities, Minnkota facilities and the rights established under the various GFAs all impact how future transmission service costs could be allocated.

Q. IS IT POSSIBLE TO KNOW WITH CERTAINTY HOW THE SEAMS AGREEMENTS (AND GFAS) WILL IMPACT COST ALLOCATION TO THE NORTH DAKOTA JURISDICTION IN A SEPARATION SCENARIO?

A. Not entirely. While we can provide good faith estimates of how we think costs could flow in various separation scenarios, actual results may differ for a variety of reasons, including differing interpretations of Seams Agreements and GFAs, difficulties or costs imposed in assigning the legacy GFAs to the North Dakota jurisdiction, charges imposed for using the transmission facilities of another entity, and other potential regulatory changes. Further, to the extent GFAs or other existing agreements need to be assigned or amended, we would require the agreement of our counterparties to those agreements which materially impacts our ability to definitively provide cost estimates. As a result, all cost estimates contained in this testimony should be viewed as good faith estimates subject to change as circumstances develop.

III. SEPARATION SCENARIOS

Q. DID THE COMPANY ANALYZE ANY PARTICULAR SEPARATION SCENARIOS FOR THIS CASE?

A. Yes. Several separation scenarios may be imagined, 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. Each separation scenario creates specific issues that may change the costs and risks associated with transmission service.

Q. PLEASE LIST THE SEPARATION SCENARIOS REVIEWED AS PART OF THE APPLICATION.

A. The Company identified four basic scenarios for discussion. These separation scenarios range from essentially maintaining the status quo to formal "legal separation" and a number of variations. Formal legal separation also has a number of potential variations, as well. They are:

1. *Regulatory Alignment*: 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.

2. *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. From a transmission perspective nothing would need to change.

3. *Pseudo Separation:* This scenario would allow the system to be operated as if North Dakota is a separate operating company (with its own cost centers and policy preferences) while retaining the current formal corporate structure. In this scenario, 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.

4. *Legal Separation:* Legal separation would result in the Company creating a separate operating entity (NSPD) to hold specified North Dakota assets and provide service to the North Dakota jurisdiction. Legal separation presents a series of costs, risks and complications depending upon how the separation is structured. Three legal separation scenarios were reviewed:
    a. *Transmission Dependent Utility Scenario;*
    b. *Joint Pricing Zone Scenario; and*

c. Separate NSPD Pricing Zone Scenario.

Each of the separation scenarios identified above present unique issues for consideration. Issues associated with each scenario are described below.

Q. HAS THE COMPANY UPDATED ITS SEPARATION ANALYSIS SINCE THE INITIAL FILING?

A. Yes. In discovery in this proceeding, the Company provided an update to its analysis and provided both refined scenarios and updated cost estimates for them. I have provided a copy of the Company's responses to NDPSC IR 2-011 through 2-014 as Schedule 2 of my Direct Testimony. I will provide a discussion of the transmission scenarios in my testimony, as well as the refined scenarios described in the Company's discovery responses.

The Company further analyzed the transmission service costs as summarized in my Direct Testimony. This updated financial analysis focuses on the scenario of converting NSPD to a transmission-dependent utility (TDU) that takes delivery service from NSPM. This analysis summarizes the projected cost shift in that case.

Q. DOES YOUR ANALYSIS REPRESENT THE ACTUAL IMPACT TO RETAIL ELECTRIC RATES FROM THE DIFFERENT SEPARATION SCENARIOS?

A. No. My analysis presents only the change in MISO expenses and revenues that could occur in the various separations scenarios. My analysis does not include the impact of any changes to retail transmission related rate base that could occur or related to recovery of transmission O&M and other related costs through retail rates. For example, in the TDU scenario, the elimination of transmission assets to NSPD will substantially change retail rates and change the cost structure as cost elements such as depreciation are removed from retail rates. Company witness Mr. Burdick provides retail rate impact estimates in his Direct Testimony.

1. Regulatory Alignment

Q. WHAT IS "REGULATORY ALIGNMENT"?

A. This is a scenario that roughly approximates the status quo. In the Company's response to NDPSC IR 2-011 (Exhibit __SJB-1), Schedule 2, we refer to this as the "Benchmark Case" since it represents current conditions and provides a basis for comparisons with a variety of potential future states. Company witness Mr. Richard D. Starkweather discusses this further in his direct testimony.

Q. PLEASE SUMMARIZE THE IMPACT OF ACHIEVING REGULATORY ALIGNMENT ON THE TRANSMISSION ISSUES YOU DISCUSS.

A. Under current circumstances, North Dakota customers 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. North Dakota customers reap the pro rata (5.3 percent) share of those credits and offsetting revenues. In a Regulatory Alignment scenario, this status quo would be maintained.

2. Proxy Pricing

Q. WHAT IS THE "PROXY PRICING" SCENARIO?

A. This scenario was identified in our Application. Under this scenario, it is likely (though not assured) that transmission could continue to be served on an integrated basis as it is today. This scenario could present variable outcomes depending upon how the proxy pricing is structured and how the NSP System evolves. Mr. Starkweather discusses this further.

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.

3. Pseudo Separation

Q. WHAT IS THE "PSEUDO SEPARATION" SCENARIO?

A. 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. 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 with MISO to make transmission service reservations and payments applicable to the entire system. Further, NSPM would remain the signatory and responsible party to the various GFAs and other agreements that would be needed to effect service to our North Dakota customers. Mr. Starkweather discusses this further.

Q. WHAT ARE THE BENEFITS AND CHALLENGES OF PSEUDO SEPARATION FROM A TRANSMISSION SERVICE PERSPECTIVE?

A. This type of structure was described in our Application. 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 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 today 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, however, 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.

4. Legal Separation

Q. WHAT IS "LEGAL SEPARATION"?

A. Legal separation is exactly what the name suggests. It contemplates separating the North Dakota jurisdiction into a separate legal entity with a separate obligation to serve North Dakota customers. Legal separation could be accomplished in a number of forms and could be structured in a variety of ways to accomplish the desired level of separation.

Q. IS THERE MORE THAN ONE WAY TO ACCOMPLISH LEGAL SEPARATION?

A. Yes. As I mentioned above, the Company considered three legal separation scenarios involving the creation of a new NSPD operating company. In our responses to NDPSC IR 2-011 through 2-014 (Schedule 2) we expanded upon and refined some of these scenarios. Each is discussed below and each carries potential benefits, costs, and risks.

To implement Legal Separation, 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 hedging value of the Stanton Agreement remains available to North Dakota customers even after the Stanton Agreement is terminated. However, that outcome would ultimately be determined by negotiations with these other parties and would require FERC approval and cannot be guaranteed.

a. Transmission Dependent Utility Scenario

Q. PLEASE SUMMARIZE THE TDU SCENARIO.

A. In this scenario, NSPD would be established to hold a minimal amount of assets. This scenario is depicted in Schedule 2. Generally speaking, NSPD would hold distribution assets located in North Dakota directly used to serve North Dakota customers. NSPD could also own North Dakota-based generation, although that would not be required and is not considered for this scenario. NSPM would retain generation sufficient to serve the system (and could retain North Dakota-based generation depending upon how NSPD is finally structured).

From a transmission perspective, NSPM would retain the transmission facilities located in North Dakota (as today) and NSPM would operate NSPD as a TDU with no owned transmission assets and taking service under the MISO Tariff[12]. This transaction structure would result in NSPD operating as a distribution-only utility.

Q. WHAT ARE THE BENEFITS OF STRUCTURING NSPD AS A TRANSMISSION DEPENDENT UTILITY?

A. In this scenario, NSPM would retain all contractual rights and obligations it has today. NSPD would take tariffed MISO network transmission service for each of the three load pockets. This would create certainty and relative simplicity in the way transmission costs are assessed.

[12] And, as mentioned previously, under the SPP Tariff for a very small network supply to its Berthold, ND customers.

The transmission charges to NSPD would be based on the MISO Tariff settlements including inputs from NSP System transmission formula rates (and the formula rates of the other entities in the NSP Joint Pricing Zone) using FERC ratemaking principles rather than the traditional retail cost of service model. NSPD would be charged the applicable zonal rate and would be responsible for MISO administrative and other fees (e.g., applicable MISO Schedule 26/26A regional charges) in proportion to its use. The applicable MISO Schedule 26A rate for the Red River Valley loads would remain entirely with NSPD rather than being averaged into the NSP System costs. The NSPD Minot area load settlement under the MISO Tariff would continue under the GRE JPZ.

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 rates for NSPD would therefore have no direct transmission revenue requirement or credits for service sold, but instead would simply reflect the costs of transmission invoice settlements under the MISO Tariff.

Q. WHAT ARE THE COSTS AND RISKS ASSOCIATED WITH STRUCTURING NSPD AS A TDU?

A. The Company recognizes that NSPD taking transmission as a TDU would result in transmission costs being incurred differently than today. In our Application, we estimated that this would result in a net transmission cost increase to NSPD compared to today's paradigm in the range of net $2 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.

Further analysis has shown that the cost shift is much more significant than initially thought. I summarize the current analysis below.

Departing from the load-ratio share allocation (which provides North Dakota customers with 5.3 percent of the costs and benefits of the overall delivery system), results in cost shifts. In the TDU scenario, a $14 million-per year decrease in revenues for NSPD, and a $20 million-per year increase in expenses for NSPD; or a total of $34 million-per year gross increase for NSPD for transmission service. This analysis does not account for the reduction in retail rates that would result from the removal of transmission rate base and O&M costs, including depreciation expense. The actual impact to customers from this scenario is addressed by Mr. Burdick in his Direct Testimony and is likely to be in the $5-6 million-per year range.

Other costs such as the direct assignment of OTP Schedule 26A or any costs incurred through intervention of neighboring utilities would also add to this impact. However, I believe this scenario also results in reduced risks for NSPD associated with transfer of GFA-based delivery entitlements when compared to scenarios where NSPD assumes ownership of transmission assets and accepts assignment of the GFAs.

Q. ARE THERE OTHER ISSUES ASSOCIATED WITH THIS SCENARIO?

A. Yes. To convert NSPD into a TDU would require realigning the existing contractual relationships NSPM has with its neighbors and ultimately would require FERC approval. We cannot fully predict the challenges and potential costs associated with this realignment.

b. Joint Pricing Zone Scenario

Q. PLEASE DESCRIBE THE JOINT PRICING ZONE SCENARIO.

A. This scenario described in the Application is roughly equivalent to our refined analysis in Schedule 2. In this scenario, the North Dakota jurisdiction is split from NSPM into a separate NSPD operating company. The transmission assets physically located in North Dakota would be transferred to NSPD, making NSPD a free-standing transmission/distribution utility that may or may not own generation.

A MISO rate structure would need to be developed to allocate costs between NSPM and NSPD based on the respective ratios of transmission investment and network demand within the zone. This scenario would require potentially complex implementation of MISO Tariff provisions to develop a joint pricing zone that accommodates the new NSPD entity. Further, NSPM would need to renegotiate a number of preexisting agreements and obtain FERC approval to accommodate splitting the North Dakota transmission activities from the NSP System.[13]

[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.

Q. PLEASE SUMMARIZE THE CHARACTERISTICS OF NSPD IN THIS SCENARIO.

A. In this 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]

All of these changes would require renegotiation of existing agreements 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 GRE JPZ and NSP JPZ agreements would need to affirmatively consent to this change. In the event that this scenario could result in costs being shifted from one utility or state to others, obtaining consent to make this change could be challenging.

[15] Note that FERC approval would be required for the transfer of facilities to NSPD, the modifications of legacy agreements, and any coordinating agreements between NSPD and NSPM.

Q. WHAT ARE THE COSTS AND RISKS OF PURSUING A JOINT PRICING ZONE STRUCTURE?

A. Even with the transfer of North Dakota transmission assets into NSPD, the resulting operating company would be very small.

Further, the allocation of NSP pricing zone costs would 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 Scenario

Q. WHAT IS THE SEPARATE NSPD PRICING ZONE SCENARIO?

A. This scenario would result in completely separating NSPD from the remainder of the NSP System and allowing NSPD to develop its own costs and cost recovery mechanisms. This scenario is described in Schedule 2. It would significantly change the way transmission costs and risks are allocated compared with the way today's costs and risks are allocated.

Q. WHY WOULD CREATING A SEPARATE NSPD PRICING ZONE FUNDAMENTALLY CHANGE HOW TRANSMISSION IS PROVIDED TO NORTH DAKOTA CUSTOMERS?

A. 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.[16]

Once again, this scenario would require renegotiation of agreements with our neighbors 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.[17]

Q. WHAT STEPS WOULD NEED TO BE TAKEN TO EFFECTUATE THIS SCENARIO?

A. To effectuate a separate NSPD transmission pricing zone, the Company would require reallocating a portion of the existing NSP System costs to ensure that North Dakota customers receive an appropriate and fair allocation of the overall transmission system investment. Since this scenario involves creating a separate NSPD pricing zone, the mechanism by which the ongoing cost allocation for an appropriate share of the NSP System would be made has not yet been established and was not conceived at the time this testimony was prepared. Other issues, such as potential for compensation to other neighboring utilities would need to be considered.

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[16] 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.

[17] 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.

Q. WHAT ARE THE BENEFITS OF COMPLETELY SEPARATING NSPD FROM THE SYSTEM FROM A TRANSMISSION PERSPECTIVE?

A. This scenario creates transmission independence for NSPD with respect to future system planning, expansion and cost allocation. Such a posture may be consistent with some policy judgments about maintaining separate operations within the North Dakota jurisdiction. Once set up (and assuming it is feasible) the NSPD operating company would stand on its own from a transmission planning, expansion and cost-allocation perspective. However NSPD's proximity with other transmission owners' systems leaves open the possibility of incurring future cost responsibility on such other systems.

Q. WHAT ARE THE COSTS AND RISKS OF COMPLETELY SEPARATING NSPD FROM THE SYSTEM?

A. As previously noted, the physical assets located in North Dakota do not currently reflect the pro rata share of transmission assets based on a load-ratio share of the overall system. Separation into a NSPD pricing zone would create a situation where existing tariff mechanism could "strand" or "cost-shift" this overinvestment by NSPM relative to the NSPD obligations and may result in the need to develop appropriate mechanisms to recoup this investment share obligation of the NSPD entity outside the currently-established MISO tariff methods.

In addition, the Company's Fargo and Grand Forks load pockets are largely adjacent to OTP's, Minnkota's and WAPA's transmission facilities respectively. In the scenario where a North Dakota-specific pricing zone is implemented, there is a risk that others may take the position NSPD cannot serve these load pockets using NSPD's own zonal facilities and claim NSPD is dependent upon neighboring facilities in those areas. 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 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.

Q. HAS THE COMPANY UPDATED ITS ANALYSIS OF THE POTENTIAL COST ASSOCIATED WITH OPERATING NSPD AS A SEPARATE TRANSMISSION OWNER WITH ITS OWN PRICING ZONE?

A. 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 transmission cost increase for NSPD 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.

IV. ADDITIONAL ISSUES

Q. HAS THE COMPANY IDENTIFIED OTHER ISSUES THAT ARE PERTINENT FOR CONSIDERATION?

A. Yes. There are two basic additional issues that should be kept in mind as having potential downstream importance in a separation scenario. They are:

1. Incurring and sharing potential SPP Seams Costs; and
2. Incurring and sharing potential Minnkota system costs.

While neither of these issues are certain to occur or can be completely quantified, they both present potential risks that stakeholders may want to consider in assessing whether and how to separate North Dakota from the larger NSP System. These issues are identified in Schedule 8 of the Company's Application. I will summarize the issues here and am available to answer questions about them.

Q. WHAT IS THE NATURE OF THE RISK OF INCURRING SPP SEAMS COSTS?

A. A utility located at the seam between MISO and SPP must be mindful of the interaction between the MISO Tariff and the corresponding SPP tariff and the potential that this could result in costs being imposed on the utility through operation of the FERC-approved JOA.

Q. WHAT IS THE NATURE OF THE RISK OF INCURRING MINNKOTA COSTS?

A. NSP's load pocket in the Grand Forks and Fargo areas are supported by transmission assets owned by Minnkota via the GFA NSPM has with Minnkota. This area of northeastern North Dakota and northwestern Minnesota lies predominantly within Minnkota's retail service territory. This GFA enables NSP power supply transmitted between Grand Forks and Fargo to cross the Minnkota system.[18]

Minnkota is not a member of MISO and it is not a member of SPP. It is an independent entity that is not bound by the MISO (or SPP) tariff. As a cooperative, Minnkota is not subject to FERC jurisdiction. This means that Minnkota has additional latitude in implementing its requirements compared to utilities who are members of a FERC-authorized RTO.

As a result, maintaining the 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

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

inapplicable to future circumstances, the North Dakota jurisdiction could potentially need to obtain alternative transmission capacity.

V. CONCLUSION

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?
A. Yes, it does.

Northern States Power Company

Stephen J. Beuning
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Cell Phone 612-366-5976
Home Phone 303-926-0592

Present Position: Director, Market Operations, Xcel Energy Inc.
(since April 2004)

Xcel Energy is a multi-state electric and gas utility holding company, with a combined system electric generating capability of approximately 31,000 MW.

I direct staff on behalf of the Xcel Energy utility operating companies: Northern States Power (MN & WI), Southwestern Public Service, and Public Service Colorado. Northern States Power operates in the MidContinent ISO ("MISO") and Southwestern Public Service operates in the Southwest Power Pool ("SPP"). The Public Service Colorado operating company is located in the Western Interconnection which today is a bilateral wholesale energy market.

My present areas of responsibility include:

- ✓ Transmission tariff rights management, including financial transmission rights and seams coordination policy
- ✓ Regional energy market design, including congestion management and renewable integration
- ✓ Regulatory and policy interface on wholesale markets and market monitor referrals
- ✓ Regulatory support for retail and wholesale rate cases

Education: Bachelor of Science in Electrical Engineering; University of Minnesota, June 1984

Ludwig-Maxmillian Universitaet Summer Course, Munich, Germany

Masters of Business Administration
Colorado State University, May 2013

Professional Activity (current):
Edison Electric Institute Supply Policy Task Force

Prior professional activities include: Transitional Committee/Board Member, California ISO Energy Imbalance Market (CAISO-EIM); Board President of the Utility Variable-Generation Integration Group (UVIG); stakeholder leadership roles with Western Electricity Coordinating Council (WECC), North American Electric Reliability Corporation (NERC), MISO, MAPP, SPP, and others.

Past Employment Positions Include:

- ✓ **Manager, Transmission Operations, Xcel Energy Markets** *(August 2001 – April 2004)*
- ✓ **Senior Operations Consultant, Xcel Energy Markets** *(July, 1999 – August 2001)*
- ✓ **Transmission Services Project Manager, Northern States Power (NSP)** (*March 1998 – July 1999)*
- ✓ **Director, Power Marketing, Cenerprise, Inc., a subsidiary of NSP** (*March 1995 – March 1998)*
- ✓ **Wholesale Account Manager, NSP** (*February 1993 - March 1995)*
- ✓ **Supervisor, Operation Coordination, NSP** (*December 1991 - February 1993)*
- ✓ **Transmission System Operations Engineer, NSP** (*June 1984 - December 1991)*

Recent Publications/Presentations:

- King, J.; Kirby, B.; Milligan, M.; Beuning, S (May 2012): Operating Reserve Reductions from a Proposed Energy Imbalance Market with Wind and Solar Generation in the Western Interconnection. 90 pp.; NREL Report No. TP-5500-54660, http://www.nrel.gov/docs/fy12osti/54660.pdf
- IEEE Power & Energy Magazine, Oct. 2011 – Balancing Act, by Mark Lauby, Daniel Brooks, Stephen Beuning, Jay Caspary, William Grant, Brendan Kirby, Michael Milligan, Mark .Malley, Mahendra patel, Richard Piwko, Pouyan Puurbeik, Dariush Shirmohammadi, & J. Charles Smith
- King, J.; Kirby, B.; Milligan, M.; S. Beuning (2011). Flexibility Reserve Reductions from an Energy Imbalance Market with High Levels of Wind Energy in the Western Interconnection. 100 pp.; NREL Report No. TP-5500-52330, http://www.nrel.gov/docs/fy11osti/52432.pdf
- M. Milligan, B. Kirby and S. Beuning: Potential Reductions in Variability with Alternative Approaches to Balancing Area Cooperation with High Penetrations of Variable Generation; Management Report, National Renewable Energy Laboratory NREL/MP-550-48427, August 2010
- IEEE Power & Energy Magazine, Oct. 2010 – The Wind at Our Backs, by J. Charles Smith, Stephen Beuning, Henry Durrwachter, Erik Ela, David Hawkins, Brendan Kirby, Warren Lasher, Jonathan Lowell, Kevin Porter, Ken Schuyler and Paul Sotkiewicz
- Eugene Danneman & Stephen Beuning: Wind Integration – System & Generation Issues, Proceedings of Power2010, July 13-15 2010, Chicago, Illinois
- M. Milligan, B. Kirby and S. Beuning: Combining Balancing Areas’ Variability: Impacts on Wind Integration in the Western Interconnection, presented at WindPower 2010, Dallas, TX, (2010)

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Xcel Energy			
Docket No.:	PU-12-813, PU-13-194, PU-13-195, PU-13-706, PU-13-707, PU-13-708, PU-13-742, PU-13-743	Data Request No.	2-11
Response To:	North Dakota Public Service Commission Commission Advocacy Staff		
Requestor:	PA Consulting Group		
Date Received:	May 10, 2017		

Question:

In the Company's response to MN Public Utilities Commission Information Request No. 10 in Docket No. E002/M-16-777, the Company states "As described in Schedule 8 of the RTF application, the issue of transmission service to a new North Dakota-based operating company is complex and there are several potential outcomes…" Please provide all analysis prepared by the Company of these potential outcomes and the associated cost implications for North Dakota and Minnesota.

Response:

Please see Schedule 8 to the Company's December 31, 2016 RTF Application for a discussion of the various transmission issues related to establishing a separate operating company to serve Xcel Energy's North Dakota electric customers. As noted in Schedule 8, there are various outcomes related to transmission service depending on if the new operating company is transmission dependent (*i.e.* distribution only) or owns its own transmission facilities. **[Trade Secret Begins…**

…Trade Secret Ends]. Consequently, provision of transmission service to a new North Dakota operating company is based on many variables, many of which are unknowable at this time.

As discussed on page 53 of the RTF Application, the Company has been utilizing a $5 million high-level place holder to account for the potential cost impacts of providing transmission service to a new operating company. The Company developed this $5

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million place-holder amount by analyzing different potential scenarios and assumptions regarding potential transmission service outcomes as well as currently contemplated additional transmission investments in the Minot area (*see* Case No. PU-16-644) **[Trade Secret Begins…**

… Trade Secret Ends]. The results of the Company's analysis identified a range of outcomes from approximately $800,000 in cost savings to our North Dakota customers to approximately $18,000,000 in additional costs to our North Dakota customers. Consequently, the Company has been using a $5 million place-holder amount as an amount reasonably within this large range of potential outcomes. The Company's analysis is provided as Attachment A.

Attachment A and other portions of this response have been redacted and designated as "Trade Secret." The redacted portions contain "trade secret" information that is proprietary financial information of the Company as it derives independent value from not being generally known, is not ascertainable by other persons, can be used by other for a variety of purposes, and is maintained as confidential by the Company. Thus, Xcel Energy maintains this information as trade secret. This designation is made pursuant to the Company's Application for Trade Secret Protection dated February 13, 2017.

Preparer:	William K. Raihala
Title:	Transmission Analyst
Department:	Market Operations
Telephone:	612-330-7563
Date:	May 24, 2017

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Case No. PU-12-813
NDPSC Data Request No. 2-11 RTF
Attachment A, pps 1-21

Summary of North Dakota Transmission Scenarios

Attachment A is Trade Secret in its entirety as it contains trade secret information that is proprietary financial information of the Company as it derives independent value from not beinggenerally known, is not ascertainable by other persons, can be used by others for a variety of purposes, and is maintained as confidential by the Company. This designation is made pursuant to the Company's Application for Trade Secret Protection dated February 13, 2017.

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Xcel Energy

Docket No.:	PU-12-813, PU-13-194, PU-13-195, PU-13-706, PU-13-707, PU-13-708, PU-13-742, PU-13-743	Data Request No.	2-12
Response To:	North Dakota Public Service Commission Commission Advocacy Staff		
Requestor:	PA Consulting Group		
Date Received:	May 10, 2017		

Question:

In the Company's response to MN Public Utilities Commission Information Request No. 10 in Docket No. E002/M-16-777, the Company states "The same is generally true for service company allocations. While the costs for some services currently billed to NSPM may shift to a new North Dakota operating company providing cost savings…" Please indicate what specific costs the Company is referring to, how those costs are allocated now between the different state utilities, and how the cost allocation would change under the referenced "shift".

Response:

Like most large utility holding companies, Xcel Energy Inc. utilizes a service company subsidiary, Xcel Energy Services Inc. (XES), to provide common services to its subsidiary companies including utility operating companies such as Northern States Power Company, a Minnesota corporation (NSPM) which provides retail electric service to North Dakota and its affiliated operating companies; Northern States Power Company, a Wisconsin corporation (NSPW); Southwest Public Service Company (SPS); and Public Service Company of Colorado (PSCo). Examples of the corporate services XES provides include managerial, financial, legal, engineering, marketing, auditing, human resources, marketing, tax, communications, network and IT services.

XES bills NSPM for its services under a Service Agreement between XES and NSPM, which is included as Attachment A. Under the Service Agreement, XES costs that can be directly identified as pertaining to a specific operating company are direct assigned to that operating company. Other costs are allocated to the various operating companies when a service company cost supports more than one affiliate. A description of the XES allocation methodology for each service is provided in the Allocation Ratios section of Appendix A of the Service Agreement. Allocation factors include the numbers of employees, amounts of assets, and amounts of revenues in each affiliate.

Should a new operating company be established to provide electric service to our North Dakota customers, a new Service Agreement between the new operating company and XES would direct assign costs incurred on behalf of the new operating company and also allocate to the new operating company common costs consistent with the allocation ratios established in the Service Agreement. It is first necessary to establish how the new operating company will be structured, how it will be staffed, what assets it will own, and other items so that it can be possible to fully calculate the "cost shifts" that would result. To provide context for the impacts of the potential changes in XES costs, our RTF Application provided a high level estimate of the impact of possible changes to service company costs. These estimates will be further refined should the outcome of this proceeding result in Xcel Energy establishing a separate operating company to serve its North Dakota customers.

Preparer:	Joanna Yugo
Title:	Principal Rate Analyst
Department:	Revenue Analysis
Telephone:	612-215-4633
Date:	May 24, 2017

FOURTH AMENDMENT TO SERVICE AGREEMENT
BETWEEN
NORTHERN STATES POWER COMPANY,
a Minnesota corporation
AND
XCEL ENERGY SERVICES INC.

THIS FOURTH AMENDMENT TO SERVICE AGREEMENT ("Fourth Amendment") is made and entered into as of the 14th day of December 2015, by and between Northern States Power Company, a Minnesota corporation ("Client Company") and Xcel Energy Services Inc. ("Service Company").

WHEREAS, Client Company and Service Company entered into that certain Service Agreement dated as of August 15, 2004 ("Original Service Agreement");

WHEREAS, the Original Service Agreement has been amended from time to time;

WHEREAS, the Original Service Agreement was most recently amended by a Third Amendment to Service Agreement dated as of May 28, 2015 and filed with the Minnesota Public Utilities Commission in Docket No. E,G002/AI-15-536 ("Third Amendment" and the Original Service Agreement as amended, the "Amended Service Agreement");

WHEREAS the Amended Service Agreement is subject to the jurisdiction of state utility commissions and the Federal Energy Regulatory Commission;

WHEREAS, additional amendments to the Amended Service Agreement are necessary to recognize new allocation methodologies that are being implemented by the Client Company and Service Company, consistent with the Minnesota Public Utilities Commission's final order in Docket No. E,G002/AI-15-536, dated November 19, 2015;

WHEREAS, Client Company and Service Company mutually desire, by means of this Fourth Amendment, to further amend the Amended Service Agreement as set forth below;

NOW THEREFORE, for and in consideration of the mutual covenants contained in this Fourth Amendment and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the par-ties agree as follows:

1. Appendix A to the Amended Service Agreement is deleted in its entirety and replaced with the contents of Schedule 1 to this Fourth Amendment.

2. Except as expressly amended by this Fourth Amendment, all other provisions of the Amended Service Agreement remain in full force and effect.

3. This Fourth Amendment to Service Agreement shall be subject to all necessary and prudent regulatory approvals.

[SIGNATURE PAGE FOLLOWS]

IN WITNESS WHEREOF, the parties hereto have executed this Fourth Amendment to Service Agreement to be executed as of the date and year first above written.

XCEL ENERGY SERVICES INC.

BY: ______________________________
Name: Judy M. Poferl
Title: Senior Vice President, Corporate Secretary and Executive Services

NORTHERN STATES POWER COMPANY,
A MINNESOTA CORPORATION

BY: ______________________________
Name: Christopher B. Clark
Title: President

[SIGNATURE PAGE TO FOURTH AMENDMENT TO SERVICE AGREEMENT]

Appendix A

DESCRIPTION OF SERVICES TO BE PROVIDED BY XCEL ENERGY SERVICES INC. AND DETERMINATION OF CHARGES FOR SUCH SERVICES TO THE OPERATING COMPANIES AND OTHER AFFILIATES

Description of Services Provided

A description of the services provided by Xcel Energy Services is detailed below. Identifiable costs will be directly assigned to the Operating Companies and other affiliates. For costs that are for services of a general nature and cannot be directly assigned, the method of allocation is described below for each service provided.

*a) Executive Management Services**

Description - Represents charges for Xcel executive management and services, including, but not limited to, officers of Xcel.

Method of Allocation - Executive Management indirect costs will be allocated based on a three-factor formula that is comprised of the average of the Revenue Ratio, the Employee Ratio and the Total Assets Ratio.

*b) Investor Relations**

Description - Provides communications to investors and the financial community. Coordinates the transfer agent and shareholder record keeping functions and plans the annual shareholder meeting.

Method of Allocation - Investor Relations indirect costs will be allocated based on a three-factor formula that is comprised of the average of the Revenue Ratio, the Employee Ratio and the Total Assets Ratio.

*c) Internal Audit**

Description - Reviews internal controls and procedures to ensure assets are safeguarded and transactions are properly authorized and recorded. Evaluates contract risks.

Method of Allocation - Internal Audit indirect costs will be allocated based on a three-factor formula that is comprised of the average of the Revenue Ratio, the Employee Ratio and the Total Assets Ratio.

*d) Legal**

Description - Provides legal services related to labor and employment law, litigation, contracts, rates and regulation, environmental matters, real estate and other legal matters.

Method of Allocation - Legal indirect costs will be allocated based on a three-factor formula that is comprised of the average of the Revenue Ratio, the Employee Ratio and the Total Assets Ratio.

*e) Claims Services**

Description - Provides claims services related to casualty, public and company claims.

Method of Allocation - Claims Services costs will be direct charged. Any costs that cannot be direct charged will be allocated using the General Allocator.

*f) Corporate Communications**

Description - Provides corporate communications, speech writing and coordinates media services. Provides advertising and branding development for the companies within the Xcel system. Manages and tracks all contributions made on behalf of the Xcel system.

Method of Allocation - Corporate Communications indirect costs will be allocated based on a three-factor formula that is comprised of the average of the Revenue Ratio, the Employee Ratio and the Total Assets Ratio.

*g) Employee Communications**

Description - Develops and distributes communications to employees.

Method of Allocation - Employee Communications indirect costs will be allocated based on the Employee Ratio.

*h) Corporate Strategy & Business Development**

Description - Facilitates development of corporate strategy and prepares strategic plans, monitors corporate performance and evaluates business opportunities. Develops and facilitates process improvements.

Method of Allocation - Corporate Strategy & Business Development indirect costs will be allocated based on a three-factor formula that is comprised of the average of the Revenue Ratio, the Employee Ratio and the Total Assets Ratio.

*i) Government Affairs **

Description - Monitors, reviews and researches government legislation.

Method of Allocation - Government Affairs indirect costs will be allocated based on a three-factor formula that is comprised of the average of the Revenue Ratio, the Employee Ratio and the Total Assets Ratio.

*j) Facilities & Real Estate**

Description - Operates and maintains office buildings and service centers. Procures real estate and administers real estate leases. Administers contracts to provide security, housekeeping and maintenance services for such facilities. Procures office furniture and equipment.

Method of Allocation - Facilities & Real Estate indirect costs will be allocated to the Operating Companies based on the Employee Ratio.

*k) Facilities Administrative Services**

Description - Includes but is not limited to the functions of Mail Delivery, Duplicating and Records Management.

Method of Allocation - Facilities Administrative Services indirect costs will be allocated based on a three-factor formula that is comprised of the average of the Revenue Ratio, the Employee Ratio and the Total Assets Ratio

*l) Supply Chain**

Description - Includes contract negotiations, development and management of supplier relationships and acquisition of goods and services. Also includes inventory planning and forecasting, ordering, accounting and database management. Warehousing services includes receiving, storing, issuing, shipping, returns, and distribution of material and parts.

Method of Allocation - Supply Chain will be direct charged. Any management and oversight of the payment and reporting services activities that cannot be direct charged will be allocated using the Invoice Transaction Ratio.

*m) Supply Chain Special Programs**

Description - Develops and implements special programs utilized across the company such as procurement cards, travel services, and compliance with corporate MWBE (minority women business expenditures) program goals.

Method of Allocation - Supply Chain Special Programs indirect costs will be allocated based on a three-factor formula that is comprised of the average of the Revenue Ratio, the Employee Ratio and the Total Assets Ratio.

*n) Human Resources**

Description - Establishes and administers policies related to employment, compensation and benefits. Maintains HR computer system, the tuition reimbursement plan, and diversity program. Coordinates the bargaining strategy and labor agreements with union employees. Provides technical and professional development training and general HR support services.

Method of Allocation - Human Resources indirect costs will be allocated based on the Employee Ratio.

*o) Finance & Treasury**

Description - Coordinates activities related to securities issuance, including maintaining relationships with financial institutions, cash management, investing activities and monitoring the capital markets. Performs financial and economic analysis.

Method of Allocation - All Finance & Treasury indirect costs will be allocated based on a three-factor formula that is comprised of the average of the Revenue Ratio, the Employee Ratio and the Total Assets Ratio, except for:

(1) all indirect costs associated with proprietary trading activities, which will be allocated based on the Joint Operating Agreement Peak Hour Megawatt Load Ratio, provided, however, that indirect costs provided jointly for both generation trading activities and proprietary trading activities will be allocated based on the Joint Operating Agreement Labor Hours Ratio.

*p) Accounting, Financial Reporting & Taxes**

Description - Maintains the books and records. Prepares financial and statistical reports, tax filings and ensures compliance with the applicable laws and regulations. Maintains the accounting systems. Coordinates the budgeting process.

Method of Allocation – All Accounting, Financial Reporting & Taxes indirect costs will be allocated based on a three-factor formula that is comprised of the average of the Revenue Ratio, the Employee Ratio and the Total Assets Ratio, except for:

(1) indirect costs incurred for services associated with proprietary trading activities, which will be allocated based on the Joint Operating Agreement Peak Hour Megawatt Load Ratio, provided, however, that indirect costs provided jointly for both generation trading activities and proprietary trading activities will be allocated based on the Joint Operating Agreement Labor Hours Ratio.

*q) Payment & Reporting**

Description - Processes payments to vendors and prepares statistical reports.

Method of Allocation - Payment & Reporting indirect costs will be allocated to the Operating Companies based on the Invoice Transaction Ratio.

*r) Receipts Processing**

Description - Processes payments received from customers of the Operating Companies and affiliates.

Method of Allocation - Receipts Processing indirect costs will be allocated based on the Customer Bills Ratio.

*s) Payroll**

Description - Processes payroll including but not limited to time reporting, calculation of salaries and wages, payroll tax reporting and compliance reports.

Method of Allocation - Payroll indirect costs will be allocated based on the Employee Ratio.

*t) Rates & Regulation**

Description - Determines the Operating Companies' regulatory strategy, revenue requirements and rates for electric and gas customers. Coordinates the regulatory compliance requirements and maintains relationships with the regulatory bodies.

Method of Allocation - Rates & Regulation indirect costs will be allocated to the Operating Companies based on the Direct Labor Ratio.

*u) Energy Supply Engineering and Environmental**

Description - Provides engineering services to the generation business. Establishes policies and procedures for compliance with environmental laws and regulations. Researches emerging environmental issues and monitors compliance with environmental requirements. Oversees environmental cleanup projects.

Method of Allocation - Energy Supply Engineering and Environmental services will be direct charged, and administrative support functions that cannot be direct charged will be allocated using the Total Plant Ratio.

*v) Energy Supply Business Resources**

Description - Provides performance, specialists and analytical services to the Operating Companies' generation facilities.

Method of Allocation - Energy Supply Business Resources indirect costs will be allocated using the MWh Generation Ratio.

*w) Energy Markets Regulated Trading & Marketing**

Description - Provides electric trading services to the Operating Companies' electric generation systems including load management, system optimization and resource acquisition.

Method of Allocation - Energy Markets Regulated Trading & Marketing indirect costs will be allocated to the Operating Companies based on the Total MWh Sales Ratio, except for:

(1) indirect costs incurred for services associated with proprietary trading activities, which will be allocated based on the Joint Operating Agreement Peak Hour Megawatt Load Ratio, provided, however, that indirect costs provided jointly for both generation trading activities and proprietary trading activities will be allocated based on the Joint Operating Agreement Labor Hours Ratio.

*x) Energy Markets - Fuel Procurement**

Description - Purchases fuel for Operating Companies electric generation systems (excluding nuclear).

Method of Allocation - Energy Markets Fuel Procurement indirect costs will be allocated based on the MWh Generation Ratio.

*y) Energy Delivery Marketing**

Description - Develops new business opportunities and markets the products and services for the Delivery Business Unit.

Method of Allocation - Energy Delivery Marketing will be direct charged.

*z) Energy Delivery Construction, Operations & Maintenance (COM)**

Description - Constructs, maintains and operates electric and gas delivery systems.

Method of Allocation - Energy Delivery COM indirect costs will be allocated based on the Delivery Services Gross Plant Ratio.

*aa) Energy Delivery Engineering/Design**

Description - Provides engineering and design services in support of capacity planning, construction, operations and material standards.

Method of Allocation - Energy Delivery Engineering/Design services will be direct charged; administrative support functions that cannot be direct charged will be allocated based on the Delivery Services Gross Plant ratios based on the services being provided.

*bb) Marketing & Sales**

Description - Provides marketing and sales services for the Operating Companies and affiliates for their electric and natural gas customers including strategic planning, segment identification, business analysis, sales planning and customer service.

Method of Allocation - Marketing & Sales indirect costs will be allocated based on the Revenue Ratio.

*cc) Customer Service**

Description - Provides service activities to retail and wholesale customers. These services include meter reading, customer billing, call center and credit and collections.

Method of Allocation - Customer Service indirect costs will be allocated based on the Customers Ratio. Indirect costs associated with administering low income and certified medical customer assistance programs will be allocated based on a composite of the Average of the Special Needs Customer Contacts Ratio and residential Customers Ratio.

*dd) Business Systems**

Description - Provides basic information technology services such as: application management, voice and data network operations and management, customer support services, problem management services, security administration and systems management. In addition, Business Systems acts as a single point of contact for delivery of all technical services to Xcel Energy. They partner with vendors to ensure the delivery of benchmarking, continuous improvement, and leadership around strategic initiatives and key developments in the marketplace.

Method of Allocation - Business Systems indirect costs will be allocated using any of the allocation ratios or combination of ratios.

*ee) Aviation Services**

Description - Provides aviation and travel services to employees.

Method of Allocation - Aviation Services will be allocated based on a three-factor formula that is comprised of the average of the Revenue Ratio, the Employee Ratio, and the Total Assets Ratio.

*ff) Fleet**

Description - Oversees the Operating Companies' Fleet Services Group.

Method of Allocation - Fleet will be direct charged.

*Corporate Governance activities within this Service Function will be allocated using the average of the Assets Ratio including Xcel Energy Inc.'s per book assets, Revenue Ratio with intercompany dividends assigned to Xcel Energy Inc., and Employee Ratio with number of common officers assigned to Xcel Energy Inc.

Allocation Ratios

The following ratios will be utilized as outlined above.

Revenue Ratio - Based on the sum of the monthly revenue amounts for the prior year ending December 31, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such time as may be required due to significant changes.

Revenue Ratio with intercompany dividends assigned to Xcel Energy Inc. - Based on the sum of the monthly revenue amounts for the prior year ending December 31, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. Xcel Energy Inc. will be assigned the amount of intercompany dividends. This ratio will be determined annually, or at such time as may be required due to significant changes.

Employee Ratio - Based on the number of employees at the end of the prior year ending December 31, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such time as may be required due to significant changes. For regulatory purposes, in the Minnesota jurisdiction, the Total Allocated Labor Hours Including Overtime shall be used. Total Allocated Labor Hours Including Overtime (FTE Hours) is the methodology ordered by the Minnesota Public Utilities Commission in Docket No. E,G002/AI-10-690, which is based on the number of labor hours including overtime for employees at the end of the prior year ending December 31, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies.

Employee Ratio with number of common officers assigned to Xcel Energy Inc. - Based on the number of employees at the end of the prior year ending December 31, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. Xcel Energy Inc. will be assigned the number of common officers. This ratio will be determined annually, or at such time as may be required due to significant changes.

Total Assets Ratio - Based on the total assets as of December 31 for the prior year, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such time as may be required due to significant changes.

Square Footage Ratio - Based on the total square footage as of December 31 for the prior year. The numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such time as may be required due to significant changes.

Invoice Transaction Ratio - Based on the sum of the monthly number of invoice transactions processed for the prior year ending December 31. The numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually or at such time as may be required due to significant changes.

Customer Bills Ratio - Based on the average of the monthly total number of customer bills issued during the prior year ending December 31. The numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such a time as may be required due to significant changes.

MWh Generation Ratio - Based on the sum of the monthly electric MWh generated by type of generator during the prior year ending December 31, the numerator of which is for an applicable Operating Company and the denominator of which is for all applicable Operating Companies. This ratio will be determined annually, or at such time as may be required due to significant changes.

Total MWh Sales Ratio - Based on the sum of the monthly electric MWh hours sold during the prior year ending December 31, the numerator of which is for an applicable Operating Company and the denominator of which is for all applicable Operating Companies. This includes sales to ultimate customers, wholesale customers, and non-requirement sales for resale. This ratio will be determined annually, or at such time as may be required due to significant changes.

Customers Ratio - Based on the average of the monthly total electric customers (and/or gas customers, or residential, business and large commercial and industrial customers, where applicable) for the prior year ending December 31, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such time as may be required due to significant changes.

Delivery Services Gross Plant Ratio - Based on transmission and distribution gross plant for the Delivery Business unit, both electric and gas or as may be applicable Electric Distribution, for the prior year ending December 31. The numerator of which is an applicable Operating Company and the denominator of which is for all applicable Operating Companies. This ratio will be determined annually, or at such time as may be required due to significant changes.

Provided, however, as follows:
(1) If the costs being allocated are directly related only to electric transmission, the ratio shall be based on the electric transmission gross plant;
(2) If the costs being allocated are directly related only to electric distribution, the ratio shall be based on the electric distribution gross plant;
(3) If the costs being allocated are directly related only to gas transmission, the ratio shall be based on the gas transmission gross plant;
(4) If the costs being allocated are directly related only to gas distribution, the ratio shall be based on the gas distribution gross plant;
(5) If the costs being allocated are directly related only to electric transmission and electric distribution, the ratio shall be based on the sum of the electric transmission gross plant and the electric distribution gross plant;
(6) If the costs being allocated are directly related only to electric transmission and gas transmission, the ratio shall be based on the sum of the electric transmission gross plant and the gas transmission gross plant;
(7) If the costs being allocated are directly related only to electric transmission and gas distribution, the ratio shall be based on the sum of the electric transmission gross plant and the gas distribution gross plant;
(8) If the costs being allocated are directly related only to electric distribution and gas transmission, the ratio shall be based on the sum of the electric distribution gross plant and the gas transmission gross plant;
(9) If the costs being allocated are directly related only to electric distribution and gas distribution, the ratio shall be based on the sum of the electric distribution gross plant and the gas distribution gross plant;
(10) If the costs being allocated are directly related only to gas transmission and gas distribution, the ratio shall be based on the sum of the gas transmission gross plant and the gas distribution gross plant;
(11) If the costs being allocated are directly related only to electric transmission, electric distribution, and gas transmission, the ratio shall be based on the sum of the electric transmission gross plant, the electric distribution gross plant, and the gas transmission gross plant;
(12) If the costs being allocated are directly related only to electric

transmission, electric distribution, and gas distribution, the ratio shall be based on the sum of the electric transmission gross plant, the electric distribution gross plant, and the gas distribution gross plant;
(13) If the costs being allocated are directly related only to electric transmission, gas transmission, and gas distribution, the ratio shall be based on the sum of the electric transmission gross plant, the gas transmission gross plant, and the gas distribution gross plant;
(14) If the costs being allocated are directly related only to electric distribution, gas transmission, and gas distribution, the ratio shall be based on the sum of the electric distribution plant, the gas transmission gross plant, and the gas distribution gross plant.

Meters Ratio - Based on the number of meters at the end of the prior year ending December 31. The numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such a time as may be required due to significant changes.

Customer Contacts Ratio - Based on the total annual number of customer contacts at the end of the prior year ending December 31. The numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such a time as may be required due to significant changes.

If the costs being allocated are directly related only to the support of special needs customers, such as those receiving low income energy assistance and those having certified medical conditions, the Special Needs Customer Contacts Ratio shall be used.

Special Needs Customer Contacts Ratio – Based on the number of contacts received by the special needs customer department at the end of the prior year ending December 31. The numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such a time as may be required due to significant changes.

Accounts Payable Transactions Ratio - Based on the total annual number of accounts payable transactions by system application at the end of the prior year ending December 31. The numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such a time as may be required due to significant changes.

Inventory Transactions Ratio - Based on the total annual number of inventory transactions by system application at the end of the prior year ending December 31, the numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such a time as may be required due to significant changes.

Work Management Transactions Ratio - Based on the total annual number of work management transactions by system application at the end of the prior year ending December 31. The numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such a time as may be required due to significant changes.

Purchasing Transactions Ratio - Based on the total annual number of purchasing transactions by system application at the end of the prior year ending December 31. The numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such a time as may be required due to significant changes.

Total Plant Ratio - Based on total property, plant and equipment at the end of the prior year ending December 31. The numerator of which is an applicable Operating Company and the denominator of which is for all applicable Operating Companies. This ratio will be determined annually, or at such a time as may be required due to significant changes.

Provided, however, as follows:
(1) If the costs being allocated are directly related only to electric production, the ratio shall be based on the total electric production plant;
(2) If the costs being allocated are directly related only to electric transmission, the ratio shall be based on the total electric transmission plant;
(3) If the costs being allocated are directly related only to electric distribution, the ratio shall be based on the total electric distribution plant;
(4) If the costs being allocated are directly related only to gas transmission, the ratio shall be based on the total gas transmission plant;
(5) If the costs being allocated are directly related only to gas distribution, the ratio shall be based on the total gas distribution plant;
(6) If the costs being allocated are directly related only to intangible plant, the ratio shall be based on the total intangible plant;
(7) If the costs being allocated are directly related only to electric

production and electric transmission, the ratio shall be based on the sum of the total electric production plant and the total electric transmission plant;

(8) If the costs being allocated are directly related only to electric production and electric distribution, the ratio shall be based on the sum of the total electric production plant and the total electric distribution plant;

(9) If the costs being allocated are directly related only to electric production and gas transmission, the ratio shall be based on the sum of the total electric production plant and the total gas transmission plant;

(10) If the costs being allocated are directly related only to electric production and gas distribution, the ratio shall be based on the sum of the total electric production plant and the total gas distribution plant;

(11) If the costs being allocated are directly related only to electric production and intangible plant, the ratio shall be based on the sum of the total electric production plant and the total intangible plant;

(12) If the costs being allocated are directly related only to electric transmission and electric distribution, the ratio shall be based on the sum of the total electric transmission plant and the total electric distribution plant;

(13) If the costs being allocated are directly related only to electric transmission and gas transmission, the ratio shall be based on the sum of the total electric transmission plant and the total gas transmission plant;

(14) If the costs being allocated are directly related only to electric transmission and gas distribution, the ratio shall be based on the sum of the total electric transmission plant and the total gas distribution plant;

(15) If the costs being allocated are directly related only to electric transmission and intangible plant, the ratio shall be based on the sum of the total electric transmission plant and the total intangible plant;

(16) If the costs being allocated are directly related only to electric distribution and gas transmission, the ratio shall be based on the sum of the total electric distribution plant and the total gas transmission plant;

(17) If the costs being allocated are directly related only to electric distribution and gas distribution, the ratio shall be based on the sum of the total electric distribution plant and the total gas distribution plant;

(18) If the costs being allocated are directly related only to electric distribution and intangible plant, the ratio shall be based on the sum of the total electric distribution plant and the total intangible plant;

(19) If the costs being allocated are directly related only to gas transmission and gas distribution, the ratio shall be based on the sum of the total gas transmission plant and the total gas distribution plant;

(20) If the costs being allocated are directly related only to gas transmission and intangible plant, the ratio shall be based on the sum of the total gas transmission plant and the total intangible plant;

(21) If the costs being allocated are directly related only to gas distribution and intangible plant, the ratio shall be based on the sum of the total gas distribution plant and the total intangible plant;

(22) If the costs being allocated are directly related only to electric production, electric transmission, and electric distribution, the ratio shall be based on the sum of the total electric production plant, the total electric transmission plant, and the total electric distribution plant;
(23) If the costs being allocated are directly related only to electric production, electric transmission, and gas transmission, the ratio shall be based on the sum of the total electric production plant, the total electric transmission plant, and the total gas transmission plant;
(24) If the costs being allocated are directly related only to electric production, electric transmission, and gas distribution, the ratio shall be based on the sum of the total electric production plant, the total electric transmission plant, and the total gas distribution plant;
(25) If the costs being allocated are directly related only to electric production, electric transmission, and intangible plant, the ratio shall be based on the sum of the total electric production plant, the total electric transmission plant, and the total intangible plant;
(26) If the costs being allocated are directly related only to electric production, electric distribution, and gas transmission, the ratio shall be based on the sum of the total electric production plant, the total electric distribution plant, and the total gas transmission plant;
(27) If the costs being allocated are directly related only to electric production, electric distribution, and gas distribution, the ratio shall be based on the sum of the total electric production plant, the total electric distribution plant, and the total gas distribution plant;
(28) If the costs being allocated are directly related only to electric production, electric distribution, and intangible, the ratio shall be based on the sum of the total electric production plant, the total electric distribution plant, and the total intangible plant;
(29) If the costs being allocated are directly related only to electric production, gas transmission, and gas distribution, the ratio shall be based on the sum of the total electric production plant, the total gas transmission plant, and the total gas distribution plant;
(30) If the costs being allocated are directly related only to electric production, gas transmission, and intangible plant, the ratio shall be based on the sum of the total electric production plant, the total gas transmission plant, and the total intangible plant;
(31) If the costs being allocated are directly related only to electric production, gas distribution, and intangible plant, the ratio shall be based on the sum of the total electric production plant, the total gas distribution plant, and the total intangible plant;
(32) If the costs being allocated are directly related only to electric transmission, electric distribution, and gas transmission, the ratio shall be based on the sum of the total electric transmission plant, the total electric distribution plant, and the total gas transmission plant;
(33) If the costs being allocated are directly related only to electric transmission, electric distribution, and gas distribution, the ratio shall be

based on the sum of the total electric transmission plant, the total electric distribution plant, and the total gas distribution plant;
(34) If the costs being allocated are directly related only to electric transmission, electric distribution, and intangible plant, the ratio shall be based on the sum of the total electric transmission plant, the total electric distribution plant, and the total intangible plant;
(35) If the costs being allocated are directly related only to electric transmission, gas transmission, and gas distribution, the ratio shall be based on the sum of the total electric transmission plant, the total gas transmission plant, and the total gas distribution plant;
(36) If the costs being allocated are directly related only to electric transmission, gas transmission, and intangible plant, the ratio shall be based on the sum of the total electric transmission plant, the total gas transmission plant, and the total intangible plant;
(37) If the costs being allocated are directly related only to electric transmission, gas distribution, and intangible plant, the ratio shall be based on the sum of the total electric transmission plant, the total gas distribution plant, and the total intangible plant;
(38) If the costs being allocated are directly related only to electric distribution, gas transmission, and intangible plant, the ratio shall be based on the sum of the total electric distribution plant, the total gas transmission plant, and the total intangible plant;
(39) If the costs being allocated are directly related only to electric distribution, gas distribution, and intangible plant, the ratio shall be based on the sum of the total electric distribution plant, the total gas distribution plant, and the total intangible plant;
(40) If the costs being allocated are directly related only to electric distribution, gas distribution, and gas transmission, the ratio shall be based on the sum of the total electric distribution plant, the total gas distribution plant, and the total gas transmission plant;
(41) If the costs being allocated are directly related only to gas transmission, gas distribution, and intangible plant, the ratio shall be based on the sum of the total gas transmission plant, the total gas distribution plant, and the total intangible plant;
(42) If the costs being allocated are directly related only to electric production, electric transmission, electric distribution, and gas transmission, the ratio shall be based on the sum of the total electric production plant, the total electric transmission plant, the total electric distribution plant, and the total gas transmission plant;
(43) If the costs being allocated are directly related only to electric production, electric transmission, electric distribution, and gas distribution, the ratio shall be based on the sum of the total electric production plant, the total electric transmission plant, the total electric distribution plant, and the total gas distribution plant;
(44) If the costs being allocated are directly related only to electric production, electric transmission, electric distribution, and intangible plant,

the ratio shall be based on the sum of the total electric production plant, the total electric transmission plant, the total electric distribution plant, and the total intangible plant;
(45) If the costs being allocated are directly related only to electric production, electric transmission, gas transmission, and gas distribution, the ratio shall be based on the sum of the total electric production plant, the total electric transmission plant, the total gas transmission plant, and the total gas distribution plant;
(46) If the costs being allocated are directly related only to electric production, electric transmission, gas transmission, and intangible plant, the ratio shall be based on the sum of the total electric production plant, the total electric transmission plant, the total gas transmission plant, and the total intangible plant;
(47) If the costs being allocated are directly related only to electric production, electric distribution, gas transmission, and gas distribution, the ratio shall be based on the sum of the total electric production plant, the total electric distribution plant, the total gas transmission plant, and the total gas distribution plant;
(48) If the costs being allocated are directly related only to electric production, electric distribution, gas transmission, and intangible plant, the ratio shall be based on the sum of the total electric production plant, the total electric distribution plant, the total gas transmission plant, and the total intangible plant;
(49) If the costs being allocated are directly related only to electric production, electric distribution, gas distribution, and intangible plant, the ratio shall be based on the sum of the total electric production plant, the total electric distribution plant, the total gas distribution plant, and the total intangible plant;
(50) If the costs being allocated are directly related only to electric production, gas transmission, gas distribution, and intangible plant, the ratio shall be based on the sum of the total electric production plant, the total gas transmission plant, the total gas distribution plant, and the total intangible plant;
(51) If the costs being allocated are directly related only to electric transmission, electric distribution, gas transmission, and gas distribution, the ratio shall be based on the sum of the total electric transmission plant, the total electric distribution plant, the total gas transmission plant, and the total gas distribution plant;
(52) If the costs being allocated are directly related only to electric transmission, electric distribution, gas transmission, and intangible plant, the ratio shall be based on the sum of the total electric transmission plant, the total electric distribution plant, the total gas transmission plant, and the total intangible plant;
(53) If the costs being allocated are directly related only to electric transmission, electric distribution, gas distribution, and intangible plant, the ratio shall be based on the sum of the total electric transmission plant, the

total electric distribution plant, the total gas distribution plant, and the total intangible plant;
(54) If the costs being allocated are directly related only to electric transmission, gas transmission, gas distribution, and intangible plant, the ratio shall be based on the sum of the total electric transmission plant, the total gas transmission plant, the total gas distribution plant, and the total intangible plant;
(55) If the costs being allocated are directly related only to electric distribution, gas transmission, gas distribution, and intangible plant, the ratio shall be based on the sum of the total electric distribution plant, the total gas transmission plant, the total gas distribution plant, and the total intangible plant;
(56) If the costs being allocated are directly related only to electric production, electric transmission, gas distribution, and intangible plant, the ratio shall be based on the sum of the total electric production plant, the total electric transmission plant, the total gas distribution plant, and the total intangible plant;
(57) If the costs being allocated are directly related only to electric production, electric transmission, electric distribution, gas distribution, and gas transmission, the ratio shall be based on the sum of the total electric production plant, the total electric transmission plant, the total electric distribution plant, the total gas distribution plant, and the total gas transmission plant;
(58) If the costs being allocated are directly related only to electric production, electric transmission, electric distribution, gas transmission, and intangible plant, the ratio shall be based on the sum of the total electric production plant, the total electric transmission plant, the total electric distribution plant, the total gas transmission plant, and the total intangible plant;
(59) If the costs being allocated are directly related only to electric production, electric distribution, gas distribution, gas transmission, and intangible plant, the ratio shall be based on the sum of the total electric production plant, the total electric distribution plant, the total gas distribution plant, the total gas transmission plant, and the total intangible plant;
(60) If the costs being allocated are directly related only to electric production, electric transmission, gas distribution, gas transmission, and intangible plant, the ratio shall be based on the sum of the total electric production plant, the total electric transmission plant, the total gas distribution plant, the total gas transmission plant, and the total intangible plant;
(61) If the costs being allocated are directly related only to electric production, electric transmission, electric distribution, gas distribution, and intangible plant, the ratio shall be based on the sum of the total electric production plant, the total electric transmission plant, the total electric distribution plant, the total gas distribution plant, and the total intangible

plant;
(62) If the costs being allocated are directly related only to electric transmission, electric distribution, gas distribution, gas transmission, and intangible plant, the ratio shall be based on the sum of the total electric transmission plant, the total electric distribution plant, the total gas distribution plant, the total gas transmission plant, and the total intangible plant.

Total Phones Ratio - Based on the number of phones at the end of the prior year ending December 31. The numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such a time as may be required due to significant changes.

Total Radios Ratio - Based on the number of radios at the end of the prior year ending December 31. The numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such a time as may be required due to significant changes.

Total Computers Ratio - Based on the number of computers at the end of the prior year ending December 31. The numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such a time as may be required due to significant changes.

Total Software Applications Users Ratio - Based on the number of users of a specific software application at the end of the prior year ending December 31. The numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such a time as may be required due to significant changes.

Joint Operating Agreement Peak Hour Megawatt Load Ratio - Based on that certain Joint Operating Agreement among Northern States Power Company, a Minnesota corporation, Northern States Power Company, a Wisconsin corporation, Public Service Company of Colorado, Southwestern Public Service Company, and Xcel Energy Services Inc., as agent, dated as of October 1, 2004, as may be amended from time to time, that designates costs to be allocated based on peak hour of megawatt load for previous year ending December 31. The numerator of which is for an applicable Operating Company or affiliate company and the denominator of which is for all applicable Operating Companies and affiliate companies. This ratio will be determined annually, or at such time as may be required due to significant changes.

Joint Operating Agreement Labor Hours Ratio - Based on that certain Joint Operating Agreement among Northern States Power Company, a Minnesota corporation, Northern States Power Company, a Wisconsin corporation, Public Service Company of Colorado, Southwestern Public Service Company, and Xcel Energy Services Inc., as agent, dated as of October 1, 2004, as may be amended from time to time, that designates costs to be allocated based on labor hours at the end of the prior year ending December 31. The numerator of which is for an applicable Operating Company and the denominator of which is for all applicable Operating Companies. This ratio will be determined annually, or at such time as may be required due to significant changes.

Direct Labor Ratio – Based on fully-loaded direct-charged Rates and Regulation labor dollars charged to individual operating affiliates by the Rates and Regulation service function. The numerator of which is the fully-loaded direct-charged labor dollars to individual operating affiliates by the Rates and Regulation service function and the denominator of which is the total fully-loaded direct-charged labor dollars to all affiliates by the Rates and Regulation service function.

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☐ **Public Document – Not Public (Or Privileged) Data Has Been Excised**
☒ **Public Document**

Xcel Energy			
Docket No.:	PU-12-813, PU-13-194, PU-13-195, PU-13-706, PU-13-707, PU-13-708, PU-13-742, PU-13-743	Data Request No.	2-13
Response To:	North Dakota Public Service Commission Commission Advocacy Staff		
Requestor:	PA Consulting Group		
Date Received:	May 10, 2017		

Question:

In the Company's response to MN Public Utilities Commission Information Request No. 10 in Docket No. E002/M-16-777, the Company states "We anticipate that Legal Separation will result in a shift of some corporate cost allocations from NSPM and NSPW to the new entity." Please indicate what specific corporate costs the Company is referring to, how those costs are allocated now between the different state utilities, and how the cost allocation would change under the referenced "shift".

Response:

Please see our response to NDPSC DR No. 2-12 regarding the allocation of corporate costs from Xcel Energy Services Inc. (XES). In addition to XES corporate services, other common corporate service (and certain other common) costs are allocated to the various Xcel Energy Inc. operating companies, including NSPM, through a Cost Assignment and Allocation Manual (CAAM) which identifies the methodologies used to ensure expenditures are appropriately and consistently assigned or allocated among utilities and jurisdictions. The CAAM is filed in the Company's rate cases. A copy of the CAAM was last filed with the Commission in the Company's most recent North Dakota rate case (PU-12-813) as Schedule 12 to the Direct Testimony of Company Witness Ms. Anne Heuer.

As discussed in more detail in our response to Data Request No. 2-12, more specific cost impacts and proposed cost allocation methods are dependent on various different variables which will need to be addressed should the Company move forward with a legal separation as part of our RTF.

Preparer:	Joanna Yugo
Title:	Principal Rate Analyst
Department:	Revenue Analysis
Telephone:	612-215-4633
Date:	May 24, 2017

PUBLIC DOCUMENT:
TRADE SECRET INFORMATION/DATA EXCISED

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☒ **Public Document – Not Public (Or Privileged) Data Has Been Excised**
☐ **Public Document**

Xcel Energy

Docket No.:	PU-12-813, PU-13-194, PU-13-195, PU-13-706, PU-13-707, PU-13-708, PU-13-742, PU-13-743	Data Request No.	2-14
Response To:	North Dakota Public Service Commission Commission Advocacy Staff		
Requestor:	PA Consulting Group		
Date Received:	May 10, 2017		

Question:
In the Company's response to MN Public Utilities Commission Information Request No. 10 in Docket No. E002/M-16-777, the Company states "We also anticipate a shift in transmission costs with the establishment of a new North Dakota entity. Serving NSPD as a stand-alone entity rather than part of NSPM can impact the MISO charges as well as transmission rate base used to set retail rates." Please provide an explanation of what specific costs will shift including the FERC accounts, the current cost allocation approach and what the Company anticipates the cost allocation would be if a separate North Dakota entity is created.

Response:
Please see our response to NDPSC Advocacy Staff Data Request No. 2-11 Trade Secret.

Portions of this response have been redacted and designated as "Trade Secret." The redacted portions contain "trade secret" information that is proprietary financial information of the Company as it derives independent value from not being generally known, is not ascertainable by other persons, can be used by other for a variety of purposes, and is maintained as confidential by the Company. Thus, Xcel Energy maintains this information as trade secret. This designation is made pursuant to the Company's Application for Trade Secret Protection dated February 13, 2017.

Preparer:	William K. Raihala
Title:	Transmission Analyst
Department:	Market Operations
Telephone:	612-330-7563
Date:	May 24, 2017

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)

Stephen J. Beuning, being first duly sworn on oath, deposes and says that he is the Director of Market Operations for Xcel Energy Services Inc. on behalf of Applicant Northern States Power Company, a Minnesota corporation, in the above-captioned matter, that the testimony and schedules submitted in the above-captioned matters under his name were prepared under his direction, that he knows the contents thereof, and that the same is true and correct to the best of his knowledge and belief.

Stephen J. Beuning

Subscribed and sworn to before me this 10 day of July, 2017.

Notary Public
My commission expires: 6/2/19

RAQUEL MADSEN
NOTARY PUBLIC
STATE OF COLORADO
NOTARY ID 20114033509
MY COMMISSION EXPIRES 06/02/2019