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August 7, 2017

**Public Document –  
Trade Secret Data Excised  
- Via Email and U.S. Mail -**

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

RE: REFILED REVENUE REQUIREMENTS TESTIMONY-PUBLIC  
APPLICATION FOR CONSIDERATION OF A RESOURCE TREATMENT  
FRAMEWORK TO ADDRESS JURISDICTIONAL COST ALLOCATION ISSUES  
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

Dear Mr. Nitschke:

Northern States Power Company, doing business as Xcel Energy, respectfully submits to the North Dakota Public Service Commission, refiles the attached Direct Testimony and Schedules of Mr. Charles Burdick in the above referenced Cases.

Upon examination of the information provided in Mr. Burdick’s Direct Testimony, the Company identified several instances of information that is considered to be Trade Secret to be improperly marked in Mr. Burdick’s Direct Testimony. Upon this discovery, the Company contacted the Commission to remove and return the versions of the Direct Testimony that were improperly marked. The Company is now filing properly marked Direct Testimony for docketing.

Information marked Trade Secret in this filing are identified in the relevant materials and the Company maintains the confidentiality of this information consistent with the Trade Secret Applications and Supplements thereto filed in the above referenced Cases.

- 183 PU-13-194 Filed 08/07/2017 Pages: 62  
Prefiled Direct Testimony of Charles R. Burdick - redacted
- 194 PU-13-743 Filed 08/07/2017 Pages: 62  
Prefiled Direct Testimony of Charles R. Burdick - redacted
- 182 PU-13-742 Filed 08/07/2017 Pages: 62  
Prefiled Direct Testimony of Charles R. Burdick - redacted
- 178 PU-13-708 Filed 08/07/2017 Pages: 62  
Prefiled Direct Testimony of Charles R. Burdick - redacted
- 179 PU-13-707 Filed 08/07/2017 Pages: 62  
Prefiled Direct Testimony of Charles R. Burdick - redacted
- 179 PU-13-706 Filed 08/07/2017 Pages: 62  
Prefiled Direct Testimony of Charles R. Burdick - redacted
- 333 PU-12-813 Filed 08/07/2017 Pages: 62  
Prefiled Direct Testimony of Charles R. Burdick - redacted

200 PU-13-195 Filed 08/07/2017 Pages: 62  
Prefiled Direct Testimony of Charles R. Burdick - redacted  
Northern States Power Company  
David Sederquist

An original and one copy of the Direct Testimony of Charles Burdick Non-Public is being provided via U.S. Mail.

Please contact me if you have any questions regarding this filing.

Sincerely,

A handwritten signature in blue ink that reads "David H. Sederquist". The signature is written in a cursive style with a large initial 'D'.

DAVID H. SEDERQUIST  
Sr. Consultant, Regulation & Finance  
Enclosures

DIRECT TESTIMONY AND SCHEDULES  
CHARLES R. BURDICK

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  
Exhibit \_\_ (CRB-1)

**Revenue Requirements Testimony**

July 15, 2017

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**I. INTRODUCTION AND QUALIFICATIONS**

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Q. PLEASE STATE YOUR NAME AND TITLE.

A. My name is Charles R. Burdick and I am the Director of Revenue Analysis in the Revenue Requirements – North department for Xcel Energy Services Inc. (XES). XES is the service company for the Xcel Energy Inc. holding company system, and provides services to all of the operating utility subsidiaries of Xcel Energy Inc., including Northern States Power Company – Minnesota (NSPM or Xcel Energy or the Company).

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE.

A. Since August 2011, I have worked with the Revenue Requirements – North department, first as a Principal Rate Analyst, then Manager, and now as the Director of Revenue Analysis. In these positions, I prepare and present cost-of-service studies, revenue requirement determinations, and jurisdictional annual reports for the electric and gas operations of NSPM to the North Dakota Public Service Commission (Commission), Minnesota Public Utilities Commission (MPUC), and the South Dakota Public Utilities Commission (SDPUC). Prior to 2011, I worked outside the Company in technology, finance, and energy-related fields. My resume is included as Exhibit \_\_\_\_ (CRB-1), Schedule 1.

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

A. I present an analysis to illustrate how implementation of the Legal Separation structure or Pseudo Separation structure supporting the Company’s proposed Resource Treatment Framework (RTF) could potentially impact the North Dakota Electric jurisdiction’s cost of service

1 and revenue requirement calculations. The discussion I provide in this  
2 testimony is intended to assist the Commission in its assessment of the RTF  
3 by demonstrating the interrelated financial assignments, allocations, and  
4 mechanisms, as well as assess the potential rate impacts of implementing  
5 these structures.

6  
7 My testimony also provides more detailed support for the estimates utilized  
8 in the Company's revenue requirements analysis provided in the Company's  
9 RTF Application (provided as Schedule 2 to Company witness Mr. Aakash  
10 Chandarana's Direct Testimony) and refines that analysis and underlying  
11 estimates to the degree possible at this time.

12  
13 Q. SINCE YOU ARE PROVIDING COST OF SERVICE AND REVENUE REQUIREMENT  
14 CALCULATIONS, ARE YOU ADVOCATING A SPECIFIC RATEMAKING POSITION?

15 A. No. This is not a ratemaking proceeding, and I am not advocating a  
16 particular ratemaking outcome. Rather, my testimony and schedules are for  
17 illustrative purposes to aid the Commission and interested parties in their  
18 understanding of the concepts outlined in the Company's Application. The  
19 numbers provided are estimates for the purpose of this illustration and not  
20 developed to the level of detail typical of a rate case.

21  
22 More specifically, the Company's RTF Application is not intended to set  
23 forth a specific cost allocation request, precise cost determinations, or a cost  
24 recovery petition. More specific cost assessments and proposed cost  
25 allocation methods (through service agreements and other affiliated interest  
26 structures) would need to be made in the future, depending on the final  
27 structure of the RTF. If we proceed down either separation path, additional

1 details and cost estimates will need to be developed. Therefore, our goal is  
2 to provide a generally reasonable estimate of the revenue requirement  
3 impacts of Legal Separation and Pseudo Separation, rather than to calculate  
4 precise outcomes.

5  
6 I note that all of the cost recovery mechanisms, allocations, adjustments, and  
7 other assumptions modeled in this analysis would require regulatory  
8 approvals to implement. As such, they may be subject to modification under  
9 those processes.

## 10 11 **II. OVERVIEW OF REVENUE REQUIREMENTS ANALYSIS**

12  
13 Q. HOW IS YOUR REVENUE REQUIREMENTS ANALYSIS ORGANIZED?

14 A. There are three aspects to our revenue requirements analysis. First, we  
15 identified a “status quo” baseline against which we can compare potential  
16 changes to the existing NSPM System. Second, we assess possible cost  
17 impacts to each state should Legal Separation be implemented. Last, we  
18 assess potential impacts should Pseudo Separation be implemented.  
19 Consistent with our overall RTF, implementation of either RTF structure  
20 would require discussion of not only how costs might be allocated or  
21 assigned, but also the potential impacts of solving for the “Disputed  
22 Resources” and other issues identified by Company witness Mr. Aakash  
23 Chandarana.

24  
25 Q. WHAT IS THE “BASELINE” IN THIS CONTEXT?

26 A. This baseline is the current revenue requirements for the overall NSP  
27 system, as presently allocated to the jurisdictions served by the system.

1 Because separation would occur at a future time (here, approximately 2020),  
2 the baseline is an estimate of what revenue requirements might look like at  
3 that time, in order to provide a comparison between the 2020 status quo  
4 baseline and revenue requirements associated with a more separate future for  
5 the North Dakota jurisdiction. The baseline is discussed in more detail in  
6 Section III of my Direct Testimony.

7  
8 Q. BY WAY OF BACKGROUND, WHAT ARE THE DISPUTED RESOURCES?

9 A. The Disputed Resources are discussed in more detail in the RTF Application  
10 and the Direct Testimony of Company witnesses Mr. Aakash Chandarana,  
11 Mr. P.J. Martin, and Mr. Richard Starkweather. For ease of reference, the  
12 Disputed Resources can be summarized as:

- 13 • Certain CBED and smaller solar resources;
- 14 • Six biomass PPAs currently serving the NSP System;
- 15 • The two PPAs that emerged from the 187 MW solar portfolio  
16 additions; and
- 17 • The Company's PPA for the capacity and energy of the Mankato  
18 Energy Center expansion (MEC II) project.

19  
20 In addition, our RTF Application discussed the need to address that the  
21 North Dakota amortization of Sherco Units 1 & 2 depreciation expense  
22 associated with their anticipated retirement at the end of 2025 and 2022,  
23 respectively, may present future cost recovery issues. Finally, we believe the  
24 resolution of the Disputed Resources should include the Company's  
25 proposed addition of 1,550 MW of wind generation, as set forth in Case No.  
26 PU-17-120 (the 2017 Wind ADP).

27

1           **III. BASELINE FOR REVENUE REQUIREMENTS ANALYSIS**

2  
3    Q.    WHAT IS THE COMPANY’S PROPOSED BASELINE?

4    A.    In the Application, we utilized the Company’s revenue requirement  
5           projection for 2020 with data as of late 2015 for each jurisdiction served by  
6           the NSP System – North Dakota, South Dakota, Minnesota, Wisconsin, and  
7           Michigan. The forecasted 2020 revenue requirement is a representation of  
8           the Company’s projected cost of serving each state on an “all-in” basis,  
9           including base rates, fuel costs, and rider revenue.

10  
11           While the baseline represents a “status quo” view of the NSP System, it still  
12           contains a number of assumptions about the future. Thus, the purpose of  
13           the Company’s baseline is not to precisely represent all future revenue  
14           requirements (given that these likely could change), but rather to enable  
15           illustration of the impacts of RTF outcomes.

16  
17    Q.    WHY WAS THE YEAR 2020 CHOSEN AS THE REPRESENTATIVE YEAR?

18    A.    We chose 2020 as the representative year because it is likely the earliest we  
19           can implement a Pseudo Separation due to rate case constraints in the  
20           affected jurisdictions, and the earliest we can likely achieve Legal Separation.  
21           Mr. Aakash Chandarana explains this timing in more detail in his Direct  
22           Testimony.

23  
24           2020 is also within the Company’s five-year planning outlook, and therefore  
25           we have sufficient data with which to estimate various rate mechanisms.

1 Q. HOW WAS THE BASELINE ESTABLISHED?

2 A. For purposes of establishing a baseline, we assumed the NSP System:

3 (1) remains integrated with all resources serving all customers,

4 (2) includes an expansion plan similar to that presented in the most  
5 recent Minnesota Integrated Resource Plan (IRP), and

6 (3) includes typical ratemaking adjustments in each jurisdiction.

7 In other words, it is a forecast of the Company's revenue requirements using  
8 currently-approved allocation methodologies but without any adjustments  
9 for the Disputed Resources in this filing, nor for implementing a new RTF  
10 structure.

11

12 Actual cost recovery will, of course, be governed by ratemaking proceedings  
13 in each state between now and 2020, and will be affected by factors such as  
14 economic and market forces, customer behaviors and sales, actual capital  
15 and operations and maintenance (O&M) plans, and regulatory outcomes.  
16 However, the existing data provide a baseline against which the Company  
17 can compare estimated cost and revenue shifts across jurisdictions that may  
18 be caused by resolving the existing resource issues and implementing a new  
19 RTF structure.

20

21 Q. WHAT IS THE SPECIFIC REVENUE REQUIREMENT BASELINE IN THE  
22 COMPANY'S APPLICATION?

23 A. Table 9 of the Company's Application provides the initial baseline, which is  
24 reproduced here as Table 1 to my Direct Testimony:

1

**Table 1**

|                              | ND Electric | MN Electric | SD Electric | NSPW  |
|------------------------------|-------------|-------------|-------------|-------|
| Baseline Model (\$ millions) | \$251       | \$3,739     | \$294       | \$869 |

2

3 Q. SINCE THIS BASELINE WAS FIRST DEVELOPED A NUMBER OF MONTHS AGO,  
4 DO YOU HAVE ANY UPDATES TO THE BASELINE?

5 A. Yes. To be consistent with other models and estimates included in the  
6 Company's direct case, the baseline calculations have been updated to a  
7 forecast as of the spring of 2017. Updates included a new capital forecast  
8 with wind project assumptions consistent with the Company's recent filings  
9 on those proposed projects, as well as updated O&M projections.

10

11 Table 2 below presents the Company's updated revenue requirement  
12 baseline, in a format that parallels the baseline provided in the Application.

13

14

**Table 2**

|                              | ND Electric | MN Electric | SD Electric | NSPW  |
|------------------------------|-------------|-------------|-------------|-------|
| Baseline Model (\$ millions) | \$245       | \$3,721     | \$262       | \$779 |

15

16 Detailed baseline amounts are included in Exhibit \_\_ (CRB-1), Schedule 4,  
17 Column A, attached to my Direct Testimony.

18

19 Q. HOW ARE THE COMPANY'S COSTS ALLOCATED IN THE BASELINE?

20 A. Under the current integrated NSP System, the Company's costs are allocated  
21 across jurisdictions based on each jurisdiction's relative contributions to  
22 cost-causation as outlined in the Company's Cost Allocation and  
23 Assignment Manual, attached to Ms. Everson's Direct Testimony. A

1 summary of the allocation factors, cost of capital rates, and other  
2 assumptions is attached as Exhibit \_\_ (CRB-1), Schedule 2 to my Direct  
3 Testimony. Further, Exhibit \_\_ (CRB-1), Schedule 3, page 1, attached to my  
4 Direct Testimony provides a conceptual diagram of the current ways in  
5 which revenues and expenses flow among the Xcel Energy operating  
6 companies to the North Dakota Electric jurisdiction.

7  
8 In general:

- 9 • Fixed costs such as generation and transmission plant assets are allocated  
10 based on each jurisdiction's relative peak demand on the system,  
11 measured in megawatts;
- 12 • Variable costs such as fuel are allocated based on each jurisdiction's  
13 relative energy loads, measured in megawatt-hours;
- 14 • Customer service costs such as call centers are allocated based on each  
15 jurisdiction's relative customer counts;
- 16 • Distribution costs such as meters and field service centers are directly  
17 assigned to the jurisdiction in which they are located; and
- 18 • Administrative and general (A&G) costs, unless otherwise classified  
19 according to cost-causative principles, are allocated using a two-factor  
20 composite allocator of relative demands and customers.

21  
22 A rate case would present data with much more detailed allocations.  
23 However, the description above provides the basic principles for purposes  
24 of comparison to Pseudo Separation and Legal Separation RTF structures.  
25

1 Q. HOW SPECIFICALLY DO THESE CONCEPTS APPLY TO DEVELOPING POTENTIAL  
2 COST OF SERVICE IMPACTS ASSOCIATED WITH THE RTF?

3 A. Exhibit \_\_ (CRB-1), Schedules 4 and 5 to my Direct Testimony provide  
4 estimated RTF Cost of Service models intended to bring together the  
5 various potential revenue requirement impacts of Legal and Pseudo  
6 Separation described in the Company's Direct Testimony. Schedule 4  
7 estimates the impacts of Legal Separation and Schedule 5 estimates the  
8 impacts of Pseudo Separation. Page 1 of each schedule illustrates overall  
9 potential impacts across the system through a Summary Bridge Schedule,  
10 while page 2 is the North Dakota Bridge Schedule that illustrates potential  
11 cost of service impacts to North Dakota. Pages 3 through 5 present the  
12 potential impacts of this same model to other NSPM jurisdictions  
13 (Minnesota, South Dakota, and Wisconsin, respectively). Each page (1-5)  
14 presents the baseline for purposes of comparing revenue requirement  
15 impacts of Legal Separation and Pseudo Separation RTF structures.

16  
17 These schedules and others attached to my testimony present typical  
18 ratemaking concepts such as rate base, revenues, operating expenses, and  
19 income taxes. The full detail of a rate case cost of service study is not  
20 necessary and perhaps distracting to the purpose of illustrating the effects of  
21 various conceptual scenarios. Therefore, for ease of understanding the  
22 general shape and direction of these scenarios, the schedules are summarized  
23 and condensed compared to those the Company might typically present in a  
24 rate case or other ratemaking proceeding.

25

1 Q. CAN YOU PLEASE WALK THROUGH THE BASELINE COMPONENTS OF YOUR  
2 RTF COST OF SERVICE MODEL IN MORE DETAIL?

3 A. Yes. Focusing on the North Dakota Legal Separation Bridge Schedule in my  
4 Schedule 4, page 2, the baseline information is presented in Column A. The  
5 components of the baseline (for each of pages 1-5 of Schedule 4) are as  
6 follows:

7

8 Forecasted average rate base balances by function are shown in Rows 1-6.  
9 The Production and Transmission amounts have been allocated to North  
10 Dakota using jurisdictional demand. Distribution, Row 4, has been direct-  
11 assigned by location. Other Rate Base on Row 5 represents general and  
12 intangible assets and other non-plant rate base offset by accumulated  
13 deferred income taxes.

14

15 Row 9 shows the currently forecasted North Dakota Electric retail revenues  
16 using current base rates and forecasted riders including fuel. Row 10 shows  
17 the NSPM other revenue that is allocated to North Dakota, which includes  
18 revenues from NSP – Wisconsin (NSPW) through the Interchange  
19 Agreement.

20

21 Rows 14-18 show O&M expenses. The fuel and production Rows 14-15 are  
22 allocated primarily based on energy. Row 16, Transmission, is allocated  
23 primarily based on jurisdictional demand. Row 17, Distribution, is primarily  
24 directly assigned based on location. Row 18, Other Operating Expenses,  
25 includes customer service and A&G costs. These costs would be direct-  
26 assigned when directly related to North Dakota service, and otherwise are

1 allocated based on customers for customer service or a two-factor composite  
2 of demand and customers for A&G costs.

3  
4 Book Depreciation, on Row 20, is allocated according to the type of asset  
5 being depreciated, consistent with the allocations described for rate base  
6 above.

7  
8 The Property Taxes on Row 22 represent the total Minnesota, North  
9 Dakota, and South Dakota production-related and transmission-related  
10 property taxes allocated to North Dakota based on a demand factor.  
11 Property Taxes also include North Dakota distribution-related property  
12 taxes that are direct-assigned to North Dakota.

13  
14 Payroll and Other Taxes, Row 23, are allocated according to the type of  
15 labor with which the tax is associated.

16  
17 Deferred Income Taxes on Row 24 are allocated according to the type of  
18 associated plant asset as in rate base, described above.

19  
20 Row 25, Federal and State Taxes, represents an income tax calculation  
21 related to the data in the column.

22  
23 Finally, Total Revenue Requirements, Row 32, are calculated based on the  
24 above amounts, using the last authorized North Dakota return on equity and  
25 capital structure.

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1 **IV. LEGAL SEPARATION IMPACTS**

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Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. In this section I discuss the revenue requirement impacts associated with implementing a Legal Separation RTF structure. This structure and its pros and cons are discussed in more detail by Company witness Mr. Starkweather, and other Company witnesses discuss many of the assumptions underlying this analysis. I summarize how these assumptions affect the overall revenue requirements that would be associated with establishing a separate operating company for the North Dakota Electric jurisdiction (NSPD).

Q. HOW WOULD THE NORTH DAKOTA ELECTRIC JURISDICTIONAL COST OF SERVICE CHANGE IF IT WERE SERVED BY A SEPARATE OPERATING COMPANY?

A. I assume three categories of changes to the cost of service:

(1) NSPM Production assets and associated costs are currently allocated in the baseline. For purposes of this analysis, we assume NSPD would not have any production assets such that those allocated assets would not be present in the proposed NSPD cost of service. Instead, NSPD would be served by a Federal Energy Regulatory Commission (FERC)-regulated production formula from NSPM to represent the legacy generation fleet and any incremental generation appropriate for a North Dakota-specific resource plan. This production formula would also address the Disputed Resources as adjustments from NSPM's total production costs. Company witness Mr. Starkweather discusses these assumptions in his Direct Testimony.

1 (2) NSPM Transmission assets and associated costs are currently allocated in  
2 the baseline. For purposes of this analysis, we assume NSPD would not  
3 have any transmission assets such that those allocated assets would not be  
4 present in the proposed NSPD cost of service. Instead, NSPD would be  
5 served by the Midcontinent Independent System Operator, Inc. (MISO)  
6 system through a FERC-regulated transmission formula that assigns North  
7 Dakota's share of the regional transmission system. Company witnesses Mr.  
8 Starkweather and Mr. Beuning discuss this in their Direct Testimonies.

9  
10 (3) NSPD would incur incremental directly-assigned costs that are needed to  
11 serve the new operating company. These would include operating company  
12 management, utility accounting, and financing costs, for example. Company  
13 witnesses Mr. Starkweather and Ms. Everson discuss this in their Direct  
14 Testimonies.

15  
16 I provide additional details about these changes later in my testimony.  
17 Schedule 3, page 2, provides a conceptual diagram of the suggested NSPD  
18 separate operating company, its relationships with the rest of the NSP  
19 System, including NSPM, NSPW, and the MISO regionally shared  
20 transmission.

21  
22 Q. IN WHAT WAYS WOULD THE COST OF SERVICE BE THE SAME EVEN WITH A  
23 SEPARATE OPERATING COMPANY?

24 A. I assume that Distribution costs that are in the State of North Dakota would  
25 continue to be directly assigned to the North Dakota Electric jurisdiction.  
26 Service company costs that are directly associated with North Dakota would  
27 continue to be directly assigned to the North Dakota Electric jurisdiction.

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I also assume that the North Dakota Electric jurisdiction’s currently allocated portion of NSPM general and common assets would be transferred to NSPD. In that way, the allocated amounts in the baseline “remain” through the transformations contemplated above.

**A. Production Formula**

Q. HOW WOULD THE USE OF A PRODUCTION FORMULA TO NSPD CHANGE THE COST OF SERVICE?

A. Please see Exhibit \_\_ (CRB-1), Schedule 4, page 2, North Dakota Legal Separation Bridge Schedule attached to my testimony, which illustrates the cost of service impacts. Columns B and C show the production-related changes.

First, in Column B, we remove the production-related rate base, operating expenses, depreciation, property taxes, and other associated taxes. This is because under Legal Separation, I assume for purposes of this analysis that NSPD would not start with any generation assets and all associated balance sheet and income statement items would remain with NSPM. This removal is illustrated in more detail in Exhibit \_\_ (CRB-1), Schedule 6 to my Direct Testimony.

Instead, on Column C, NSPD would incur a production-related expense based on a production formula calculation. This formula is discussed in more detail below, and illustrated in Exhibit \_ (CRB-1), Schedule 7 to my Direct Testimony.

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Q. AT A HIGH LEVEL, HOW MIGHT THE PRODUCTION FORMULA BE CALCULATED?

A. The rate formula estimation is based on a traditional net plant revenue requirement calculation that has been functionalized into three categories of costs: production demand-related costs, production non-fuel energy-related costs, and base fuel costs (energy). The NSPM production-related revenue requirement calculation is the sum of the return on rate base, purchased energy and capacity costs, operating and maintenance expense, depreciation expense, taxes other than income taxes, income taxes, and revenue credits, divided between the three functionalized categories discussed above. Each functionalized revenue requirement is divided by the NSPM total system demand (kW) or energy (kWh) units as developed in the Company's 2020 budget to estimate the demand or energy charges. The demand and energy charges are then allocated to North Dakota based on jurisdictional demand (kW) or energy (kWh) forecasts.

Q. HOW DID THE COMPANY IMPLEMENT A PRODUCTION FORMULA CALCULATION FOR PURPOSES OF THIS DIRECT TESTIMONY?

A. To estimate the production formula calculation, we used a template from a past FERC production formula and modified for this purpose. The starting point was a FERC-approved formula that NSPW used to bill its electric wholesale customers, which was focused on production costs.<sup>1</sup>

The formula calculation is presented in Exhibit \_\_ (CRB-1), Schedule 7 to my Direct Testimony, which contains the following information:

---

<sup>1</sup> This NSPW formula is no longer in use, as no wholesale customers are being served by such service since 2013. As such, we believe this is a good proxy but a new formula would require FERC approval.

- 1           • Page 1, Summary:  
2           A summary of the demand and energy production charges, and the  
3           allocation to North Dakota.
- 4           • Page 2, A-1:  
5           Calculation of the NSPM demand charge based on the Company's  
6           2020 budgeted demand-related costs.
- 7           • Page 3, A-2:  
8           Calculation of the NSPM energy charges (fuel and non-fuel) based on  
9           the Company's 2020 budgeted energy-related costs.

10

11 Q.   HOW WOULD THE DISPUTED RESOURCES BE REPRESENTED IN A  
12       PRODUCTION FORMULA?

13 A.   We assume the production formula would be adjusted for the Disputed  
14       Resources. That is, the formula inputs start with the NSPM total  
15       production-related costs, and Disputed Resources and other items are  
16       removed from those total costs before the allocation to North Dakota.

17

18       Our estimation model for the production formula in Schedule 6 reflects the  
19       total unadjusted NSPM amounts. Therefore, the Disputed Resources must  
20       be separately adjusted. To that end, our RTF Cost of Service model in  
21       Schedule 4 takes the Schedule 6 result and reduces it by three adjustments:

- 22           • Disputed Resources,
- 23           • New Wind, and
- 24           • Sherco Units 1 & 2 Retirement.

25

1           **1.     Disputed Resources Adjustment**

2  
3    Q.    PLEASE DESCRIBE THE DISPUTED RESOURCES ADJUSTMENT.

4    A.    The Disputed Resources represent certain biomass, wind, and solar power  
5           purchase agreements that were supported in Minnesota but disputed in  
6           North Dakota, as further discussed in the Direct Testimonies of Company  
7           witnesses Mr. P.J. Martin and Mr. Aakash Chandarana. Please note that  
8           these costs do not assume the recently-filed biomass optimization proposals.  
9           The expected cost of these Disputed Resources in 2020 is \$189 million. In  
10          the baseline, North Dakota would be allocated approximately 5.5 percent of  
11          these amounts, or \$10.4 million.

12  
13          To estimate the impact of removing these costs from North Dakota and  
14          reallocating them to the remaining NSP System, we compare the cost of  
15          these resources to the replacement cost of energy. For example, the cost of  
16          the Disputed Resources is removed from North Dakota (-\$10.4 million), and  
17          instead North Dakota would incur the cost of replacement energy (+\$2.5  
18          million), for a net impact of lowering North Dakota's costs by -\$7.9 million.

19  
20          Simultaneously, the resulting shift to the remaining NSP System is estimated  
21          to be an increase of about \$7.9 million.

22  
23          Exhibit \_\_ (CRB-1), Schedule 11 attached to my Direct Testimony provides  
24          this calculation.

25  
26          As noted, the amounts included in this analysis are based on 2020 expected  
27          costs. This estimate is expected to vary in the years after 2020 as the costs

1 of the Disputed Resources change and the replacement cost of energy  
2 changes fluctuates with energy markets. The Company's forecast shows this  
3 \$7.9 million shift will decrease from 2021 to 2030.

4  
5 **2. New Wind Adjustment**

6  
7 Q. PLEASE DESCRIBE THE NEW WIND ADJUSTMENT.

8 A. The Company is planning on adding 1,550 MW of wind generation to the  
9 NSP System over the next several years. The new wind is among those  
10 resources for which we believe that there is likely to be a near-term  
11 disagreement. As outlined by Mr. Chandarana, we propose to fully allocate  
12 the costs or savings related to the new wind projects to the remainder of the  
13 NSP System and not to North Dakota.

14  
15 Schedule 12 attached to my testimony provides a calculation of this shift in  
16 2020.

17  
18 The revenue requirements model reflects the costs related to both the 1,150  
19 MW of owned wind and 400 MW of PPA wind. Additionally, this model  
20 assumes reduced production costs (i.e., avoided fuel), changes to MISO  
21 purchases and sales, and changes in wind congestion, integration, and coal  
22 cycling.

23  
24 Q. WHAT IS THE NET IMPACT OF THE WIND ADJUSTMENT?

25 A. The net impact of the wind additions in 2020 is estimated to be \$1 million.  
26 We then reallocated what would have been North Dakota's portion to the  
27 remainder of the NSP System. Please note, however, that this estimate

1 changes in the years after 2020 and is expected to increase over the period  
2 from 2021 through 2030.

3  
4 **3. Sherco Units 1 & 2 Adjustment**

5  
6 Q. PLEASE DESCRIBE THE SHERCO UNITS 1 & 2 ADJUSTMENT.

7 A. Company witness Mr. Chandarana describes the Sherco Units 1 & 2  
8 retirements, and the proposal to recover North Dakota's undepreciated  
9 balance from the remainder of the System.

10  
11 Schedule 13, attached to my Direct Testimony, develops this concept and  
12 shows the Minnesota and North Dakota cost shift.

13  
14 The current Commission-approved remaining life for Sherco Units 1 & 2 is  
15 through 2034. Because we anticipate retiring Sherco Unit 2 in 2022 and Unit  
16 1 in 2025, there will be unrecovered depreciation expense due to the  
17 difference between the approved remaining life and the anticipated  
18 retirement dates. All other NSPM states have approved remaining lives for  
19 Sherco Units 1 & 2 that accommodate the Company's proposed retirement  
20 dates.

21  
22 In our analysis of separating Disputed Resource costs, we assumed that  
23 North Dakota will continue to incur its anticipated depreciation expense at  
24 the original, un-accelerated pace, as though the units would retire in 2034.  
25 This would continue until each unit is actually retired in 2022 and 2025.  
26 This would result in a remaining undepreciated balance of approximately \$13  
27 million for North Dakota.

1  
2 Our analysis assumes the \$13 million would be reduced from the  
3 accumulated depreciation balance in Minnesota starting in 2020. The shift is  
4 spread from 2020 to 2025 to match the anticipated retirement dates.

5  
6 The result is that a forecast of North Dakota's depreciation expense related  
7 to these units would remain unchanged until 2025, then be zero for 2026  
8 through 2034, for a total estimated \$13 million cost reduction to North  
9 Dakota over those years, based on current assumptions.

10  
11 Minnesota's depreciation expense would increase by approximately \$3  
12 million in 2020. Depreciation in 2021 through 2025 would also increase, so  
13 that a total of \$13 million would be collected by 2025, equaling North  
14 Dakota's undepreciated portion.

15  
16 **B. Transmission Formula**

17  
18 Q. HOW WOULD TRANSMISSION COSTS CHANGE IN THE COST OF SERVICE?

19 A. Company witness Mr. Stephen Beuning discusses transmission-related  
20 changes associated with Legal Separation, while I provide the revenue  
21 requirement impact. Please see Exhibit \_\_ (CRB-1), Schedule 4, Columns D  
22 and E, which illustrate the transmission-related revenue requirement changes  
23 associated with Legal Separation, based on Mr. Beuning's analysis.

24  
25 In Column D, we remove the transmission-related rate base, non-retail  
26 revenue, operating expenses, depreciation, property taxes, and other  
27 associated taxes. Like production described above, we assume NSPD would

1 not own any transmission assets and all associated balance sheet and income  
2 statement items would remain with NSPM. This removal is illustrated in  
3 Exhibit \_\_ (CRB-1), Schedule 8 to my Direct Testimony.

4  
5 Rather than receiving an allocated portion of transmission costs from  
6 NSPM, the North Dakota Electric jurisdiction would receive transmission  
7 service through the MISO transmission formula. Company witness Mr.  
8 Steve Beuning discusses the transmission formula. Using his analysis, we  
9 show the resulting transmission expense to North Dakota in Column E of  
10 Exhibit \_\_ (CRB-1), Schedule 4, with support attached to my Direct  
11 Testimony as Exhibit \_\_ (CRB-1), Schedule 9.

12  
13 Using this estimation, we see North Dakota incurring \$1.3 million more  
14 transmission-related revenue requirements than their current cost of service,  
15 which is approximately a 4 percent change. These estimates show a modest  
16 cost shift between the two revenue requirement methods.

17  
18 **C. Service Functions**

19  
20 Q. WHAT PARTS OF NORTH DAKOTA'S REVENUE REQUIREMENTS WOULD  
21 CHANGE RELATED TO THE SERVICE FUNCTION?

22 A. Please see Exhibit \_\_ (CRB-1), Schedule 4, Columns F through I, which  
23 illustrate the service function differences.

24  
25 Company witness Ms. Karen Everson describes how the North Dakota  
26 Electric jurisdiction would receive an allocation as NSPD from the service  
27 company that is different from the two-factor allocation that would be

1 received as part of the NSPM operating company. This difference in  
2 operating company and jurisdictional allocations is illustrated in Column F,  
3 shown as an A&G difference in the Other Operating Expenses row of  
4 Exhibit \_\_ (CRB-1), Schedule 4. I note that this is a significant change from  
5 the estimate provided in the Application which assumed a net increase in  
6 allocation costs. This is primarily driven by our now refined assumptions  
7 about the size of NSPD, in which NSPD would not have any production or  
8 transmission assets making it relatively small compared to the other Xcel  
9 Energy Inc. operating companies. This is in contrast to the initial, high-level  
10 analysis provided in the Application which did not take into account material  
11 changes in the size of NSPD. I further note that any change in service  
12 company allocations is slightly offset by the production formula.

13  
14 Ms. Everson also discusses the incremental additional A&G costs that would  
15 be necessary to support a new, separate operating company. The total  
16 incremental costs are shown on Column G, again as a difference to A&G.

17  
18 Mr. Richard Starkweather discusses the range of transaction and startup  
19 costs that might be incurred in the establishment of a new operating  
20 company. The high end of his range, with one year of a proposed five-year  
21 amortization is shown as an A&G cost in Column H. Schedule 10 attached  
22 to my Direct Testimony calculates this amortization.

23  
24 Lastly, Mr. Starkweather also addresses the anticipated financing costs  
25 necessary for supporting NSPD. Some of these costs are expenses, which  
26 are shown in Column I. Additionally, Mr. Starkweather estimates that  
27 NSPD would incur a higher cost of debt than is available to NSPM, which

1 has a greater asset base and longer track record. This difference in debt cost  
2 is reflected in the revenue requirement on line 32 of Column I. The  
3 calculation presents the difference in debt rates times the cumulative rate  
4 base in Columns A through H.

5  
6 **D. Total Legal Separation Impacts**

7  
8 Q. IN TOTAL, WHAT DO YOU PRESENTLY ESTIMATE AS THE POTENTIAL  
9 DIFFERENCE IN REVENUE REQUIREMENT BETWEEN THE BASELINE AND  
10 LEGAL SEPARATION?

11 A. We estimate that legal separation could decrease revenue requirements to the  
12 North Dakota Electric jurisdiction by \$1.9 million, which is a difference of  
13 less than 1 percent. This is shown in Column K of Exhibit \_\_ (CRB-1),  
14 Schedule 4, page 2. The impact to other jurisdictions is also estimated to be  
15 less than 1 percent.

16  
17 Q. HOW DO YOUR UPDATED ESTIMATES ABOVE COMPARE TO THE INITIAL  
18 ESTIMATES PROVIDED IN THE APPLICATION?

19 A. Overall, this updated and more detailed analysis confirms many of the  
20 observations provided in the Application. We see a few differences,  
21 particularly related to fuel costs, service company allocations, and  
22 transmission shifts. These differences are mainly due to assumptions we  
23 made regarding the structure and size of NSPD. These assumptions are  
24 subject to change.

25  
26 The current projection of fuel costs is also lower than that used at the time  
27 of the Application. Given that fuel costs are commodities that vary with

1 market forces, and that those costs are often volatile, I do not place much  
2 import on that difference.

3  
4 Service company allocation amounts in Legal Separation are the largest  
5 estimation difference, primarily driven by the current assumption that NSPD  
6 would only have distribution assets and not transmission assets. This also  
7 assumes that current allocators, developed for the current corporate  
8 structure, will remain in place. Final allocation factors may change or the  
9 size of NSPD may change.

10  
11 Lastly, the transmission shifts in Legal Separation assumed in the  
12 Application are less dramatic when now analyzing alongside the  
13 corresponding rate base shift.

14  
15 Q. CAN YOU GUARANTEE THAT LEGAL SEPARATION COULD BE ACCOMPLISHED  
16 FOR THE AMOUNT ASSUMED HERE?

17 A. No. The Company witnesses made many assumptions and used forecast  
18 data to estimate potential impacts. The actual experience would likely vary.  
19 In addition, we selected 2020 as a measurement year, however the costs  
20 being measured vary year to year. Therefore, an estimate of the difference in  
21 2020 may be different than an expectation in 2025 or 2030.

22  
23 Q. WHAT WOULD NORTH DAKOTA'S RATE BASE BE UNDER THIS SCENARIO?

24 A. Assuming North Dakota Electric only contains distribution, general, and  
25 common assets, we estimate that legal separation would decrease rate base in  
26 2020 from a projected \$628 million down to \$205 million of remaining rate

1 base. This represents a much smaller jurisdiction in assets, though as  
2 discussed above, its cost of service would be similar to current forecasts.

3  
4 Q. COULD THE COMPANY'S CURRENT GENERATION THAT IS PHYSICALLY  
5 LOCATED IN NORTH DAKOTA BE TRANSFERRED FROM NSPM TO NSPD?

6 A. Yes, but we have assumed that it will not for a variety of reasons. The  
7 Company's only generation assets physically located in North Dakota are the  
8 Borders Wind project, Courtenay Wind Farm, and the soon-to-be-  
9 constructed Foxtail project. Renewable projects carry significant tax  
10 incentives and a separate NSPD would not likely have sufficient taxable  
11 income on its own to efficiently utilize the tax benefits. If the tax benefits  
12 cannot be utilized, the revenue requirements related to those assets would  
13 increase significantly and be more costly to ratepayers. Additionally, it is  
14 likely we would need to exchange the energy from these wind facilities back  
15 to NSPM, further complicating the operating company structures and  
16 relationships.

17  
18 Q. WHAT WOULD BE THE IMPACTS TO THE OTHER NSP SYSTEM JURISDICTIONS?

19 A. Exhibit \_\_ (CRB-1), Schedule 4, pages 3 through 5, attached, are provided in  
20 similar formats to Exhibit \_\_ (CRB-1), Schedule 4, page 2 discussed above.  
21 They provide the baseline and are itemized for Minnesota Electric, South  
22 Dakota Electric, and NSPW, respectively, under the same assumptions.

23  
24 Table 3 below summarizes our estimated cost shifts among the NSP  
25 jurisdictions.

**Table 3**

| Legal Separation change | ND Electric | MN Electric | SD Electric | NSPW    |
|-------------------------|-------------|-------------|-------------|---------|
| \$ millions             | (\$1,903)   | \$8,489     | \$433       | \$1,855 |
| Percent                 | -0.8%       | 0.2%        | 0.2%        | 0.2%    |

**V. PSEUDO SEPARATION IMPACTS**

Q. HOW WOULD THE NORTH DAKOTA ELECTRIC JURISDICTIONAL COST OF SERVICE CHANGE IF IT WERE SERVED BY A MODIFIED COST ALLOCATION AND ASSIGNMENT FOR PSEUDO SEPARATION?

A. Exhibit \_\_ (CRB-1), Schedule 5 attached to my testimony illustrates the impacts of Pseudo Separation.

It begins with the same 2020 forecasted baseline as in the Legal Separation analysis discussed above. It then makes adjustments to recognize the treatment of the Disputed Resources, new wind, and Sherco Units 1 & 2 depreciation. Finally, it is necessary to account for additional administrative expenses associated with implementing Pseudo Separation.

Q. PLEASE DISCUSS THE POTENTIAL REVENUE REQUIREMENT IMPACT OF THE COMPANY'S PROPOSED RESOLUTION OF THE DISPUTED RESOURCES.

A. In general, we envision removing most of the Disputed Resources (Minnesota-based CBED, certain solar, and biomass resources) that have been disallowed or otherwise disfavored by the Commission from North Dakota rates. Company witnesses Mr. Chandarana and Mr. Martin describe the Company's proposal in more detail. This approach would require

1 reallocating these costs (as well as the capacity, energy, and revenues) to  
2 other jurisdictions served by these resources. This potential change is  
3 reflected in Exhibit \_\_ (CRB-1), Schedule 11 to my Direct Testimony, and  
4 carries forward to Column M of Schedule 5.

5  
6 We also believe it would be reasonable to allocate the MEC II PPA costs  
7 and benefits on the standard jurisdictional basis, as this resource was  
8 supported in Minnesota but also provides reliable supply options to North  
9 Dakota as it looks toward a more independent resource planning future.  
10 This is assumed in the baseline model.

11  
12 Q. WHAT ARE THE REVENUE REQUIREMENTS ASSOCIATED WITH THE  
13 COMPANY'S PROPOSED RESOLUTION OF THE DEPRECIATION COSTS  
14 ASSOCIATED WITH SHERCO UNITS 1 & 2?

15 A. As with Legal Separation, the Company recognizes that our plan to retire  
16 Sherco Units 1 & 2 in the 2020s, rather than have them serve out their full  
17 remaining useful lives as reflected in our North Dakota depreciation rates  
18 for these units, has been received differently in our North Dakota and  
19 Minnesota jurisdictions. Therefore, our Pseudo Separation model includes  
20 recovery of the difference in depreciation expense for these resources from  
21 the remainder of the NSP System on an amortized basis. These potential  
22 impacts in 2020 are reflected in Schedule 13 to my Direct Testimony, and  
23 carry forward to Column O of Schedule 5.

24

1 Q. WHAT ARE THE REVENUE REQUIREMENTS ASSOCIATED WITH TREATMENT OF  
2 THE NEW WIND IN A PSEUDO SEPARATION STRUCTURE?

3 A. To offset the increase in Minnesota costs associated with a shift in the cost  
4 recovery of the Disputed Resources and Sherco Units 1&2, our Pseudo  
5 Separation model assumes allocation of the proposed new, wind additions to  
6 the remainder of the NSP System. As discussed in the Company's  
7 Application for an Advanced Determination of Prudence in Case No. PU-  
8 17-120, the new wind resources are cost-effective over the life of the  
9 proposed assets but result in a net increase in rates in their initial years of  
10 operation, resulting in substantial offset of the costs of the Disputed  
11 Resources and Sherco depreciation over time.<sup>2</sup> These potential impacts for  
12 2020 are reflected in Exhibit \_\_ (CRB-1), Schedule 12 to my Direct  
13 Testimony, and carries over to Column of my Schedule 5.

14

15 Q. DID THE COMPANY IDENTIFY ANY ADDITIONAL REVENUE REQUIREMENT  
16 IMPACTS ASSOCIATED WITH THE PSEUDO SEPARATION STRUCTURE?

17 A. Yes. In the RTF Application we identified the likely need for additional staff  
18 to manage the Pseudo Separation, and provided a high-level estimate of  
19 approximately \$1 million in incremental costs to implement Pseudo  
20 Separation. As described in more detail by Company witness Ms. Karen  
21 Everson, the Company's updated and more detailed estimate of incremental  
22 costs is approximately \$0.6 million. I incorporate our current cost estimates  
23 into the Pseudo Separation revenue requirement impact model appended to  
24 my Direct Testimony as Schedule 5, page 2.

25

---

<sup>2</sup> Because the analysis examines only the year 2020, the entire benefit of the new wind over the asset life on the remaining NSP System is not shown.

1 Q. CAN YOU PROVIDE A SUMMARY OF THE TOTAL ESTIMATED COST SHIFTS  
2 ASSOCIATED WITH PSEUDO SEPARATION?

3 A. Yes. Table 4 below provides a summary of the impact of both resolving the  
4 resource issues described in Section IV of my Direct Testimony and  
5 implementing Pseudo Separation.  
6

7 **Table 4**

| Pseudo Separation impacts | ND Electric | MN Electric | SD Electric | NSPW    |
|---------------------------|-------------|-------------|-------------|---------|
| \$ millions               | (\$7,724)   | \$8,503     | \$605       | \$1,830 |
| Percent                   | -3.2%       | 0.2%        | 0.2%        | 0.2%    |

8  
9 These impacts are also provided in more detail in Schedule 5, page 1 to my  
10 Direct Testimony.  
11

12 Q. WHAT DO YOU CONCLUDE WITH RESPECT TO THE TOTAL REVENUE  
13 REQUIREMENT IMPACTS OF PSEUDO SEPARATION?

14 A. The updated allocation of resources provided in Table 3 resulted in less than  
15 a one percent increase to rates in the remainder of the NSP System while  
16 acknowledging different states' resource choices and beginning the process  
17 of separating North Dakota from the NSP System. At the same time, the  
18 impact to North Dakota is savings of about three percent. Together, we  
19 believe these allocations reflect one reasonable set of cost impacts in each  
20 state while providing greater flexibility for state policy choices and resource  
21 selections. However, for the reasons discussed by Mr. Chandarana and Mr.  
22 Starkweather, a Legal Separation may be preferred to provide better certainty  
23 and long-term solutions.  
24

1

## VI. CONCLUSION

2

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

4 A. Yes, it does.

## **Resume of Charles R. Burdick**

**Director of Revenue Analysis  
Revenue Requirements North**

**Xcel Energy Services Inc.  
414 Nicollet Mall  
Minneapolis, MN 55401**

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### **Current Responsibilities**

Since August 2011, I have worked in the Revenue Requirements – North department, first as a Principal Rate Analyst, then Manager, and now as Director of Revenue Analysis. In this position, I prepare and present cost of service studies, revenue requirement determinations, and jurisdictional annual reports for the electric and gas operations of Northern States Power Company to the North Dakota Public Service Commission, Minnesota Public Utilities Commission, and the South Dakota Public Utilities Commission.

### **Prior Testimony**

Minnesota – Electric Rate Case  
Docket No. E002/GR-15-826

South Dakota – Electric Rate Case  
Docket No. EL14-058

Minnesota – Wind Energy Siting  
Docket No. IP6701/WS-08-1233

### **Energy-Related Employment History**

Xcel Energy – Minneapolis, MN

- Director of Revenue Analysis, April 2017 to Present
- Manager of Revenue Analysis, July 2015 to April 2017
- Principal Rate Analyst, August 2011 to July 2015

National Wind, LLC – Minneapolis, MN

- Senior Wind Energy Developer, August 2009 to August 2011
- Wind Energy Developer, April 2008 to August 2009

### **Education**

University of North Carolina at Chapel Hill, May 2005  
Master of Business Administration

Macalester College, May 1999

Bachelor of Arts – Mathematics, Computer Science, Music

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Northern States Power Company  
Allocations, WACC, and Tax Assumptions

Case Nos. PU-12-813, et al.  
Exhibit\_\_\_\_(CRB-1), Schedule 2  
Page 1 of 1

|                                 |                        |                   |
|---------------------------------|------------------------|-------------------|
| <b>2020 Utility Allocators:</b> | <b><u>Electric</u></b> | <b><u>Gas</u></b> |
| E&G Common Allocator (3 Factor) | 92.2457%               | 7.7543%           |

|                                     |                    |                    |
|-------------------------------------|--------------------|--------------------|
| <b>2020 Interchange Allocators:</b> | <b><u>NSPM</u></b> | <b><u>NSPW</u></b> |
| 36 mth Interchange Demand Allocator | 84.2085%           | 15.7915%           |
| Interchange Energy Allocator        | 83.9301%           | 16.0699%           |

|  |                  |                  |                  |
|--|------------------|------------------|------------------|
| <b>2020 Jurisdictional Allocators:</b> | <b><u>MN</u></b> | <b><u>ND</u></b> | <b><u>SD</u></b> |
| Electric Demand                        | 87.2087%         | 6.2492%          | 6.5421%          |
| Electric Energy                        | 87.2273%         | 6.5599%          | 6.2128%          |
| Electric Customer                      | 87.1715%         | 6.4591%          | 6.3694%          |
| Electric Two Factor A&G                | 87.3149%         | 6.2959%          | 6.3922%          |

|  |                  |                  |                  |                    |
|--|------------------|------------------|------------------|--------------------|
| <b>Total System Demand Allocators:</b> | <b><u>MN</u></b> | <b><u>ND</u></b> | <b><u>SD</u></b> | <b><u>NSPW</u></b> |
| NSP System Before Legal Separation     | 73.4371%         | 5.2624%          | 5.5090%          | 15.7915%           |
| NSP System After Legal Separation      | 77.5163%         |                  | 5.8150%          | 16.6687%           |

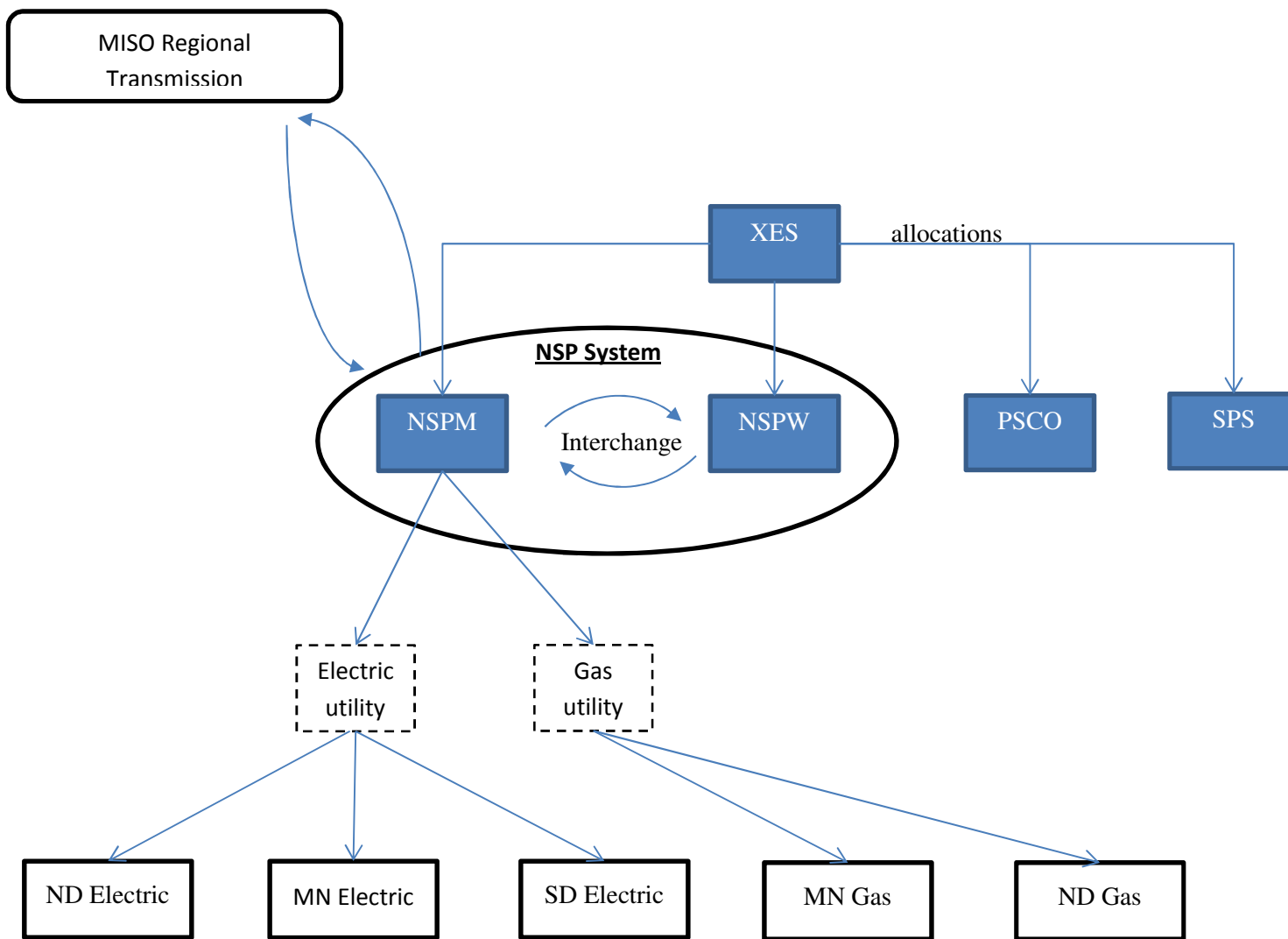
|  |                  |                  |                  |                    |
|--|------------------|------------------|------------------|--------------------|
| <b>Total System Energy Allocators:</b> | <b><u>MN</u></b> | <b><u>ND</u></b> | <b><u>SD</u></b> | <b><u>NSPW</u></b> |
| NSP System Before Legal Separation     | 73.2100%         | 5.5057%          | 5.2144%          | 16.0699%           |
| NSP System After Legal Separation      | 77.4756%         |                  | 5.5182%          | 17.0062%           |

|  |                  |                  |                  |                    |
|--|------------------|------------------|------------------|--------------------|
| <b>Total System Two Factor Allocators:</b> | <b><u>MN</u></b> | <b><u>ND</u></b> | <b><u>SD</u></b> | <b><u>NSPW</u></b> |
| NSP System Before Legal Separation         | 73.2835%         | 5.2842%          | 5.3650%          | 16.0699%           |
| NSP System After Legal Separation          | 77.3699%         |                  | 5.6641%          | 16.9660%           |

|                            |                  |                  |                  |                    |  |
|----------------------------|------------------|------------------|------------------|--------------------|--|
| <b>Capital Structures:</b> | <b><u>MN</u></b> | <b><u>ND</u></b> | <b><u>SD</u></b> | <b><u>NSPW</u></b> | <b><u>ND After Legal Separation:</u></b> |
| Long Term Debt Ratio       | 46.20%           | 46.20%           | 46.78%           | 45.70%             | 46.20%                                   |
| Short Term Debt Ratio      | 1.30%            | 1.30%            | 0.00%            | 1.77%              | 1.30%                                    |
| Common Equity Ratio        | 52.50%           | 52.50%           | 53.22%           | 52.53%             | 52.50%                                   |
| Long Term Debt Rate        | 4.72%            | 4.72%            | 4.71%            | 4.95%              | 6.00%                                    |
| Short Term Debt Rate       | 3.92%            | 3.92%            | 0.00%            | 2.23%              | 3.50%                                    |
| Common Equity Rate         | 10.25%           | 10.25%           | 10.25%           | 10.25%             | 10.25%                                   |
| Weighted Debt Rate         | 2.23%            | 2.23%            | 2.20%            | 2.30%              | 2.82%                                    |
| Weighted Equity Rate       | 5.38%            | 5.38%            | 5.46%            | 5.38%              | 5.38%                                    |
| Required Rate of Return    | <b>7.61%</b>     | <b>7.61%</b>     | <b>7.66%</b>     | <b>7.98%</b>       | <b>8.20%</b>                             |

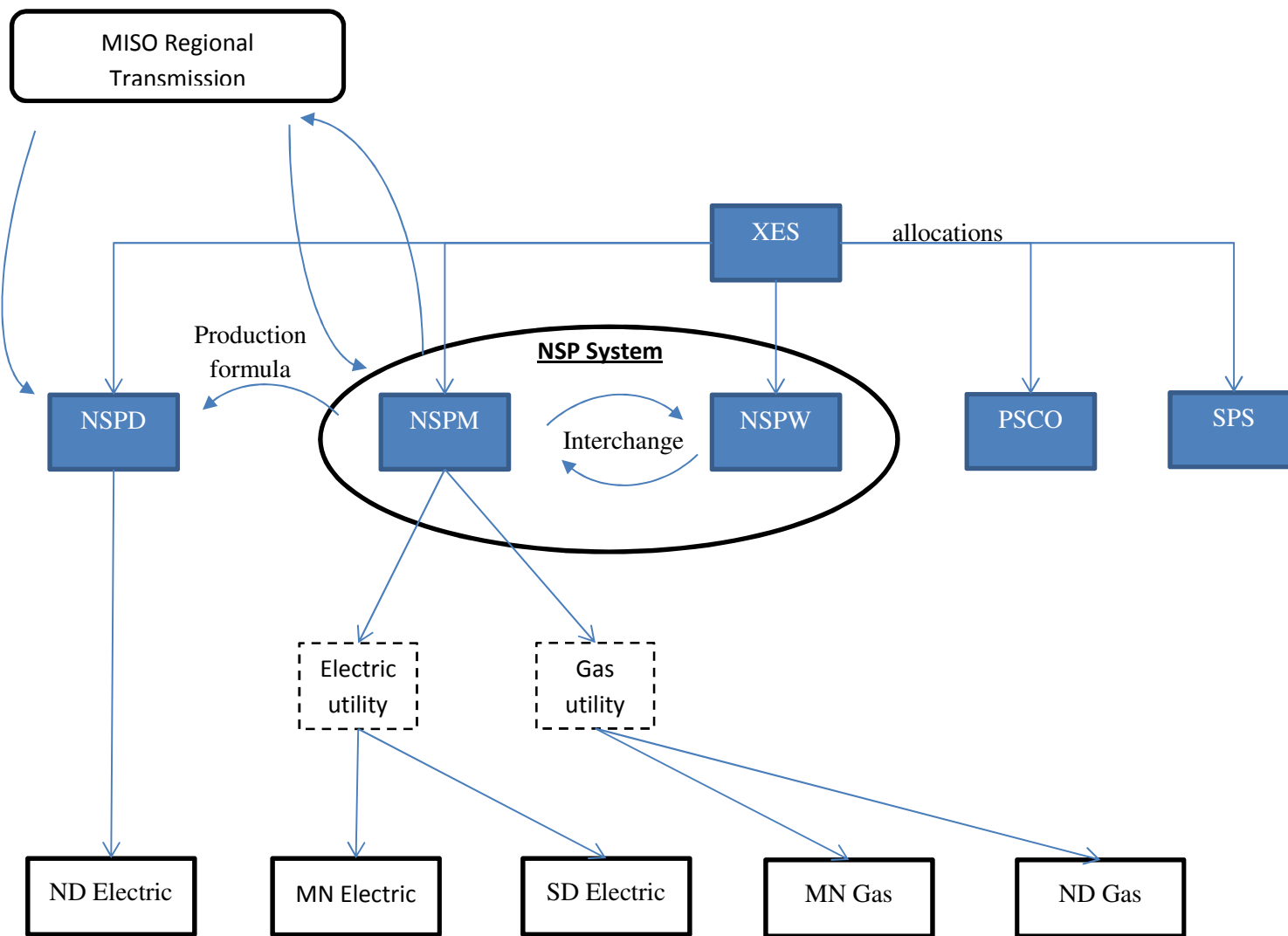
|                      |                  |                  |                  |                    |
|----------------------|------------------|------------------|------------------|--------------------|
| <b>Tax Rates:</b>    | <b><u>MN</u></b> | <b><u>ND</u></b> | <b><u>SD</u></b> | <b><u>NSPW</u></b> |
| Tax Rate             | 9.80%            | 4.31%            | 0.00%            | 7.90%              |
| Tax Rate (Fed)       | 35.00%           | 35.00%           | 35.00%           | 35.00%             |
| Tax Rate (Composite) | 41.37%           | 37.80%           | 35.00%           | 40.14%             |

### Status Quo revenue and expense relationships



This diagram is not intended to illustrate legal entity structures.

### Legal Separation revenue and expense relationships



This diagram is not intended to illustrate legal entity structures.





















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Northern States Power Company  
**Reallocate Production workpaper**  
Amounts in \$000s

Case Nos. PU-12-813, et al.  
Exhibit\_\_\_\_(CRB-1), Schedule 6  
Page 1 of 1

NSP System Demand Allocators (not including ND)      77.52%      5.82%      16.67%

|                                      | ND Baseline    | Remove ND<br>Production | MN Production<br>Allocation | SD Production<br>Allocation | NSPW<br>Production<br>Allocation |
|--------------------------------------|----------------|-------------------------|-----------------------------|-----------------------------|----------------------------------|
| 1 <b>Rate Base:</b>                  |                |                         |                             |                             |                                  |
| 2    Production                      | 292,221        | (292,221)               | 226,519                     | 16,993                      | 48,709                           |
| 3    Transmission                    | 131,122        |                         | -                           | -                           | -                                |
| 4    Distribution                    | 93,462         |                         | -                           | -                           | -                                |
| 5    Other Rate Base                 | 111,492        |                         | -                           | -                           | -                                |
| 6 <b>Total Rate Base</b>             | <b>628,296</b> | <b>(292,221)</b>        | <b>226,519</b>              | <b>16,993</b>               | <b>48,709</b>                    |
| 7                                    |                |                         |                             |                             |                                  |
| 8 <b>Revenues:</b>                   |                |                         |                             |                             |                                  |
| 9    Retail                          | 221,669        |                         |                             |                             |                                  |
| 10   Other                           | 55,753         | (33,381)                | 25,876                      | 1,941                       | 5,564                            |
| 11 <b>Total Revenues</b>             | <b>277,421</b> | <b>(33,381)</b>         | <b>25,876</b>               | <b>1,941</b>                | <b>5,564</b>                     |
| 12                                   |                |                         |                             |                             |                                  |
| 13 <b>Expenses:</b>                  |                |                         |                             |                             |                                  |
| 14   Fuel & Purchased Energy         | 76,255         | (73,652)                | 57,093                      | 4,283                       | 12,277                           |
| 15   Production                      | 49,670         | (49,670)                | 38,502                      | 2,888                       | 8,279                            |
| 16   Transmission                    | 27,213         | -                       | -                           | -                           | -                                |
| 17   Distribution                    | 8,590          | -                       | -                           | -                           | -                                |
| 18   Other Operating Expenses        | 22,283         | -                       | -                           | -                           | -                                |
| 19                                   |                |                         |                             |                             |                                  |
| 20   Depreciation/Amortization       | 44,410         | (25,160)                | 19,503                      | 1,463                       | 4,194                            |
| 21                                   |                |                         |                             |                             |                                  |
| 22   Property Taxes                  | 12,670         | (7,797)                 | 6,044                       | 453                         | 1,300                            |
| 23   Payroll & Other Taxes           | 1,944          | (1,196)                 | 927                         | 70                          | 199                              |
| 24   Deferred Income Taxes           | 5,375          | (4,089)                 | 3,170                       | 238                         | 682                              |
| 25   Federal & States Taxes          | (3,990)        | 55,977                  | (47,487)                    | (3,012)                     | (9,936)                          |
| 26 <b>Total Expenses</b>             | <b>244,419</b> | <b>(105,587)</b>        | <b>77,751</b>               | <b>6,383</b>                | <b>16,995</b>                    |
| 27                                   |                |                         |                             |                             |                                  |
| 28   AFUDC/Other Income              | -              | -                       | -                           | -                           | -                                |
| 29                                   |                |                         |                             |                             |                                  |
| 30 <b>Net Income</b>                 | <b>33,002</b>  | <b>72,207</b>           | <b>(51,876)</b>             | <b>(4,442)</b>              | <b>(11,431)</b>                  |
| 31                                   |                |                         |                             |                             |                                  |
| 32 <b>Total Revenue Requirements</b> | <b>244,699</b> | <b>(151,843)</b>        | <b>117,881</b>              | <b>8,836</b>                | <b>25,586</b>                    |

Production Formula Workpaper Summary  
Northern States Power Company  
Annual Production Charges - Test Year 2020

Case Nos. PU-12-813, et al.  
Exhibit\_\_\_\_(CRB-1), Schedule 7  
Page 1 of 3

|     |                           | [Trade Secret Begins.... |    | NSP MN System | NSP ND |
|-----|---------------------------|--------------------------|----|---------------|--------|
| 1.  | Demand Charge/kw          | A1                       |    |               |        |
| 2.  | Production Fuel/kwh       | A2                       |    |               |        |
| 3.  | Production Non-Fuel/kwh   | A2                       |    |               |        |
| 4.  | Total Energy Related      |                          |    |               |        |
| 5.  | Total Production Billings |                          |    |               |        |
|     |                           | Demand                   |    | Energy        |        |
|     |                           | NSP System               | ND | NSP System    | ND     |
| 6.  | January                   |                          |    |               |        |
| 7.  | February                  |                          |    |               |        |
| 8.  | March                     |                          |    |               |        |
| 9.  | April                     |                          |    |               |        |
| 10. | May                       |                          |    |               |        |
| 11. | June                      |                          |    |               |        |
| 12. | July                      |                          |    |               |        |
| 13. | August                    |                          |    |               |        |
| 14. | September                 |                          |    |               |        |
| 15. | October                   |                          |    |               |        |
| 16. | November                  |                          |    |               |        |
| 17. | December                  |                          |    |               |        |
| 18. |                           |                          |    |               |        |

**...Trade Secret Ends]**



Production Formula Workpaper A-2  
Determination of Energy-Related Costs and Energy Charges  
Twelve Months Ended December 31, 2020

Case Nos. PU-12-813, et al.  
Exhibit\_\_\_\_(CRB-1), Schedule 7  
Page 3 of 3

Current Year  
Energy Related

[Trade Secret Begins...

1. Total fuel and purchased power energy
2. Non-Fuel production expense
3. Interchange Agreement Charges - Fuel
4. Interchange Agreement Charges - Non-Fuel Production Expense
5. Other production expense
6. Total production cost
7. Less: Variable Production Expense Revenue Credit
8. Plus: Gain/Loss on Disposition of Allowances
9. Subtotal
10. Administrative and general expense
11. Return on investment
12. Depreciation Expense
13. Taxes Other Than Income
14. Income tax
15. Annual production variable costs
  
16. Net mwh generated and purchased, less mwh sold
  
17. Production fuel costs (Lines 1 + Line 3 - Line 7)
18. Plus: Estimated Changes
19. Production fuel costs with Estimated Changes
  
20. Base Fuel cost
  
21. Non-fuel costs (Line 15 - Line 17)
22. Revenue Credit Non-Fuel
23. Plus: Estimated Changes
24. Non-fuel costs with Estimated Changes
  
25. Non-Fuel Energy charge

...Trade Secret Ends]

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Northern States Power Company  
**Reallocate Transmission workpaper**  
Amounts in \$000s

Case Nos. PU-12-813, et al.  
Exhibit \_\_\_\_ (CRB-1), Schedule 8  
Page 1 of 1

NSP System Demand Allocators (not including ND)      77.52%      5.82%      16.67%

|                                      | ND Baseline    | Remove ND<br>Transmission | MN<br>Transmission<br>Allocation | SD<br>Transmission<br>Allocation | NSPW<br>Transmission<br>Allocation |
|--------------------------------------|----------------|---------------------------|----------------------------------|----------------------------------|------------------------------------|
| <b>1 Rate Base:</b>                  |                |                           |                                  |                                  |                                    |
| 2 Production                         | 292,221        |                           | -                                | -                                | -                                  |
| 3 Transmission                       | 131,122        | (131,122)                 | 101,641                          | 7,625                            | 21,856                             |
| 4 Distribution                       | 93,462         |                           | -                                | -                                | -                                  |
| 5 Other Rate Base                    | 111,492        |                           | -                                | -                                | -                                  |
| 6 <b>Total Rate Base</b>             | <b>628,296</b> | <b>(131,122)</b>          | <b>101,641</b>                   | <b>7,625</b>                     | <b>21,856</b>                      |
| 7                                    |                |                           |                                  |                                  |                                    |
| <b>8 Revenues:</b>                   |                |                           |                                  |                                  |                                    |
| 9 Retail                             | 221,669        |                           |                                  |                                  |                                    |
| 10 Other                             | 55,753         | (18,364)                  | 14,235                           | 1,068                            | 3,061                              |
| 11 <b>Total Revenues</b>             | <b>277,421</b> | <b>(18,364)</b>           | <b>14,235</b>                    | <b>1,068</b>                     | <b>3,061</b>                       |
| 12                                   |                |                           |                                  |                                  |                                    |
| <b>13 Expenses:</b>                  |                |                           |                                  |                                  |                                    |
| 14 Fuel & Purchased Energy           | 76,255         |                           | -                                | -                                | -                                  |
| 15 Production                        | 49,670         |                           | -                                | -                                | -                                  |
| 16 Transmission                      | 27,213         | (27,213)                  | 21,095                           | 1,582                            | 4,536                              |
| 17 Distribution                      | 8,590          |                           | -                                | -                                | -                                  |
| 18 Other Operating Expenses          | 22,283         |                           | -                                | -                                | -                                  |
| 19                                   |                |                           |                                  |                                  |                                    |
| 20 Depreciation/Amortization         | 44,410         | (4,301)                   | 3,334                            | 250                              | 717                                |
| 21                                   |                |                           |                                  |                                  |                                    |
| 22 Property Taxes                    | 12,670         | (3,208)                   | 2,487                            | 187                              | 535                                |
| 23 Payroll & Other Taxes             | 1,944          | (253)                     | 196                              | 15                               | 42                                 |
| 24 Deferred Income Taxes             | 5,375          | (1,657)                   | 1,285                            | 96                               | 276                                |
| 25 Federal & States Taxes            | (3,990)        | 8,858                     | (7,515)                          | (476)                            | (1,581)                            |
| 26 <b>Total Expenses</b>             | <b>244,419</b> | <b>(27,774)</b>           | <b>20,881</b>                    | <b>1,654</b>                     | <b>4,525</b>                       |
| 27                                   |                |                           |                                  |                                  |                                    |
| 28 AFUDC/Other Income                | -              |                           | -                                | -                                | -                                  |
| 29                                   |                |                           |                                  |                                  |                                    |
| 30 <b>Net Income</b>                 | <b>33,002</b>  | <b>9,409</b>              | <b>(6,646)</b>                   | <b>(586)</b>                     | <b>(1,464)</b>                     |
| 31                                   |                |                           |                                  |                                  |                                    |
| 32 <b>Total Revenue Requirements</b> | <b>244,699</b> | <b>(31,171)</b>           | <b>24,527</b>                    | <b>1,800</b>                     | <b>5,359</b>                       |

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Northern States Power Company  
Transmission Formula workpaper  
Amounts in \$000s

Case Nos. PU-12-813, et al.  
Exhibit\_\_\_\_(CRB-1), Schedule 9  
Page 1 of 1

**Summary of Transmission Service Impacts - 2020.**

| <b><u>Present Single System NSP</u></b> |  | <b>Total NSP</b>    | <b>MN/SD/WI</b>      | <b>ND</b>              |
|---|--|---------------------|----------------------|------------------------|
| Line                                    |  |                     |                      |                        |
| 1                                       | Revenue (+) - Present Single System NSP  | \$ 269,617,331      | \$ 255,327,612       | \$ 14,289,719          |
| 2                                       | Expenses (-) - Present Single System NSP   | \$ (241,387,973)    | \$ (228,594,411)     | \$ (12,793,563)        |
| 3                                       | Net Position   | \$ 28,229,358       | \$ 26,733,202        | \$ 1,496,156           |
| 4                                       |  |                     |                      |                        |
| 5                                       |  |                     |                      |                        |
| 6                                       |  |                     |                      |                        |
| 7                                       | <b><u>NSPD is TDU (No Transmission Ownership, Depart from Allocated Rev &amp; Exp)</u></b> | <b>Total NSP</b>    | <b>MN/SD/WI</b>      | <b>ND</b>              |
| 8                                       |  |                     |                      |                        |
| 9                                       | Revenues (+) with Split NSPM & NSPD Systems, NSPD is TDU                                   | \$ 284,327,136      | \$ 284,327,136       | \$ -                   |
| 10                                      | Expenses (-) with Split NSPM & NSPD Systems, NSPD is TDU                                   | \$ (256,834,624)    | \$ (224,366,396)     | \$ (32,468,228)        |
| 11                                      | Net Position with NSPD as TDU  | \$ 27,492,512       | \$ 59,960,741        | \$ (32,468,228)        |
| 12                                      |  |                     |                      |                        |
| 13                                      |  |                     |                      |                        |
| 14                                      | <b>Net Change from Present Single System to NSPD as TDU</b>                                | <b>\$ (736,845)</b> | <b>\$ 33,227,539</b> | <b>\$ (33,964,384)</b> |
| 15                                      |  |                     |                      |                        |
| 16                                      |  |                     |                      |                        |
| 17                                      |  |                     |                      |                        |
| 18                                      |  |                     |                      |                        |
| 19                                      |  | <b>MN</b>           | <b>SD</b>            | <b>WI</b>              |
| 20                                      | NSP System Demand Allocators (not including ND)  | 77.52%              | 5.82%                | 16.67%                 |
| 21                                      |  |                     |                      |                        |
| 22                                      | Revenues   | 22,479,365          | 1,686,325            | 4,833,833              |
| 23                                      | Expenses   | 3,277,402           | 245,860              | 704,754                |

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DATA HAS BEEN EXCISED

Northern States Power Company  
Transaction Costs workpaper  
Amounts in dollars

Case Nos. PU-12-813, et al.  
Exhibit\_\_\_\_(CRB-1), Schedule 10  
Page 1 of 1

|                         |         | <b><u>Total</u></b> | <b><u>5yr Amort</u></b> |
|-------------------------|---------|---------------------|-------------------------|
| Starkweather estimate:  | minimum | \$8,000,000         | \$1,600,000             |
|                         | maximum | \$15,000,000        | \$3,000,000             |
| Split 50% to ND and MN: | minimum | \$4,000,000         | \$800,000               |
|                         | maximum | \$7,500,000         | \$1,500,000             |

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DATA HAS BEEN EXCISED

Northern States Power Company  
Disputed Resources workpaper  
Amounts in \$millions

Case Nos. PU-12-813, et al.  
Exhibit\_\_\_\_(CRB-1), Schedule 11  
Page 1 of 1

| <u>Line</u> | <b>Cost shift of Disputed Resources:</b>                 | NSP System Energy Allocators: |                  |                  |                  |                  |
|-------------|--|-------------------------------|------------------|------------------|------------------|------------------|
|             |  | 5.51%                         | 77.48%           | 5.52%            | 17.01%           |                  |
|             |  | <b><u>Total</u></b>           | <b><u>ND</u></b> | <b><u>MN</u></b> | <b><u>SD</u></b> | <b><u>WI</u></b> |
| 1           | Biomass  | 119.70                        | (6.59)           | 5.11             | 0.36             | 1.12             |
| 2           | CBED Wind  | 48.10                         | (2.65)           | 2.05             | 0.15             | 0.45             |
| 3           | Solar  | 21.13                         | (1.16)           | 0.90             | 0.06             | 0.20             |
| 4           | Total  | <b>188.93</b>                 | <b>(10.40)</b>   | <b>8.06</b>      | <b>0.57</b>      | <b>1.77</b>      |
| 5           |  |                               |                  |                  |                  |                  |
| 6           |  |                               |                  |                  |                  |                  |
| 7           | <b>Replacement cost shifts for Disputed Resources:</b>   | (7.93)                        | 2.47             | (1.91)           | (0.14)           | (0.42)           |
| 8           |  |                               |                  |                  |                  |                  |
| 9           |  |                               | <b><u>ND</u></b> | <b><u>MN</u></b> | <b><u>SD</u></b> | <b><u>WI</u></b> |
| 10          | <b>Total Disputed Resources &amp; Replacement Costs:</b> |                               | (7.93)           | 6.15             | 0.44             | 1.35             |

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DATA HAS BEEN EXCISED

Northern States Power Company  
New Wind workpaper  
Amounts in \$000s

Case Nos. PU-12-813, et al.  
Exhibit\_\_\_\_(CRB-1), Schedule 12  
Page 1 of 1

| <u>Line</u>  | <u>2020</u>  | NSP System Energy Allocators: |           |           |           |
|--|--------------|-------------------------------|-----------|-----------|-----------|
|  |              | <u>ND</u>                     | <u>MN</u> | <u>SD</u> | <u>WI</u> |
| 1 New Ownership Wind, 1150MW                           | 74,302       | (4,091)                       | 3,169     | 226       | 696       |
| 2 New PPA Wind, 400MW                                  | 23,824       | (1,312)                       | 1,016     | 72        | 223       |
| 3 Reduced Production Costs (Avoided Fuel)              | (41,366)     | 2,277                         | (1,765)   | (126)     | (387)     |
| 4 Change in MISO Purchases & Sales                     | (79,998)     | 4,404                         | (3,412)   | (243)     | (749)     |
| 5 Change in Wind Congestion, Integration, Coal Cycling | 24,458       | (1,347)                       | 1,043     | 74        | 229       |
| 6 Total  | <b>1,220</b> | <b>(67)</b>                   | <b>52</b> | <b>4</b>  | <b>11</b> |

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DATA HAS BEEN EXCISED

Northern States Power Company  
Sherco Retirement workpaper  
Amounts in dollars

Case Nos. PU-12-813, et al.  
Exhibit\_\_\_\_(CRB-1), Schedule 13  
Page 1 of 2

| <b>MN Current View</b> | <b>2020</b> | <b>2021</b> | <b>2022</b> | <b>2023</b> | <b>2024</b> | <b>2025</b> | <b>2026</b> |
|------------------------|-------------|-------------|-------------|-------------|-------------|-------------|-------------|
| Plant End Bal          | 577,266,787 | 598,701,772 | 598,701,772 | 598,701,772 | 598,701,772 | 598,701,772 | retired     |
| Accum Depr End Bal     | 494,557,848 | 529,784,860 | 552,358,844 | 567,806,487 | 583,254,129 | 598,701,772 | retired     |
| Net Plant              | 82,708,939  | 68,916,912  | 46,342,928  | 30,895,285  | 15,447,643  | -           | retired     |
| Book Depr Expense      | 45,221,217  | 35,227,012  | 22,573,984  | 15,447,643  | 15,447,643  | 15,447,643  | -           |
| <b>ND Current View</b> | <b>2020</b> | <b>2021</b> | <b>2022</b> | <b>2023</b> | <b>2024</b> | <b>2025</b> | <b>2026</b> |
| Plant End Bal          | 41,366,132  | 42,902,133  | 42,902,133  | 42,902,133  | 42,902,133  | 42,902,133  | 42,902,133  |
| Accum Depr End Bal     | 24,568,512  | 25,955,112  | 27,258,729  | 28,562,346  | 29,865,963  | 31,169,580  | 32,473,197  |
| Net Plant              | 16,797,620  | 16,947,020  | 15,643,403  | 14,339,786  | 13,036,170  | 11,732,553  | 10,428,936  |
| Book Depr Expense      | 1,326,855   | 1,386,600   | 1,303,617   | 1,303,617   | 1,303,617   | 1,303,617   | 1,303,617   |

**Separation View**

| <b>MN</b>                                       | <b>2020</b> | <b>2021</b> | <b>2022</b> | <b>2023</b> | <b>2024</b> | <b>2025</b> | <b>2026</b> |
|---|-------------|-------------|-------------|-------------|-------------|-------------|-------------|
| Plant End Bal                                   | 577,266,787 | 598,701,772 | 598,701,772 | 598,701,772 | 598,701,772 | 598,701,772 | retired     |
| Reserve Reallocation                            | (2,972,483) | (2,972,483) | (2,972,483) | (1,345,191) | (1,345,191) | (1,345,191) | retired     |
| Accum Depr End Bal (After Reserve Reallocation) | 494,557,848 | 529,784,860 | 552,358,844 | 567,806,487 | 583,254,129 | 598,701,772 | retired     |
| Net Plant                                       | 82,708,939  | 68,916,912  | 46,342,928  | 30,895,285  | 15,447,643  | -           |             |
| Book Depr Expense                               | 48,193,699  | 38,199,495  | 25,546,467  | 16,792,834  | 16,792,834  | 16,792,834  | -           |
| <b>ND</b>                                       | <b>2020</b> | <b>2021</b> | <b>2022</b> | <b>2023</b> | <b>2024</b> | <b>2025</b> | <b>2026</b> |
| Plant End Bal                                   | 41,366,132  | 42,902,133  | 42,902,133  | 42,902,133  | 42,902,133  | 42,902,133  | 42,902,133  |
| Reserve Reallocation                            | 2,972,483   | 2,972,483   | 2,972,483   | 1,345,191   | 1,345,191   | 1,345,191   | -           |
| Accum Depr End Bal (After Reserve Reallocation) | 27,540,995  | 31,900,077  | 36,176,177  | 38,418,162  | 40,660,147  | 42,902,133  | 42,902,133  |
| Net Plant                                       | 13,825,137  | 11,002,055  | 6,725,956   | 4,483,970   | 2,241,985   | -           | -           |
| Book Depr Expense                               | 1,326,855   | 1,386,600   | 1,303,617   | 896,794     | 896,794     | 896,794     | -           |

**Difference**

| <b>MN</b>          | <b>2020</b> | <b>2021</b> | <b>2022</b> | <b>2023</b> | <b>2024</b>  | <b>2025</b>  | <b>2026</b>  |
|--------------------|-------------|-------------|-------------|-------------|--------------|--------------|--------------|
| Plant End Bal      | -           | -           | -           | -           | -            | -            | retired      |
| Accum Depr End Bal | -           | -           | -           | -           | -            | -            | retired      |
| Net Plant          | -           | -           | -           | -           | -            | -            | retired      |
| Book Depr Expense  | 2,972,483   | 2,972,483   | 2,972,483   | 1,345,191   | 1,345,191    | 1,345,191    | -            |
| MN                 | 2,304,159   | 2,304,159   | 2,304,159   | 1,042,743   | 1,042,743    | 1,042,743    |              |
| SD                 | 163,754     | 163,754     | 163,754     | 74,107      | 74,107       | 74,107       |              |
| WI                 | 469,400     | 469,400     | 469,400     | 212,426     | 212,426      | 212,426      |              |
| <b>ND</b>          | <b>2020</b> | <b>2021</b> | <b>2022</b> | <b>2023</b> | <b>2024</b>  | <b>2025</b>  | <b>2025</b>  |
| Plant End Bal      | -           | -           | -           | -           | -            | -            | -            |
| Accum Depr End Bal | 2,972,483   | 5,944,965   | 8,917,448   | 9,855,816   | 10,794,184   | 11,732,553   | 10,428,936   |
| Net Plant          | (2,972,483) | (5,944,965) | (8,917,448) | (9,855,816) | (10,794,184) | (11,732,553) | (10,428,936) |
| Book Depr Expense  | -           | -           | -           | (406,823)   | (406,823)    | (406,823)    | (1,303,617)  |



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

