

DIRECT TESTIMONY AND SCHEDULES  
AAKASH H. CHANDARANA

**BEFORE THE PUBLIC SERVICE COMMISSION  
OF THE STATE OF NORTH DAKOTA**

NORTHERN STATES POWER COMPANY  
ADVANCE PRUDENCE – BIOMASS PPAS  
APPLICATION

CASE No. PU-17-\_\_\_\_\_

NORTHERN STATES POWER COMPANY  
DEFERRED ACCOUNTING – BIOMASS PPAS  
APPLICATION

CASE No. PU-17-\_\_\_\_\_

**Policy Testimony**

Exhibit \_\_ (AHC-1)

June 30, 2017

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**Schedule**

Statement of Qualifications

Schedule 1

1 **I. INTRODUCTION AND QUALIFICATIONS**

2  
3 Q. PLEASE STATE YOUR NAME AND TITLE.

4 A. My name is Aakash H. Chandarana. I am the Regional Vice President for  
5 Rates and Regulatory Affairs for Northern States Power Company-  
6 Minnesota (NSP or Xcel Energy or the Company). In this role, I am  
7 responsible for the Company’s regulatory filings with the utility commissions  
8 in Minnesota, North Dakota, and South Dakota, including proceedings  
9 related to rates, resource planning, and service quality filings.

10  
11 Q. PLEASE DESCRIBE YOUR QUALIFICATIONS AND EXPERIENCE.

12 A. Prior to joining Xcel Energy, I was a partner at the Briggs and Morgan, P.A.  
13 law firm. My practice focused on the energy industry, primarily the state and  
14 federal regulation of utilities. I represented utilities in commercial  
15 transactions involving generation interconnection agreements, power  
16 purchase agreements, and other related types of transactions. I also assisted  
17 my clients in regulatory proceedings, including state electric rate cases, and  
18 transmission interconnection disputes at the Federal Energy Regulatory  
19 Commission.

20  
21 In 2013, I joined Xcel Energy as its Lead Assistant General Counsel –  
22 Regulatory North. In that role, I was the lead regulatory attorney for the  
23 Company’s operations in Minnesota, North Dakota, South Dakota,  
24 Wisconsin, and Michigan. In January 2015, I assumed my current role.  
25 Exhibit \_\_\_\_ (AHC-1), Schedule 1 summarizes my qualifications.

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

2 A. The purpose of my testimony is to provide support for our request for an  
3 Advance Determination of Prudence (ADP) for Xcel Energy's Biomass  
4 power purchase agreement (PPA) cost-savings transactions. This consists of  
5 three transactions that relate to our biomass portfolio and will reduce costs  
6 for our customers: (1) the Benson Power (Fibrominn) PPA Termination and  
7 Acquisition for Subsequent Shutdown; (2) the Pine Bend Biogas PPA Early  
8 Termination; and (3) the Hennepin Energy Recovery Center (HERC) PPA  
9 Extension and Restructuring (collectively, the Proposed Transactions). I  
10 also provide support for our request for authorization for deferred  
11 accounting for some the costs of our Proposed Transactions.

12

13 **II. THE BIOMASS PPA PROPOSED TRANSACTIONS**

14

15 Q. PLEASE DESCRIBE XCEL ENERGY'S BIOMASS PPA PROPOSED  
16 TRANSACTIONS.

17 A. The Company is entering into a series of transactions that are intended to  
18 help optimize our biomass portfolio and significantly drive down costs for  
19 our customers. In total, we estimate that our Biomass PPA Proposed  
20 Transactions will save customers over \$377 million net present value (NPV)  
21 over the next eleven years.

22

23 Our initiative is composed of the following transactions:

24

25 (1) *Benson Power (f/k/a Fibrominn)*: We are proposing to terminate  
26 our existing PPA with Benson Power for the output of the 55 MW  
27 Benson Power turkey litter fueled generating facility; acquire the

1 Benson Power facility; and shut it down. We estimate that this  
2 transaction will provide net savings of approximately \$345 million  
3 NPV.

4  
5 (2) *Pine Bend Biogas*: We are proposing to terminate our existing  
6 PPA for the output of the 12 MW Pine Bend biogas facility in  
7 exchange for a margin earning agreement that sets the date of  
8 termination. We estimate that this transaction will provide net savings  
9 of \$5 million.

10  
11 (3) *HERC*: We are proposing to restructure the PPA for the  
12 output of the 33.7 MW HERC waste-to-energy facility, in recognition  
13 of HERC's right to extend the PPA at fair market value. The PPA  
14 restructuring provides certainty to the Company in lieu of potential  
15 litigation over the existing PPA and is expected to provide overall  
16 savings of approximately \$27 million when compared against  
17 continuing under the existing PPA.

18  
19 Company witness Mr. Greg Chamberlain provides additional information  
20 regarding the key terms of these transactions. Company witness Mr. P.J.  
21 Martin discusses the economic analyses that supports the proposed  
22 transactions in his Direct Testimony.

23  
24 Q. WHY IS NSP PURSUING THESE TRANSACTIONS?

25 A. To save our customers money. The PPAs at issue in this Application are  
26 considerably above current market prices as well as the cost of most other  
27 resources in the NSP System's generating portfolio. NSP initiated

1 negotiations with the purpose of eliminating these costly PPAs in order to  
2 save money for customers and optimize NSP's portfolio.

3  
4 Q. WHAT PROMPTED THE COMPANY TO EXAMINE ITS BIOMASS PORTFOLIO?

5 A. NSP was notified that the owners of the Benson Power facility were looking  
6 to sell it. The Company decided to take the opportunity to analyze the  
7 potential benefits of purchasing the plant and shutting it down rather than  
8 continuing to purchase power under the existing PPA terms. The Company  
9 determined that purchasing the plant, shutting it down, and replacing the  
10 energy in the market would save NSP customers hundreds of millions of  
11 dollars over the remaining term of the PPA.

12  
13 Q. WHAT DROVE THE EXAMINATION OF THE PINE BEND AND HERC PPAs?

14 A. The significant cost savings that customers would realize if the Benson  
15 Power facility was purchased and closed encouraged us to reevaluate the  
16 remainder of our biomass portfolio to determine whether other PPAs could  
17 be terminated or amended in order to provide more savings to ratepayers.  
18 The Company determined that early termination of the Pine Bend PPA and  
19 amendment of the terms of the HERC PPA could substantially reduce  
20 energy costs.

21  
22 Q. IS THE COMPANY PURSUING OTHER OPPORTUNITIES SIMILAR TO THE  
23 PROPOSED TRANSACTIONS?

24 A. We believe that it is worthwhile to pursue opportunities as they may arise to  
25 drive down costs for our customers. For example, we are currently  
26 negotiating the potential termination of our biomass PPA with the  
27 Laurentian Energy Authority. Should we reach agreement with Laurentian,

1 we will also bring that transaction to the North Dakota Public Service  
2 Commission (Commission).

3  
4 Q. ARE THE PROPOSED TRANSACTIONS CONSISTENT WITH THE CURRENT  
5 REGULATORY AND STATUTORY FRAMEWORK FOR BIOMASS FACILITIES?

6 A. Yes. The Benson Power facility was built pursuant to Minnesota's statutory  
7 Biomass Mandate, which I discuss in more detail later in my testimony. The  
8 continued emergence of more economic and efficient sources of renewable  
9 energy, such as wind and solar, as well as the low cost of natural gas has  
10 prompted legislators and regulators to reexamine the practicality of biomass  
11 energy production. These factors prompted the Company to work with the  
12 Minnesota legislature to make practical, cost saving changes to the 1994  
13 legislation that contains the Biomass Mandate. The Benson Power  
14 transaction proposed in the Company's Application is consistent with those  
15 recent amendments.

16  
17 The Pine Bend and HERC facilities were built pursuant to the federal Public  
18 Utilities Regulatory Policies Act (PURPA). PURPA does not restrict the  
19 Company from buying out or amending the Pine Bend or HERC PPAs.

20  
21 Q. WILL THE PROPOSED BIOMASS TRANSACTIONS REQUIRE REGULATORY  
22 APPROVAL OUTSIDE OF NORTH DAKOTA?

23 A. Yes. All of the transactions are subject to the approval of the Minnesota  
24 Public Utilities Commission (MPUC). We filed a Petition for Approval of  
25 the biomass transactions with the MPUC on June 30, 2017—the same day  
26 we filed our Application in this Case.

27

1 The Company will also be filing for approval of the Benson Power  
2 transaction from the Federal Energy Regulatory Commission (FERC) under  
3 Section 203 of the Federal Power Act. Upon taking ownership of the  
4 Benson Power facility, the Company will file Attachment Y (Notification of  
5 Generation Resource/SCU/Pseudo-tied Out Generator Change of Status)  
6 with MISO regarding the proposed closure of the Benson Power facility.

7  
8 Q. DO THE GOVERNING CONTRACTS ADDRESS APPROVAL BY THE COMMISSION  
9 AS A CONDITION PRECEDENT TO CLOSING?

10 A. Yes. The agreements governing each transaction contemplate obtaining the  
11 approval of the Commission prior to closing. Because the Pine Bend and  
12 HERC agreements do not, by themselves, trigger the Company's ADP  
13 obligation, the requirement to obtain Commission approval is not  
14 absolute—as it is in the Benson Power contract. That said, the Company  
15 chose to present the transactions as a package and, accordingly, have  
16 brought them forward for Commission approval.

17  
18 Q. WHAT ARE THE EXPECTED SAVINGS TO THE COMPANY'S NORTH DAKOTA  
19 CUSTOMERS AS A RESULT OF THE PROPOSED TRANSACTIONS?

20 A. The following chart summarizes the expected savings for all NSP customers,  
21 and, more specifically, for North Dakota customers.

22

1 **Table 1: Estimated Savings of Proposed Transactions**

Transaction	Nominal Dollars in Millions				NPV Dollars in Millions			
	System			ND	System			ND
	Current	Proposed	Savings	Savings	Current	Proposed	Savings	Savings
Pine Bend	15.4	8.8	6.6	0.4	12.3	7.1	5.2	0.3
HERC	89.1	56.2	32.9	1.8	71.5	44.9	26.6	1.5
Fibrominn	771.6	292.0	479.6	26.3	561.2	215.6	345.6	19.0
<b>Total</b>	<b>876.1</b>	<b>357.0</b>	<b>519.1</b>	<b>28.5</b>	<b>645.0</b>	<b>267.6</b>	<b>377.4</b>	<b>20.7</b>

2  
3  
4 North Dakota customers should save a total of \$21 million NPV as a result  
5 of NSP’s proposed biomass transactions. The Direct Testimony of P.J.  
6 Martin provides a detailed description of our cost savings analysis and  
7 calculations.

8  
9 **III. EVOLUTION OF THE COMPANY’S BIOMASS PORTFOLIO**

10  
11 Q. HOW DID THE COMPANY’S BIOMASS PORTFOLIO DEVELOP?

12 A. For over thirty years, Xcel Energy has been developing its biomass portfolio.  
13 As the service provider for five states with large agricultural and timber  
14 product industries, development of biomass fueled generation has been an  
15 interest of the Company and our stakeholders. To that end, the Company  
16 has developed a portfolio of biomass projects totaling approximately 180  
17 MW.

18  
19 Different projects were acquired pursuant to different laws and programs.  
20 We acquired our first several biomass projects under our obligation to  
21 purchase the output from qualifying facilities as required by PURPA. We  
22 then acquired three more biomass contracts under Minnesota’s Biomass

1 Mandate. Finally, our last biomass contracts were acquired under the  
2 auspices of the Minnesota Renewable Development Fund (RDF) program.

3  
4 Q. WHAT ROLES DO THE BIOMASS PPAS PLAY IN THE NSP SYSTEM?

5 A. The Company believes that fostering emerging technologies is in our  
6 customers' best interest. We are a leader in wind generation due, in part, to  
7 our early adoption of the technology. By being an early adopter in the past,  
8 we are now positioned to add additional wind generation to our system and  
9 materially drive down customer costs. Unlike wind, biomass fueled  
10 generation has not emerged as an economic renewable generation  
11 alternative.

12  
13 Q. PLEASE DESCRIBE THE PURPA PROJECTS.

14 A. Starting in the 1980s, the Company entered into a series of hydroelectric and  
15 biomass PPAs that arose generally under PURPA and state implementing  
16 statutes. PURPA allows a "qualifying facility" to require a utility such as  
17 Xcel Energy to purchase the output of the facility at the utility's "avoided  
18 cost." PURPA was designed, in part, to promote small power production  
19 and the potential use of alternative fuels. Two of the PPAs that are part of  
20 the current restructuring arose out of the Company's purchase requirements  
21 under PURPA, namely the Pine Bend and HERC PPAs. Additionally, the  
22 WM Renewables (MN Methane) PPA was also added to Xcel Energy's  
23 biomass portfolio under PURPA.

24  
25 While PURPA allows the owner of a qualifying facility to force utilities to  
26 purchase power at the "avoided cost," it does not preclude the owner and a  
27 utility from negotiating terms of or terminating a PPA. Accordingly, the

1 bilateral agreements between NSP and the biomass facilities covered by  
2 PURPA are permitted under the statute.

3  
4 Q. PLEASE DESCRIBE THE MINNESOTA BIOMASS MANDATE?

5 A. A significant amount of the Company's biomass power additions have been  
6 driven by Minnesota legislative requirements arising out of the Company's  
7 nuclear power program. In 1994, the Minnesota Legislature passed the  
8 Prairie Island Cask Storage Authorization Act. Through the Act, the  
9 Minnesota Legislature required the Company to acquire biomass resources  
10 (the Biomass Mandate) in exchange for being allowed to continue the  
11 operation of its nuclear power plants. This legislation was essential to the  
12 Company's continued operation of its Prairie Island nuclear power station.  
13 The Company was running out of space to store spent nuclear fuel and  
14 needed authority to construct on-site spent nuclear fuel storage. Without  
15 statutory authorization to construct on-site storage, Prairie Island would  
16 have been forced to cease operations.

17  
18 While the 1994 legislation authorized the necessary on-site spent nuclear fuel  
19 storage, it also mandated that the Company construct and operate, or  
20 contract to obtain, 125 MW of installed capacity generated by farm grown  
21 closed-loop biomass. The legislation also included a wind-energy mandate  
22 as well as other obligations on NSP in exchange for the right to keep the  
23 Prairie Island nuclear power plant operational.

24  
25 Q. HOW DID NSP COMPLY WITH THE BIOMASS MANDATE?

26 A. After the initial Biomass Mandate legislation was passed, the Company  
27 sponsored a series of competitive processes to seek qualifying projects to

1 help satisfy the mandate. The Company encountered difficulties in finding  
2 projects that were financially viable or cost-effective, given the state of  
3 technology at the time. We encountered situations where projects were  
4 proposed that, for one reason or another, were not able to advance to  
5 commercial operation.

6  
7 In an effort to facilitate compliance, the Minnesota legislature modified the  
8 Biomass Mandate each legislative session for several years. This helped  
9 vendors refine their proposals in an effort to advance projects capable of  
10 achieving commercial operation. Since initial enactment of the Biomass  
11 Mandate in 1994, the biomass statute (Minn. Stat. § 216B.2424) has been  
12 amended fifteen times, including (1) a reduction of the total biomass capacity  
13 requirement from 125 MW to 110 MW, and (2) amendment of the definition  
14 of biomass to refine and expand the acceptable fuel sources. Many of the  
15 statutory amendments over the years were driven by the challenges the  
16 industry encountered in developing feasible projects given the state and cost  
17 of the technology at the time.

18  
19 The Company met its requirements under the Biomass Mandates by entering  
20 into PPAs with Benson Power (Fibrominn's successor in interest), the  
21 Laurentian Energy Authority, and St. Paul Cogeneration. These three  
22 contracts meet the 110 MW Biomass Mandate. NSP's Proposed  
23 Transactions include terminating the Benson Power PPA, purchasing the  
24 facility, and shutting it down.

25

1 Q. ARE THE TRANSACTIONS INVOLVING PPAS SUBJECT TO THE BIOMASS  
2 MANDATE ALLOWED BY THE STATUTE?

3 A. In the most recent legislative session, Minn. Stat. § 216B.2424 was amended  
4 to add subdivision 9. This section provides that the MPUC may approve an  
5 amended PPA, the early termination of a PPA, or the purchase and closure  
6 of a biomass facility if: (1) all contracting parties agree to the terms and  
7 conditions of the amended/terminated PPA/ purchase and closure of a  
8 facility; and (2) the action is in the best interest of the customers. We  
9 supported these legislative changes in Minnesota as we believed it would  
10 provide an opportunity for the Company to pursue cost savings that would  
11 positively impact customers in all of our states. A copy of these legislative  
12 changes is provided as Attachment A to our Application.

13  
14 Q. WHAT BIOMASS PROJECTS WERE INITIATED UNDER THE MINNESOTA RDF?

15 A. The 1994 Minnesota Prairie Island Cask Storage Act also established the  
16 Minnesota Renewable Development Fund (RDF). As part of the RDF, the  
17 Company administers a grant program that is intended to help support the  
18 development of renewable energy projects utilizing nascent stage  
19 technologies. Two biomass PPAs – one with Rahr Malting for the KODA  
20 Energy Facility and one with Diamond K Dairy for their biodigester project  
21 – have become part of Xcel Energy’s biomass portfolio through the RDF  
22 program.

23  
24 Q. DO ANY OF THE PROPOSED TRANSACTIONS AFFECT FACILITIES CREATED  
25 UNDER THE MINNESOTA RDF?

26 A. No. The Proposed Transactions do not implicate any RDF projects.  
27

1 Q. FOR REFERENCE, PLEASE SUMMARIZE THE DIFFERENT ASPECTS OF THE  
2 COMPANY'S BIOMASS PORTFOLIO.

3 A. Table 2, below, identifies the contracts making up the Company's biomass  
4 portfolio, their size, under which program they were acquired, their North  
5 Dakota recovery status, and if they are included in the Company's Proposed  
6 Transactions.

7  
8

**Table 2: Biomass Portfolio**

<b>Project</b>	<b>Size</b>	<b>Program Acquired</b>	<b>ND Recovery Status</b>	<b>Proposed Transaction?</b>
Benson Power (Fibrominn)	55 MW	MN Biomass Mandate	Subject to Refund	Yes
KODA Energy	12 MW	RDF	Subject to Refund	No
WM Renewable Energy	4.7 MW	PURPA	Subject to Refund	No
HERC	33.7 MW	PURPA	No Restrictions	Yes
Laurentian Energy Authority	35 MW	MN Biomass Mandate	Subject to Refund	No
Pine Bend	12 MW	PURPA	Subject to Refund	Yes
Diamond K Dairy	0.35 MW	RDF	No Restrictions	No
St. Paul Cogeneration	25 MW	MN Biomass Mandate	Subject to Refund	No

9

10 Q. HOW HAS THE COMMISSION ADDRESSED THE COMPANY'S BIOMASS PPAS IN  
11 THE PAST?

12 A. The Commission has allowed the Company to recover the costs of all of its  
13 biomass contracts since their inception. In the Company's 2013 test year  
14 rate case (Case No. PU-12-813), Commission Advocacy Staff raised issues

1 with six key biomass contracts: (1) KODA Energy LLC, (2) WM Renewable  
2 Energy (MN Methane), (3) Pine Bend, (4) Benson (Fibrominn), (5)  
3 Laurentian Energy Authority I, and (6) St. Paul Cogeneration. Pursuant to  
4 the Negotiated Agreement approved by the Commission on March 29, 2016,  
5 in Case Nos. PU-12-813. *et al.*, the Company is currently recovering the cost  
6 of these six biomass PPAs subject to a potential fifty percent refund which is  
7 triggered if the Company fails to construct a gas-fired power plant in eastern  
8 North Dakota by the end of 2025. The remaining biomass PPAs have not  
9 been singled out for scrutiny and are being recovered by the Company with  
10 no conditions.

11  
12 Q. ARE THERE SPECIFIC CONSIDERATIONS RELATING TO NORTH DAKOTA'S  
13 TREATMENT OF THE COMPANY'S BIOMASS PPAs?

14 A. Yes. Pursuant to the Negotiated Agreement approved by the Commission  
15 in Case No. PU-12-813, if Xcel Energy does not complete construction of a  
16 gas-fired power plant in eastern North Dakota by 2025, it will have to refund  
17 50 percent of the revenues collected from North Dakota customers that  
18 exceed the revenues that would have been collected if North Dakota  
19 customers had paid an adjusted system average cost for power instead of  
20 purchasing the power from specific biomass facilities. If the transactions  
21 move forward, both the price of power paid by North Dakota customers  
22 and the amount of the potential refund will be affected.

23  
24 Q. PLEASE PROVIDE A BRIEF DISCUSSION OF THE HISTORY OF THE REFUND  
25 PROVISION OF THE NEGOTIATED AGREEMENT.

26 A. In 2016, the Company and Commission Advocacy Staff entered into a First  
27 Revised Negotiated Agreement (Negotiated Agreement) that addressed the

1 biomass PPAs at issue in this Application, among others.<sup>1</sup> In the Negotiated  
2 Agreement, we agreed to either (i) build or have located in eastern North  
3 Dakota a natural gas-fired electric generation facility with the capacity of at  
4 least 200 MW by the end of 2025, or if the facility is not in service by that  
5 time (ii) refund to its North Dakota customers 50 percent of the revenues  
6 collected from North Dakota customers that exceed the revenues that would  
7 have been collected if North Dakota customers had paid an adjusted system  
8 average cost for fuel, and energy, and associated capacity for the six biomass  
9 PPAs identified in the Negotiated Agreement. The Benson Power and Pine  
10 Bend PPAs were named in the agreement.

11  
12 Q. WILL THE COMPANY COMPLETE THE NORTH DAKOTA FACILITY BY 2025?

13 A. The Company is in the process of developing its next Integrated Resource  
14 Plan, which it will file with the Commission in February 2019. Through this  
15 work, we hope to identify opportunities to meet our commitment.

16  
17 Q. HOW WOULD THE PROPOSED TRANSACTIONS AFFECT THE REFUND?

18 A. Even if the refund required by the Negotiated Agreement is triggered in the  
19 future, it would still be in North Dakota customers' best interest for the  
20 Company to move forward with the Proposed Transactions. The cost to  
21 North Dakota customers of continuing with the existing PPAs above the  
22 system average cost of fuel has been estimated to be approximately \$53  
23 million from 2016 through 2025, the period covered by the refund  
24 provisions of the Negotiated Agreement. This would result in a potential  
25 refund of \$26.5 million from NSP if the North Dakota electric generation

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<sup>1</sup> See *N. States Power Co. 2013 Elec. Rate Increase Application*, Case Nos. PU-12-813, *et al.*, ORDER APPROVING FIRST REVISED NEGOTIATED AGREEMENT (Mar. 9, 2016).

1 facility is not completed by 2025. As a result, the net cost to North Dakota  
2 ratepayers over that period would be \$26.5 million.

3  
4 If the Company moves forward with the proposed biomass transactions, the  
5 cost to North Dakota customers of the remaining biomass PPAs would  
6 drop to \$38 million from 2016 to 2025. If the refund becomes applicable,  
7 North Dakota customers would receive \$19 million from the Company and  
8 the net cost to the ratepayers would drop to \$19 million net of the refund.

9  
10 In sum, providing an ADP for our Proposed Transactions will benefit North  
11 Dakota customers regardless of whether NSP meets the 2025 electric  
12 generation facility deadline provided for in the Negotiated Agreement. If  
13 NSP finishes construction by that date, the cost to customers associated with  
14 the biomass PPAs will drop from \$53 million to \$38 million, a savings of \$15  
15 million. If the facility is not completed by 2025, the biomass PPAs' cost to  
16 customers, net of the refund from NSP, will drop from \$26.5 million to \$19  
17 million, a savings of \$7.5 million. In either event, customers will realize  
18 savings from our cost-saving initiative and these savings will be realized  
19 sooner than 2025.

20  
21 Q. HOW ARE THE PROPOSED TRANSACTIONS IMPLICATED IN THE COMPANY'S  
22 RESOURCE TREATMENT FRAMEWORK (RTF) PROCEEDING?

23 A. As part of the RTF proceeding, the Company has proposed, as one option,  
24 to allocate the costs, energy, capacity, and other benefits of all of the  
25 biomass contracts to the remainder of the NSP System and not our North  
26 Dakota customers. In the event this option became a reality, the HERC  
27 restructuring would still impact our North Dakota customers while the

1 remaining Proposed Transactions would be moot with respect to our North  
2 Dakota customers.

3  
4 **IV. REQUEST FOR DEFERRED ACCOUNTING**  
5

6 Q. HOW DOES THE COMPANY INTEND TO RECOVER THE COSTS ASSOCIATED  
7 WITH THE PROPOSED TRANSACTIONS?

8 A. The costs of the proposed biomass transactions are reasonable and prudent  
9 to achieve the resultant net cost savings. While the ADP statute, N.D.C.C. §  
10 49-05-16, makes clear that the finding of prudence is binding for ratemaking  
11 purposes, it does provide for timely rate recovery of the costs of the prudent  
12 resource additions. The Company intends to seek to recover the North  
13 Dakota share of these costs in future proceedings, most likely a rate case of a  
14 fuel cost recovery rider filing.

15  
16 Q. IS THE COMPANY MAKING ANY REQUEST WITH RESPECT TO THE COSTS OF  
17 THE PROPOSED TRANSACTIONS AT THIS TIME?

18 A. Yes. So as not to delay our ability to execute on the Proposed Transactions,  
19 the Company is requesting authority for deferred accounting so that the  
20 Company can create a regulatory asset and defer recognizing the costs of the  
21 Proposed Transaction when they occur so that they can be recovered in the  
22 future.

23  
24 Q. WHY DOES THE COMPANY PROPOSE DEFERRED ACCOUNTING FOR THE  
25 COSTS THROUGH CREATION OF A REGULATORY ASSET?

26 A. The costs associated with purchasing and shutting down the Benson Power  
27 facility and terminating the Pine Bend PPA are above and beyond both what

1 the Company has budgeted for normal utility operations and what was  
2 reflected in the costs of service to set current rates. It would be  
3 inappropriate to expense these costs as they occur due to the nature and  
4 materiality of the expenses. These one-time extraordinary expenditures are  
5 most appropriately accounted for through the creation of a regulatory asset.  
6 Failure to obtain deferred accounting treatment would force the Company to  
7 write off these costs in the year in which they occur, signaling no support for  
8 the Proposed Transactions.

9  
10 The size and magnitude of these transactions--the purchase of Benson  
11 Power and the payments to Pine Bend--are sufficiently large that they could  
12 potentially require the Company to file a rate case and the Company does  
13 not have excess earnings to offset the higher costs. The Commission has  
14 previously allowed deferred accounting when the amounts are sufficiently  
15 large that they could accelerate the timing of a rate case, and when the utility  
16 does not have excess earnings that should first be used to offset the higher  
17 costs.

18  
19 Q. FOR WHAT COSTS IS THE COMPANY SEEKING A DEFERRAL?

20 A. The Company is requesting that it be authorized to accumulate the costs  
21 incurred with purchasing and shutting down the Benson Power facility and  
22 terminating the Pine Bend PPA in a regulatory asset in Account 182.3. The  
23 Company also requests that it be allowed to include a cost of capital return  
24 on the asset. The costs to be deferred in the regulatory asset for Benson  
25 Power relate to the North Dakota share of costs necessary to terminate the  
26 PPA, acquire the plant, and shut it down, and also the North Dakota share  
27 of the O&M costs necessary to run the plant as it is shut down in an orderly

1 fashion. The costs to be deferred in the regulatory asset for the Pine Bend  
2 PPA relate to the North Dakota share of the termination payment of  
3 \$1,050,000. The Company will propose mechanisms to recover these costs  
4 sometime in the future.

5  
6 Q. WHY IS THE COMPANY NOT SEEKING DEFERRED ACCOUNTING TREATMENT  
7 FOR THE HERC TRANSACTION?

8 A. As a restructuring of a PPA, recovery of the costs of the HERC transaction  
9 are authorized for recovery through our FCR Rider. Consequently, there is  
10 already a real-time recovery mechanism available for this transaction. The  
11 same is not true with respect to the costs of the other Proposed  
12 Transactions.

13  
14 **V. PRUDENCE OF THE CUSTOMER COST-SAVING INITIATIVE**

15  
16 Q. ARE THE PROPOSED TRANSACTIONS PRUDENT?

17 A. Yes. The Company's Proposed Transactions are prudent. Our analysis,  
18 with its conservative assumptions, shows that the Proposed Transactions  
19 will result in significant cost savings to customers from both a long-term  
20 perspective and a near-term rate impact perspective. We anticipate that  
21 North Dakota customers will save, conservatively, approximately \$21  
22 million. Based on our analyses, we believe that it is prudent, reasonable and  
23 in our customers' best interests for the Commission to grant an ADP for the  
24 Proposed Transactions.

25

1 **VI. PRESENTATION OF WITNESSES**

2  
3 Q. WHO ARE THE WITNESSES FOR THE COMPANY IN THIS PROCEEDING?

4 A. In addition to my Direct Testimony, the Company sponsors the following  
5 witnesses:

- 6  
7 ● Mr. P.J. Martin discusses the economic analyses and expected cost  
8 savings that we expect to achieve by undertaking our Proposed  
9 Transactions.  
10 ● Mr. Greg Chamberlain discusses the key terms of the Proposed  
11 Transactions.

12  
13 **VII. CONCLUSION**

14  
15 Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

16 A. Yes, it does.

**Aakash H. Chandarana**  
**Regional VP, Rates and Regulatory Affairs**  
**NSP**

Aakash Chandarana is Regional Vice President of Rates and Regulatory Affairs – Minnesota. He is responsible for Xcel Energy’s regulatory filings with the utility commissions in Minnesota, North Dakota, and South Dakota.

Chandarana joined Xcel Energy in 2013 as Lead Assistant General Counsel – Regulatory North where he was the lead regulatory attorney for Xcel Energy’s operations in Minnesota, North Dakota, South Dakota, Wisconsin, and Michigan. He represented Xcel Energy in regulatory proceedings and handled most issues related to rate cases, nuclear issues, fuel costs, depreciation, renewable energy, and resource planning. In January 2015, he was promoted to his current role. He has more than 10 years of experience in energy and regulation.

Chandarana serves on the Finance Board of the Boys and Girls Club. He also is a member of the Minnesota State Bar Association.

Prior to joining Xcel Energy, Chandarana was a partner at the law firm of Briggs and Morgan where his practice focused on the energy industry. He represented utilities in commercial transactions involving generation interconnection agreements, power purchase agreements, and regulatory proceedings.

Chandarana received his B.A. in biology and business management from Washington University in St. Louis and his law degree from Washington University in St. Louis School of Law.

