

Direct Testimony and Schedules
Aakash H. Chandarana

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____(AHC-1)

Policy

July 15, 2017

Table of Contents

I.	Introduction and Qualifications	1
II.	Xcel Energy and North Dakota	9
III.	Integrated Service	13
IV.	Framework for Separation	25
V.	Separation Structures	33
VI.	Conclusion	39

Schedules

Qualifications	Schedule 1
Resource Treatment Framework Application	Schedule 2
Xcel Energy's June, 2016 Compliance Filing	Schedule 3
Utility Dive Article: July 11, 2017 - "Steel for Fuel"	Schedule 4

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 (NSPM or Xcel Energy or the Company). In this role, I am
7 responsible for NSPM’s regulatory filings with the utility commissions in
8 Minnesota, North Dakota, and South Dakota, including proceedings related
9 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. I provide policy support for the Company's proposed Resource Treatment
3 Framework (RTF). I also adopt the Company's RTF Application and the
4 Company's June, 2016 Compliance Filing, which are provided as
5 Exhibit____(AHC-1), Schedule 2 and Schedule 3, respectively.

6

7 Q. DO YOU HAVE ANY INITIAL COMMENTS REGARDING THIS PROCEEDING?

8 A. Yes, I do.

9

10 We have successfully managed our integrated System for nearly a century.
11 In that time, we have been able to provide safe and reliable electric service at
12 affordable cost for all our customers in all the states we serve. Starting
13 almost two decades ago, the legal, regulatory, and policy priorities of the
14 states we serve – specifically of Minnesota and North Dakota – began to
15 diverge. This divergence began driving the development of the NSP System
16 in a way that stressed the integrated nature of our System. Starting in 2007
17 those stressors began to manifest themselves in rate proceedings to a point
18 where they required attention.

19

20 In our most recent rate case, policy-driven historic resource decisions were
21 at the forefront of the litigated issues. In addition, our last rate case also
22 examined North Dakota's role in the overall NSP System through challenges
23 to the demand allocation methodology we have used for decades to tie
24 together the states served by the Company through rates. As part of the
25 settlement of that rate case we agreed to seek a solution to these issues. The
26 Settlement Agreement contemplated a "restacking" of the NSP System to
27 provide our North Dakota customers with a resource mix consistent with

1 North Dakota priorities. This began our work that is culminating in this
2 proceeding.

3
4 It became clear in our last rate case that our North Dakota stakeholders were
5 concerned that our service to North Dakota comes from an integrated
6 System in which our North Dakota operations make up only a small part.
7 Since that time, we began to experience denial of resource recovery by the
8 Commission more frequently along with more frequent concerns with the
9 Company's current resource decisions. We are concerned that
10 disagreements relating to resource selection are becoming more holistic in
11 nature and are shifting away from resource decisions clearly attributable to
12 Minnesota statutory energy policies. We feel that there may be developing in
13 North Dakota unbridgeable disagreements regarding assessment of resource
14 decisions as the NSP System begins to change.

15
16 Our most recent resource planning cycle has begun the transformation of
17 the NSP System into a cleaner and nimbler fleet. This includes the
18 upcoming closure of Sherco Units 1 and 2 and the development of a large
19 combined cycle generating facility at the Sherco site. It also includes the
20 development of large amounts of wind energy resources to drive down
21 system costs by providing low-cost energy to our customers. Additionally,
22 we believe there is a role for solar energy and other emerging technologies
23 on the System. We believe that this path to a cleaner and more nimble fleet
24 is both in the best interests of our customers and consistent with our
25 business plans. We also recognize that this path is consistent with
26 Minnesota's legal and regulatory priorities. We appreciate, however, that this
27 path may not be embraced in North Dakota.

1 We will continue assessing the future of the NSP System in our next
2 resource planning cycle, which will begin in February of 2019. Through
3 these efforts, we will attempt to position the NSP fleet for the challenges of
4 the future. We intend to always make resource decisions that are in the best
5 interest of our customers and consistent with the requirements of all the
6 states we serve. However, it is unclear if our North Dakota stakeholders
7 share our vision or if we can implement a transformation of the NSP System
8 in a manner that can gain acceptance in both Minnesota and North Dakota.

9
10 We recognize and appreciate the accommodations that the Commission and
11 its Staff have provided us as we worked to develop a solution. It was our
12 hope that such a solution would allow us to evolve the NSP System in a way
13 that can retain its integrated nature while meeting the requirements and
14 priorities of all the states we serve. However, our work to seek a solution
15 has also led us to examine options that would lead to a more separate future
16 for our North Dakota customers. This work ultimately led us to the
17 conclusion that integration may no longer be feasible, and that separation
18 may be the right long-term outcome.

19
20 As we worked to develop a long-term solution, we remained cognizant of
21 the financial implications of these disagreements on the Company.
22 Currently, the financial impacts of managing interjurisdictional
23 disagreements have become material. To the extent that there continues to
24 be disagreement on resource choices, these financial implications could grow
25 to be entirely unmanageable. Consequently, we believe we must reach an
26 outcome in this proceeding.

1 We are hopeful that we can reach consensus on an appropriate path forward.
2 To that end, we have already built a robust record. Our June, 2016
3 Compliance Filing (provided as Schedule 3 to my Direct Testimony)
4 provides an in-depth discussion of both the legal regulatory and policy
5 differences between Minnesota and North Dakota and key regulatory
6 outcomes that illustrate continuing disagreement. Our RTF Application
7 (provided as Schedule 2 to my Direct Testimony) provides our proposed
8 Resource Treatment Framework; discusses the resource planning landscape
9 that underlies our proposal; and provides high-level resource planning and
10 rate impact analyses for the Commission's consideration. We continue to
11 build this record through our direct case, here.

12
13 Specifically, through our direct case we refine our RTF—we now
14 recommend separating our North Dakota operations from the remainder of
15 the NSP System. By using the Legal Separation structure, we can support
16 the separate future that is becoming increasingly clear. In our direct case, we
17 provide additional information and refined and updated analyses for the
18 Commission to consider regarding the costs and benefits of remaining part
19 of the integrated system as well as separating from the NSP System. We
20 believe this additional information will assist the Commission as we work
21 together to determine how best to address past resource disagreements and
22 plan for the future.

23
24 Q. PLEASE DESCRIBE THE COMPANY'S DIRECT CASE.

25 A. Our direct case presents the testimony of five witnesses, each of which
26 builds upon the testimony of the other.

1 I provide policy support for our proposed RTF and include information to
2 place our proposal in context.

3
4 Company witness Mr. Richard “Rick” Starkweather provides a more detailed
5 discussion of our RTF. He also discusses the benefits and costs of
6 integration to provide context for our proposal. He then discusses the
7 various structures we have been evaluating to support our Framework and
8 the conclusions we have reached. Mr. Starkweather then analyzes the
9 benefits and costs of the two separation structures that were discussed at
10 length in our RTF Application—Pseudo Separation and Legal Separation.
11 Mr. Starkweather supports our choice for Legal Separation and also provides
12 support for our vision of a new operating company as being a distribution-
13 only utility. Mr. Starkweather also addresses the operational and
14 organizational matters that must be addressed to support a more separate
15 future. He then identifies and supports the assumptions utilized by our
16 other witnesses to provide more detailed analyses of our proposal and
17 alternatives.

18
19 Company witness Mr. Philip Joseph “P.J.” Martin discusses how we plan for
20 the NSP System, the benefits of the integrated NSP System, and updated
21 resource planning analyses supporting our proposal. Mr. Martin’s analyses
22 demonstrate that continued integration could be beneficial to our North
23 Dakota customers but that separation could also be feasible when that
24 separation is undertaken gradually to retain the value of the majority of the
25 NSP System which our North Dakota customers have supported for
26 generations.

1 Company witness Ms. Karen Everson's Direct Testimony provides
2 information regarding our corporate accounting and the cost impacts to
3 corporate allocations that can occur through Legal Separation as well as how
4 a Pseudo Separation structure could be implemented.

5
6 Company witness Mr. Charles Burdick consolidates the information
7 provided by Company witnesses Mr. Starkweather, Ms. Everson, and Mr.
8 Martin to develop a revenue requirements analysis. His testimony thus
9 provides information regarding the impact of our RTF on North Dakota
10 rates.

11
12 Last, Company witness Mr. Stephen Beuning addresses transmission service
13 to our North Dakota customers. While many of the issues we have been
14 addressing to date are related to generation service, when analyzing the
15 potential for separation scenarios it is necessary to ensure that we can
16 continue to deliver electricity to our customers. The historic development of
17 the transmission system in and around North Dakota makes this particularly
18 challenging and Mr. Beuning provides context for understanding these
19 challenges.

20
21 Q. HOW IS YOUR DIRECT TESTIMONY ORGANIZED?

22 A. I first discuss Xcel Energy Inc. and the Company to provide context for how
23 we serve our North Dakota customers and our overall corporate vision of
24 the future. I then discuss our specific North Dakota operations. I also
25 demonstrate how, through over a century of service, the Company has taken
26 seriously both its obligation to provide electric service and its role as an
27 integral part of the communities we serve. I believe this information is
28 important to help the Commission understand our goals and our

1 responsibilities and how they manifest themselves for our customers. This
2 discussion also provides a reminder to participants in this proceeding that
3 the Company has a long track record in North Dakota of not only safe and
4 reliable utility service but also of strong corporate citizenship.

5
6 I next discuss the mechanics of how we provide our North Dakota
7 customers electric service through the integrated NSP System, the benefits
8 of that system, the evolution of the NSP System over the upcoming decades,
9 and our concern that our North Dakota stakeholders may not share our
10 vision for the future of the NSP System—despite the Company’s belief that
11 continued integration is in our customers’ best interest.

12
13 Thereafter, I present the Company’s proposal to gradually separate our
14 North Dakota electric operations from the NSP System. I also discuss our
15 proposal to resolve past and likely near-term future disagreements to
16 establish a “Legacy System” that can continue to serve our North Dakota
17 customers as a bridge to a more separate future.

18
19 I then discuss the Company’s recommendation that our proposed RTF be
20 implemented through the Legal Separation structure. I address the Pseudo
21 Separation structure but conclude that it does not provide sufficient certainty
22 for the Company going forward and—thus—recommend Legal Separation
23 as the preferred structure notwithstanding the associated costs.

II. XCEL ENERGY AND NORTH DAKOTA

1
2
3 Q. PLEASE DESCRIBE XCEL ENERGY INC.

4 A. Headquartered in Minneapolis, Minnesota, Xcel Energy Inc.'s operations
5 include the activity of four wholly-owned utility subsidiaries that serve
6 electric and natural gas customers in our eight states: Minnesota, North
7 Dakota, South Dakota, Wisconsin, Michigan, Colorado, Texas, and New
8 Mexico. These utility subsidiaries, referred to as operating companies, are
9 Northern States Power Company-Minnesota, Northern States Power
10 Company-Wisconsin, Public Service Company of Colorado and
11 Southwestern Public Service Company. Together, these operating
12 companies service almost three and half million electric customers and
13 almost two million gas customers.

14
15 Xcel Energy Inc. is a recognized industry leader in delivering renewable
16 energy and in reducing carbon and other emissions, efforts that have put us
17 on a path to a more sustainable energy future. Through a growing range of
18 innovative solutions, we continue to empower our customers with industry-
19 leading options and energy alternatives to support their goals and objectives.
20 In a rapidly changing industry, we are taking a smart and thoughtful
21 approach to how we produce and deliver energy, looking for better ways to
22 serve our customers.

23
24 In service to our customers we have outlined a vision for the future that
25 focuses on renewable energy and decarbonizing our generation fleet. We
26 call our current initiative "Steel for Fuel." This name reflects how we
27 continue to add renewable energy to our system to replace fossil generation.
28 In furtherance of this, Xcel Energy Inc. is adding 1,550 MW of wind

1 generation to the NSP System and the 600 MW Rush Creek wind project in
2 Colorado, among other projects. These wind additions allow us to capture
3 the production tax credits that make wind a cheap source of energy, driving
4 down overall system costs in the long-term. We also plan to pivot to what
5 may come next, such as solar. Solar's pricing is becoming more and more
6 attractive and tax credits for solar will begin to decrease in 2020. These
7 investments will also support our pledge to reduce carbon emissions 60
8 percent by 2030. I expect that the Company, as the largest operating
9 company in the Xcel Energy Inc. system, will play a large role in our overall
10 vision for the future.

11
12 I provide as Exhibit___(AHC-1), Schedule 4 to my Direct Testimony a brief
13 article summarizing a recent interview with Xcel Energy Inc.'s CEO
14 regarding this vision.

15
16 Q. PLEASE DESCRIBE XCEL ENERGY'S OPERATIONS IN NORTH DAKOTA.

17 A. Xcel Energy serves approximately 93,000 electric and 24,000 gas customers
18 in North Dakota. We have been providing service to our North Dakota
19 customers since 1911, when we purchased the utility companies then serving
20 customers in and around Fargo, Minot, and Grand Forks, North Dakota;
21 including customers on the Minnesota side of the Red River in Moorhead
22 and the East Grand Forks area.

23
24 We serve our electric customers in North Dakota through the integrated
25 NSP System. The NSP System is comprised of the transmission and
26 generation assets of NSPM, and its sister corporation, Northern States
27 Power Company, a Wisconsin corporation (NSPW). Together, the NSP
28 System serves over 1.6 million electric customers in five states: Minnesota,

1 Wisconsin, South Dakota, North Dakota, and Michigan. Overall our
2 Minnesota customers comprise approximately 75 percent of the overall load
3 served by the NSP System, our Wisconsin customers make up about 15
4 percent of our overall system load, and our North Dakota customers make
5 up about five percent of the total NSP System load, with South Dakota and
6 Michigan making up the remainder.

7
8 Our North Dakota operations make us the largest utility in the State of
9 North Dakota. However, in the context of the overall operations of Xcel
10 Energy Inc., our North Dakota operations make up approximately one
11 percent of the Company's overall balance sheet.

12
13 Q. DO CUSTOMERS DERIVE BENEFITS FROM BEING SERVED BY SUCH A LARGE
14 CORPORATION?

15 A. Yes. Customers benefit from the size and scope of Xcel Energy Inc.'s and
16 Northern States Power Company's large size through leveraging economies
17 of scale. For example, we have a centralized sourcing function that allows us
18 to become a "preferred provider" for many of our vendors – this means we
19 get attractive pricing on everything from tools to steel to wind turbines. We
20 can then pass these savings on to our customers.

21
22 Additionally, our size and scope provides us with larger financial
23 wherewithal than smaller utilities. This is reflected in our strong balance
24 sheet and attractive cost of debt.

25
26 Last, our size and scope as a Fortune 250 company allows us the ability to
27 support the communities we serve. We recognize that it is a privilege to be

1 afforded the right to provide utility service, and we believe it is the right
2 thing to do to give back to our communities.

3
4 Q. CAN YOU PROVIDE EXAMPLES OF HOW XCEL ENERGY IS INVOLVED IN ITS
5 NORTH DAKOTA COMMUNITIES?

6 A. Xcel Energy has a culture of community service dating back to at least the
7 late 1920s, when the volunteer fire department in Minot, North Dakota, was
8 made up entirely of Company employees. Today, the Company continues to
9 work to strengthen the social and economic well-being of its North Dakota
10 service territory by engaging in philanthropic activities ranging from
11 supporting the United Way to volunteering at Feed My Starving Children
12 and the Wild West Rodeo for Special Kids.

13
14 Further, Xcel Energy employees and retirees work with various nonprofits in
15 North Dakota during the Company's Annual Day of Service; volunteer every
16 holiday season for the Salvation Army; and volunteer time and talent to
17 inspire and prepare young people to succeed in a global economy through
18 the Junior Achievement program, where Xcel Energy employees volunteer
19 in K-12 classrooms to equip students with skills around financial literacy,
20 entrepreneurship, and work readiness.

21
22 Q. ARE THE OTHER EXAMPLES YOU WOULD LIKE TO MENTION?

23 A. Yes, our service is not just limited to good works in the community but also
24 extends to supporting important research. For example, we are actively
25 involved with the drone program in Mayville, North Dakota, where,
26 alongside a team of researchers, we are conducting a series of test flights and
27 analyses as part of a year-long research project testing the effectiveness of
28 using drones for assessing areas of destruction to electric infrastructure.

1 Q. ARE THESE ACTIVITIES RECOVERED IN YOUR RATES?

2 A. No, many of these activities, and their costs, are not eligible for rate
3 recovery. For those costs that are eligible for rate recovery, the Commission
4 has disallowed from rates our charitable contributions since at least our 2013
5 rate case (PU-12-813). Notwithstanding that disallowance, we continue to
6 participate in many of these charitable activities because we consider active
7 participation in our communities to be a core value.

8

9 Q. WHY DO YOU BELIEVE IT IS IMPORTANT TO ESTABLISH XCEL ENERGY'S
10 NORTH DAKOTA ACTIVITIES AS PART OF THE RECORD IN THIS PROCEEDING?

11 A. I think it is important to remind the Commission and the parties to this
12 proceeding that we have served our North Dakota customers and been a
13 part of the North Dakota community for generations. We have gone
14 beyond satisfying our obligation to serve and have established ourselves as a
15 contributing member of the North Dakota community. While this
16 proceeding may be acrimonious; we hope that we can arrive at a reasonable
17 resolution that meets the needs of our customers, regulators, and
18 stakeholders in a way that balances competing priorities while achieving just
19 outcomes.

20

21

III. INTEGRATED SERVICE

22

23 Q. PLEASE DESCRIBE THE INTEGRATED NSP SYSTEM.

24 A. As I mentioned, the current NSP System is comprised of a diverse electric
25 generating fleet with an installed capacity of over 10,000 MW meeting the
26 energy needs of approximately 1.6 million electric customers.

1 Our generation portfolio currently includes the High Bridge, Riverside, and
2 Angus Anson natural gas plants in Minnesota and South Dakota, the
3 Monticello and Prairie Island nuclear facilities in Minnesota, and the Sherco
4 and Allen S. King plants in Minnesota. The NSP System also includes
5 peaking plants located in Minnesota and Wisconsin, as well as approximately
6 5,000 MW of renewable energy capacity, including the 1,550 MW Wind
7 Portfolio. These resources include Border Winds, Courtenay, and soon to
8 be constructed Foxtail wind farms in North Dakota. NSPM and NSPW
9 continue to own all levels of the electric supply chain, *i.e.*, generation,
10 transmission, and distribution, and are regulated by each of the states served
11 by the NSP System (and the Federal Energy Regulatory Commission
12 (FERC)) as vertically integrated utilities.

13
14 The integrated nature of the NSP System allows us to construct, plan and
15 operate generation and transmission facilities across the five-state area to
16 provide economic and reliable supply of electricity to meet the needs of our
17 customers. The integrated NSP System supports our customers by
18 providing opportunities to leverage economies of scale, access diverse and
19 numerous generation resources, take advantage of load diversity, and
20 construct a robust and resilient transmission system.

21
22 Company witness Mr. Martin provides additional information regarding the
23 integrated NSP System in his Direct Testimony.

24
25 Q. IS XCEL ENERGY UNIQUE IN SERVING NORTH DAKOTA THROUGH AN
26 INTEGRATED SYSTEM?

27 A. Yes and no. All the investor-owned utilities providing electric service in
28 North Dakota do so through multi-state integrated systems. By doing so,

1 they can aggregate total system load to achieve better economies of scale
2 through integrated generation and transmission development than if they
3 were serving their native North Dakota load on a stand-alone basis.

4
5 That said, Xcel Energy is unique in that its North Dakota load is the largest
6 in the state; its integrated system is far and away the largest of all the investor
7 owned utilities in North Dakota. However, our North Dakota customers
8 make up the smallest percentage of the overall system load for the NSP
9 System when compared to the other integrated systems serving North
10 Dakota customers.

11
12 Q. WHAT DO YOU CONCLUDE FROM THIS?

13 A. Generally, I conclude that—given their relative contribution to the NSP
14 System—our North Dakota customers derive more value from the NSP
15 System than other North Dakota electric customers derive from their
16 respective integrated systems

17
18 Q. WHAT IS THE VALUE OF THE NSP SYSTEM?

19 A. In general, the states served by the NSP System are in a more secure
20 environment than if they were served independently due to the sheer size of
21 the System. There is a certain “safety in numbers” that helps cushion the
22 states we serve from external, unanticipated impacts and the size and scope
23 of the system allows the Company to position itself to meet the challenges of
24 the future.

25
26 For example, the System is sufficiently large so that we can almost always
27 choose to acquire new generation to meet needs rather than taking short
28 term market positions. This provides material hedges against energy market

1 pricing, through dispatch of owned generation, and against capacity market
2 pricing, through owning our resources. The System is also sufficiently large
3 to provide material fuel diversity from coal to gas to wind to nuclear without
4 overreliance on any specific fuel type. This hedges against fuel cost
5 volatility.

6
7 Additionally, the NSP System allows us to defray costs over a very large
8 customer base, allowing us to acquire and gain crucial knowledge regarding
9 new technologies as they begin to emerge. Xcel Energy's early experience
10 with wind power provided us with the knowledge to acquire, develop and
11 integrate wind into the system so that we could quickly take advantage of
12 expiring production tax credits to create our 1,550 MW Wind Portfolio and
13 integrate it into the overall NSP System. We similarly expect that our
14 experience to date with solar technologies – including the 100 MW of
15 distributed solar from the Aurora Project – will give us important
16 operational experience in integrating the very small percentage of solar
17 resources that make up our resource mix today to maximize the value of this
18 technology as prices continue to fall.

19
20 Company witness Mr. Martin further discusses the benefits of the integrated
21 NSP System in his Direct Testimony.

22
23 Q. ARE THERE COSTS TO INTEGRATED SERVICE FROM THE NSP SYSTEM?

24 A. Yes, the NSP System is not without costs. Current market conditions and
25 historically low natural gas prices have exacerbated the cost of the hedge
26 value of the System. Many of the disagreements that we were experiencing
27 over the past decade occurred at a time of historically low gas prices which
28 are driving down overall costs in the marketplace. There appears to have

1 been more opportunities to reach agreement when natural gas and market
2 prices were higher. But there is important value in the integrated nature of
3 the NSP System notwithstanding the effect of these price fluctuations.
4

5 Q. DO YOU BELIEVE THAT THERE IS GENERAL SUPPORT FROM YOUR NORTH
6 DAKOTA STAKEHOLDERS FOR THE INTEGRATED NSP SYSTEM?

7 A. Yes, I do. There is little disagreement on most resources that make up the
8 current NSP System. In fact, the Settlement of Case No. PU-12-813, which
9 provided the negotiating principles for our Restack efforts, explicitly
10 recognized this. This recognition is consistent with the fact that the
11 biomass, C-BED, and solar resources identified in the 2013 rate case are
12 essentially on the margins of the System. While their costs are material and
13 the Company cannot forgo their recovery, they make up a small percentage
14 of the capacity and energy serving the NSP System.

15
16 Since that time, however, more central resource decisions have been
17 questioned by the Commission. Examples of this include our proposal to
18 add combined cycle capacity to the NSP System through the Mankato
19 Energy Center Expansion (MEC II) project PPA as well as the reception of
20 our proposal to close Sherco Units 1 and 2. While these more recent
21 disagreements do not necessarily indicate to the Company that there is no
22 longer any support for the NSP System, I am concerned that support for the
23 integrated NSP System is eroding just as we are entering a time where
24 System changes must occur.

25
26 Q. WHAT IS DRIVING CHANGES TO THE NSP SYSTEM?

27 A. Our RTF Application discusses the resource planning landscape that
28 underlies our development of the RTF. The reality is that five key PPAs will

1 expire between 2025-2027 and eight key energy and capacity units will reach
2 the end of their useful lives between 2030-2037. This is before considering
3 the several hundred megawatts of peaking resources that are at, or nearing,
4 the end of their useful lives.

5
6 Q. WHAT DOES THAT MEAN FOR THE FUTURE OF THE NSP SYSTEM?

7 A. It means that the NSP System must evolve to replace the expiring resources
8 in a totally different fuel and market environment than the one in which the
9 current NSP System was created. Earlier in my testimony, I discussed how
10 Xcel Energy is seeking to do so. While the current system was created over
11 the course of generations, decisions regarding the future evolution of the
12 System will be made over a much shorter period. This presents significant
13 opportunities and material challenges.

14
15 Q. WHAT OPPORTUNITIES DOES THIS PRESENT?

16 A. The fact that so much of the NSP System, and essentially all our key
17 baseload units, will be turning over in the next two decades allows us to take
18 a comprehensive and holistic approach to what the future NSP System will
19 look like. This is materially different than how the System grew into what it
20 is today through meeting incremental growth by acquiring the right resource
21 to meet an identified need.

22
23 We are therefore presented the significant opportunity to position the NSP
24 System so that it can perform nimbly within the current market
25 environment. This includes considering operational aspects of replacement
26 resources, such as ramp rates, and the appropriate resource mix given
27 existing market forces and the current – and potentially long-term – low gas
28 price environment.

1 We can also consider newer resource types that are now available – these
2 include mature resources such as wind and emerging resources such as solar.
3 We believe it is now an established fact that using wind as an energy
4 resource can materially drive down system costs, and solar appears to be
5 moving in a similar direction. To the extent that these types of intermittent
6 resources will play a key role in the evolution of the NSP System, it will be
7 important to acquire large capacity resources that can follow load and
8 support a system with material wind and solar penetration. Distributed
9 generation, installed not as part of the larger network but at the distribution
10 level, will also continue to evolve and we have an opportunity to develop a
11 system that can support and exploit this. Last, as demand side management
12 technologies continue to improve, they may be able to provide another
13 avenue to serve our customers through fewer resource additions.

14
15 Q. WILL THESE CHANGES RESULT IN A SMALLER OVERALL NSP SYSTEM?

16 A. No. Although the NSP System must change, the size and scope of the
17 system will continue to be an important benefit to our customers. Much of
18 the System's value proposition today will remain for our customers in the
19 future. Physical hedges against market forces will likely be more valuable
20 tomorrow than they are today. Fuel diversity will also continue to be a key
21 value proposition of the System as market forces have established the
22 primacy of gas which has pushed coal fired generation to the margins. On a
23 smaller scale, our ability to utilize existing interconnection and transmission
24 rights should also provide additional value as we transform the fleet.

25
26 The opportunities presented to us require a different view of resource
27 planning, one that values flexibility over a strict need plus least cost
28 paradigm. If we can evaluate resource decisions in this more comprehensive

1 light, we have a once-in-a-lifetime opportunity to rebuild the NSP System to
2 meet the challenges of tomorrow.

3
4 Q. WHAT CHALLENGES DOES THE EVOLUTION OF THE NSP SYSTEM PRESENT?

5 A. The evolution of the NSP System is likely to exacerbate the current
6 challenges that underlie this proceeding; namely, the ability to garner
7 consensus across the five states as to the direction of the NSP System. This
8 can be difficult, as all of the states that are served by the NSP System have
9 different legal and regulatory requirements that influence resource planning
10 decisions. We describe many of these differences in our June, 2016
11 Compliance Filing provided as Schedule 3 to my Direct Testimony.

12
13 As the NSP System evolves, it must do so in light of these requirements.
14 For example, Minnesota's preference for renewable energy, de-carbonization
15 goals, renewable and solar mandates, and externality requirements will play a
16 role in our resource planning efforts as these are the requirements set forth
17 by the jurisdiction driving seventy-five percent of the NSP System's scope
18 and size. We think these requirements align with the Company's efforts to
19 address tomorrow's challenges. However, we recognize that our North
20 Dakota jurisdiction may disagree with evolving the NSP System in a
21 direction consistent with these requirements.

22
23 Further, we may incur additional near-term costs to better position the NSP
24 System for the future. Doing so may be consistent with some states'
25 planning paradigms but not others. Finding the appropriate balance is made
26 more challenging when we are operating in an environment where the
27 integrated System is not fully and fairly valued.

1 Q. HAS THE COMPANY BEGUN THE EVOLUTION OF THE NSP SYSTEM?

2 A. Yes. Our most recently completed resource planning cycle has set us on a
3 path of System transformation. The Company is beginning to evolve the
4 System by adding 1,550 MW of wind energy to drive down overall system
5 costs; retiring Sherco Units 1 and 2 and replacing them with a combined-
6 cycle gas generating facility which provides fuel diversity and a generation
7 source that can better follow load; identifying ways to optimize our current
8 energy resources by revisiting historic contracts that may no longer be
9 economic; and continuing to develop solar and other technologies, such as
10 demand response and advanced grid technologies.

11

12 Q. WHAT ARE THE NEXT STEPS?

13 A. As part of our next resource planning cycle we will also be making a
14 comprehensive assessment regarding our baseload fleet and determining
15 how best to manage these resources through their remaining lives, including
16 the potential of early retirements. We expect that this resource planning
17 cycle will continue to set the evolutionary path of the NSP System. The next
18 resource plan is ordered by the Minnesota Public Utilities Commission
19 (MPUC) to be filed February 1, 2019.

20

21 Through this work, we expect that over the next decades the NSP System
22 will continue to shift to a different portfolio than the one serving our
23 customers today. We are beginning to make changes based on our best
24 judgments about the challenges and dynamics of the future. Despite the
25 potential for rational and legitimate disagreement, we believe strongly that,
26 over the long-term, this direction is in all our customers' best interest.

1 Q. GIVEN THE LIKELY CHANGES TO THE NSP SYSTEM, DO YOU BELIEVE THAT
2 IT IS IN YOUR NORTH DAKOTA CUSTOMERS' BEST INTEREST TO REMAIN PART
3 OF IT?

4 A. As I noted earlier, yes. The NSP System provides numerous benefits to
5 those states served by it, benefits that we believe far outweigh the costs.
6 Those benefits will likely remain as the System evolves. We hope that there
7 is a way to resolve interjurisdictional differences so that the Company can
8 recover its full cost of service in each of its jurisdictions, thereby preserving
9 the fully integrated nature of the System. However, this would require our
10 North Dakota stakeholders to value the benefits of integrated NSP System
11 sufficiently to shoulder their proportional share of its total costs.

12
13 Q. WHAT DO YOU MEAN THAT NORTH DAKOTA CUSTOMERS SHOULD
14 SHOULDER THEIR PROPORTIONAL SHARE OF THE NSP SYSTEM'S COSTS?

15 A. The NSP System provides material benefits through economies of scale to
16 all the customers served by it. Our North Dakota customers make up only
17 about five percent of the NSP System. whereas our Minnesota customers
18 make up approximately 75 percent of the System. Because of this
19 imbalance, our North Dakota customers can be served by a larger and more
20 diverse system than they otherwise could be, either as a separate utility or as
21 part of a different utility system. This provides material benefits including
22 hedges against future uncertainty that cannot be obtained in other ways. We
23 believe it is reasonable to ask that our North Dakota customers shoulder the
24 costs of the System in order to receive its benefits.

25
26 Stated plainly, the Company believes that if North Dakota customers are to
27 obtain the benefits of the NSP System, they must pay their share of all the
28 costs of the NSP System.

1 Q. WHAT DOES THIS MEAN WITH RESPECT TO THE COMMISSION'S OVERSIGHT
2 OF THE COMPANY'S RESOURCE SELECTIONS?

3 A. North Dakota is a sovereign state, with its own laws and independent utility
4 regulators. Respecting North Dakota's sovereign dignity has been a core
5 principle guiding our management of the NSP System for generations and an
6 important reason for this proceeding. We must determine how to best
7 respect North Dakota's sovereignty considering the multi-state nature of the
8 NSP System and our North Dakota customers' role in it. One purpose of
9 this proceeding is to evaluate if North Dakota would like to continue to
10 participate in the integrated NSP System.

11

12 Q. DOES THE COMPANY PREFER AN INTEGRATED SOLUTION?

13 A. It is the Company's preference to retain a fully integrated system with all
14 states currently served by it continuing to participate, now and into the
15 future. We believe that this is not only in our customers' best interest but
16 that alternatives to continued integration are likely to be contentious and
17 imperfect.

18

19 Q. DOES THE CURRENT STATUS QUO ACHIEVE THIS OUTCOME?

20 A. We cannot continue to retain an integrated System under the current status
21 quo. First, the current status quo allows our North Dakota customers to
22 obtain the benefits of the NSP System without paying their fair share. Over
23 time, this ultimately leads to free rider issues and fundamental
24 interjurisdictional inequities. Second, we cannot allow five percent of the
25 NSP System to retain a veto on resource decisions; this is inconsistent with
26 the overall contribution to the economies of scale of the NSP System
27 provided by our North Dakota customers. Said differently, failure to make
28 changes to the current status quo ultimately results in the Company failing to

1 recover its full cost of service while providing five percent of the NSP
2 System with the ability to block all future action for the System. Neither of
3 these outcomes is acceptable.

4
5 Therefore, to retain an integrated solution, something must change. Those
6 changes must include a recognition by the Commission that their resource
7 decisions should be made within the context of the overall integrated
8 System. This was the case for the many years prior to our most recent rate
9 case. It also requires the Company to recognize North Dakota's role in the
10 integrated NSP System and to ensure that it appropriately invests in the
11 state. These types of changes can, potentially, allow us to narrow
12 disagreements in the future so that such disagreements can be manageable.
13 The Regulatory Alignment structure discussed in our RTF Application and
14 by Mr. Starkweather is intended to allow for these changes to occur, if
15 continued integration is the chosen path. We are open to discussing how
16 these changes to the current status quo can be achieved to retain the
17 integration of the NSP System.

18
19 Q. IS THE COMPANY PROPOSING AN INTEGRATED SOLUTION FOR ITS RESOURCE
20 TREATMENT FRAMEWORK?

21 A. Our judgment is that given the current state of affairs, an integrated solution
22 is not feasible. Therefore, our proposal is to gradually separate our North
23 Dakota customers from the NSP System so that as the NSP System evolves,
24 North Dakota can be served by a separate system that meets its needs
25 consistent with its size.

1 **IV. FRAMEWORK FOR SEPARATION**

2
3 Q. WHAT IS THE COMPANY PROPOSING IN THIS PROCEEDING?

4 A. We are proposing a framework that will result in a more separate future for
5 the NSP System by, over time, separating our North Dakota service territory
6 from the remainder of the integrated NSP System. Our proposed RTF
7 achieves this separate future gradually while recognizing the long-term
8 investment that all our customers have made in the vast majority of the
9 current generation portfolio of the NSP System.

10
11 Q. HOW DOES THE COMPANY’S PROPOSAL ACHIEVE THIS?

12 A. At a high level, our RTF seeks to resolve past and likely near future
13 disagreements; establish separate operating parameters for our North
14 Dakota electric operations; and serve our North Dakota customers from a
15 “Legacy System” that will serve as a bridge to the establishment of a system
16 serving our North Dakota customers separate from the remainder of the
17 NSP System. These elements form the basis of our Resource Treatment
18 Framework. Our RTF Application presented our proposed Resource
19 Treatment Framework and each of its five components. Company witness
20 Mr. Starkweather discusses each component of our proposal in more detail.

21
22 At its core, our RTF is intended to solve for past disagreements and
23 equitably separate our North Dakota electric operations from the remainder
24 of the NSP System.

25
26 Q. WHY IS THE COMPANY PROPOSING TO SEPARATE NORTH DAKOTA FROM
27 THE REMAINDER OF THE NSP SYSTEM?

28 A. It our current judgement that the direction in which the Company is taking

1 the NSP System may not be fully supported in North Dakota. This
2 judgment leads us to believe that it is unlikely that we will be able to fully
3 recover the North Dakota share of total System costs into the future.
4 Consequently, we are left with few options other than separation.

5
6 Q. WHY DO YOU BELIEVE THAT THE COMPANY'S VISION OF THE FUTURE IS NOT
7 SUPPORTED BY ITS NORTH DAKOTA STAKEHOLDERS?

8 A. Our experience over the past decade has demonstrated to us that the
9 regulatory paradigm in North Dakota will apparently no longer permit the
10 Company to recover certain costs that are incurred for the NSP System that
11 are incompatible with North Dakota's energy priorities. Over the past
12 decade, the Commission has rejected, or otherwise expressed concern
13 regarding, generating resource additions serving the entire NSP System as
14 well fundamental ratemaking issues that tie the NSP System together. We
15 provide a detailed discussion of the stressors on the System in both our June
16 2016 Compliance Filing and our RTF Application.

17
18 As we look to the future, we are concerned that the Commission is likely to
19 have similar concerns over increasingly consequential decisions regarding the
20 future direction of the NSP System. These include decisions regarding unit
21 retirements, new resource additions, the future of our nuclear fleet, and
22 expansion of solar generation on the System, the impacts of distributed
23 generation on the System, as well market driven decisions relating to the
24 impact of low gas prices on coal operations. As the NSP System continues
25 to evolve in the coming years, we see it as increasingly unlikely that we can
26 chart a path for the NSP System that can obtain the full support of the
27 regulators in both North Dakota and other states of the System. Therefore,
28 we are proposing a separate future for our North Dakota customers so that

1 we can develop a system to meet their specific interests as expressed by the
2 Commission.

3
4 Q. IS A SEPARATE FUTURE FEASIBLE?

5 A. Yes. As discussed in our RTF Application, the evolution of the utility
6 industry, including the establishment of energy markets, Regional
7 Transmission Organizations (RTOs), and other innovations no longer
8 requires that a relatively small amount of load be part of a large, integrated
9 system to receive economic service. Rather, these changes create options,
10 other than central station integrated utility systems, by which utilities can
11 provide safe and reliable service to their customers. We believe that these
12 changes provide the opportunity to establish a system profile for North
13 Dakota with a different set of risks and rewards than if it were part of the
14 NSP System, while maintaining safe and reliable service. Mr. Starkweather
15 discusses this further in his Direct Testimony.

16
17 Key to our RTF is achieving full separation gradually while recognizing the
18 support our North Dakota customers have had for the large portion of the
19 existing NSP System that currently serves them. A gradual approach will
20 mitigate the impacts of separation on all stakeholders of the NSP System and
21 allow us to plan fully meet all of our customers' needs into the future.

22
23 Q. HOW DOES THE COMPANY'S PROPOSAL ACHIEVE SEPARATION GRADUALLY?

24 A. Our RTF does so by proposing to establish a Legacy System and continuing
25 to serve our North Dakota customers from it. This allows our North
26 Dakota customers to retain the benefits of being part of the NSP System
27 through service by the majority of the existing NSP System which they have
28 supported and paid for over the years. By continuing service from the

1 Legacy System, the separation of our North Dakota operations will be
2 gradual as a new North Dakota-only generation fleet will be developed to
3 meet needs created by North Dakota load growth or by the retirement or
4 expiration of existing NSP System resources.

5
6 Q. WHAT RESOURCES DOES THE COMPANY PROPOSE BE INCLUDED AS PART OF
7 THE LEGACY SYSTEM?

8 A. We are proposing to establish the Legacy System as all the generating
9 resources of the NSP System after the reallocation of resources we have
10 identified as related to past disagreements between states and likely future
11 disagreements. The ultimate determination of what resources will be
12 included in the Legacy System depends, in part, on how the costs for these
13 disagreements are assigned among our states and therefore requires
14 consensus on the composition of the Legacy System requires the input of
15 the Commissions.

16
17 Q. WHAT ARE THE PAST RESOURCE DISAGREEMENTS TO WHICH YOU ARE
18 REFERRING?

19 A. These resources are specifically identified in our RTF Application and
20 generally include certain biomass power purchase agreements (PPAs);
21 smaller solar resources, larger-scale solar PPAs, and solar gardens;
22 community-based energy development (C-BED) resources; wind PPAs; and
23 the Mankato Energy Center Expansion (MEC II) project PPA. We call
24 these resources the “Disputed Resources” for ease of reference. While other
25 resources and costs are implicated in this concept, the Disputed Resources
26 are those for which the Company is not recovering fully its costs in North
27 Dakota or is recovering its costs subject to refund.

1 Q. TO WHAT ANTICIPATED FUTURE DISAGREEMENTS ARE YOU REFERRING?

2 A. We would expect that additional items may come before the Commission
3 that could be implicated in resolving past and new future disagreements
4 prior to our being able to implement our RTF in approximately 2020. There
5 are four issues of which we are currently aware that we believe should be
6 addressed in this Case:

7 (1) The appropriate allocations for the Company's proposed 1,550
8 MW Wind Portfolio filed in Case No. PU-17-120;

9 (2) The Company's need to recover the portion of Serco Units 1 and
10 2 that will not be fully depreciated on our North Dakota books by the time
11 of their retirement; in contrast to all other states in the NSP System;

12 (3) The final disposition of the Company's PPA for the expansion of
13 the combined-cycle MEC II, the ADP for which the Commission dismissed
14 without prejudice on Case No. PU-15-96; and

15 (4) How to address the Company's proposed biomass optimization
16 transactions filed in Case No. PU-17-270.

17

18 Q. HAS THE COMPANY DEVELOPED A PROPOSAL TO ADDRESS PAST AND NEAR
19 TERM FUTURE DISAGREEMENTS?

20 A. Yes. Our RTF Application provides a proposal that could result in what we
21 believe would be an equitable outcome. We believe a reasonable approach
22 could include:

23 • Allocating all Disputed Resources, with the exception of MEC II, to
24 the remainder of the NSP System and not to North Dakota;

25 • Allocating and recovering from the remainder of the NSP System and
26 not from North Dakota the necessary accelerated depreciation due to
27 the mismatch of book life in North Dakota for Sherco Units 1 & 2;

- 1 • Fully allocating the costs or savings associated with the Company’s
2 proposed new wind projects to the remainder of the NSP System and
3 not to North Dakota; and
- 4 • Recovering North Dakota’s allocated share of the MEC II PPA in
5 North Dakota.

6

7 To be clear, however, we are not advocating for a specific resolution of the
8 treatment of these resources; the above is provided as one of many
9 potentially viable approaches that we believe would result in an equitable
10 outcome. We propose that this proceeding be used to garner consensus
11 among all our stakeholders on a resolution. We believe that our proposed
12 approach is one that reasonably balances the equities involved.

13

14 Q. WHY DOES THE COMPANY BELIEVE ITS PROPOSED RESOLUTION OF THE PAST
15 AND NEAR-TERM FUTURE DISAGREEMENTS RESULTS IN AN EQUITABLE
16 OUTCOME?

17 A. The logic behind our proposal is that it accepts a future in which North
18 Dakota does not fully participate in the NSP System. Our proposed
19 approach implements the North Dakota Commission’s resolution of the
20 Disputed Resources as well as the anticipated disallowance of the
21 unrecovered depreciation for Sherco Units 1 and 2 and shifts these costs to
22 the remainder of the System. Respecting the Commission’s judgment on
23 these issues is important to the Company. I note that shifting the biomass
24 PPAs to the remainder of the NSP System moots our biomass optimization
25 plans in North Dakota.

1 In light of acceptance of the Commission's judgment on the Disputed
2 Resources and Sherco depreciation, we are proposing to allocate the 1,550
3 MW Wind Portfolio away from the North Dakota jurisdiction. We view the
4 Wind Portfolio as demonstrative of the benefits that a large, integrated
5 system can bring on behalf of all our customers. Our view is that to obtain
6 these benefits requires full participation in the NSP System. By accepting an
7 outcome that does not have North Dakota fully participating in all resources
8 of the NSP System, allocating the Wind Portfolio to the remainder of the
9 NSP System can begin the path toward separation.

10
11 With respect to MEC II, our ADP Application for this project was
12 dismissed without prejudice at our request. We continue to believe that this
13 combined-cycle resource addition is prudent and consistent with North
14 Dakota's priorities. Therefore, we propose allocating the North Dakota
15 share to North Dakota and making this resource part of the Legacy System.

16
17 As Mr. Martin and Mr. Burdick discuss, our economic analysis of this
18 outcome demonstrates that this proposal will provide immediate short-term
19 benefits to our North Dakota customers and is consistent with our view of
20 the long-term benefits of the NSP System. More specifically, our proposal
21 will result in immediate savings in North Dakota and increase costs
22 immediately for the remainder of the NSP System. Over time, however,
23 costs in North Dakota will be higher than if all resources were equally
24 allocated to our North Dakota customers for their life.

25
26 Q. BASED ON THIS, WHAT RESOURCES DO YOU ANTICIPATE WILL COMPOSE THE
27 LEGACY SYSTEM?

28 A. We provided a comprehensive list of resources in Schedule Four of our RTF

1 Applications. In short, all key existing resources of the NSP System – such
2 as our coal, nuclear, and gas fleet – will be part of the Legacy System.

3
4 Q. WHY IS IT REASONABLE TO CONTINUE TO SERVE YOUR NORTH DAKOTA
5 CUSTOMERS FROM THE LEGACY SYSTEM?

6 A. There are several reasons. First, and most importantly, continued service
7 from the Legacy System allows our North Dakota customers to retain the
8 portions of the NSP System that they have long supported and have paid
9 for. Second, continued service from the Legacy System will be least
10 impactful to North Dakota rates in that we would expect that the cost of
11 service from these existing resources would be similar in a separation
12 scenario than they would be today. Third, planning for and developing a
13 stand-alone 500 MW system takes considerable amounts of time; continuing
14 service from the Legacy System provides a bridge period during which to
15 accomplish this. Fourth, and finally, continued service from the Legacy
16 System respects the equities related to stranded costs and recognizes that our
17 North Dakota customers should pay for the liabilities created by the
18 resources they have enjoyed for generations.

19
20 Continued service from the Legacy System is a key component of our
21 proposed RTF to both preserve the System for our customers and to help
22 ensure that the Company can fully recover its investments in the System.

23
24 Q. YOU MENTION EARLIER THAT THE NSP SYSTEM IS EVOLVING AND THAT
25 YOU WILL BE ANALYZING THE CURRENT NSP SYSTEM'S FLEET IN YOUR
26 UPCOMING RESOURCE PLANNING CYCLE. IF THE LEGACY SYSTEM IS RETIRED
27 EARLY, WHAT HAPPENS?

28 A. We recognize that either the Company or the environmental or economic

1 regulators in the states where we maintain generating assets may cause a
2 generating unit to be retired early for a variety of reasons. We believe we
3 would have sufficient notice of this happening to allow us to plan to begin
4 creating the North Dakota-only system to cover the capacity and energy
5 requirements which an early retirement may require. This would be the case
6 in any scenario we are proposing for the RTF.

7
8 Q. IS IT REASONABLE TO REQUIRE NORTH DAKOTA CUSTOMERS TO TAKE
9 SERVICE FROM THE LEGACY SYSTEM WHEN IT CANNOT CONTROL SYSTEM
10 RETIREMENTS?

11 A. Yes, it is. This is no different than the current status quo. That said, we
12 recognize that the results of our upcoming resource planning cycle could
13 result in material proposed changes to the NSP System. To that end, we
14 analyzed and proposed a scenario where our North Dakota customers would
15 break with the Legacy System in 2025 and retain service only from our
16 nuclear fleet. We do not recommend this scenario but are open to
17 discussing it further. Company witness Mr. Martin discusses the analysis we
18 performed of this scenario and the prudence of retaining service from at
19 least our nuclear fleet in any event.

20 21 **V. SEPARATION STRUCTURES**

22
23 Q. WHAT STRUCTURES TO SUPPORT THE RTF DID THE COMPANY CONSIDER?

24 A. We analyzed four separate structures that could support an equitable
25 resolution in this proceeding:

- 26 1) *Regulatory Alignment*, which essentially maintains the status quo with an
27 understanding that obtaining the benefits of an integrated system
28 requires full participation in that system;

- 1 2) *Proxy Pricing*, which would set a proxy price for resources rejected by a
2 particular state commission; the Company has rejected this structure
3 as infeasible;
- 4 3) *Pseudo Separation*, which would utilize ratemaking structure to allocate
5 costs and revenues of generating resources to create two separate
6 structures: a “pseudo” system with one serving North Dakota and the
7 other serving the remainder of the NSP System. While we believe this
8 approach can be implemented mechanically, we have rejected this
9 approach, as it requires continuous and long-term agreement on
10 allocation factors amongst the states, agreement we do not believe will
11 be possible over the long term; and
- 12 4) *Legal Separation*, which would have the Company establishing a new
13 operating Company to serve North Dakota.

14

15 These structures are explained in our RTF Application. Further, Company
16 witness Mr. Starkweather discusses these structures and their pros and cons
17 in more detail, as well as what assumptions we utilized in analyzing each of
18 the structures.

19

20 Q. WHAT STRUCTURES WOULD BE FEASIBLE TO SUPPORT THE COMPANY’S
21 PROPOSAL TO SEPARATE ITS NORTH DAKOTA JURISDICTION FROM THE
22 REMAINDER OF THE NSP SYSTEM?

23 A. As discussed in our RTF Application, both the Pseudo Separation and Legal
24 Separation structures can support the separation of our North Dakota
25 jurisdiction from the remainder of the NSP System.

1 Q. IS THE COMPANY RECOMMENDING IMPLEMENTATION OF A PARTICULAR
2 STRUCTURE TO SUPPORT SEPARATING ITS NORTH DAKOTA OPERATIONS
3 FROM THE NSP SYSTEM AT THIS TIME?

4 A. Yes. Our proposed framework is meant to guide the Commissions and the
5 Company in reaching an agreement as to what should happen with the
6 future of the NSP System through open dialogue. As we continued to
7 examine our proposal over the past several months, we are now
8 recommending the implementation of the Legal Separation structure. We
9 believe that a Legal Separation structure will provide all our stakeholders
10 with more certainty and flexibility into the future while charting a path for an
11 implementable and permanent separation.

12
13 Q. PLEASE FURTHER DESCRIBE THE LEGAL SEPARATION STRUCTURE.

14 A. Under a Legal Separation structure, we would create a separate operating
15 company—NSP-Dakota (NSPD)— to serve our North Dakota customers.
16 NSPD would be part of the Xcel Energy Inc. corporate family and would be
17 a separately regulated utility in North Dakota. The new operating company
18 would have its own rate base, operating expenses, and fuel costs that would
19 form that basis of its rates, separate from the rest of the NSP System. We
20 envision NSPD to be an electric-only, distribution-only, operating company
21 and that our gas operations would continue as they are today. Mr.
22 Starkweather discusses this further in his Direct Testimony.

23
24 Q. WHAT WOULD BE THE RELATIONSHIP OF NSPD TO NSPM AND NPSW?

25 A. We would expect that NSPD would enter into contracts with NSPM to
26 obtain service from the Legacy System. The terms of those contracts would
27 need to be developed. Additionally, we would expect that NSPD and
28 NSPM would share services with each other to maximize efficiencies within

1 the Xcel Energy corporate family. Over time, that relationship could
2 change. For example, with an NSPD established, it could potentially join in
3 the Interchange Agreement with NSPM and NSPW if that would make
4 sense for all our customers. Company witness Mr. Starkweather discusses
5 this further.

6
7 Q. WHAT ARE THE ADVANTAGES OF THE LEGAL SEPARATION STRUCTURE?

8 A. Legally separating the North Dakota operations from the rest of the NSP
9 System would provide us with more stability and flexibility as we move
10 forward. Legal Separation provides stability because it completely removes
11 the need for Minnesota and North Dakota to agree on resource selection,
12 ratemaking structures, and the assignment of costs for shared resources on
13 the NSP System. Legal Separation also provides flexibility by completely
14 separating North Dakota operations from the operations of the rest of the
15 System, creating separate operating entities with separate needs that can be
16 fulfilled on an independent basis, without consideration of how those needs
17 will impact other jurisdictions. Significant to North Dakota, the new
18 operating company would have its own independent corporate identity and
19 no longer be subject to the regulatory requirements or decisions of other
20 states.

21
22 Q. WHAT CHALLENGES HAS THE COMPANY IDENTIFIED WITH RESPECT TO
23 ESTABLISHING A NEW OPERATING COMPANY?

24 A. Establishing a new operating company is expensive. We estimate that
25 several million dollars will be needed for creation of the new operating
26 company. Moreover, establishing a new operating company will require
27 significant up-front effort. Many decisions would need to be made regarding
28 the structure and size of a new NSPD operating company; what assets will

1 be included in NSPD's rate base; how to ensure sufficient transmission and
2 generation service is provided to NSPD; and how an NSPD operating
3 company would be managed at a corporate level, among other matters that
4 would need to be resolved before an effective and efficient new operating
5 company can be operational. Mr. Starkweather discusses this further in his
6 Direct Testimony and provides the Company's recommendations and
7 assumptions regarding overall structure of an NSPD.

8
9 Q. WHY IS THE COMPANY RECOMMENDING A LEGAL SEPARATION STRUCTURE?

10 A. We understand the complexities in implementing a Legal Separation
11 structure but also recognize the long-term value that could be derived for the
12 Company and our customers. The creation of a separate operating company
13 could resolve the challenges the Company is facing with respect to resource
14 selection and cost recovery by allowing us to separately meet the needs and
15 preferences of North Dakota without any interference from other states.

16
17 Simply, the Legal Separation structure provides us with the certainty
18 necessary to move forward. Mr. Starkweather discusses this further in his
19 Direct Testimony.

20
21 Q. WHY DID THE COMPANY REJECT THE PSEUDO SEPARATION STRUCTURE?

22 A. As we continued to develop our RTF analysis, it became clear that Pseudo
23 Separation will create its own set of issues upon which the NSP System
24 states could disagree in the future. Pseudo Separation, in essence, requires
25 that new sets of system allocators be created to allocate costs on a unit-
26 specific basis where possible, and also that reasonable proxies be found for
27 costs that cannot be allocated on a unit specific basis. Because of this, we
28 believe that establishing a Pseudo Separation structure would merely shift

1 the ability for states to disagree from resource decisions to cost allocation
2 decisions. The inability to bind future commissions regarding appropriate
3 allocation factors provides insufficient certainty for the Company to operate
4 in a Pseudo Separation environment.

5
6 Q. PLEASE ELABORATE ON THIS CONCERN.

7 A. As Company witness Mr. Starkweather explains more fully in his Direct
8 Testimony, Pseudo Separation is a ratemaking solution to the issues driving
9 the need for an RTF. It requires that all of the NSPM states agree to new
10 cost allocation methods so that rates reflect a pseudo separated NSP System.
11 Our experience regarding examination of the demand allocator in our last
12 North Dakota rate case makes clear that any commission in any state can
13 reopen cost allocations at any time. Without some way to bind Commission
14 to the allocation methods necessary for Pseudo Separation, we are
15 concerned that lack of future certainty may make it impossible to reasonably
16 implement.

17
18 Q. WHEN WOULD THE COMPANY ANTICIPATE IMPLEMENTING A LEGAL
19 SEPARATION STRUCTURE?

20 A. We believe that we could complete the necessary work to form a new
21 operating company and receive all the necessary regulatory approvals from
22 the MPUC, this Commission, FERC, and others by 2020. Mr. Starkweather
23 discusses what needs to be accomplished to implement the Legal Separation
24 structure.

25
26 Q. HAS THE COMPANY CONSIDERED THE SALE OF ITS NORTH DAKOTA
27 BUSINESS AS PART OF THE RTF?

1 A. Sale of our North Dakota business is not currently part of our business
2 plans. The State of North Dakota allows us to operate in a strong business
3 and regulatory environment. Moreover, similar to what is involved for the
4 separation scenarios discussed below, the Company would need to mitigate
5 stranded cost issues if sale of our North Dakota business were considered.
6 Consequently, we have not considered a sale of our North Dakota service
7 territory. With that said, we believe a Legal Separation structure will provide
8 more optionality concerning a potential future sale of our North Dakota
9 electric business should that be in our customers and shareholders best
10 interest at that time.

11

12

VI. CONCLUSION

13

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

15 A. Yes.

Aakash H. Chandarana
Regional VP, Rates and Regulatory Affairs
NSPM

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 before the Minnesota Public Utilities Commission 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.



414 Nicollet Mall
Minneapolis, MN 55401

December 31, 2016

—VIA ELECTRONIC FILING—

Darrell Nitschke
Executive Secretary
North Dakota Public Service Commission
State Capitol
600 East Boulevard
Bismarck, North Dakota 58505-0480

RE: 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, submits this Application for Consideration of a Resource Treatment Framework to Address Jurisdictional Cost Allocation Issues in the above-referenced Cases. The Company is making this filing consistent with the terms of the Negotiated Agreement adopted by the Commission on March 9, 2016, in Case Nos. PU-12-813 *et. al.*

Enclosed please find an original and 12 copies of the Application, and an electronic copy of our Application and supporting information on a CD.

Please contact me at (612) 215-4663 or aakash.chandarana@xcelenergy.com or David Sederquist at (701) 241-8632 or dave.sederquist@xcelenergy.com if you have any questions regarding this filing.

Sincerely,

A handwritten signature in black ink, appearing to read 'Aakash H. Chandarana', written over a horizontal line.

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

cc: Illona Jeffcoat-Sacco
Jack Schuh
Sara Cardwell
Victor Schock
Pat Fahn
Jerry Lein

**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**

**APPLICATION FOR CONSIDERATION OF A RESOURCE TREATMENT FRAMEWORK
TO ADDRESS JURISDICTIONAL COST ALLOCATION ISSUES**

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

STATE OF NORTH DAKOTA
BEFORE THE
PUBLIC SERVICE COMMISSION

IN THE MATTER OF NORTHERN STATES POWER COMPANY, A MINNESOTA
CORPORATION D/B/A XCEL ENERGY JURISDICTIONAL COST ALLOCATION MATTERS

MPUC Docket No. E-002/M-16-223

NDPSC Case Nos. PU-12-813, *et. al.*

**APPLICATION FOR CONSIDERATION OF A RESOURCE
TREATMENT FRAMEWORK TO ADDRESS JURISDICTIONAL COST
ALLOCATION ISSUES**

I. INTRODUCTION

Northern States Power Company, a Minnesota corporation, doing business as Xcel Energy (NSPM or Xcel Energy or the Company), respectfully submits this Application for consideration of a Resource Treatment Framework (RTF or Framework) simultaneously to the North Dakota Public Service Commission (NDPSC) and the Minnesota Public Utilities Commission (MPUC) (collectively the Commissions).¹

Since the time the *Negotiated Agreement* was adopted in North Dakota and we submitted our *Compliance Filing* in Minnesota, we have completed resource planning and ratemaking analyses, and benefitted from conversations with the Minnesota and North Dakota Commissions, their Staffs, and other stakeholders. Through this work, we see a path that no longer selects future resources on the basis of a wholly integrated NSP System; rather, we recommend a framework that would allow Minnesota and North Dakota to gradually become more independent of one other

¹ With respect to North Dakota, the purpose of this Application is to build upon prior rate case settlements and the NDPSC-adopted *Negotiated Agreement*. See *N. States Power Co. 2013 Elec. Rate Increase Application*, Case Nos. PU-12-813, *et al.*, ORDER ADOPTING REVISED SECOND AMENDED COMPREHENSIVE SETTLEMENT AGREEMENT (NDPSC Feb. 26, 2014) (provided as Appendix D); *N. States Power Co. Elec. Rate Increase Application*, Case No. PU-07-776, ORDER ADOPTING SETTLEMENT AGREEMENT (NDPSC Dec. 31, 2008) (provided as Appendix E); *N. States Power Co. 2013 Elec. Rate Increase Application*, Case Nos. PU-12-813, *et al.*, ORDER APPROVING FIRST REVISED NEGOTIATED AGREEMENT (NDPSC Mar. 9, 2016) (stating the Company’s obligation to file a “Resource Treatment Framework” or “RTF”) (provided as Appendix A). For Minnesota, this Application is submitted consistent with the Company’s commitments made in our June 13, 2016, *Compliance Filing* submitted in MPUC Docket No. E002/M-16-223, as well as the MPUC’s Letter on *Guiding Principles for Future Cost Allocation Proposals* filed on September 15, 2016, in the same docket. See *Compliance Filing on Jurisdictional Cost Issues*, Docket No. E002/M-16-223, COMPLIANCE FILING (MPUC June 13, 2016) (provided as Appendix B); *Compliance Filing on Jurisdictional Cost Issues*, Docket No. E002/M-16-223, LETTER – GUIDING PRINCIPLES FOR FUTURE COST ALLOCATION PROPOSALS (MPUC Sept. 15, 2016) (provided as Appendix C).

with respect to future resource selection. We believe this will provide each state with greater flexibility and customization around energy resource planning and selection.

With this Application, the Company asks each Commission to engage in a dialogue with the goal of achieving consensus on the future structure of the NSP System. To be clear, we are not seeking orders that will allow us to finalize an end state through this Application. Rather, we seek consensus on (a) the structure the NSP System will take over the long term; and (b) each state's responsibility for the Legacy System in which it has participated for generations.² We believe addressing past generation resource selections that were supported in Minnesota and questioned in North Dakota (Disputed Resources) is integral to resolving the latter issue.³

To facilitate moving ahead, we present feasible future system structures consistent with our recommendation (including Pseudo Separation and Legal Separation),⁴ and proposals for addressing the Disputed Resources. We also provide supporting information regarding these different structures from a qualitative/feasibility perspective; resource planning analyses; and outlines of potential revenue requirement impacts to facilitate discussion and achieve consensus on the appropriate path forward.

II. OVERVIEW

The Company, along with the five states it serves in the upper Midwest, have long benefitted from operating an integrated system. Three principles, which we previously articulated, have been the foundation to achieving alignment amongst all participants:

- Retain the integrated nature of the NSP System to capture the benefits of scale and diversity for all of our customers;

² We define the Legacy System as all of the generating resources of the NSP System after a reasonable allocation of the Disputed Resources identified in footnote 3, below. For discussion purposes, we have identified the resources that could comprise the Legacy System based on a potentially equitable allocation of Disputed Resources in Schedule 4.

³ We consider the following resources to be Disputed Resources, more specifically identified in Schedule 3: (1) certain CBED and smaller solar resources; (2) all biomass PPAs currently serving the NSP System; (3) the Company's PPAs for its 187 MW solar portfolio; (4) the Company's PPA for the capacity and energy of the Mankato Energy Center expansion (MEC II) project; and (5) solar gardens developed under Minn. Stat. § 216B.1691, subd. 2f. Based on the NDPSC's decision in Case No PU-15-95 and the MPUC's decision in Docket No. E002/M-15-330, we are not considering the Aurora Solar project to be a Disputed Resource.

⁴ Pseudo Separation preserves the current corporate and overall ratemaking structure of Xcel Energy, but treats each future resource as direct assigned to the jurisdiction(s) that supports it, requiring development of new cost recovery and accounting methods. Legal Separation involves creation of a separate operating company for North Dakota, which provides a more complete separation and eliminates the need for future alignment between the states on all future decision making – but is more complex and costly to implement.

- Respect the sovereign nature of each of the states we serve, while ensuring that they understand and bear the costs and risks associated with their decisions; and
- Ensure the Company has an opportunity to fully recover its cost of service in each state served by the NSP System.⁵

These principles can only function appropriately when all participants in the System are aligned in equitably sharing both the benefits and costs of the NSP System on a proportional basis. In the last decade, however, we have experienced an erosion in the alignment that is necessary to successfully operate an integrated system. Fundamental disagreements have arisen and persisted between the MPUC and NDPSC, including differences of opinion regarding resource need, renewable and thermal resources, and other ratemaking structures such as depreciation and demand allocations. These fundamental disagreements have resulted in the misalignment between the states we serve around the integration of the NSP System, resulting in the Disputed Resources as well as mismatched rate recovery for these resources and uncertainty around any future resource selection. Since we do not anticipate this misalignment ameliorating into the next decade, we are providing a framework to manage known and unknown misalignments between Minnesota and North Dakota.

A. Our Proposal

Based on our analyses, we conclude that the most robust and equitable RTF will address past disagreements first, then gradually move away from a fully-integrated resource portfolio serving all states and toward development of separate generation portfolios serving North Dakota and the remainder of the NSP System as NSP System resources are retired or added in the future. Through a less integrated system, our North Dakota customers would be able to select resources more independently and would see little immediate cost impact – but may potentially bear somewhat higher risk due to our North Dakota customers being served by a smaller and less diverse resource portfolio commensurate with their size and scope. At the same time, our Minnesota stakeholders would be able to more efficiently pursue state energy goals with less interstate conflict and potential delay, with little incremental cost.

⁵ NSPM has been able to bring the benefits of carbon-free nuclear generation, low-cost coal and natural gas generation, and significant imported hydroelectric generation to our customers in Minnesota, North Dakota, and South Dakota by aggregating our customers across state lines with our sister company, Northern States Power Company, a Wisconsin corporation (NSPW), serving Wisconsin and Michigan through the FERC jurisdictional Interchange Agreement. *Xcel Energy Operating Cos.*, FERC Docket No. ER01-1014, RESTATED AGREEMENT TO COORDINATE PLANNING AND OPERATIONS AND INTERCHANGE POWER AND ENERGY BETWEEN NORTHERN STATES POWER COMPANY (MINNESOTA) AND NORTHERN STATES POWER COMPANY (WISCONSIN) (Jan. 19, 2001); *see also N. States Power Co., a Minn. Corp.*, FERC Docket No. ER15-1575, LETTER ORDER (June 22, 2015) (unpublished letter order of Xcel Energy's most recent update to the Interchange Agreement).

Our RTF provides a framework to achieve this outcome. As a preliminary matter, we believe an equitable framework must acknowledge that our customers have historically benefitted from the economies of scale and diversity of resources available to a larger, integrated system that shares resources. To achieve a fair and balanced RTF, NSP System customers who have participated in those benefits for decades should continue to share the costs and liabilities incurred to create and operate the Legacy System.⁶

Moreover, the time is right to achieve the intertwined goals of aligning the states' roles with respect to accountability for the Legacy System and establishing greater flexibility for the Company to serve our North Dakota and Minnesota customers even where their priorities differ. The NSP System is changing, apart from any new decisions that may be made in the future. We anticipate unavoidable expirations of several key power purchase agreements (PPAs) and the planned retirement of key baseload generation such as Sherco 1 and 2. At the same time, we do not anticipate significant additional capacity needs until the mid-2020s. This timing provides a window in approximately the 2020 timeframe to resolve past issues and also achieve a form of separation that permits more independent future energy choices in the NSP System states when we reach the 2020s and beyond. Our RTF seeks to leverage this timing opportunity to achieve an equitable outcome for each state we serve.

To that end, we propose the following Resource Treatment Framework:

1. All currently anticipated and past resource selection and other disagreements will be permanently addressed and the Legacy System established.
2. All NSPM states will continue to be served by the Legacy System and all of our customers will enjoy the benefits and bear the burdens of the Legacy System.
3. With respect to future new resource additions, the Company will be able to assess and propose resources for North Dakota and the remainder of the NSP System separately.

⁶ Continued service for North Dakota from the Legacy System was a key component of the *Settlement Agreement* in Case No. PU-12-813, which formed the basis for our RTF. See *N. States Power Co. 2013 Elec. Rate Increase Application*, Case Nos. PU-12-813, et al., ORDER ADOPTING REVISED SECOND AMENDED COMPREHENSIVE SETTLEMENT AGREEMENT at 15, Negotiating Principle 3 of Settlement Agreement(NDPSC Feb. 26, 2014) (Appendix D).

- a. When a resource need arises in North Dakota, that need will be met by a resource sized for, dedicated to serve only, and fully recovered in North Dakota.
 - b. When a resource need arises in, or new resources are otherwise planned for, the remainder of the NSP System, those resources will be sized for, dedicated to serve only, and fully recovered in the remainder of the NSP System. Consequently, our North Dakota jurisdiction will not obtain the benefits or pay the costs associated with new NSP System resource additions.
 - c. Xcel Energy may propose particular future resources to be utilized concurrently by North Dakota and the remainder of the NSP System should circumstances warrant, and will propose cost-sharing arrangements at that time.
4. Over time, the generation portfolio serving North Dakota and the remainder of the NSP System will materially separate as units of the NSP System retire or expire.
 5. South Dakota may elect to join North Dakota under this framework or remain part of the NSP System consistent with its own outlooks.⁷

Each enumerated item in our RTF presents multiple questions and sub-questions that need to be resolved to distill this framework into an implementable solution. Our purpose in this proceeding is to solve two fundamental questions: (1) what structure will the integrated NSP System take in the future; and (2) what resources will continue to be shared as part of the Legacy System, which includes addressing the Disputed Resources. This Application presents the economic, ratemaking, and policy analyses to begin a robust discussion between the Commissions and the Company on these questions, as well as to offer potential answers. It is our goal through the course of this proceeding to ultimately reach a consensus outcome with the Commissions, which would align the states into the future.

⁷ Throughout the remainder of this document, we largely refer to North Dakota as the entity separating from the NSP System under our proposed RTF. We recognize South Dakota may also wish to consider whether to participate with North Dakota, and our RTF is intended to provide that optionality to our South Dakota customers. We are presenting this optionality as part of our RTF as the South Dakota Public Utilities Commission (SDPUC) is currently undertaking a review of our fuel clause rider recovery. *See In the Matter of Comm'n Staff's Request to Investigate N. States Power Co. d/b/a Xcel Energy's Proposed Fuel Clause Rider*, Docket No. EL16-037, ORDER SUSPENDING FUEL CLAUSE RIDER FOR 180 DAYS (SDPUC Dec. 12, 2016).

To serve North Dakota and Minnesota separately at a future time, it is first necessary to determine how this can occur. Two potential structures can support our proposed RTF: (1) Pseudo Separation and (2) Legal Separation. Pseudo Separation does not require corporate structure changes, but directly assigns the costs and benefits of each resource to the jurisdiction(s) that supports it. Pseudo Separation therefore requires new cost recovery and accounting methods to be developed, implemented, and managed over time. Legal Separation would involve creation of a separate operating company for North Dakota. This more complete separation eliminates the need for future agreement or compromise between the states, but is more complex and costly to implement at the outset. Each of these structures can ultimately result in the same resource outcomes envisioned by our proposed RTF and each structure has benefits and drawbacks.

Regardless of the structure, we envision that all states will continue to be served by the Legacy System. In light of this, separate generation portfolios would only be implemented over time as aging resources drop off the system and need replacement. The result would be a more gradual, long-term move toward separation.

That said – and based on the potential for accelerated transformation of the NSP System via our next Integrated Resource Plan (IRP) to be filed in 2019, with which North Dakota may not agree – we could identify a fixed date to begin serving North Dakota by its own resource portfolio. As discussed in more detail in this Application, we believe that this portfolio should include the nuclear resources of the Legacy System. This approach would create freedom to more fully develop and plan for a separate future for North Dakota sooner by spurring a load-serving need in North Dakota for generation development in that state. At the same time, continued service from our nuclear fleet provides hedge value and baseload support while being consistent with the equities of ensuring that our customers retain liabilities consistent with their past participation in and enjoyment of the Legacy System. This alternative separation scenario could therefore provide North Dakota with the benefits of Legacy System resources that the NDPSC has historically supported, while moving North Dakota toward a stand-alone resource portfolio sooner.

We will also need to determine the extent to which existing or planned resources will comprise the Legacy System. This determination requires us to address the Disputed Resources. While there are multiple possible outcomes that could achieve an equitable result, we believe a reasonable approach could be:

- All Disputed Resources except for the MEC II PPA will be allocated to the remainder of the NSP System and not North Dakota;

- The necessary accelerated depreciation due to the mismatch of book life in North Dakota as compared to the remainder of the NSP System for Sherco Units 1 & 2 will be allocated to and recovered from the remainder of the NSP System;
- No portion of costs or savings associated with the Company's proposed new wind projects⁸ will be allocated to North Dakota, but rather will be fully allocated to the remainder of the NSP System; and
- North Dakota's allocated share of the MEC II PPA will be recovered in North Dakota.

Our resource planning analysis indicates that this approach could generate a reasonably balanced outcome, as the costs of allocating the Disputed Resources and the Sherco Units 1 & 2 accelerated depreciation to the NSP System other than North Dakota will be offset by the fuel savings to the remainder of the System provided by the Company's proposed new wind additions over their life. Conversely, recovery of the MEC II PPA in North Dakota will help ensure that sufficient capacity and energy is available to our North Dakota customers as we transform the NSP System. A resolution along these lines allows us to establish a baseline from which we can begin planning a less integrated future.

B. Achieving Consensus

For our RTF to be successful, we cannot overstate the importance of obtaining the support, approval, and alignment of both Commissions with respect to each of the above questions. Failure to find consensus will drive us toward lowest common denominator planning and resource-by-resource negotiations, meaning we could only implement resources acceptable to all states in the NSP System. This, in turn, means we would be less able to pursue more holistic solutions, such as development of North Dakota generation or a more emissions-free energy future, that could otherwise be pursued during the coming fleet transformation.

We look forward to an open and robust dialogue to ultimately meet the goals and objectives of all the states currently served by the NSP System. To that end, we propose an approximately eighteen-month procedural schedule to provide the

⁸ Pursuant to our most recent Minnesota IRP, the MPUC ordered the Company to acquire at least 1000 MW of wind by 2020. On October 24, 2016, in Docket No. E002/M-16-777, the Company notified the MPUC that it intends to acquire at least 750 MW of wind resources based on its self-build proposal and its most recent wind request for proposal (RFP) process. *See In the Matter of the Petition of Xcel Energy for Approval of the Acquisition of Wind Generation from the Co.'s 2016-2030 Integrated Res. Plan*, Docket No. E002/M-16-777, PETITION at 1 (MPUC Oct. 24, 2016). Based on the results of the Company's wind RFP process, it appears likely that we will propose 1500 MW to be added from our self-build and RFP selections, with supplemental information supporting our proposal forthcoming in the first quarter of 2017.

Commissions and our stakeholders with ample time to analyze, issue discovery, and to work through the issues presented in this Application. The last portion of this Application identifies a procedural proposal to review our recommendation as well as discussion of how our proposal would be implemented.

Should the Commissions ultimately approve a common Framework, we would seek to obtain the necessary approvals and implement the RTF as quickly as is reasonable. We envision that a Pseudo Separation outcome could be implemented in a rate case following the completion of review of this Application, likely in 2020. Should a Legal Separation structure be preferred, we anticipate that we could complete the significant work to form the new operating company and seek approvals in all regulatory forums (Minnesota, North Dakota, the Federal Energy Regulatory Commission (FERC), and others) by approximately 2020. The work assessing and discussing this Application will inform the future of the NSP System, and we welcome this robust discussion.

C. Remainder of Filing

The remainder of this filing provides the detailed support for our Application, and will address the following:

- *The Need for Change*: provides a brief historical context for the need for an RTF.
- *Analytical Framework*: outlines the different potential RTF structures.
- *Resource Planning Analysis*: sets forth our resource planning analysis, assumptions, and results that underpin our consideration of RTF alternatives.
- *Revenue Requirement Analysis*: summarizes how rates are impacted by the RTF alternatives.
- *Recommendation and Next Steps*: outlines the Company's recommendation and proposal for implementation.
- *Conclusion*: summarizes our proposal.

Xcel Energy is making this Application in North Dakota in compliance with the *Negotiated Agreement* approved on March 9, 2016, pursuant to N.D.A.C. § 69-02-02-04 and in Minnesota as a Miscellaneous Filing pursuant to Minn. R. 7829.1300. Required compliance information is provided in Schedules 1 and 2 to this Application.

III. THE NEED FOR CHANGE

We begin this Application by presenting the case for change within the NSP System. Prior rate case settlements and the *Negotiated Agreement* in North Dakota, as well as the *Compliance Filing* submitted in Minnesota, introduced the Company's concerns with

respect to disagreements regarding resource selection, cost recovery, and system planning in the states we serve. At the same time, we recognize the benefits of service via the fully-integrated NSP System and the appropriateness of preserving those benefits through individual resource resolutions. To date, we have not fully succeeded in reconciling the benefits of integration and the lack of full cost recovery for certain investments in all states served.

This portion of the Application explains how and why we developed the current integrated system, addresses why the status quo is not sustainable for the Company and may not be preferable to the states we serve, and introduces known and potential system changes that may further prompt the need for change. This information forms the initial basis for the development of our RTF proposal.

A. Evolution of the Integrated NSP System

For several generations, the integrated NSP System has successfully provided service on a multi-jurisdictional basis to our customers in Minnesota, North Dakota, and South Dakota, and through coordination with NSPM's sister company, NSPW, to customers in Wisconsin and Michigan. Collectively, the NSP System serves approximately 1.6 million electric customers in these five states.

The NSP System developed as part of an electric service model that required or supported various large-scale investments to serve customers over time, particularly during lengthy periods of high load growth. These investments created the integrated NSP System in its current form, which reflects the Company's ongoing responsiveness to the circumstances it has faced to date. We believe this responsiveness has benefited all system participants along the way. However, we also recognize that the Company has not always fully outlined how the integrated NSP System came to be in its current form, or how this evolution has benefited system participants. To address this in part, Schedule 5 to this Application explains the historic development and drivers of the integrated NSP System.

By way of summary, integration was a function of the needs of our customers during past eras of significant load growth, supply uncertainty, and pricing volatility. Each resource in the NSP System – whether generation or transmission⁹ – was developed in consideration of the whole, balancing the need for diversity and hedges against supply and cost volatility encountered at various times over the past several decades when economies of scale were only available through integrated system planning. This

⁹ Consistent with long-standing ratemaking practices, distribution costs have been direct assigned to particular jurisdictions.

integrated approach supported achievement of economies of scale system-wide, allowed the states we serve to share in the costs of resources, and provided diversity and hedge benefits that might not otherwise have been available.

On behalf of all customers, we have taken advantage of the geographic, supply, and resource diversity that the five-state NSP System provides, with all states sharing in the costs and benefits of this system. While maintaining an integrated system at times requires necessary compromises between the various customer groups and jurisdictions we serve, this diversity continues to act as a “hedge” for customers against fuel cost variability, concentrated geographic changes to the system, and supply problems. It also provides value to stakeholders in the form of assurance that energy supply would be adequate and reliable regardless of market changes.

In light of the historic benefits of integration within the NSP System, our RTF first recognizes that all states that have participated in the development of the Legacy System should also continue to pay their fair share of its costs. This concept is discussed in more detail later in this Application.

B. Current Stressors on the System

Despite this successful history, the current integrated NSP System faces many challenges today that result from evolution in the industry as well as disagreements on a variety of issues as between Minnesota and North Dakota. Because these disagreements are varied, it has become clear that the term we have historically used to describe the drivers of resource disagreements between Minnesota and North Dakota – “divergent energy policies” – is insufficient to fully describe the fundamental difference in outlooks between the NDPSC and the MPUC.

It would be correct to say that some disagreements between the MPUC and NDPSC are driven by renewable energy or other clear legislative mandates such as Minnesota’s Renewable Energy Standard (RES) or the Minnesota Metro Emissions Reduction Program (MERP). Others, however, are driven by more fundamental differences between the needs and wants of our various customers. These differences include not only the mid-nineties passage of externality laws in Minnesota¹⁰ and the concomitant passage of anti-externality laws in North Dakota,¹¹ but also the perception of how to meet load-serving needs and incorporate the availability of competitive markets for energy, ancillary services, and capacity to provide our customers with the power they need.

¹⁰ Minn. Stat. § 216B.2422, subd. 3; H.F. 1253, 78th Leg., Reg. Sess. (Minn. 1993).

¹¹ N.D.C.C. § 49-02-23; H.B. 1312, 59th Leg. Reg. Sess. (N.D. 1995).

Further, regulators in North Dakota have both formally and informally called into question material Company investments or initiatives – even those that had been previously recovered, in part, from our North Dakota customers. These included concerns over:

- the Company’s Demand Side Management (DSM) programs;¹²
- Legislative requirements in Minnesota to add wind and biomass resources in order to continue to operate its nuclear facilities, and the establishment of a Renewable Development Fund (RDF);¹³
- Company investments in its High Bridge plant under MERP;¹⁴
- Cost recovery of existing resources such as community-based economic development (CBED), small solar, and biomass PPAs;¹⁵
- Company investments in wind facilities such as Grand Meadow,¹⁶ Prairie Rose,¹⁷ Odell, and Pleasant Valley;¹⁸ and

¹² *N. States Power Co. Demand Side Management & Cost Recovery Rider Tariff*, Case No. PU-08-171, ORDER (Nov. 5, 2008) (denying the Company’s proposed cost recovery tariff rider).

¹³ *N. States Power Co. Elec. Rate Increase Application*, Case No. PU-07-776, ADVOCACY STAFF POST-HEARING BRIEF at 19-23 (NDPSC Aug. 22, 2008) (arguing that it was unjust and unreasonable to require North Dakota ratepayers to pay the costs incurred due to Minnesota’s renewable energy standards); *N. States Power Co. Elec. Rate Increase Application*, Case No. PU-07-776, ORDER ADOPTING SETTLEMENT AGREEMENT at 3, 14 of Settlement Agreement (NDPSC Dec. 31, 2008) (Appendix E).

¹⁴ *N. States Power Co. Elec. Rate Increase Application*, Case No. PU-07-776, ADVOCACY STAFF POST-HEARING BRIEF at 12-19 (NDPSC Aug. 22, 2008) (arguing that the costs incurred due to MERP should not be included in the Company’s revenue requirement); *N. States Power Co. Elec. Rate Increase Application*, Case No. PU-07-776, ORDER ADOPTING SETTLEMENT AGREEMENT at 12 of Settlement Agreement (NDPSC Dec. 31, 2008) (Appendix E) (acknowledging that investments in the High Bridge power plant was a primary issue of dispute in the proceeding).

¹⁵ *N. States Power Co. 2013 Elec. Rate Increase Application*, Case Nos. PU-12-813, et al., ORDER APPROVING FIRST REVISED NEGOTIATED AGREEMENT at 4 (NDPSC Mar. 6, 2016) (Appendix A) (excluding the costs and volumes of fifteen CBED and two small solar PPAs from the calculation of the Company’s North Dakota Fuel Cost Recovery Rider); *N. States Power Co. Elec. Rate Increase Application*, Case Nos. PU-12-813, et al., ORDER ADOPTING REVISED SECOND AMENDED COMPREHENSIVE SETTLEMENT AGREEMENT at 17-18 Settlement Agreement (NDPSC Feb. 26, 2014) (Appendix D) (calling into question twenty-three of the Company’s existing renewable PPAs related to CBED, solar, and biomass).

¹⁶ *N. States Power Co. Elec. Rate Increase Application*, Case No. PU-07-776, ORDER ADOPTING SETTLEMENT AGREEMENT at 12 of Settlement Agreement (NDPSC Dec. 31, 2008) (Appendix E) (acknowledging that the Grand Meadow wind farm was a primary issue of dispute).

¹⁷ *N. States Power Co. Advance Determination of Prudence – Geronimo Wind Application*, Case No. PU-12-59, FINDINGS OF FACT, CONCLUSIONS OF LAW AND ORDER at 2-4 (NDPSC Dec. 21, 2012).

¹⁸ *N. States Power Co. 2013 Elec. Rate Increase Application*, Case Nos. PU-12-813, et al., ORDER ADOPTING REVISED SECOND AMENDED COMPREHENSIVE SETTLEMENT AGREEMENT at 22 of Settlement Agreement (NDPSC Feb. 26, 2014) (Appendix D) (reserving disposition of the Odell and Pleasant Valley wind projects until adoption of the Negotiated Agreement).

- Company costs related to the 187 MW solar portfolio (now resized as a 162 MW portfolio) and the 100 MW Aurora Solar PPA.¹⁹

We note also that some misalignment between Minnesota and North Dakota is a result of resource selection by the MPUC that was not necessarily supported by the Company but for which it was necessary for us to seek approval in North Dakota. For example, the Company advocated against selection of the Aurora Solar project in the Minnesota Certificate of Need proceeding but the project was nonetheless selected.²⁰ Thereafter, the Company defended the project before the NDPSC notwithstanding our reservations, but the NDPSC has not approved the project. In this instance, the Company was nonetheless able to resolve its inability to recover the North Dakota share of that project through commercial arrangements. However, without a robust RTF, the Company will be left with few tools but to cancel these types of projects in the future.

Resource selection differences are not the only factor impacting the health of the integrated System. Equitable and consistent cost allocation for shared resources is also necessary to maintain integration. However, in our 2008 North Dakota rate case, Case No. PU-07-776, depreciation schedules for Sherco Units 1, 2, & 3, among other plants,²¹ were established that differed from those of the other states of the NSP System. This was due to different outlooks regarding the future of these plants in North Dakota than in the other states of the NSP System.²² The resulting mismatch in remaining lives is an example of rate structure misalignment between Minnesota and North Dakota.

Furthermore, in our most recent North Dakota rate case, Case No. PU-12-813, the NDPSC raised concerns regarding the jurisdictional demand allocation methodology used to allocate demand-related costs across the NSPM jurisdictions. Minnesota,

¹⁹ See *N. States Power Co. Advance Prudence – 187 MW Solar Energy Portfolio Application*, Case No. PU-14-810, FINDINGS OF FACT, CONCLUSIONS OF LAW AND ORDER at 3-4 (NDPSC June 17, 2015); *N. States Power Co. Advance Prudence – 100 MW Aurora Solar, LLC Application*, Case No. PU-15-095, FINDINGS OF FACT, CONCLUSIONS OF LAW AND ORDER at 3-4 (NDPSC Sept. 16, 2015).

²⁰ See *In the Matter of the Petition of N. States Power Co. d/b/a Xcel Energy for Approval of Cost Recovery of the Aurora Power Purchase Agreement*, Docket No. E002/M-15-330, ORDER DENYING RECOVERY OF NORTH DAKOTA-RELATED PURCHASED-POWER COSTS at 2 (MPUC Apr. 13, 2016).

²¹ In addition to Sherco Units 1, 2, & 3, other combustion plants with differing depreciation schedules due to extended service lives include the Angus C. Anson generating station, the Granite City plant, the High Bridge plant, the Inver Hills plant, the Key City plant, and the Prairie Island nuclear plant. See *N. States Power Co. Elec. Rate Increase Application*, Case No. PU-07-776, ORDER ADOPTING SETTLEMENT AGREEMENT at 10 of Settlement Agreement (NDPSC Dec. 31, 2008) (Appendix E).

²² *N. States Power Co. Elec. Rate Increase Application*, Case No. PU-07-776, ADVOCACY STAFF POST-HEARING BRIEF at 8-10 (NDPSC Aug. 22, 2008).

North Dakota, and South Dakota have been utilizing the 12 CP method for over thirty years as an equitable way to allocate shared costs across the NSP System. While the Company was able to settle the jurisdictional allocator issue with NDPSC Staff in the rate case *Settlement Agreement*²³ and *Negotiated Agreement*,²⁴ the NDPSC's focus on the uniform jurisdictional allocator signaled to the Company that the integrated NSP System is being stressed potentially to the breaking point. Ensuring agreement on this fundamental cost allocation is critical to equitable cost recovery across the NSP System, and to identifying the type of structure that should be implemented to support our RTF.

These stressors on the NSP System present business concerns as well as regulatory considerations. The different and sometimes conflicting regulatory views on the projects supported (or not supported) by the Commissions is creating increasing uncertainty for the Company with respect to business planning and the likelihood of future cost recovery. Incomplete recovery of investments that are ordered by one jurisdiction but not supported in another erodes the baseline principle that recovering the costs of reasonable investments made on behalf of customers is foundational to the success of any utility. While we have worked creatively to manage interstate conflicts in the past, continuing to accept lower cost recovery due to differing resource approvals in the states we serve is not sustainable. These ongoing disagreements therefore lead to the conclusion that a less integrated future may be preferable.

C. Forecasted System Transformation

There are many unknowns as we plan for the future of the NSP System. Environmental regulations are in a state of potential flux; tax laws may change; demand may fluctuate more than expected; and fuel costs may change unpredictably. While these areas of uncertainty make it impossible to predict the future in several respects, this section of our Application is intended to look to the known resource planning future. In particular, we know that the Company will experience significant PPA expirations and the retirements of Sherco Units 1 & 2 in the next decade, regardless of future resource plan proceedings. This upcoming period of significant resource expirations (without the need for additional baseload capacity before the mid-2020s) presents a window of opportunity to implement an RTF structure that

²³ *N. States Power Co. 2013 Elec. Rate Increase Application*, Case No. PU-12-813, et al., ORDER ADOPTING REVISED SECOND AMENDED COMPREHENSIVE SETTLEMENT AGREEMENT at 18-20 of Settlement Agreement (NDPSC Feb. 26, 2014) (Appendix D).

²⁴ *N. States Power Co. 2013 Elec. Rate Increase Application*, Case No. PU-12-813, et al., ORDER APPROVING FIRST REVISED NEGOTIATED AGREEMENT at 7 of Negotiated Agreement (NDPSC Mar. 9, 2016) (Appendix A).

permits greater flexibility and customer responsiveness before future resource selections must be made.

We also anticipate that Minnesota stakeholders will continue to state a preference for a more renewable future in the years ahead,²⁵ furthering Minnesota's carbon reduction goals.²⁶ Conversely, we know that North Dakota stakeholders are unlikely to agree with Minnesota's preference to give greater weight to the present value of societal cost (PVSC) of resources than to the present value of revenue requirements (PVRR) perspective. These known factors make it more challenging to maintain an integrated system that satisfies the needs of the Company and its various stakeholders, but also present the right reasons and timing to implement a more separate future.

1. Current IRP

As discussed in the Company's recent IRP,²⁷ Xcel Energy anticipates significant upcoming reductions in energy resources due to several key changes occurring in the next 10 to 15 years, including:

- 2023: Blue Lake Units 1-4 (natural gas combustion turbines (CTs)) cease operation (153 MW);
- 2025: Manitoba Hydro contracts expire (850 MW);
- 2026: Cottage Grove Combined Cycle Energy Center contract expires (262 MW); and
- 2027: Mankato Energy Center Combined Cycle (MEC I) contract expires (375 MW).

The Company also faces the impending retirement of a number of baseload system resources. In the Company's recent IRP proceeding, the MPUC approved the

²⁵ See Minn. Stat. § 216B.243, subd. 3a (providing that the MPUC "may not issue a certificate of need under this section for a large energy facility that generates electric power by means of a nonrenewable energy source, or that transmits electric power generated by means of a nonrenewable energy source, unless the applicant for the certificate has demonstrated to the commission's satisfaction that it has explored the possibility of generating power by means of renewable energy sources and has demonstrated that the alternative selected is less expensive . . . than power generated by a renewable energy source").

²⁶ See Minn. Stat. § 216H.02, subd. 1.

²⁷ See *In the Matter of Xcel Energy's 2016-2030 Integrated Res. Plan*, Docket No. E002/RP-15-21, MINUTES – OCTOBER 13, 2016 AGENDA (MPUC Nov. 1, 2016) (detailing the MPUC's determinations regarding the Company's IRP), available at <https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={281E9278-B77B-4DA1-917F-A3BDBD55CDB4}&documentTitle=201611-126198-01>. MPUC deliberations occurred on October 13, 2016; no order has yet issued. We will provide an update to the record once an order has issued. See also *2015 Upper Midwest Integrated Res. Plan*, Case No. PU-15-019, RESOURCE PLAN 2016-2030 (NDPSC Jan. 5, 2015) (The Company files its IRP in North Dakota for informational purposes; consistent with past practice, the NDPSC did not act on the Company's IRP).

Company's plan to retire Sherco Units 1 & 2 in 2026 and 2023, respectively, with a combined impact in excess of 1,300 MW.

At the same time, newer technologies such as distributed energy resources and demand response continue to impact system demand and the types of resources available to meet that demand. The Commissions' perspectives on the correct response to these changes may contribute to future misalignment.

Because of the Company's current load profile and forecast, however, the Company does not anticipate the need to add significant additional baseload capacity until Sherco Unit 1 is retired in 2026.²⁸ The lack of immediate capacity need combined with existing System changes provides an opportunity to separate North Dakota before the next large capacity resources are added to the System. While long lead-times are needed to plan for large future resource additions, the gap in anticipated capacity needs make now the right time to identify a long-term solution for current and potential future stressors on the NSP System. We can then implement separate solutions for each jurisdiction when the need to add resources does arise.

2. Future Changes

In addition to these known retirements and expirations, further evolution of the NSP System may also be under consideration, which could heighten and accelerate potential future disagreements regarding integrated System resources. In the 2030s, more than 2500 MWs of additional system resources are also scheduled to retire, including:

- 2030: Monticello Nuclear Generating Plant (671 MW)
- 2033: Prairie Island Nuclear Generating Plant Unit 1 (548 MW)
- 2034: Prairie Island Nuclear Generating Plant Unit 2 (548 MW)
- 2037: Allen S. King Plant (511 MW)
- 2040: Sherco Unit 3 (860 MW)

While retirement of these resources will occur at some future time, retirement along the timelines noted above is not certain. In the Company's recent IRP proceeding, the MPUC directed the Company to file its next resource plan on February 1, 2019, and to describe in that filing our plans and possible scenarios for the cost-effective and orderly retirement of our aging baseload fleet. The MPUC also required the

²⁸ The MPUC also determined in that proceeding that it is more likely than not that there will be a need for 750 MW of intermediate capacity coinciding with the retirement of Sherco Unit 1 in 2026, and authorized the Company to file a petition for a Certificate of Need to meet that need.

Company to evaluate, in addition to generation resource options and alternatives, combinations of supply-side (distributed and centralized), demand-side, and transmission solutions that could, in the aggregate, meet post-retirement energy and capacity needs as well as contribute to grid support. These directives, which could accelerate closures of large baseload plants ahead of current anticipated useful lives, will generate additional discussion in the states we serve.

As we continue to analyze the potential retirement of other baseload generation, recovery of the costs of the assets and liabilities incurred by our customers' use of these assets through depreciation reserves and other rate recovery methods is critical to the success of our RTF. At the same time, we recognize that prospective acceleration of the retirement of these baseload resources – potentially through our next IRP filed in early 2019 – may further misalign the Commissions with respect to the future of the NSP System. These considerations highlight the importance of identifying a consensus RTF for resource planning approaches, the future of the NSP System, and equitable cost recovery in the context of this proceeding. In the next section of this Application, we therefore identify potential structural solutions to achieve our RTF, and walk through our qualitative analyses of the viability of each option.

IV. ANALYTICAL FRAMEWORK

The path toward our recommended RTF began with our efforts to “Restack” the NSP System pursuant to ten principles set forth in the *Settlement Agreement* from our 2013 test year rate case in North Dakota.²⁹ While significant effort was expended to achieve the outcome envisioned in that *Settlement Agreement*, we were ultimately unsuccessful. Consequently, we agreed to the *Negotiated Agreement's* terms that obligated the Company to develop an RTF and propose it to the NDPSC. Since the NDPSC's adoption of the *Negotiated Agreement*, the MPUC has also analyzed the stresses on integration of the NSP System and ordered that the Company present a compliance filing identifying the important historical background and principles that were driving our development of the RTF, considering our obligations under the *Negotiated Agreement*. This resulted in our June 2016 *Compliance Filing*.

Through these proceedings, we have articulated to both Commissions that an RTF should:

²⁹ See *N. States Power Co. 2013 Elec. Rate Increase Application*, Case Nos. PU-12-813, et al, ORDER ADOPTING REVISED SECOND AMENDED COMPREHENSIVE SETTLEMENT AGREEMENT at 14-17 of Settlement Agreement (NDPSC Feb. 26, 2014) (Appendix D).

- (1) be forward looking to address future resource selection disagreements (policy divergence) amongst the states, should they occur;
- (2) find opportunities to continue an integrated approach to serving all of our customers, where possible; and
- (3) continue to keep the existing, or legacy, fleet available to all of our customers in all of the states we serve.

These principles continue to form the basis of our decision-making process, as have the six principles provided by the MPUC.³⁰ Last, the input we have received from the Commissions and their respective Staffs has been helpful in our development of an RTF.

Our RTF considers the extent to which there may be tension between these principles, as well as the extent to which they are consistent with each other. This has included determining whether relatively recent disagreements over resource selection (as compared to the entire history of the System) will predominate the evolution of the NSP System or whether there is likely to be more agreement than less going forward. This puts primacy on the first principle, which requires an RTF to be forward looking. The less disagreement that occurs, the more integrated an RTF can be, highlighting the second principle. While we hope that the level of disagreement amongst the states will moderate in the future, an RTF can only be successful if it is sufficiently robust to address material disagreements that continue to exist and will likely occur in the future – particularly as resources on the NSP System, and the utility industry as a whole, continue to evolve.

To this end, our RTF is primarily a forward-looking framework, while also addressing past and likely near-term future jurisdictional disagreements. We therefore begin our analysis by setting forth potential future resource pricing and corporate structure alternatives that could support our long-term RTF, and assessing which of those alternatives may be feasible and productive (this Section IV). This initial identification of alternatives also provides the underpinnings of our long-term review of resource options (Section V), as well as the revenue requirement impacts of our recommended resolution of Disputed Resources (set forth in Sections V and VI) and of feasible structural alternatives for the future (also discussed in Sections V and VI). Taken together, we believe this analytical framework, focused resource planning, and

³⁰ See *Compliance Filing on Jurisdictional Cost Issues*, Docket No. E002/M-16-223, LETTER – GUIDING PRINCIPLES FOR FUTURE COST ALLOCATION PROPOSALS at 1-2 (MPUC Sept. 15, 2016) (Appendix C).

revenue requirement analyses provide the information needed to promote discussion around a viable long-term RTF.

A. Alternatives for the Future

Our work in developing an RTF has been focused on four alternatives for the future structure of the NSP System. In this section of the Application, we describe our qualitative assessment of these alternatives in terms of whether they are viable options that can achieve the RTF development principles described above. We note, however, that not one of these structures is alone a sufficiently robust RTF. Rather, we determined that a broader framework that can be supported by several structures is more appropriate for our RTF, so that we may present sufficient optionality to achieve consensus between the Company and the Commissions on the appropriate path forward. This section will discuss the different structures we analyzed to ultimately reach the RTF proposal presented in this Application.

Consistent with the record developed in support of the *Negotiated Agreement* and as further articulated in our *Compliance Filing*, we identified four structures upon which we focused our analysis:

- (1) *Regulatory Alignment (“Full Recovery”)*: Better align the resource selection processes of the states to reach consensus on resource selection. Should a state direct the acquisition of a particular resource that is not approved by the other states, then all costs of the resource will be recovered from only the approving states or the Company will not move forward with that particular resource.
- (2) *Proxy Pricing*: States that reject a particular resource will pay a “proxy price” for that resource to better align the costs of a particular resource with that state’s resource selection outlook.
- (3) *Pseudo-Separation*³¹: Separate the generation portfolios serving North Dakota and the remainder of the NSP System, without changing the corporate structure of NSPM, by assigning the benefits and burdens of a resource to the states that support it and developing separate resources for non-approving states should they be needed.

³¹ In past filings with the NDPSC, we have sometimes referred to this structure as the “Pricing Zone Concept.” See *N. States Power Co. 2013 Elec. Rate Increase Application*, Case Nos. PU-12-813, et al., PRE-FILED DIRECT TESTIMONY OF DAVID SEDERQUIST IN SUPPORT OF NEGOTIATED AGREEMENT at 8 (NDPSC Nov. 30, 2015).

- (4) *Separate Operating Company or Legal Separation*: Establish a separate operating company to serve our North Dakota customers.

We have described these structures as being part of a spectrum of options – meaning they span a range of outcomes from full integration with every resource serving a unified NSP System, to full, legal separation with a new operating company serving our North Dakota customers.

In analyzing each alternative, the Company is focused on selecting the most effective solution that delivers on the principles of state sovereignty and cost recovery. Feasibility of implementation is also imperative. To that end, the next section outlines the conceptual opportunities and challenges associated with each RTF alternative. We further identify obstacles to implementation or to achievement of overall equity. Our quantitative resource planning and revenue requirement analyses follow this baseline assessment of alternatives.

1. Regulatory Alignment

Regulatory alignment seeks to maintain the integrated nature of the NSP System while recognizing that we have entered a period in which interjurisdictional disagreements have become commonplace. In concept, the states we serve would agree that only those customers of states that approve a given resource will bear the costs of that resource even if the resource serves the entire System. In the event agreement cannot be reached, the Company would not move forward with a particular resource.

Regulatory alignment, then, places a high value on maintaining integration. Additionally, that agreement must be reached on the cost allocations before the Company will move forward with a given resource speaks to the principles of state sovereignty and cost recovery. But it does so at the risk of planning to meet only those common resource needs consistent with all states' planning paradigms. This may mean the Company would not implement resource additions that a particular state may consider a high priority but which another state (or states) does not support.

Notably, seeking early input to help pursue better alignment of regulatory outcomes was a component of the settlement adopted by the NDPSC in our 2008 North Dakota rate case.³² There, the focus was on bolstering the NDPSC's oversight of Company resource decisions by formalizing the filing and review of the Company's Upper Midwest IRPs in North Dakota and requiring that our analyses include North

³² See *N. States Power Co. Elec. Rate Increase Application*, Case No. PU-07-776, ORDER ADOPTING SETTLEMENT AGREEMENT at 4-6 of Settlement Agreement (NDPSC Dec. 31, 2008) (Appendix E).

Dakota modeling sensitivities. The *Settlement* in that proceeding also provided the NDPSC with an opportunity to assess the Company's resource decisions prior to implementation through the filing of Advance Determination of Prudence (ADP) applications with the NDPSC for "major" transmission and generation resources.³³

To date, our experience has been that these procedural changes have only underscored the extent of jurisdictional disagreements. For example, the North Dakota analysis now included in the Company's IRP filing has only served to further illustrate the differences between North Dakota and Minnesota without providing a procedural avenue to reconcile those differences. Should we move forward with a regulatory alignment structure, it will be necessary to modify the IRP process so IRPs can act as a true vehicle to better align outcomes in the states we serve. This is especially the case as significant resource retirements are being considered.

Similarly, bringing forward resources for evaluation under North Dakota's ADP law³⁴ has provided earlier identification of resource selection disagreements without means of resolving those disagreements. When we undertook the 2008 rate case settlement, the North Dakota ADP statute was recently enacted. Prior to that time, almost all resource decisions were reviewed after the fact in North Dakota rate cases. Under the rate case review paradigm, new resources (and retired resources) could be assessed in a holistic manner while reviewing all of the Company's other costs and their drivers. While we appreciate advanced reviews of resource selections by the NDPSC through the ADP process, this process can result in review of individual resources with less consideration of the larger, system-wide context in which resources are selected.

Additionally, interpretation of the ADP statute has evolved in a way that creates a new form of uncertainty regarding resource approvals. Under the NDPSC's interpretation of the ADP statute, resource *approval* is binding for future cost recovery purposes but *rejection* of an ADP is not binding. Consequently, although an ADP provides some guidance as to potential future NDPSC action on a particular resource, a rejection provides no definitive decision upon which the Company can act.

The use of ADPs has been helpful where agreement exists and in providing earlier identification of potential disagreements between the NSPM states regarding certain resources. This has given the Company more information as it assesses whether to move forward with a resource and in seeking commercial solutions where

³³ *N. States Power Co. Elec. Rate Increase Application*, Case No. PU-07-776, ORDER ADOPTING SETTLEMENT AGREEMENT at 4-7 of Settlement Agreement (NDPSC Dec. 31, 2008) (Appendix E); *In the Matter of Xcel Energy's Filing on Jurisdictional Cost Issues*, Docket No. E002/M-16-223, COMPLIANCE FILING at 21-23 (MPUC June 13, 2016) (Appendix B).

³⁴ N.D.C.C. § 49-05-16.

disagreements exist. Accordingly, up to now, rejection of an ADP by the NDPSC has not resulted in any project cancellations. However, this is not sustainable. To the extent the Company's ability to recover its costs is put in jeopardy by failure to obtain an ADP, it may become necessary to cancel such projects rather than risk under recovery of investments.

The various ADP proceedings have also provided additional clarity or confirmation regarding various aspects of the NDPSC's planning paradigm,³⁵ including: (1) recognition by the NDPSC that the state that hosts a particular resource retains the ultimate decision-making responsibility regarding its future; (2) the NDPSC's requirement to better match the timing of load serving need and resource additions; and (3) movement toward accepting that resources, though perhaps not intended to meet a specifically identified load-serving need, drive down overall system cost.³⁶ Future resource alignment, if it is the preferred outcome, will benefit from understanding these principles.

We modeled certain outcomes based on regulatory alignment with respect to known Disputed Resources in our IRP, but at this time, we cannot predict where or to what extent each of the states we serve might compromise to achieve regulatory alignment over the longer term. Nor do we gain more information about the viability of Regulatory Alignment by modeling structural changes, since Regulatory Alignment assumes continuation of full integration of the NSP System. As such, we present the Regulatory Alignment option as a general approach, rather than an alternative that is transformative from a resource planning or ratemaking standpoint. We anticipate further dialogue on this option through this proceeding.

2. Proxy Pricing

Another alternative structure is to institute a proxy pricing overlay to resource selections of the various NSPM states. This type of structure is premised on the

³⁵ *N. States Power Co. Elec. Rate Case*, Case No. PU-400-87-6, FINDINGS OF FACT, CONCLUSIONS OF LAW AND ORDER at 30 (Mar. 24, 1988) ("We expect NSP to continue to use least cost planning to supply energy at the lowest possible cost. In this regard, we define 'least cost planning' or 'integrated resource planning' for an electric utility to be the consideration of both supply- and demand-side options in selecting the least cost method of meeting the energy and demand needs of customers. The demand-side and supply-side resources considered will be evaluated in terms of benefit/cost criteria. A resource will be considered as passing the primary test for cost effectiveness if it can satisfy load at a lower cost to the utility than any other resource. Once this test is satisfied, the resource will be further considered in terms of other impacts: rate impacts, environmental impacts, load profile impacts and other pertinent impacts. If these other impacts do not negatively outweigh a favorable benefit/cost ratio for the resource, the resource should be adopted.")

³⁶ *See, e.g., N. States Power Co. Advance Prudence – 200 MW Courtenay Wind Farm Application*, Case No. PU-15-181, FINDINGS OF FACT, CONCLUSIONS OF LAW AND ORDER (NDPSC Aug. 24, 2015).

concept that different states value different types of resources differently. Thus, the logic behind proxy pricing is that all states accept that resources provide, at a minimum, capacity and energy to the NSP System and that those benefits should be paid for by all jurisdictions. The use of proxy pricing would provide that payment for the capacity and energy supplied by a particular resource while leaving the difference between the proxy price and the actual price (either positive or negative) to be recovered from the jurisdictions that support a particular resource type over others.

The Proxy Pricing concept is intended to address the “type” question when analyzing resources from a size, type, and timing perspective. It may also require compromises regarding size and timing, recognizing that adding a certain size and type of resource today may affect the size and type of other resources needed in the future.

A Proxy Pricing structure can be most successful when utilized to level differences between jurisdictions regarding mandated resource selections, such as renewable energy mandates. In those instances, if one state’s law requires the addition of a particular type of resource and the other state does not, utilizing a Proxy Pricing regime can mitigate the cost shift of the mandated resources to the non-mandating states while still having all states contribute to the energy and capacity of a particular resource. By addressing a particular set of resources, such as those required by renewable energy mandates, the application of proxy pricing is cabined to a small subset of resources.

However, a Proxy Pricing structure is less capable of addressing different views regarding resource additions when they are not easily defined as mandated or when there is a mismatch in size and timing as well as type. It would be necessary and complex to determine the extent to which proxy pricing is needed in each case where there is disagreement on a type of resource, and only some level of agreement on the need for a resource of a particular size at a particular time.

Accordingly, a Proxy Pricing outcome requires ongoing inter-jurisdictional coordination and is most effective when a limited set of resources that would be subject to proxy pricing can be clearly defined. In such circumstances, larger system integration is feasible and a minority of resources can be addressed through proxy pricing. This is consistent with our experience addressing the different renewable energy mandates between our Texas and New Mexico jurisdictions. For example, the New Mexico Renewable Portfolio Standard required the acquisition of five solar PPAs. To retain the integration of the Texas/New Mexico system, Southwestern Public Service Company proposed, and the New Mexico Public Regulation Commission approved, a proxy pricing model that allowed: (1) Texas to pay its allocated share of the costs of the PPAs up to the system avoided energy costs, which

meant Texas retail customers were indifferent as to the acquisition of the PPAs; and (2) New Mexico to pay the remainder of the PPA costs to keep Southwestern Public Service Company whole.

Recent history makes clear, however, that (as discussed previously in Section III.B of this Application) the resource misalignment between the NSPM states touch more than just those resources related to Minnesota's renewable mandates and that trend may well continue into the future. By way of example, the Company has developed a plan to add significant wind resources beyond what is currently needed for compliance, because doing so is economically beneficial. While we have not brought that plan before either Commission for formal approval, initial feedback from the Commissions leads us to believe that our proposal may receive different treatment in North Dakota and Minnesota.

Further, as new technologies become available we would likely need to institute new proxy pricing terms to address the impact of these technologies on the system. These experiences call into question whether proxy pricing is a viable long-term solution.

Our experience in negotiating the "Restack" of the NSP System under the settlement of our 2013 test year North Dakota rate case, Case No. PU-12-813, further underscores the weaknesses of the Proxy Pricing approach. There, even though the parties were working from ten guiding principles, they were unable to reach agreement on proxy pricing. Key impediments to success included determining the appropriate pricing proxies and how to address resources added to the NSP System that were not determined as "needed" under North Dakota's resource planning paradigms. These concerns continue to counsel against a Proxy Pricing structure at this time.

3. Pseudo Separation

Given the difficulties in developing an equitable Proxy Pricing structure, we also explored how to maintain the overall integration of the NSP System and legal structure of NSPM by allowing the system to continue to jointly serve North Dakota, South Dakota, and Minnesota while direct assigning certain generating resource costs and benefits to individual states where there is disagreement. We call this a "Pseudo Separation" because it would effectively separate generation portfolios serving different states, but would not legally alter the existing Xcel Energy corporate structure nor impact other ratemaking paradigms in the states.

At its simplest, a Pseudo Separation structure assigns the entire bundle of benefits and burdens of a resource to the states that support it without changing the corporate

structure of NSPM. The bundle of benefits and burdens includes costs (such as the PPA price for contracted resources or capital and operations and maintenance (O&M) of Company-owned resources); revenues (from sale of output into the Midcontinent Independent System Operator (MISO) energy market or of unit-specific capacity); resource planning/adequacy attributes (such as capacity value and energy); and other values (such as environmental credits). In many ways, Pseudo Separation identifies the economic portions of how a particular generation interacts with rates and seeks to ensure costs and benefits are allocated to the cost causative and supportive jurisdictions.

The first question with respect to Pseudo Separation was whether it is feasible, which includes determining how, if at all, we could assign the costs, revenues, and attributes of a particular resource to a particular jurisdiction. We also needed to assess how states that do not participate in a particular resource would be served when that resource is dispatched by MISO. Our feasibility screen indicated that Pseudo Separation was technically feasible though complex, as it would require ongoing accounting and other operational refinements.

At its core, Pseudo Separation would account for generation activities on a generator level rather than on the system-wide level upon which we allocate costs and revenues today. Pseudo Separation would essentially reallocate the economic impacts of the federal market overlay, bi-lateral transaction, and MISO dispatch of the NSP System to particular states. More specifically, to implement Pseudo Separation, MISO day-ahead and real-time market transaction revenues would be allocated to each generator so that revenues can then be allocated to particular jurisdictions based on their participation (or lack thereof) in a particular generation resource. Non-participating jurisdictions would pay the MISO locational marginal price (LMP) as if market purchases were being made in place of dispatching system generation resources in which they do not participate. Pseudo Separation would also address the revenues from generation margins and ancillary services, revenue sufficiency guarantee uplifts, and other MISO market constructs. Capacity sales and purchases would be similarly allocated, as well as renewable energy credits (RECs) and other non-power-based attributes of a particular resource. Similarly, each state's load could be treated as a separate entity for bidding purposes. We provide additional detail regarding the mechanics of Pseudo Separation in Schedule 6.

For resource planning purposes, under Pseudo Separation, we would establish separate Loads and Resources tables for each state to reflect the specific generation mix in which a particular state has chosen to participate. We would then plan for each state's load serving needs and energy policy priorities separately. Over time, this would result in different resource mixes serving different states.

We anticipate several advantages to a Pseudo Separation structure. By separating resource assignments as between North Dakota and the remainder of the NSP System, Pseudo Separation would enable the Company to plan for differing future views of need and resource selection between the states we serve. Because we would be direct assigning costs to the jurisdiction(s) for which the future resource is selected and approved, cost recovery would also be more specific to the state(s) that approved the resource. This structure therefore allows the Company to plan for resources with more flexibility in each part of the System, and with more certainty that the otherwise reasonable costs of a selected investment will be recoverable.

Further, Pseudo Separation does not require structural changes to the Xcel Energy corporate organization since NSPM would continue to provide service in Minnesota, North Dakota, and South Dakota. Rather, the separation occurs at the resource selection and cost allocation level, meaning that once there is agreement on resolution of past resources, Pseudo Separation could be implemented in our next rate case following the end of this proceeding. As such, the overall implementation of this structure is expected to be less expensive and less complex up front than creating a new North Dakota-serving corporate subsidiary would be under the Legal Separation alternative discussed below.

Pseudo Separation also presents challenges, as it requires some initial interstate decisions regarding how to assign pricing, and may require ongoing cooperation between the NSPM states to manage a Pseudo Separation structure into the future. While we currently manage resources on a system-wide, aggregated basis, Pseudo Separation would require a unit-specific management approach. This, in turn, requires related ratemaking choices to manage the newly unit-specific nature of the system.

For example, we would need to determine – and obtain approval in multiple jurisdictions for – the appropriate load node pricing to be paid by a particular jurisdiction. Because the vast bulk of the NSP System is located in Minnesota, the main load pricing node providing the cost the Company pays for energy is MISO's NSP.NSP node,³⁷ located in the heart of the NSP System in Minnesota. A successful Pseudo Separation structure would require determination of the energy costs paid by each load node. There are multiple ways to accomplish this: we could use NSP.NSP as the pricing node system-wide; we could use each and every load node closer to our

³⁷ By managing the NSP System on an integrated basis, we bid our various loads at their node but allocate costs as an integrated whole. Since the vast bulk of NSP System load is located at the NSP.NSP load node, our average System costs generally reflect this load node pricing.

load – such as OTP.NSP for our North Dakota load; or we could use the load nodes closest to the generation being dispatched. Each of these choices is justifiable, but will need to be made initially and continually agreed to in all of the NSPM states to achieve sustainable implementation of this structure.

A Pseudo Separation structure also would likely require us to change other ways we analyze and operate the NSP System. For example, we currently consider distributed energy resources as generating resources serving the entire system in our resource planning. However, these resources are not dispatched by MISO and instead are viewed by MISO as a reduction in load for MISO's energy market operations. Consequently, we receive no MISO revenues for these generation resources and pay no market costs for the equivalently-reduced load. We would therefore need to shift allocation factors between the states, and find agreement between states as to how this should be accomplished to equitably establish a Pseudo Separation structure. In addition, MISO has recently proposed a capacity market structure for retail choice states.³⁸ While this does not impact the NSP System directly, the Pseudo Separation structure would need to be changed to accommodate a new federal overlay if such changes occur in the future.

Lastly, implementing a Pseudo Separation structure could impact the NSPM/NSPW relationship through the existing Interchange Agreement. We would have to make appropriate accommodations to address this.

We believe each of these tasks is achievable and would maintain all other benefits of the System status quo while addressing generation resources and ensuring equitable management of the costs incurred on the NSP System to date. Accordingly, we believe this alternative warrants further discussion.

4. Legal Separation

The final structure we analyzed was the creation of a separate operating company, "NSP-Dakota" or "NSPD," to serve our North Dakota customers. We evaluated the Legal Separation option because it provides stability and flexibility on a going-forward basis that we believe can provide long-term value to the Company, our customers, and our various stakeholders. However, Legal Separation is also the most complex and difficult alternative to implement initially.

³⁸ *Midcontinent Indep. Sys. Operator, Inc.*, FERC Docket No. ER17-284, PROPOSED COMPETITIVE RETAIL SOLUTION IN NEW MODULE E-3 AND CORRESPONDING REVISIONS TO EXISTING TARIFF SECTIONS IN Modules A, D, AND E-1 (Nov. 1, 2016).

Under a Legal Separation structure, we would serve our customers in North Dakota through a separate operating company that would continue to be part of the Xcel Energy Inc. corporate family. At the time of creation, NSPD would be the regulated entity in North Dakota and its rate base, operating expenses, and fuel costs would form the basis of its rates. This is in contrast to the allocated portion of the NSPM rate base, operating expenses, and fuel costs that are currently underlying the rates of our North Dakota customers. This revenue requirement structural shift, which is addressed in the Revenue Requirement Analysis section of this Application, is a key component of evaluating this RTF structure.

Once formed, a separate operating company provides a platform from which we can address the resource needs of the jurisdictions we serve on a truly individual basis. The key advantages of Legal Separation are certainty and flexibility by creating distinct entities with distinct needs and the capacity to take on separate legal liabilities and separate corporate ownership of assets. This structure permanently removes the need for agreement between all states regarding the reasonableness and prudence of not only resource selection, but also all costs (such as depreciation and taxes) that may lead to incompatible ratemaking and cost recovery outcomes across the NSPM states.

Legal Separation also creates greater opportunities for the Company to more fully participate in valued investments in North Dakota, such as development of gas generation, without requiring the agreement of the other NSPM states or to incur liabilities for NSPM. By legally separating, the new operating company would own its own assets, have its own contractual relationships with third-parties, and therefore have its own corporate existence separate from NSPM and the regulatory requirements or decisions of other states.

Consistent with our proposed RTF, Legal Separation does not mean that we must fully dis-integrate the NSP System. Rather, it will merely change the relationship of our North Dakota customers to the remainder of the NSP System. More specifically, we envision that rather than being allocated a share of the costs of the Legacy System, NSPD would transition to a unit-specific supply agreement with the NSP System to take service from the Legacy System. NSPD could then work with North Dakota regulators to establish future resource selections that suit North Dakota's views of need and appropriate types of cost-effective resources for North Dakota customers.

That said, establishing a new operating company requires significant up-front cost and effort. It would first be necessary to determine the size, scope, and structure of the new operating company. For example, we would need to establish whether NSPD will serve only our North Dakota load, or whether it will also serve our South Dakota load – which would effectively double the amount of customers served. It is also

necessary to determine what assets will be owned by each operating company after separation. This determination requires evaluation of the distribution system, transmission assets, and generating resources. Issues such as size of load of the new operating company, costs of providing service through MISO, and supply mix and form will all need to be determined.

Decisions regarding what assets would comprise NSPD's rate base and how to provide transmission and generation service to NSPD would be multifaceted. For example, if the current North Dakota-based transmission assets become part of the NSPD rate base, close to 100 different transmission agreements will need to be assigned or amended to accommodate transmission service to the new entity. This is but one example of the implications of unwinding the integrated system in order to establish NSPD.

We would also need to determine how a new operating company should be managed at the corporate level, what employees it will have, and what services it will take from its affiliates within Xcel Energy Inc. It would then be necessary to establish service agreements that direct assign specific costs and allocate common costs, including, for example, how we would support our Dilworth and East Grand Forks customers in Minnesota from service centers in North Dakota.

We would also need to determine immediate supply options and mid-term plans for meeting generation and transmission needs of the new operating company. This includes ensuring that any liabilities incurred for use of the NSP System stay with the new operating company, as well as determining how to structure a supply agreement with the NSP System. Additionally, it would be necessary to determine whether and how NSPD would utilize the market structures that were not available to it when the NSP System was developing. This determination includes assessing how to provide hedges against MISO market costs that will no longer be provided to North Dakota by the larger NSP System.

Last, Legal Separation is potentially costly. We estimate that an investment of several million dollars will be required to establish a new operating company.

These structural decisions would present challenges, but – like the challenges associated with Pseudo Separation – we do not believe that they are insurmountable. Further, the very process of working through these issues would provide our stakeholders greater insight into the contributions and costs to the System of the various states we serve.

B. Initial Conclusions

As a result of our evaluation, we concluded the RTF should enable the Legacy System to serve all states while affording North Dakota and Minnesota a certain degree of control in their future resource selections. To that end, we propose to have the RTF allow for the separation of North Dakota from the NSP System. A separation alternative becomes particularly desirable as we look ahead to an overall fleet transformation.

Two of the future separation structures presented – Pseudo Separation and Legal Separation – could, over time, satisfy this RTF.³⁹ Either structure would result in our North Dakota customers being served by their own resource mix – either as part of NSPM or as a separate operating company. Therefore, it is necessary to determine whether it is economically feasible and reasonable to serve North Dakota outside the integrated system. It is also necessary to determine the impact of the loss of the North Dakota load to the remainder of the NSP System. These questions form the basis of our resource planning analysis, which is described in more detail in Section V below.

A revenue requirement analysis is also necessary to evaluate the costs of establishing Pseudo Separation, or of forming a new operating company under a Legal Separation structure. Our revenue requirement analysis is described in Section VI of the Application.

V. RESOURCE PLANNING ANALYSIS

In addition to the qualitative assessment of various structures that might support our RTF, we undertook a robust resource planning analysis that identified the costs and benefits of system integration. Our analysis also assessed cost mitigation strategies so that an implemented RTF would result in reasonable impact to all our customers.

We utilized our Strategist resource planning tool to facilitate our resource planning analysis. While Strategist is a useful tool, it is a modeling tool and therefore only as good as the assumptions that underlie the model. We believe that we have used reasonable assumptions to conduct our analysis, but we stress that these are only assumptions. Further, it is necessary to recognize that the impacts of the RTF could be permanent – or at least last for decades, during which the NSP System will evolve, along with technologies, legal requirements, and the industry as a whole. It is not fully possible to predict all the forms this evolution will take, nor all the potential impacts

³⁹ Either RTF separation structure can be expanded to include South Dakota.

on our customers. Therefore, while we believe our resource planning analysis supports our recommendation, it is intended to validate our more qualitative assessment of the need for and reasonableness of our proposed RTF rather than to determine optimal resource choices as in a resource plan or resource selection proceeding.

The steps in our resource planning analysis, which are described in more detail in this section of our Application, are as follows:

- *Evaluate an Equitable Legacy System through allocation of Disputed Resources:* First, we validated the potentially equitable allocation of Disputed Resources which underlie our resource planning analysis to help ensure that we are fairly allocating costs and benefits for those Disputed Resources.
- *Establish the Baseline Future NSP System:* Next, to evaluate options for the future of the NSP System, we established a “status quo” baseline. However, even that process cannot be based on static information. Our resource planning analysis begins with the presently known future of the NSP System, consistent with the outcome of our most current IRP proceeding (referred to as the IRP Plan). However, most of the assumptions that were developed for the IRP proceeding are nearly two years old, as we first submitted the IRP in early January of 2015. Consequently, we also present a view of the IRP with updated modeling assumptions, as well as our currently forecasted amount of wind acquisitions and updated pricing that we will fully present to the MPUC in March (referred to as the Updated Plan). These analyses establish a baseline from which to continue to analyze our RTF.
- *Determine the Impact of the North Dakota Load on the NSP System:* We then assessed the impact of the North Dakota load on the NSP System to understand the effect of the potential loss of the North Dakota load on the remainder of the NSP System and the effect to North Dakota of exiting the integrated system. With this information, we sought to identify a date on which we could equitably establish a separate North Dakota-based generation portfolio.
- *Assess Continued Service to North Dakota from the Legacy System:* We also examined the reasonableness of continuing to serve North Dakota from the Legacy System. As discussed earlier in the Application, the various principles we have established for managing the NSP System recognize the history and value of the Legacy System; therefore, to develop an RTF we needed a resource planning assessment of the equities of continuing to serve North Dakota from

the Legacy System. We identified two potential generation portfolios that could serve North Dakota and reflect a high capital cost and low capital cost resources to separately serve our North Dakota customers. These potential portfolios act as comparison points by which we could determine the impacts and validity of our proposed path to continue to largely serve North Dakota with the Legacy System after the point of separation identified in the second phase of our analysis.

- *Evaluate a North Dakota Separation Scenario:* We then analyzed a scenario under which North Dakota would largely leave the Legacy System (an exit scenario) after the 2025 equitable exit date established by our analysis. While we are not proposing an exit scenario, we recognize that either or both Commissions may prefer an exit scenario if the baseload resources presently existing on the NSP System should evolve more quickly than presently contemplated, as such an exit scenario could better allocate the costs and liabilities of an accelerated transformation of the NSP System. We also believe that informing the record with an exit scenario is important. As described above, should an exit scenario occur, we are proposing that our North Dakota customers continue to be served by our nuclear portfolio to provide baseload generation and fuel diversity to North Dakota and for reasons of equity. Therefore, our analysis of these scenarios includes continued service in North Dakota by our nuclear fleet.

Our resource planning analysis is equally applicable to both the Pseudo Separation and Legal Separation structures, as the cost of particular generation portfolios would likely be equivalent under both structures. The main difference between the two would be that under the Pseudo Separation structure, the costs of different service options would be allocated through state-based ratemaking allocations, whereas under a Legal Separation structure the costs of different service options would be allocated contractually between the new NSPD and the remainder of the NSP System.

We have conducted our analysis on a present value of societal cost (PVSC) basis (with externalities) and a present value of revenue requirements (PVRR) basis (without externalities).⁴⁰ Our potential allocation of Disputed Resources, described further in Section VI.A, is included in our analysis.

⁴⁰ Consistent with the proceedings in NDPSC Case No. PU-12-59, we have removed the capacity credit from the PVRR analysis presented in this Application. We provide a PVRR analysis with the capacity credit included for all scenarios analyzed in this Application in Schedule 7 as the PVRR_{cc} sensitivities. Please see Schedule 7 for a further discussion regarding the analyses and our modeling assumptions.

A. Potential Equitable Resolution of Disputed Resources

To establish a resource planning analysis baseline, we first sought to determine a potentially equitable allocation of the Disputed Resources. Based on the implementation timing of our RTF, we also sought to determine the impact of our new wind additions (currently scheduled to go in-service in 2020 – at the same time we plan to implement our RTF) as part of our resource planning analysis. Beginning with our Updated Plan, we compared (1) an RTF that continued service by the Legacy System comprised of all resources on the NSP System and an allocation of the new wind additions to all states consistent with current allocation methods to (2) an RTF that allocated the North Dakota share of the Disputed Resources, except MEC II, to the remainder of the NSP System, as well as allocating all of the new wind resources to all states of the NSP System except North Dakota, consistent with the description of an equitable path forward on the Disputed Resources above. A summary of the results of that analysis are presented in Table 1, below. We present the annual impact in Schedule 7.

Table 1: Costs of the Reallocation of Disputed Resources Compared to Shared 1500 MW Wind

PVRR, \$M	MN/SD/NSPW	ND
Shared Legacy, Jur Future, Share 1500MW wind	48,435	2,430
Shared Legacy, Jur Future, Jur Reallocated Disputed Resources and wind	48,404	2,467
PVRR Delta, \$M	MN/SD/NSPW	ND
Shared Legacy, Jur Future, Share 1500MW wind	-	-
Shared Legacy, Jur Future, Jur Reallocated Disputed Resources and wind	(32)	37

As shown in Table 1, over the modeling period, reallocating the North Dakota share of the Disputed Resources to the remainder of the NSP System while also allocating all of our new wind additions to the remainder of the NSP System results in approximately \$32 million savings on a PVRR basis to the NSP System states and approximately \$37 million in additional costs on a PVRR basis to North Dakota. The impact of these long-term cost shifts are moderated by the fact that in the near term, North Dakota will realize immediate cost savings from this potential allocation of Disputed Resources (as shown in our revenue requirements analysis below). Because of the long-term savings to Minnesota and the short-term savings to North Dakota, we believe this analysis validates a potential path to address Disputed Resources.

B. The Baseline Future NSP System

Having reached one potentially equitable resolution of past Disputed Resources, our next task was to establish a baseline against which to measure the potential effects of future changes to the NSP System. We identified the Reference Case from our IRP proceeding as a reasonable comparison point against which to measure the future of the NSP System. The Reference Case represents a future look at the NSP System that we believe would have met our minimum system needs and compliance obligations in all states. The Reference Case assumes that Sherco Units 1 & 2 will run through the planning period's end at 2030, adds 400 MW of wind by 2020, has 287 MW of utility scale solar representing our 187 MW solar portfolio and the Aurora Solar project, and then adds only combustion turbines to meet capacity needs consistent with the Loads and Resources analysis presented in our recent IRP.⁴¹

Given that the assumptions underlying the Reference Case are from the December 2014 modeling underlying our January 2015 initial IRP filing, we then updated the Reference Case to account for new, updated assumptions regarding load growth, renewable energy pricing, and gas pricing, among others. This provides us a similar comparison point with updated assumptions rather than carry forward our 2014 modeling assumption from the IRP proceeding. We also applied the same updated assumptions to the outcome of the IRP. The Updated Reference Case removes three combustion turbines from the Reference Case in 2025, 2027, 2031, 2032, and 2033, and adds an additional combined cycle unit in 2032.⁴²

We also modeled an expansion plan based on the IRP Plan. This includes the addition of at least 1000 MW of wind by 2020, the closure of Sherco Units 1 & 2 in 2026 and 2023, respectively, and an additional 800 MW of utility scale solar additions.⁴³ We note that notwithstanding the MPUC's decision that all resource types be considered to meet capacity needs in the out-years of the planning period, our analysis here assumes those needs are met by combustion turbines for the sake of simplicity and uniformity. Additionally, given the uncertainty surrounding the costs of acquiring demand response resources, the MPUC's order for up to 400 MW of

⁴¹ The use of combustion turbines to meet capacity needs is consistent with our IRP assumptions and is assumed throughout our resource planning analysis. We recognize that many of the capacity needs in the mid-2020s will be due to expiration of PPAs that may be renewed. However, given the uncertainty as to the terms of any potential renewal, our analysis in this Application assumes combustion turbine additions in place of PPA renewal throughout.

⁴² Expansion plans for the Reference Case and the Updated Reference Case are provided in Schedule 7.

⁴³ Consistent with current practice, our resource planning analysis assumes that the costs for Solar Gardens (labelled "small solar" in the IRP Plan) are wholly recovered in Minnesota and not allocated to the other states of the NSP System.

demand response resources in 2025 is not included in our analysis.⁴⁴ Table 2 below provides the IRP Plan.

Table 2: IRP Plan

IRP Expansion Plan	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	Total
Small Solar	10	259	159	91	83	76	17	20	24	29	34	41	49	59	71	85	-	-	-	-	-	1,107
Large Solar	-	-	287	-	-	-	-	200	100	100	200	100	100	400	-	-	-	-	-	-	-	1,487
Wind	350	200	200	-	1,200	-	-	-	-	-	400	200	-	-	-	-	-	-	-	-	-	2,550
PPA CT	-	-	-	-	-	-	-	-	-	-	460	460	460	230	-	-	-	-	-	-	-	1,610
PPA CC	-	-	-	-	345	-	-	-	-	-	-	-	-	-	-	-	778	778	-	778	778	3,457
Fargo CT	-	-	-	-	-	-	-	-	-	-	230	-	-	-	-	-	-	-	-	-	-	230
BD/Sherco CT	-	-	-	-	232	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	232
SH Boiler	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sherco CC/BD CC	-	-	-	-	-	-	-	-	-	-	-	-	786	-	-	-	-	-	-	-	-	786

We then updated the IRP Plan (Updated Plan) using current assumptions much like we did for our Reference Case. This updating also accounted for our currently known wind expansion plans. These updates include a new sales forecast, updates to gas pricing assumptions, and updated renewable energy pricing for wind and solar. Our updated assumptions are presented in Schedule 7. Table 3, below provides our Updated Plan.

Table 3: Updated Plan

Updated Expansion Plan	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	Total
Small Solar	10	259	159	91	83	76	17	20	24	29	34	41	49	59	71	85	-	-	-	-	-	1,107
Large Solar	-	-	287	-	-	-	-	300	100	200	100	100	-	400	-	-	-	-	-	-	-	1,487
Wind	350	200	200	-	1,500	-	-	-	-	-	100	200	-	-	-	-	-	-	-	-	-	2,550
PPA CT	-	-	-	-	-	-	-	-	-	-	230	460	230	230	-	-	-	460	-	-	-	1,610
PPA CC	-	-	-	-	345	-	-	-	-	-	-	-	-	-	-	-	778	-	-	778	1,556	3,457
Fargo CT	-	-	-	-	-	-	-	-	-	-	230	-	-	-	-	-	-	-	-	-	-	230
BD/Sherco CT	-	-	-	-	232	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	232
SH Boiler	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sherco CC/BD CC	-	-	-	-	-	-	-	-	-	-	-	-	786	-	-	-	-	-	-	-	-	786

Table 4, below, provides the system-wide impact of our Reference Case, our Updated Reference Case, our IRP Plan, and our Updated Plan on a PVSC and PVRR basis.

**Table 4: Cost of Resource Plan to NSP System
 BASE CASE**

Total System, \$M*	PVSC	PVRR
IRP Reference Case	43,513	38,603
IRP Plan	43,375	39,552
Updated Reference Case	44,987	40,753
Updated Plan	44,069	40,955
Delta, IRP Assum	(138)	949
Delta, Current Assum	(918)	202

* NPV calculations in this table are through 2040

The North Dakota impact analysis is presented in Table 5 on a PVSC basis and PVRR basis.

⁴⁴ Additional demand response resources could be a substitute for the combustion turbines identified in the IRP Plan.

Table 5: Cost of Resource Plan to North Dakota

BASE CASE		
ND Jur, \$M*	PVSC	PVRR
IRP Reference Case	2,441	2,243
IRP Plan	2,413	2,272
Updated Reference Case	2,224	2,068
Updated Plan	2,169	2,062
Delta, IRP Assum	(28)	29
Delta, Current Assum	(54)	(6)

* NPV calculations in this table are through 2040

Figures 1 and 2, below, show the system-wide costs of the IRP Plan and the Updated Plan compared to each respective Reference Case, relative to each other on a PVSC and PVRR basis.

Figure 1

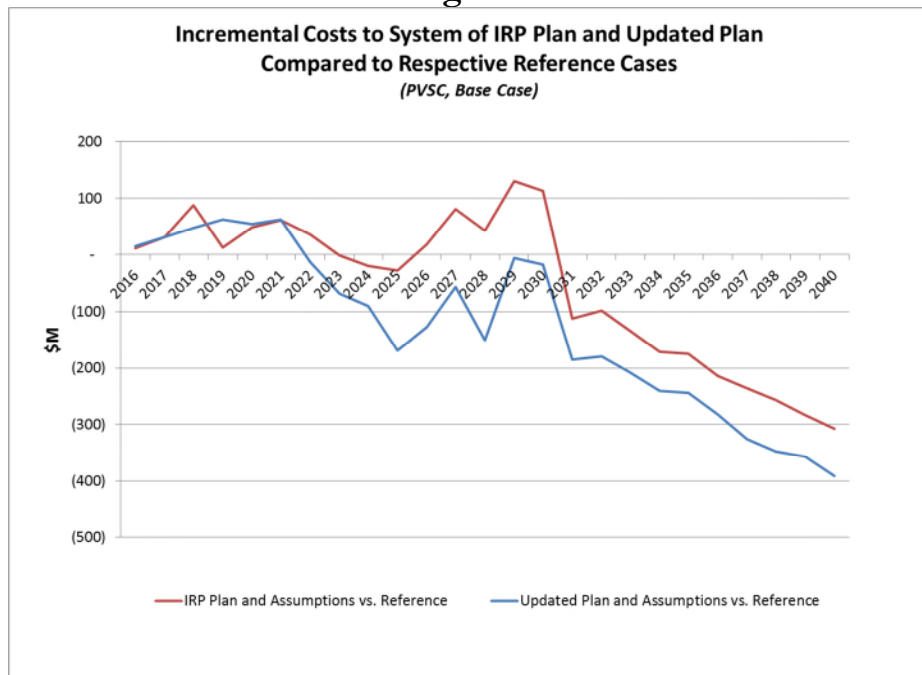
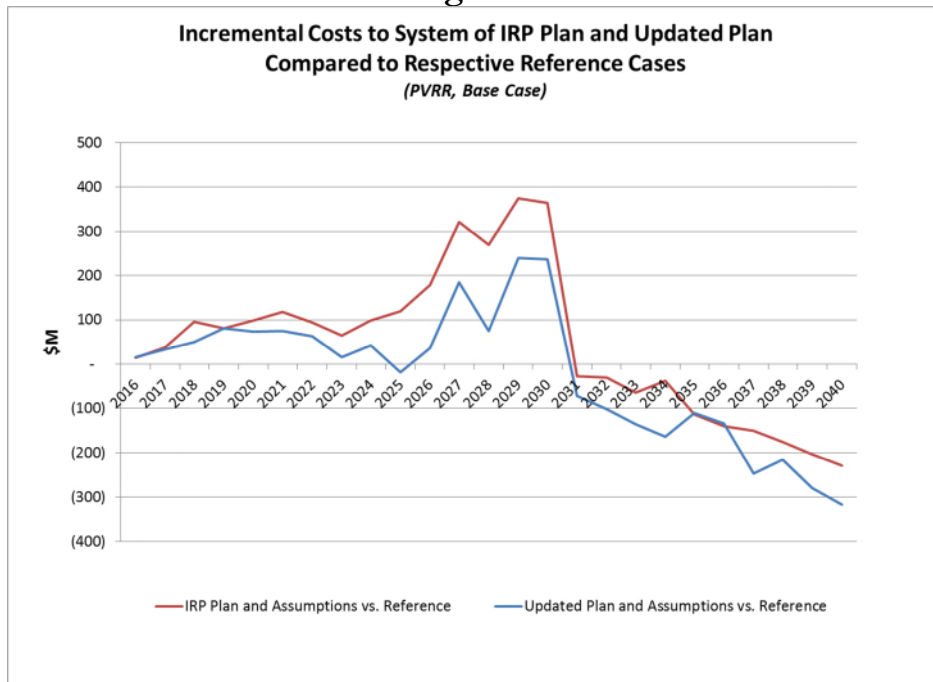


Figure 2



Figures 3 and 4, below, show the cost impact to North Dakota of the IRP Plan and the Updated Plan compared to each respective Reference Case, relative to each other on a PVSC and PVRR basis.

Figure 3

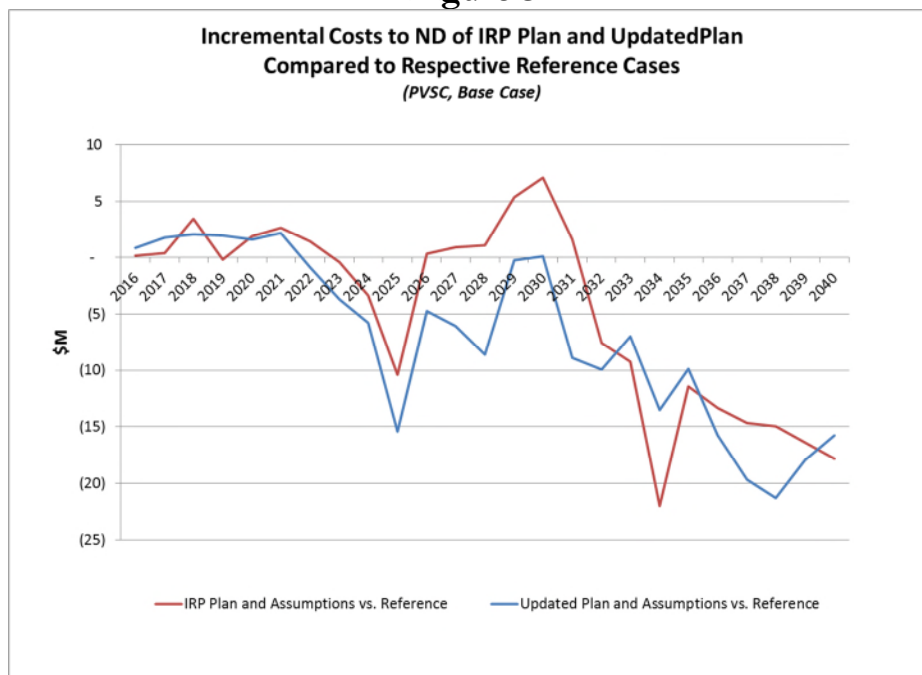
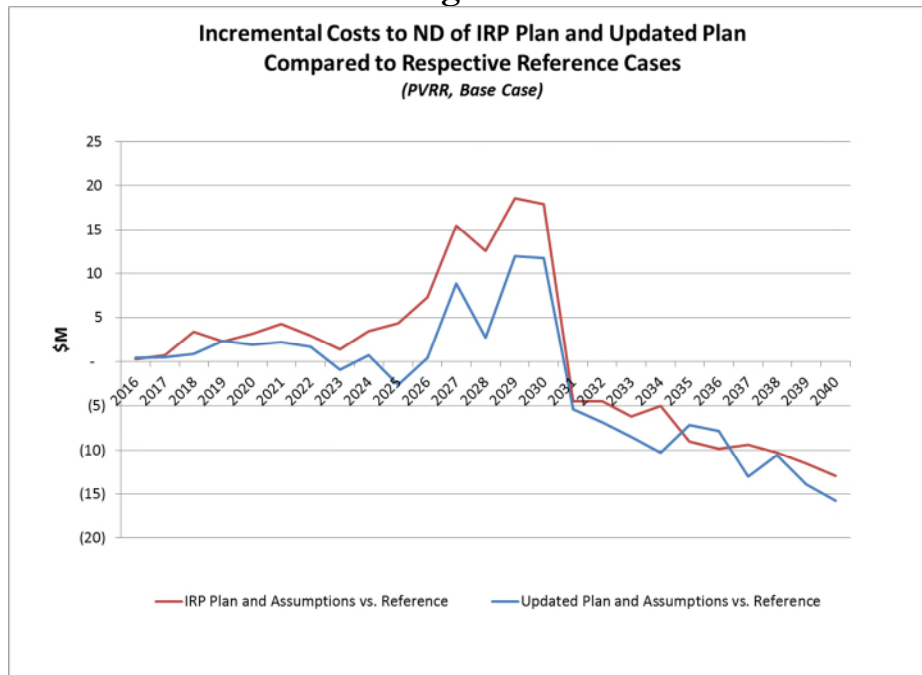


Figure 4

Our baseline analysis identified that based on the modeling assumptions in our recently MPUC-approved IRP, the IRP Plan was more expensive than the Reference Case on a PVRR basis, while on a PVSC basis was somewhat less expensive than the Reference Case over the life of the plan. When we updated both the Reference Case and the IRP Plan with new information, especially renewable pricing and the increased amount of production tax credit (PTC)-eligible wind in the model, the results changed and the Updated Plan became less expensive on both a PVSC and PVRR basis.

That said, both the IRP Plan and the Updated Plan accelerate the need to make material capital investments in the NSP System due to the closure of Sherco Units 1 & 2 in the mid-2020s when compared to their respective Reference Case. In the long-run, this is smoothed out as the capital investments planned for 2030 in the Reference Cases are merely accelerated and there is less cost impact than in the Reference Cases in 2030 and beyond due to depreciation of the capital investment beginning earlier. The impacts of accelerated investments are also materially mitigated in the Updated Plan based on the fuel savings attributable to increasing the amount of PTC-eligible wind on the System. However, given the accelerated impact to system costs and informal concerns raised by the NDPSC and its Staff regarding the accelerated closure of Sherco Units 1 & 2, we are assuming that the Updated Plan will still be unacceptable in North Dakota, notwithstanding its overall lower modeled costs over its life.

Establishing this baseline view helps to demonstrate that our proposed RTF is appropriate. The MPUC approved a resource plan that was least cost when externalities were accounted for and not least cost when they were not. This tends to support an assumption that the resource planning outlooks of North Dakota and Minnesota are incompatible.

C. North Dakota Load and the NSP System

We next performed an examination of the impact of the North Dakota load on the NSP System. We undertook this analysis to determine the magnitude of the costs of the NSP System carried by our North Dakota customers and what the impact would be to the remainder of the NSP System should it lose the customer base that constitutes our North Dakota load.

We chose 2023 as the earliest date to perform this analysis because it is the earliest reasonable time by which we can permit and install new generation resources in North Dakota. Additionally, we performed this analysis to better understand the impacts of our North Dakota load on our current system profile – specifically, what would occur to the NSP System from a cost perspective should it lose the North Dakota load before and after the shutdown of Sherco Unit 2 at the end of 2023 and after the shutdown of Sherco Unit 1 at the end of 2026. Additionally, we modeled the assumption of continued service to North Dakota from the Legacy System to quantitatively validate the qualitative assumptions that underlie our proposed RTF.

Table 6, below, identifies the impact of the loss of North Dakota load on the remainder of the NSP System in 2023, 2025, and 2027 on a PVSC, PVRR, and rate impact basis. Table 6 includes the impact of continued sharing of the Legacy System by all NSP System customers.

Table 6: Impact of Loss of ND Load on Remainder of NSP System

MN/SD/NSPW, \$M	BASE CASE		LOW GAS		HIGH GAS	
	PVSC	PVRR	PVSC	PVRR	PVSC	PVRR
Updated Plan	52,493	48,302	49,213	45,106	57,477	53,201
Shared Legacy, Jur Future	52,350	48,348	49,182	45,203	57,296	53,164
Loss of ND Load, 2023	52,614	48,462	49,399	45,344	57,477	53,240
Loss of ND Load, 2025	52,496	48,365	49,282	45,248	57,360	53,141
Loss of ND Load, 2027	52,439	48,314	49,228	45,197	57,307	53,090

Delta, \$M	BASE CASE		LOW GAS		HIGH GAS	
	PVSC	PVRR	PVSC	PVRR	PVSC	PVRR
Updated Plan	-	-	-	-	-	-
Shared Legacy, Jur Future	(144)	45	(31)	97	(181)	(37)
Loss of ND Load, 2023	121	160	186	238	(0)	40
Loss of ND Load, 2025	2	63	68	142	(117)	(59)
Loss of ND Load, 2027	(54)	12	15	91	(171)	(111)

Figures 5 and 6, below, identify the impact of the loss of North Dakota load on the remainder of the NSP System in 2023, 2025, and 2027 on a PVSC and PVRR basis. Figures 5 and 6 also identify the impact of continued sharing of the Legacy System.

Figure 5

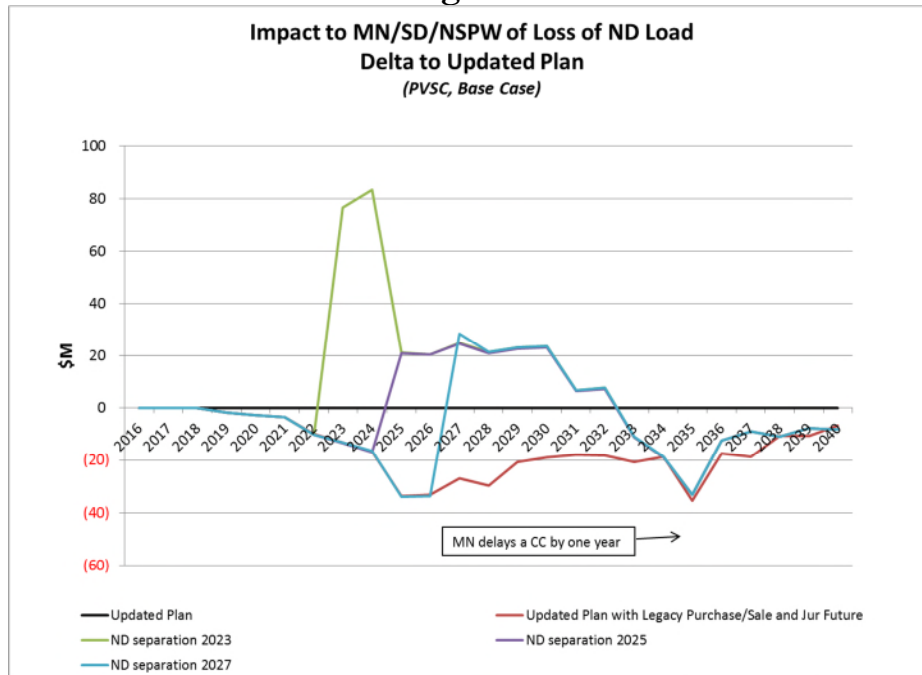
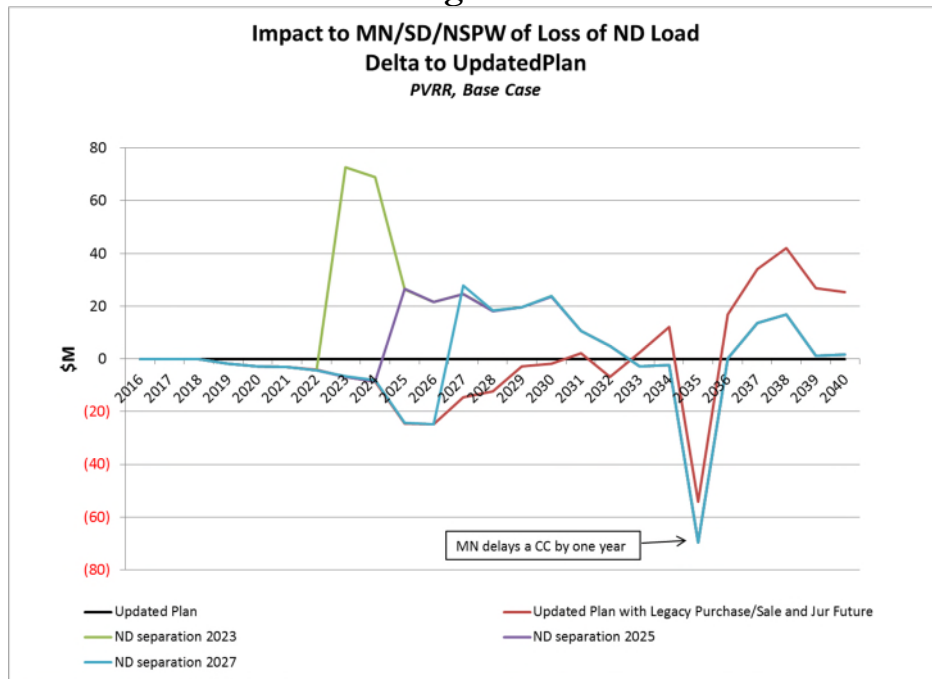


Figure 6



Loss of the North Dakota load also impacts the Updated Plan. The loss of North Dakota load results in two fewer 230 MW combustion turbines added to the system through 2030. Additions of combustion turbines and a combined cycle unit in 2035 are also delayed by the loss of the North Dakota load. We present the Updated Plans in Schedule 7.

As shown above, the later that the NSP System loses the support of the North Dakota load, the more the impact to the remainder of the NSP System is mitigated. We can also infer from this analysis that the inverse is true regarding the effects on our North Dakota customers from staying on the NSP System longer. Said differently, the earlier the North Dakota load separates from the NSP System, the earlier the cost shifts occur to the remainder of the System. However, the true impact to our North Dakota customers from separating from the NSP System cannot be fully modeled without assumptions about the generation portfolio that would serve North Dakota as a stand-alone system.

This analysis leads us to several conclusions. First, continued service from the Legacy System is reasonable and materially mitigates the impacts to the remainder of the NSP System from the loss of our North Dakota load. Second, 2025 is the most equitable date for the NSP System to lose the North Dakota load, should that be the preferred outcome of the Commissions. This is because the cost impacts of a 2025 date are equitably balanced between savings to North Dakota and impacts to the remainder of the NSP System by the loss of the North Dakota load. Third, to retain these equities,

our North Dakota customers should continue to be served by the Legacy System from the implementation of our RTF, expected to be in 2020, until 2025 under any circumstances. Therefore, the remainder of our resource planning analysis utilizes a 2025 date as the appropriate measuring point for North Dakota service scenarios.

D. Reasonableness of Continued Service from the Legacy System

After establishing key baseline information in the analyses above, we then sought to validate the reasonableness of continued service to North Dakota from the NSP System beginning in 2025. We undertook our validation analysis by developing two potential generation portfolio scenarios that we believe would identify the low-end of costs and high-end of costs of serving North Dakota separately, and also allow assessment of the volatility of these scenarios when compared to the Legacy System. Recognizing the myriad of different service options that may be available, we believe that these scenarios provide reasonable “bookends” to quantitatively validate the qualitative assessments that underlie our proposed RTF. Because this analysis is focused on serving North Dakota, we present our figures here on a PVRR basis only.

The first generation portfolio we developed was based on full service to our North Dakota customers from only combustion turbines (the CT Scenario). Under this scenario, we assumed that a combustion turbine fleet would be installed in 2025, consistent with our analysis above, and that our North Dakota customers would be served from the Legacy System until then. We developed this scenario to analyze the costs of least-cost capacity resources with low capacity factors which therefore require material reliance on energy markets to serve our North Dakota load.

The CT Scenario adds only combustion turbines to serve our North Dakota load with the majority of the energy supplied by the markets. The resource additions are in 2025 (230 MW), 2031 (115 MW), and 2041 (115 MW). For the alternative where North Dakota continues to be served by the Legacy System, with jurisdictional planning for future resources, resource needs requiring resource additions have combustion turbines being added in 2031, 2035, 2041, and 2051 and are all sized at 115 MW.

The second generation portfolio we developed was based on full service to our North Dakota customers from combined cycle plants (the CC Scenario). Under this scenario, we assumed that the combined cycle fleet would be installed in 2025, consistent with our analysis above, and that our North Dakota customers would be served from the Legacy System until then. We developed this scenario to analyze the costs of higher capacity factor resources which have higher initial capital costs that

mitigate reliance on energy markets to serve our North Dakota compared to the CT Scenario.

In this scenario, a single 389 MW combined cycle plant was added in 2025 to serve our North Dakota load. A combined cycle plant was not an option for the scenario where North Dakota continues to be served by the Legacy System, with jurisdictional planning for future resources, as the incremental load-serving need was not large enough to justify a larger unit. Resource needs are therefore met by combustion turbines in the Legacy System scenario as described above.

We used the CC and CT Scenarios, which represent extremes on both ends of potential service options, to provide comparison points for continued service to North Dakota by the Legacy System. Recognizing that the CT Scenario and CC Scenario are single fuel and rely on market purchases for some or most of the energy needs of our North Dakota customers, we also performed an analysis for high and low gas sensitivities. Additionally, for the purposes of validating our RTF, we performed this analysis on the CT and CC Scenarios without the inclusion of the support of the Company's nuclear fleet, as described above.

Table 7, below, identifies the costs of service to North Dakota from the CT Scenario, Legacy System, and CC Scenario on a PVSC and PVRR basis under our base case and high and low gas sensitivities, as well as the differential between these scenarios and our Updated Plan. Figure 7 represents the PVRR view of these scenarios compared to our Updated Plan graphically for our base case. Figure 8 represents the PVRR view of the base case, high gas, and low gas scenarios compared to our Updated Plan graphically.

Table 7: Cost of North Dakota Service Scenarios

ND, \$M	BASE CASE		LOW GAS		HIGH GAS	
	PVSC	PVRR	PVSC	PVRR	PVSC	PVRR
Updated Plan	2,711	2,567	2,521	2,384	2,993	2,846
Shared Legacy, Jur Future	2,899	2,515	2,575	2,245	3,243	2,903
Loss of ND Load, 2025, CT, No Nuclear	2,958	2,477	2,522	2,120	3,382	3,005
Loss of ND Load, 2025 CC, No Nuclear	2,786	2,512	2,485	2,218	3,218	2,948

Delta, \$M	BASE CASE		LOW GAS		HIGH GAS	
	PVSC	PVRR	PVSC	PVRR	PVSC	PVRR
Updated Plan	-	-	-	-	-	-
Shared Legacy, Jur Future	188	(52)	54	(139)	251	57
Loss of ND Load, 2025, CT, No Nuclear	247	(90)	1	(264)	389	159
Loss of ND Load, 2025 CC, No Nuclear	75	(55)	(36)	(166)	225	102

Figure 7

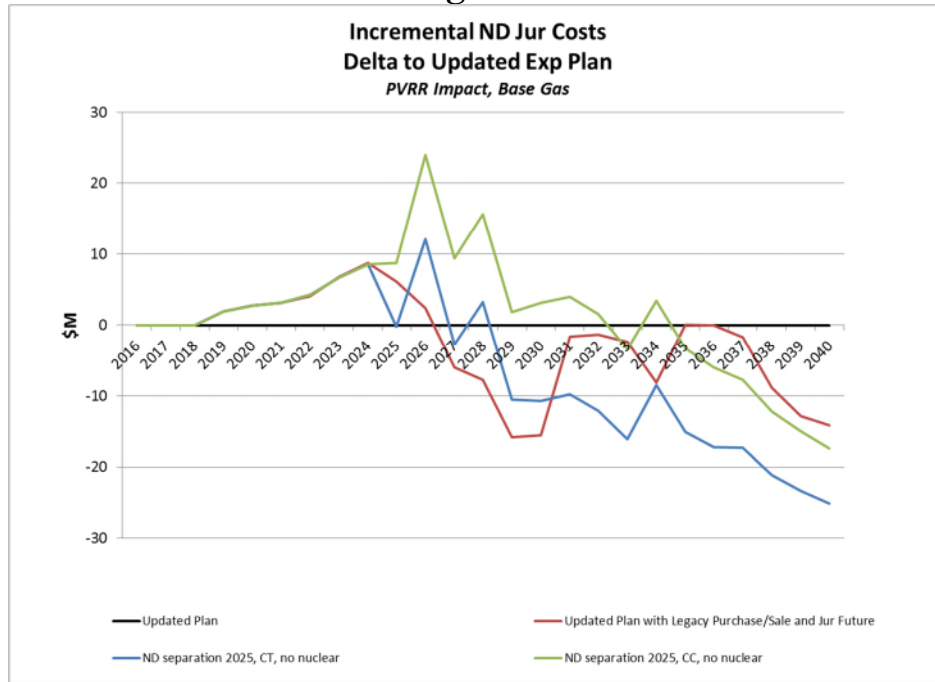
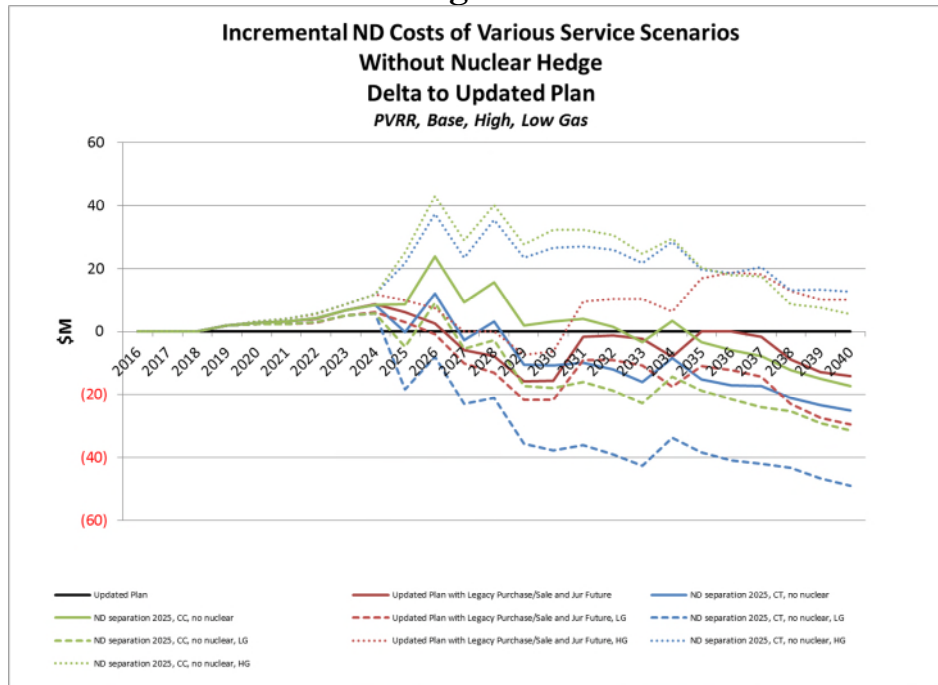


Figure 8



Using our base case assumptions, the CT Scenario is the lowest cost. As shown in Figure 7, the capital costs of installing the first 230 MW of combustion turbines results in less rate impact when compared to our Updated Plan than either continued service from the Legacy System or in the CC Scenario. However, as shown in Table 7

and Figure 8, the CT Scenario is the most volatile, as it had the largest range of outcomes when assessing the base case, as well as high and low gas scenarios. The exposure to the energy markets based on the assumed ten percent capacity factor of the combustion turbines and the impact on energy markets from gas prices, leads us to conclude that service from only combustion turbines may not be prudent.

In contrast, the Legacy System performed reasonably in our base case and in a high and low gas scenario, especially through the 2020s. While not the cheapest scenario under our base case, continued service from the Legacy System reduces the need for capital investment in 2025, making this a less impactful outcome in the early years of the analysis period. Additionally, through the 2020s, service by the Legacy System was least volatile, demonstrating the hedge value of the Legacy System. Of note, the Legacy System scenario under our base case assumptions outperformed the CC Scenario under our low gas sensitivity through 2030, which further demonstrates the value of the fuel diversity of the Legacy System.

The CC Scenario was the most impactful in the early years but also a reasonable service option when compared to our Updated Plan in a base case scenario. The performance of the CC Scenario was materially impacted by the lumpiness of constructing these types of generators, with material capital investments in the early years of this scenario but with that capacity and energy being sufficient for many years. And while more volatile than the Legacy System, it was less volatile than the CT scenario when comparing the base case to the high and low gas sensitivities.

Based on this, we conclude that continued service to North Dakota from the Legacy System is reasonable as it results in no immediate impact to rates, is less expensive than service under our Updated Plan over its life under base case assumptions, and is the least volatile of the scenarios should gas prices materially change (either to serve the CC Scenario with gas or the impact to the market energy providing ninety percent of the energy in the CT Scenario). Consequently, we believe that this analysis quantitatively validates the qualitative assessments that led to our proposed RTF.

E. North Dakota Separation Scenarios

Lastly, we analyzed separation scenarios to provide context for the Commissions and also to provide an alternative view should the judgment of the Commissions be that the evolution of the Legacy System will accelerate in the future should continued service from the entire Legacy System not be preferred by the Commissions past 2025. To mitigate some of the volatility identified in the CT Scenario and CC Scenario analyzed above and to retain the equity of the incurred liabilities for the use of the Legacy System proposed as part of our RTF, we paired our nuclear fleet to the

CT Scenario and CC Scenario for our analysis of separation scenarios (CT Scenario + Nuclear and CC Scenario + Nuclear, respectively). The expansion plans for these scenarios are provided in Schedule 7.

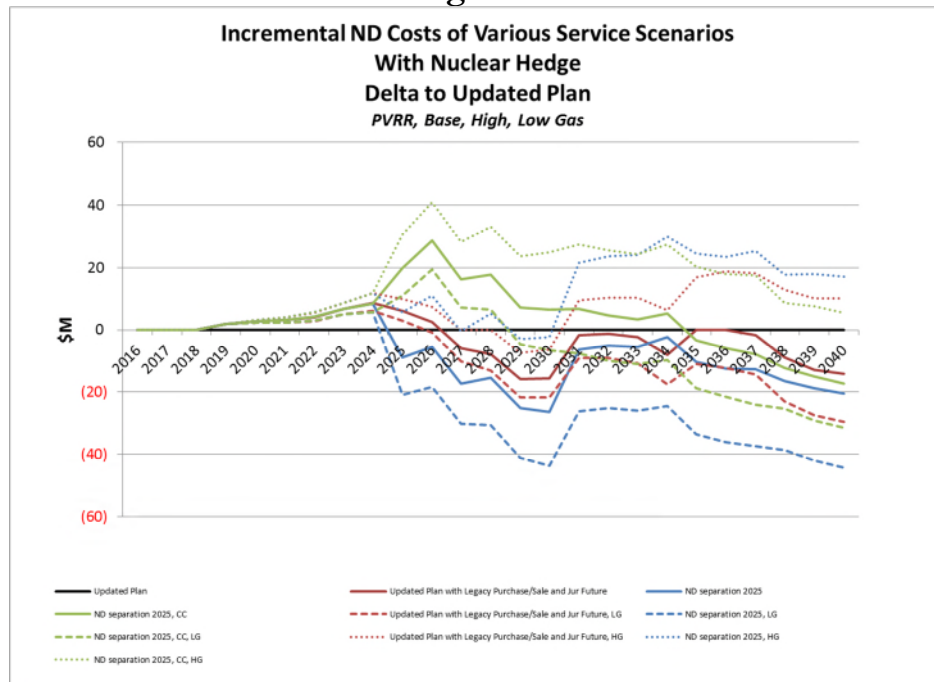
From a resource planning standpoint, we would expect that the addition of approximately twenty percent of capacity needs being met by a high capacity alternative fuel source would materially mitigate the volatility of the CC Scenario and CT Scenario and also offset earlier capital investment needs, which could lead to better overall cost performance. Our analysis bears this out. Table 8 identifies the PVSC and PVRR performance of the CT Scenario + Nuclear, the CC Scenario + Nuclear, and continued service from the Legacy System as well as a comparison to our Updated Plan. Figure 9 provides a graphic representation of our modeling outputs.

Table 8: ND Service Scenarios with Nuclear Hedge

ND Jur, \$M	BASE GAS		LOW GAS		HIGH GAS	
	PVSC	PVRR	PVSC	PVRR	PVSC	PVRR
Updated Plan	2,711	2,567	2,521	2,384	2,993	2,846
Shared Legacy, Jur Future	2,899	2,515	2,575	2,245	3,243	2,903
Loss of ND Load, 2025, CT	2,884	2,456	2,491	2,130	3,307	2,944
Loss of ND Load, 2025 CC	2,780	2,534	2,507	2,265	3,182	2,937

Delta, \$M	BASE GAS		LOW GAS		HIGH GAS	
	PVSC	PVRR	PVSC	PVRR	PVSC	PVRR
Updated Plan	-	-	-	-	-	-
Shared Legacy, Jur Future	188	(52)	54	(139)	251	57
Loss of ND Load, 2025, CT	173	(111)	(30)	(254)	314	98
Loss of ND Load, 2025 CC	69	(33)	(14)	(119)	189	92

Figure 9



Comparing the outputs of Table 7 with Table 8, we can see that the CT scenario performs better when paired to our nuclear portfolio than without it from both a PVR analysis as well as from a volatility perspective, with the nuclear portfolio providing a fuel and market hedge for the CT Scenario. The CC scenario also performed better over its life when tied to our nuclear portfolio due to the offset of capital investment provided by carrying forward our nuclear portfolio, as well as the fuel hedge provided by alternative, baseload fuel sources. Additionally, on a PVR basis, the Legacy System performed in the midpoint, with the least volatility, when compared to the other two scenarios.

Based on this, we conclude that continued service to North Dakota from the Legacy System continues to be the most prudent path forward under any RTF structure. However, should the Commissions choose to separate North Dakota from the Legacy System sooner than its natural retirement dates, continued service from our nuclear fleet is a key component of doing so, as it would provide material fuel hedge value and offset initial capital investments to help smooth a transition to stand-alone service for our North Dakota customers.

F. Resource Planning Conclusions

Based on our resource planning analysis, continued service to North Dakota from the Legacy System would be a reasonably equitable outcome. However, should the Commissions determine that a more complete separation should be undertaken, then

doing so in 2025 with continued service to our North Dakota customers from our nuclear fleet is a reasonable time and way to do so. Last, our resource planning analysis confirmed that our potentially equitable method to address the Disputed Resources provides immediate cost savings to our North Dakota customers while providing overall cost savings to the remainder of the NSP System over time.

In summary, our Resource Planning Analysis yields the following key findings:

- **Fair Treatment of Disputed Resources** – Table 1 shows that reallocating the Disputed Resources over the remainder of the NSP System while also allocating all of our wind additions to the remainder of NSP System results in an equitable outcome for both our North Dakota customers and our customers being served by the remainder of the NSP System.
- **Reduced Costs of Our Updated Plan** - Figures 1 through 4 demonstrate that the Updated Plan (with incremental wind) is less costly than the IRP Plan from both a PVRR and PVSC basis for both the NSP System and North Dakota.
- **Impacts and Timing of Dissolving the Legacy System** - Figures 5 and 6 demonstrate that continued service from the Legacy System is reasonable and mitigates cost shifting to the remainder of the NSP System and that 2025 is the most equitable time for North Dakota to separate (should the Commissions choose to do so).
- **Costs and Risks of Replacement Generation Options** - Figures 7 and 8 demonstrate that if North Dakota separates in 2025 and chooses to self-supply generation resources, a combined cycle resource offers the highest expected portfolio cost and lower risk profile while combustion turbine resources offer the lowest expected portfolio cost with a higher risk profile. Importantly, this validates the reasonableness of continued service from the Legacy System.
- **Benefits of Legacy System and Nuclear** – Figures 8 and 9 also demonstrate how the diversity of resources in the Legacy System, or at least our nuclear fleet, help provide the lowest risk profile for North Dakota in terms of replacement generation options with a mid-range cost impact.

VI. REVENUE REQUIREMENT ANALYSIS

As noted above, the Company's resource planning analysis is intended to illustrate the viability of certain service scenarios in the future. It is not intended to propose or support a particular resource selection. In addition, certain aspects of our proposed RTF – including the resolution of the Disputed Resources and potential Pseudo or Legal Separation – are likely to have some degree of revenue requirement impact, depending on the assumptions made about their implementation. Therefore, our

revenue requirement analysis is intended to help the Commissions assess the more immediate potential rate impacts of implementing our RTF.

There are two aspects to our revenue requirement analysis. First, we assess the possible cost impact to each state of resolving past and near-future resource selection disagreements. Second, we compare the cost impacts of either a Pseudo Separation structure or Legal Separation structure.

We began our revenue requirement analysis with the Company's revenue requirement projection for 2020 with data as of late 2015 for each jurisdiction served by the NSP System – North Dakota, South Dakota, Minnesota, Wisconsin, and Michigan.⁴⁵ The forecasted 2020 revenue requirement is a representation of the Company's projected cost of serving each state on an "all-in" basis, including base rates, fuel costs, and rider revenue. We chose 2020 as the representative year because it is consistent with our next Minnesota rate case schedule, which is needed to implement a Pseudo Separation structure, and is likely the earliest we can achieve Legal Separation. This data provides a baseline against which we can compare cost and revenue shifts across jurisdictions that are likely to be caused by defining the Legacy System and resolving the Disputed Resources through our RTF.

For purposes of establishing a baseline, we assumed a shared system with resources similar to those presented in the most recent Minnesota IRP, with typical ratemaking adjustments in each jurisdiction. Actual cost recovery will, of course, be governed by ratemaking proceedings in each state. This Application is not intended to set forth a specific cost allocation request, precise cost determinations, or a cost recovery petition. More specific cost assessments and proposed cost allocation methods (through services agreements and other affiliated interest structures) would be made in the future, depending on the outcomes amongst the NSPM states on the specific components of our RTF.

The goal of our revenue requirement analysis is to identify change levels, generally, to facilitate review of our proposed RTF. More specific and detailed analyses will be performed should we move forward with an RTF that involves Pseudo Separation or Legal Separation.

⁴⁵ Both Wisconsin and Michigan are served by NSPW, such that a reference to NSPW is intended to encompass both our Wisconsin and Michigan customers.

A. Resolving Resource Disagreements

Under the current integrated NSP System, the Company's costs are allocated across the jurisdictions we serve based on each jurisdiction's relative contributions to cost-causation. As discussed earlier in this Application, however, not all costs are fully recovered through this allocation due to differing views between the jurisdictions we serve. In the instance of Pseudo Separation, we would seek to allocate costs of the Disputed Resources through review of this Application and subsequent rate case filings. In the instance of Legal Separation, we would seek to allocate costs of Disputed Resources through the implementation of a supply agreement for NSPD and the remainder of the NSP System.

Recognizing that there are many different equitable resolutions to these misalignments that would result in reasonable outcomes, we look forward to discussions with the Commissions and all of our stakeholders to determine a solution that can gain consensus. That said, we believe that one reasonable approach would generally recognize the differing resource selection preferences of North Dakota and Minnesota, and allocate the costs of Disputed Resources accordingly with moderate net impact (on a percentage basis) for either state.

First, we could envision removing the Disputed Resources (Minnesota-based CBED, certain solar, and biomass resources) that have been disallowed or otherwise disfavored by the NDPSC from North Dakota rates. Similarly, we recognize that our plan to retire Sherco Units 1 & 2 in the 2020s, rather than have them serve out their full remaining useful lives as reflected in our North Dakota depreciation rates for these units, has been received differently in our North Dakota and Minnesota jurisdictions. Therefore, we believe it could be equitable to recover the difference in depreciation expense for these resources from the remainder of the NSP System on an amortized basis. This creates a modest increase in Minnesota rates on a percentage basis.

To offset the modest increase in Minnesota costs, we believe it could be reasonable to allocate the proposed new, cost-effective wind additions to the remainder of the NSP System, with their approval. As discussed above, the new wind resources are cost-effective over the life of the proposed assets. Since this analysis examines only 2020, the entire benefit of the new wind over the asset life on the remaining NSP System is not shown.

Lastly, we believe it would be reasonable to allocate the MEC II PPA costs and benefits consistent with current allocation methods between the states we serve, as this resource was supported in Minnesota but also provides reliable supply options to

North Dakota as it looks toward a more independent resource planning future. This is assumed in the baseline model.

B. Costs of Pseudo Separation

As part of our feasibility analysis for a Pseudo Separation structure, we identified the likely need for additional staff to manage the Pseudo Separation, as well as additional investment in our information technology infrastructure to support the more complex accounting and allocation processes required to undertake the Pseudo Separation structure. While we will prepare in-depth estimates of the likely actual costs of implementing the Pseudo Separation should that be the outcome of this proceeding, for purposes of this Application we are providing a high-level estimate of \$1 million of additional costs for this structure on a revenue requirements basis.

Because one of the primary benefits of the Pseudo Separation structure is that it retains the existing nature of NSPM except with regards to generation, we believe it could be reasonable to allocate these costs consistent with current allocation methods.

Table 9, below, identifies the revenue requirement impact of what we believe is a reasonable potential resolution to past disputes over resource selection.

Table 9

\$ million rev req	2020 Test Period				Notes
	ND Jur	MN Jur	SD Jur	NSPW	
Baseline Model (nearest million)	\$251	\$3,739	\$294	\$869	A
Pseudo-Separation Differences					
Biomass	(\$6.6)	\$5.1	\$0.4	\$1.1	B
CBED Wind	(\$2.3)	\$1.8	\$0.1	\$0.4	B
Solar	(\$1.2)	\$0.9	\$0.1	\$0.2	B
Replacement cost for Disputed Resources	\$3.1	(\$2.4)	(\$0.2)	(\$0.5)	C
New Wind and Fuel Savings	\$4.1	(\$3.2)	(\$0.2)	(\$0.7)	B
Sherco Units 1 and 2 retirements	(\$1.3)	\$1.0	\$0.1	\$0.2	D
Additional accounting and IT	\$0.1	\$0.7	\$0.1	\$0.2	E
Total Pseudo-Separation Differences	(\$4.1)	\$4.0	\$0.3	\$0.9	
Difference % from Baseline	-1.6%	0.1%	0.1%	0.1%	
Notes:					
A	Includes 1500 MW new wind and 2022 Sherco 1 & 2 ret.				
B	Shift to remaining jurisdictions				
C	Paid back to remaining jurisdictions				
D	Depreciation difference shift to remaining jurisdictions				
E	\$1m rough estimate for additional allocation complexity				

As demonstrated in Table 9, this allocation of resources resulted in less than a one percent increase to rates in the remainder of the NSP System while acknowledging North Dakota's concern with the Disputed Resources and beginning the process of separating North Dakota from the NSP System. At the same time, the impact to North Dakota is savings of about one and a half percent. Together, we believe these allocations reflect one reasonable set of cost impacts in each state, while also having the potential to better align the states we serve with the resources they support.

C. Costs of Legal Separation

In the event the approved RTF involves Legal Separation, it is necessary to consider the likely revenue requirement impacts associated with creating and operating NSPD, which, as a company, would necessarily be smaller than the current combined NSPM. Because a separate operating company would include only the revenues, expenses, rate base, and resources necessary to serve those customers in North Dakota, the new utility would have a lesser capitalization than the combined utility.

We determined that creating a separate legal entity would require some new costs, including dedicated oversight, financing, service company allocations, and regionally-shared transmission. Additionally, we would incur transaction costs for the creation and regulatory approvals necessary to establish NSPD.

1. Dedicated Oversight

First, a separate utility would likely require its own operating company president and board of directors and other oversight, as well as dedicated separate staffing. There are currently over one hundred Xcel Energy employees working in North Dakota and we would need to determine which of these would become NSPD employees and which would remain Xcel Energy Services Inc. (XES) or NSPM employees. Should we move forward with Legal Separation, further analysis will need to be conducted regarding this issue. For purposes of this high-level assessment only, we have provided an estimate of approximately \$2 million.

2. Financing

Based on current analyses and the present lending marketplace, we anticipate a North Dakota utility would likely incur a higher cost of long-term debt due to its smaller asset base and revenues when compared to NSPM. We have roughly estimated that an NSPD entity's cost of long-term debt would be approximately 6 percent, compared to approximately 4.8 percent for NSPM. Should we move forward with Legal Separation, further analysis will need to be conducted regarding this issue. For purposes of this high-level assessment only, we have provided an estimate of approximately \$1 million.

3. Service Company Allocations

We anticipate that Legal Separation will result in a shift of some corporate cost allocations from NSPM and NSPW to the new entity. Service company costs are presently billed directly from XES to each operating company on an administrative services agreement. The XES costs billed to NSPM are then allocated to each of the separate NSPM states based on currently-approved ratemaking allocation methodologies. An NSPD stand-alone entity would likely enter into its own administrative services agreement with XES and see an increase in its service company costs when it is direct billed for services rather than being allocated a share of NSPM's service company costs. Should we move forward with Legal Separation, further analysis will need to be conducted regarding this issue. For purposes of this high-level assessment only, we have provided an estimate of approximately \$3 million.

4. Regionally-Shared Transmission

We also anticipate a shift in transmission costs with the establishment of a new North Dakota entity. Serving NSPD as a stand-alone entity rather than part of NSPM can impact the MISO charges as well as transmission rate base used to set retail rates. Consequently, we expect that the costs of providing transmission service to NSPD could increase and we have taken into consideration in our rate analysis. Schedule 8 provides additional information regarding transmission service to our North Dakota customers under an NSPD scenario. Should we move forward with Legal Separation, further analysis will need to be conducted regarding this issue. For purposes of this high-level assessment only, we have provided an estimate of approximately \$5 million.

5. Transaction Costs

We currently estimate several million dollars in transaction costs to establish NSPD. Actual transaction costs will be a function of the assets that comprise NSPD and the work necessary to transfer these assets and the associated issues that relate to those particular assets. Transaction costs would be for the legal, regulatory, accounting, banking, and other activities that we would need to undertake to create NSPD.

Because creating a new operating company is outside of our normal operations, we believe it would be reasonable to allocate these transaction costs equally between NSPD and NSPM. Additionally, we believe it reasonable to amortize the transaction costs over the five-year period from 2020 to 2025 to mitigate the single year impact of these one-time costs to our customers. We propose amortization over five years for consistency with our resource planning analysis indicating that 2025 is the most equitable date for removing the North Dakota load from the NSP System, if Legal Separation is the Commissions' preferred outcome. Should we move forward with Legal Separation, further analysis will need to be conducted regarding this issue. For purposes of this high-level assessment, only, we have provided an estimate of approximately \$10 million for analysis purposes only.

Table 10, below demonstrates the revenue requirement impact for creating and operating NSPD.

Table 10: Cost Impact of Legal Separation in 2020

\$ million rev req	2020 Test Period				Notes
	ND Jur	MN Jur	SD Jur	NSPW	
Pseudo-Separation Differences except A&G	(\$4.2)	\$3.2	\$0.2	\$0.7	F
Legal Separation Differences					
Dedicated Oversight additional A&G	\$2.0	N/A	N/A	N/A	G
Financing	\$1.0	N/A	N/A	N/A	H
Service Company Allocations	\$3.0	(\$2.3)	(\$0.2)	(\$0.5)	I
Transmission	\$5.0	(\$3.9)	(\$0.3)	(\$0.9)	J
Transaction Costs	\$1.0	\$1.0	\$0.0	\$0.0	K
Total Legal Separation Differences	\$7.8	(\$1.9)	(\$0.2)	(\$0.7)	L
Difference % from Baseline	3.1%	-0.1%	-0.1%	-0.1%	
Notes:					
F	From Table 9 not including incremental accounting and IT costs				
G	\$2m rough estimate				
H	Treasury estimates 6% long term debt. \$1m rough estimate.				
I	\$3m rough estimate				
J	See Schedule 8				
K	\$10m estimate amortized over 5 yrs, 50% ND and 50% to remaining NSPM				
L	Total including Disputed Resources treatment and Legal Separation				

As indicated by Table 10, creating and operating NSPD would create a modest impact to North Dakota rates on a percentage basis.

A rate impact analysis for a typical customer bill is also provided in Schedule 9. Overall, we believe the revenue requirement impacts of the solutions suggested in this section of the Application are reasonable to achieve our overall RTF.

VII. RECOMMENDATION

Underlying the development of our proposed RTF is the recognition that the current status quo is unsustainable. The Company's recent history of managing different resource selection outcomes with creative, one-off solutions has somewhat mitigated inequitable results. However, the Company is currently not recovering its full cost of service in all of the states it serves and has additional cost recovery risks into the future if differing approaches to resource selection cannot be resolved.⁴⁶

⁴⁶ See *N. States Power Co. 2013 Elec. Rate Increase Application*, Case No. PU-12-813, et al., ORDER APPROVING FIRST REVISED NEGOTIATED AGREEMENT (NDPSC Mar. 9, 2016) (Appendix A).

Without the implementation of a framework to manage interjurisdictional disagreements, the Company is left with few options going forward. As we continue to evaluate resource needs and selections in the future, we can either choose not to implement a resource addition (or retirement) that does not have the full support of all jurisdictions, or implement a resource addition (or retirement) and fail to recover our full cost of service for that resource addition (or retirement). Neither of these options is satisfactory. Failure to implement resource additions or retirements that are not supported by all NSPM states fails to recognize the varying size and impact of the different jurisdictions on the overall NSP System. And failure to recover our full cost of service in all of the states we serve is inequitable to Xcel Energy, ultimately implicates free rider issues, and may lead to unjust and unreasonable rates in some jurisdictions.

Consequently, the development of our recommended RTF assumes that there will be continuing – and potentially exacerbated – disagreements between the NSPM states into the future. We therefore placed primacy on providing mechanisms for each state to make decisions separately as the NSP System evolves. We also sought to develop an RTF that provides certainty to the Company, our customers, regulators, and stakeholders now and into the future.

Further, as previously noted, fundamental principles of equity require that our North Dakota customers retain the liabilities they have incurred for their enjoyment of the NSP System. To that end, our proposed RTF includes the continued service of all of the NSP System states by the Legacy System.⁴⁷ In this way, all participants in the Legacy System remain responsible for the liabilities and benefits incurred historically while having greater optionality with respect to future resource selection. Our resource planning analysis supports our conclusion that retaining the existing NSP System for serving all of the NSPM states is reasonable from a PVR and PVSC perspective. Retaining the Legacy System also provides a large, diverse supply portfolio that can provide a physical hedge against any future uncertainty in ways that market-based mechanisms cannot. Therefore, continuing to utilize the Legacy System to serve all of our customers is in the best interest of our customers, the Company, and all of our stakeholders.

With that said, we recognize that there may be interest in accelerating separation of the NSP System if the System is transformed earlier than presently anticipated due to early retirements of key baseload resources. Such transformation, we believe, is compatible with Minnesota's view of the future but may be incompatible with the

⁴⁷ As previously noted, Disputed Resources are not considered part of the Legacy System for purposes of this Application, but rather would be resolved through a separate allocation or assignment of those Disputed Resources.

outlooks of the other NSPM states. That will be a topic for our 2019 Minnesota IRP. However, should such transformation occur earlier than expected, any RTF must be sufficiently robust to accommodate it. To that end, an RTF should provide the ability for our customers to retain the benefits of today's NSP System for as long as is feasible, but also provide flexibility that enables the utility to propose future resources that meet the potentially differing goals and determinations of need in the various states we serve.

A. Proposed RTF

As we undertook our analyses, we came to believe that our proposed RTF should be just that – a framework. With an overall framework in mind, we can seek consensus between the states as to the appropriate structures to support that framework. To that end, our proposed RTF is as follows:

1. All currently anticipated and past resource selection and other disagreements will be permanently addressed and the Legacy System established.
2. All NSPM states will continue to be served by the Legacy System and all of our customers will enjoy the benefits and bear the burdens of the Legacy System.
3. With respect to future new resource additions, the Company will be able to assess and propose resources for North Dakota and the remainder of the NSP System separately.
 - a. When a resource need arises in North Dakota, that need will be met by a resource sized for, dedicated to serve only, and fully recovered in North Dakota.
 - b. When a resource need arises in, or new resources are otherwise planned for, the remainder of the NSP System, those resources will be sized for, dedicated to serve only, and fully recovered in the remainder of the NSP System. Consequently, our North Dakota jurisdiction will not obtain the benefits or pay the costs associated with new NSP System resource additions.
 - c. Xcel Energy may propose particular future resources to be utilized concurrently by North Dakota and the remainder of the NSP System should circumstances warrant, and will propose cost-sharing arrangements at that time.

4. Over time, the generation portfolio serving North Dakota and the remainder of the NSP System will materially separate as units of the NSP System retire or expire.
5. South Dakota may elect to join North Dakota under this framework or remain part of the NSP System consistent with its own outlooks.

We believe this framework is consistent with the three principles guiding our management of the NSP System, the three principles guiding our development of the RTF, and the ten principles espoused in the 2013 test year rate case settlement agreement in North Dakota, as well as the guiding principles identified in Minnesota. Consequently, we believe that this RTF identifies the appropriate end state that we have been working toward for several years and will equitably address current and future disagreements among the NSPM states.

B. Structures to Support the Proposed RTF

Key to a successful implementation of our RTF will be the development of a resource management structure to support the outcome we envision. As discussed, we have been analyzing four separate structures to support an equitable resolution to interjurisdictional disagreement: (1) Regulatory Alignment; (2) Proxy Pricing; (3) Pseudo Separation; and (4) Legal Separation.

At this time, we are not recommending moving forward with a Regulatory Alignment structure. It remains unclear whether there can be opportunities for compromise or whether all of the states find value in continued integration into the future. Further, the Regulatory Alignment structure is the least robust method of addressing disagreements between the NSPM states and places the most financial risk on the Company. We do look forward to continued discussions to determine whether there may be opportunities to better align the regulatory frameworks of all the NSPM states through compromise. If a viable path can be found, there may be value in exploring opportunities to align the regulatory processes in all of our states to find common ground. But given the nature of current disagreements and the future evolution of the NSP System, we do not believe that a Regulatory Alignment structure can bridge the perceived gap between the states.

For several reasons, we also do not support a Proxy Pricing framework. First, previous failure to reach agreement on key aspects of a Proxy Pricing regime in North Dakota indicates that there will be difficulties in finding agreement between all of the NSPM states. This is mainly because different states value different resources differently.

Second, instituting a Proxy Pricing outcome requires continued agreement between the states; as new technologies continue to develop and legal structures evolve, a Proxy Pricing structure instituted today may not be able to appropriately address resources that have fundamentally different profiles than utility scale, central station resources – even if they are renewable. Continually modifying any Proxy Pricing RTF could continue to amplify the disagreements of the participants in the NSP System rather than provide the flexibility to address them.

Third, a Proxy Pricing structure will likely be insufficiently robust because it is difficult to predict all the possible permutations of resource selection outcomes that will need to be accommodated with a Proxy Pricing structure. As the NSP System continues to evolve, further disagreements are likely – which could implicate more and more resources that would need to be proxy priced, thereby further adding to potential inequities within the integrated NSP System.

We have determined that the Pseudo Separation structure is a viable option. It has the least near-term rate impacts and retains the current status quo regarding non-resource cost structures such as service company allocations and integrated transmission service. It also could achieve our overall goal of providing greater autonomy to the states we serve.

However, Pseudo Separation can result in long-term management difficulties. These concerns relate to ensuring that costs are appropriately allocated to the cost causative jurisdiction while accounting for common management costs appropriately. Like Proxy Pricing, the Pseudo Separation structure also requires continual review and refinement – and therefore continued agreement – regarding appropriate allocation methods between the states. Notwithstanding these challenges, if implemented with initial and ongoing cooperation from all stakeholders, Pseudo Separation is the least impactful structure to support our RTF.

If the Commissions do not support the Pseudo Separation structure, the Company is willing to move forward with Legal Separation. Legal Separation is the most complex and difficult to implement initially and can increase costs. That said, it provides stability and flexibility that we believe can provide long-term value to the Company, our customers, and our various stakeholders into the future. By creating a separate operating company, we can be more responsive to our differing customer needs and preferences in each of those states, presenting (as needed) different solutions in different jurisdictions to meet our customer needs, business goals, and desired regulatory outcomes.

VIII. NEXT STEPS

Through this filing, Xcel Energy is making its recommendation, informing the Commissions' consideration of alternatives and preferences, and seeking consensus on the path forward. With this information, the Company hopes to spur conversation over the next year with its regulators in both states to develop and implement a structure that can support our proposed RTF and that can be supported by all states served by the NSP System.

With respect to this Application, we propose an approximately eighteen-month evaluation period to review our recommendation, as discussed in depth below. We believe this proposed process will best manage the challenges presented in aligning the differing regulatory and legal processes of Minnesota and North Dakota. Generally, in Minnesota, the Company believes that consideration of the RTF is best handled through facilitating open discussion through written comments and replies.⁴⁸ Conversely, North Dakota law requires that all cases go before the NDPSC for record development. We therefore plan to build the record in North Dakota through pre-filed testimony and proceedings before the NDPSC given that there is no other procedural alternative available.

When considering issues of high complexity like those presented by the RTF, the Company understands the importance of ensuring ample time for discovery to answer questions and respond to concerns in the most transparent and consistent way possible. Accordingly, throughout the duration of the eighteen-month RTF evaluation period, the Company proposes to permit sufficient time for open rounds of discussion in both states. The Company also commits to cross-filing all comments and testimony filed in the respective state cases/dockets to ensure transparency of the information gathered in the other jurisdiction. Additionally, our proposed procedural schedule allows the stakeholders in each of our states to evaluate the comments and proposals of the stakeholders in the other states with sufficient time to substantively respond.

The Company proposes the following procedural schedules, specified by state, for consideration and evaluation of the RTF:

⁴⁸ Because the Company believes that the possible issues that may arise with respect to consideration of the Application and RTF can be satisfactorily resolved on the basis of the current filing and subsequent rounds of comments from parties to the proceeding, the Company does not believe a contested case is warranted.

North Dakota

- By January 1, 2017: Filing of the Application
- January-April 2017: Ongoing discovery and outreach
- May 1, 2017: NSP Direct Testimony
- August 1, 2017: Staff Rebuttal Testimony
- September 15, 2017: NSP Surrebuttal Testimony
- November/December 2017: Hearing
- January/February: Briefing
- Post-Hearing Matters (work sessions; informal hearings; opportunities for settlement)
- June/July 2018: NDPSC Order

Minnesota

- By January 1, 2017: Filing of the Application
- January-March 2017: Ongoing discovery and outreach
- April 1, 2017: Intervenor Comments
- May 1, 2017: NSP Reply Comments (may be reflected in NSP North Dakota Direct Testimony)
- June 30, 2017: Intervenor Reply Comments
- September 15, 2017: NSP Reply Comments
- November/December 2017: Cross Reply Comments
- March/April 2017: Oral Argument and Deliberations
- June/July 2018: MPUC Order

The Company believes the above procedural timeframe permits ample opportunities for open dialogue between and discovery for all parties and the Commissions; ensures transparency between the jurisdictions of the information filed in both state cases/dockets; and allows sufficient periods of time to engage in discussion regarding settlement in both jurisdictions (before and after hearings) and between jurisdictions.

It is important to be clear that this process is intended to facilitate a reasonable but expeditious path forward for selection of the conceptual RTF. As stakeholders and the Company approach or achieve a mutually-agreeable RTF, the Company will then implement the RTF that results from this proceeding.

Should the RTF be supported by a Pseudo Separation structure, we envision that we can implement the necessary ratemaking and cost allocation changes through rate cases in Minnesota and North Dakota. We expect to do so in 2020 consistent with our current rate case schedule in Minnesota and potentially in North Dakota.

Should the RTF be supported by a Legal Separation structure, we would expect to expeditiously work to create NSPD and undertake any additional filings that may be needed (depending on the separation structure ultimately selected) with the MPUC, the NDPSC, and FERC. Given our proposed procedural schedule for this proceeding and the complexity in creating NSPD and resolving the myriad issues such as assignment of transmission agreements, creation of a FERC tariff, and other implications of legally separating our North Dakota operations from NSPM, we would expect to make the necessary filings for regulatory approval in approximately 2020.

Our anticipated eighteen-month timeframe to achieve conceptual approval of the RTF would be complete in approximately the middle of 2018, giving all parties ample time and a series of opportunities to work through the appropriate framework for long-term solutions to the issues outlined in this Application.

IX. CONCLUSION

Our proposed RTF will balance the historic equities of long-standing service by the integrated NSP System while addressing continued disagreement between the NSPM states regarding the most prudent evolution of the NSP System. By solving for past disagreements and charting a more separate path into the future, our RTF will provide flexibility to all impacted stakeholders and help to ensure the ongoing financial health of Xcel Energy.

As described previously, our RTF presents a general framework. Our resource planning and revenue requirement analysis validate the reasonableness of our proposal, but we believe additional discussion is needed. Through the course of this proceeding, we seek to find consensus on an RTF, as well as finality regarding past and near-term future disagreements among the states. We also seek to find consensus

regarding the appropriate cost assignment and corporate structure to support our RTF.

We recognize that these issues are complex and that finding consensus may not be easy. However, we believe our proposal balances a variety of considerations discussed in this Application, and charts an equitable path upon which consensus can be found. Our proposed eighteen-month procedural timeline should provide all interested parties ample time to assess our proposal and undertake their own analyses.

At the conclusion of this proceeding, we hope to receive orders from the Commissions providing us with the necessary guidance to implement our RTF in 2020.

Respectfully submitted,

Northern States Power Company

INFORMATION REQUIRED BY MINN. R. 7829.1300**A. Summary of Filing**

Pursuant to Minn. R. 7829.1300, subp. 1, a one-paragraph summary of the filing is provided as Attachment 1 to this Schedule 1.

B. Service on Other Parties

Pursuant to Minn. R. 7829.1300, subp. 2, Xcel Energy has served a copy of this Application on the Department of Commerce and the Office of the Attorney General – Residential Utilities and Antitrust Division. A summary of the filing has been served on all parties on the attached service list.

C. General Filing Information

Pursuant to Minn. R. 7829.1300, subp. 3, Xcel Energy provides the following required information:

1. Name, Address, and Telephone Number of Filing Party

Northern States Power Company, doing business as:
Xcel Energy
414 Nicollet Mall
Minneapolis, MN 55401
(612) 330-5500

2. Name, Address, Electronic Address, and Telephone Number of Filing Party Attorney

Alison C. Archer
Assistant General Counsel
Xcel Energy
401 Nicollet Mall
Minneapolis, MN 55401
Alison.C.Archer@xcelenergy.com
(612) 215-4662

NDPSC Case Nos. PU-12-813, *et al.*
MPUC Docket No. E-002/M-16-223
SCHEDULE 1
Page 2 of 3**3. Date of Filing**

Date of Filing: December 31, 2016

Proposed Effective Date: Upon Commission Order

4. Statute Controlling Schedule for Processing Filing

No statute controls the schedule for processing this filing. Under Minn. R. 7829.0100, subp. 11, the Company's Application submission falls within the definition of a miscellaneous tariff filing, because no determination of Xcel Energy's general revenue requirement is necessary. Under Minn. R. 7829.1400, initial comments on a miscellaneous filing are due within 30 days of filing, with reply comments due 10 days thereafter; however, the Company respectfully requests waiver of those rules and that the Commission order a procedural schedule consistent with the Company's proposal.

5. Signature, Electronic Address, and Title of Utility Employee Responsible for Filing

Aakash H. Chandarana
Regional Vice-President
Rates and Regulatory Affairs
Xcel Energy
401 Nicollet Mall
Minneapolis, MN 55401
Aakash.Chandarana@xcelenergy.com
(612) 215-4663

6. Description of the Filing, Impact on Rates and Services, Impact on Any Affected Person, and Reasons for the Filing

The Company's Application for consideration of a Resource Treatment Framework addresses issues regarding energy resource planning and selection in Minnesota and North Dakota. The Application presents the results of focused analysis to determine the most appropriate structures to accommodate current and future misalignment between the states regarding resource additions and other system management issues related to the integrated NSP System.

NDPSC Case Nos. PU-12-813, *et al.*
MPUC Docket No. E-002/M-16-223
SCHEDULE 1
Page 3 of 3

A more comprehensive description of the filing, its impact on rates and services, its impact on any affected person, and the reasons for the filing are included in the Company's Application.

MPUC Docket No. E-002/M-16-223
NDPSC Case Nos. PU-12-813, et al.
ATTACHMENT 1 to SCHEDULE 1
Page 1 of 1

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

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

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

Docket No. E-002/M-16-223

**APPLICATION FOR CONSIDERATION OF
A RESOURCE TREATMENT FRAMEWORK
TO ADDRESS JURISDICTIONAL COST
ALLOCATION ISSUES**

SUMMARY OF FILING

Please take notice that on December 31, 2016, Northern States Power Company, a Minnesota corporation doing business as Xcel Energy (Company), submitted to the Minnesota Public Utilities Commission its Application for Consideration of a Resource Treatment Framework to Address Jurisdictional Cost Allocation Issues (Application). The Application presents the results of the Company’s analysis to determine the most appropriate structures to accommodate current and future misalignment between Minnesota and North Dakota regarding resource additions and other system management issues related to the integrated NSP System.

NDPSC Case Nos. PU-12-813, *et al.*
MPUC Docket No. E-002/M-16-223
SCHEDULE 2
Page 1 of 2**INFORMATION REQUIRED BY N.D.A.C. § 69-02-02-04**

North Dakota Administrative Code section 69-02-02-04 governs the contents of an application filed with the North Dakota Public Service Commission (NDPSC). In compliance with Section 69-02-02-04, Northern States Power Company, a Minnesota corporation, doing business as Xcel Energy (NSPM or Xcel Energy or the Company) provides the following required information.

1. Full Name and Post-Office Address of Applicant:

Northern States Power Company, doing business as:
Xcel Energy
414 Nicollet Mall
Minneapolis, MN 55401

2. Authorization or Permission Sought

The Company's Application for Consideration of a Resource Treatment Framework to Address Jurisdictional Cost Allocation Issues (Application) addresses issues regarding energy resource planning and selection created by differences in resource outlooks between the states served by NSPM. The Application presents the results of the Company's analysis in determining the most appropriate structures to accommodate current and future misalignment between the NSPM states regarding resource additions and other system management issues related to the integrated NSP System.

3. Statutory Provision or Other Authority Under Which the Commission Authorization or Permission is Sought:

This Application is being filed in conformity with the Company's obligation to propose a Resource Treatment Framework addressing our long-term plans for managing differing state energy policies per the *Negotiated Agreement* entered into between the Company and NDPSC Advocacy Staff and adopted by the NDPSC in Case Nos. PU-12-813 *et al.* on March 9, 2016.¹

¹ See *N. States Power Co. 2013 Electric Rate Increase Application*, Case Nos. PU-12-813 *et al.*, ORDER APPROVING FIRST REVISED NEGOTIATED AGREEMENT at 4, at 2-3 of Negotiated Agreement (NDPSC Mar. 9. 2016) (provided as Appendix A to the Application).

NDPSC Case Nos. PU-12-813, *et al.*
MPUC Docket No. E-002/M-16-223
SCHEDULE 2
Page 2 of 2

4. Number of Copies

An original and at least seven copies of the Application are being filed with the NDPSC consistent with N.D.A.C. § 69-02-02-04(2).

5. Articles of Incorporation and Certificate of Good Standing

The Company incorporates by reference the corporate papers filed in our Corporate Documents case, Case No. PU-09-664. The Company's Articles of Incorporation were filed on September 30, 2009, and our most recent Certificate of Good Standing was filed on January 15, 2016.

Disputed Resources

	Fuel	OWN/PPA	UCAP (MW)	Retirement	PPA Termination
Laurentian Energy Authority	Bio	PPA	31.2	--	12/31/2026
KODA Energy LLC	Bio	PPA	12.0	--	5/17/2019
FibroMinn	Bio	PPA	52.0	--	6/30/2028
St Paul Cogeneration	Bio	PPA	25.0	--	4/30/2023
WM Renewable Energy (MN Methane)	Bio	PPA	4.0	--	3/31/2020
Pine Bend	Bio	PPA	4.1	--	12/31/2025
Adams Wind Generations	Wind	PPA	3.9	--	3/8/2031
Big Blue	Wind	PPA	5.1	--	20 Yrs from COD
North Community Turbines	Wind	PPA	2.8	--	5/27/2031
North Wind Turbines	Wind	PPA	2.5	--	5/27/2031
Danielson Wind Farms	Wind	PPA	3.2	--	3/10/2031
Ewington Energy Systems LLC	Wind	PPA	3.1	--	5/27/2028
Grant County Wind, LLC	Wind	PPA	4.7	--	8/8/2030
Hilltop Power	Wind	PPA	0.2	--	2/19/2029
Jeffers Wind 20, LLC	Wind	PPA	6.6	--	10/9/2028
Ridgewind Power Partners LLC	Wind	PPA	3.8	--	1/12/2031
Uilk Wind Farm	Wind	PPA	0.0	--	1/14/2030
Valley View Transmission	Wind	PPA	1.4	--	11/29/2031
Winona County Wind	Wind	PPA	0.0	--	10/26/2031
Woodstock Municipal Wind, LLC	Wind	PPA	0.0	--	1/24/2031
Slayton	Solar	PPA	0.8 (X)	--	1/1/2033
Best Power (St. Johns)	Solar	PPA	0.2 (X)	--	5/27/2030
Best Power International (Sr. Notre Dame)	Solar	PPA	0.4 (X)	--	11/30/2030
Marshall Solar	Solar	PPA	31.1 (X) (Y)	--	1/6/2042
North Star Solar	Solar	PPA	50.0 (X) (Y)	--	12/31/2041
Mankato Energy Center Expansion (MEC II)	CC Gas	PPA	unknown	--	5/31/2039

(X) Solar UCAP - Accredited values based on MISO 50% nameplate rating for first year

(Y) Solar Resources with first full year of MISO accreditation 2018/19

Legacy System

	Fuel	OWN/PPA	UCAP (MW)	Retirement	PPA Termination
AS King 1	Coal	OWN	500.1	12/31/2037	--
Sherco 1	Coal	OWN	694.8	5/31/2027	--
Sherco 2	Coal	OWN	987.8	5/31/2024	--
Sherco 3	Coal	OWN	524.1	12/31/2040	--
Monticello 1	Nuclear	OWN	601.2	12/31/2030	--
Prairie Island 1	Nuclear	OWN	509.3	8/31/2033	--
Prairie Island 2	Nuclear	OWN	504.2	10/31/2034	--
Black Dog CC (5 &2)	CC Gas	OWN	218.0	12/31/2031	--
Angus Anson 2	CT Gas	OWN	87.1	12/31/2030	--
Angus Anson 3	CT Gas	OWN	76.4	12/31/2030	--
Angus Anson 4	CT Gas	OWN	142.2	5/31/2035	--
Blue Lake 7	CT Gas	OWN	143.3	5/31/2035	--
Blue Lake 8	CT Gas	OWN	141.3	5/31/2035	--
Flambeau 1	CT Gas	OWN	11.8	12/31/2018	--
Granite City 1-4	CT Gas	OWN	51.5	12/31/2023	--
Inver Hills 1	CT Gas	OWN	41.9	12/31/2026	--
Inver Hills 2	CT Gas	OWN	44.4	12/31/2026	--
Inver Hills 3	CT Gas	OWN	39.5	12/31/2026	--
Inver Hills 4	CT Gas	OWN	42.0	12/31/2026	--
Inver Hills 5	CT Gas	OWN	35.1	12/31/2026	--
Inver Hills 6	CT Gas	OWN	39.1	12/31/2026	--
Wheaton 1	CT Gas	OWN	40.5	12/31/2025	--
Wheaton 2	CT Gas	OWN	42.7	12/31/2025	--
Wheaton 3	CT Gas	OWN	39.5	12/31/2025	--
Wheaton 4	CT Gas	OWN	38.8	12/31/2025	--
HighBridge CC	CC Gas	OWN	528.8	5/31/2048	--
Riverside CC (9,10 & 7A)	CC Gas	OWN	454.8	3/31/2049	--
LS Power - Cottage Grove	CC Gas	PPA	231.0	--	9/30/2027
Calpine Mankato Energy Center	CC Gas	PPA	281.6	--	7/31/2026
Invenergy Cannon Falls	CT Gas	PPA	316.4	--	4/10/2025
French Island 3	Oil	OWN	59.6	12/31/2023	--
French Island 4	Oil	OWN	59.6	12/31/2023	--
Blue Lake 1	Oil	OWN	39.7	12/31/2023	--
Blue Lake 2	Oil	OWN	39.3	12/31/2023	--
Blue Lake 3	Oil	OWN	36.4	12/31/2023	--
Blue Lake 4	Oil	OWN	41.7	12/31/2023	--
Wheaton 5	Oil	OWN	0.0	12/31/2025	--
Wheaton 6	Oil	OWN	44.6	12/31/2025	--
Red Wing 1-2	Bio	OWN	17.0	12/31/2027	--
Wilmarth 1-2	Bio	OWN	18.0	12/31/2027	--
French Island 1-2	Bio	OWN	6.8	12/31/2023	--
BayFront 4	ST Gas	OWN	0.0	12/31/2023	--
Bay Front 5	Bio	OWN	11.0	12/31/2023	--
Bay Front 6	Bio	OWN	15.0	12/31/2023	--
Barron	Bio	PPA	2.0	--	Evergreen
HERC	Bio	PPA	23.0	--	12/31/2017
Diamond K Dairy	Bio	PPA	0.3	--	12/31/2024
Apple River Falls 1-4	Hydro	OWN	0.0	(W)	--
Big Falls 1-3	Hydro	OWN	4.0	(W)	--
Cedar Falls 1-3	Hydro	OWN	5.0	(W)	--
Chippewa Falls 1-6	Hydro	OWN	8.0	(W)	--
Cornell 1-4	Hydro	OWN	8.0	(W)	--
Dells 1-5	Hydro	OWN	0.0	(W)	--
Hayward 1	Hydro	OWN	0.0	(W)	--
Hennepin Island 1(St. Anothony Falls)	Hydro	OWN	9.0	(W)	--
Holcombe 1-3	Hydro	OWN	22.0	(W)	--
Jim Falls 1-3	Hydro	OWN	27.0	(W)	--

	Fuel	OWN/PPA	UCAP (MW)	Retirement	PPA Termination
Ladysmith 1-3	Hydro	OWN	0.0	(W)	--
Menomonie 1-2	Hydro	OWN	0.0	(W)	--
Riverdale 1-2	Hydro	OWN	0.0	(W)	--
Saxon Falls 1-2	Hydro	OWN	0.0	(W)	--
St. Croix Falls 1-8	Hydro	OWN	15.0	(W)	--
Superior Falls 1-2	Hydro	OWN	0.0	(W)	--
Thornapple 1-2	Hydro	OWN	0.0	(W)	--
Trego 1-2	Hydro	OWN	0.0	(W)	--
White River 1-2	Hydro	OWN	0.0	(W)	--
Wissota 1-6	Hydro	OWN	17.0	(W)	--
Manitoba Hydro - 375/325 MW PSA	Hydro	PPA	369.0	--	4/30/2025
Manitoba Hydro - 350 MW Diversity	Hydro	PPA	344.0	--	4/30/2025
Manitoba Hydro - 125 MW PSA	Hydro	PPA	123.0	--	4/30/2025
Manitoba Hydro - 4-Year Diversity	Hydro	PPA	74.0	--	5/31/2020
Byllesby	Hydro	PPA	2.1	--	2/28/2021
City of Hastings	Hydro	PPA	<1	--	6/30/2033
City of St. Cloud	Hydro	PPA	7.0	--	10/31/2021
Dairyland Power Cooperative			1.1	--	(V)
Eau Galle Hydro	Hydro	PPA	<1	--	7/31/2026
Lac Courte Orielles (Chippewa)	Hydro	PPA	<1	--	12/31/2021
Neshonoc	Hydro	PPA	0.4	--	12/31/2020
Rapidan Hydro Plant	Hydro	PPA	2.0	--	4/30/2017
SAF Hydroelectric, LLC	Hydro	PPA	6.0	--	12/18/2031
Grand Meadows (1-67)	Wind	OWN	17.0	12/31/2033	--
Nobles (1-134)	Wind	OWN	37.0	12/31/2035	--
Pleasant Valley	Wind	OWN	31.2	12/31/2040	--
Border	Wind	OWN	23.3	12/31/2040	--
Courtenay	Wind	OWN	0.0	12/31/2041	--
Agassiz Beach	Wind	PPA	0.3	--	2/27/2031
Boeve	Wind	PPA	0.3	--	8/8/2028
Carleton College	Wind	PPA	0.0	--	9/19/2024
Chanarambie Power Partners	Wind	PPA	12.8	--	12/14/2023
Cisco	Wind	PPA	1.3	--	5/27/2028
Fenton Power Partners I	Wind	PPA	38.9	--	11/12/2032
Fey Windfarm	Wind	PPA	0.3	--	9/3/2028
FPL Mower County	Wind	PPA	14.9	--	12/2/2026
JJN Windfarm	Wind	PPA	0.2	--	12/16/2029
Kas Brothers Windfarm	Wind	PPA	0.2	--	12/9/2031
k-Brink	Wind	PPA	0.3	--	2/12/2028
Lake Benton Power Partners (LBI)	Wind	PPA	12.6	--	12/13/2028
Lake Benton Power Partners II (LBII)	Wind	PPA	9.6	--	5/30/2025
Metro Wind LLC	Wind	PPA	0.0	--	2/28/2031
MinnDakota Wind	Wind	PPA	28.3	--	12/30/2022
Moraine Wind I	Wind	PPA	8.1	--	12/21/2018
Moraine Wind II Note (1)	Wind	PPA	11.5	--	2/17/2019
Lakota Ridge	Wind	PPA	1.3	--	4/30/2034
Shaokatan Hills	Wind	PPA	1.4	--	4/30/2034
Odell	Wind	PPA	0.0	--	7/29/2036
Olsen Windfarm	Wind	PPA	0.0	--	12/14/2031
Prairie Rose	Wind	PPA	0.0	--	12/10/2032
Rock Ridge Power Partners	Wind	PPA	0.4	--	4/11/2021
Shane's Wind Machine	Wind	PPA	0.3	--	8/10/2026
South Ridge Power Partners	Wind	PPA	0.4	--	4/11/2021
St. Olaf	Wind	PPA	0.0	--	10/5/2028
Velva Windfarm	Wind	PPA	2.2	--	12/31/2026
Windcurrent	Wind	PPA	0.3	--	5/30/2028
Wind Power Partners 1993 ("WPP-93")	Wind	PPA	3.9	--	5/2/2019
Windvest Power Partners	Wind	PPA	0.4	--	4/11/2021
Woodstock Wind Farm	Wind	PPA	1.2	--	6/23/2030

	Fuel	OWN/PPA	UCAP (MW)	Retirement	PPA Termination
Buffalo Ridge Wind Farm	Wind	PPA	0.2	--	12/17/2018
CG Windfarm	Wind	PPA	0.2	--	12/27/2028
Moulton Heights Wind Power Project	Wind	PPA	0.2	--	12/17/2018
Muncie Power Partners LLC	Wind	PPA	0.2	--	12/17/2018
North Ridge Wind Farm LLC	Wind	PPA	0.2	--	12/17/2018
TG Windfarm	Wind	PPA	0.2	--	12/27/2028
Tofteland Windfarm	Wind	PPA	0.2	--	12/27/2028
Vandy South Project	Wind	PPA	0.2	--	12/17/2018
Viking Wind Farm	Wind	PPA	0.2	--	12/17/2018
Vindy Power Partners	Wind	PPA	0.2	--	12/17/2018
Wilson-West Windfarm LLC	Wind	PPA	0.2	--	12/17/2018
Asian Children Support, Inc.	Wind	PPA	0.2	--	2/13/2028
Bangladesh Children Support	Wind	PPA	0.2	--	2/13/2028
Brandon Windfarm	Wind	PPA	0.2	--	4/30/2025
BT, LLC	Wind	PPA	0.2	--	9/25/2027
Burmese Children Support, Inc.	Wind	PPA	0.2	--	2/13/2028
G M, LLC	Wind	PPA	0.2	--	9/25/2027
Gar Mar Wind I	Wind	PPA	0.2	--	4/30/2025
Henslin Creek Windfarm	Wind	PPA	0.2	--	4/30/2025
Indian Children Support	Wind	PPA	0.2	--	2/13/2028
McNeilus Windfarm, LLC	Wind	PPA	0.2	--	9/25/2027
Salvadoran Children Support, Inc.	Wind	PPA	0.2	--	2/13/2028
SG (JCKD)	Wind	PPA	0.2	--	9/25/2027
Triton Windfarm	Wind	PPA	0.2	--	4/30/2025
Wasioja Windfarm, LLC	Wind	PPA	0.2	--	4/30/2025
Willhelm Wind	Wind	PPA	0.2	--	4/30/2025
REAP, LLC (REAP I)	Wind	PPA	0.2	--	9/27/2027
REAP, LLC (REAP II)	Wind	PPA	0.2	--	9/14/2021
Grant Windfarm	Wind	PPA	0.2	--	4/30/2025
Elsinore	Wind	PPA	0.2	--	9/14/2021
Ashland	Wind	PPA	0.2	--	4/30/2025
University of Minesota - UMORE Park	Wind	PPA	0.0	--	4/1/2021
Bendwind	Wind	PPA	0.2	--	2/28/2026
DeGreeff DP	Wind	PPA	0.2	--	4/4/2026
DeGreeffpa	Wind	PPA	0.2	--	3/7/2026
Groen Wind	Wind	PPA	0.2	--	4/23/2026
Hillcrest Wind	Wind	PPA	0.2	--	4/27/2026
Larswind	Wind	PPA	0.2	--	3/19/2026
Sierra Wind	Wind	PPA	0.2	--	4/30/2026
TAIR Wind	Wind	PPA	0.2	--	4/22/2026
Carstensen Wind	Wind	PPA	0.3	--	12/31/2024
Greenback Energy	Wind	PPA	0.3	--	1/24/2025
Lucky Wind	Wind	PPA	0.3	--	1/1/2025
Northern Lights Wind	Wind	PPA	0.3	--	1/24/2025
Stahl Wind Energy	Wind	PPA	0.3	--	1/1/2025
Autumn Hills (NAE)	Wind	PPA	0.2	--	2/14/2031
Florence Hills (NAE)	Wind	PPA	0.3	--	1/8/2031
Hope Creek LLC (NAE)	Wind	PPA	0.3	--	1/19/2031
Jack River LLC (NAE)	Wind	PPA	0.2	--	2/17/2031
Jessica Mills LLC (NAE)	Wind	PPA	0.2	--	2/22/2031
Julia Hills LLC (NAE)	Wind	PPA	0.2	--	2/23/2031
Soliloque Ridge LLC (NAE)	Wind	PPA	0.3	--	1/18/2031
Spartan Hills LLC (NAE)	Wind	PPA	0.3	--	1/12/2031
Sun River LLC (NAE)	Wind	PPA	0.2	--	2/23/2031
Tsar Nicolas (NAE)	Wind	PPA	0.2	--	2/16/2031
Twin Lake Hills (NAE)	Wind	PPA	0.3	--	1/3/2031
Winter Spawn LLC (NAE)	Wind	PPA	0.3	--	1/24/2031
Hadley Ridge LLC (NAE)	Wind	PPA	0.3	--	12/27/2030
Ruthon Ridge LLC (NAE)	Wind	PPA	0.3	--	1/22/2031

	Fuel	OWN/PPA	UCAP (MW)	Retirement	PPA Termination
Breezy Bucks-I	Wind	PPA	0.1	--	5/10/2026
Breezy Bucks-II	Wind	PPA	0.1	--	5/10/2026
Roadrunner-I	Wind	PPA	0.1	--	5/10/2026
Salty Dog-I	Wind	PPA	0.1	--	5/10/2026
Salty Dog-II	Wind	PPA	0.1	--	5/10/2026
Wally's Wind Farm	Wind	PPA	0.1	--	5/10/2026
Windy Dog-I	Wind	PPA	0.1	--	5/10/2026
MacBeth - 3	Wind	PPA	0.3	--	9/3/2025
MacBeth - 1	Wind	PPA	0.3	--	9/3/2025
MacBeth - 2	Wind	PPA	0.3	--	9/3/2025
Gary J.T.	Wind	PPA	0.3	--	8/27/2025
Jenna M.T.	Wind	PPA	0.3	--	8/27/2025
Krysta J.T.	Wind	PPA	0.3	--	8/27/2025
Mark J.P.	Wind	PPA	0.3	--	8/24/2025
Theresa M.T	Wind	PPA	0.3	--	8/27/2025
Minwind III	Wind	PPA	0.2	--	2/1/2025
Minwind IV	Wind	PPA	0.2	--	2/1/2025
Minwind IX	Wind	PPA	0.2	--	2/1/2025
Minwind V	Wind	PPA	0.2	--	2/1/2025
Minwind VI	Wind	PPA	0.2	--	2/1/2025
Minwind VII	Wind	PPA	0.2	--	2/1/2025
Minwind VIII	Wind	PPA	0.2	--	2/1/2025
Aurora Solar*	Solar	PPA	50.0 (X) (Y)	--	12/1/2014

(V) - Contract term is based on life of the Flambeau Plant

(W) Owned Hydro - for planning purposes, these resources extend through the planning period (currently 2053)

(X) Solar UCAP - Accredited values based on MISO 50% nameplate rating for first year

(Y) Solar Resources with first full year of MISO accreditation 2018/19

* As noted in the Application in footnote 3, we are not considering the Aurora Solar project to be a Disputed Resource.

EVOLUTION OF THE NSP SYSTEM

The electric utility industry has evolved significantly over the past several decades, as has the governing regulatory paradigm. This evolution and the new and emerging ways that utility systems can meet customer needs provides useful context for the Commissions' consideration of alternatives to the integrated NSP System. In this Schedule, we provide a discussion of the development of the integrated NSP System that exists today, illustrating how the System has evolved to address changes in the industry and in technology to meet customer needs. As each state in the System has participated in that evolution, each has also shared in the benefits and costs of developing it. Further, discussion of the optionality provided by the more recent marked-based approach pursued by the Federal Energy Regulatory Commission (FERC) can help to frame the benefits and burdens of integration to all the NSP System states and a Resource Treatment Framework (RTF) that equitably addresses these issues.

A. Historical Development Drove Integration

Almost from the beginning of electrification, electric utilities have focused on the twin goals of maximizing economies of scale and diversification to bring value for their businesses and their customers. These goals have been substantially driven by a combination of three important factors:

- technological advances that allow utilities to consolidate operations and increase efficiency;
- the development and expansion of substantial central station power and high-voltage transmission that allows customers to take advantage of multiple forms of generation resources on the same system (i.e., fuel diversity); and
- evolving environmental standards that encourage the development of new and more sustainable energy sources in conjunction with central stations.

Developing economies of scale and diversification has taken several different forms over the years, resulting in an integrated and highly-efficient grid that supports current robust markets for energy and ancillary services and emerging capacity markets. For example, including generating power from a variety of sources in different locations and tied together with high-voltage transmission hedges risk better than having discrete community-specific generators. The Company's experience with this

NDPSC Case Nos. PU-12-813, *et al.*
MPUC Docket No. E-002/M-16-223
SCHEDULE 5
Page 2 of 7

dynamic is important. From the 1940s to the early 1960s, NSP focused on constructing a series of (largely coal-fired) generators in and around the Company's main load center of the Twin Cities. This resulted in the development and expansion of generators at Black Dog in the south metro, Riverside in Minneapolis, and High Bridge in St. Paul, as well as the construction of the King Plant in Bayport. These plants were tied together with high-voltage transmission that allowed all our customers on the system to take advantage of this low-cost central station power. The Company's load centers in North Dakota and South Dakota were largely served using a combination of imported energy using the existing transmission system and the purchase of capacity and energy from neighboring utilities who had power plants nearby.

By the late 1950s, however, it was becoming evident that the existing system and local generation plants could no longer produce and deliver enough electricity to meet the needs of the growing population and economy encompassing the NSP System. At the time, load was growing by 7 percent annually – doubling every 10 years. The then-existing transmission system was strained and it became evident that significant high-voltage upgrades to the transmission system and new generation sources had to be added to serve customers at that time and long into the future.

In the 1960s, the Company built the 345 kV transmission loop around the Twin Cities that follows the Highway 494/694 ring today. This was a feasible option and necessary for long-term community service reliability. In addition, the Company concluded that a 345 kV voltage line was needed to support the types of large electric generators that were going to be needed to support rapid load growth. Whereas in the past the system could withstand an outage of a smaller power plant and local generation support was available, once the larger plants came on-line, power would have to be imported from other states if one of the generators went off-line.

In addition, to provide greater reliability the Company embarked on a series of investments that benefited the area and supported the overall goals of maximizing economies of scale and enhancing diversity. NSP and six other regional utilities constructed a new 345 kV transmission line from the Twin Cities to St. Louis. Two other 345 kV lines, connecting the Twin Cities to Chicago and Omaha, were also built. NSP was also instrumental in developing and building a 500 kV transmission line from Winnipeg to the Twin Cities. This line facilitated the import of significant amounts of hydro-electric generation from Manitoba to Minnesota and the rest of the NSP System.

NDPSC Case Nos. PU-12-813, *et al.*
MPUC Docket No. E-002/M-16-223
SCHEDULE 5
Page 3 of 7

This transmission system development facilitated the Company's ability to support highly-efficient large central station generators in the 1970s. In that timeframe, NSP's new plant investments included the 529 MW Allen S. King plant (King) that became operational in 1968; 600 MW Monticello plant in 1971; 1,100 MW Prairie Island plant to the southeast which became fully operational in 1973 and 1974; and two 750 MW generators at the Sherburne County plant (Sherco) in 1976-77. In the 1980s, NSP expanded its Sherco site with the installation of the 850 MW Sherco Unit 3. These large generators were made possible because of the development of the regional transmission system and all of these generators allowed NSP to provide adequate and low-cost service to all of its customers in North Dakota, Minnesota, and the other states served by the integrated system.

These larger generators were much more efficient and cost-effective, and allowed the system to be expanded in a way that served all customer needs throughout the five-state region. The addition of the 500 kV transmission line from Manitoba to Minnesota facilitated the import of a significant amount of carbon-free hydroelectric generation long before policymakers concluded that carbon-free electric generation provided additional value. Finally, in the 1980s and 1990s, the Company added a significant amount of natural gas generation to the system, including peaking units and combined-cycle intermediate units spread throughout the system to provide system support as well as energy and capacity to the system.

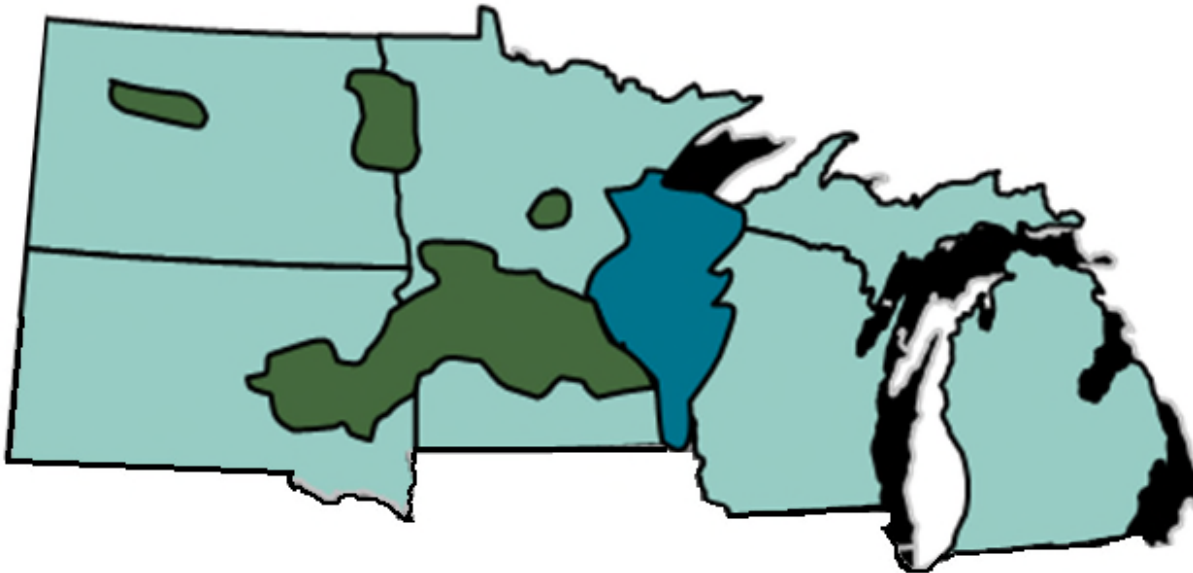
The development of these larger power plants supported customer needs by efficiently maximizing the economies of having a robust transmission system and several large central-station generation sources. This development also met the companion goal of diversifying fuel types to hedge the fuel cost risk of overreliance on any particular fuel source. As noted, from the 1960s through the 1990s, the Company added a significant amount of coal, nuclear, hydro and natural gas generation. Finally, since the mid-1990s to the present, the Company has deployed approximately 2,500 MW of renewable energy generation on its system that serves both significant environmental benefits as well a fuel hedge since that generation generally displaces fossil fuel generation.

It is important to note that while the modern NSPM obtained and served its North Dakota service territory prior to consolidating its operations in the Twin Cities, the service territory and load in North Dakota is physically isolated from the remainder of NSPM's service territory. In addition, our service territory in North Dakota is physically separated between the main metropolitan areas of North Dakota served by

the Company: Fargo/West Fargo, Grand Forks, and Minot. This is illustrated in the service territory map provided in Figure 1, below.

Due to this, the bulk of our North Dakota load was served through alternative supply arrangements, most notably through agreement with what is now Great River Energy (GRE) via the Stanton Displacement Agreement.¹ The physical separation of our North Dakota customers also leads us to the conclusion that our recommended RTF is a viable option for, and consistent with, continued prudent service in North Dakota.

Figure 1: Service Territory Map



Development of a robust integrated NSP System was consistent with the regulatory paradigm that existed through most of that evolution. In the days before open access

¹ NORTH DAKOTA-WESTERN MINNESOTA 230 KV FACILITIES CO-ORDINATING AGREEMENT BETWEEN MINNKOTA POWER COOPERATIVE, INC., OTTER TAIL POWER COMPANY, MINNESOTA POWER & LIGHT COMPANY, AND NORTHERN STATES POWER COMPANY (July 29, 1966); *see also* MISO Tariff, Attachment P, Contract No. 317. The Stanton Displacement Agreement is a Grandfathered Transmission Agreement in MISO. The agreement currently provides for GRE to provide the Company the output of Stanton, a coal-fired power plant in Stanton, North Dakota, which is typically about 188 MW per hour. At the same time, the Company delivers to GRE the same MW amount from Sherco (188 MW each hour). *See 2011 Annual Automatic Adjustment of Charges Report – Electric*, Docket No. E999/AA-11-792, NORTHERN STATES POWER COMPANY REPLY COMMENTS at 5 (July 11, 2012).

transmission and before regional energy and capacity markets, it was important for regional utilities, such as NSP, to ensure that it had adequate infrastructure to serve its customers under all reasonable circumstances. Essentially, building generation and associated transmission to serve the NSP System acted as a physical hedge against the risk of any shortfall – be it from capacity, mechanical failures, or other impacts to the System. Bigger was better as it hedged risk for all participants and there were few other options.

B. Existence of Competitive Markets Creates Optionality

Although stand-alone resources and intra-system integration were historic cornerstones of utility systems, significant regulatory changes in the past 30 years have moderated the importance of utilities having significant stand-alone resources in the same manner as in the past. This change in the regulatory landscape has transformed the industry, moving away from utilities planning and operating on a stand-alone basis toward a competitive market-based structure that allows many of the benefits of the larger system to be realized by market participants without actual ownership of assets.

First, in 1978, Congress enacted the Public Utility Regulatory Policy Act (PURPA) which began to bring about major changes in the industry. PURPA ushered in an era when independent power producers could, for the first time, build power plants to sell electricity on the open market and in competition with incumbent utilities. By injecting supply competition, PURPA set the stage for industry restructuring that resulted in the market-based approach that exists today.

Second, in 1992, passage of the Energy Policy Act hastened the movement to restructuring in a market-based format. The Energy Policy Act called for the creation of broad, competitive wholesale electric markets to be overseen by FERC. This began the long process of opening the nation's high-voltage grid to use on a comparable and non-discriminatory basis. Without going into great detail about the history of the transmission system development, it can be said that the system was historically built to deliver the power output of power plants to local utilities that serve their end-use customers in a defined geographic service territory. Utilities in adjoining areas interconnected their systems to maintain reliability and to make limited wholesale power transactions with their neighbors.

Under the auspices of the Energy Policy Act, in 1996 FERC issued Order Nos. 888 and 889, requiring all public utilities to provide open access to their transmission facilities. These landmark orders further required utilities to separate their

NDPSC Case Nos. PU-12-813, *et al.*
MPUC Docket No. E-002/M-16-223
SCHEDULE 5
Page 6 of 7

marketing/generation functions from their transmission functions and to operate the transmission function in a separate way. Order No. 888 also set the stage for the voluntary formation of regional transmission organizations. These developments had a profound impact on the industry and made it possible, for the first time, for utilities to take advantage of competitive market forces regardless of whether the utility owned the power plants and transmission lines used to serve their customers. The planning principles and priorities espoused in Order No. 888 were further refined and made mandatory through Order No. 890 in 2007.

Third, four years after the issuance of Order Nos. 888 and 889, FERC issued Order No. 2000, which was designed to speed the development of regional transmission organizations and further encourage wholesale competition. This led to the development of the Midcontinent Independent System Operator (MISO) (formerly, the Midwest Independent System Operator) as an independent system operator in the early 2000s, further opening the regional system to competitive forces.

Fourth, and most importantly, beginning in 2005 MISO implemented its energy market function and began centralized dispatch of all generation across its upper-Midwest footprint. The centrally-operated market was expanded in 2009 to include ancillary services and in 2013 to include a capacity auction. This overall competitive market structure allows energy, capacity, and ancillary services to be transacted through a centralized market based on bids and offers that are cleared and administered by MISO.

The federal integration of the national transmission grid is currently continuing through implementation of FERC Order No. 1000, which mandates interregional transmission planning and competitive transmission development to further allow for market efficiencies to displace the historic economies of scale of large, stand-alone utility systems. And while controversial and subject to litigation, the creation of mandatory capacity markets in regions such as PJM on the east coast of the United States have impacted resource planning and other, historically utility- and state-specific responsibilities regarding resource adequacy. As a result, these functions are now regionally and market based as well.

Acknowledging that there are now options other than large, central station integrated utility systems by which utilities can provide safe and reliable service to their customers may change the value proposition of large integrated systems, especially for smaller states or load pockets. At the same time, the Company cannot move forward as if integration did not exist for the last century, but rather must resolve past

NDPSC Case Nos. PU-12-813, *et al.*
MPUC Docket No. E-002/M-16-223
SCHEDULE 5
Page 7 of 7

disagreements on System resources and then chart a path for the future. Under any scenario, industry evolution will play a role as the existing NSP System ages and evolves.

Mechanics of North Dakota Pseudo Separation

The purpose of this Schedule is to identify, on a draft basis, the accounting mechanisms under a North Dakota Pseudo Separation. As explained in the Application, Pseudo Separation essentially reallocates the economic impacts the federal market overlay, bi-lateral transaction, and MISO dispatch of the NSP System to particular states. Pseudo Separation would also address the revenues from generation margins and ancillary services, revenue sufficiency guarantee uplifts, and other MISO market constructs. Capacity sales and purchases would be similarly allocated, as well as RECs and other non-power-based attributes of a particular resource. The Legacy System will be allocated to each jurisdiction using the existing methodology. To assist in a further understanding of the mechanics of a Pseudo Separation structure, the treatment of specific cost and revenue categories with respect to new resource additions as units of the NSP System retire or expire are explained, categorically, below.

We note, however, that while the Pseudo Separation concept is derived from the pricing zone concept in gas operations, we will be implementing it here for the first time with no experience in doing so. We expect that considerable trial and error may be necessary to achieve Pseudo Separation. We also expect that Pseudo Separation will require additional personnel and investments in our information technology infrastructure to manage. We look forward to working with our stakeholders in developing the specific accounting and other protocols to manage this complex endeavor.

Fuel and Purchased Power Expense

Under a Pseudo Separation structure, MISO costs and revenues would be separately tracked, with revenues from sales of energy into the MISO market being assigned to the specific jurisdiction(s) paying for the energy resource. MISO load costs, or purchases of energy from the MISO market, would be allocated to specific jurisdictions based on load-ratio share. For example, the Minnesota jurisdiction would be allocated MISO load costs based on the ratio of Minnesota jurisdiction calendar month sales to NSP System calendar month sales. The North Dakota jurisdiction would be allocated MISO load costs based on the ratio of North Dakota jurisdiction billing month sales to NSP system billing month sales. MISO load costs include Behind the Meter Generation (BTMG). BTMG reduces the amount of load settled through the MISO market. Fully resolving BTMG issues will be complex and we will need to work to find consensus on the final approach adopted.

It should be noted that a portion of the North Dakota load is currently included in the NSP.NSP load node. Should a requirement arise for specific North Dakota jurisdictional pricing of load, commercial and network models would need to be updated.

With respect to non-MISO load costs, fuel and non-MISO purchased power costs would be assigned to the specific jurisdiction(s) paying for the energy resource.

Ancillary Services Market (ASM)

MISO provides three primary ASM products – regulation, spinning, and supplemental reserves. Under a Pseudo Separation structure, ASM costs and revenues would be separately tracked by jurisdiction. Purchases of ASM from the MISO market that are divided into “reserve zones” by MISO would be allocated to each jurisdiction based on load-ratio share, similar to the MISO load cost allocations. For example, the Minnesota jurisdiction would be allocated ASM purchases based on the ratio of Minnesota jurisdiction calendar month sales to NSP System calendar month sales. The North Dakota jurisdiction would be allocated ASM purchases based on the ratio of North Dakota jurisdiction billing month sales to NSP System billing month sales. The revenues from ASM sales into the MISO market would be assigned to the specific jurisdiction(s) paying for the energy resource.

Trade Margins

Trade margins are addressed in two separate categories – non-asset based margins and asset based margins. With respect to non-asset based margins, under a Pseudo Separation scenario, no changes are anticipated to the current process of allocating these margins to jurisdictions. For asset based margins, only the specific jurisdiction(s) paying for the energy resource would benefit from any generation margins arising from excess sales related to the generating asset or PPA. Currently, the excess energy sold into the market is assigned the highest energy cost by hour. A sales summary by generator would be produced from Cost Calculator – an internal proprietary costing software – for the current month estimate, for actual resettlement versus its respective estimate, and for final resettlement versus its respective actual resettlement.

NDPSC Case Nos. PU-12-813, *et al.*
MPUC Docket No. E-002/M-16-223
SCHEDULE 6
Page 3 of 4

Plant Related

Plant records, including plant in-service, accumulated depreciation, accumulated deferred income tax, depreciation expense, and schedule M items, are currently maintained by generating plant. This would allow for plant-related costs to be assigned to a specific jurisdiction under a Pseudo Separation structure. Moreover, property tax expense is available by generating plant, allowing for costs to be assigned to a specific jurisdiction.

Operation and Maintenance Expense

Operation and maintenance expenses, including fuel handling expense, are currently available by generating plant in the general ledger, allowing for costs to be assigned to a specific jurisdiction. Under a Pseudo Separation structure, however, a methodology may need to be developed to allocate production costs that cannot be assigned to a specific generating plant or jurisdiction.

Other Electric Revenues

Other electric revenue, like ash handling and refuse derived fuel, are available by generating plant in the general ledger, allowing for the revenues to be assigned to a specific jurisdiction under a Pseudo Separation structure.

Capacity Costs

With respect to capacity costs, to the extent that Xcel Energy purchases capacity through a Power Purchase Agreement or other contractual arrangement that has separate and distinct capacity pricing, we would assign those costs to supporting jurisdiction(s) much like plant related costs.

With respect to capacity sales, such as through the MISO capacity markets or bilateral contracts, to the extent they represent a “slice of the system” we would expect to allocate those revenues on a pro-rata basis based on percentage of system participation by each jurisdiction in the sum-total of resources that make up that “slice of the system.” To the extent that capacity sales are unit or station specific, we would expect to assign the revenues from those sales.

NDPSC Case Nos. PU-12-813, *et al.*
MPUC Docket No. E-002/M-16-223
SCHEDULE 6
Page 4 of 4

Demand Side Management

Demand Side Management costs are currently directly assigned and we would expect to continue doing so.

Conservation Improvement Program

Conservation Improvement Program costs are currently directly assigned and we would expect to continue doing so.

Renewable Energy Credits (RECs)

All RECs produced by qualified renewable generation resources are registered in the Midwest Renewable Energy Tracking System (M-RETS) database and are allocated to specific accounts by jurisdiction. Under the Pseudo Separation structure, only the specific jurisdiction(s) paying for the qualified renewable generation resources would receive an allocation of the RECs. Any sale of RECs would be from the jurisdictional portfolio and would be direct assigned to the jurisdiction from which the sale is made.

General Reporting and Gathering of Information

Under a Pseudo Separation structure, NSPM's general ledger and other systems, like CXL, Cost Calculator, and REC Tracker, may need to be modified to accommodate additional information reporting needs. NSPM currently possesses the sophisticated software systems required to precisely calculate and shadow results for accounting for granular ISO market transactions. These types of systems would need to be maintained for Pseudo Separation, along with securing access to results produced by such systems. Further, additional reporting would likely need to be developed to facilitate the gathering of information.

These are but some of the many different allocation changes that would be required to implement a Pseudo Separation structure. We look forward to working with our stakeholders in this proceeding to better refine issues concerning this structure. Should the Commissions approve moving forward with Pseudo Separation, we would provide more detailed allocation proposals in an upcoming rate case.