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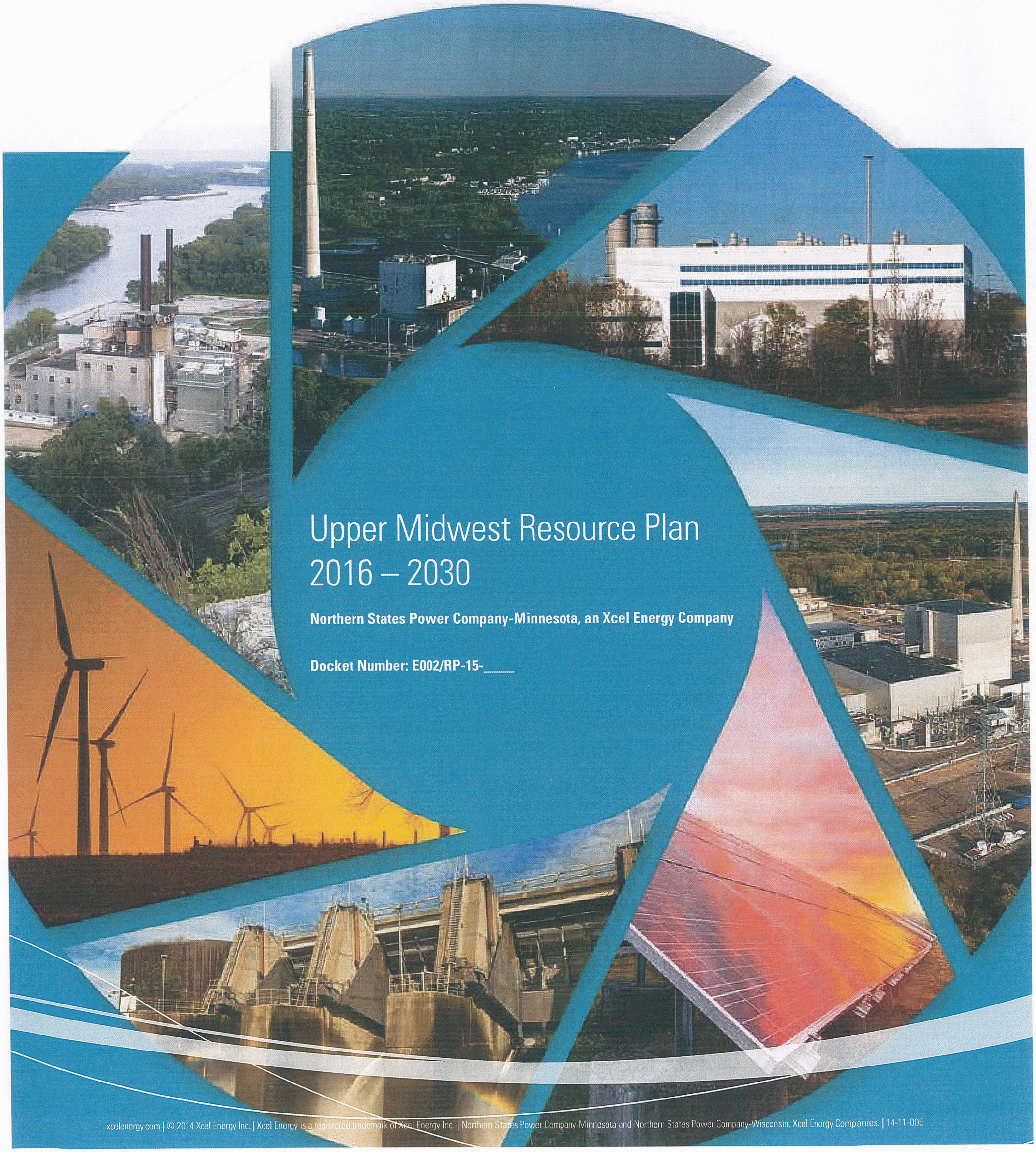

Upper Midwest Resource Plan 2016 – 2030

Northern States Power Company-Minnesota, an Xcel Energy Company

Docket Number: E002/RP-15-____

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I. EXECUTIVE SUMMARY

Northern States Power Company, a Minnesota corporation, doing business as Xcel Energy, submits to the Minnesota Public Utilities Commission its 2016-2030 Upper Midwest Resource Plan as required by the Commission's May 23, 2014 Order in Docket No. E002/CN-12-1240.[1]

On December 22, 2014, the Company submitted its Request for Planning Meeting and Dialogue – Roadmap for Supporting the e21 Initiative in which we presented our recommendations for implementing the recommendations of the e21 Initiative. That group of diverse stakeholders convened to consider the changes needed to the regulatory and utility business model to respond to evolutionary changes occurring in the energy industry, including:

- Customers want more choice in their energy services and products,
- Advancements in renewable generation technologies,
- The expanding role of distributed generation and the distribution system, and
- The inevitable rising cost of providing service.

One element of our interrelated roadmap to take the e21 recommendations to the next level is to achieve a 40 percent carbon dioxide (CO_2) emission reduction by 2030. We noted in our letter that we would provide details on how to achieve this goal in our Resource Plan. Not only does our Resource Plan present more details regarding achieving 40 percent carbon emission reduction by 2030, it also provides information required by Minnesota law, the Commission's Rules and prior Commission Orders.

As with any Resource Plan, our objective here is to identify the appropriate resources and conservation efforts to continue providing safe and reliable service to our customers. The unique attribute of this planning period is the fact that there is a confluence of changing industry and state and federal policy objectives that may occur in the next fifteen years. As we developed this Resource Plan we wanted to position our customers well for the future and build upon our environmental leadership which has benefitted our customers, shareholders, the economy of all the states we serve, and the environment.

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[1] The Company notes that the Commission recently completed its deliberations in Docket No. E002/CN-12-1240. The modeling presented in this Resource Plan does not incorporate the oral decision from December 15, 2014. As discussed later, we intend on updating our resource planning analysis at a later time.

Consistent with this, we developed a flexible and proactive Preferred Plan, which presents an affirmative approach for significantly reducing CO_2 emissions by 2030, while moderating costs and retaining the ability to respond to future environmental requirements and market trends. The framework we are advancing allows for these accomplishments while providing our customers with the full benefits of the significant investments they have made in the NSP System.

With our Preferred Plan we specifically propose to do the following:

- Add approximately 1,800 MW of wind resources.
- Add approximately 1,700 MW of utility-scale solar resources.
- Add approximately 1,750 MW of natural gas peaking resources.
- Operate our carbon-free, baseload nuclear plants through at least 2030.
- Operate Sherco Units 1 and 2 at reduced levels through 2030.
- Extend the life of Blue Lake Units 1-4 an additional four years through 2023.

We believe our Preferred Plan works together to provide several interrelated, tangible and intangible benefits to our customers and stakeholders.

First, by adding significant renewable generation, we are able to reduce CO_2 emissions by approximately 30 percent by 2020 and approximately 40 percent by 2030, and, at the same time, continue using our existing, cost-effective thermal generation. This is an innovative solution that can provide benefits to our customers and the environment while positioning us to be responsive to the state's greenhouse gas reduction goals and federal greenhouse gas rules, should they solidify during the planning period.

Second, by continuing the operation of Sherco Units 1 and 2 through the planning period, our customers will continue to get the benefit of their investment in these baseload generating units while accomplishing a 40 percent emission reduction and maintaining a diverse fuel portfolio.

Third, our Preferred Plan adds resources in a thoughtful and proactive manner. In the first five years, we have no capacity needs and are therefore proposing to only make resource additions to meet the Solar Energy Standard and accomplish a 30 percent carbon reduction by 2020. The most significant resource additions occur in the out years of the planning period.

By doing so, we allow for the existing investment cycle to come to rest, and for changes in industry and market conditions to mature before embarking on another round of significant investments. We believe this is valuable for our customers as the resources we foresee needing today may no longer be needed tomorrow. For example, we are seeing significant interest in our community solar gardens program which may affect our future need for utility-scale solar.

Fourth, our Preferred Plan provides flexibility to allow us to address the changes to our resource mix in the out-years of the planning period and beyond. In addition to our Sherco Units 1 and 2, which we discuss in this Resource Plan, during the out years, there are both significant reductions in energy resources due to power contracts expiring without extension or renewal, and base load plant retirements. For example, from 2025 through 2034, the first phase of the Mankato Energy Center and the Cottage Grove combined cycle power purchase agreements will expire, the Manitoba Hydro power purchase agreement will expire, and our nuclear plant licenses will reach their end dates. As a result, during this planning horizon, as well as the next, we must address nearly 75 percent of the energy producing resource on the NSP System.

We acknowledge that replacing these resources will be challenging and could expose our customers to market volatility. As a result, we developed the Preferred Plan to use renewable resources, backed by natural gas peaking units, in an effort to minimize this exposure, and allow for greater flexibility to add new resources when our baseload plants are retired. By doing so, our system will not be overly-reliant on any one fuel source, and we will have enough flexibility to consider economical retirement options. A diversity of ownership structures for these resource additions can also aid the flexibility achieved by our Preferred Plan.

Lastly, our Preferred Plan provides these benefits in a cost-effective manner. Over the next fifteen years, the Company will have to add resources to continue providing safe, and reliable service, to comply with state energy requirements, and to address plant retirement and power purchase agreement expirations. There is a cost in order to meet these needs. For an additional, average annual two percent increase, our Preferred Plan also provides the tangible and intangible benefits we have described here.

When considering whether the public interest test has been met, the Commission's rules require consideration of: (1) maintaining or improving the adequacy and reliability of utility services; (2) keeping customer bills and utility rates as low as practicable; (3) minimizing adverse socioeconomic effects and adverse effects upon the environment; (4) enhancing the utility's ability to respond to changes in the financial, social, and technological factors affecting its operations; and (5) limiting the risk of unforeseeable adverse effects. As we explain with greater detail throughout our Resource Plan, we believe that our Preferred Plan satisfies each of these factors and is therefore in the public interest.

We recognize that our Preferred Plan is not without controversy or challenges. For example, our decision to continue operating the Sherco 1 and 2 units through the planning period may be received favorably by some and unfavorably by others. Also energy policies and goals of the five jurisdictions served by the NSP System are not aligned. Although this Resource Plan focuses on the policies and goals of Minnesota – the largest load in the integrated NSP System – it is important to recognize that not all of the states we serve share Minnesota's energy priorities.

We believe the e21 Initiative identified an elegant solution for how to work through these types of challenges. Specifically, the e21 Initiative recommended the replacement of the current resource plan process with an Integrated Resource Analysis. Rather than adjudicating each detail in a Resource Plan, this new process would guide the five-year action plan and create opportunities to have more dialogue with our stakeholders to create consensus around resource planning decisions.

We are receptive to using this new procedural process here. We can engage in a robust discussion with our stakeholders about their thoughts and ideas about the future of Sherco Units 1 and 2, and ways to address diverging state energy policies and goals. Since our Preferred Plan seeks to deploy a significant amount of renewable generation, we also believe it would be helpful to garner consensus around innovative rate making and diversified ownership portfolios, such as the one used by the Company in the Metropolitan Emissions Reduction Program and to comply with the Next Generation Energy Act. We believe using a new procedural process can create efficiencies and tie resource decisions more closely to the actual costs of implementing a Resource Plan.

While we look forward to discussing this further at the Planning Meeting we requested as part of our December 22nd letter, we respectfully request that the next step in the process allow for us to engage our stakeholders in a dialogue about our resource modeling, the sensitivities we modeled, and our Preferred Plan. We welcome the opportunity to host technical conferences where we can begin sharing ideas and information related to our Resource Plan. We believe this will work well considering that our resource planning models and analyses need to be updated to reflect the significant interest in our Community Solar Garden program and the Commission's recent decisions in the Competitive Acquisition Process. By first allowing for additional dialogue, we can incorporate the CSG and CAP updates in concert with other potential updates that result from the collaborative process.

In conclusion, our Preferred Plan presents an innovative, flexible approach for addressing evolving changes confronting the resource planning landscape. With our Preferred Plan, we have laid out an approach for accomplishing a significant environmental policy goal, while limiting costs to our customers and retaining the flexibility to be responsive to future environmental requirements and market trends. For that reason, we believe our Preferred Plan is in the public interest. We recognize, however, that reasonable minds can differ and look forward to engaging in a spirited dialogue with our stakeholders as we move forward.

II. NON-TECHNICAL SUMMARY OF RESOURCE PLAN

Northern States Power Company-Minnesota is a wholly-owned operating subsidiary of Xcel Energy, Inc. that owns and operates, in conjunction with its affiliate Northern States Power Company-Wisconsin, the integrated NSP System of generation and transmission assets that serves more than 1.5 million electric customers in Michigan, Minnesota, North Dakota, South Dakota, and Wisconsin. This 2016-2030 Upper Midwest Resource Plan builds on the strong foundation of cost-effective environmental performance that we have been working toward since our 2010 Resource Plan. It also presents an achievable carbon emissions management plan that will cost-effectively meet and exceed state greenhouse gas, solar, and renewable energy requirements and objectives.

To understand our Preferred Plan, we first present a Reference Case. The Reference Case is the baseline scenario identifying the resource additions necessary to continue meeting our customers' needs, comply with renewable energy requirements, and achieve the 30 percent CO_2 reduction from 2005 levels objective that resulted from our last Resource Plan. We analyzed numerous assumptions and sensitivities that best meet our customer needs, and our obligations and goals during the planning period The Preferred Plan emerged as the best suite of resources that meet our planning guiding principles.

Our Preferred Plan will be evaluated based on its ability to: maintain or improve the adequacy and reliability of utility service; keep the customers' bills and the utility's rates as low as practicable, given regulatory and other constraints; minimize adverse socioeconomic effects and adverse effects upon the environment; enhance the utility's ability to respond to changes in the financial, social, and technological factors affecting its operations; and limit the risk of adverse effects on the utility and its customers from financial, social, and technological factors that the utility cannot control.[2]

We believe our Preferred Plan meets these criteria, and positions the Company to address evolving industry changes, including the changes we expect to the NSP System to meet our customers changing expectations.

[2] Minn. R. 7843.0500, subp. 3

A. A Changing Planning Landscape

The utility industry is at a pivotal point. Technology advancements are bringing generation options directly to our customers. Public policies are evolving toward supporting renewable and distributed generation resources. Our customers are expressing a greater desire for diversified services and products. Against this backdrop, utilities, including the Company, must continue investing in their systems to provide safe, reliable service.

On December 22, 2014, the Company submitted its *Request for Planning Meeting and Dialogue – Roadmap for Supporting the e21 Initiative,* in which we laid out a roadmap for responding to the changes confronting the energy industry today and tomorrow. We built upon the recommendations of a diverse group of stakeholders (e21 Initiative) that spent a better part of last year analyzing changes to the existing regulatory and utility business model. While our roadmap consists of several interrelated elements, relevant to the Resource Plan is achieving a 40 percent CO_2 emission reduction by 2030. We indicated in our request that we would provide details on how to meet this goal in this Resource Plan. We do so here, but first provide a contextual discussion of the planning landscape within which we developed and are presenting the results of our current resource planning efforts.

1. *Evolving Environmental Regulation*

Since submitting our last Resource Plan, new air, water, and waste regulations have been updated and adopted by the Environmental Protection Agency (EPA). Regulations for criteria pollutants, particularly oxides of nitrogen, sulfur dioxide, particulate matter, and ozone, continue to be updated and are likely to impose added constraints on operation of some power plants. These regulations inform our thinking as to what will be necessary to maintain compliance at our generating facilities and the need for and type of resource additions we may make in the future.

With that said, uncertainty surrounds some of the EPA's environmental regulations. The primary example is the EPA's existing source greenhouse gas (GHG) performance standard, known as the Clean Power Plan, or Section 111(d). The EPA has issued proposed rules, which are expected to be finalized in June 2015. The proposed 111(d) process will determine what compliance alternatives are available, whether each our jurisdictions will implement rate-based or mass-based programs, whether they will collaborate with other states in multi-state plans, and how much of the CO_2 reduction burden they will assign to the Company versus other utilities. We will not definitively know our share of the responsibility for meeting the attainment requirements in any of the states we serve, or our compliance options, until the states submit and EPA approves a state plan.

Any final rule is likely to face legal challenges, which depending whether or not the rule is stayed during litigation, may affect the timeline for state implementation plan (SIP) development. If the rule is not stayed, each state will draft plans and submit them to EPA by 2016 to 2018, for approval by EPA one year later with compliance beginning in 2020. If the rule is stayed, it is unknown what the compliance obligations will be or when compliance obligations will begin.

Even though this is an arena in flux, we can see change afoot and believe it to be reasonable to plan our resources accordingly.

2. *Challenges of Divergent State Energy Policies*

In the last five years, we started to see divergence in the energy policies of some of the states we serve. The Company has been a leader in advancing renewable energy in the upper Midwest and has been able to do so at reasonable costs for the most part. It is important to recognize, however, that some of the states we serve value conservative, least cost resource planning principles instead of environmental leadership. While some states have been moving fast in one direction, other states that are part of the integrated NSP System, have signaled a desire to move in a different direction. This creates both opportunities and challenges as we try to plan for an integrated system that meets the requirements of all of our customers.

Our experience in North Dakota is illustrative. As part of our most recent electric rate case in North Dakota, we committed to "restack" the generation resources used to serve our North Dakota customers to address the impact of other states' policy choices on our North Dakota customers. At a high-level, the "restack" will ensure that the Company's North Dakota customers pay a reasonable cost for the used and useful capacity and energy of any resource addition that the Company makes; however, North Dakota customers will not pay their full jurisdictional share for resources the North Dakota Commission determines are imprudent for policy reasons. As of the date of filing this Resource Plan, we are currently negotiating the terms of the System Restack with our North Dakota regulators, and commit to keeping all of our jurisdictions informed as to the status and impacts of these discussions.

While we believe that the System Restack will provide a reasonable short- to mid-term solution to the divergence in energy policies affecting North Dakota, it does not fully resolve the effect of diverging energy policies. The System Restack does not address the impact of the Company's resource choices that are driven by Minnesota or North Dakota energy policies on our other customers – nor does it address how the integrated NSP System can develop under fundamentally different policy views.

This experience was top of mind as we worked through our resource planning efforts for the current planning period.

3. *Changing Customer Expectations*

We are increasingly hearing from our customers that they have a growing interest in increasing their energy management capabilities and desire a more customized energy mix than has been traditionally available. Residential customers tell us that they value choice and clean, affordable, and reliable energy. At the same time, municipalities within our service territory are expressing changing expectations to address their citizens' interests in achieving sustainability goals and engage residents around energy issues.

Our customers also are interested in various types of self-generation. This includes increased small-scale solar penetration through behind the meter installations or community solar gardens. Industrial customers are also interested in exploring the addition of larger scale Combined Heat and Power (CHP) installations at their facilities. The installation of self-generation on our system impacts our resource needs, planning goals, and ultimate resource mix.

We also know that customers are sensitive to rate changes. For example, our large industrial customers are energy-intensive and highly-sensitive to energy rate, with less sensitivity to other terms of service. These are key considerations as we plan our resource mix to meet the needs of our customers over the planning period.

4. *Emerging Technologies*

The rapid pace of advancement in energy technologies has impacted and will continue to impact the future of our industry. Emerging technologies related to grid modernization, energy storage, electric vehicles, resource extraction, renewable energy and other alternative fuels and generation methods are enabling a smarter and more resilient energy system.

While this new technology provides opportunities for a modernized energy system, operating that system is a complex matter. We are taking a measured approach to identify new and better ways to provide our customers with high quality service, meet increasing environmental requirements, and implement advancements and standardized processes that enhance the safety of our operations and overall value to customers. Our approach to these emerging technologies is to learn from the current deployments, both internal to Xcel Energy and within the industry, and implement initiatives at the pace of value to our customers and operations.

5. The Evolving NSP System

In addition to Sherco Units 1 and 2, which will be discussed as part of this Resource Plan, from 2025-2035, we will experience a reduction in energy resources due to power contracts expiring, plant retirements, and the expiration of our nuclear licenses. More specifically, in 2025, our Manitoba Hydro contracts expire. In 2026 and 2027, our contracts for the output of the Cottage Grove Combined Cycle Energy Center and the Mankato Combined Cycle Energy Center expire. In 2030, our license to operate our Monticello nuclear plant expires, and in 2033/34 our licenses for our Prairie Island nuclear plant expires.

The loss of our Manitoba Hydro, Cottage Grove and Mankato Energy Center contracts during the planning period, and the potential retirement of our nuclear fleet just beyond the planning period, suggests that a significant proportion of our baseload and intermediate generation resources may be retired within 15 to 20 years. The impact of these system changes was critical to our resource planning analysis as we evaluated meeting our capacity and energy needs while retaining flexibility and avoiding over-reliance on any one fuel source.

6. Planning Landscape Conclusions

The planning landscape underlying this Resource Plan has greatly informed our planning efforts. We continue to believe that proactive leadership in the face of evolving industry, new and proposed environmental regulation, customer expectations, emerging technologies, and changes to the NSP System will allow us to affirmatively address these trends rather than being shaped by them. The planning landscape also calls for sufficient flexibility to allow us to adjust and react as we gain more clarity on the planning landscape.

B. Key Considerations of the Preferred Plan

Resource Planning is a complex and integrated process of planning for the capacity, energy, and emission requirements of the electric system. The process incorporates a number of key assumptions or industry projections that helps all participants develop a common vision of what the future planning environment may look like. This ongoing planning process requires utilities to examine and establish a long-term proposal for management, operation, and expansion or contraction of their generating and demand management resources to meet customer needs.

Traditionally a primary focus of resource planning has been to identify the least-cost approach to provide reliable service and meet growing demand. While this is still a part of our foundation, this Plan begins to move away from a more concentrated view of traditional thermal generation to incorporating new generation technologies, increasing carbon-free energy, reducing emission profiles, and thereby positioning the NSP System for the future.

The Preferred Plan we present was developed to address the planning landscape in which it was developed. In light of this, our Preferred Plan was developed based on five key considerations: (1) the solid foundation that has resulted from our investment cycle; (2) innovative use of renewable energy to drive down emissions and preserve flexibility; (3) strategic flexibility; (4) cost effectiveness; and (5) a plan to address the future of Sherco Units 1 and 2.

1. Building on a Solid Foundation

At the time we submitted our 2010 Resource Plan, we were in the midst of a significant program of investment to expand and renew our generation fleet to meet our customers' needs while complying with state and federal requirements. As a consequence of our 2010 Resource Plan, we have made investments for approximately 1,350 MW of wind power, and 71 MW of nuclear uprates. This is in addition to other investments to maintain and operate our existing thermal fleet, to extend the life of our nuclear plants, and to renew our contractual relationship with Manitoba Hydro.

The Preferred Plan we are proposing recognizes these investments and seeks to allow our customers to obtain the full benefits of them. We believe it appropriate to build upon our previous investments in our nuclear and thermal fleet so that our customers can get the maximum benefit from these low cost capacity and energy resources.

2. *Innovative Use of Renewable Energy*

Our Preferred Plan is centered around the innovative use of the addition of renewable energy facilities to achieve strategic, environmental, and renewable energy policy objectives.

Because we are already on track to meet our Renewable Energy Standard (RES) requirements through the planning period, our Preferred Plan utilizes significantly more renewable energy to minimize the reliance on natural gas during and beyond the planning period, rather than for merely compliance purposes. We structured the Preferred Plan this way because natural gas is likely to play a much larger role in potentially replacing key baseload resources in the out years of the planning period and beyond. Further, new solar energy requirements have emerged in Minnesota that require a 1.5 percent penetration by 2020, and a goal of 10 percent penetration by 2030. Our Preferred Plan also addresses these needs.

Further, utilizing significant renewable energy additions will also position us well to meet future GHG requirements. The nature of renewable energy is such that it impacts the dispatch of our thermal fleet thereby impacting emissions. Utilizing renewable energy in this way innovatively obtains emissions reductions while preserving for our customers our investments in out thermal fleet and the fuel diversity they provide. In fact, we are able to achieve a 30 percent CO_2 reduction in 2020 merely by the addition of approximately 400 MW of wind to our system in 2020, although we note that our Preferred Plan proposes to add 600 MW of wind by 2020 to smooth our transition to the 40 percent CO_2 reduction by 2030.

Additionally, by planning to add significant amounts of renewable energy to the NSP System to meet strategic goals, we add additional flexibility into the Preferred Plan with respect to timing these investments. Therefore, we can either accelerate or delay these additions in light of market conditions at the time.

3. *Strategic Flexibility*

As the utility industry evolves, it is necessary to maintain strategic flexibility to respond to a changing regulatory environment and marketplace. Therefore, by focusing on out-year policy goals, we have built strategic flexibility into our Preferred Plan. This way we are able to address emerging environmental regulation, tax and other incentives for renewable energy, and the ability to address technological change in the industry. Further, our Preferred Plan preserves our ability to fully utilize our investments in existing resources while respond to changing customer needs, and provides us the flexibility to make future resource additions at times that are in the best interest of our customers.

Not only do we require flexibility to address the evolving utility landscape, the strategic flexibility we have built into the Preferred Plan is especially important given the evolution of the NSP System that is expected to occur toward the end of and beyond the planning period. Consequently, the flexibility built into our Preferred Plan allows key resource decisions to be fully evaluated prior to making firm planning decisions during this period of uncertainty.

4. *Cost Effectiveness*

We are aware of the impact that our current investment cycle has had on our customers. The benefit of this current investment cycle is that we have addressed all of our immediate capacity and energy requirements for at least the next five years. With that said, we recognize that investments will be needed to address expiring power purchase agreements, retirements and our on-going obligation to provide safe and reliable service in the out-years. Additionally, resource investments will be needed if we are going to proactively meet the changing planning landscape.

To balance the rate impacts of our resource planning decisions with being proactive, we set a threshold of 2 percent average, annual cost above the Reference Case. Our Preferred Plan meets this threshold.

5. *The Future of Sherco*

We recognize that the future of Sherco Units 1 and 2 is of fundamental interest to all of our regulators and other stakeholders. Through our Preferred Plan we present one potential vision for the future of Sherco. Specifically, our Preferred Plan assumes the continued operation of Sherco Units 1 and 2 through 2030, recognizing that operation beyond 2030 without SCRs is unlikely. This Preferred Plan therefore has the potential for Sherco Units 1 and 2 to cease operations in 2031. Our Preferred Plan allows our customers to continue to benefit from our investments in these low cost units while still achieving a 40 percent reduction in CO_2 emissions from 2005 levels.

That said, pending environmental regulations provide uncertainty with respect to the need to make significant investments in environmental controls at Sherco Units 1 and 2, namely the installation of Selective Catalytic Reduction (SCR) technology to control nitrogen oxide (NO_X) emissions. Building off of the analysis we undertook in the Sherco LCM Study and based on information we know to-date, we believe that we can continue to operate Sherco Units 1 and 2 through the planning period (2030) without making significant investment in SCRs. However, the outcome of pending environmental regulations may change this analysis.

Given this uncertainty around future environmental regulation, we analyzed alternative scenarios to our Preferred Plan. These scenarios include a single Unit retirement, retirement of both Units, significant investment in environmental control equipment, or some combination of these. While our analysis indicates that our Preferred Plan performs as well or better than those scenarios that contemplate retirement of one or both of Sherco Units 1 and 2, we look forward to discussing the future of Sherco Units 1 and 2 with our stakeholders during this resource planning process.

C. The Preferred Plan

To develop the Preferred Plan, we first developed a Reference Case capacity expansion plan that would continue the path we set out in our 2010 Resource Plan. This Reference Case provides an opportunity to achieve 30 percent CO_2 reduction goals set in our previous Resource Plan, while meeting our minimum system needs and compliance obligations. Our Reference Case provides a base line against which we have measured the emission reduction benefits, renewable energy additions and estimated cost impacts of our Preferred Plan. We present the timing, type, and size of resource additions in our Reference Case Expansion Plan in Table 1 below:

Table 1: Reference Case Expansion Plan

Resource	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Resource	Total
Small Solar	18	18	14	13	13	13	13	13	13	13	13	13	13	13	13	13	Small Solar	219
Large Solar	-	-	187	-	-	-	-	-	-	-	-	-	-	-	-	-	Large Solar	187
Wind	-	-	-	-	-	400	-	-	-	-	-	-	-	-	-	-	Wind	400
CT	-	-	-	-	-	-	-	-	-	219	1,095	657	-	219	-	-	CT	2,190
CC	-	-	-	-	-	-	-	-	-	-	-	-	778	-	-	-	CC	778

Beginning with our Reference Plan to meet our minimum system needs, we then analyzed 12 main scenarios to determine a reasonably cost-effective plan to achieve state policy goals in a cost-effective manner that would provide us with the flexibility to respond to the evolving utility landscape and address the future of a Sherco plant. Key scenarios analyzed include:

- *Reference Case and Variants.* Analyses to address minimum system needs as well as achieve 30 percent CO_2 reduction by 2020.
- *Preferred Plan and Variants.* Analyses to determine which resource addition mix best meets the current and potential future needs of our customers.
- *Sherco Scenarios.* Analyses of many scenarios with respect to the addition of SCRs, retirement of Sherco Units 1 and 2, separately or together, various replacement options, and combinations of these.

Based on these analyses, we believe that our Preferred Plan meets all of the key considerations necessary for a successful opportunity to meet or exceed customers' needs, and position us well within the planning landscape. Our Preferred Plan reasonably balances outcomes and cost while providing us with the necessary strategic flexibility to address the planning landscape.

Key components of our Preferred Plan include:

- Addition of 1,800 MW of additional wind resources:
  - 600 megawatts of new wind by 2020, which allows us to achieve an initial 30 percent reduction in CO_2 emissions by 2020,[3]
  - An additional 1,200 megawatts of wind by 2027, which allows us to achieve a 40 percent CO_2 reduction by 2030 within our strategic framework,
- Addition of approximately 2,400 MW of utility-scale and customer-driven small solar resources:

[3] From 2005 levels.

  - Adding 187 MW of utility-scale solar by the end of 2016 before the Investment Tax Credit (ITC) benefits reduce to ten percent to meet our Solar Energy Standard (SES) compliance requirements,
  - Targeting the addition of 1,700 MW of utility-scale solar by 2030 to meet the 10 percent solar energy goal, and
  - Approximately 500 MW of customer-driven small solar by 2030,
- Operating our carbon-free, baseload nuclear plants through at least 2030, which is supported by their current operating licenses,
- Assuming the operation of Sherco Units 1 and 2 through 2030,
- Extending the life of Blue Lake Units 1-4 an additional four years through 2023 with little incremental increase in costs, and
- Adding approximately 1,750 MW of gas peaking facilities to meet our customers' capacity needs.

We provide the proposed timing, type, and size of resource additions comprising the Preferred Plan Expansion Plan in Table 2 below:

Table 2: Preferred Plan Expansion Plan

Resource	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Resource	Total
Small Solar	18	18	14	13	13	13	16	19	23	28	33	40	48	58	69	83	Small Solar	506
Large Solar	-	-	187	-	-	-	-	-	-	100	400	300	200	500	-	200	Large Solar	1,887
Wind	-	-	-	-	-	600	-	-	200	-	600	-	400	-	-	-	Wind	1,800
CT	-	-	-	-	-	-	-	-	-	-	876	438	219	219	-	-	CT	1,752
CC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	CC	-

Our Preferred Plan achieves several important goals:

Reliability. Our Preferred Plan maintains the safe and reliable service we have been providing for many years and ensures that the NSP System has sufficient capacity and energy available during the planning period.

Environmental Outcomes. Implementing our Preferred Plan will allows us to achieve a 40 percent CO_2 emissions reduction from 2005 levels by 2030. Additionally, our Preferred Plan adds significant renewable energy to the NSP System above and beyond any other scenario analyzed.

Strategic Flexibility. Our Preferred Plan also takes into account customer impacts by mitigating the need for investments in non-renewable energy and associated natural gas fuel price/supply risks. Specifically, the Preferred Plan allows us to delay the need to add thermal generating facilities to the NSP System until the early- to mid-2020s. This allows customers to benefit from the availability of existing thermal capacity resources on our system, and provides greater flexibility to determine the best way to cost-effectively meet customers' energy in the out-years of the planning period and beyond. This also preserves the future expansion potential of our energy mix by delaying the need for a combined cycle unit during the planning period and preserving the ability for combined cycle resources to replace retired baseload units without shifting our resource mix heavily to gas.

Cost-Effective. We estimate that our Preferred Plan can be implemented at reasonable cost to our customers. More specifically, our Preferred Plan achieves environmental outcomes and preserves strategic flexibility at an average of cost of 2 percent on an annual basis above the Reference Case.

D. Rate Impacts

Overall, our Preferred Plan results in an estimated average annual increase in revenue requirements of less than two percent above the average estimated revenue requirements for the Reference Case over the planning period. This is demonstrated in Figure 1, below:

Figure 1: Annual Percent Change in Revenue Requirements 2016 -2030
(Preferred Plan above Reference Case)

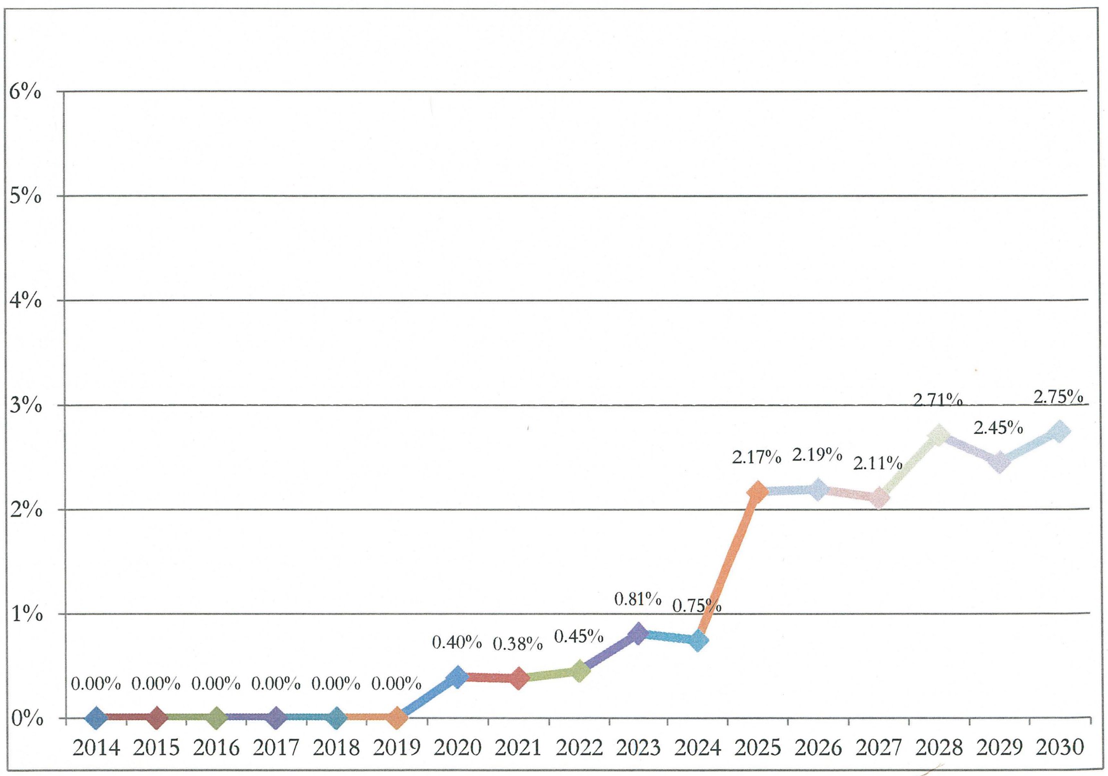
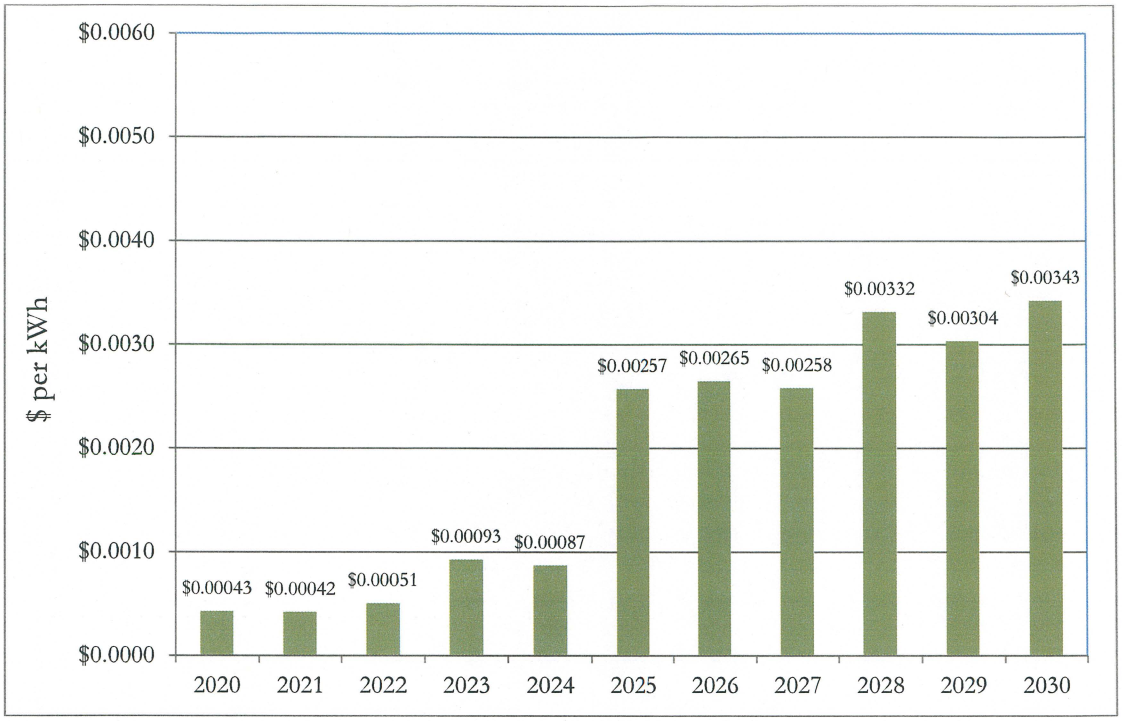


Figure 2, below demonstrates the actual impact implementation of our Preferred Plan would have on our customers' bills:

Figure 2: Incremental Rate Impact of Preferred Resource Plan
State of Minnesota – All Customers



E. Proposal for a Collaborative Process

We have submitted this Plan under Minnesota's existing Integrated Resource Planning rules, which provide a procedural mechanism to bring important resource-related issues forward for discussion. However, we propose taking a new, collaborative approach to the resource planning process, similar to the facilitated process we used for the Sherco LCM Study we submitted in July 2013 – and consistent with the collaborative approach contemplated by the e21 Initiative.

Specifically, we propose to initiate a stakeholder process where we engage with the Commission and other stakeholders to discuss our Plan. This process would guide the five-year action plan and create opportunities to create a consensus around out-year resource additions and the impact of resource retirements. As we noted previously, due to recent material changes in our resource portfolio due outcomes in the CAP proceeding, it will also be necessary to update the analyses supporting this Resource Plan. We envision this process beginning with a planning meeting with the

Commission to establish next steps, followed by collaborative meetings with stakeholders to further develop issues, solutions, and inputs.

F. Conclusion

The Preferred Plan we propose for our Upper Midwest customers builds on our strong foundation of environmental performance, while continuing to reliably meet our customers' electricity needs in a cost-effective manner. It will allow the Company to meet the most stringent of its state CO_2 emissions reduction and renewable energy requirements and objectives – and put us on a path to address federal EPA Clean Power Plan requirements. The Plan also provides a balanced diversity of energy sources used to generate needed electricity, and creates investment opportunities benefiting Minnesota's economy. Finally, it acknowledges the divergent state policies among the NSP System states, and proposes action to affect necessary changes in the generation mix and resulting rate impacts for customers.

III. PLANNING LANDSCAPE

In this Chapter, we discuss some of the key developments and challenges we expect to face over the planning period that impact our resource needs and operations, as well as our resulting cost of service and customer rates. Specifically, we discuss:

- Evolving environmental regulations,
- Diverse regional and state policies in the NSP System area,
- Changing customer expectations,
- Technology advancements that will impact the future of the grid,
- Our supporting infrastructure and infrastructure needs, and
- The evolving NSP System.

This framework "sets the stage" for our resource needs and plans discussed in other portions of this Resource Plan, which build off existing circumstances and resources.

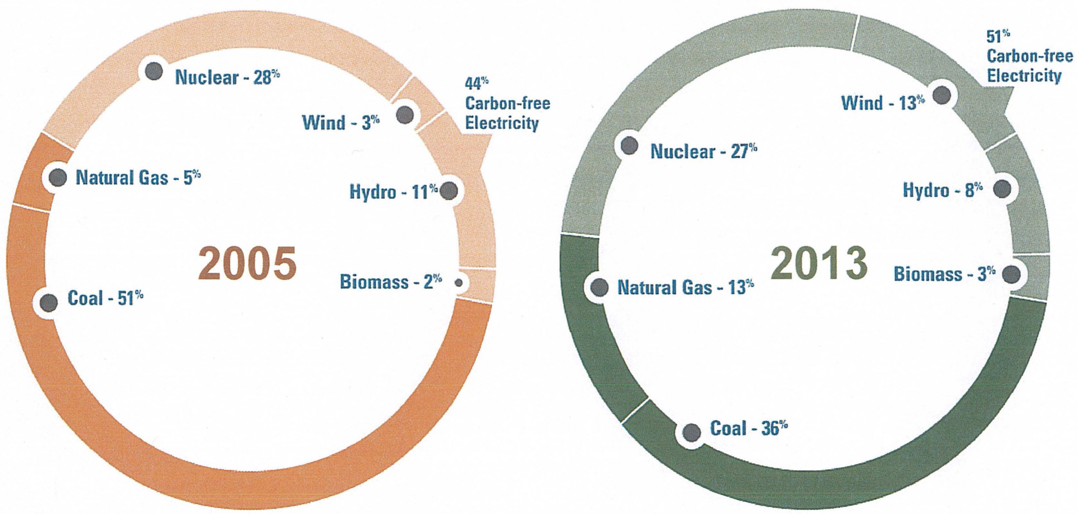
A. Evolving Environmental Regulations

Since submitting our last Resource Plan, multiple new air, water and waste regulations have been updated and adopted by the EPA, increasing our knowledge of what will be required to maintain compliance at our generating facilities. Regulations for criteria pollutants – particularly oxides of nitrogen, sulfur dioxide, particulate matter, and ozone – continue to be updated, and are likely to impose added constraints on operation of some power plants.

In past Resource Plans, we have pursued a strategy of shifting our resource portfolio toward lower-emission options while maintaining our focus on fuel diversity, affordability and reliability. Since 2005, we have added more than 2,200 MW of renewable energy to our NSP System, reduced our CO_2 emissions by 23 percent and our CO_2 intensity by 19 percent, and secured 3.4 billion kWh of cumulative energy efficiency savings. We have done this all while keeping electricity rates below the national average, and maintaining fuel diversity that protects our customers from over-reliance on any one resource.

In 2013, we reached an important milestone of over 50 percent carbon-free electricity, as illustrated in Figure below:

Figure 3: Upper Midwest Energy Mix Shift



We believe the overall thrust of EPA and state regulations validates our proactive strategy as the best choice for our customers and stakeholders. For example, the EPA has been developing updated requirements for water quality at thermal power plants and management of coal combustion residuals at coal-fired power plants. Regulations for mercury and air toxics, interstate transport of pollution, ozone, particulate matter, regional haze and visibility, water quality, and coal combustion residuals all create pressures in generally the same direction as the CO_2 rules.

However, we continue to experience significant uncertainty surrounding environmental regulation, which requires us to maintain flexibility in the way we may respond. Probably the biggest – and most uncertain – factor is the EPA's existing source GHG performance standard, known as the Clean Power Plan or Section 111(d) Rules, which EPA expects to finalize in June 2015. The final rule is likely to face legal challenges, which depending whether or not the rule is stayed during litigation, may affect the timeline for state plan development. If the Rule is not stayed, each state will draft plans and submit them to EPA by 2016 to 2018, for approval by EPA one year later; compliance will begin in 2020.

While much remains unknown, it seems clear that the Rule:

- Will put increasing pressure on coal plants, possibly resulting in reduced utilization levels or additional retirements,
- Is likely to increase generation from existing and new natural gas plants, and
- Will push us to continue adding renewable energy and energy efficiency.

Some stakeholders expect us to proactively reduce emissions and invest in cleaner generation, despite uncertainty in environmental regulations, uncertainty about cost recovery, and uncertainty whether the Company's early action will be recognized by regulators. On one hand, waiting for a clearer mandate could mean higher costs due to tight timeframes or supply bottlenecks across the industry. On the other hand, it is more difficult to argue to our Commissions and customers that further early action is justified if our early actions to-date are not rewarded in federal carbon policy.

Implementation of 111(d) by the states will likely determine what compliance flexibilities are available, whether our states will implement rate-based or mass-based programs, whether they will collaborate with other states in multi-state plans, and how much of the CO_2 reduction burden they will assign to the Company versus other utilities. We will know whether our states intend to assign compliance obligations only to regulated power plants, or take a portfolio approach (at the state or utility level) that allows us to implement various power plant, renewable energy, energy efficiency and other measures to achieve a utility-level rate or mass goal. All of these "known unknowns" significantly affect how we plan our compliance in Resource Plans.

The coming years will also see important developments in carbon, air quality, water, and waste regulations that will impact our Resource Plans, as follows:

It is becoming more difficult to maintain fuel diversity, which we believe is key to reliability, affordability and predictable costs. A system with less coal generation and dramatically more natural gas and intermittent renewable generation could be more volatile. Nuclear is a crucial carbon-free, baseload resource; federal and state carbon goals will become more difficult to meet when our nuclear plants retire.

Legislation in some of our states pushes for ever greater CO_2 reductions – Minnesota has established an energy policy goal of up to 80 percent CO_2 reduction by 2050, and 30 percent or more renewable electricity – but legislators and regulators in our other states do not always support these objectives or agree that our customers in their states should be asked to pay the costs. The NSP System is a five-state integrated electricity system, and we will need to address divergent state energy policies in the absence of clear federal guidance.

The Commission's Further Investigation into Environmental and Socioeconomic Costs - Under Minn. Stat. § 216B.2422, subd. 3, the Minnesota Commission is presently updating the values assigned to externality costs of CO_2, $PM_{2.5}$, SO_2, and NO_X.[4] The outcome of this renewed consideration of externalities may further affect the determination of appropriate fuel diversity and renewable resources. We note, however, that some of our other jurisdictions, particularly North Dakota, make it illegal to consider externality costs in the selection resource additions without a federal obligation to address those pollutants.[5] This mismatch between selection criteria in several of the states served by the NSP System is a significant driver in the types of divergent energy policies that must be addressed.

For ozone, EPA is currently revising the National Ambient Air Quality Standards (NAAQS) and considering a range of 65-70 parts per billion (ppb) for the eight-hour standard. EPA is also taking comments on a standard as low as 60 ppb. A standard of 65 ppb could, and a standard of 60 ppb would, put some areas of the NSP System in nonattainment. We will know what level EPA has chosen in 2015, then EPA will classify areas in 2017 and, if there are nonattainment areas, the relevant state agencies will develop a state implementation plan in 2019-20. In the state planning process, relevant state agencies would evaluate whether to require additional NO_X controls at our plants.

For nitrogen dioxide (NO_2), air quality monitors currently show attainment of the NO_2 standard. Near-road monitors will go into place in 2014-17. If these near-road monitors show high enough NO_2 levels for a nonattainment designation in 2017-18, we believe that a state implementation plan would need to focus on mobile source emissions. We will not know until 2017 whether there is any potential to impact our plants.

For interstate transport of SO_2 and NO_X, the Cross-State Air Pollution Rule (CSAPR) goes into effect in 2015. We can comply with CSAPR's emission limits without installing additional controls at our plants. In the future, EPA may reduce the SO_2 and NO_X emission allowance levels whenever the ozone or particle NAAQS are made more stringent, and if further reductions are needed to assist nonattainment areas in downwind states. Depending on the level of reductions needed, we might be required to install additional controls for NO_X, but further SO_2 controls are not likely to be required.

[4] Docket No. E999/CI-14-643.

[5] North Dakota Century Code, 49-02-23.

For regional haze, a five-year progress report on 2009 state implementation plan is due in December 2014. We understand that 2018 goals are expected to be met and that no further changes are needed. We note that for Sherco Units 1 and 2, the relevant state agency, the Minnesota Pollution Control Agency (MPCA), determined that the Best Available Retrofit Technology (BART) would be low NO_X burners and related combustion controls, as well as upgrades to the existing SO_2 scrubbers. We have recently completed these emission control projects at Sherco, and will be subject to our BART emission limits starting in January 2015. It is possible, but currently unknown, whether any 2018 plan revisions could require SCRs for NO_X control in 2020-25.

For visibility, a lawsuit is pending that seeks to require EPA to determine best available retrofit technology for Sherco Units 1 and 2 to address an uncommon type of alleged visibility impairment in Voyageurs and Isle Royale National Parks. While we contest this allegation and believe it should not lead to additional controls on these Units, one possible outcome could be a requirement to install SCRs for NOx control on these units in the early 2020s.

Overall, we think it is important to take a balanced approach that continues our clean energy trajectory while maintaining the broadest range of options for an uncertain environmental regulatory future, which is a foundational principle of the Preferred Plan we propose in this Resource Plan. We provide a more detailed discussion of relevant federal and state environmental regulations as Appendix D.

B. Divergent State Policies

The NSP System serves over 1.8 million retail electric customers in Michigan, Minnesota, North Dakota, South Dakota, and Wisconsin. Allocation of system costs is performed according to the percentage of the system utilized by each Operating Company and jurisdiction. Because customers in these five states are served by the same system, we have been able to achieve significant economies of scale that provide benefits to all of our customers in all of the states we serve. We have also been able to successfully plan for, and manage, the integrated NSP System to meet all of our customers' needs for almost 100 years.

However, the planning for, and managing of, the integrated NSP System requires us to balance the needs and policy goals of all of the jurisdictions we serve. It is important to recognize, however, that not all states we serve have the same energy policies and environmental goals. While some states have been moving fast in one direction, other states that are part of the NSP System, are moving in a different direction. This Resource Plan achieves certain energy policy and priorities to position us to meet the planning landscape. This will impact all of the customers in all of the jurisdictions we serve and how our Preferred Plan fits with the policy priorities of the states we serve is a key consideration with respect to implementation of the outcome of this Resource Plan.

Our experience in North Dakota is illustrative. For example, there are irreconcilable differences between the requirements of Minnesota and North Dakota law with respect to resource evaluation. In light of these considerations, we believe that our ability to position us to meet the planning landscape in a manner consistent with all states' energy policies is becoming increasingly difficult, if not impossible. For context, we provide information in this section identifying the experience of divergent energy policies and our experience in North Dakota.

1. Overview

We are the largest electric utility in North Dakota, serving over 112,000 customers located in the Fargo, West Fargo, Grand Forks, and Minot areas. The integrated NSP System has provided safe, reliable and cost-effective generation resources to North Dakota for many years, and the North Dakota Public Service Commission has generally supported our investments in our coal, natural gas, and nuclear generation resources.

However, our 2007 proposed addition of the Grand Meadow Wind Farm triggered the North Dakota Commission to reevaluate the methodologies used for its review of resource additions to the NSP System. As a result of these concerns, we agreed to a series of process changes to provide the North Dakota Commission with the ability to offer input into our resource decisions earlier in the process.

While these process improvements had generally proved useful, in our most recent North Dakota rate case it became apparent that the 2007 process improvements were insufficient to address the North Dakota Commission's growing concerns with the impact of different energy policies on the Company's North Dakota customers. In light of this, we agreed to attempt to shift the resource portfolio serving our North Dakota jurisdiction.

2. *2007 Process Changes and Outcomes*

In settlement of our 2007 North Dakota rate case, where concern about Grand Meadows was raised, we agreed to a series of process changes that would, among other things, require the Company to apply for an Advanced Determination of Prudence from the North Dakota Commission for any resource addition to the NSP System of 50 MW and larger – and to present in North Dakota a Resource Plan that would be consistent with North Dakota policy, which prohibits the valuing of externalities in making resource decisions, and has a voluntary 10 percent renewable energy objective. Later in this Resource Plan we present scenarios that represent the North Dakota Version Resource Plan.

Due to these process changes, since 2008 the North Dakota Commission has been more actively involved in evaluating the resources we have proposed to add to the NSP System. Importantly, the North Dakota regulatory paradigm has been evolving from a post-decision review in rate cases to a more proactive evaluation of the Company's resource decisions through the use of North Dakota's Advanced Determination of Prudence methodology. This means that the North Dakota regulatory process is moving closer a model where our regulators have significant input into our resource planning and resource selection decisions prior to their implementation. Therefore we expect, on a going forward basis, that we will have a pre-approval process in two of the five states we serve.

Historically, we have generally been able to implement all states' energy policies in a least-cost manner, such that the North Dakota Commission has approved several resource additions under the 2007 process changes. Examples of this include the Nobles and Merricourt wind projects.[6]

However, the North Dakota Commission has also disallowed the recovery of our investment in the Prairie Rose Wind project as incompatible with North Dakota energy policies. The North Dakota Commission perceived the sole purpose of this resource as achieving compliance with the Minnesota RES, and that there was no demonstrated need for this resource.[7]

Consistent with this perspective, the North Dakota Commission has subsequently also found imprudent and inconsistent with North Dakota energy policies our investment in the Odell Wind project and the Pleasant Valley Wind project,

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[6] See NDPSC Case Nos. PU-08-907 and PU-08-908

[7] See NDPSC Case No. PU-12-059.

notwithstanding the demonstrated cost-effectiveness of these resources.[8] However, consistent with North Dakota law's presumption of prudence for projects located within North Dakota, the North Dakota Commission has determined that our investment in the Courtenay Wind project and the Border Winds project are prudent.[9]

Additionally, through these revised processes, the North Dakota Commission has approved our proposal for a combustion turbine unit at our Black Dog facility (Black Dog Unit 6), as well as for two combustion turbines in the Red River Valley area of North Dakota (Red River Valley Units 1 and 2) to meet the Company's then-identified resource needs in the 2017-2019 timeframe.[10] These approvals were obtained prior to the Commission's decision in our Competitive Acquisition Process in Docket No. E002/CN-12-1240, and notwithstanding the outcome ultimately reached by the Commission.

The discrepancy in outcomes in North Dakota and other states has created a concern for the Company with respect to its ability to comply with its obligations in in all of the states' we serve, and to have a reasonable opportunity to recover our costs of this compliance in all NSP System jurisdictions. More specifically, as we work toward an energy future consistent with certain energy priorities, we are concerned that our investments could be rejected by the North Dakota Commission. In the event this occurs, we will not be able to fully recover the costs of these investments without the ability to allocate any unrecovered costs to our customers in the cost-causative jurisdiction. These concerns were amplified in the Company's most recent North Dakota rate case.

3. 2013 North Dakota Rate Case

Our 2013 North Dakota rate case was mainly focused on North Dakota's role in the NSP System. At issue in that rate case were, among other things, the:

- Appropriate inter-jurisdictional demand cost allocation methodology,
- PPA costs for projects that were perceived to be driven solely by Minnesota policy (such as C-BED projects and other Minnesota legislatively-mandated resource additions) and not cost-effective, and
- Company's lack of investment in North Dakota based infrastructure for reliability reasons.

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[8] See NDPSC Case Nos. PU-13-707 and PU-13-708.
[9] See NDPSC Case Nos. PU-13-706 and PU-13-742.
[10] See NDPSC Case No. PU-13-194.

Use of settlement agreements are the most common procedural practice in North Dakota, and we were able to obtain a reasonable settlement in that rate case. However, the terms of that settlement fundamentally impact the relationship of North Dakota to the integrated NSP System. Given these issues, the Preferred Plan we advance in this Resource Plan will likely continue to lead to discrepant outcomes in North Dakota and other states we serve, and it is possible that the North Dakota Commission will determine that the Preferred Plan is driven by energy priorities not consonant with North Dakota's energy policies. This could create a situation where we make investments to further certain energy priorities to position us to meet the planning landscape while the North Dakota Commission could be unwilling to allow full recovery of these costs from its jurisdiction.

As a further impact to resource planning, we have committed to construct a North Dakota based, fossil-fueled generation resource by 2036. We anticipate that up to 400 MW of additional thermal generation identified in this Resource Plan will be proposed to be constructed in North Dakota, near our North Dakota customers to support reliability in those areas and increase the diversity of generation location throughout the integrated NSP System.

We also agreed to a "Restack" of the integrated NSP System generation resources to address the North Dakota cost impacts of policy-driven changes to the NSP System determined to be incompatible with North Dakota's energy vision.

4. *System Restack*

A key component of the 2013 North Dakota rate case settlement was a framework for the negotiation of a System Restack. Under the Restack concept, resource additions to the NSP System that the North Dakota Commission determines are imprudent for policy reasons would be replaced with a financial proxy "resource" more consonant with North Dakota policy priorities.

Because the North Dakota Commission always retains the ability to disallow as imprudent any resource additions to the integrated NSP System, the replacement proxy feature of the Restack concept helps to ensure that our North Dakota customers pay a reasonable cost for the used and useful capacity and energy benefits of any resource addition that we make.[11] The Restack "proxy" is intended to provide

[11] We note that we intend to seek recovery of the difference between the actual costs of the resource and the cost recovered by our North Dakota customers from the cost causative jurisdiction.

a reasonable financial alternative to the resource being added to the system to "price" the policy implications of a particular resource addition. The Restack negotiating framework is based on ten negotiating principles outlined in the 2013 rate case settlement agreement, which are based on three fundamental concepts:[12]

1. *Benefits and Burdens Retained.* All policy choices come with benefits and drawbacks and that the benefits and the burdens of a particular policy choice should be borne by the jurisdiction making such choice. To the extent that the Restack results in increased costs to North Dakota customers, then they must bear these burdens.

2. *No Self Serving Selection.* Restacking of existing resources should result in a reasonable approximation of what would have occurred, so that a resource mix consistent with North Dakota energy policy does not result in only the lowest cost resources available making-up the total agreed-to North Dakota resource mix. The Restack is not intended to allow for hindsight to select only a lowest cost resource mix.

3. *Future Outcomes Must Be Addressed.* The energy and capacity of any future resource addition must be accounted for in a final Restack agreement based on marginal pricing. Marginal cost pricing was chosen as a future resource proxy as it represents the cost of the next additional unit of energy or capacity within MISO, and therefore represents the "least cost" resource consistent with the North Dakota Commission's requirements.[13]

The 2013 rate case settlement also provided for a default outcome should the North Dakota Commission ultimately not adopt the Restack agreement. This default outcome would result in the restacking of 24 PPAs that were identified in the 2013 rate case as being driven by Minnesota energy policy at what North Dakota Commission staff determined was at an unreasonably high cost.[14] We note, however, that if the default outcome is adopted and no framework for addressing future resource additions is available, the impact of divergent state energy policies could accelerate considerably should our North Dakota stakeholders choose not to participate in implementation of the outcome of this Resource Plan.

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[12] See NDPSC Case No. PU-12-813.
[13] N.D. Admin. Code § 69-09-02-33.
[14] See Attachment E of Appendix S.

The Restack represents the continued evolution of the inter-jurisdictional nature of the integrated NSP System and the divergence of state energy policies. To the extent policy goals continue to drive the evolution of the integrated NSP System and not all of our jurisdictions share those same goals, we contemplate seeking recovery of costs disallowed by other states in the cost-causative jurisdiction.

For example, should the North Dakota Commission disallow recovery of the costs of investments made to meet Minnesota's renewable energy or carbon goals, we would expect to seek recovery of any costs not paid by our North Dakota customers from our Minnesota customers. We believe the Restack concept will help to mitigate the cost shifts inherent in addressing divergent energy policies by providing certainty in proxy pricing for future resources and addressing the actual used and useful capacity and energy that future resource additions will provide to our North Dakota customers.

That said, we do not believe that the Restack is sustainable over the long-term. More specifically, the Restack only mitigates the impacts to our North Dakota customers of resource choices perceived by the North Dakota Commission as being driven by energy policies inconsistent with their vision. It does not address the impact of the Company's resource choices that are driven by North Dakota energy policies on our other customers – nor does it address how the integrated NSP System can develop under fundamentally different policy views. Thus while the Restack provides a reasonable short- to mid-term solution to the divergence in energy policies, it is merely a mitigation tool rather than a solution. Consequently, we are exploring next steps to help ensure the Company is able to meet the legal requirements of each state in the NSP System, achieve each state's energy policies, and allow the Company to recover prudently-incurred costs associated with resource additions to the NSP System.

Solutions we are exploring include the potential to plan and operate our North Dakota jurisdiction separately from the integrated NSP System, so that we can pursue the energy goals of North Dakota within its own framework while addressing cost allocation matters through creative ratemaking methodologies. Alternatively, we are also analyzing the feasibility of creating a separate, North Dakota-based, operating company, so that there is a legal separation between our North Dakota jurisdiction and the remainder of the integrated NSP System. We believe that these outcomes may be achievable in a cooperative fashion that can appropriately allocate the benefits and burdens of the policy choices of all the states we serve. We look forward to a robust dialogue with all of our regulators and stakeholders as we move toward this future.

We recognize that any solution will impact our customers. However, developing a permanent solution to the divergence of state energy policies will be necessary for the continued financial health of the Company and for us to continue to meet diverse energy policy goals.

C. Changing Customer Expectations

Providing safe, high quality, reliable service that meets our customers' needs is one of our top priorities. We are increasingly hearing from our customers that they have growing interest in increasing their energy management capabilities and a more customized energy mix than has been traditionally available. We also know that customers are sensitive to the rates they pay for their energy service. These are key considerations as we plan our resource mix to meet the needs of NSP System customers over the fifteen-year planning period.

1. *Diverse Customer Interests*

Because we serve a diverse mix of customers, we experience differing preferences with respect to energy policies and options. For example, our *large industrial* customers are very energy-intense, and therefore are highly sensitive to energy rates. Traditionally, these customers have been primarily concerned with various elements of rate design to ensure each customer group is paying as close as possible to the actual costs to serve the group.

However, in our most recent rate case, the Xcel Large Industrials proposed a tariff that would allow the Company to sell renewable energy from new incremental resources directly to large high load factor customers to take advantage of synergies between off-peak output of certain renewable resources and high load factor customer load that is steady during off-peak hours – noting such synergies could make renewable energy more affordable while mitigating the impact of the Company's overall C&I Demand rates. We continue to work on new products, such as these, to help meet our customers' needs.

Cities and municipalities are also expressing changing expectations for their utility companies. As communities become more energy-aware, they are seeking opportunities to achieve sustainability goals and engage residents around energy issues. Many cities have set goals for energy efficiency and conservation, as well as GHG emissions reduction across city operations. Some, such as the City of Minneapolis, have developed plans that serve as a roadmap to achieving those sustainability goals. Meeting the needs of these cities and municipalities will be a key consideration as we move forward into the future.

For example, in October 2014, we, along with CenterPoint Energy, signed a first-of-its-kind Clean Energy Partnership agreement with the City of Minneapolis that recognizes the long relationship that has existed between the city and the utility, and also marks a new stage for the Company to collaborate with customers and communities on innovative approaches and enhanced outcomes in energy efficiency and the use of renewable energy.

Finally, *residential* customers tell us that they value choices and clean, affordable, reliable energy. In response, we have developed programs that offer more convenient payment options, rebates for energy efficient upgrades and the chance to make a difference by choosing renewable energy. Customers are taking advantage of the programs we have developed that offer more convenient payment options, rebates for energy efficiency upgrades and renewable energy solutions in large numbers – and they have expressed strong satisfaction with their ability to select programs that best meet their individual energy needs. We are, however, continuing to evaluate and develop new programs and offerings that provide our customers meaningful information and methods to further engage in energy decisions impacting their lives.

2. *Distributed Generation*

The advancement of distributed energy resources such as distributed generation (DG), energy storage, and other decentralized devices that supply power to the grid, but are not necessarily energy generators, are contributing to the evolution of the utility industry. We are particularly seeing and expecting significant increases in DG, which we broadly define as generation that is located on or near the site where the output is primarily to be used, interconnected to and operated in parallel with the electric grid, with a total capacity of no more than 10 MW.[15]

[15] *In the Matter of Establishing Generic Standards for Utility Tariffs for Interconnection and Operation of Distributed Generation Facilities under Minnesota Laws 2001, Chapter 212*, Docket No. E-999/CI-01-1023, ORDER ESTABLISHING STANDARDS (September 28, 2004). Minnesota defines renewable projects between 10 and 40 megawatts as "dispersed" renewable generation. See Laws of Minnesota 2007, chapter 136, article 4, section 17.

Additionally, the capacity of the DG installation must be lower than the minimum load of the distribution system to which it would be interconnected, so that the energy generated by the DG facility is used locally. Generally, customers are increasingly interested in various types of self-generation – two types of which that are topical for this Resource Plan are Solar and CHP, which we discuss below:

a. Solar

We currently have 14 MW (AC) of solar on our system. This renewable capacity is comprised of two small PPAs for just under 2 MW of solar, and the remaining 10 MW from customer-sited systems, including those receiving incentives under the first generation of our Solar*Rewards program. We are poised to grow our solar portfolio significantly in the coming year, as fully described later in this Resource Plan.

Growth in solar across all market segments is driven by several forces. Namely, its economics are improving through state and federal incentives and manufacturing advancements; customers are increasingly interested in new energy choices, including the option to install solar on their homes and businesses to produce their own energy; and, state and federal policies are promoting solar as a way to reduce GHG emissions and support local economic development.

Specifically, recent enactment of an SES in Minnesota has been the key driver for expansion of our customer solar programs and our solar acquisition plans. We discuss these significant changes, as well as some of the challenges facing solar expansion in more detail in Appendix E.

b. Combined Heat and Power

CHP, also known as cogeneration, is a technology that generates electricity and recovers the excess heat from that electrical generation process for use at the point of consumption. CHP has historically been economically viable only at an industrial or municipal level and the potential for impact on the NSP System has primarily been from large industrial loads with high electric load factors and thermal demand. The site-specific nature of CHP is such that development of a large generic input for system modeling purposes is not practical, and we therefore have not included any CHP generation in our Strategist models.

Since our 2010 Resource Plan, we worked with the Electric Power Research Institute (EPRI) and Resource Dynamics Corporation to conduct a study to explore the technical and economic potential for DG and CHP. This study is differentiated from other generic studies by our use of Company-specific customer data that enabled identification of project opportunities by customer segment, as well the potential project sizes for each customer segment and their associated payback.

The EPRI Study estimates that we have approximately 300 MW of potential CHP opportunities, primarily from large industrial facilities, hospitals and colleges/universities, with payback periods ranging from 6 to 10 years. The Study analyzed technical potential among commercial/industrial customers with maximum demands of 1 MW or larger, and found that under current market conditions, large industrial facilities that can install CHP systems over 5 MW in size have the most attractive project economics. We provide that Study as Appendix R to this Plan.

We believe there may be a role for CHP in the future on the NSP System, as a strategy to promote efficient system operation, reduce CO_2 emissions, and expand options available to customers. However, in order to incorporate CHP as a viable technology, there must be a rational and cost-effective strategy for its expansion on the NSP System. In 2014, the Department of Commerce held a series of stakeholder engagement meetings on the potential for CHP deployment, in which Xcel Energy staff participated. We will continue to participate in efforts to design an appropriate CHP program to aid in broader adoption of the technology.

We note that the site-specific nature of CHP is such that development of a large generic input for system modeling purposes is not practical; any CHP (or other DG) that may be added to the system is subsumed in the assumed small scale solar additions in our model.

D. Emerging Technologies

The rapid pace of advancement in energy technologies has continued since we submitted our 2010 Resource Plan, and continues to impact the future of our industry. Emerging technologies related to grid modernization, energy storage, electric vehicles, resource extraction, renewable energy and other alternative fuels and generation methods are enabling a smarter and more resilient energy system that can better adapt to the evolving utility landscape.

While this provides opportunities for modernizing our system, operating that system is a complex matter. It is critical that we take a measured approach to identify new and better ways to provide our customers with high quality service, meet increasing environmental requirements, and implement advancements and standardized processes that enhance the overall safety of our operations. Our approach to these emerging technologies is to learn from the current deployments, both internal to Xcel Energy and within the industry, and implement initiatives at the pace of value to our customers and operations.

E. Demand Side Management

Demand-Side Management (DSM) is a key component to our environmental commitment to the communities we serve, and is an important resource that has saved over 6,940 GWh of energy and 2,944 MW of demand since 1990. We have one of the longest-running and most successful DSM programs in the country. Between 1990 and 2013, we spent over $1 billion (nominal) on our DSM efforts and have demonstrated strong portfolio performance, first achieving energy savings at Minnesota's 1.5 percent target in 2011 – and then exceeding the target the next two years.[16]

Historically, DSM has been a win-win business decision, as it reduced rates for all customers, and resulted in positive benefits for the utility. However, in recent years, the landscape of DSM has been changing, and the benefits of such investments are lowering for both the utility and its customers as a whole. We have continued to grow our DSM portfolio since our 2010 Resource Plan, but achieving the same level of energy savings has become much more difficult. Factors such as increases to energy efficiency standards and building codes, organic conservation, and flattening of electricity sales over the recent past are combining to greatly reduce the impact that utility-sponsored DSM programs can have on energy usage and demand.

As with energy efficiency, we have a successful history with Demand Response (DR) programs. Beginning in the 1980s, we were one of the first utilities in Minnesota to bring various load management programs to all customer classes to market. Our portfolio today exceeds 933 MW, or approximately 10 percent of our system peak.

Unlike past Resource Plans, today we find ourselves in a period of uncertainty for the future use of DR as peak demand reduction tool. While we continue our commitment to providing customer options and growing DR resources, it has become increasingly important to observe the quickly changing marketplace and adjust programs based on this movement. Like energy efficiency resources, the

[16] Annual CIP Status Report savings as approved by the Department of Commerce – Division of Energy Resources. Docket Nos. E,G002/CIP-09-198.05, E,G002/CIP-09-198.06, and E,G002/CIP-12-447.06

landscape for DR is changing as federal and local regulations are defined. Additionally, projected baselines are adjusting based on new technologies and avoided costs. As a result, we believe it would be challenging to actively increase DR resources in this environment.

We discuss these challenges in more detail, as well as the savings we expect these programs to contribute to the planning period in Appendix G.

F. Supporting Infrastructure – Transmission and Distribution

All of this change requires that we have an infrastructure that can support and adapt to the changing landscape of the utility industry. Although transmission and distribution planning are conducted independently of resource planning, we recognize that that our transmission and distribution infrastructure must adapt and support emerging technologies, expanding renewable policies, and the resource planning process – much like our generating portfolio. We discuss these elements of our supporting infrastructure below.

Over the course of the next five years, we expect the expansion of the transmission grid that has been occurring over the last several years to ebb. However, we also expect our efforts to modernize the transmission grid and distribution system to increase to ensure continued reliable, high quality service to customers, enhance the options we can offer, and ensure we are able to successfully integrate the renewable and Distributed Energy Resources we expect will significantly expand.

1. Transmission System

We manage transmission planning and resource planning as separate but interrelated functions because transmission development is an important part of the resource planning process. The integration of increased renewable energy and DG on our system will require significant investments in our grid. Transmission needs are driven by multiple factors including increased customer electric demand, new generator interconnections that adjust the flows on the existing transmission system, and generation resource choices and the availability of transmission to meet the demand for these resources. The interconnected nature of the transmission system also means that system development decisions (either transmission or generation) of other utilities could have impacts on the NSP System transmission system.

Significant study work is underway to establish a comprehensive planning framework for new transmission that can respond to generation planning efficiently in the years to come. The major drivers influencing future transmission associated with new generation include distance from the major load centers (particularly the Twin Cities), size of the proposed generation additions, proximity to other generation resources, and whether the proposed generation site is near an existing major high voltage interconnection (*i.e.* 345 kV).

In Appendix H we outline some of the transmission efforts being undertaken to ensure sufficient transmission resources are available to meet resource planning requirements, greater integration of wind and other renewable resources, and other need drivers such as load and reliability.

2. *Distribution System*

As we consider the evolution of our current resource mix and we prepare for an increasingly distributed world, we know that our distribution system will be a key enabler for future changes. Accordingly, our system requires thoughtful investments to continue to safely deliver reliable energy to our customers and to serve the needs of expanding DG.

DG has already begun to impact the distribution planning process. Our system was initially built to support one-directional flows of energy. Increased DG penetration levels pose new challenges to the distribution system to accommodate two-directional flows. As DG installations increase in an area, feeders or substations may require further analysis to ensure this equipment is adequate to continue providing reliable service. Similarly, we must monitor DG contributions in relation to the system load. By identifying load and generation separately, rather than analyzing only the net result, we are able to more comprehensively evaluate whether system facilities are adequate to meet system needs under a range of likely scenarios.

Over the next five years, we will make distribution system investments to increase reliability, enhance customer choice, and integrate with DG sources. Investments include technologies to facilitate advanced applications, such as fault locating, isolation and restoration, and enhanced voltage and reactive power (VAr) controls. These technologies will also provide for improved data collection, which is necessary to manage higher penetrations of electric vehicles and DG on our system. Additionally, we will install a communication technology called Supervisory Control and Data Acquisition (SCADA) at more substations throughout the system to reduce system losses and to further accommodate increased DG through improved communications and data.

We provide an overview of our distribution system, discuss what informs our distribution planning process, note the impact of increasing DG that we expect on the system, and explain how our distribution system investments support a more responsive and modernized system in Appendix H.

G. The Evolving NSP System

In addition to these external factors surrounding this Resource Plan, we are entering a period of significant evolution of the NSP System. Although we have built a strong foundation upon which we are proposing our Preferred Plan, our planning efforts must be viewed through the lens of significant change to our resource mix in the out-years of the planning period and beyond.

During the out years of the planning period, there are both significant reductions in energy resources due to power contracts expiring without extension or renewal and a corresponding addition of significant amounts of wind and solar energy resources as well as and adding natural gas peaking resources as the lowest cost option to fulfilling unmet capacity needs. Several potential key changes during the planning period include:

- 2023: Blue Lake Units 1-4 cease operation (153 MW)
- 2025: Manitoba Hydro contracts expire (850 MW)
- 2026: Cottage Grove Combined Cycle Energy Center contract expires (262 MW)
- 2027: Mankato Combined Cycle Energy Center contract expires (357 MW)

Our Preferred Plan must include sufficient resource considerations to meet energy needs and sustain carbon reduction progress, while maintaining flexibility to address changing market conditions and fuel diversity.

The potential retirement of our three baseload nuclear units, along with the discussion about the continued operation of the Sherco Units 1 and 2 in this Resource Plan, suggest that a significant proportion of our baseload generation may be retired within 15 to 20 years. These five generating units have been the backbone of the NSP system for many years and have formed the foundation to provide low cost and highly reliable service to our customers. Replacing the benefits that these energy producing units have provided the NSP system will be challenging.

Current technology suggests that natural gas combined cycle units, along with additional renewable energy will be the likely candidates to replace the energy and capacity these units have provided. As a result of the large potential exposure to natural gas in the 2025 to 2035 timeframe, our Resource Plan must attempt to minimize this exposure going into that timeframe, allowing for greater flexibility to add more natural gas units when our backbone baseload plants are retired.

Table 3 below identifies the magnitude and timing of the potential retirements of our baseload or energy producing generation in the 2025 to 2038 timeframe.

Table 3: Potential Generation Retirements

Year	Baseload	Intermediate - Natural Gas CC	Peaking - Natural Gas CT
2016			
2017			
2018			
2019			Flambeau (13 MW)
2020	Manitoba Hydro (75 MW)		
2021			
2022			
2023			
2024	Bayfront (Biomass) (67 MW)		Blue Lake 1-4 (157 MW)
	French Island (Biomass) (16 MW)		French Island (CT) (122 MW)
			Granite City (54 MW)
2025	Manitoba Hydro (500 MW)	Invenergy (358 MW)	
	Manitoba Hydro (350 MW)		
2026		Calpine Mankato (357 MW)	Wheaton (298 MW)
2027			Inver Hills (287 MW)
2028	Red Wing (Biomass) (21 MW)	LSG Cottage Grove (262 MW)	
	Wilmarth (Biomass) (19 MW)		
2029			
2030			
2031	Monticello (671 MW)		Angus Anson 2&3 (186 MW)
2032		Black Dog 52 CC (285 MW)	
2033			
2034	Prairie Island 1 (548 MW)		
2035	Prairie Island 2 (548 MW)		Anson 4 (149 MW)
			Blue Lake 7&8 (309 MW)
2036			
2037			
2038	AS King (541 MW)		

Notes: ICAP capacity values. The year listed is the first year *without* the resource. We have excluded Sherco from this table as it is a subject of this proceeding.

H. Planning Landscape Conclusions

As a whole, the energy industry is at a pivotal point. As discussed in this Planning Landscape segment of our Resource Plan, the development of new environmental policies with a focus on renewable energy, increasing customer interest in choice and competition, and emerging technologies are all contributing to this time of great change. At the same time, not all states in the NSP System have the same energy policies, and it is becoming increasingly infeasible to satisfy multiple states' divergent policies with a single Resource Plan.

Minnesota's continued interest in energy efficiency and DR are also becoming harder to achieve as increases to energy efficiency standards and building codes, organic conservation, and flattening of electricity sales combine to reduce the impact of utility-sponsored programs. Finally, we view this landscape from the perspective of significant potential system retirements on the planning horizon.

We believe that the changing landscape surrounding this Resource Plan calls for proactive leadership. We continue to seek to be an industry leader in identifying and implementing proactive solutions during to respond to the planning landscape. We build upon this broad planning landscape in the next section of our Resource Plan, where we discuss our forecast and minimum system needs in the "new" energy environment. Ultimately, we believe that our Preferred Plan demonstrates such leadership, balancing costs and appropriate performance goals.

In addition, we continue to evaluate other solutions that may enable our customers to benefit from our previous investments as well as position us well to meet and exceed the policy goals and customer needs of the future. One example of this is our current work on innovative coal fleet management strategies. As we were developing our Preferred Plan, we analyzed the potential to dispatch our coal fleet based on environmental parameters instead of purely economic consideration. By adopting this proactive approach, we were able to retain the benefits of the low-cost energy and significant installed capacity that our coal fleet provides while limiting emissions and further utilizing renewable energy to further meet our customers' energy needs.

Our Preferred Plan ultimately adds sufficient renewable resources to the NSP System to affect the operation of our coal plants and thereby reduce emissions even without additional innovative management strategies, but we believe that innovative solutions like this will be key to success for our stakeholders in an evolving planning landscape.

We will continue to examine the feasibility of environmentally-based dispatch while this Resource Plan is being considered. We recognize that implementing such innovative outcomes will require the consent of all of our regulators and stakeholders as well as changes to FERC and MISO dispatch protocols. However, we believe work on these and other innovative solutions will ultimately allow us to continue to serve our customers in successful, proactive ways.

IV. MINIMUM SYSTEM NEEDS

We have laid important groundwork to build a solid foundation upon which we now have the opportunity to cost-effectively transform the energy supply for our Upper Midwest customers. As we describe in this Chapter, we have no need to add capacity resources to our system until the early- to mid-2020s. Consequently, we have incorporated 30 percent CO_2 reduction by 2020 goal developed in our last Resource Plan into our minimum system needs analysis to complete the course of action we set out in our 2010 Resource Plan.

Below, we outline the elements that contribute to our overall resource need for the planning period. Specifically, we outline our forecast for meeting our customers' demand and electricity needs, our regional resource adequacy requirements, and the resources we need to meet the renewable energy standards, objectives and nearer term CO_2 goals in the NSP System states that informed our Reference Case.

A. Meeting Customer Needs

Forecasting our customers' need for electricity is a key component of any resource plan, and provides the basis for determining the type and amount of resources that will be needed over the 15-year planning period. Determining this need starts with a forecast of our customers' peak demand for electricity. To that, we add a Reserve Margin to reflect our contribution to MISO's pool of generation that can respond to unexpected equipment outages. The combination of Peak Demand and Reserve Margin less DR represents our total Resource Need, which is then compared to the generation resources we have available to meet that obligation, as shown below:

Peak Customer Demand Forecast
plus *Reserve Margin*
equals *Total Generating Capacity Obligation*

Total Generating Capacity Obligation
minus *Demand Response Capability*
and *Existing Generation Capacity as Measured by UCAP*
and *Generation Adjustments*
equals *Net Resource Need/Surplus*

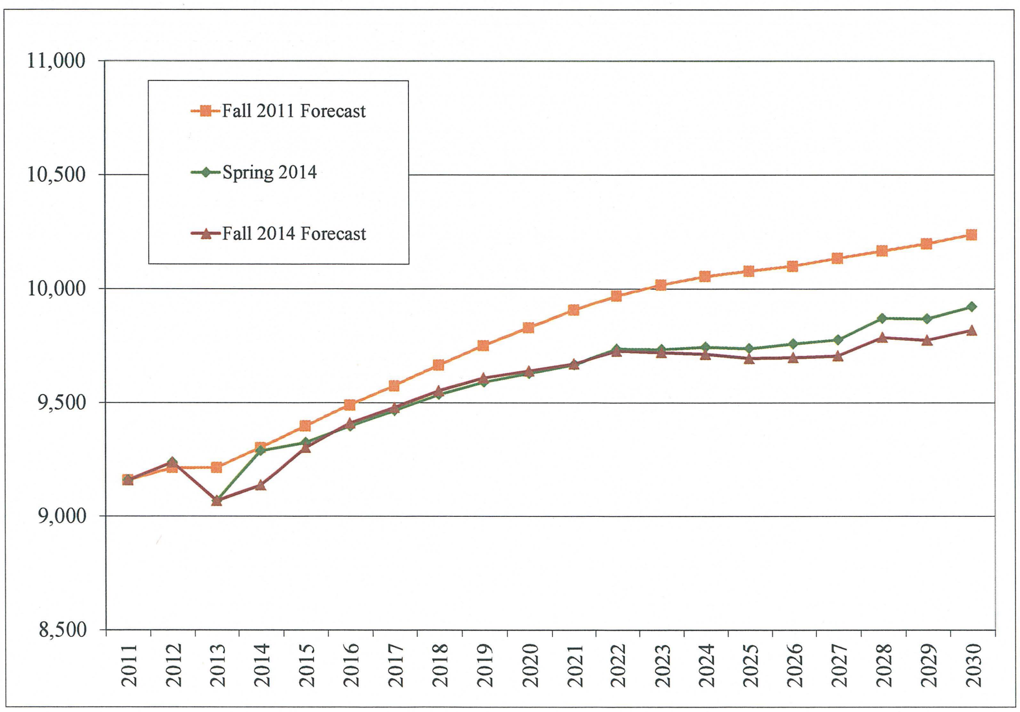
1. *Customer Needs Forecast*

When forecasting our customers' energy needs, we assess both their needs for energy and capacity. This analysis starts with a capacity, or peak demand, assessment, which informs the *amount* of generating resources needed to meet the peak-hour of energy requirements of our customers in each year of the planning period. We also assess the amount of energy we expect customers to consume in each year of the planning period, which helps to inform the *type* of generating resources we need to meet their needs.

a. Peak Demand Requirements

We use econometric analysis and the historical actual coincident net peak demand data for our customers to determine the Peak Demand requirements for the planning period. We forecast a period of relatively flat growth such that our median base peak will increase only 0.4 percent in each year of the planning period, which we show in comparison to the historical NSP System peak demand in Figure 4 below.

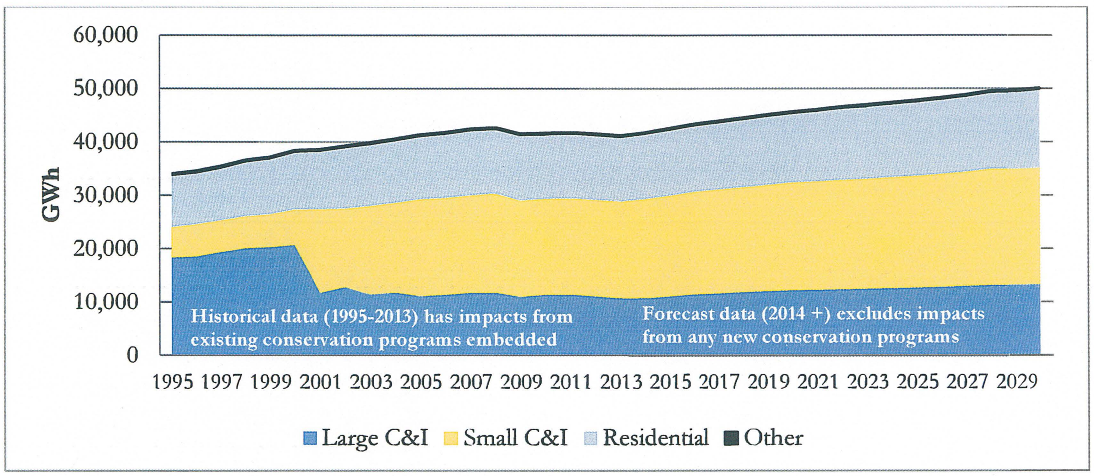
Figure 4: Historic and Forecast Peak Demand



b. Energy Requirements

In terms of electric energy requirements, we also forecast relatively flat average annual growth of 0.4 percent over the planning period. This level of growth is consistent with the actual growth we have seen over the past few years. When the economic recession hit in 2008, electric retail customer growth slowed, and was followed by very weak growth in 2009. We saw some recovery in 2010, but then growth slowed again in 2011 and 2012. Growth has continued to be relatively slow at 0.4 percent. Figure below shows NSP System historic and forecast energy requirements by customer class.

Figure 5: Historic And Forecast Annual Retail Sales By Class
(Losses not included)



c. Forecast Adjustments

To improve the accuracy of our forecasts, we make adjustments to account for the impact of events or trends we reasonably expect to occur in the planning period. We summarize our key adjustments below:

Demand Side Management. In addition to adjusting the forecast to account for our expected achievement of 1.5 percent of annual retail sales, we made an adjustment to recognize the decline in customer use that is resulting from changes in codes and standards that are being adopted at an accelerated pace, but fall outside of our DSM programs. In addition to discussing the specifics of this adjustment in our Forecasting Appendix, we provide a further discussion of this and other impacts to our expected DSM performance in the planning period in Appendix G.

Small Scale Customer Solar Generation. To properly recognize the impact of Minnesota's SES during the planning period, we developed a forecast that reflects the impact we expect on customer demand and energy from our small-scale solar programs.

Expected Customer Changes. We have made adjustments to account for planned changes in production levels for several large customers in Minnesota and Wisconsin. The most significant of these changes impacting both energy and demand began in late 2013 and is expected to continue through 2019.

The drivers of our expected moderate growth are continued moderate economic indicators and the continued decline in use per customer in the Residential and Small Commercial and Industrial classes that we have been seeing for several years. We provide a more detailed discussion of our forecasting process, inputs, assumptions, adjustments and results in Appendix I. We also discuss the decline in use per customer in Appendix G, in conjunction with our outlook for customer energy efficiency savings over the planning period.

2. *MISO Resource Adequacy Requirements Process*

MISO administers an annual Resource Adequacy process to assist with the provision of adequate reliability of the bulk electric supply system by requiring LSE resources to exceed their level of demand by an adequate margin. While a reliability view addresses both near-term operations and longer-term planning, Resource Adequacy focuses on the longer-term need to provide sufficient resources to reliably serve load on a forward-looking basis – which is what is needed for Resource Planning.

The Company is one of over 140 Load Serving Entities (LSE) that MISO has across 15 states. The company's load is nearly completely in Zone 1 of MISO's nine Local Resource Zones (LRZ or Zone).[17] MISO establishes LRZs to account for the strength of electrical interconnections between and among various subregions within MISO. [18]

[17] LRZ 1 includes almost all of Minnesota, western Wisconsin, and the Dakotas. Almost all of the NSP System load is within LRZ 1, with the exception of approximately 7 MW along the Minnesota-Iowa border, which is located in LRZ 3, which covers the Iowa region.

[18] LRZ boundaries are subject to change by MISO, which may be prompted by changes in MISO membership, or changes in resources or the transmission system. For example, the recent integration of southern LSEs created two new LRZs, expanding from seven LRZs to the present nine.

MISO's Resource Adequacy process establishes the margin by which resources are required to exceed demand in order to cover:

- Planned maintenance,
- Unplanned or forced outages of generating facilities,
- Deratings in resource capabilities,
- Variations in weather, and
- Load forecasting uncertainty.

MISO's planning period is an annual construct, which begins with the summer period. For example, the 2015/2016 planning period will extend from June 1, 2015 through May 31, 2016.

The "currency" used for determining LSE capacity obligations and to demonstrate sufficient fulfillment of Resource Adequacy is measured in terms of Zonal Resource Credits (ZRC), each of which are equivalent to one MW of capacity obligation or accredited resource capacity for the applicable planning period.

Prior to each planning year, MISO determines two different capacity obligations for each LSE; one for the entire MISO footprint as a whole, and one for the Zone where the LSE resides. For any particular planning year, an LSE's PRM is the greater of the LSE's capacity obligation for the MISO footprint or its capacity obligation for its LRZ.

i. MISO Footprint Capacity Obligation.

On November 1 prior to a planning period, MISO issues the finalized PRM applicable to all LSEs within MISO's footprint. MISO determines the PRM by performing a technical probabilistic analysis to determine the minimum PRM needed to achieve a MISO footprint Loss of Load Expectation (LOLE) of 0.1 day per year, expressed as a percentage. For example, for the planning year covering June 1, 2015 through May 31, 2016 the PRM is 7.1 percent.

Each LSE is required to have resources sufficient to meet the forecasted demand at the time of MISO's peak demand, plus its PRM margin. MISO's tariff acknowledges a state regulatory body's authority to establish a PRM for LSEs within its jurisdiction, and that would trump whatever PRM otherwise determined by MISO.

ii. Zonal Capacity Obligation.

Annually, MISO also determines the resources required within each Zone, known as a Local Clearing Requirement (LCR). Thus, separate LCR amounts are determined for each of the nine Zones. These values are a function of the LOLE Study.

The LOLE study determines a Local Reliability Requirement (LRR) for each LRZ. The LRR is the necessary resource requirement in order for a Zone to achieve an LOLE of 0.1 day per year, without relying on any resources outside of the Zone.

The fact that each LRZ (having a smaller footprint than the overall MISO footprint) does not receive the same level of peak load diversity benefits as does the larger MISO footprint which is comprised of multiple LRZ's, it can be expected that an LRZ's LRR is greater than the sum of the LSE's MISO footprint capacity obligations.

The LOLE Study includes a determination of the extent by which the transmission system will accept imports into, or exports out of, each Zone. A Zone's ability to import is referred to as its Capacity Import Limit (CIL), and its ability to export is referred to its Capacity Export Limit (CEL).

Each Zone's LCR for a particular planning year is equal to its LRR, minus its CIL (a Zone's LCR = Zone's LRR *minus* Zone's CIL). Each LSE's LCR is based on its share of the LRZ's demand at the time of the LRZ's peak demand (Zonal Coincident Peak).

If an LRA has sufficient CIL, the resulting LCR is usually low enough that its individual LSEs realize lower zonal capacity obligations compared to their respective MISO footprint capacity obligations.

This is the case for eight of MISO's nine LRZs for the 2014-2015 planning year. LSE's in Zone 8 (Arkansas) have a Planning Reserve Margin Requirement (PRMR) of 12.3 percent for this planning year instead of the 7.3 percent PRMR for the other eight Zones, because of limited CIL to draw on support from the rest of the MISO footprint.

Zone 1 currently has sufficient import capability to avoid its LSEs having zonal capacity obligations that are higher than their MISO footprint capacity obligations.

Therefore, we used MISO's 7.1 percent PRM for purposes of estimating our need for additional generation capacity for the Resource Planning period of 2016-2030.

iii. Capacity Obligations Derived from Forecasted Demands.

The LSE's MISO footprint capacity obligation and the LSE's zonal capacity obligation are both derived from the forecast of peak demand (peak load).

While LSEs typically forecast the peak demand for their individual system, the resource adequacy process requires the LSE to also forecast:

- The LSE's demand at the time of the MISO footprint's peak demand (MISO Coincident Peak Demand, or MISO CPD), and
- The LSE's demand at the time of the LRZ's peak demand (Zonal Coincident Peak Demand, or Zonal CPD).

Because the LRZ footprint is smaller than the MISO footprint, the load diversity is lower than the load diversity of the MISO system, and the LSE's resulting Zonal CPD is equal to or greater than its MISO CPD.

- Demand Forecasting Practices:
    - By November 1st of each year, LSEs submit their system demand forecasts for the upcoming June 1 – May 31 planning period.
    - System demand forecasts are based on the 50th percentile. A 50th percentile forecast is defined as one based on a 50 percent probability that actual demand will exceed the forecast and a 50 percent probability that actual demand will be below the forecast.

iv. Example Calculation of an LSE's Capacity Obligations

If an LSE's forecast for the upcoming planning year has the following demands:
LSE's MISO CPD (demand at time of MISO's peak demand) = 4,900 MW
LSE's Zonal CPD (demand at time of the LRZ's peak demand) = 5,000 MW

And if MISO makes the following determinations, for the upcoming planning year:
PRM (a MISO-wide determination) = 7.1%

LRZ's Zonal CPD = 17,500 MW (summation of LSEs' Zonal CPDs)

LRZ's LRR = 20,000 MW (a determination made for each LRZ through the LOLE study)
LRZ's CIL = 4,000 MW (a determination made for each LRZ through the LOLE study)
LRZ's LCR (LRR minus its CIL)= 20,000 MW – 4,000 MW = 16,000 MW

The LSE's MISO Footprint Capacity Obligation:
LSE's MISO CPD x (1 + PRM) =
4,900 MW x (1 + .071) = 5,247.9 MW
(or 5,247.9 Zonal Resource Credits, or ZRCs)

The LSE's Zonal Capacity Obligation:
LRZ's LCR x (LSE's Zonal CPD ÷ LRZ's Zonal CPD) =
16,000 MW x (5,000 MW ÷ 17,500 MW) = 4,571.4 MW (or 4,571.4 ZRCs)

The LSE's Planning Reserve Margin Requirement (PRMR):
The greater of the LSE's MISO Footprint Capacity Obligation or its Zonal Capacity Obligation, which in this case is its MISO Footprint Capacity Obligation of 5,247.9 ZRCs.

Alternative Hypothetical Scenario
If the LRZ was import constrained (CIL = 0 MW), its LCR would have been LRR – CIL, or 20,000 MW – 0 MW = 20,000 MW. In this case, the LSE's Zonal Capacity Obligation would have been:
LRZ's LCR x (LSE's Zonal CPD ÷ LRZ's Zonal CPD) =
20,000 MW x (5,000 MW ÷ 17,500 MW) = 5,714.3 MW, or 5,714.3 ZRCs.

Then, the LSE's PRMR would have been 5,714.3 ZRCs since it's Zonal Capacity Obligation (5,714.3 ZRCs) is greater than its MISO Footprint Capacity Obligation (5,247.9 ZRCs).

v. Capacity Accreditation of Resources.

<u>Qualification of Planning Resources</u>. MISO's tariff and business practices set forth procedures to enable various types of resources to be used to achieve Resource Adequacy. While there are different requirements among the various types of resources, common characteristics require resources participate in the annual registration process, requiring annual testing and reporting of capability or reporting

of historical output. Each resource must have firm delivery to load, and resources must be available throughout the entire planning period.

- Types of Planning Resources. Resources used to achieve MISO's resource adequacy requirements are referred to as Planning Resources. These consist of the following types:
  - Capacity Resources are physical Generation Resources (physical assets and purchase agreements), External Resources if located outside of MISO's footprint, and Demand Response Resources participating in MISO's energy and operating reserves market, available during emergencies.
  - Load Modifying Resources include Behind-the-Meter Generation and Demand Resources available during emergencies.
  - Energy Efficiency Resources are installed measures on retail customer facilities designed and tested to achieve a permanent reduction in electric energy usage while maintaining a comparable quality of service.

MISO's resource accreditation represents a measure of a resource's reliable contribution to the system's resource adequacy needs. A generator's operation, maintenance, and utilization directly impact the portion of nameplate capacity rating recognized as an accredited resource. So, instead of using installed or nameplate capacity (ICAP), MISO calculates an unforced capacity value (UCAP) for each resource:

- *ICAP Value* – Installed Capacity Rating - Capacity accreditation valuation begins with an annual testing of generating capability or historical output with the result being referred to as Generation Verification Test Capability (GVTC). This value is also referred to as the ICAP rating (ICAP = lesser of GVTC or Interconnection Service).

- *UCAP Value* – Unforced Capacity Rating - The generator's forced outage rate is typically based on the individual unit's historical performance. MISO will then apply a forced outage rate to the ICAP to determine the UCAP rating (UCAP = ICAP x (1 – Forced Outage Rate).

- *Intermittent Resources* (ex. Solar, Wind, Hydro) - An individual unit's historical performance during the peak hours of the planning period is utilized to determine the accredited capacity of the resource. Currently, these units are measured on historical performance during the operating hours of 1500 to

1700 in the months of June-August over the three most recent summers. Each site must have one complete historic period of data prior to unit accreditation.

- *Planning Resources* such a Demand Response have their UCAP ratings determined through other methods. For example, Demand Response UCAP ratings are determined through a documented process of placing a value on its effectiveness in load reduction.

3. Demand Side Management

We offer our customers opportunities to lower their energy use and manage their peak demand through our Conservation Improvement Programs. As discussed in the Planning Landscape section, despite the historic success of our DSM program, the environment for energy efficiency has changed since the Commission last examined our goals in our 2010 Resource Plan. In this Resource Plan, we propose continuing our current 1.5 percent of retail sales goal, which we believe is an aggressive, yet cost-effective DSM goal. We based our proposed goal on the outcome from several studies that we conducted over the recent past. For purposes of determining minimum system needs, the customer sales forecast has been adjusted by 1.5 percent to reflect our expected DSM achievement over the planning period.

Unlike energy efficiency, DR is based on a one-time reduction in a customer's demand, and MISO now requires that we register our DR resources annually. As we discuss in Appendix G, in today's landscape, it would be challenging to actively increase DR resources without knowing the future rules to which we will be held accountable. Therefore, while we recognize an opportunity to grow our existing DR portfolio from the Study we completed in compliance with the Commission's Order in our last Resource Plan, we forecast moderate growth of 76 MW through 2030, for a total DR portfolio of 1,009 MW of demand reduction by 2030. We continue to anticipate significant change in the portfolio over the next several years.

We discuss the studies that informed our expected energy efficiency and DR levels, our analysis, and the changing DSM landscape in more detail in Appendix G.

4. Existing Resources

Our current generating resources are comprised of a combination of nuclear, coal, wind, biomass, solar, hydro, natural gas and oil-fueled facilities. Our physical generating assets have a net maximum capacity of over 7,700 MW, including 300 MW of wind.[19] In addition to physical assets, our resources include over 3,200 MW of negotiated PPAs. Together, these provide over 11,000 MW of generation resources, of which almost 1,600 MW is supplied by wind.

a. Renewable Resources

We maintain a variety of renewable resources on our system. In total, we have approximately 2,150 MW of renewable capacity serving the NSP System, including:[20]

- 1,591 MW of wind (nameplate capacity)
- 260 MW of hydroelectric power
- 280 MW of biomass and landfill gas

b. Nuclear

Our Monticello and Prairie Island nuclear plants provide more than 1,500 MW of clean energy and capacity to our customers. Historically these units have monthly capacity factors of 90 percent or higher, and together provide approximately 28 percent of the energy that our Upper Midwest customers use.

c. Coal Fleet

Our coal fleet includes our Sherco Units 1, 2 and 3 in Becker, Minnesota and the Allen S. King plant in Bayport, Minnesota. Together, our coal fleet provides almost 2,500 MW of valuable base load and cycling generating capacity, and helps maintain our system reliability.

d. Natural Gas (and Oil-Fired) Fleet

Our natural gas fleet consists of three intermediate-type generation assets, providing 1,300 MW of capacity. Peaking-type resources are located at eight sites, providing almost 1,600 MW of capacity. These facilities provide valuable intermediate and peaking capacity for our system, and are designed to follow load and can be cycled as necessary to achieve this goal. Consequently, they provide important flexibility to our generation operations.

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[19] The Net Maximum Capacity (NMC) is defined as the unit's Gross Maximum Capacity less any capacity (MW) that is used for that unit's station service or auxiliary load.

[20] 200 MW of wind energy is also available, but not available as capacity, making the total nameplate capacity of wind to 1,791 MW, and total renewables to 2,350 MW.

For example, Blue Lake Units 1-4 are oil-fired peaking units that are dispatched only a few times a year to provide energy during peak demand periods. These four units have combined capacity of 157 MW. We believe we can accomplish a short extension to their operating life through 2023. Further, we anticipate only minor improvements and repairs in order to extend the life of these units through the 2020-2023 period. This work will require a small amount of capital, fixed and variable O&M. Consequently, our planning models assume this life extension.

5. *Net Resource Surplus/Deficit*

As described previously, our forecast of our customers' Peak Demand (*less 1.5 percent DSM*) and our MISO Resource Adequacy requirements results in our overall Total Generating Capacity Obligation. From this, we deduct our expected DR achievements and add the UCAP generating capacity of our various resource types to determine our net generation surplus or deficit.[21] As shown below, we anticipate a net surplus through 2023.

Table 4: Load and Resources 2016-2030 Planning Period

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Forecasted Load	9,442	9,525	9,597	9,649	9,674	9,694	9,754	9,748	9,766	9,798	9,868	9,962	10,136	10,151	10,251
MISO System Coincident	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%
Coincident Load	8,970	9,048	9,117	9,167	9,190	9,209	9,266	9,261	9,278	9,308	9,375	9,464	9,629	9,644	9,739
MISO Planning Reserve	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%
Obligation	9,607	9,691	9,764	9,818	9,843	9,864	9,925	9,919	9,937	9,969	10,041	10,136	10,313	10,329	10,431
	2016	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Load Management	1,009	1,021	1,033	1,044	1,056	1,067	1,078	1,090	1,101	1,103	1,098	1,094	1,089	1,085	1,080
Coal	2,372	2,395	2,395	2,395	2,395	2,395	2,395	2,395	2,395	2,395	2,395	2,395	2,395	2,395	2,395
Nuclear	1,648	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643
Natural Gas	3,451	3,476	3,476	3,465	3,465	3,465	3,465	3,465	3,137	2,824	2,298	2,047	1,812	1,812	1,812
Biomass/RDF/Hydro/Wind	1,341	1,339	1,316	1,279	1,205	1,437	1,430	1,383	1,310	461	451	407	318	300	299
Solar	25	131	137	143	149	156	165	175	187	202	221	242	269	301	339
Existing Resources	9,846	10,004	9,999	9,970	9,913	10,164	10,176	10,150	9,772	8,628	8,106	7,827	7,526	7,536	7,569
Net Resource (Need)/Surplus	239	313	234	151	70	300	251	231	(165)	(1,341)	(1,936)	(2,309)	(2,788)	(2,793)	(2,862)

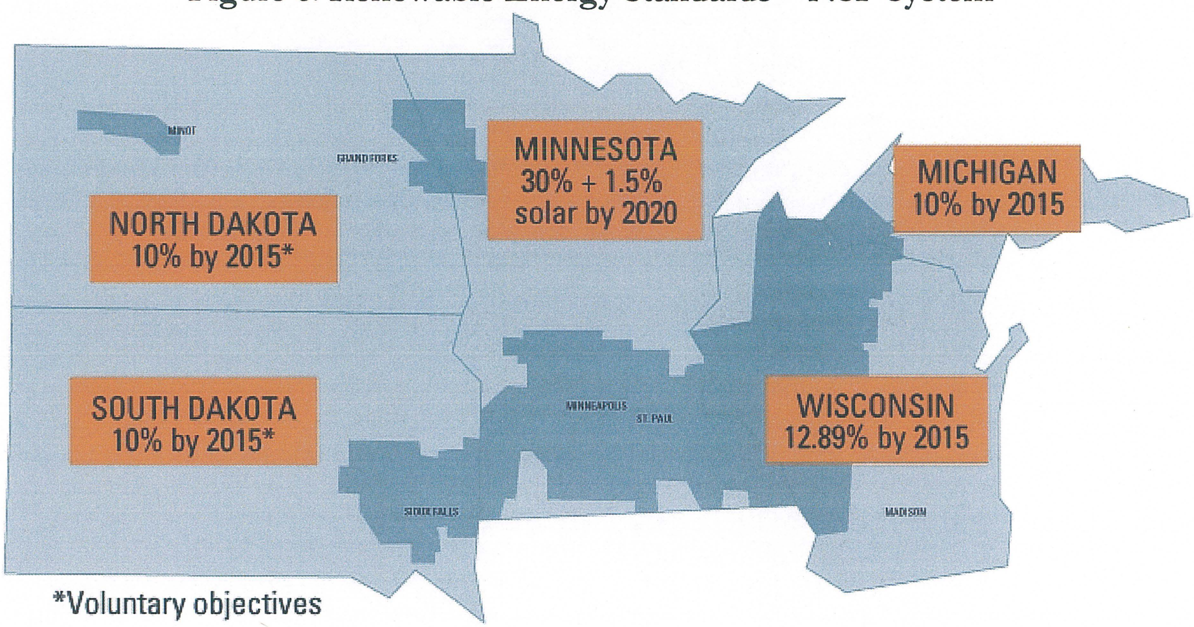
21 UCAP is a generating resource's production capability reduced by an amount to reflect unforced outages. We have used UCAP values based on each unit's average unforced outage rates over the last five years. We believe this calculation reasonably reflects MISO UCAP values over the long term. ICAP values reflect a generating resource's maximum generating capability without unforced outage adjustments and are not used in MISO's resource adequacy process. As requested by the Commission we have provided a load and resources table using ICAP which can be found in Appendix J.

B. Meeting Renewable Energy Requirements and Goals

1. *Minimum Compliance Requirements*

Each of the states within our multijurisdictional service territory has a different public policy with respect to renewable energy requirements. Figure below illustrates the renewable energy standards for each state in the NSP System.

Figure 6: Renewable Energy Standards – NSP System



North Dakota and South Dakota each have a voluntary objective that includes renewable or recycled energy.[22] Further, our North Dakota regulators have indicated that compliance with the North Dakota Renewable Energy Objective should be accomplished with competitively-priced energy. The remaining states have standards, expressed as a percentage of electric retail sales from qualifying resources by a certain date. Minnesota's RES is the most stringent, and also includes interim targets of 18

[22] As defined in North Dakota Century Code, 49-02-25, recycled energy means "systems producing electricity from currently unused waste heat resulting from combustion or other processes into electricity and which do not use an additional combustion process. The term does not include any system whose primary purpose is the generation of electricity unless the generation system consumes wellhead gas that would otherwise be flared, vented, or wasted." South Dakota Codified Law 49-34A-94 contains a similar definition.

percent by 2012 and 25 percent by 2016, and requires that 25 percent of the electricity it provides at retail come from wind energy by 2020.[23]

Legislation passed in the 2013 session established an SES for Minnesota that requires that investor-owned utilities in the state generate 1.5 percent of 2020 retail sales, net of customer exclusions, from solar energy resources. Of the 1.5 percent, 10 percent must come from systems with capacity less than 20 kW. The legislation also established a goal of 10 percent of energy sales from solar by 2030.

We have been implementing a strategy to meet the most stringent renewable energy requirements which would, by default, mean we have met the requirements in our other jurisdictions. This strategy has meant that we have been planning for renewable energy additions, and allocating their benefits, to all of our jurisdictions. As state energy policies continue to diverge, we expect that it may be necessary to engage with our state regulatory Commissions to determine if a change in strategy is necessary.

2. *RES Compliance*

With recent renewable resource additions scheduled to begin operation in 2015, we project sustained compliance with the renewable energy goals and standards in each of our NSP states. Our early actions to add renewable resources to our portfolio have positioned us well to achieve these goals and have produced other important benefits, including hedging against volatility in fuel markets. Perhaps most importantly to our ratepayers, we added these generation resources at a time when renewable generation, wind energy in particular, was a low cost resource relative to other alternatives.

The Company currently maintains a set of banked Renewable Energy Credits (RECs) for future compliance.[24] Our REC bank allows us to manage the type, size, and timing of renewable energy additions on our system to ensure that we identify and acquire the renewable generation resources that provide our customers with the greatest value at the lowest cost. We currently generate sufficient RECs annually to deliver approximately 18 percent of the energy we provide our NSP customers from

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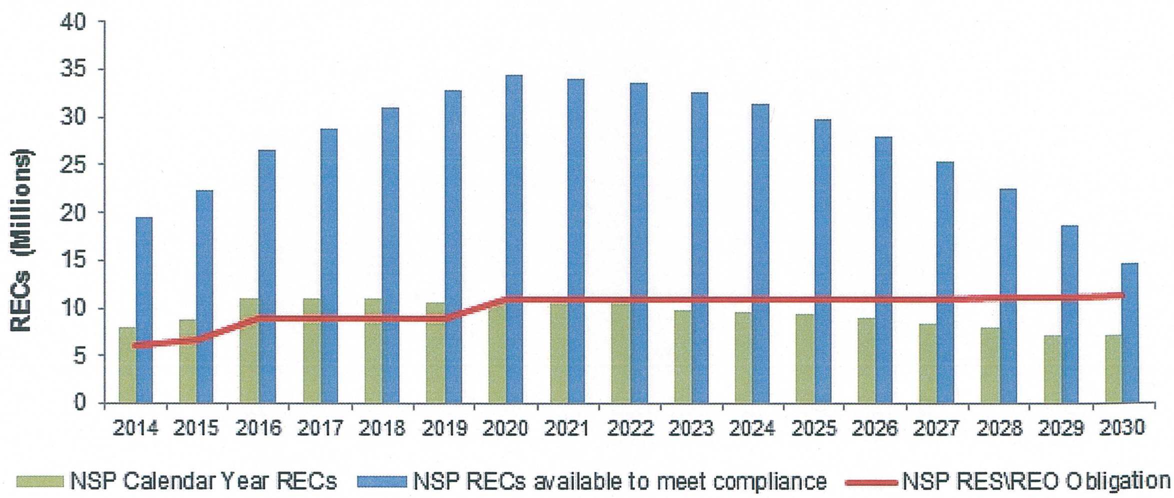
[23] This requirement is included in the total 30 percent RES, and we are authorized to count a limited amount of solar energy towards this 25 percent. Large hydro does not count as a renewable energy source for purpose of the Minnesota RES. Minn. Stat. § 216B.1691

[24] RECs are the renewable energy attributes associated with each kilowatt-hour of renewable energy generation, and are the currency for compliance with state renewable targets.

eligible renewable resources.[25] This amount is expected to exceed 21 percent by the end of 2015.

Figure 7 below illustrates available and annually generated RECs across the NSP System, with no new resource additions. In this base case scenario, we will have sufficient RECs to comply with the renewable energy goals and standards of all of our NSP states through 2030 without securing additional renewable resources.

Figure 7: Baseline RES Compliance For NSP System



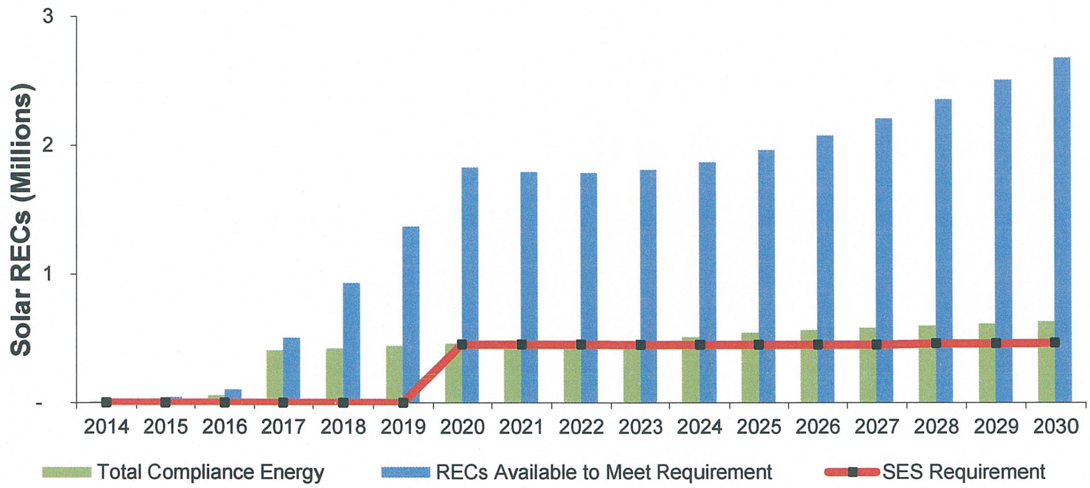
3. *SES Compliance*

With the proposed addition of 187 MW of utility-scale solar by 2017 resulting from our 2014 Solar RFP and our small retail solar offerings projected to reach about 100 MW by 2020, we estimate that we will have more than enough Solar Renewable Energy Credits (S-RECs) to meet the SES. In its April 25, 2014 Order in Docket No. E999/CI-13-542, the Commission ruled that S-RECs used for compliance with the 2020 requirements of the SES could be accrued beginning in August 2013 and would have a four-year shelf life commencing January 2020. Our existing solar incentive programs operating in 2013 – Solar*Rewards and Minnesota Bonus – accrued 26 S-RECs that can be banked for future compliance.

[25] RECs are the renewable energy attributes associated with each kilowatt-hour of renewable energy generation, and are the currency for compliance with state renewable targets.

Figure 8 below demonstrates our compliance with the SES, based on available and annual generated S-RECs, for the Reference Case scenario.

Figure 8: Baseline SES Compliance for Minnesota



More details on our existing renewable energy resources and programs, our renewables acquisition plan, barriers, considerations and opportunities for further solar development, and our proposal to meet the compliance requirements can be found in Appendix E.

C. Energy Policy Goals

As demonstrated, we believe that we can meet our minimum system needs through at least 2020. This reality prompted us to analyze whether we can meet any policy *goals* during this period. To that end, we identified an opportunity to meet Minnesota's interim goal of 30 percent by 2025, and our commitment to meet this goal sooner – in 2020 – during this period of no customer-based need. We have determined that adding approximately 400 MW of wind to the integrated NSP System by 2020 will allow us to initially achieve 30 percent by 2020. Therefore, we have included initial achievement of the 30 percent CO_2 reduction goal into our Reference Case.

D. Reference Case

We incorporate all of these elements into Strategist, which allows us to fully explore how we best meet our customer and policy requirements under a variety of conditions, and at a reasonable cost. We work with internal and external subject matter experts to characterize our current system, and to develop starting assumptions that accurately reflect the expert opinion of likely future conditions. We then test the robustness of the plans through sensitivity analysis by individually changing key assumptions (such as future fuel prices) and re-running the plans under these changed assumptions. Our analysis resulted in our Reference Case Expansion Plan, which we outline in Table 5 below:

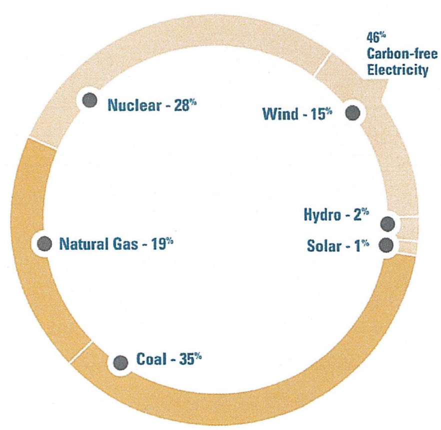
Table 5: Reference Case Expansion Plan

Reference Case

Resource	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Resource	Total
Small Solar	18	18	14	13	13	13	13	13	13	13	13	13	13	13	13	13	Small Solar	219
Large Solar	-	-	187	-	-	-	-	-	-	-	-	-	-	-	-	-	Large Solar	187
Wind	-	-	-	-	-	400	-	-	-	-	-	-	-	-	-	-	Wind	400
CT	-	-	-	-	-	-	-	-	-	219	1,095	657	-	219	-	-	CT	2,190
CC	-	-	-	-	-	-	-	-	-	-	-	-	778	-	-	-	CC	778

This plan results in the following energy mix by 2030:

Figure 9: Reference Case Energy Mix - 2030



We outline and discuss the starting assumptions, scenarios, and sensitivities that formed our Strategist analysis and resulted in our Preferred Plan below and in Appendix J.

V. THE PREFERRED PLAN

A. Overview

The Preferred Plan we outline in this Resource Plan builds upon a strong foundation that we have created through our current investment cycle, of which we are crossing the peak. As we noted earlier, the Commission's decisions in our CAP docket were issued very close in time to the finalization of this Resource Plan filing, so we were unable to incorporate the outcomes into this Plan. We expect the outcomes of that docket, as well as very recent higher-than-expected solar garden applications and the development of other issues, to likely affect the cost, need, and timing of our future investments.

However, we also find ourselves also with an unusual luxury of time given that we currently project that we will have sufficient resources to meet customer need and satisfy various renewable energy and solar requirements into the early- to mid-2020s without adding additional assets. We propose to use this time wisely to further assess and discuss our Preferred Plan and the evolving planning landscape presently facing the utility industry.

Over the longer-term, we face more change as key assets on our system begin to expire. Our Preferred Plan begins the process to strategically address the evolution of the NSP System. Currently, plans call for the operation of the Blue Lake Units 1-4 oil-fired peaking units to continue through 2023, resulting in a 153 MW accredited capacity reduction, which the Preferred Plan offsets with combustion turbine additions in 2024. In 2025 about 850 MW of Manitoba Hydro contracts expire. Our Preferred Plan adds 876 MW of combustion turbines to meet capacity needs, and 600 MW of wind generation, 400 MW of large solar, and 33 MW of small solar in 2025 to address the loss of these contracts.

In 2026 and 2027, the 262 MW contract for output from the Cottage Grove Combined Cycle Energy Center and the 357 MW contract for output from the Mankato Combined Cycle Energy Center expire. Correspondingly, during this time, our Preferred Plan would add 657 MW of combustion turbines to meet capacity needs and 400 MW of wind, 500 MW of large solar and 88 MW of small solar energy resources are added to meet energy needs.

Beyond the Planning Period, in 2030, our license to operate our Monticello nuclear plant expires, and in 2033/34 our licenses for our Prairie Island nuclear plants expire.

Given this, and combined with consideration of the future of Sherco Units 1 and 2, we must maintain strategic flexibility to add and replace resources in a prudent manner while providing a substantial hedge against natural gas price increases.

Therefore, the Preferred Plan we propose is based on a longer-term look at the needs of the integrated NSP System – and is driven largely by shifts in the planning landscape. Based on our in-depth analysis of potential options, we analyzed many scenarios that balance policy goals and system costs to develop a Preferred Plan that allows us to meet and exceed the expectations of our regulators, customers, and other stakeholders.

B. Key Considerations

To meet our long-term goals and develop a Preferred Plan, our key considerations include: (1) building upon a solid foundation for meeting our customers' demand for electricity in light of our current investment cycle; (2) the strategic addition of renewable generation to further our compliance position and progress toward Minnesota's renewable energy and CO_2 reduction goals; (3) achieving the policy goals in a cost-effective manner; (4) preserving strategic flexibility; and (5) constructively addressing the future of Sherco Units 1 and 2.

1. Solid Foundation

Our current investment cycle, of which we are crossing the peak, has laid a solid foundation upon which we can build this Resource Plan. Our recent investments have allowed us to maintain and build our system to continue to meet our customers' electricity needs in a cost-effective manner. These investments have also provided us the luxury of time to position us to address the planning landscape, especially an evolving NSP System over the course of the planning period (and retain flexibility to address challenges beyond the planning period) of this Resource Plan. Our Preferred Plan is intended to allow our customers to obtain all of the value of the investments we have made over the past several years. Key investments that have provided this solid foundation include:

- *Nuclear operations.* We have recently completed a series of life-cycle management investments at our Prairie Island and Monticello nuclear plants to extend their lives through the end of the planning period. These investments have allowed us to maintain the 1,600 MW of carbon-free, baseload power capabilities these key facilities provide. These investments provide the core of our solid foundation toward a reduced CO_2 future.

- *Coal fleet.* We have made significant investments in our coal fleet to allow us to use these low-cost, baseload facilities through the planning period. Investments include the addition of emission reduction technologies at our King and Sherco plants to sustain long-term compliance with existing environmental regulations. Additionally, we have continued to invest in maintaining these plants to sustain efficient and reliable operations.
- *Supporting infrastructure.* We have made significant investments in new transmission facilities to continue to reliably serve our customers and provide the necessary infrastructure to support the continued addition of renewables to the NSP System. Investments include the CapX2020 Group 1 Projects, as well as additional transmission facilities such as the La Crosse – Madison 345 kV transmission project. Additionally, with a significant number of small solar projects requesting to interconnect with the distribution system, we are upgrading our distribution system capabilities to sustain its current safe and reliable service to customers.
- *New wind facilities.* We recently entered into contracts for 750 MW of low-cost additional wind facilities to be added to our system in 2015. These new facilities provide additional renewable energy to meet system energy needs, with the additional benefit of limiting reliance on natural gas in order to reduce fuel price risk exposure and contribute to our renewable energy compliance obligations.
- *Solar facilities.* We are currently awaiting Commission action on proposed Power Purchase Agreements comprising a 187 MW of utility-scale solar resource portfolio. Our analysis, which assumes these additions will be made to the integrated NSP System, indicates that these additions, coupled with growing small-scale, customer-based solar generation, will allow us to cost-effectively meet our 1.5 percent SES compliance obligation.

2. *Renewable additions*

Our Preferred Plan is centered around the strategic addition of renewable energy facilities to position us well in this planning landscape. Not only does the addition of renewable resources allow us to further our compliance position with respect to Minnesota's RES and SES, but they are also expected to increase our carbon-free energy to over 60 percent by 2030 in anticipation of increased GHG-related regulatory requirements. In addition, the influx of renewables on the NSP System will reduce MISO's dispatch of our thermal generating fleet, which will contribute to achievement of a 40 percent CO_2 reduction by 2030.

a. Compliance Requirements

Through the solid foundation we have built, our renewable energy compliance obligations are being met for the near future. Our planned 187 MW of solar utility-scale solar additions, coupled with customer-based solar expansion, will allow us to more that meet the 1.5 percent SES through the planning period. We have sufficient wind and other renewable resources on the integrated NSP System to sustain our compliance requirements in the states we serve through the planning period.

b. Beyond Compliance

The key components of our Preferred Plan is the use of renewable energy to address the planning landscape of this Resource Plan. The use of renewable energy helps us to achieve CO_2 emissions reductions to meet potential GHG requirements. Further, significant renewable energy additions also allow us to mitigate our gas exposure through the use of combustion turbines to back the renewable energy additions instead of the utilization of combined cycle gas fired units to meet our capacity and energy needs thereby satisfying other needs for flexibility, fuel diversity, and reliability.

Our continued strategic addition of wind generation has placed us on a path to further meet and exceed our renewable obligations in all the states we serve. Our analysis indicates that adding 600 MW of wind capacity by 2020 smoothes our path to achieving a 40 percent reduction in CO_2 emissions by 2030. This 600 MW of additional wind is a foundational element of our Preferred Plan and our five-year action plan.

3. Strategic Flexibility

Because the utility industry is in the midst of a period of evolution and this Resource Plan is focused on the out years of the planning period, maintaining strategic flexibility is a key component of our Preferred Plan. Significant issues for which optionality is a key consideration include:

- *Environmental Regulation.* Environmental requirements that impact our system are in a period of significant change. The EPA has proposed its existing source Clean Power Plan, and that proposal is in the process of being finalized. Further, Regional Haze Rules and other environmental regulations will also impact our generation fleet. Maintaining flexibility to comply with these requirements will be an important of the Preferred Plan over the course of the planning period.

- *Evolution of the NSP System.* The planning period addressed in this Resource Plan has unique attributes that have shaped the flexibility we have factored into our Preferred Plan. While we have no immediate resource needs during the first years of the planning period, in the out years, several key resources, such as the Manitoba Hydro power purchase agreement will expire. Additionally, beyond the planning period, our nuclear licenses will expire and as well as the Cottage Grove and Mankato Energy Center PPAs. We view this Resource Plan as the first of several where the Company, the Commission and our other stakeholders will develop plans to meet the needs of the evolving NSP System. This Resource Plan can allow us to take the time to make decisions in a thorough and thoughtful manner. As discussed in more detail below, our Preferred Plan is intended to provide us with strategic flexibility and result in an energy mix that does not make us overly reliant on natural gas fired energy by 2030. This is an important outcome, so that we have sufficient flexibility to consider economical retirement options for our baseload fleet.

- *Tax Incentives.* The ITC and PTC provide material reductions in the cost of renewable energy. For example, our recent acquisition of 750 MW of wind was made significantly more cost-effective due to the continuation of the PTC. Similarly, the 187 MW of utility-scale solar that we recently proposed to add to our portfolio was made cost-effective by the current 30 percent ITC. Historically, the ITC and PTC have existed within a volatile expiration and renewal cycle such that it is difficult to plan and ensure that we can capture these incentives when needed for compliance. Consequently, our Preferred Plan contemplates strategic flexibility as to when we add renewable energy to our system to be able to capture these types of incentives. We note, however, our Preferred plan remains cost-effective even if similar incentives are no longer available.

- *Emerging Technology.* Renewable generation technology has continued to evolve by becoming more efficient and therefore more cost-effective. This is especially the case with solar photovoltaic technology. We believe it appropriate to maintain strategic flexibility for implementation of the Preferred Plan to help ensure reasonable opportunity to capture cost and efficiency gains provided by emerging and evolving technologies, as well as from added competition in the marketplace.

- *Market Conditions.* As the utility industry evolves, it adds another level of complexity to definitively predicting future customer demand, contract pricing, construction costs, natural gas prices, MISO rules, and other issues that affect customer costs. By retaining the flexibility as to when we make the resource additions contemplated by our Preferred Plan, we are able to adjust and adapt to changing market circumstances.

4. Cost Effectiveness

We are mindful that our current investment cycle and proposed addition of resources to achieve Plan goals must be achieved in a cost-effective manner. Our analysis was focused on identifying the reasonable mix of furthering strategic outcomes at reasonable cost. Through this work, our Preferred Plan is expected to achieve strategic outcomes, including, 40 percent CO_2 reduction by 2030, with a cost impact limited to an average of approximately 2 percent on an annual basis above our Reference Case for the planning period.

5. The Future of Sherco

We recognize that the future of Sherco Units 1 and 2 is of fundamental interest to all of our regulators and other stakeholders. Through our Preferred Plan we present one potential vision for the future of Sherco. Specifically, our Preferred Plan assumes the continued operation of Sherco Units 1 and 2 through 2030.

We believe that the earliest further NO_x reductions could be required on Sherco Units 1 and 2 is in the mid-2020s timeframe. However, this depends on as-yet unresolved litigation and future regulations. There are a myriad of potential outcomes based on the pending litigation and future regulations that impact our proposal for Sherco. Therefore, building off of the analysis we undertook in the Sherco LCM Study and based on information we know to-date, we believe that we can continue to operate Sherco Units 1 and 2 through the planning period without making significant investment in SCRs, recognizing that operation beyond 2030 without SCRs is unlikely. However, the outcome of pending environmental regulations may change this analysis.

While we believe our Preferred Plan presents a reasonable approach considering these and other uncertainties, we have analyzed several scenarios with respect to the future of Sherco. These include ceasing operation of one unit in 2025, ceasing operations of two units in 2025, and continued operation of Sherco Units 1 and 2 through the planning period. The scenario under which we propose our Preferred Plan does not have us installing SCRs on Sherco Units 1 and 2 in the planning period, rather awaiting greater clarity on these regulatory and legal developments. In the event that future developments clarify that further NO_X emission reductions are required by a given year, we will consider whether SCR installation, unit retirement or another action is in our customers' interests, and propose a strategy in a future integrated resource plan.

We recognize that the future of Sherco is of interest to the Commission and our other stakeholders. This Resource Plan presents several scenarios for analysis. We believe, however, that our Preferred Plan provides flexibility to address continued operation of Sherco when we have more clarity on pending environmental regulations – and allows our customers to continue to benefit from our investments in these low-cost baseload resources while still achieving a 40 percent CO_2 reduction from 2005 levels in a cost-effective manner.

C. Expansion Plan

Based on our analysis, our Preferred Plan achieves a 40 percent CO_2 emissions reduction by 2030 in a cost-effective manner, while maintaining needed flexibility to address the evolving utility landscape. Our Plan relies on strategic addition of emission-free renewable energy facilities above and beyond our actual load-serving and minimum compliance obligations to offset the operation and associated emissions of our thermal generating facilities. We also preserve important flexibility to capture tax incentives, such as the ITC or PTC, should they become available during the planning period, as well as to address currently contemplated environmental regulations.

Key attributes of our Preferred Plan include:

Wind. We propose total wind additions of 1,800 MW during the planning period, with our initial 600 MW addition in 2020 to achieve a 30 percent CO_2 emissions reduction by 2020 and smooth our path to 40 percent by 2030.

Utility-Scale Solar. We propose adding 1,700 MW of utility-scale solar resources, which is in addition to the 187 MW we proposed be added to our system to meet our 2020 SES compliance requirement before the 30 percent ITC ratchets down to 10 percent at the end of 2016. We would expect to make our next utility-scale solar resource acquisition in 2024, which we believe will allow sufficient time for technology improvements to result in cost reductions. This timing also supports our objective to reduce CO_2 emissions by 40 percent from 2005 levels by 2030 in a cost-effective manner for our customers.

Small Solar. We have assumed a relatively constant level of small solar additions in early years, increasing in the latter years of the planning period, which also reflects our assumption that solar technology costs will continue to drop with an corresponding increase in customer interest in small solar. Our Preferred Plan allows us the flexibility to adjust our resource additions as we gain more experience with customer interest in small-scale solar generation, which after seeing the initial response to our Community Solar Gardens program launch, we believe will be above the penetration our analyses currently assumes.

Natural Gas Additions. We do not anticipate the need to add thermal resources to the NSP System until 2025, because the timing and magnitude of renewable resource additions will provide substantial energy that defers the need for a thermal addition. However, our Preferred Plan identifies the fact that natural gas-fired generation will likely be necessary to meet our capacity needs in a cost-effective manner over the long-term.

That said, our Preferred Plan focuses on low cost natural gas capacity through the addition of combustion turbine peaking facilities (rather than combined cycle gas additions) to mitigate our gas exposure during the planning period. This will allow us the flexibility to evaluate combined cycle replacements for key facilities beyond the planning period without significantly shifting our resource mix to be heavily reliant on natural gas-fired combined cycle generation. Additionally, reliance on lower cost peaking facilities for unmet capacity needs during the planning period helps to provide us additional flexibility as we begin to examine the future of nuclear fleet and other changes to the NSP System that will occur shortly after the end of the planning period.

Table 6 below presents the amount and timing of resource additions we propose.

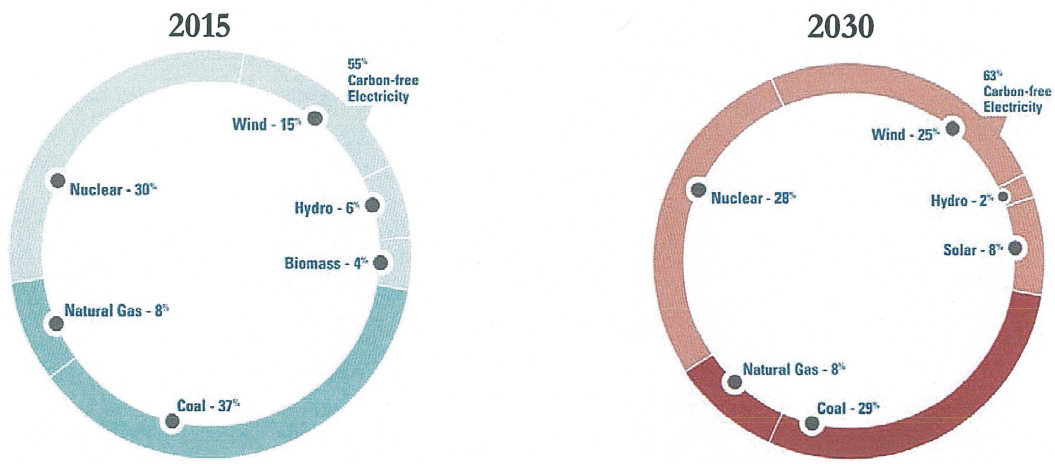
Table 6: Preferred Plan Resource Additions

Preferred Plan

Resource	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Resource	Total
Small Solar	18	18	14	13	13	13	16	19	23	28	33	40	48	58	69	83	Small Solar	506
Large Solar	-	-	187	-	-	-	-	-	-	100	400	300	200	500	-	200	Large Solar	1,887
Wind	-	-	-	-	-	600	-	-	200	-	600	-	400	-	-	-	Wind	1,800
CT	-	-	-	-	-	-	-	-	-	-	876	438	219	219	-	-	CT	1,752
CC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	CC	-

Implementation of our Preferred Plan would result in the following resource mix:

Figure 10: Energy Mix – Preferred Plan



From an energy mix perspective, the Preferred Plan reduces coal energy contribution by 8 percent and increases renewable energy contribution by 17 percent by 2030. The Preferred Plan's energy mix also achieves at a least a 40 percent reduction in CO_2 emissions from 2005 levels by 2030. Wind and Solar energy contributions increase to 25 percent and 8 percent of NSP System energy requirements by 2030, compared to only 1 percent Solar and 15 percent wind in the Reference Case in 2030.

D. Five-Year Plan

Our Preferred Plan does not require any additional capacity resources through 2020; thus our actions in the next five years are primarily steps to:

- Continue to provide the benefits our previous investments to our customers by preserving our existing and cost-effective base load generation while reducing CO_2 emissions,
- Propose addition of renewable energy resources to take advantage of cost-effective opportunities, which in turn enable us to achieve a 30 percent by 2020 reduction in CO_2 emissions,
- Continue to achieve reductions in energy and capacity needs through innovative and effective DSM and DR programs, and
- Invest in our transmission and distribution systems to accommodate increased renewable energy and distributed generation.

We therefore present the following five year action plan:

Wind. We expect that the 750 MW of wind generation resulting from our 2013 RFP will achieve commercial operation in 2015. If PTCs are extended beyond 2014, we propose to issue an RFP in 2015 to add up to 1,000 MW of additional wind resource that achieves commercial operation by December 2017. If no PTC incentive has occurred by 2018, we propose to issue an RFP in 2018 to add 600 MW of non-PTC wind by 2020 to meet our identified CO_2 reduction objectives and further buffer our compliance with renewable energy requirements.

Solar. We have proposed adding 187 MW of utility-scale solar, which is pending the Commission's consideration. If the Commission approves the portfolio of solar resources we proposed in early in 2015, we anticipate that these projects will be operational by the end of 2016. Additionally, we will continue implementing small-scale solar programs to add additional solar energy to the system.

Hydro. We anticipate adding 75 MW of energy and capacity through a new diversity agreement with Manitoba Hydro in 2015.

Natural Gas/Oil Peaking. We anticipate retiring all three Combustion Turbines at our Key City facility in 2015. And, we anticipate extending the life of Blue Lake Units 1-4 through 2020-2023, providing 153 MW of capacity to the NSP System.

Coal. We will retire the coal-fired Blackdog Units 3&4, comprising 230 MW, in 2015.

North Dakota Restack. We continue to work through negotiations, and in 2015, intend to seek approval of the North Dakota Public Service Commission on a System Restack proposal. We believe additional discussions with all of our state Commissions will be necessary during the five-year action planning period to address divergent energy policies and changes in cost allocations that may result.

E. Long-Term Plan

By 2020, we expect we will have achieved a 31 percent CO_2 reduction from 2005 levels, positioning us to achieve 40 percent by 2030. We will largely achieve this by adding nearly 4,000 MW of new renewables during the 2020-2030 time period, including 1,800 MW of non-PTC wind, 1,700 MW of utility-scale solar resources, and approximately 500 MW of small-scale solar resources as distributed generation.

We further recognize Minnesota's goal of achieving 80 percent CO_2 reduction by 2050. The Next Generation Energy Act includes a statewide goal to reduce GHG emissions "across all sectors producing those emissions… to a level at least 80 percent below 2005 levels by 2050."[26] In its 2014 session, the Minnesota Legislature passed energy legislation that includes the following provision:

> *Long-range emission reduction planning.* Each utility required to file a resource plan under subdivision 2 shall include in the filing a narrative identifying and describing the costs, opportunities, and technical barriers to the utility continuing to make progress on its system toward achieving the state greenhouse gas emission reduction goals established in section 216H.02, subdivision 1, and the technologies, alternatives, and steps the utility is considering to address those opportunities and barriers.[27]

Since we already project achievement of the goals for 2015 and 2025, we address here only the costs, opportunities, and technical barriers relative to the 2050 goal.

A CO_2 reduction of this magnitude implies a complete transformation in the way electricity is produced and used in the Upper Midwest. Our CO_2 emissions of 30.6 million tons in 2005 would need to decline to about 6 million tons per year by 2050.[28] This would mean an electricity generation, transmission, distribution and storage system that is largely carbon-free, supported by a small fossil fuel share – probably highly efficient natural gas combined cycle and combustion turbines – used primarily for integrating intermittent renewables, and to a limited extent for peaking power and ancillary service needs.

Importantly, each increment of CO_2 reduction may be more challenging and costly than the last. We expect to reduce CO_2 emissions 30 percent below 2005 by 2020 – and in this plan anticipate reaching 40 percent below 2005 levels by 2030 – but the steps needed to go from 40 percent to 80 percent reduction are qualitatively different.

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[26] Minn. Stat. § 216H.02, subd. 1.

[27] HF2834, signed into law May 16, 2014, Sec. 13 Subd. 2c. The City of Minneapolis has adopted a similar goal, but using a 2006 rather than 2005 baseline. An 80 percent reduction from NSP's 2006 CO_2 emissions from owned and purchased power (32.5 million tons) would allow slightly higher annual CO_2 emissions as compared to the Minnesota goal, or 6.5 million tons.

[28] This interprets the 80 percent reduction goal in reference to the CO_2 emissions from electricity supply (owned and purchased) of Northern States Power Company overall. The goal could instead be interpreted as applicable to NSPM electricity emissions, not the share assigned to NSPW, since Wisconsin does not have a GHG reduction goal comparable to Minnesota's; or as applicable only to CO_2 emissions from electric generating facilities physically located in Minnesota. However the NSP generation portfolio is operated as an integrated NSP System, with costs and revenues allocated per the FERC interchange agreement between NSPM and NSPW, and the Company generally does not attempt to split CO_2 emissions or emission reductions between NSPM and NSPW.

Initially, it was possible to retire relatively older, smaller and less efficient coal units, invest in the most cost-effective renewable resources, and invest in the "low-hanging fruit" among DSM opportunities. To reach 80 percent reduction implies:

- Retiring larger, highly efficient and cost-effective baseload coal units, whose generation is expensive to replace,
- Becoming more reliant on a single fuel (natural gas) to provide peaking power and support and balance high levels of intermittent renewable generation integration,
- Relying on higher levels of renewable resource additions and significant transmission additions to support reliable delivery of renewable energy to customers from these generation resources,
- Capturing more difficult and costly DSM savings, and
- Managing reliability in a power supply system increasingly made up of variable intermittent resources (solar and wind), particularly in the absence of proven commercial-scale energy storage technologies.

We believe that our Monticello and Prairie Island nuclear facilities will be essential to achieving Minnesota's 80 percent by 2050 CO_2 emissions reduction goal, and the EPA's 2030 Clean Power Plan objectives. The recent lifecycle management investments made these facilities at have positioned the plants to operate safely and reliably for more than 60 years. The decision whether to continue to operate the plants beyond the current 60-year operating license that expires in 2030 will fall within the 15-year planning period of our next Resource Plan.[29] Our Preferred Plan provides us the flexibility to address the future of nuclear fleet in a responsible manner.

For additional detail on the Company's status relative to the 2015 and 2025 CO_2 reduction goals, and the costs, opportunities, and technical barriers relative to the 2050 goal, please see Appendix D. Additionally, achievement of these goals, without a concomitant federal requirement, will continue to impact the fact that policy goals of the states we serve continue to diverge. Over the out years of the planning period, we intend to implement proposals to address these divergent state energy policies and their ultimate impact on planning for the integrated NSP System.

[29] Operating the plants beyond their current 2030, 2033, and 2034 license expiration dates would require a number of state and federal regulatory approvals, with applications needed in the early 2020s.

VI. SELECTION OF THE PREFERRED PLAN

A. Overview

As previously noted, this resource planning process begins to signal a change in focus away from a more concentrated view of the capacity needs of the system to a plan that is focused more on a balance between the energy mix of the system, our emission profiles, and the need to retain strategic flexibility to address the evolving planning landscape and evolution of the NSP System. Building off of our Reference Case, this Chapter of our Resource Plan provides a detailed discussion of our process for assessing alternatives, developing representative scenarios, and identifying the Preferred Plan discussed in Chapter IV, above. We provide additional detail regarding our analysis in Appendix J.

B. Planning Framework

As mentioned in the previous chapters, this Resource Plan is being presented under unique circumstances where there is no near term needs to be met as well as at a time of evolution within the utility industry, and when the evolution of the NSP System is becoming a key consideration of our planning efforts. It is around these considerations that we developed our planning framework. Our Preferred Plan is a result of analysis that seeks to balance several important planning goals with, what we believe, are innovative strategies.

First, we strove to develop a plan that allows us to provide safe, reliable electric service in a cost-effective manner from within an uncertain planning landscape. We developed a framework to analyze different scenarios and sensitivities through which we could identify the most robust and lowest cost scenario across a range of outcomes. We strove to develop a Preferred Plan that allows us to make renewable resource additions in a manner that captures potential tax benefits and addresses technological changes. We also strove to develop a plan that minimizes reliance on combined cycle generation to allow strategic flexibility around our reliance on gas as a fuel source to address the evolution of the NSP System in the out years of the planning period and beyond.

Second, we examined State policy objectives and other factors of the planning landscape to determine the appropriate features of a resource plan to meet the planning landscape. Third, we recognized the impact on our customers that our recent investment cycle has had and therefore, cost effectiveness to achieve policy goals is a key consideration in our planning framework. While it is always possible to do more, the impact to our customers was a key consideration when developing our Preferred Plan. Consequently, the goal in developing our Preferred Plan was to select the scenario that is expected to provide the greatest balance between positioning us within the planning landscape, strategic flexibility and the impact on our customers.

Given these pillars of our planning framework and the need to appropriately balance them, through our resource planning efforts we developed innovative strategies to achieve a reasonable, balanced outcome. At the heart of that outcome is the use of renewable energy resources supported by gas combustion turbines to meet out-year needs and achieve policy goals. By utilizing this type of methodology, we are able to meet customer needs and achieve CO_2 outcomes in light of expected GHG regulatory requirements, and maximize customer value in our existing thermal fleet, all without tilting the NSP System to being overly-reliant on combined cycle gas units during the planning period.

These outcomes provide us with significant flexibility to meet the challenges of the evolving NSP System beyond the planning period. Additionally, focusing on renewable energy backed by peaking capacity affords us additional strategic flexibility to accelerate or delay many of the renewable resource additions as market conditions dictate. Last, by utilizing significant renewable energy resources to meet our customers' needs, we impact the operations of our coal fleet thereby achieving significant emissions reductions while retaining the benefits that this installed capacity and low cost energy provides to our customers.

It is within this planning framework that we utilized traditional least-cost resource planning techniques to develop and propose our Preferred Plan.

C. Strategist Assumptions and Sensitivities

To perform our analyses, we utilized the Strategist Resource Planning model. Strategist is a resource planning software model we have used in our Resource Plans since 2000 to estimate the costs of various resource expansion plans, evaluate specific capacity alternatives, and measure the potential risks of new environmental legislation and other policy scenarios. Strategist results are used as a decision support tool to guide development of a preferred plan and test the robustness of the plan under a variety of assumptions and sensitivities.

1. *Assumptions*

Important starting assumptions in our analysis include:

Forecast. We develop plans to meet the 50 percent probability level of forecasted peak demand, and the 50 percent probability level of forecasted energy requirements. We incorporated a 7.1 percent reserve margin requirement, and offset the forecast by a 5 percent MISO system coincident factor.

Existing Fleet. We develop forecasts for cost and performance assumptions (such as variable O&M, heat rate, forced outage rate, maintenance requirements, etc.) based on historical data, with adjustments for known changes, if applicable. Additional assumptions include:

- Costs are escalated based on corporate estimates of expected inflation rates,
- Retirement of our Prairie Island nuclear plant at the end of its proposed license renewal (2033, 2034), and Monticello nuclear at the end of 2030,[30]
- Continued operation of Sherco Units 1 and 2 through the planning period with no additional environmental investments at the plants,
- Retirement of all other facilities at their current expected end of life if within the resource planning period, unless we have specifically included costs of life extension,[31]
- Continuation of our existing power purchase contracts until their contractual termination dates, and
- Continued operation of the Company's owned hydroelectric resources based on historical performance.

Renewable Energy. In addition to the 750 MW of wind that has already been approved for addition to the NSP System in 2015, we have assumed:

- Generic addition of 400 MW of wind in 2020,
- Accreditation of wind resources based on currently 14.4 percent MISO planning reserve credit,

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[30] Monticello's current license expires September 30, 2030. For simplicity purposes, we have assumed December 31, 2030 in our modeling.

[31] The one exception to this assumption is with regard to our Sherco 1 and 2 units. These facilities reach the end of their book lives in 2023. However, the plans for these facilities is a key part of this Resource Plan so they are assumed to operate through 2030 under the starting assumptions and numerous alternative plans are analyzed in detail. Decisions regarding unit retirement or continued operation beyond 2030 will be addressed in response to actual future market and environmental policy outcomes.

- No extension of the PTC or 30 percent ITC past the expiration dates as per current law,
- 187 MW of utility-scale solar added in 2016 pursuant to the Company's pending request in Docket No. E002/M-14-162, and
- Distributed and utility-scale solar additions sufficient to meet the 1.5 percent standard by 2020. Distributed solar additions continue through 2030 at the same annual MW level as are planned for 2020.

Markets. Due to the uncertainty surrounding the EPA's 111(d) rule and the impact on both market price forecasts and assigned CO_2 content of market purchases, the starting assumption was to run the Strategist model with economy purchases off. A sensitivity with economy purchases on was run to test the impacts of this assumption on the various plans.

Emissions. Emission rates for existing and planned resources consistent with historical and expected performance, and:

- $ 21.50 per ton CO_2 as a regulatory cost, starting in 2019 and escalating at inflation. The societal value of CO_2 as an externality was included as a sensitivity case (more detail in the *Sensitivity Analysis* section of Appendix J),
- The Minnesota Commission's high externality values for specified emissions,
- SOx assumed zero regulatory cost due to large surplus of allowances and weak sales market. Zero externality cost per Minnesota Commission policy, and
- NOx modeled as an externality cost.

Generic Resources. Strategist uses generically-defined resources to meet future demand when existing resources fall short, as follows:[32]

- 226 MW gas-fired Combustion Turbine peaking unit (CT),
- 100 MW gas-fired Combustion Turbine peaking unit (CT),
- 786 MW gas-fired Combined Cycle intermediate unit (CC),
- 290 MW gas-fired Combined Cycle intermediate unit (CC),
- 500 MW Super Critical Pulverized Coal base load unit, with an alternate version including 90 percent carbon capture and storage.[33]

[32] The cost and performance data for these units are based on a consultant's estimates and internal company data. Availability dates are selected based on our estimates of the lead time needed for regulatory approvals, financing, permitting and construction.

- 50 MW Bubbling Fluidized Bed Biomass unit, burning wood waste,
- 200 MW Wind project, with PTC for 2016, without PTC afterwards, and
- 50 MW Solar project, single-axis tracking, with ITC for 2016, without ITC afterwards.

We provide additional information regarding strategist and our modeling assumptions in Appendix J.

2. *Sensitivities*

To determine how changes in our assumptions impact the costs or characteristics of different plans, we examine them under a number of sensitivities. Generally, if a plan is extremely sensitive to changes in assumptions, it is not a robust course of action for the Company to pursue. For this Resource Plan, we tested the following sensitivities:

- *Load.* The base forecast (unadjusted for DSM) is the 50 percent probability level of forecasted peak demand, and the 50 percent probability level of forecasted energy requirements (same approach as used by MISO). To test the sensitivity, we increase the growth rates for peak demand and energy by 50 percent for the high load sensitivity, and decrease the growth rates for peak demand and annual sales by 50 percent for the low load sensitivity. The high load sensitivity helps to identify resources that may be needed if we experience a robust economic recovery.

- *Natural Gas Costs.* Adjusted the growth rate up and down by 50 percent from the base natural gas cost forecast.

- *Coal Costs.* Adjusted the growth rate for the cost of delivered coal up and down by 50 percent from the base coal cost forecast.

- *Renewables.* Increased costs for incremental solar and wind units by +/- 10 percent.

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[33] We note that the new large energy facility definition in Minn. Statute § 216H.03, subd. 1 would not allow for any new coal plant development in Minnesota. However, not all states (for example, North Dakota) have enacted such prohibitions. However, pending federal rules, which we believe are likely to be enacted, will require sequestration be installed on all new coal plants. See Standard of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units, 79 Fed. Reg. 1430 (proposed Jan. 8, 2014) (to be codified in 40 C.F.R. Parts 60, 70, 71 and 80). Consequently, we believe it appropriate to have this equipment as part of a coal plant assumption.

- *CO_2 Values.* For CO_2 sensitivity used $21.50/ton beginning in 2019, the average of a low of $9/ton and to a high of $34/ton. We also performed a sensitivity of no CO_2 cost.
- *Externalities.* Used the high Minnesota Commission externality values all cases, and also performed a sensitivity that replaced the regulated cost of CO_2 with the Federal "Societal Cost of Carbon" as an externality.
- *Sherco Costs.* Sensitivities for: (1) Sherco 1&2 ongoing capital and fixed O&M costs at +10 percent.
- *Markets On.* Market sales (i.e. "economy sales") are off in all cases, as it is the policy of the Company to not plan the system based on speculative sales opportunity. In this sensitivity, economy purchases were turned on, creating a "system integrated with the market" view.
- *North Dakota Assumptions.* To reflect the diverse energy policies among the various states we serve, this sensitivity was included to attempt to represent the plans' economics under the policy preferences of North Dakota. Specifically, all CO_2 and externality values as well as all future renewables were removed. To offset loss of the renewable capacity, additional 219 MW natural gas fueled combustion turbines were added in 2019, 2025 and 2030 compared to the Reference Case.
- *Combination Sensitivities.* To test the robustness of the plans under a wide range of possible futures, we performed several "linked" sensitivities, which are various combinations of the above-described types.

We provide the specific sensitivity analyses performed in Appendix J.

D. Scenarios Analyzed

To arrive at our Preferred Plan, we analyzed twelve key scenarios evaluated against nine key sensitivities. The list of key scenarios was developed using the lowest cost scenario from each scenario type described below (and in **bold type** for easy reference) and those scenarios that address key Sherco options. The list of key sensitivities was developed by selecting the major sensitivities typically evaluated in testing the robustness of a scenario (possible plan option). Scenarios were ranked based on their emissions performance contrasted against a Net Present Value Revenue Requirement (PVRR) as well as a Net Present Value Of Societal Costs (PVSC) from our modeling period of 2015-2053 analysis.

In the discussion below, we provide descriptions of key scenarios evaluated. For each scenario family, we have placed the lowest cost scenario being used for ranking and cost comparison in bold type for reference. A complete discussion of all scenarios evaluated is provided in Appendix J.

1. *Reference Case Scenarios*

We describe the development of our Reference Case in Chapter III, Minimum System Need. In the **Reference Case**, which is an extension of our 2010 Resource Plan, Sherco 1 and 2 continue operation through 2030 and do not have SCRs installed. There are two 200 MW non-PTC wind projects added in 2020 for CO_2 goal attainment 187 MW of utility-scale solar generation resources are added by year-end 2016 and small distributed solar generation additions increase at a sustainable rate through 2020. Thereafter, the annual level of distributed solar generation additions is assumed to continue at the 2020 level through 2030. Large 2x1 natural gas fueled combined cycle plants and natural gas fueled combustion turbines are the thermal generation resource options used to optimize the resource plan to fill capacity and energy needs not met by renewable generation additions and DSM resources.

To test the robustness of our Reference Case, we also analyzed variants. In a key variant, Scenario 1B (**Add SCR Case**), SCRs are installed on Sherco 1 in 2024 and on Sherco 2 in 2025. The units operate through 2030. This Scenario is provided to estimate the impacts of SCRs on the units, although as previously discussed, the Company believes a definitive decision on Sherco SCRs and/or retirement dates should be deferred until there is more certainty on proposed environmental regulatory requirements and market impacts are clearer.

2. *Preferred Plan and Variants*

We developed our Preferred Plan building off of the Reference Case. To determine the robustness and inherent flexibility in our Preferred Plan we analyzed several scenarios to identify the effects of a renewal of the Federal PTC as well as the retirement of a Sherco unit. Key scenarios analyzed to develop the Preferred Plan include:

- Scenario 10 (**Preferred Plan)** - Adds one additional 200 MW wind project in 2020 for a total of 600 MW wind in 2020. It also adds 1,200 MW wind (non-PTC) and 1,700 MW of utility-scale solar projects in the 2020s. Distributed small solar annual additions continue to grow sustainably after 2020 at a year-over-year growth rate of 20 percent.

- Scenario 10A (**Preferred Plan with PTC**) – Designed to show the effects of a PTC extension on the Preferred Plan. Adds 1,000 MW of PTC wind projects in 2018 and an additional 800 MW of non-PTC wind resource comprised of several projects added during the 2020s. The same total amount (1,800 MW) of wind generation is added as in the Preferred Plan, but accelerated to capture the benefit of a PTC extension. Solar generation projects are added in the same amount and timing as the Preferred Plan.
- Scenario 10B **(Preferred Plan with Sherco 1 Retirement)** - Is the same as the Preferred Plan (Scenario 10) but Sherco 1 retires year end 2025.
- Scenario 10C (**Preferred Plan with Sherco 1 Retirement and PTC**) - Is the same as Scenario 10A but Sherco 1 retires year end 2025.

3. *Additional Sherco Scenarios*

We recognize that the future of Sherco is a key issue for the Commission and our stakeholders. We believe that our Preferred Plan provides us the flexibility to address the impact of environmental regulations on this unit in subsequent resource plans. However, to demonstrate the robustness and effectiveness of our Preferred Plan (and to meet our compliance obligations) we analyzed a series of different scenarios related to Sherco.

First, we analyzed scenarios related to the retirement of Sherco Unit 1 and continued operation of Sherco Unit 2 through the planning period. Key scenarios related to this analysis include:

- Scenario 2 (CC Replacement) - Sherco 1 retires year end 2025 and is replaced with a 2x1 natural gas combined cycle unit in 2026.
- Scenario 3 (*CT Replacement*) - Sherco 1 retires year end 2025 and is replaced with three natural gas combustion turbines units in 2026.
- Scenario 4A (50 percent Renewable Replacement, Wind) - Sherco 1 retires year end 2025 and is replaced with three natural gas combustion turbine units and 600 MW of wind generation projects in 2026.
- Scenario 4B (**Retire Unit 1 Replace with 50 percent Renewables**)- Sherco 1 retires year end 2025 and is replaced with two natural gas combustion turbine

units, 400 MW of wind generation projects, and 450 MW of utility scale solar generation projects in 2026.

- Scenario 4C (*50 percent Renewable Replacement, Wind, Solar, DSM*) - Sherco 1 retires year end 2025 and is replaced with two natural gas combustion turbine units, 400 MW of wind generation projects, 250 MW of utility scale solar generation projects, and DSM resources are added at 1.7 percent scenario level in 2026.
- Scenario 5A (*75 percent Renewable Replacement, Wind*) - Sherco 1 retires year end 2025 and is replaced with three natural gas combustion turbine units and 1,000 MW of wind generation projects in 2026.
- Scenario 5B (**Retire Unit 1 Replace with 75 percent Renewables**)- Sherco 1 retires year end 2025 and is replaced with two natural gas combustion turbine units, 600 MW of wind generation projects, and 700 MW of utility scale solar generation projects in 2026.
- Scenario 5C (*75 percent Renewable Replacement, Wind, Solar, DSM*) - Sherco 1 retires year end 2025 and is replaced with one natural gas combustion turbine unit, 600 MW of wind generation projects, 500 MW of utility scale solar generation projects, and DSM resources are added at 1.7 percent scenario level in 2026.

We also analyzed scenarios where we retired both Sherco Units during the planning period. We believe that a 2025 retirement is the earliest reasonably practicable timeframe. Key two unit retirement scenarios include:

- Scenario 6 (CC Replacement) - Sherco 1 and 2 retire year end 2025 and are replaced with two 2x1 natural gas combined cycle units in 2026.
- Scenario 7 (*CT Replacement*) - Sherco 1 and 2 retire year end 2025 and are replaced with six natural gas combustion turbine units in 2026.
- Scenario 8A (*50 percent Renewable Replacement, Wind*) - Sherco 1 and 2 retire year end 2025 and are replaced with six natural gas combustion turbine units and 1,200 MW of wind generation projects in 2026.
- Scenario 8B (**Retire Units 1&2 Replace with 50 percent Renewables**)- Sherco 1 and 2 retire year end 2025 and are replaced with four natural gas combustion turbine units, 800 MW of wind generation projects, and 800 MW of utility scale solar generation projects in 2026.

- Scenario 8C (*50 percent Renewable Replacement, Wind, Solar, DSM*) - Sherco 1 and 2 retire year end 2025 and are replaced with four combustion turbine units, 800 MW wind, 600 MW of utility scale solar projects, and DSM resources are added at 1.7 percent scenario level in 2026.
- Scenario 9A (*75 percent Renewable Replacement, Wind*) - Sherco 1 and 2 retire year end 2025 and are replaced with five natural gas combustion turbine units and 1,800 MW of wind generation projects in 2026.
- Scenario 9B (**Retire Units 1&2 Replace with 75 percent Renewables**)- Sherco 1 and 2 retire year end 2025 and are replaced with three natural gas combustion turbine units, 1,200 MW of wind generation projects, and 1,250 MW of utility scale solar generation projects in 2026.
- Scenario 9C (*75 percent Renewable Replacement, Wind, Solar, DSM*) - Sherco 1 and 2 retire year end 2025 and are replaced with three combustion turbine units, 1,200 MW wind, 1,000 MW of utility scale solar projects, and DSM resources added at 1.7 percent scenario level in 2026.

Last, we analyzed scenarios related to repowering Sherco. Key scenarios analyzed include:

- Scenario 11 (*Gas Boiler*) - Converts Sherco 1 to a gas boiler unit in 2026 and runs to 2040. Sherco 2 operated through 2030.
- Scenario 12 (*CC Repowering*) - Converts Sherco 1 to a 4x1 natural gas combined cycle facility by repowering the steam turbine generator. The plant is brought offline year end 2025 and is back online in early 2027. Sherco 2 retires year end 2025.

4. *North Dakota Plan*

As discussed in the Planning Landscape Chapter, Xcel Energy plans and operates a single system that serves customers in five states. Over the past several years, North Dakota has significantly increased our resource planning and other regulatory requirements. Since 2008, we have been obligated in North Dakota to file our Midwest Resource Plan with the North Dakota Commission and include in that filing an analysis of a scenario that is compliance with North Dakota law and its energy policies.

To that end, we are including in this Resource Plan and North Dakota based scenario that is designed to meet but not exceed North Dakota environmental and renewable requirements as they currently exist (**North Dakota Plan**). Specifically, we made the following changes to the Strategist model to arrive at the North Dakota scenario:

- We eliminated all CO_2 costs and constraints.
- We allowed Strategist to select one or more Supercritical Pulverized Coal Plants (500 MW each), which, however would have carbon sequestration equipment on it per EPA requirements.[34]
- We did not account for meeting any renewable energy objective.
- We assume no growth in small scale solar as opposed to our Reference Case.

E. Strategist Results and Analysis

After identifying the scenarios for analysis utilizing our planning framework and compliance requirements, we utilized our Strategist modeling tool to identify the expansion plans and their resultant cost and emissions impacts. In performing this analysis, we first utilized traditional resource planning methods and ranked the scenarios based on costs. In addition to the traditional least-cost analysis, we performed a more holistic analysis to determine if our Preferred Plan was appropriately balanced within our planning framework when compared to the other scenarios analyzed. We present both analyses in this section and demonstrate that our Preferred Plan provides the most reasonable outcome under both a least cost analysis pricing in CO_2 and under a more comprehensive analysis.

1. *Traditional Resource Planning Analysis*

Under the traditional resource planning concepts, scenarios were ranked based on PVSC with carbon cost of \$21.50/ton of CO_2 and on their PVRR without carbon cost over the modeling period of 2015-2053. The PVSC and PVRR values are the sum of all operating, depreciation, return on rate base, emissions, externality, and tax costs, less any revenues from sales discounted back to 2015 using the Company's most recently authorized weighted after tax cost of capital of 6.62 percent.

Consistent with resource planning requirements governing this Resource Plan, we first analyzed our modeling output on a PVSC basis to determine the least cost plan.[35]

[34] *Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Generating Units*, Docket No. EPA-HQ-OAR-2013-0495, 79 Fed. Reg. 1,430 (Jan. 8, 2014). *See* http://www2.epa.gov/carbon-pollution-standards/2013-proposed-carbon-pollution-standard-new-power-plants

Table 7, below, provides the PVSC outcomes of key scenarios identified above. Table 8, below, provides a ranking of the scenarios on a PVSC basis from lowest cost to highest cost.

Table 7: PVSC Results

PVSC

Scenario	BASE	LOW LOAD	HIGH LOAD	LOW GAS	HIGH GAS	LOW WIND	HIGH WIND	LOW SOLAR	HIGH SOLAR
Reference Case	52,429	49,055	56,075	48,976	57,190	52,298	52,560	52,429	52,429
Reference Case with SCRs	52,838	49,383	56,403	49,303	57,518	52,626	52,888	52,757	52,757
Preferred Plan	51,997	48,724	55,589	49,114	55,997	51,662	52,332	51,827	52,167
Preferred Plan with PTC	51,142	47,873	54,723	48,242	55,169	51,008	51,275	50,971	51,312
Preferred Plan with Sherco 1 Retire	52,001	48,719	55,607	49,048	56,078	51,666	52,336	51,831	52,171
Preferred Plan with Sherco 1 Retire & PTC	51,146	47,868	54,741	48,176	55,249	51,012	51,280	50,976	51,316
Retire 1 Unit Replace with 50% Renewables	52,329	48,993	55,983	48,900	57,043	52,177	52,482	52,282	52,377
Retire 1 Unit Replace with 75% Renewables	52,249	48,902	55,891	48,918	56,821	52,063	52,435	52,176	52,323
Retire 2 Units Replace with 50% Renewables	52,266	48,914	55,917	48,934	56,840	52,046	52,485	52,182	52,350
Retire 2 Units Replace with 75% Renewables	52,169	48,814	55,806	49,023	56,481	51,883	52,455	52,037	52,300
North Dakota Plan	52,518	49,104	56,121	48,826	57,626	52,518	52,518	52,518	52,518

Table 8: PVSC Rankings

CO2 PVSC Ranking

Scenario	BASE	LOW LOAD	HIGH LOAD	LOW GAS	HIGH GAS	LOW WIND	HIGH WIND	LOW SOLAR	HIGH SOLAR
Reference Case	9	9	9	7	9	9	10	9	9
Reference Case with SCRs	11	11	11	11	10	11	11	11	11
Preferred Plan	3	4	3	10	3	3	3	3	3
Preferred Plan with PTC	1	2	1	2	1	1	1	1	1
Preferred Plan with Sherco 1 Retire	4	3	4	9	4	4	4	4	4
Preferred Plan with Sherco 1 Retire & PTC	2	1	2	1	2	2	2	2	2
Retire 1 Unit Replace with 50% Renewables	8	8	8	4	8	8	7	8	8
Retire 1 Unit Replace with 75% Renewables	6	6	6	5	6	7	5	6	6
Retire 2 Units Replace with 50% Renewables	7	7	7	6	7	6	8	7	7
Retire 2 Units Replace with 75% Renewables	5	5	5	8	5	5	6	5	5
North Dakota Plan	10	10	10	3	11	10	9	10	10

As shown in Table 7, the Preferred Plan has a PVSC that is $432 million lower than the Reference Case and, absent renewal of PTC legislation, and is the lowest cost plan on a PVSC basis. The scenario with the Preferred Plan coupled with the retirement of a Sherco unit in 2025, as opposed to operating until 2030, is the second lowest cost plan under the base case assumptions barring PTC renewal. In fact, as Table 8 indicates, when ranked, the Preferred Plan ranks highest absent PTC renewal across all sensitivities except low gas price (50 percent reduction in growth rate from the base gas price forecast) and low load (50 percent reduction in growth rate. If PTCs are sensitivities. Consequently, our analysis supports selection of the Preferred Plan as least cost on a PVSC basis in almost all scenarios.

[35] Minn. Stat. § 216B.2423

In analyzing the Preferred Plan under different sensitivities, it became apparent that the cost assumptions of the of the renewable resources being added was one of the major drivers in the economic viability of the plan. Since the addition of significant levels of renewable energy is one of the key components of the Preferred Plan, the ability to acquire additional wind resources at a pricing level that incorporates the impact of the current Federal PTC was a significant benefit to the Plan. As a result, a key action step of implementing the Preferred Plan is seizing the opportunity to acquire significant new wind resources if PTC-based pricing is available over the next year or two. Our Preferred Plan allows us the flexibility of obtaining the cost advantages of the Federal PTC; however, since there is no current indication that the PTC will be extended, our analysis utilizes scenarios that include the PTC as an alternative. At this time, we do not know if and when the PTC may be extended, and consequently, the scenarios that include capturing the PTC are considered an alternative to our Preferred Plan.

Because actual impact to our customers was a key component of our planning framework, and because not all states we serve allow for an analysis that includes externalities, we also performed a least cost analysis on a PVRR basis, which does not include carbon costs. Table 9, below identifies the PVRR results of these key scenarios. Table 10, below, provides a ranking of the scenarios on a PVRR basis from lowest cost to highest cost.

Table 9: PVRR Results

PVRR

Scenario	BASE	LOW LOAD	HIGH LOAD	LOW GAS	HIGH GAS	LOW WIND	HIGH WIND	LOW SOLAR	HIGH SOLAR
Reference Case	45,895	42,961	49,105	42,518	50,626	45,764	46,026	45,895	45,895
Reference Case with SCRs	46,230	43,296	49,440	42,853	50,960	46,099	46,361	46,230	46,230
Preferred Plan	46,184	43,321	49,319	43,363	50,166	45,849	46,519	46,014	46,354
Preferred Plan with PTC	45,410	42,555	48,521	42,572	49,421	45,276	45,544	45,240	45,580
Preferred Plan with Sherco 1 Retire	46,330	43,447	49,490	43,453	50,378	45,994	46,665	46,159	46,500
Preferred Plan with Sherco 1 Retire & PTC	45,556	42,681	48,692	42,662	49,633	45,422	45,690	45,386	45,726
Retire 1 Unit Replace with 50% Renewables	46,104	43,155	49,311	42,759	50,783	45,951	46,257	46,057	46,151
Retire 1 Unit Replace with 75% Renewables	46,134	43,169	49,329	42,895	50,669	45,948	46,320	46,060	46,207
Retire 2 Units Replace with 50% Renewables	46,397	43,437	49,604	43,144	50,937	46,177	46,616	46,313	46,481
Retire 2 Units Replace with 75% Renewables	46,491	43,497	49,635	43,433	50,767	46,205	46,777	46,359	46,622
North Dakota Plan	45,747	42,803	48,993	42,103	50,831	45,747	45,747	45,747	45,747

Table 10: PVRR Rankings

No CO2 PVRR Ranking

Scenario	BASE	LOW LOAD	HIGH LOAD	LOW GAS	HIGH GAS	LOW WIND	HIGH WIND	LOW SOLAR	HIGH SOLAR
Reference Case	4	4	4	2	5	4	4	4	4
Reference Case with SCRs	8	7	8	6	11	9	7	9	7
Preferred Plan	7	8	6	9	3	5	8	5	8
Preferred Plan with PTC	1	1	1	3	1	1	1	1	1
Preferred Plan with Sherco 1 Retire	9	10	9	11	4	8	10	8	10
Preferred Plan with Sherco 1 Retire & PTC	2	2	2	4	2	2	2	2	2
Retire 1 Unit Replace with 50% Renewables	5	5	5	5	8	7	5	6	5
Retire 1 Unit Replace with 75% Renewables	6	6	7	7	6	6	6	7	6
Retire 2 Units Replace with 50% Renewables	10	9	10	8	10	10	9	10	9
Retire 2 Units Replace with 75% Renewables	11	11	11	10	7	11	11	11	11
North Dakota Plan	3	3	3	1	9	3	3	3	3

Table 9 and Table 10 indicate that from a strictly PVRR perspective and absent PTCs, the North Dakota Plan would tend to be the lowest cost plan, except in the case of high gas prices, since it relies most heavily on natural gas generation additions compared to the Preferred Plan or Reference Case.

Table 9 and Table 10 also indicate that our Reference Case scores the next best on a PVRR basis. Our PVRR analysis also indicates that retiring one Sherco unit in 2025 would result in outcomes costing less than our Preferred Plan but by less than $150 million. In other words, although not the least cost on a PVRR basis, our Preferred Plan fared well and was reasonably close in cost to those scenarios ranked above it. And because our Preferred Plan provides the flexibility to take advantage of PTCs if they should become available, this Plan further serves our customers well under multiple circumstances.

Utilizing traditional resource planning analyses, our Preferred Plan was the least cost scenario on a PVSC basis absent PTCs, and fared well under a PVRR analysis. This supports selection of the Preferred Plan when externality costs are factored into the analysis. Additionally, the Preferred Plan's PVRR performance indicates that it will have a reasonable impact on customers when compared to other potential scenarios. Importantly, the PVSC and PVRR analysis supports further, more comprehensive, analyses of the Preferred Plan against the other scenarios to determine if it performs within our planning framework by achieving an appropriate balance of furthering policy goals, reasonable impacts to customers, and strategic flexibility to address the uncertain planning landscape.

2. *Planning Framework Analysis*

Our Resource Plan was driven by the evolving planning landscape, balanced against reasonable impacts to customers all while retaining strategic flexibility. Our PVSC and PVRR analysis under traditional resource planning principles demonstrates that the addition of carbon costs into our analysis materially impacts the performance of each scenario when measured against the other. This indicates that environmental attributes of the various scenarios have a material impact on their relative performance when measured against their actual impact to customers. Consequently, a more holistic analysis was appropriate to identify which scenario best balances the competing interests of the planning framework.

Table 11 below, provides our "Run Key." The Run Key provides a more comprehensive view of the performance of each of the different scenarios analyzed with respect to their environmental performance, strategic flexibility, and cost. The Run Key carries forward the PVSC and PVRR ranking of each scenario to provide a reference point for the broader analysis. The Run Key also identifies key policy outcome metrics such as amount of CO_2 emissions reductions from 2005 levels and the amount of renewable energy added to the NSP System under each scenario.

From a flexibility perspective, the Run Key identifies the "gas burn," which is the amount of gas as fuel that would be consumed under a particular scenario. The "gas burn" metric provides a way to measure the NSP System's reliance on gas as a fuel that each particular scenario would require indicating a measure of strategic flexibility to meet issues related to the evolving NSP System beyond the planning period.

Additionally, the Run Key identifies the impact of each scenario on the capacity factors of our existing coal fleet. This metric provides a way to measure the impact of each scenario on the installed capacity and low cost energy provided by these key units on our system. We believe reducing the energy production of our coal fleet represents the ability of a particular scenario to maximize the value of our investment cycle for our customers while further reducing emissions from these units in light of the planning landscape.

Table 11: RUN KEY

	PVRR Ranking*	PVSC Ranking	2030 Coal Gen vs. Ref Case*	2030 Gas Burn (Bcf)*	2030 Percent CO2 Reduction**	Total Renewable Additions (MW)
Reference Case	4	9	-	68	23%	806
Reference Case with SCRs	8	11	+0%	68	23%	806
Preferred Plan	7	3	-15%	36	42%	4,193
Preferred Plan with PTC	1	1	-15%	36	42%	4,193
Preferred Plan with Sherco 1 Retire	9	4	-33%	55	49%	4,193
Preferred Plan with Sherco 1 Retire & PTC	2	2	-33%	55	49%	4,193
Retire 1 Unit Replace with 50% Renewables	5	8	-26%	82	36%	1,656
Retire 1 Unit Replace with 75% Renewables	6	6	-27%	76	39%	2,106
Retire 2 Units Replace with 50% Renewables	10	7	-56%	107	50%	2,406
Retire 2 Units Replace with 75% Renewables	11	5	-57%	93	54%	3,256
North Dakota Plan	3	10	+2%	81	18%	None

* For No CO2 dispatch cost sensitivity

** For No CO2 dispatch cost sensitivity, CO2 reduction is from 2005 levels

We believe that the Run Key bolsters the selection of our Preferred Plan as the scenario that best balances the planning framework considerations, absent PTCs.

As part of this more holistic analysis, it is important to keep in mind that the Preferred Plan, absent PTCs, performed best under a traditional resource planning analysis when externalities are included in that analysis. As the Run Key indicates, our Preferred Plan also performs best in several key metrics. Our Preferred Plan provides the most flexibility by having the lowest "gas burn" (i.e. lowest dependence on energy from new natural gas generation). Further, our Preferred Plan adds the most amount of renewable energy to our system, furthering our ability to address current and future GHG regulatory requirements and expectations. Last, our Preferred Plan provides a significant reduction in energy production and associated emissions from our coal fleet while retaining the benefits of our investment cycle.

Given the performance of our Preferred Plan on the Run Key metrics, we believe that the Run Key supports the selection of the Preferred Plan over those scenarios that scored above it on a PVRR basis. The Preferred Plan, absent PTCs, provides more carbon reduction, more renewable energy, more flexibility and a larger impact to our coal operations than any of the scenarios ranking higher on a PVRR basis including those where one Sherco unit is retired in 2025, the Reference Case, and the North Dakota Plan. Importantly, our Preferred Plan is only plan that avoids the addition of a combined cycle facility during the planning period. Consequently, we believe that so long as our Preferred Plan achieves a cost impact under our proposed average annual two percent threshold above the Reference Case, that the policy, flexibility, and cost outcomes of the Preferred Plan suggest it is a superior holistic path forward than those scenarios with a better PVRR ranking.

We also performed a more comprehensive analysis of the Preferred Plan compared against the remaining competitive scenarios, namely those that retire two Units at Sherco and replace them with renewable energy. These scenarios were closely ranked with the Preferred Plan on a PVSC basis, indicating reasonably strong environmental performance. An analysis based on the Run Key metrics enables us to determine if these scenarios perform significantly better than the Preferred Plan on a more holistic basis, so as to merit further review. Additionally, our Preferred Plan's reliance on renewable energy additions allows us to capture PTCs should they become available.

The Run Key demonstrates that the Preferred Plan performs better than those scenarios that retire two Sherco Units and replace them with renewable energy on all of the metrics except for CO_2 reduction. Importantly, our Preferred Plan has a significantly lower "gas burn" and a significant impact on the energy production of our coal fleet. This means that the Preferred Plan provides significantly more strategic flexibility on a going forward basis than retiring Sherco Units 1 and 2 in 2025 and replacing them with renewable energy – as even at 75 percent replacement with renewable energy, retiring both Sherco Units during the planning period requires the addition of a combined cycle facility. Our Preferred Plan adds about 1,000 to nearly 3,400 MW more renewable energy to the NSP System than those scenarios as well.

The only metric where our Preferred Plan does not perform as well as the retirement of Units 1 and 2 of Sherco is in CO_2 emissions reduction. While the Preferred Plan achieves a significant incremental reduction in CO_2 emissions of 42 percent, retiring two Sherco units in 2025 will achieve more. That said, when viewed holistically, we believe that the merits of the Preferred Plan on issues of flexibility and cost, as well as significant achievement of CO_2 emission reduction, would argue that the Preferred Plan performs better overall when analyzed within the planning framework.

We recognize that reasonable minds can differ when a broader analysis of the various scenarios is performed. We look forward to a dialogue with the Commission and our stakeholders to address these issues and determine the appropriate balance of cost, flexibility, and policy achievement of any resource plan going forward. In any event, traditional resource planning methods and a comprehensive analysis support the selection of our Preferred Plan and its approximately 40 percent carbon emissions reduction performance as a reasonable outcome of this Resource Plan.

3. *Cost Analysis*

The last stage of our analysis was to ensure that the impact to our customers of the Preferred Plan as compared to the Reference Case was reasonable. Figure 11 identifies the PVRR impact above the Reference Case of our Preferred Plan as well as the other highest performing scenario under the PVSC analysis and the highest performing scenario under the PVRR analysis for reference all absent PTCs.

Figure 11: PVRR Impact Above Reference Case

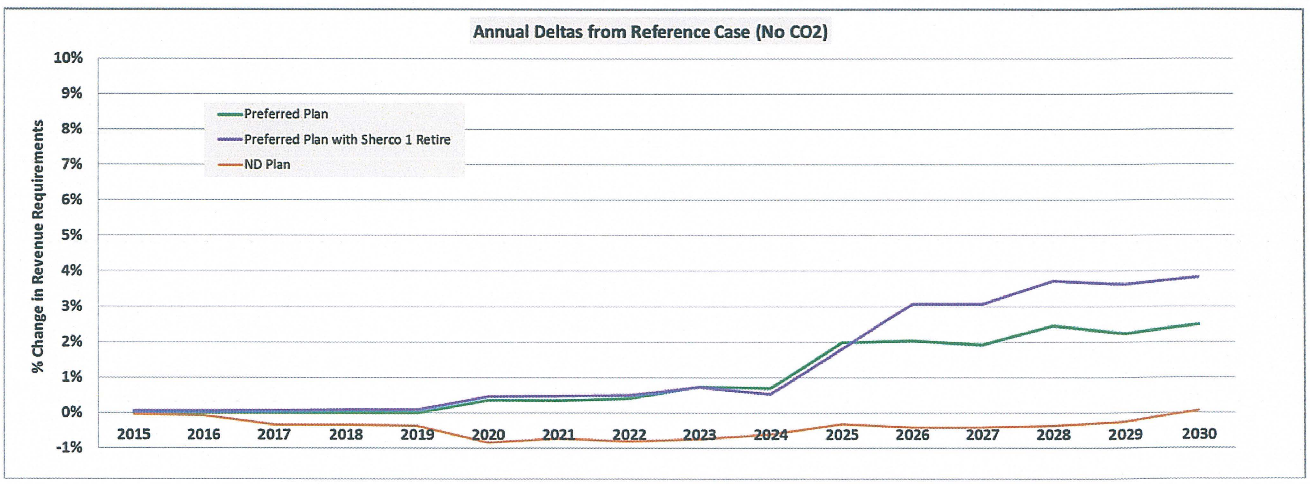


Figure 11 demonstrates that on average, our Preferred Plan achieves a reasonable cost outcome. We provide further information with respect to the customer cost impact section of our Preferred Plan.

F. Public Interest Analysis

Based on our detailed analysis, we conclude that the Preferred Plan is in the public interest, as it provides the best option in the evolving planning landscape to meet established resource planning requirements and result in achievement of carbon reduction and renewable objectives while effectively managing costs and preserving flexibility on behalf of our customers.

The Commission's rules identify the factors that the Commission is to consider when determining if the Resource Plan selected is in the public interest.[36] More specifically, these rules require that resource options and resource plans are to be evaluated on their ability to:

A. maintain or improve the adequacy and reliability of utility service,
B. keep the customers' bills and the utility rates as low as practicable, given regulatory and other constraints,
C. minimize adverse socioeconomic effects and adverse effects upon the environment,
D. enhance the utility's ability to respond to changes in the financial, social, and technological factors affecting its operations, and
E. limit the risk of adverse effects on the utility and its customers from financial, social, and technological factors that the utility cannot control.

Our Preferred Plan is best able to meet these criteria, especially when analyzed on a comprehensive basis in light of the planning landscape facing the Company and the industry.

1. Reliability

Our Preferred Plan is designed to maintain adequacy and reliability of the generation resources of the NSP System and allow us to continue to provide safe and reliable service to our customers. To help ensure our Preferred Plan can provide reliable service, we recognized that the large addition of renewable energy can affect the operation of the NSP System. To help ensure that the effects of this will not adversely affect reliability, we performed a wind integration study which indicates that the NSP System can support the wind energy additions we propose. The Study is provided as Appendix M. We additionally discuss other supporting infrastructure to support our renewable energy additions in Appendix H. Further, our Preferred Plan positions us to help ensure the continued adequacy and reliability of the NSP System beyond the planning period.

2. Impact to Customers' Bills

We developed our Preferred Plan with impacts to customers in mind. Given the regulatory and other constraints of the planning landscape, we sought to achieve additional flexibility and achievement of policy goals at a reasonable additional cost to

[36] Minn. R. 7843.0500, subp. 3.

the business as usual outcome of our Reference Case. We have achieved this at an additional annual cost of approximately 2 percent, on average, over the planning period. This is below the cost of other scenarios analyzed that would address the planning landscape. Therefore, our Preferred Plan will keep our rates as low as practicable given regulatory and other constraints.

3. Socioeconomic and Environmental Effects

Our Preferred Plan minimizes socioeconomic effects and adverse effects upon the environment. We are proposing to operate Sherco Units 1 and 2 during the planning period which will preserve key jobs at this facilities. Additionally, the significant additions of renewable energy will also have additional socioeconomic benefits.

Our Preferred Plan also provides environmental benefits. Our Preferred Plan will achieve an approximately 40 percent reduction in CO_2 emissions from 2005 levels by 2040. Also, our Preferred Plan will reduce the operation of our coal fleet further reducing other emissions as well. Consequently, our Preferred Plan will minimize adverse effects upon the environment from our operations.

4. Flexibility to Respond to Change

Our Preferred Plan was developed to position us well in the current planning landscape. Obtaining strategic flexibility is a key component of doing so. This flexibility enhances our ability to respond to changes in the financial, social, and technological factors affecting our operations during the planning period and preserves optionality for us to respond to these factors beyond the planning period.

5. Limiting Risks

Much like the flexibility to respond to change, the strategic flexibility inherent in our Preferred Plan limits the risk of adverse effects on the Company and our customers from financial, social, and technological factors beyond our control. Key in limiting risk is our ability to avoid significantly increasing or reliance on natural gas a fuel with our Preferred Plan providing a hedge against volatility in gas prices.

For these reasons, our Preferred Plan represents the best option to meet customers' needs in light of the planning landscape for the planning period – and presents the best path forward for the Company, our customers, and the energy future of the Upper Midwest area.

VII. CUSTOMER COST IMPACTS

In this Chapter, we explain how we approximated a baseline level of revenue requirements associated with our Reference Case and measured the incremental cost impacts of our Preferred Plan at NSP System, state of Minnesota, and individual Minnesota customer class levels.

Initially, our primary purpose for developing a cost impact process was to estimate the incremental rate impacts of various scenarios to help the Company arrive at its Preferred Plan. Ultimately, it serves to approximate the incremental impacts of the Company's Preferred Plan on customers.

Overall, our Preferred Plan results in an estimated average annual increase in revenue requirements of less than two percent more than the average estimated Reference Case over the planning period.

We discuss the methodology we used to calculate the revenue requirements associated with our Reference Case and impacts on an overall NSP System and Minnesota customer class level below.

A. Reference Case Rate Forecast Methodology

To calculate the long-term rate impacts of the Preferred Plan as compared to the Reference Case, we first developed a forecast of total rates under Reference Case assumptions. To do this, we used forecasted 2014 total system revenue requirements and escalated it at an annual growth rate of 1.68 percent through the planning period.

We determined this growth rate by using a combination of the Company's shorter range financial forecasts and a special-purpose Strategist model used to project total system revenue requirements for extended periods. Typically, the Strategist model develops projections for generation-related costs. To derive a total system (including transmission, distribution, A&G, etc.) forecast, we expanded the standard Strategist model by adding capital and expense items associated with the other costs that are not typically modeled.

We input starting net plant and deferred tax balances, capital spend forecasts and O&M forecasts for the existing generation, transmission, distribution and overhead business areas, and calibrated the model such that the total revenue requirements approximately tracked the more refined short-term financial forecasts during the initial years.

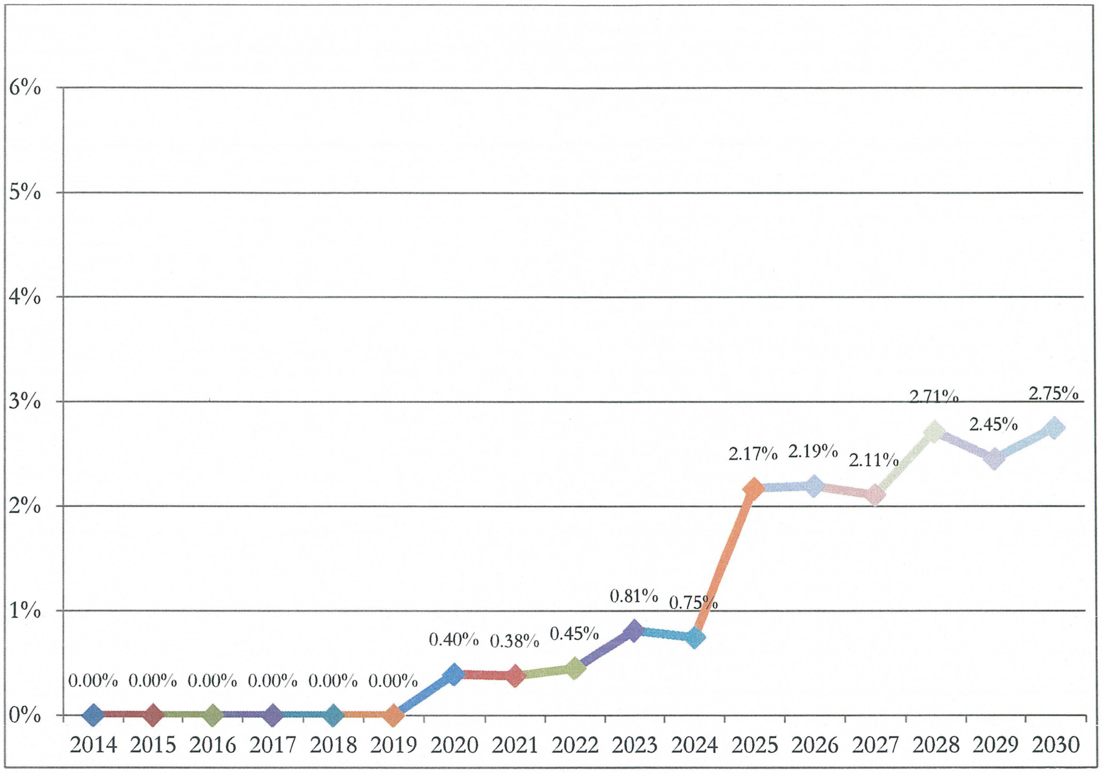
We extended the transmission, distribution and administrative business area capital and O&M forecasts through the planning period based on a general trending approach, and removed known outliers in the short-term forecast, such as large projects (CAPX 2020 transmission costs, for example) and escalated the underlying "base spend" at a rate comparable to inflation.

We treated the generation business area forecasts slightly differently due to the inherent functionality of Strategist in forecasting these costs. We developed capital and O&M costs for existing Company-owned assets similarly to the other business areas, with existing capital accounts and forecasted capital and O&M costs trended over time. Incremental (i.e. new) resource costs, as well as Sherco 1 and 2 costs and any other resource costs already explicitly modeled in the Resource Plan Strategist data are the same as the Resource Plan scenario runs.

We used this expanded Strategist model, after calibration, to determine the 2014-2030 forecasted growth rate in total system revenue requirements (1.68 percent annually), which we then applied to the base year (2014) *known* revenue requirement to develop the Reference Case forecast.

To determine the impact to Minnesota customers, and individual customer classes in Minnesota, we converted the differential in annual expenses and capital spend of the Preferred Plan compared to the Reference Case into a differential revenue requirement forecast. We then jurisdictionalized the differential revenue requirements and applied rate design principles to calculate impacts on individual Minnesota customer classes. We show the various impact analyses and discuss our methodologies below.

Figure 12: Annual Percent Change in Revenue Requirements 2016 -2030
(Preferred Plan above Reference Case)



B. Determining Class Rate Impacts

After determining the incremental revenue requirement impacts from the Preferred Plan and Reference Case for the Minnesota jurisdiction, we determined *class* revenue requirement impacts by allocating incremental costs to rate classes for each year in the planning period (2016-2030). After costs are allocated, we then calculate revenue requirement impacts for each customer class.

The following expense items are impacted by the Resource Plan:

- Fuel
- Purchased energy
- Production O&M expenses

The cost allocation methods that we used to allocate these costs to each rate class are the same methods that were approved in the Company's most recent rate case Order in Docket No. E002/GR-12-961, as follows:

1. Fuel and Purchased Energy

These costs are allocated to class using the Commission approved E8760 energy allocator. The E8760 allocator is calculated by taking the forecast hourly load for each of the 8,760 hours of the test year for each customer class, then weighting the hourly load by the forecasted hourly marginal energy cost in each respective hour. The approved E8760 allocator from the last rate case order is shown in Table 12 below:

Table 12: Approved E8760 Energy Allocator

MN	Residential	Commercial Non- Demand	C&I Demand	Lighting
100.00%	28.88%	3.38%	67.31%	0.43%

2. Production O&M Expense

Production O&M expenses are split into energy-related and capacity/demand-related components using the Company's plant stratification analysis approved in our most recent Minnesota rate case.

The plant stratification approach begins by comparing the replacement cost of each type of generation plant (fossil, combined cycle, etc.) to the replacement cost of a combustion turbine. Combustion turbines are 100 percent capacity/demand-related since they are the generation source with the lowest capital cost and the highest operating cost. For each generation type, the percent of total generation costs that exceeds the cost of combustion turbine peaking plant are classified as being energy-related. These costs are in excess of the capacity/demand-related portion, and as such, were not incurred to obtain capacity, but rather to obtain lower cost energy.

We show the Commission-approved plant stratification analysis that we applied to production O&M expenses for each plant type in Table 13 below:

Table 13: Stratification Analysis by Plant Type

Plant Type	Replacement Value $/kW	Capacity Ratio	Capacity/Demand Percentage	Energy Percentage
Combustion Turbine	$689	$689 / $689	100.0%	0.0%
Fossil	$1,912	$689 / $1,912	36.0%	64.0%
Combined Cycle	$997	$689 / $997	69.1%	30.9%
Wind	$15,297	$689 / $15,297	4.5%	95.5%

After production O&M expenses for each type of generation plant are split into capacity-related and energy related components based on the percentages shown in Table 13 above, those expenses that have been classified as being energy-related are allocated to class using the E8760 energy allocator shown in Table 13 above. The production O&M expenses that have been classified as being capacity or demand-related are allocated to customer class using the Commission-approved D10S capacity allocator.

The D10S allocator is simply each class's load that is coincident with the NSP System peak load. The Commission approved D10S class allocator percentages are shown in Table 14 below:

Table 14: Approved D10S Capacity Allocator

MN	Residential	Commercial Non-Demand	C&I Demand	Lighting
100.00%	35.31%	3.82%	60.87%	0.00%

3. Calculation of Class Rate Impacts

After the class cost allocations that are described above are done for each year, we calculate revenue requirements for each class in each year. We calculated rate impacts in $ per kWh by dividing each class's revenue requirement in each year by the forecasted sales in each year. The incremental revenue requirement impact of the Preferred Plan versus the Reference Case is shown in column 3 of Table 15 below. Column 4 of the below Table also shows the incremental impact of the Preferred Plan as a percent of the total State of Minnesota revenue requirement.

Table 15: Estimated Incremental Impact – Preferred Plan

1	2	3	4
Year	**State of MN Total Revenue Req ($000)**	**Incremental Impact of Preferred Resource Plan** ($000)	**% Change**
2014	**$3,034,754**	$0	0.00%
2015	$3,085,664	$0	0.00%
2016	$3,137,429	$0	0.00%
2017	$3,190,062	$0	0.00%
2018	$3,243,577	$0	0.00%
2019	$3,297,991	$0	0.00%
2020	$3,353,317	$13,258	0.40%
2021	$3,409,572	$12,985	0.38%
2022	$3,466,770	$15,686	0.45%
2023	$3,524,928	$28,603	0.81%
2024	$3,584,061	$26,771	0.75%
2025	$3,644,187	$79,061	2.17%
2026	$3,705,321	$81,300	2.19%
2027	$3,767,480	$79,471	2.11%
2028	$3,830,683	$103,946	2.71%
2029	$3,894,945	$95,439	2.45%
2030	$3,960,286	$108,730	2.75%

We visually portray the information contained in Table 15 above in Figure 13 below.

Figure 13: Incremental Rate Impact of Preferred Resource Plan State of Minnesota – All Customers

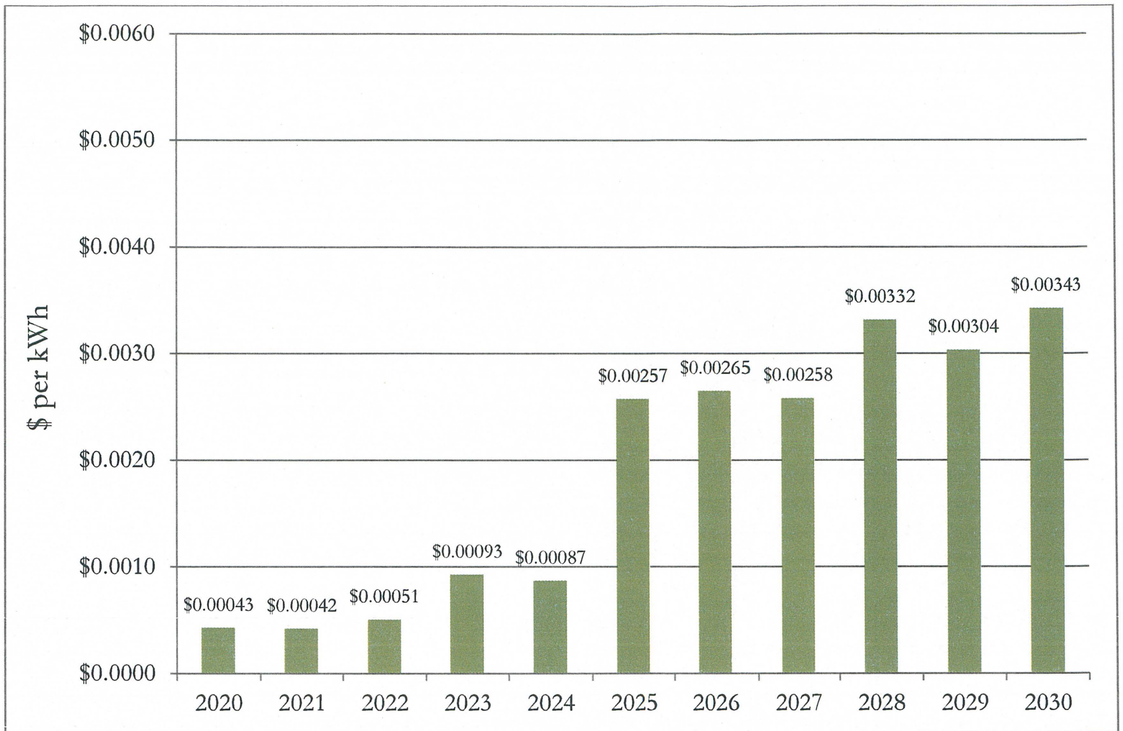
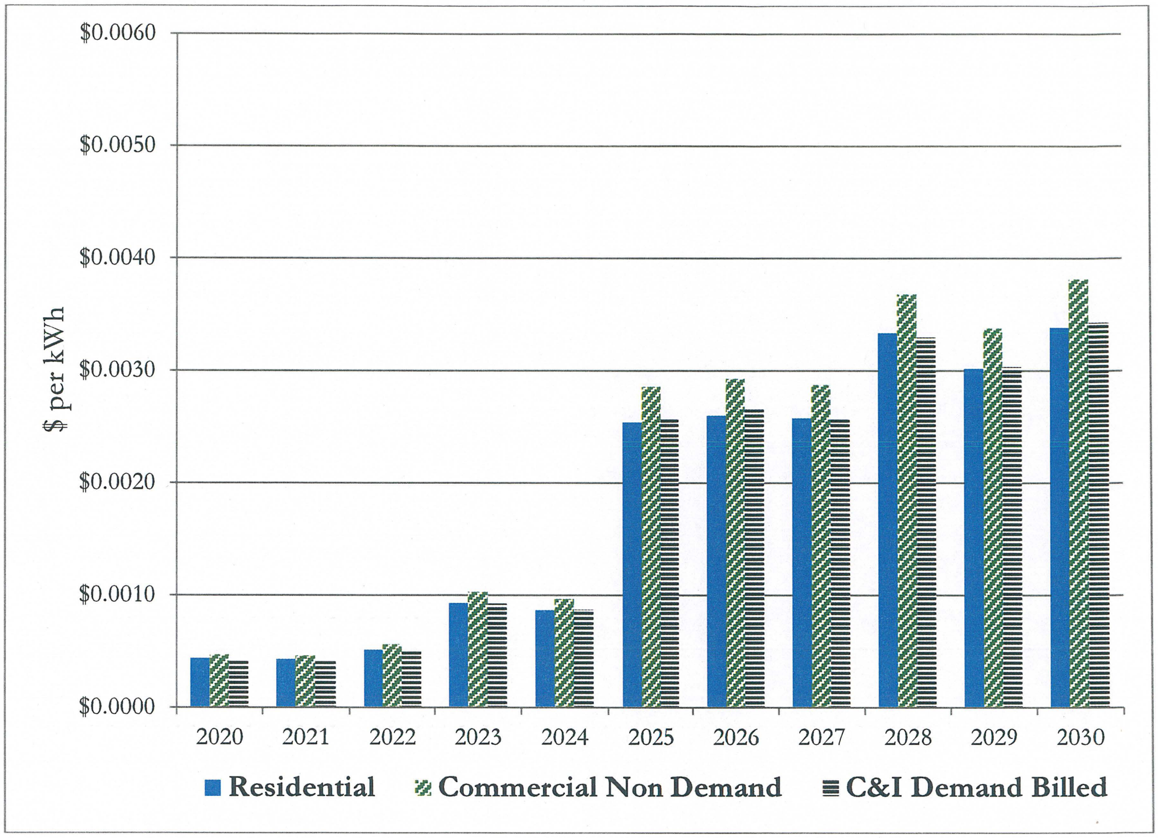


Figure 14 below shows the approximate incremental impacts of our Preferred Plan by customer class.

Figure 14: Incremental Rate Impact of Preferred Resource Plan by Customer Class – State of Minnesota



VIII. PROCEDURAL PROPOSAL

This Resource Plan is presented to the Commission in a time of policy, regulatory, and industry change. The Company and the e21 Initiative have identified industry trends that are affecting both our resource planning and the broader regulatory environment, including the rising costs of providing service; the challenge of meeting environmental and other policy mandates; a more competitive marketplace; the expansion of distributed generation; and rate case fatigue.

The e21 Initiative's initial report likewise identified a potentially new approach to resource planning, by introducing the concept or an Integrated Resource Analysis rather than the traditional Integrated Resource Plan. All of these circumstances have converged during a period when the Company is experiencing relatively level demand growth and has identified no resource need in the near term. We believe this environment calls for a progressive approach to resource planning in light of industry change.

We therefore propose review of this Plan in a manner that acknowledges the broader planning landscape and provides greater opportunity than ever before to review industry-wide issues and incorporate stakeholder input. To achieve the state's long-term vision in a thoughtful manner, we recommend a collaborative process. Rather than proceeding directly to solicitation of written comments on the Plan, we propose to engage our stakeholders in a dialogue about resource modeling, sensitivities, and issues arising from the evolving planning landscape.

We believe this process will dovetail with the need to update our resource planning analyses to reflect recent Commission decisions in our CAP docket, the significant interest in our Solar*Rewards Community garden program, our utility-scale solar petition, and other issues that bear on resource planning. Similar to our proposal for next steps following the December 2014 e21 Initiative Phase I Report, the goal of this dialogue and any stakeholder conferences would be to gather input from stakeholders, determine whether changes to the Plan are needed, and address any advance stakeholder concerns in a proactive, collaborative manner. In this way, the Plan ultimately presented to the Commission for decision would reflect considered incorporation of stakeholder feedback and a robust planning process.

We request any Rule variances that may be required to carry out this process, including delays of the uncontested proceeding process contemplated by Minn. R. 7843.0300, subp. 9, the deadline for written comments and response comments set forth in Minn. R. 7843.0300, subp. 10 and 11, and the deadline for intervention set forth in Minn. R. 7843.0300, subp. 7. We believe variances from the intervention and comment deadlines in Minn. R. 7843.0300 are further warranted by the timing of this initial Resource Plan filing, which follows from the Commission's variance to Minn. R. 7843.0300, subp. 2 implemented through the Commission's May 23, 2014 Order in Docket No. E002/CN-12-1240.

Pursuant to Minn. R. 7829.3200, the Commission has the authority to vary the requirements of Minnesota Rule 7843.0300. Under Rule 7829.3200, the Commission may vary the requirements of any of its rules upon the following findings:

1. Enforcing the rule would impose an excessive burden upon the applicant or others affected by the rule,
2. Granting the variance would not adversely affect the public interest, and
3. Granting the variance would not conflict with any standards imposed by law.

Enforcement of the traditional resource planning timelines would impose an excessive burden on stakeholders wishing to participate in a collaborative process, and in light of the nontraditional timing of this initial filing. Granting the variance would further enhance, rather than adversely affect, the public's interest in a robust level of stakeholder participation and a thorough planning process that accounts for broadly changing circumstances. Finally, the variance would not conflict with any standards imposed by law.

IX. CONCLUSION

We are pleased to present this Resource Plan to the Commission, and look forward to a robust and productive dialogue regarding the current planning landscape and the Company's vision for our resource future.