UPPER MIDWEST INTEGRATED RESOURCE PLAN

2020-2034

Northern States Power Company
Docket No. E002/RP-19-368

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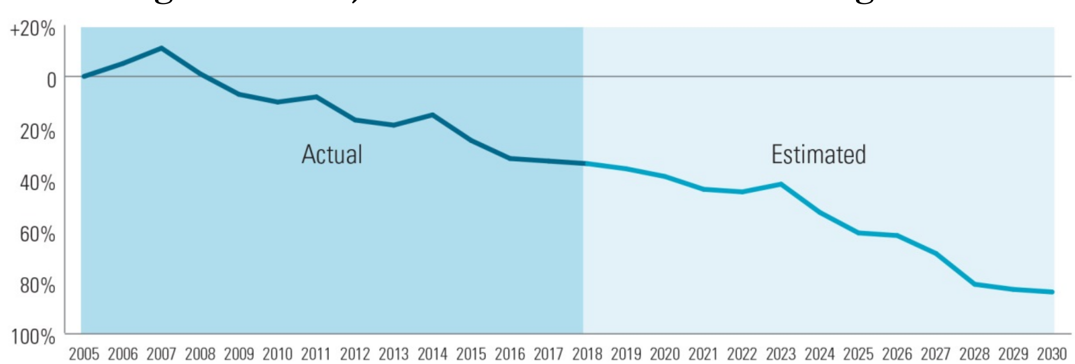
2020-2034 UPPER MIDWEST INTEGRATED RESOURCE PLAN

CHAPTER 1
EXECUTIVE SUMMARY

I. INTRODUCTION

This 2020-2034 Upper Midwest Integrated Resource Plan charts the path toward achieving some of the most ambitious carbon reduction goals of any utility in the U.S. Specifically – we aim to reduce carbon emissions 80 percent by 2030, and provide 100 percent carbon-free energy by 2050. This Resource Plan not only reaches the 2030 goal through retirement of our coal fleet, extension of nuclear, aggressive renewable additions, and demand-side management including both energy efficiency (EE) and demand response (DR), and a mix of load supporting, firm dispatchable resources – it embraces technology and innovation and is well-grounded in reliability and affordability. And while the last stretch of total carbon reduction – from 80 to 100 percent – will require technologies that have not yet been developed or deployed economically, we are confident that we can work with regulators, policymakers, and stakeholders to position ourselves so we are prepared to take advantage of the cost-effective solutions that emerge over the course of the next 30 years.

Figure 1-1: Projected Carbon Emissions Through 2030



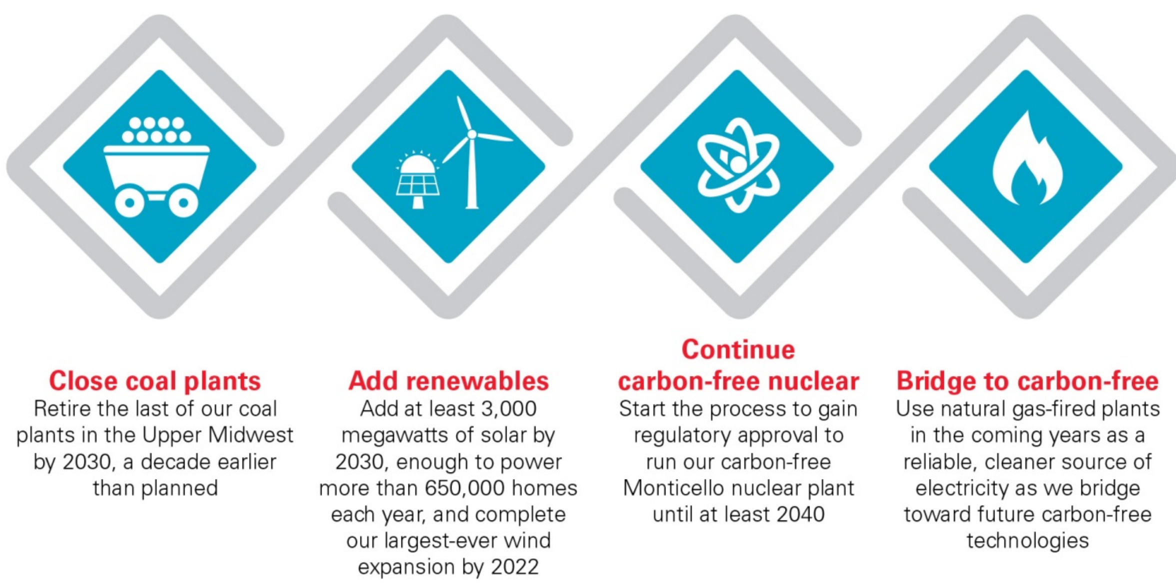
Our Preferred Plan is the product of an unprecedented stakeholder process that included 13 public workshops, independent expert analysis, and months of information sharing as we developed a Preferred Plan. As a result of those efforts, our Preferred Plan is the product of an unusual amount of consensus this early in the Resource Plan process. That consensus is represented by an agreement signed by the Company, the Clean Energy Organizations,[1] Center for Energy and Environment,

[1] The Clean Energy Organizations include Clean Grid Alliance, Minnesota Center for Environmental Advocacy, Fresh Energy, and Union of Concerned Scientists.

Sierra Club, and LIUNA Minnesota and North Dakota that resolves (among those parties) many of fundamental building blocks of our plan.

Those building blocks include the elimination of coal-fired generation from our system by 2030, as well as the reduced, seasonal dispatch of Sherco 2 until its retirement in 2023. The agreement also includes the acquisition of at least 3,000 megawatts (MW) of utility-scale solar by 2030, and a substantial increase in EE programs, representing an average annual savings of over 780 gigawatt hours (GWh). Finally, the agreement includes support for the Company's proposal to take ownership of the Mankato Energy Center (MEC) combined cycle (CC), which will be central to our reliability strategy as we retire 2,400 MW of coal and integrate several gigawatts (GW) of new renewable resources. The Company's Preferred Plan builds upon this agreement and adds proposals to operate our carbon-free Monticello nuclear plant for an additional 10 years beyond its current license, add a significant amount of DR resources, and construct a new CC at our Sherco site. In total, we have an ambitious plan that supports the Company's goal of reducing carbon emissions 80 percent by 2030, and it moves us toward our ultimate vision of 100 percent carbon-free energy by 2050.

Figure 1-2: Preferred Plan Highlights



Throughout this process, we have taken steps to ensure that we can meet these progressive carbon reduction goals while preserving the reliability our customers have enjoyed for decades. To that end, the Company's engineering and operations teams have conducted extensive analyses to ensure that we can continue to serve customers every hour of every day, even as we progress toward relying on intermittent resources for a majority of our generation. In this work, we have aimed to embrace change while addressing the physical realities of our system and the responsibility that comes with providing a genuinely essential service.

The addition of several gigawatts of renewable resources requires that we consider not only our traditional summer peak, but also whether we have sufficient dispatchable resources to meet other peaks, including in winter when solar energy is typically unavailable and wind resources may not be available for long periods of time. Our Preferred Plan addresses these reliability issues in three ways. First, the extension of Monticello by an additional 10 years and the continued operation of Prairie Island will anchor our grid in around-the-clock, carbon-free energy. Second, we are proposing to take ownership of the Mankato Energy Center and build a new CC plant at our Sherco site in 2026. These dispatchable resources will be critical as we retire 2,400 MW of coal-fired baseload and transition to a system that is nearly 60 percent renewable and intermittent generation. Finally, we propose several firm dispatchable, load-supporting resources – but defer these additions until the latter part of the decade, in anticipation of technological advancements that will improve the functionality and drive down the cost of resources, like storage, that can take the place of traditional gas peaking units.

We also recognize that the achievement of our carbon reduction goals will depend on our ability to keep rates affordable. We believe that our Preferred Plan accomplishes this by keeping annual cost growth below the rate of inflation. The modest cost of our plan is facilitated by our strategy of deferring resource additions until later in the plan and making use of existing assets on our system. Additionally, we believe technological improvements will continue to drive the costs of renewables down, which is a key element in our strategy of proposing significant solar additions in the latter half of the next decade.

We also know that our proposed plan includes impacts both on the communities we serve and our employees. We appreciate not only the challenge – but the stakes for those impacted – and we plan to build on our successful track record of working with our communities, policymakers, stakeholders and employees to successfully manage this clean energy transition.

We further recognize that the agreement underlying our Preferred Plan is simply the beginning of a process. And although elements of our Preferred Plan are captured by the Settlement, the parties to the agreement have not endorsed the entire plan and the Commission has not yet approved the plan. As a result, we look forward to a healthy discussion on the best way forward. That said, we view the agreement – which promises the elimination of coal and the new prominence of solar on our system – as a great foundation from which to work. We believe both the process and outcome of this collaborative effort are a testament to the regulatory landscape in the states we serve, and we look forward to continuing the discussion around this transformational plan and our collective energy future.

II. EXECUTIVE SUMMARY

In our last Resource Plan (Docket No. E002/RP-15-21), we discussed the rapid evolution of our industry due to changing technology, enhanced customer expectations, and the increasing consensus around the importance of carbon reduction. We also noted that partnership among our stakeholders, communities, and the Company would become even more important to navigating these changes. In approving our prior plan, the Commission likewise noted that resource planning is a collaborative and iterative process and that a full understanding of the relevant facts requires exposure to the views of engaged and knowledgeable stakeholders.

We are filing this 2020-2034 Upper Midwest Integrated Resource Plan following an unprecedented stakeholder process that included 13 public workshops with topics from the evolving resource planning process, to more technical considerations, such as transmission and system reliability. We also engaged a third-party consultant—Energy and Environmental Economics, Inc. (E3) to conduct independent, parallel analysis to inform the Company's future resource strategy. E3 presented its findings to a diverse group of stakeholders at a workshop in April 2019. We then presented our own preliminary Preferred Plan at our final stakeholder workshop in May 2019.

We believe this combination of a significant internal effort, extensive collaboration, independent expert analysis, and transparency has improved not only the process that led to the development of our Preferred Plan but also the plan itself. In fact, it was through this stakeholder engagement that the Company, the Clean Energy Organizations,[2] Center for Energy and Environment, Sierra Club, and LIUNA Minnesota and North Dakota were able to reach an agreement that addressed many of the cornerstones of our Preferred Plan, including: (1) retirement of our last two coal units by 2030; (2) seasonal dispatch of Sherco 2 until its retirement in 2023; (2) acquisition of the MEC CC; (3) acquisition of at least 3,000 MW of utility-scale solar by 2030; and (4) a substantial EE goal.

We acknowledge that this agreement is just the start of the process – a process that

[2] The Clean Energy Organizations include Clean Grid Alliance, Minnesota Center for Environmental Advocacy, Fresh Energy, and Union of Concerned Scientists.

began with the Commission and its request to conduct a holistic review of our baseload resources. As we return to the Commission and begin to engage with the Commission directly in this Integrated Resource Plan docket, we look forward to the opportunity to demonstrate the substantial benefits of our Preferred Plan. It is also true that the terms of the agreement outlined above do not cover all components of our Preferred Plan, and we recognize that stakeholders continue to have wide-ranging perspectives on our collective energy future. We welcome those perspectives as part of this process, and we look forward to more collaboration and iteration as this docket moves forward. That said, we view the agreement as a very good start and a positive outcome from our stakeholder process; we appreciate the Commission setting us on the path; and, we believe the agreement demonstrates that stakeholders and the Company can find common ground and build consensus around key building blocks of a plan that satisfies the needs of our five-state Upper Midwest region – and meets individual state goals as well. Indeed, meeting the varied interests of our integrated system was an important foundation of our planning process.

Both the agreement and our overall Preferred Plan are consistent with the Company's environmental goals. For more than a decade, Xcel Energy has been a leading wind energy provider in the nation and has pursued a successful strategy to transition to clean energy. We have surpassed both national and international goals, including the U.S. commitment under the Paris Climate Accord of 26-28 percent reduction in carbon emissions by 2025. To-date, we have reduced carbon emissions 38 percent companywide from 2005 levels. We are proud of these achievements and grateful to our many stakeholders who have played a role in our journey.

In December 2018, the Company expanded on its commitment to clean energy by announcing industry-leading goals to reduce carbon emissions 80 percent Company-wide by 2030,[3] and to provide 100 percent carbon-free electricity across our service territory by 2050. This 2020-2034 Upper Midwest Integrated Resource Plan charts a path to accomplishing these goals through the elimination of all coal generation on our system by 2030, the addition of over 5,000 MW of renewables, and the expansion of our industry leading EE and DR programs. It accomplishes these environmental milestones while not sacrificing operational reliability or affordability. Specifically, we propose to do the following:

- ***Coal Resources -*** Retire our last two units early: King in 2028 (nine years early) and Sherco 3 in 2030 (ten years early). Additionally, continue our plan to retire Sherco 1 and 2 in 2026 and 2023, respectively, and commit to offering Sherco Unit 2 into Midcontinent Independent System Operator (MISO) on a seasonal basis until its retirement.

[3] From 2005 levels.

- ***Nuclear Resources-*** Operate our Monticello unit through 2040 (10 years longer than its current license) and operate both Prairie Island units through the end of their current licenses (PI Unit 1 to 2033 and PI Unit 2 to 2034).[4]
- ***Renewable Resources –*** While the exact wind and solar mix could vary based on a variety of reasons, at this time we propose to add 4,000 MW of cumulative utility scale resources by 2034 (the first being in 2025) and approximately 1,200 MW of cumulative wind by 2034 to replace wind that is set to retire from our system during that period.
- ***Combined Cycle Resources –*** Acquire and operate MEC and build, own and operate the Sherco CC to satisfy significant capacity and operational need created by coal closures.
- ***Firm Load Supporting Resources –*** Starting in 2031, add approximately 1,700 MW of cumulative firm dispatchable, load-supporting resources by 2034.
- ***Demand Side Management (DSM) -*** Include EE programs representing approximately 780 GWh of savings annually through 2034 (compared to average annual energy savings of 444 GWh in our last Resource Plan) and the addition of 400 MW of incremental DR by 2023 with a total of over 1,500 MW DR by 2034.

This plan demonstrates that we can achieve our 2030 goal with existing technologies and resources while maintaining both reliability and affordability.[5] However, it also creates opportunities to introduce emerging technologies as part of the solution. We see opportunities for innovation in our ongoing EE and DR programs. Likewise, we believe the industry will deliver new and improved technologies that will support our long-term need for firm, load supporting resources. The plan also advances a framework that achieves these goals in manageable steps as opposed to transitioning the entire system and grid all at once. By doing so, we can continue to ensure the reliability of our system and maintain flexibility to respond to future market trends, technology advancements, and changing regulatory policies
Below, we discuss our proposed resource mix further, as well as the priorities and considerations that drove the development of our plan.

[4] Given that our operating licenses for Prairie Island run until 2033 and 2034, we believe there is sufficient time to address the future of that plant in upcoming resource plans.
[5] As we explained our December 2018 announcement, we recognize that serving customers with 100 percent carbon-free electricity will likely require technologies not yet commercial available, and we look forward to discussing these technological developments in future resource plans.

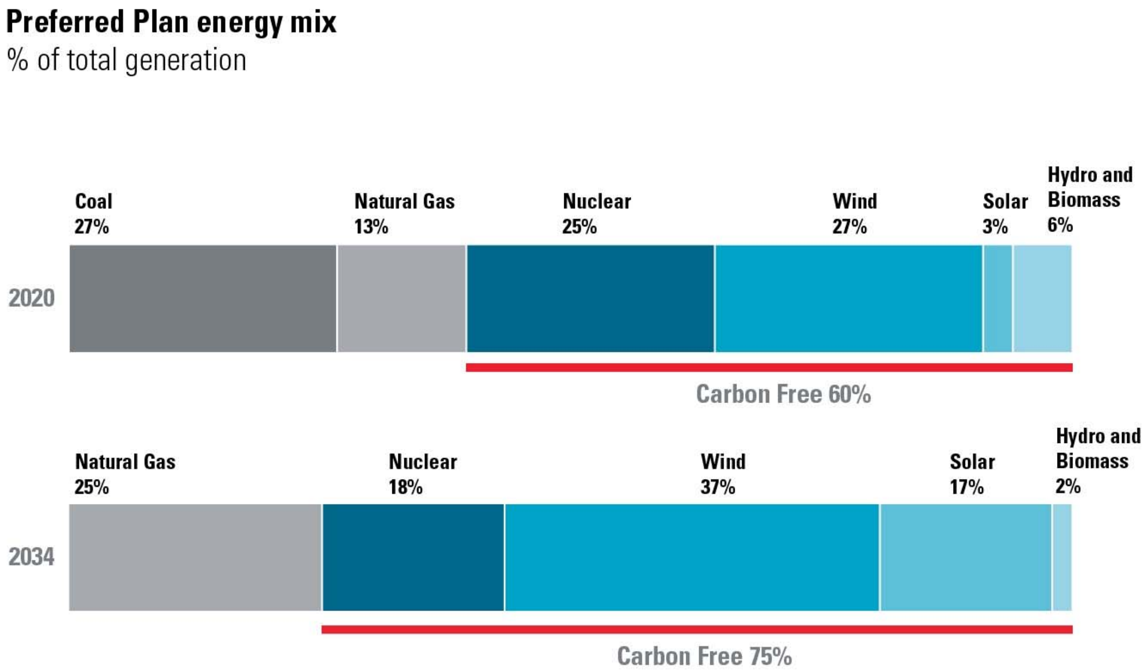
A. Proposed Resource Mix

Our Preferred Plan reflects a significant transformation of our resources. We have more than 1,300 MW of energy resources subject to power purchase contracts that are expiring. Our plan is also informed by an extensive study of all of our baseload resources, completed in response to the Commission's last Resource Plan Order. That study included seven Attachment Y2 studies by MISO and a more traditional NERC-based analysis of our fleet by an external consultant. All of these potential retirements were then studied in conjunction with the addition of significant renewable resources needed to meet our 80-by-30 goal, which identified reliability and stability issues that will need to be resolved as we move through the planning period.

As a result of this work, our Preferred Plan takes a measured approach to adding and retiring resources, and it prioritizes reliability and long-term system planning – as it must. In the first five years, we have no incremental capacity needs and propose only minimal additions.[6] In fact, there are no significant resource additions until 2025 when our first utility-scale solar is proposed. By relying on our existing resources in the near term, we preserve flexibility to respond to changing customer needs and regulatory policies, and we can monitor technological change to ensure we make future resource investments at the speed of value when they are in the best interest of our customers. We will continue our aggressive support of EE and DR and are looking to emerging resources to be part of that solution.

[6] Our actions in the next five years will address previously approved or pending resource additions and retirements, wind repowering and procurement to meet specific customer or program needs, community solar garden growth, and DSM programs.

Figure 1-3: Preferred Plan Energy Mix through 2034



That said, in light of the potential baseload retirements and expiring power contracts, we must address nearly 75 percent of the energy-producing resources on the NSP System during the 15-year planning horizon. We developed the Preferred Plan with an eye toward maximizing cost-effective renewable resources, backed by natural gas to support renewable integration and system reliability, in an effort to minimize market and commodity exposure. By doing so, our system will not be overly reliant on any one fuel source, and we will retain our trademark reliability – along with the flexibility to consider the economics of new resources as our baseload plants retire.

We discuss the components of our proposed resource mix in greater detail below.

1. Coal

With respect to coal-fired generation, our 2020-2034 Resource Plan represents a monumental step forward in transitioning our fleet. Today, as a result of our agreement with the Clean Energy Organizations, Center for Energy and Environment, Sierra Club, and LIUNA, we are proposing to retire our King plant in 2028 and Sherco 3 in 2030 – meaning that Xcel Energy will complete its transition away from coal-fired generation in 2030 – a full decade earlier than previously anticipated. In total, we plan retire approximately 2,400 MW of coal-fired generation in the next decade.

The early retirement of these plants allows us to reduce and ultimately eliminate our reliance on coal, enable additional cost-effective renewable resources, and save customers money. In addition to these retirements and the early retirements of Sherco Units 1 and 2 approved in our 2015 Resource Plan, we are also proposing to offer Sherco Unit 2 into MISO on a seasonal basis until its retirement in 2023, which we expect will reduce its carbon emissions in the near term.

This accelerated transition away from coal requires the Company to plan for the retirement of 2,400 MW of coal-fired generation in the next decade, which represents almost one-fourth of the total capacity in our current generation fleet. This will be an unprecedented period of transition for our system that necessitates a prudent replacement strategy. Our strategy for replacing these MWs includes a combination of natural gas CC resources, continued reliance on nuclear generation, large renewable additions during the planning period, and a continued commitment to both EE and DR, all of which will be critical to maintaining reliability throughout this baseload transition. We discuss each in turn below.

2. Nuclear

Carbon-free nuclear generation has been a cornerstone of our generation fleet for nearly half a century. Today, our nuclear plants generate about half the carbon-free energy for our Upper Midwest customers – amounting to the avoidance of about 7 million metric tons of carbon dioxide annually. This is equivalent to removing 1.5 million cars from the road. Our nuclear fleet is therefore critical to meeting our "80-by-30" goal and maintaining that level into the future.

Our nuclear units enable the Company to achieve and maintain our carbon reduction goals while incorporating incremental renewables at a reasonable pace and maintaining reliability. Nuclear is also an important system resource during the winter months, as it does not experience fuel supply issues and has a great track record during cold weather events – making it a critical piece of our reliability strategy, which we discuss below.

In light of these considerations and others discussed later in this filing, our Preferred Plan includes operating our Monticello nuclear plant until 2040, along with the continued operation of Prairie Island through its current operating licenses (which expire outside the planning period of this Resource Plan, in 2033 and 2034). By continuing the operation of these plants and extending our Monticello license, we can continue to enjoy the substantial carbon-free benefits these baseload units provide while saving our customers money by leveraging existing assets on our system.

Absent a Monticello operating extension, based on the reliability needs of the system, any suitable replacement resource would add carbon to our portfolio. We simply could not maintain our system reliably, or affordably, given the massive renewable additions and corresponding transmission infrastructure that would be required to replace our Monticello nuclear plant, if it were even possible by 2030, given MISO's current transmission expansion issues.

The recommendation to extend the Monticello unit is supported by its operational performance, which has achieved an average capacity factor of 96.5 percent over the past three years (including a record-setting 99.3 percent in 2018). Moreover, we achieved this performance all while reducing production costs by more than 20 percent since 2015. We believe this performance demonstrates that we can achieve deep carbon reduction along with industry-leading safety and reliability at an affordable cost. For all of these reasons, our nuclear strategy is sound and is in our customers' best interest and consistent with the public interest.

Procedurally, we intend to bring a petition for a Certificate of Need (CON) to address the Monticello license extension request to the Commission in the coming years. In that filing, we will provide detailed capital budgets and O&M forecasts, as well as economic modeling to justify our request. Given that the Prairie Island Units' licenses do not expire until 2033 and 2034, we believe we have time to address the future of these units in our next Resource Plan. We look forward to engaging with the Prairie Island Indian Community, Monticello, and Red Wing as we begin a discussion about the role of nuclear in our energy future.

3. Renewable Resources

Substantial renewable additions are a central component of our energy future and thus a cornerstone of this Preferred Plan – which proposes to add 4,000 MW of cost-effective, utility-scale solar generation and approximately 1,200 MW of cumulative wind resource additions. While the exact mix of wind and solar added to our system may vary (in concert with a variety of factors including technology advancements and price changes), our commitment to renewable energy will not.

In total, our Preferred Plan envisions a system that is approximately 60 percent renewable energy – a level that puts us among those leading the nation. And, while we are confident in our ability to deliver on our reliability commitment at this high level of renewable penetration, we are somewhat cautious at the same time about going much beyond those levels in light of our own experience, as well as recent industry studies regarding the complexity and complications of an exceedingly high renewable grid.[7] That said, some of our customers and municipalities have environmental goals that include the achievement of 100 percent renewable energy to meet their needs, and we are confident we can meet those needs given the substantial renewable additions proposed in this Resource Plan.

The capacity value of renewables combines with our cost-effective gas and nuclear generation to deliver safe and reliable service that will withstand the summer and winter peaks of the Upper Midwest. Significantly, with these additions, there would be enough solar generation to power more than 650,000 homes each year.

Wind generation also continues to play a prominent role in this Resource Plan. Xcel Energy has long been one of the nation's leading providers of wind energy, and we are currently engaged in the largest build-out of new wind resources in our Company's history – thanks in large part to the Commission's approval of our last Resource Plan and our 1,850 MW wind portfolio. By 2024, wind will provide approximately 35 percent of the electricity for our customers in this region, making it the largest component of our overall generation portfolio.

4. Combined Cycle Resources

In addition to our carbon-free nuclear baseload resources, the continuation of dispatchable generation on our system will be vital to our ability to manage the retirement of approximately 2,400 MW of coal-fired generation over the next decade while maintaining reliability. It will also facilitate our ability to successfully integrate large amounts of renewables; we can ramp the output of these resources up or down in response to our system's changing needs throughout the day, as renewable resources generate more or less energy due to their variable nature. Finally, dispatchable generation will also help us plan for the expected marginal decline in load carrying capability from renewables as their penetration increases, which we believe could result in additional capacity needs.

To that end, our Preferred Plan includes our acquisition of MEC (a 760 MW two-unit CC), as proposed in Docket No. IP6949,E002/PA-18-702,[8] as well as our plan to build the approximately 800 MW Sherco CC located in Becker, Minnesota in the mid-2020s. As discussed in the pending MEC docket, that plant is already an integral part of our system, as its output is committed to the Company through two Commission-approved PPAs. By securing ownership of the plant, we can mitigate the risk

[7] *See* https://twin-cities.umn.edu/news-events/research-brief-planning-future-energy-demand-renewable-energy and MISO's *Renewable Integration Impact Assessment* (RIIA), which we discuss in Appendix J2: Reliability Requirement.
[8] We will incorporate any Commission decision from that docket into our modeling and supplement the record as necessary.

associated with expiration of the first PPA in 2026, thereby achieving additional certainty with respect to capacity and dispatchable energy.

As discussed in our last Resource Plan, we propose to locate a CC at the existing Sherco site because it will allow us to cost-effectively address significant transmission issues identified by the MISO Attachment Y2 study, ensure the stability and reliability of the transmission system, mitigate impacts to the local community and our employees, and potentially provide improved access to natural gas supplies for communities in Central Minnesota.

Together, our MEC acquisition and constructing the Sherco CC will not materially impact the amount of gas generation on our system. As already discussed, MEC is already an existing resource on our system, and the Sherco CC will primarily offset the retirement of other gas generation on our system, including the Cottage Grove facility (approximately 250 MW in 2027) and Black Dog 5 (approximately 300 MW in 2032). This additional gas generation is not only reasonable, but an operational necessity in light of the much larger coal retirements planned – and the large amounts of variable renewable additions we anticipate in the same period.

5. Load Supporting Resources

Reliability is the bedrock of any resource plan. We are particularly focused on the reliability of our system in this plan, however, as we plan for such a large turnover of our baseload fleet and transition to a portfolio that is approximately 60 percent renewable and intermittent generation. We recognize that our transition to cleaner energy will only be successful if we can execute our vision without disrupting our customers' lives and businesses, so we are steadfastly committed to maintaining our performance when it comes to this core tenant of our business.

Based on the results of extensive reliability studies that we discuss further below, we are proposing approximately 1,700 MW of cumulative additions of firm dispatchable, load supporting resources from 2031-2034. The need for these dispatchable resources emerges in this later timeframe due to the major plant retirements already discussed, as well as the expiration of several PPAs. Our reliability analysis demonstrates that these additions are necessary to continue to support grid reliability and resiliency in light of the increased renewables being added to the system and the baseload units being retired. That said, because these units are not needed until the out years of our current plan, we have not identified a specific resource type to meet this need. However, with the expected price declines and technology development, between now and the 2030s, we fully expect utility-scale storage will be an integral resource used to meet this need. Likewise, we believe the deployment of advanced grid investments could position DR to better compete with traditional generation to fill some of this firm dispatchable need. We are committed to pursuing all of these options not only in the longer term, but in the near term as well in order to position ourselves to leverage this technology as it matures.

In addition, as discussed in our last Resource Plan, system retirements will impact our current blackstart plans and we are currently analyzing our blackstart path to determine the best fit for our system needs. While we do not propose any action related to the system blackstart at this time, we anticipate addressing this in our next Resource Plan or earlier, if system needs dictate the need to do so.

By keeping options open and remaining technology agnostic, we can acknowledge the need for a firm resource at the tail end of our plan but allow the market to advance as we file future resource plans and continue to collaborate with our stakeholders and the Commission as the need for these resources begins to materialize.

In the meantime, we are analyzing potential locations and sizing of storage solutions as well as the potential values storage assets might provide to the system.

6. Energy Efficiency

Our Preferred Plan also proposes to add significant amounts of EE based on the December 2018 *Minnesota Energy Efficiency Potential Study: 2020-2029*. In fact, our proposal includes an annual average of over 780 GWh of savings for 2020-2034. Our last Resource Plan included 1.5 percent annual EE savings assumption, but our current proposal achieves much higher levels of savings – ranging from approximately 2 to 2.5 percent annually. Relative to a 1.5 percent assumed savings level, our proposal achieves more than 200 MW of additional demand savings by 2023, and more than 800 MW by 2034.

7. Demand Response

Finally, consistent with the Commission's Order in our last Resource Plan, our Preferred Plan proposes to add 400 MW of incremental DR by 2023 (with a total of over 1,500 MW of DR by 2034). When it comes to DR, the Company leads the way in MISO, with 830 MW registered in the current planning year. In the last Resource Plan, the Commission ordered the addition of 400 MW of incremental DR by 2023. As we understood the Commission's reasoning, it sought to add incremental, cost effective DR to avoid near-term reliance on additional combustion turbines. As can be seen in our analysis, however, no combustion turbines or other firm, dispatchable resource additions are required until the 2031 timeframe as the model instead prefers solar additions as the most attractive resource in the 2025-2030 timeframe.

That said, we decided to include the DR in our Preferred Plan for several reasons: (1) to be consistent with the Commission's Order in our last Resource Plan, (2) to fill gaps if/when the solar capacity credit declines, (3) to help meet firm dispatchable resource needs in the 2030s, (4) to help support customer programs, and (5) to integrate new and emerging technology and tools. We note that for purposes of our modeling, we have included all of the DR identified in the Brattle study as cost-effective, including expansions to conventional DR programs (i.e., Savers Switch, smart thermostats, and interruptible rates) and a non-conventional smart electric water heater program. Additionally, we included the addition of Auto DR, another non-conventional DR program that automates control of various end-uses like HVAC and lighting. We believe the advancement of our grid and technology generally may take the form of less traditional DR, so we are requesting the flexibility to evaluate and pursue the required incremental DR through a variety of means and technologies over the coming years.

In this filing, our objective is to bring forward information on all of the viable options so the Commission, stakeholders, and the Company can engage in an informed exchange.

B. Plan Priorities

1. Reliability

The foundation of our business is providing safe and reliable electric service, and the purpose of a Resource Plan is to identify the appropriate resources to continue providing that service to our customers. Building on the reliability and stability issues identified as part of our Baseload Study and renewable integration work, and recognizing that many other utilities within the MISO planning area are also planning to retire their baseload units, we made reliability and resilience a primary consideration of this Resource Plan.

To that end, we have conducted a detailed analysis of what resources will be necessary over the full planning period – once many of our baseload units are retired and the renewable resources have taken their place as our primary source of generation. As part of that work, we have paid increased attention to analyses around our winter peak, when solar is diminished and wind facilities can also drop off as a result of extreme temperatures. That analysis points to a baseline operational level of firm resources needed to continue to support a reliable and resilient grid at all hours of the day, on all days of the year. This operational guidance was then used in our modeling tool, Strategist, to inform the resource decisions and ensure that all resource mixes we considered would be operationally feasible and reliable to meet our ongoing need to serve our customers. Below, we summarize how we determined the appropriate operational requirement.

Within a large pool of generation resources and an established wholesale energy market like MISO, there is a tendency for market members to project reliance on market resources based on the size of that pool, rather than the specific performance of those resources and the capabilities of the overall system to deliver additional resources. As we move further into a future that relies less on centralized and dispatchable generation resources, these operational considerations around system and resource capabilities become exponentially more important. In other words, as renewable penetration increases throughout the MISO footprint, it becomes increasingly important to consider the variable nature of these resources and their effect on the overall pool when considering reliability and market reliance. Thus, while we can, and do, still rely on the market, that reliance should be tempered during extreme events, because the nature of these events is such that they tend to impact a geographical footprint that is broader than a single plant or transmission line outage. While MISO is working to address these transmission needs, there is a clear need for more collaboration to enable transmission capability to help support the market's ability to facilitate carbon-free objectives going forward.

Due to the variability of renewable generation, the current generation fleet encounters times in which Net Load (defined as the difference between gross demand and renewable generation supply at a given point in time) is near, or even equal to, the gross demand on the system. This is evident in extreme cases, such as the 2019 polar vortex (when MISO used an average of 6,500 MW resource "reserves[9]" to remain operational), but also during normal winter operations like February 5, 2019, which was representative of conditions we typically experience throughout the winter season. For instance, on February 5th, the system encountered 16 hours of demand greater than 5,500 MW (60 percent of annual peak demand). During this same time, the Net Load was above 5,400 MW, with wind and solar together producing only 6 percent of their installed nameplate capacity (dipping at certain hours to 3 percent). Another example, on July 29, 2018, the entire MISO wind portfolio (over 17,000 MW at that time) had a combined output of minus 11 MW – meaning the wind turbines that were online, were taking more power than they were producing. This hour was part of an approximately 110 hour sustained stretch in which the combined output of all wind resources in the MISO footprint fell well below the accredited values used in

[9] These reserves consisted of non-firm resources offered by neighboring regional transmission organizations into the MISO market

present planning processes.

This real-world experience reveals several operational truths:

- First, variable resources cannot meet demand in all hours of the year; firm dispatchable resources are necessary.
- Second, simply increasing the level of renewables on the system cannot address resource shortfalls. With an increased level of renewables, we see some improved ability to meet demand but still encounter several hours in which the net load is very close to the gross load. In fact, the amount of additional renewable generation that would be required to meet customer demand in the above scenarios and without other resources could be in excess of 180,000 MW.
- Third, our ability to rely on the MISO market during winter peaking events is limited by periods of extremely low renewable generation across the MISO footprint and a shortfall of these resources compared to their accredited capacity.
- Finally, the current state of battery storage technology does not have the ability to match the duration of such events without significant (and very expensive) over-build of those resources, and DSM programs also lack the scale to significantly impact the analysis.

In light of these issues, we have determined that sufficient firm, dispatchable resources are required to meet the approximate 6,400 MW winter peak load obligation, and we have imposed this requirement in our Strategist modeling as part of this Resource Plan. Figure 4 below demonstrates the calculation of the firm resources used meet this need.

Figure 1-4: NSP System Reliability Requirement Calculation

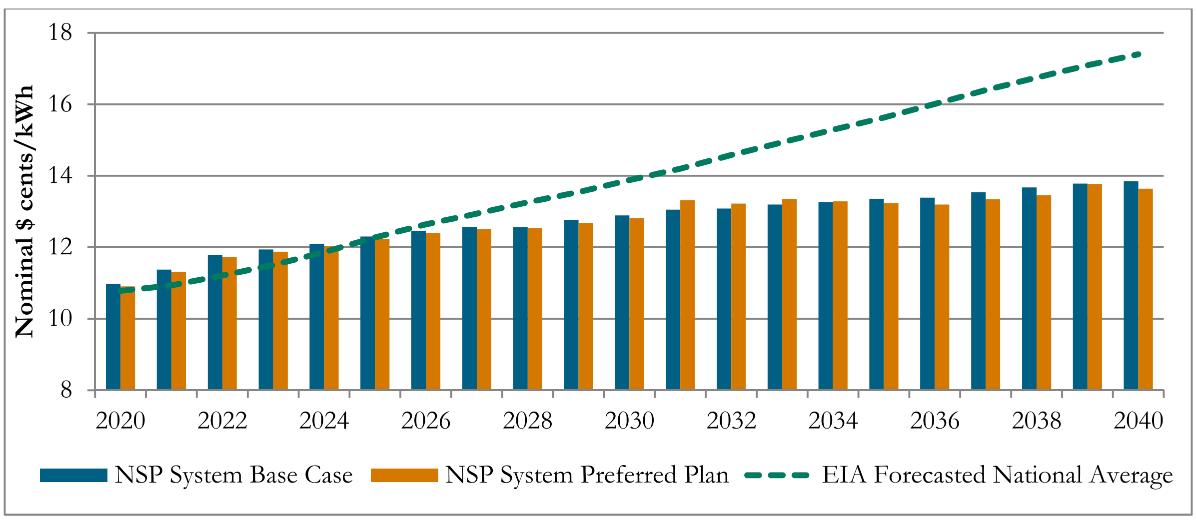
Peak Demand Proxy	6,400 MW
Firm Demand Response Proxy	-200 MW
Firm Market Supply Proxy	-500 MW
Reliability Requirement (Firm Dispatchable Resources)	5,700 MW

Our analysis shows that these resources will help us match the net load gaps discussed above by ensuring that we maintain a stable and reliable energy system for customers, while moving through our baseload transition and achieving our nation-leading carbon goals. We discuss our reliability and operational analysis in greater detail later in this filing.

2. *Affordability*

Another priority for Xcel Energy, and our Resource Plan, is energy affordability. Currently, the average monthly Minnesota Xcel Energy residential customer's electricity bill is below the national average. Our goal is to keep bill increases at or below the rate of inflation – and this Resource Plan positions us well for success. In fact, our Preferred Plan achieves over 80 percent carbon reductions (from 2005 levels) for a nominal customer cost of just over one percent Compound Annual Growth Rate (CAGR) over the plan period. The opportunity to achieve such significant reductions in our carbon emissions for a nominal increase in cost is one of the principal benefits of our Preferred Plan. The following graph shows the relative cost growth of our Preferred Plan in comparison to the national average:

Figure 1-5: Preferred Plan Average Rate Impact for the NSP System



To be clear, the resources the Company needs to add over the next 15 years to continue providing safe and reliable service, to comply with state energy requirements, and to address plant retirements and PPA expirations come at some cost. But we believe that cost – which keeps rates at or below the level of inflation – is both modest and appropriate compared to the substantial benefits we have described here.

III. CONCLUSION

Our Preferred Plan – which accounts for more variables and changes than any other previous Xcel Energy resource plan – proposes to eliminate coal, add even more renewables, and continue our industry-leading EE and DR programs, all while preserving reliability and affordability for our customers. It also meets the varied interests of our five-state Upper Midwest region. And by planning ahead and charting an orderly, gradual transition of our generation fleet, we believe we can achieve all of these goals while managing the impacts to our host communities and employees, preserving the reliability and stability of our system, and maintaining affordability for our customers. For these reasons, and those discussed throughout this filing, we believe our Preferred Plan is in the public interest and merits Commission approval.

CHAPTER 2
PLANNING LANDSCAPE

I. INTRODUCTION

Northern States Power Company, doing business as Xcel Energy, submits to the Minnesota Public Utilities Commission this 2020–2034 Upper Midwest Integrated Resource Plan, which eliminates coal-based generation from our system by 2030, proposes to add thousands of megawatts of renewable resources – and charts the path toward achieving some of the most ambitious carbon reduction goals of any utility in the United States.

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 1.8 million customers in Michigan, Minnesota, North Dakota, South Dakota, and Wisconsin. This Resource Plan builds on our strong foundation of cost-effective environmental performance and the generating fleet transition we began in our last Resource Plan.

Our plan is founded on unprecedented levels of stakeholder engagement and technical analyses that examined an orderly retirement of our baseload generating units. We analyzed numerous assumptions and sensitivities to identify the plan that best meets customer needs, achieves our obligations and goals, and ensures we maintain a resilient and reliable grid. The Preferred Plan we propose emerged as the best suite of resources that balances our planning objectives, as follows:

Figure 2-1: Xcel Energy Integrated Resource Plan Objectives

To understand our Preferred Plan, we first present a Reference Case. The Reference

Case is the baseline scenario identifying the resources necessary to continue meeting our customers' needs, comply with renewable energy requirements, achieve our 80 percent CO_2 reduction from 2005 levels objective, add 400 MW of incremental Demand Response (DR) consistent with the Commission's Order in our last plan, and achieve the significant EE targets identified in the *Minnesota Energy Efficiency Potential Study*.[1]

The Commission's Rules provide the factors to consider in issuing its findings of fact and conclusions.[2] In addition to considering the characteristics of the available resource options and of the Preferred Plan as a whole, resource options and plans must 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's 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 meets these criteria, and provides the flexibility to address the evolving planning landscape, including the changes we expect to the NSP System to achieve our ambitious vision of a 100 percent carbon-free energy mix by 2050. That said, we respectfully request the Commission to approve our Preferred Plan, as follows:

- ***Coal Resources.*** Retire our last two units early: King in 2028 and Sherco Unit 3 in 2030. Additionally, continue our plan to retire Sherco 1 and 2 in 2026 and 2023, respectively.
    - Our plan also commits to offer Sherco Unit 2 into MISO on a seasonal basis until its retirement, and working with our employees at, and the communities around, the Sherco and King plants to support them through the transition of our remaining coal fleet.
- ***Nuclear Resources.*** Operate our Monticello unit through 2040 (10 years longer than its current license) and operate both Prairie Island units through

[1] Available at: http://mn.gov/commerce-stat/pdfs/mn-energy-efficiency-potential-study.pdf
[2] Minn. R. 7843.0500, subp. 3

the end of their current licenses (PI Unit 1 to 2033 and PI Unit 2 to 2034).[3]

- We expect to initiate a Certificate of Need proceeding with the Commission within the next five years and begin working toward license extension with the Nuclear Regulatory Commission during this timeframe.

- ***Renewable Resources.*** While the exact wind and solar mix could vary based on a variety of reasons, at this time we propose to add 4,000 MW of cumulative utility scale resources by 2034 (the first being in 2025) and approximately 1,200 MW of cumulative wind by 2034 to replace wind that is set to retire from our system during that period. We specifically request flexibility in the timing and amounts of renewable additions to take advantage of market and other conditions that we believe will provide value to our customers.
  - ***Wind.*** We are committed to pursuing repowering and/or contract extension opportunities for this resource and we intend to pursue incremental wind resources as needed to meet customer needs in growing customer programs like Renewable*Connect.
  - ***Solar.*** Our Preferred Plan proposes an initial planned addition of 500 MW in 2025. Our plan includes forecasted growth of distributed solar. If actual distributed solar capacity exceeds our expectations, we anticipate this will displace a portion of our proposed grid-scale solar resources.
- ***Combined Cycle Resources.*** Acquire and operate the Mankato Energy Center and build, own and operate (Sherco CC) to satisfy significant capacity and operational need created by coal closures.[4]
- ***Firm Load Supporting Resources.*** Extend the life of Blue Lake Units 1-4 through 2020-2023.[5] Add approximately 1,700 MW of cumulative firm dispatchable, load-supporting resources between 2031-2034. Because these units are not needed until the out-years of our current plan, we have not identified a specific resource type to meet this need. With the expected price declines and technology development between now and the 2030s, we believe utility-scale storage will be an integral resource used to meet this need.
- ***Demand Side Management.*** EE programs representing 2-2.5 percent of savings annually (over 780 GWh for each of 2020-2034), compared to average

[3] Given that our operating licenses for Prairie Island run until 2033 and 2034, we believe there is sufficient time to address the future of that plant in upcoming resource plans.
[4] MEC is currently pending Commission consideration in Docket No. IP6949, E002/PA-18-702. For the Sherco CC, we expect to submit our plans in a separate proceeding.
[5] Pending decision in Docket E,G002/D-19-161.

annual energy savings of 444 GWh in our last Resource Plan, and the addition of 400 MW of DR by 2023. We are requesting the flexibility to evaluate and pursue the required incremental DR through a variety of means and technologies over the coming years.

- ***Storage and Other Emerging Technologies.*** Pursue storage and other emerging technologies, on both a large and small scale.

Finally, as we have previously discussed, system retirements will impact our current blackstart plans, or our ability to restart the system in the event of a catastrophic failure. While we do not propose any action related to the system blackstart at this time, we anticipate addressing this in our next Resource Plan or earlier, if system needs dictate the need to do so.

The balance of our Resource Plan discusses the evolving planning landscape, presents our Preferred Plan and the economic modeling framework from which it emerged, and estimated customer cost and rate impacts. We additionally provide Appendices that include the results of our Baseload Study, Load and Distributed Energy Resource (DER) forecasts, and discussion about our Supporting Transmission and Distribution Infrastructure, Environmental Regulations and Compliance, and numerous others.

II. PLANNING LANDSCAPE

Every business that conducts long term planning needs to account for both its internal goals and the external environment within which it operates. In this Chapter, we discuss some of the key internal and external market contexts that affect how we have developed, and plan to execute on, our Preferred Plan – which supports our ambitious carbon reduction vision, to reduce our carbon emissions to 80 percent below 2005 levels by 2030.

Specifically in this section we examine:

- Xcel Energy's Carbon Reduction Goals
- Regional Reliability and Market Constructs
- Distributed Energy Resources (DER)
- Community and Employee Considerations
- Customer Preferences
- Supply and Technology Trends
- Jurisdictional Updates

While all of these factors affect how we develop our plan, a few stand out above others as being particularly influential in this Integrated Resource Plan cycle – chief among them, regional market constructs and renewable integration. While the regional system operator that designs many of our market and planning requirements continues to examine the effects of high renewable adoption on the grid, it has not yet developed robust and forward-looking capacity accreditation constructs to account for how renewables' contributions to peak demand will change over time. This introduces complexity to designing a plan far into the future, and how we carry out those plans.

Likewise, while we are committed to substantially increasing renewables on our system to achieve our carbon reduction goals, we also anticipate facing challenges to integrating this new clean generation, given the delayed interconnection studies and current limited state of open transmission availability. Our ability to connect these new renewables in a cost-effective manner depends materially on constructs that enable careful management of our interconnection rights in the near-to-medium term as well as new transmission in the long term.

These and other factors, such as DER adoption rates, community and employee impacts, and satisfying the needs of five different states, all affect how we developed the Preferred Plan presented in this filing – and the issues we anticipate encountering as we pursue our goals to lead the energy transition while keeping our grid services reliable and affordable.

A. Carbon Reduction Goals

In December 2018, the Company announced its goals to reduce carbon dioxide (CO_2) emissions 80 percent by 2030 below 2005 levels companywide, and to serve customers with 100 percent carbon-free electricity by 2050. We believe our 2030 goal is achievable with the clean generation and energy storage technologies available today. We believe our 2050 vision, however, will be achievable only with advancements in new technologies such as: carbon-free dispatchable generation technologies and longer-duration storage that are not currently available at the necessary scale and cost, or carbon capture and sequestration. Until these or other technologies are further developed and commercialized, we will require a certain amount of conventional flexible and dispatchable generation to integrate increasing levels of renewables on the grid.

To achieve our 80 percent reduction by 2030 goal, we anticipate the following elements will be essential parts of future plans, across one or more of our service areas:

- Adding thousands of megawatts of additional renewable resources to our system and incrementally retiring emitting baseload generation, while also incorporating flexible, dispatchable generation to enable grid reliability throughout this transition;
- Operating our carbon-free nuclear units at least through the remainder of their licenses, with the potential for license extensions;
- Supporting the strategic electrification of certain end uses and enabling flexible demand, which will help to reduce carbon emissions in other sectors while also providing flexible loads to help integrate more renewables;
- Investing in critical infrastructure, such as transmission and advanced grid technology on our distribution system, to integrate the DER our customers choose, as well as improve reliability and the customer experience.

These goals, the science behind them, and the path we will take to achieving them, are all detailed further in Appendix E: Xcel Energy Carbon Report:Building a Carbon-Free Future.

With these aggressive carbon goals in mind as one of the main tenets of our Preferred Plan, below we discuss the key forces that affect how we have developed, and plan to execute on, our Preferred Plan.

B. Regional Reliability and Market Constructs

The Company's Upper Midwest system is part of the Midcontinent Independent System Operator (MISO) market. MISO is charged with several responsibilities, chief of which are overseeing wholesale energy markets in the member region and planning for bulk system reliability (i.e. transmission planning, generator interconnection, and ensuring sufficient reserve margins). Many aspects of MISO's operations affect how we conduct resource planning, but here we focus primarily on system reliability constructs that will be increasingly tested as we and others transition to a fuel mix relying on more variable renewable resources.

1. *Reserve Margin*

One of MISO's core responsibilities includes administering resource adequacy requirements to enable utilities like us, and other Load Serving Entities (LSEs), across the region to fulfill their obligation to serve customers reliably. Trends are emerging, however, that raise questions regarding how planning constructs will adapt to ensure the system remains reliable as emitting, but stable, baseload generation continues to retire and be replaced by clean, but variable, renewable energy.

MISO and its system reliability oversight organization, the North American Electric Reliability Corporation (NERC) undertake studies to determine the appropriate level of reserve capacity that should be maintained, what affect a resource retirement has on the broader system, and how increasing renewable adoption will change how they analyze and ensure grid reliability. All of these studies point toward an increasingly complex grid that will have to be carefully managed through the transition to a lower-carbon future.

MISO's Planning Reserve Margin (PRM) analysis is one important piece of the current reliability planning paradigm. The PRM is an estimation of how much generating capacity, over and above expected customer load, needs to be present on the system to ensure reliability in all but the most extreme circumstances (called a 1-in-10 year Loss of Load Expectation or LOLE). In the 2018 report, MISO established a reference planning reserve margin of 17.1 percent for the 2018-2019 planning year; in other words, they determined that the total installed capacity available on the system should be 17.1 percent higher than the system's peak load.[6] This reference threshold is provided to the NERC, which sets standards and studies

[6] MISO's PRM for the 2018-2019 Planning Year indicates a PRM for both installed capacity (ICAP) and a rating that derates capacity to account for potential outages (called UCAP). The UCAP PRM for the 2018 planning year is 8.4 percent These two measures of PRM are discussed further in the next section on Minimum System Needs.

reliability across the continent, and of which regional system and transmission operators like MISO are a part.

As part of its oversight and governance activities, NERC conducts a reserve margin analysis across all system operators in North America, in a report called the Long Term Reliability Assessment (LTRA). The 2018 LTRA indicated that MISO is one of three regions that are projected to drop below their reference reserve margin levels by the year 2023, unless certain measures are taken.[7] This report indicates that inclusion of Tier 2 resources (those that are in more advanced stages of planning but not yet under construction) would likely allow for the MISO footprint to preserve system reliability. However, the unprecedented rate of announced, but not yet evaluated, baseload generation retirements and uncertainty in future firm capacity additions creates a tension between maintaining reliability and transitioning away from baseload generation.

It is important to note that retiring some baseload generation and transitioning to a cleaner grid with more wind and solar does not present an insurmountable challenge; indeed we are proposing to retire all of our coal by 2030. Rather, the transition will need to be actively and carefully managed, likely with incremental retirements and supporting transmission upgrades that are carefully studied.

2. *Renewable Integration Challenges*

In addition to challenges around baseload retirement issues, we also see planning issues developing around how renewable additions are evaluated for their reliability impacts. In the aggregate, when MISO has studied high levels of renewable penetration on the grid, grid instability increases and capacity values of variable resources decline, sometimes significantly. Retaining firm dispatchable generating units helps ensure the system will continue to operate reliably.

MISO has also recognized that its capacity accreditation framework – the manner by which it assesses variable renewables' ability to contribute to peak demand needs – will likely change as these resources become more prevalent on the grid. However, MISO has not yet developed sufficiently robust forward guidance for resource planning processes to account for how those values might change in the future, which creates uncertainty in the resource planning process. We discuss these renewable integration studies and specific capacity accreditation issues in more detail below.

[7] *See* "NERC Long Term Reliability Assessment 2018" at 14. Available at: https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2018_12202018.pdf

a. Renewable Integration Impact Assessment

In preparation for an expected future grid with high levels of non-dispatchable renewable penetration and declining baseload generation, MISO is undertaking additional studies with respect to its system's reliability and resource adequacy of its system. The *Renewable Integration Impact Assessment* (RIIA) seeks to inform future long-term planning by understanding what the power system will need to operate reliably with these high levels of variable resources, specifically by examining operational adequacy, transmission adequacy, system stability and resource adequacy limitations.

In Phase I, the study examined a scenario in which variable generation achieves a 40 percent share of the total capacity on the MISO system. It found that the complexity of operating such a system reliably is significantly higher than that of even a system with 30 percent variable resources. Under the circumstances studied, the system experienced more dynamic stability issues and other operational stressors, and resource adequacy requirements increased. For example, the modeled system exhibited high levels of energy curtailment and very high ramping rates in the hours when variable resources were not always available to meet demand. In this scenario, loss of load projections were narrowed to fewer likely hours during the year, but the probability of occurrence increased significantly over the current state. This points to the value that flexible, dispatchable resources supporting grid stability continue to provide in these scenarios; while they run for fewer hours than the current market constructs would warrant, they need to be able to respond quickly, moving from minimum generation levels to higher levels of output to meet these fluctuations in net load quickly.

Further, at high levels of wind and/or solar adoption, the RIIA study found that appropriate resource adequacy values to assign these resources degraded, sometimes significantly from current levels. As a key piece of planning our future system, these resource adequacy capacity accreditation values are discussed in more depth below.

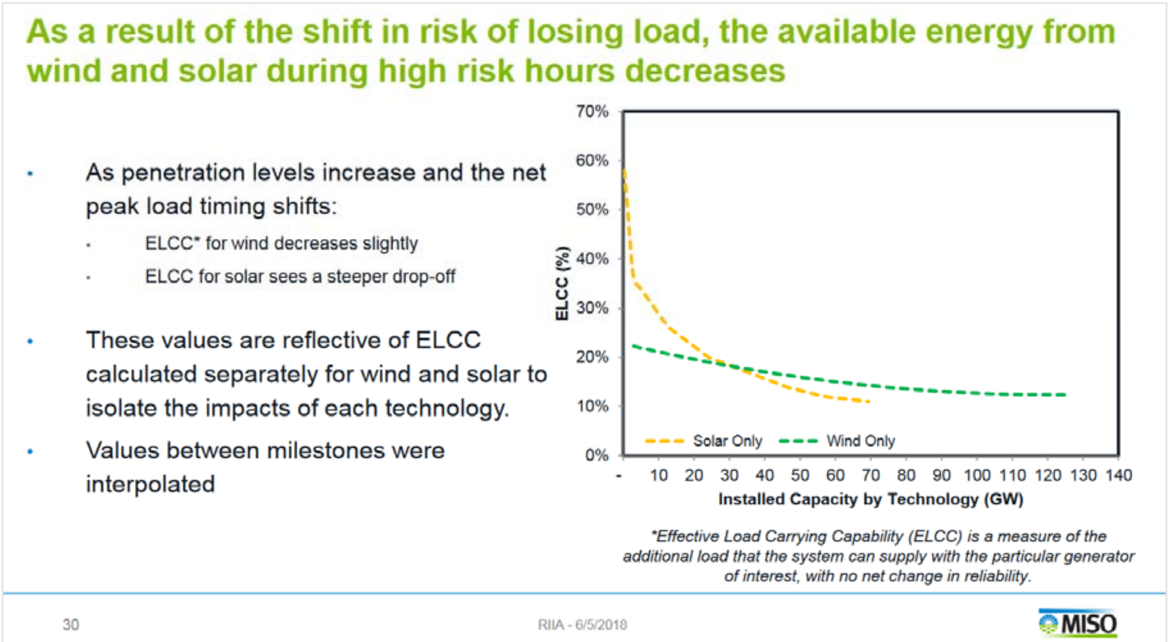
b. Capacity Accreditation Values

Variable renewable resources such as wind and solar are becoming more cost competitive and utilities across the region, including the Company, are increasingly adopting these technologies as important components of their resource mixes. This generation is largely displacing more traditional, thermal dispatchable units. As variable resources are dependent on natural resource availability in a given moment (i.e. wind blowing or sun shining), their capacity does not replace retiring dispatchable units one-for-one in terms of the amount of energy it produces, or assurance that this capacity will produce energy when needed. To account for this, MISO applies a certain accreditation discount to these resources to get a more appropriate probabilistic view of how much capacity can be counted on to contribute to peak demand across the year. This is captured in a measure called the Effective Load Carrying Capability (ELCC).

These administratively set values have a significant impact on how we achieve our carbon reduction goals while maintaining affordable and reliable service. Currently, MISO assigns wind generation an average ELCC value of 15.7 percent; meaning that for every 100 MW of wind installed, only 15.7 MW can be counted as capacity toward the planning reserve margin. For new solar resources, in the absence of an observed historical value, MISO assigns the current initial year default ELCC of 50 percent. The appropriateness of these values in reflecting actual grid conditions is dependent on the pace at which wind and solar penetration increases on the grid, and subsequently how MISO conducts review and adjusts the values. The ELCC is currently evaluated as an annual average, and forward values are not projected.

In reality, however, the capacity value these intermittent resources can provide are subject to diminishing marginal returns. When a single variable resource type increases its penetration level on the grid, each incremental unit of capacity inherently provides a little less capacity benefit to the system than the last unit. For example, MISO's RIIA study estimates that solar in particular would experience steep ELCC reductions within the first 10 gigawatts installed, and this value continues to drop off at higher levels of adoption. Further, in particular for these variable assets, the realized capacity value may change throughout the year, as the capacity value a wind or solar plant can provide reasonably changes in accordance with seasonally variable environmental conditions.

Figure 2-2: Modeled Wind and Solar ELCC as Penetration Increases[8]



The operational realities surrounding future variable resource additions and their seasonal aspects aside, we continue to use the administratively-set annual average ELCC levels in our planning that MISO has established for today's market.

While we recognize that it is difficult for MISO to accurately project future wind and solar penetration levels and load shapes (two key variables in determining future ELCC values), this presents a key challenge as we plan our future system. As the ELCC construct does not currently provide forward-looking values, we have to apply current values to our resource modeling process, even though we are modeling 15 years into the future. However, we know in reality that these values will degrade as we and others add variable renewables to the MISO system, and so what appears to be a net capacity surplus today may look rather different in future assessments.

It is worth noting here that we may encounter changing assumed resource adequacy contributions for use-limited resources in the future as well. In general, resources such as DR and energy storage would be subject to declining ELCC values as they become more prevalent on the system, in the same way wind or solar ELCCs realistically decline.[9] Notably, MISO is also considering changes to how it accounts

[8] MISO. *"Renewable Integration Impact Assessment"* Workshop presentation June 5, 2018. Available at: https://cdn.misoenergy.org/20180605%20RIIA%20Workshop%20Presentation213125.pdf
[9] *See* the E3 Study in Appendix P2 for further discussion on how marginal ELCC for DR and energy storage resources may decline as adoption increases.

for DR's capacity accreditation overall, such as enforcing more stringent testing requirements. MISO is also following up on actual performance during DR events, which may result in accredited value reductions going forward. Both these factors mean that the DR we currently depend on as a baseline resource in our portfolio, in addition to that which we may select in this or future resource plans, may not yield the same benefits in future years as we have historically expected.

c. Interconnection Queue

The current state of grid interconnection processes and transmission capabilities in MISO introduce complexity not only to our planning processes, but also how we execute on the plan.

The MISO generator interconnection process is designed to allow generators reliable, non-discriminatory access to the electric transmission system, in a timely manner, while maintaining transmission system reliability. Recently, as the number of proposed projects in MISO has expanded significantly, this process has been mired in delays. Delay impacts are particularly evident in the Definitive Planning Process (DPP) phases, where MISO undertakes generation interconnection studies. Current studies are a number of months behind, due to the large volume (including speculative requests) and a generator interconnection process that allows late withdrawals from the queue with limited consequences. Despite some recent process reforms, MISO has not been able to keep pace with the expanding queue. And where projects do make it through the DPP, they are sometimes assigned high transmission system upgrade costs that challenge the project's economic viability. MISO's interconnection challenge is multi-faceted.

First, there is a substantial volume of capacity currently in the queue requesting study and interconnection approval. As of early June 2019 there were over 100 GW of new capacity in the active MISO queue (although this number has fluctuated substantially), the vast majority of which is comprised of wind and solar projects.[10] Each cycle of the DPP is handling expanding levels of requested capacity; for example, the recently completed cycle for the MISO West region (started in August 2016) started out with 31 projects totaling just over 5,600 MW.[11] The April 2019 DPP study cycle,

[10] MISO "Generator Interconnection: Overview." Updated as of June 1, 2019, at: https://cdn.misoenergy.org/GIQ%20Web%20Overview272899.pdf
[11] *See* "MISO DPP 2016 August West Area Phase 1 Study." Siemens (August 20, 2018). Available at: https://cdn.misoenergy.org/GI_DPP_2016_Aug_West_Phase1_SIS_Report277263.pdf

scheduled to begin in March 2020, includes 58 projects totaling 8,800 GW in the same area.[12] While the level of proposed new renewable project is a positive indication of aspirational renewable development in the region, MISO has also indicated that a substantial amount of this capacity is speculative, in early stages of project development or representing duplicative requests.

Further, the existing transmission system's capability to interconnect new projects without substantial infrastructure upgrades is limited, and thus, the generation interconnection planning studies indicate there will likely be costly upgrades assigned to the prospective generators. In the past, initiatives such as CapX2020 and Multi-Value Projects (MVPs) were able to integrate large quantities of new renewable power and socialize transmission infrastructure costs across a larger swath of benefitting MISO customers. However, wind power in particular expanded on the MISO grid faster than expected, and the interconnection capacity afforded by these projects has been largely used. Since then, few new transmission lines have been proposed or approved for the purposes of renewable integration.

Generally speaking, this means that, if new generation projects in the queue want to interconnect, the generation interconnection study process identifies substantial additional transmission system upgrade costs and assigns them to the generation owner(s). In the aforementioned MISO West DPP cycle that recently completed, for example, the approximately 5,600 MW of proposed projects were expected to incur approximately $3.2 billion in transmission upgrades, if all were to interconnect to the system.[13] These assigned high-cost transmission system upgrade requirements can sometimes render projects uneconomic, forcing a queue withdrawal and additional MISO study on the remaining projects.

d. Regional Seam Issues

Limitations on transmission infrastructure and coordination, both within MISO and between MISO and the Southwest Power Pool (SPP), illustrate further challenges.

Within MISO, the transmission system is showing constraints and the resulting curtailment slows our progress toward a cleaner energy future across the Upper Midwest system. Currently, wind generation from the western part of MISO flows toward the load centers in the east such as the Minneapolis–St. Paul area and load centers across the transmission interconnection between Minnesota and Wisconsin. However, existing west-to-east transmission capacity is, at times, operating at its limit.

[12] *See* MISO "Definitive Planning Phase Estimated Schedule." Updated as of June 1 2019. Available at: https://cdn.misoenergy.org/Definitive%20Planning%20Phase%20Estimated%20Schedule106547.pdf
[13] "MISO DPP 2016 August West Area Phase 1 Study." Siemens, September 2018, at xvii.

The transmission interface across the Minnesota-Wisconsin border in particular is currently stability-limited, and trying to force additional renewable energy through these lines could result in voltage collapses in Northern Wisconsin that would destabilize the grid. Curtailing this energy at its source in the west is operationally and economically inefficient, keeping us from fully utilizing the inexpensive and clean energy to which we have access; but, without additional transmission capacity, we will more frequently encounter this problem as we add more renewable generation to our system.

Further, coordination (or historical lack thereof) between MISO and SPP introduces challenges to bringing onto the system, and utilizing, more clean energy. First, for projects that can be considered interregional in nature, a project must currently meet economic benefit hurdles in a joint review, as well as separate MISO and SPP regional evaluations. This slows the process significantly, and may overestimate the amount of interconnection upgrades required, adding to project uncertainty and cost.

Second, although our load and generation sit within MISO, the nature of power flows inevitably results in some of our energy entering the SPP system. In turn, both MISO and SPP may charge to transmit that energy from the point of generation to the load, challenging a project's economic viability or raising customer costs for projects already online.

Finally, MISO and SPP disagree on what should happen when one region or the other has to "lean" more on the system than its contracted delivery amounts for a certain time. Where SPP would levy penalties in this scenario, MISO views this situation as a normal and acceptable result of an integrated grid. All of these issues increase transaction costs and uncertainty for a given generation project coming online, and represents a potential barrier to efficiently bringing additional renewable generation to the grid.

3. Mitigation Efforts

In response to direction from FERC and in recognition of the challenges described above, MISO is undertaking several actions that could serve to mitigate challenges to bringing new, clean resources online. In essence, they allow generation owners to leverage existing interconnection agreements to maximize utilization and fit renewable additions into the relatively few remaining open spaces on the grid. While we expect these processes to mitigate some of the near term challenges to additional renewable capacity, they do not address all challenges (in particular our ability to depend on neighboring regions for renewables and maintaining reliability) and we expect that longer term solutions will eventually need to be developed.

a. Generator Replacement Process

Interconnection study delays and speculative queueing are challenges not only to projects that are actually commercially viable, but also to generation owners that are looking to retire aging assets. Companies that are required to meet a certain level of reserve capacity, like Xcel Energy, face potential compliance and commercial risk if we retire existing assets without the ability to re-utilize that interconnection capacity. Recognizing these issues, MISO filed and received approval for a proposed Replacement Generator Process that would allow current generation owners to retain and re-utilize these interconnection rights where a resource plans to retire, within certain technical limitations on the new generator's attributes. The new generating units could be developed on the same site, or on a site in close proximity that uses the same grid interconnection point. Per the new MISO tariff provisions, the new generation resource would need to have an in-service date not later than three years after the existing generator ceased operation. Importantly, these projects would be studied outside the traditional DPP timeline, with the intention of avoiding the significant delays associated with that process, as described above.

b. FERC 845

In 2018, FERC issued Order 845, *Reform of Generator Interconnection Procedures and Agreements*[14] that also opens additional opportunities for generation owners to add resources to the system outside the normal interconnection queue process. The Order directs all transmission providers to develop a procedure to allow interconnection customers to use surplus availability at an existing point of interconnection without that new project entering the full MISO queue and planning process, within certain technical limitations. MISO has referred to surplus interconnection availability as "Net Zero" interconnection, as the addition of this new project would not result in an overall increase to the interconnection capacity requirements of the site; rather, it would be expected to increase the overall *utilization* of the interconnection site.

While MISO allowed Net Zero resources prior to FERC 845, the new Order also allows existing interconnection rights owners the first right to utilize the surplus availability on that interconnection. It also revises the definition of a generating facility to explicitly include energy storage resources. These actions work to support generation owners increasing renewable utilization on existing interconnections, and could support future project hybridization (e.g. solar and storage or wind and storage). We expect that generator replacement, Net Zero, and other FERC Order

[14] See Reform of Generator Interconnection Procedures and Agreements, 163 FERC ¶ 61,043 (2018) (Order No. 845).

implementation efforts will alleviate some of the barriers to planning and executing on a future with substantial renewable additions. However, these do not address the underlying challenges around queue length and timeline, intra-MISO and interregional seams congestion challenges, and integrating high levels of renewables reliably and affordably. MISO has recently attempted to mitigate the queue volume challenge by proposing process reforms that increase the stringency of entering this phase of interconnection process; however, while recognizing the challenges MISO faces, FERC recently rejected the proposal.[15] While the Company and others have begun contemplating new MVP-like projects, the lack of alignment across MISO and long lead-times required for such projects mean that these challenges are unlikely to be resolved in the near term.

C. Distributed Energy Resources

At the same time as we work to clean our power supply, we also recognize that customers are now exercising more choice around how and from where they consume energy. This is a key consideration as we plan our resource mix for the next 15 years.

Some customers are choosing DER that can reduce customer consumption and even provide energy back to our system from decentralized locations on the grid. Examples of DER include, but are not limited to: rooftop solar panels, energy storage, community solar gardens, or the EE enabled by a smart thermostat or time of use electric rate. To-date, community solar gardens makes up the clear majority of the DER on our system in the Upper Midwest.

Our customers' adoption of DER and new types of load mean that consumption patterns from our centralized power system are changing. This can represent an opportunity: if we can harness the benefits of these resources to make demand more flexible, we can use this to better match demand to energy production from our large, variable renewable resources. For example, we could utilize managed or "smart" charging of electric vehicles (EVs), to delay charging to off-peak hours or to times when renewable output is the highest. We could also use advanced metering technology alongside customer programs and tariffs to enable load shifting away from peak hours.

There are also DER coming onto our grid, in the form of electric transportation options – enabling not only flexible load opportunities but also broader economy-wide emissions reduction – and we have developed several programs and rate options

[15] *See* FERC "Order Rejecting Tariff Revisions re: Midcontinent Independent System Operator, Inc. under ER19-637." Available at: https://elibrary.ferc.gov/idmws/file_list.asp?accession_num=20190319-3076

to encourage that adoption.

The transportation electrification initiatives we have implemented and continue to develop are not only enabling customer choice, but also to the broader economy in helping to meet greenhouse gas (GHG) emissions reductions goals. The transportation sector is now the leading contributor to Minnesota's overall emissions,[16] and as our system (and the state's electric sector more broadly) continues to transition to a cleaner energy mix, transportation's share of GHG emissions will continue to expand. This shift highlights an opportunity for the electric sector to facilitate GHG reductions in the transportation sector, as electricity is increasingly used for transportation fuel.

While the opportunities are exciting, it is also important to recognize that customer adoption of DER and new types of load behind the meter introduce uncertainties in our planning processes, particularly if we do not have adequate visibility into how and when that new DER or demand is coming onto our system.

One tool we have to mitigate this DER and electrification uncertainty is our Integrated Distribution Plan (IDP) and grid modernization efforts. Our IDP process and proposed investments will help us leverage DER and new load to enable more flexible demand management, improve reliability and, we anticipate, enable better decision-making about large-scale investments as well. In our last IDP we discussed these enabling technologies, which include: Advanced Distribution Management Systems (ADMS), which will allow us to better integrate DER onto our grid and maintain reliability; the Field Area Network (FAN), which enables two-way communication from field devices and Company back office operations; Advanced Metering Infrastructure (AMI), which enables time of use rates by metering consumption at smaller time intervals; and automated, remote reliability-sensing and enhancing technologies such as and Fault Location, Isolation, and Service Restoration (FLISR). Many of these investments will help us develop capabilities to use load more flexibly. We also hope to enhance the customer experience by creating new programs and offerings that fit their needs and preferences based on the capabilities these investments provide.

Our Preferred Plan is substantially dependent on anticipated customer load, which incorporates the best estimates we have about customer adoption of DER, as well as robust statistical forecasting methods. We have also modeled sensitivities to address some of this uncertainty. But we still often do not have visibility into which

[16] See the Minnesota Pollution Control Agency's statewide GHG inventory data, available at https://www.pca.state.mn.us/air/greenhouse-gas-emissions-data.

technologies, and at what pace, customers will adopt and thus, how that changing load will affect our grid needs in the future.

D. Community and Employee Considerations

As we move forward with our carbon reduction goals, we are cognizant that phasing out some of our legacy generation assets has a significant impact not only on our energy mix, but on the economies of communities where those plants are located and the employees who work in those plants. This is particularly true of our coal facilities, where the plants are prominent places of employment and contributors to the property tax base in the community. This is why we make efforts to spur economic development in locations where our current units will eventually be phased out.

For example, since our most recent Resource Plan, where we proposed to retire the Sherco 1 and 2 coal units in Becker, we have worked extensively with local units of government, community stakeholders, and the State to draw new development to support the local economy. This includes a planned CC generating unit at the Sherco site, the relocated Northern Metal Recycling facility, and, prospectively a new Google data center with energy matched by a wind facility. Some of that activity (e.g. the Google data center) is also anticipated to spur new renewable energy development on our system.

Related, we are participating in a study overseen by Center for Energy and Environment (CEE) that will examine the impacts of the large baseload generation plants in Minnesota on the host communities. The other participants in the study include the Coalition of Utility Cities, Minnesota Power, and the Prairie Island Indian Community. The study will consist of a quantitative and qualitative component. The quantitative component of the study is similar to the study we conducted for Sherco 1 and 2 in our last Resource Plan. For the qualitative component, CEE will engage with host community residents and business to gauge awareness, opinions and concerns around potential power plant closures. Efforts on both components are underway and we will supplement this Resource Plan filing when each component is completed. As this docket progresses, we expect to be able to incorporate further findings and hold additional discussions incorporating the finalized report outcomes. Further discussion of the scope and status of this study is included as Appendix O2.

In addition to community impacts, we are also aware that these plant closures impact our employees and their families. With this in mind, and consistent with our past practices, we will work with these impacted employees to transition them to other Xcel Energy plants or areas of the company. In the past, when plants have been closed or converted (and impacted headcount) we have provided résumé writing services, support for interview practice, job training, and job shadowing opportunities. Through natural attrition and job relocations, we have been able to successfully "re-home" nearly all impacted employees from plant closures and conversions to-date.

Moving forward we will work with local unions and set a course to negotiate multiskilling for our impacted sites. This skill set will position our employees for other job opportunities within Xcel Energy. As we get closer to closure dates, temporary workforce will be utilized to back fill benefit employees who have relocated to other positions within the company. This strategy lessens the burden and stress for benefit employees to find positions, as plants near closure dates. In addition, plant management, Work Force Relations and Human Resources will work together with other business organizations within the company to help coordinate interviews for affected employees.

And, as we continue toward achievement of our aggressive carbon goals, we will continue to make significant investments in clean energy in the states we serve. As we do so, we will look for opportunities to create fair access to clean energy programs, jobs and economic development opportunities. Going forward, we continue to be dedicated to working with employees, communities, and stakeholders to manage community impacts throughout our clean energy transition.

E. Customer Preferences

Our Upper Midwest system continues to serve a diverse mix of customers with varied interests and preferences. While most customers continue to prioritize affordability, we have seen increasing interest in sustainability, carbon reduction, and clean energy objectives. Again, these are important considerations to keep in mind while planning our resource mix for the future.

1. Municipal

Cities and municipalities are increasingly setting and developing strategies around sustainability and climate goals. In fact, there are 11 cities in our Upper Midwest jurisdiction that have set carbon reduction or renewable energy goals. Minneapolis is the most prominent example, as evidenced by the Clean Energy Partnership that had just started when we filed our last Resource Plan. Since then, the partnership has flourished and advanced, helping to achieve progress toward the city's sustainability goals. Other municipalities and communities are also developing goals and action plans around renewable energy and climate goals. We work with many of these communities through our Partners in Energy program to support achievement of these goals.

2. *Commercial and Industrial Customers*

Our commercial and industrial customers place a high priority on keeping costs low to remain competitive in their own markets. This is particularly true of large industrial customers, where energy costs can make up a substantial portion of their operating expenses. However, corporate efforts to achieve sustainability goals are also increasing, both in the US broadly and within our system. And as the cost of renewable energy declines, affordability and sustainability goals increasingly go hand in hand. Within our system, several of our corporate customers are co-members of the Minnesota Sustainable Growth Coalition, which is a business-led public-private partnership working to advance clean energy and other sustainability and circular economy objectives. We hear from these and other corporate customers across our Upper Midwest system that sustainability and clean energy are important to them, and they want us to offer products that meet these needs, and Renewable*Connect is one such product.

In 2015 we worked with customers to develop Renewable*Connect. The program achieved full subscription in its first year, and in January 2019 we filed for an expansion of this program, and included an option for high load factor customers (i.e. those that operate continuously during the day) to be served primarily with competitively priced wind and a smaller portion of solar. Significantly, this program advances the sustainability goals of the participating companies without creating additional costs that must be carried by other, non-participating customers. In 2019, we also developed a new program called Certified Renewable Percentage (CRP). The CRP is a new Renewable Energy Certificate (REC)-based accounting methodology that clarifies the percentage of our system energy delivered to customers that is renewable. The CRP is not a subscription service or program customers need to enroll in. Instead, the Company will retire sufficient RECs on behalf of all our retail customers such that the total RECs retired annually reflects the portion of delivered energy that is renewable. This will allow all retail customers to claim the percentage of renewable energy on the system as the starting point towards their sustainability goals.

Our willingness to work with customers to balance clean energy objectives and affordability needs, while facilitating economic development opportunities, has also attracted new customers to the service area. The new Google Data Center slated for development in Becker is a clear example. Google has an objective to match 100 percent of its energy consumption needs with renewable energy purchased from incremental projects, and has future plans to go even further by sourcing carbon-free energy for its operations on a 24/7 basis. We were able to work together with Google to develop a proposal to help it achieve its renewable energy goals.

3. Residential Customers

Residential customers likewise 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 EE upgrades, and the chance to reduce the environmental impact of their consumption by choosing renewable energy. Customers are taking advantage of these programs in large numbers – and they have expressed strong satisfaction with their ability to select programs that best meet their individual energy needs.

F. Supply and Technology Trends

Trends around the supply of generation and energy storage equipment we need to fulfill our resource plan have a significant impact on the mix and timing of our resource proposals.

In the years since our last Resource Plan, wind and solar technology costs have continued to improve overall; solar in particular has experienced significant cost declines, with installed costs falling over 35 percent on average since 2015.[17] Consistent with past years, we generally expect wind and solar capital costs will continue to decline, although at perhaps a slower pace as these technologies advance on their respective maturity curves. We also expect technology advancements improve capacity factors. These two factors continue to improve the cost competitiveness of wind and solar resources in real terms, changes to incentive policies notwithstanding, relative to the other resource options we may consider. For example, the National Renewable Energy Laboratory projects that large-scale solar prices could decline 17 percent in real terms over the next 10 years.[18] For modeling purposes, however, our generic representations of these resources are static in terms of capacity factor and accredited capacity, and we have represented the combined future cost and performance trends through the levelized energy cost forecast for these technologies.

We also continue to examine the role energy storage can play in meeting our system needs. The Company has been developing our experience around the type of services energy storage can provide to our system, through the operation of an existing

[17] Bolinger, Mark and Seel, Joachim. *Utility Scale Solar 2018 Edition.* Lawrence Berkeley National Laboratory September 2018. Available at: https://emp.lbl.gov/utility-scale-solar

[18] This projection reflects data provided by the NREL's *Annual Technology Baseline* report, which we use in our modeling. This trend reflects changes in projected solar levelized costs in real terms (2016$) and are not adjusted for the potential impact of tax credits.

pumped hydro facility in Colorado and several pilot battery energy storage installations across Xcel Energy's service areas. Technologically, we expect grid-scale energy storage will support our clean energy goals in the future, by helping us maintain grid stability and supporting peak management while integrating the higher quantities of intermittent renewable generation we envision on our system. We are committed to pursuing this technology although challenges remain, in particular for battery energy storage, to managing seasonal renewable energy variability and longer duration demand-shifting needs.

From a cost perspective, battery energy storage has experienced significant improvements over the last few years and we would expect battery energy storage costs to further decline going forward. There are also other battery chemistries and different types of storage that may emerge as technology research and development continues. While we are confident utility-scale battery storage will be a part of our long-term resource mix, we are also evaluating the potential for near-term battery storage around our service territories to fulfill distribution system or other needs.

Finally, as we have noted, achieving our 100 percent carbon-free electricity by 2050 goal will require further development of technologies that have not yet been identified and commercialized. While not included in our resource planning optimization, we continue to monitor industry activity around other emerging technologies that may contribute to achievement of our goals. In addition to potential new battery chemistries mentioned above, potential emerging clean energy technologies include advanced nuclear reactors, carbon capture and storage applications, hybridized gas-hydrogen generators, other types of energy storage technologies beyond batteries, and others. As new technologies achieve commercialization, we will remain technology agnostic as we consider including them in our future resource planning analyses.

G. Jurisdictional Updates

Our integrated Upper Midwest system provides service on a multi-jurisdictional basis to 1.8 million customers across five states. Through this integration, we have historically leveraged economies of scale to support needed investments. Each resource on the Upper Midwest system – whether generation or transmission – was developed in consideration of the whole system, to take advantage of the economies of scale available through integrated system planning. Below we provide a brief overview of key prevailing and emerging energy policy in Minnesota, North Dakota, South Dakota, Wisconsin, and Michigan, where these objectives may affect our future planning for the Upper Midwest system as a whole.

1. *Minnesota*

In 2007, Minnesota passed the Next Generation Energy Act, which set successive, economy-wide greenhouse gas reduction goals relative to 2005 levels; 15 percent below reduction by 2015, 30 percent below by 2025, and 80 percent below by 2050. Since that time, the electric sector has outpaced emissions reductions in all other sectors, achieving a 29 percent reduction below 2005 levels by 2016 (the most recent year reported). However, the state has missed its economy-wide goal, achieving approximately 12 percent reduction over the same time period.[19] This data drives our view that the electric sector can, and likely must, facilitate reductions in other sectors, such as transportation and building energy use, if Minnesota is to meet its economy-wide carbon reduction goals.

Specific to the electric sector, the Minnesota Renewable Portfolio Standard, passed in 2007, remains our prevailing clean energy requirement. The 2019 session included passage, however, of energy storage provisions that (1) enable utility-owned energy storage pilot projects, and clarifying cost recovery for such pilots, (2) requiring resource plans to include an Energy Storage Systems Assessment, including how storage may contribute to generation and capacity needs and ancillary services, and (3) requiring a cost-benefit study of energy storage systems by the Department of Commerce.[20] We provide our Energy Storage Systems Assessment in Appendix F7.

2. *North Dakota*

Since our last Resource Plan, we submitted a Resource Treatment Framework (RTF) simultaneously to the Minnesota Public Utilities Commission (MPUC) and the North Dakota Public Service Commission (NDPSC). The RTF filing was submitted to the NDPSC in compliance with a Commission Order adopting the Negotiated Agreement in the Company's last rate case,[21] with the purpose of establishing a framework to address the costs and benefits of the Company's Upper Midwest system resources in a way that was both fair to all customers and aligned with North Dakota's policy objectives.

In the RTF, we developed a proposal that evaluated four potential implementation structures: (1) legal separation of the North Dakota portion of the system; (2) pseudo

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[19] *See* Minnesota Pollution Control Agency "Greenhouse Gas Emissions Data." Available at: https://www.pca.state.mn.us/air/greenhouse-gas-emissions-data

[20] "19-5227 – Omnibus Jobs, Economic Development, Comerce and Energy." Available at: https://www.senate.mn/committees/2019-2020/3098_Committee_on_Jobs_and_Economic_Growth_Finance_and_Policy/19-5227.pdf

[21] See North Dakota Case No. PU-12-813. In Minnesota, the Company submitted the RTF consistent with our commitments made in MPUC Docket No. E002/M-16-223

separation, applying generator-specific cost/benefit allocations; (3) proxy-pricing, which would replace the cost of a disputed generation resource with a proxy price deemed acceptable; or (4) gaining regulatory alignment in the selection of resources, so that all states could fully participate in the integrated NSP system. Our intent was to seek a framework solution that can not only address current resource disputes, but also those that may arise in the future.

Our initial proposal would have legally separated the North Dakota portion of our service area into a separate operating company, with pseudo-separation identified as a second best option. Under the legal separation framework, we felt confident we could retain the benefits of economies of scale in our resource planning, yet be able to customize resource portfolios for certain states, to the extent necessary. Pseudo-separation could also prove feasible, if each state agreed to the method by which we would propose to conduct these cost allocations.

In response to this proposal, the North Dakota Staff recommended against legal separation, instead preferring a solution that used a form of proxy pricing to determine appropriate resource cost allocations for resources in the Upper Midwest system. Further, Staff was interested in pursuing the Company's proposal to institute a formal resource planning process in the state, in order to provide the North Dakota Commission with more information about planned resource additions earlier in the process, and to provide the Company more certainty regarding the state's policy objectives and deemed customer needs.

While we do not see proxy pricing as a viable forward-looking solution for reconciling resource treatment, we continue to believe that instituting a formal resource planning process is beneficial and will provide more clarity to the Commission and the Company on what resources may work as system resources. In response to the Commission's request for a more detailed proposal, we submitted a framework outlining essential pieces of a North Dakota Resource Plan, including a default presumption that the system would continue to be planned in an integrated fashion, and a proposed timeline for filing that is consistent with the Minnesota process. We discussed the proposal at an informal hearing with North Dakota Commissioners in March of this year, where the Commission confirmed that it is interested in a more formalized resource planning process.

Currently, we do not recover the full PPA costs of the Aurora, Marshall, and North Star solar PPAs, the Community Based Energy Development (C-BED) PPAs, or the Renewable Development Fund (RDF) PPAs from our North Dakota customers.

3. *South Dakota*

We have also faced challenges in recovering the costs of certain resources in South Dakota. In December 2016, the South Dakota Public Utilities Commission (SDPUC) suspended the fuel clause adjustment in order to investigate the costs of certain disputed resources recovered through the fuel clause.[22] The Company worked with South Dakota Commission Staff to development a Settlement to address these concerns. In September 2017, the Commission approved a Settlement Stipulation that addressed the costs recovery for the Aurora solar resource and several biomass resources. The Settlement also required the development of proxy prices for several remaining disputed resources, which include the Marshall and North Star solar PPAs, C-BED PPAs, and Renewable Development Fund PPAs. The Company submitted a proxy price proposal to the South Dakota Commission which provided eight potential proxy pricing options for the Commission's consideration and recommends a combination of market-based and index-based pricing, depending on the particular resource.[23] We are engaging in ongoing discussions with South Dakota Staff as we work toward a resolution of these outstanding issues. While we are working to develop proxy prices as a resolution for past resources, when disputes arise in the future we would work to develop a cost allocation mechanism to allocate the costs and benefits of new resources to the participating jurisdictions.

Currently, we do not recover the full PPA costs of the Aurora solar project from our South Dakota customers and we are recovering the costs of the PPAs for the disputed resource subject to refund based on the resolution of the proxy price proceeding.

4. *Wisconsin*

In Wisconsin, the Company is subject to a Renewable Portfolio Standard (RPS) equal to 12.89 percent of its three-year average in-state retail energy sales. In 2018, excluding renewable energy used for voluntary renewable programs, NSPW provided 24.3 percent of its retail energy sales from RPS-eligible renewable-based energy sources, and the Company is in compliance with its 2018 RPS requirements.[24] This requirement has not changed recently. However, the state's newly elected governor has identified climate objectives as one focus of his administration. In line with these goals, the administration has proposed carbon reduction goals for the state's electric sector that are broadly consistent with our objectives to reduce emissions by 80 percent from 2005 levels by 2030, and 100 percent by 2050. It is not yet clear

[22] *See* South Dakota Docket No. EL16-037.
[23] *See* South Dakota Docket No. EL18-004.
[24] *See* Docket 5-RF-2018 *Renewable Portfolio Compliance Plan for CY 2018. Northern States Power Company, a Wisconsin Corporation.*

whether these proposed goals will result in additional mandates for the electric sector.

5. Michigan

In Michigan, the Company is subject to a Renewable Energy Standard (RES) equal to 15 percent of retail sales by 2021, with a goal of 35 percent renewables and 25 percent energy waste reduction by 2025. We are ahead of schedule on both these goals, already exceeding the 2021 RES requirements and expecting to meet the 2025 goals by 2020.

This year will also be the first time we are required to submit a Resource Plan to the Michigan Public Service Commission, in accordance with Public Act 341 of 2016. Michigan's new Resource Plan process allows us to file the same resource plan in Michigan as we are filing with the Minnesota Commission, and on a similar timeframe, with the understanding that the Michigan Commission may ask for additional supplemental information to help them evaluate the plan as it relates to Michigan.[25] We plan to file this multi-state Resource Plan in Michigan on July 31.

H. Conclusion

We believe our progressive carbon reduction goals are the right path forward for the our customers, our employees, our Company and the State. We are confident in our ability to achieve these goals while maintaining the reliability and affordability our customers count on. This transition, while exciting, is not without challenges. We will continue to navigate significant market and regulatory uncertainty, jurisdictional differences, technology changes and more. That said, we are optimistic that these challenges also present opportunities to engage with customers, regulators, market operators, communities, and employees on our goals in a way that meets multiple stakeholders' objectives.

[25] *See* U-15896/U-18461 at 11.

CHAPTER 3
MINIMUM SYSTEM NEEDS

Our resource planning process focuses on deep carbon reductions while serving our Upper Midwest customers reliably and affordably. In this Chapter, we describe in more detail how we arrived at the minimum amount of resources our system will need through the planning period. The system needs and existing resources evaluated here formulate the baseline upon which we have developed the Reference Case, our modeling scenarios, and ultimately our Preferred Plan.

We have made the following changes to aspects of our Minimum System Needs approach with this Resource Plan:

- *Supply-side Resource Treatment for DSM.* In this Resource Plan we are treating both EE and DR as supply-side resources, rather our previous treatment of EE as an adjustments to future load. Supply-side resources available to the model now include incremental EE and DR in "bundles," or amounts of achievement that we formed from the *Minnesota Energy Efficiency Potential Study* and *Brattle Demand Response Potential Study*, respectively.
- *Reliability Requirement.* We have developed and applied a threshold requirement for firm dispatchable resources. This Requirement is needed to ensure system reliability and resilience until MISO evolves its capacity accreditation construct to better recognize the variability and declining incremental electric load carrying capability of wind and solar resources.

I. MEETING CUSTOMER NEEDS

Forecasting customers' needs for electricity is a key component of any resource plan, and provides the foundation for determining the type and amount of resources that will be needed over the 15 year planning period. The first step is forecasting the amount of electricity our customers will need over the planning period. To this, we add a reserve margin that is prescribed by MISO. We then subtract the resources we already have or expect to have (with some adjustments), to determine our net surplus or need.

We illustrate this concept and discuss each of the components below.

Figure 3-1: Net Resource Need/Surplus Calculation

Customer Needs Forecast
Plus MISO Reserve Margin
Equals **Total Capacity Obligation**
Minus Demand Response Capability
Minus Generation Capacity (measured by UCAP)
Minus Generation Adjustments
Equals **Net Resource Need/Surplus**

A. Customer Needs Forecast

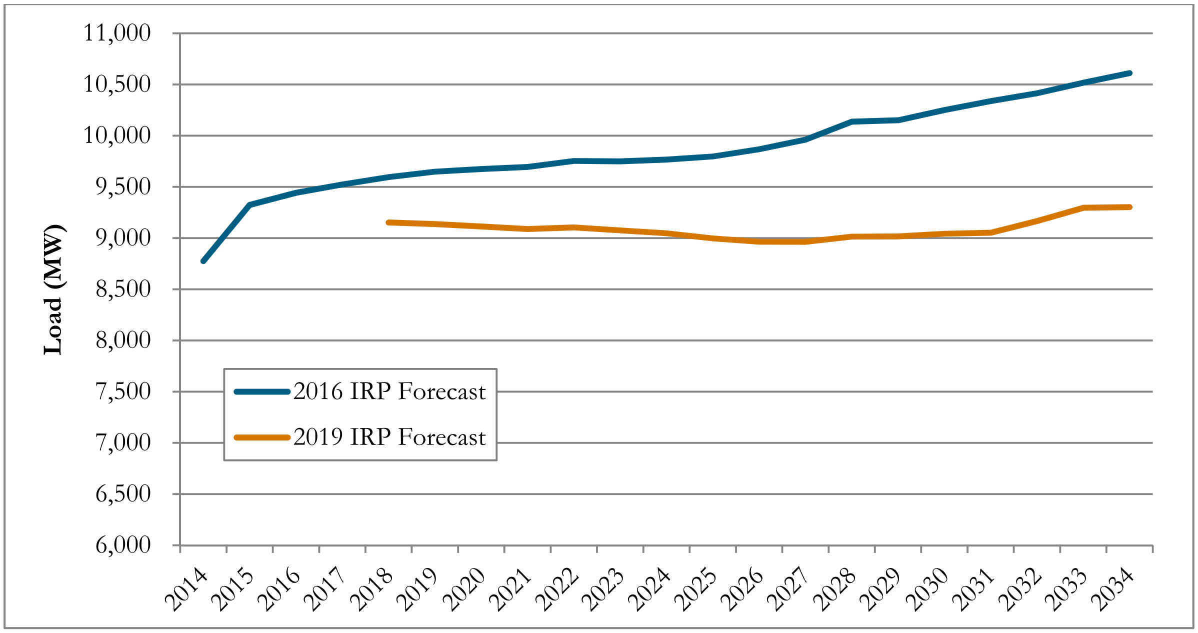
Forecasting our customers' energy needs starts with a capacity, or peak demand, assessment, which informs the total amount of generating capacity (in megawatts, or MW) needed to meet our customers' needs in the highest demand hour (i.e. peak-hour) in each year of the planning period. We also assess the amount of total energy (measured in megawatt hours or MWh) we expect customers to consume in each year of the planning period. Together, the peak demand and total energy needs inform the type of generating resources that will best meet customer needs.

1. *Peak Demand Requirements*

We use econometric analysis and historical actual coincident net peak demand data to determine system capacity requirements for each year. We provide a detailed discussion about our peak demand forecasting methodology in Appendix F1.

Our current forecast shows essentially flat load relative to current levels, with an average annual growth rate of less than 0.2 percent, after accounting for EE. Figure 3-2 below shows the current forecast in relation to the forecast from our last Resource Plan.

Figure 3-2: Forecasted Peak Load, After Energy Efficiency Adjustments (MW)[1]



We have changed our approach to how we present our peak forecast from our last Resource Plan based on our treatment of EE as a supply-side resource in this Plan. The peak forecast in our previous Resource Plan included both a demand reduction associated with historic EE, as well as from the impact of future incremental EE as approved in the previous Resource Plan.

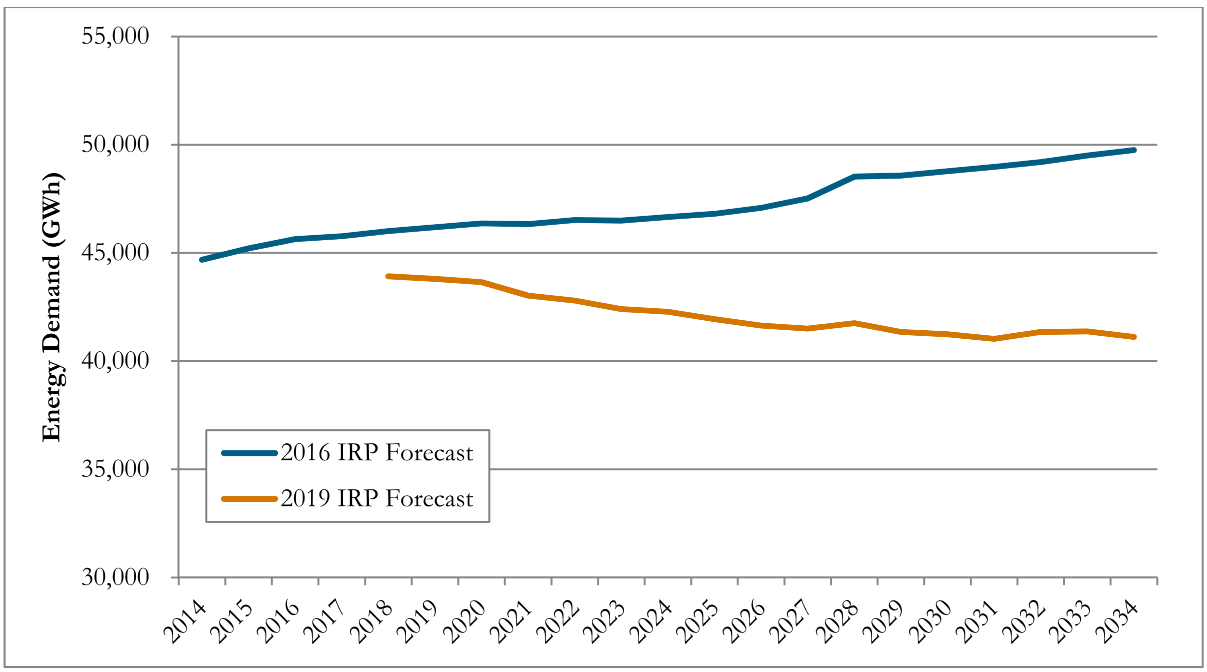
For this Resource Plan, we have changed our approach to addressing EE in two ways. First, the load forecast used in our Strategist modeling no longer has embedded incremental EE, although it is shown in that manner in the charts above for comparison purposes with previous Resource Plans. Instead, we treat EE as a supply-side option that the Strategist model can select in its resource optimization. To do so, we developed EE "Bundles," which we describe in Part III below and in more detail in the Strategist Assumptions Appendix F2. As a result, rather than adjust our peak forecast based on an assumed level of future EE adoption (this would have been 1.5 percent per the level approved in our last Resource Plan), we are reflecting our commitment to *higher* levels of EE achievement (approximately 2.5 percent reduction) in our Reference Case. This level of EE reflected in the Reference Case is representative of two of the EE Bundles available for Strategist to select.

[1] Although we modeled EE bundles as supply-side resources in this Resource Plan, we show the estimated resulting EE as a load reduction from gross load for purposes of the chart above.

2. Energy Requirements

We forecast declining energy needs of approximately 0.4 percent over the 2020-2034 planning period, after accounting for EE included in the Reference Case. As discussed above, the inclusion of two incremental EE Bundles reflects achievement of approximately 2.5 percent EE, which leaves our Net Demand substantially lower than forecast in our last Resource Plan. Figure 3-3 below compares our estimated net energy demand adjusted by the two EE Bundles, to the energy forecast in our last Resource Plan.

Figure 3-3: Forecasted Net Energy Requirements, After Energy Efficiency Adjustments[2] (GWh)



3. Forecast Adjustments

After determining the base peak capacity and energy demand forecasts, we make certain forecast 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:

DSM. In past Resource Plans, the load forecasts used by Strategist were adjusted for

[2] Although we modeled EE bundles as supply-side resources in this Resource Plan, we show the estimated resulting EE as a demand reduction from gross demand for purposes of the chart above.

the expected effects of existing DSM programs. In this Resource Plan, based on feedback from stakeholders, incremental EE is no longer embedded in the load forecast, rather EE is treated as potential supply-side resource in our modeling, like DR. Both EE and DR are shown as separate line items in our Loads and Resources table below, though in an effort to maintain consistency with Load and Resource reporting between this and previous Resource Plans, we show EE "above the line" as a subtraction from gross load. We further discuss the EE and DR (collectively, DSM) in the context of our resource planning process in Appendix G1.

Distributed and Small Scale Customer Solar Generation. We have historically considered customer adoption of distributed solar (i.e. DG solar as well as CSG) installations as a modification to load in the resource planning process. In this Resource Plan, we have accounted for DG solar including CSG resources as a supply-side resource with assumed adoption levels, as shown in the Loads and Resources calculation below. Reference Case assumptions currently take into account interconnection requests and expectations based on policy-driven programs. However, we also conduct sensitivity testing around potential increased levels of adoption and are working to develop new tools that improve our understanding of how key market drivers will affect customer distributed solar adoption going forward. We note that our methods for projecting distributed solar installations are currently evolving. As our tools and methods mature, we will increasingly incorporate them into both our Resource Plan and IDP processes.

Expected Customer Changes. We also make adjustments to account for known changes in load on our system. These typically reflect expected changes in specific large customers' electricity usage, either as a result of increased behind the meter energy generation (decreasing demand) or increased production activities (increasing demand).

Light Duty Electric Vehicle Adoption. We adjust our residential energy and peak demand forecasts to account for increasing use of plug-in electric vehicle charging. These forecasts are based on expectations around current stock and future adoption (including the effect of financial incentives to facilitate adoption), and the expected electricity consumption per vehicle.

We use standard statistical modeling techniques to reflect these and other potential sources of variation around our expected forecasts. We discuss our forecasting process, inputs, assumptions, adjustments and results in more detail in Appendix F1: Load and Distributed Energy Resource Forecasting.

II. MISO RESOURCE ADEQUACY REQUIREMENTS

MISO prescribes Resource Adequacy (RA) requirements that are intended to help ensure adequate reliability of the bulk electric supply system. MISO's RA process requires load serving entities (LSE) like the Company to maintain resources that exceed their level of demand by a specific margin (planning reserve margin or PRM) to cover potential uncertainty in the availability of resources or level of demand.[3] The RA requirements are fundamental to the resource planning process, and inform the level of capacity we need in our portfolio to adequately serve customers over a long-term planning process. We describe the various aspects of the calculation below, and note that our effective reserve margin is 2.98 percent.

MISO's RA requirements are set based on an annual planning period; the 2018/2019 planning period covers June 1, 2018 through May 31, 2019. 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 Local Resource Zone (LRZ or Zone) where the LSE resides.[4] 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.

A. MISO Footprint Capacity Obligation

By November 1 prior to a planning period, MISO issues the finalized PRM applicable to all LSEs within its footprint. MISO determines the PRM by performing a technical probabilistic analysis to determine the minimum PRM needed to achieve a Loss of Load Expectation (LOLE) of 0.1 day per year, expressed as a percentage. For example, for the planning year covering June 1, 2018 through May 31, 2019 the overall MISO PRM was 17.1 percent on an installed capacity (ICAP)[5] basis and 8.4 percent on an unforced capacity rating (UCAP) basis.[6] The study also provides

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[3] The factors affecting availability and demand include: Planned maintenance, Unplanned or forced outages of generating facilities, Deratings in resource capabilities, Variations in weather, and Load forecasting uncertainty.

[4] Almost all of the NSP system load is located within LRZ 1, which includes almost all of Minnesota, western Wisconsin, and the Dakotas. Approximately 7 MW of load along the Minnesota-Iowa border is located in LRZ 3.

[5] ICAP refers to units' Installed Capacity Rating, which is a capacity accreditation measure based on annual or historical tested generating. The ICAP is the lesser of the generator verification testing capacity or the interconnection service capacity.

[6] UCAP refers to units' Unforced Capacity Rating, which is a function of the unit's installed capacity and its anticipated forced outage rate. A generator's anticipated forced outage rate is typically based on the individual unit's historical performance. UCAP = ICAP x (1 – Forced Outage Rate). *See* "Planning Year 2018-2019 Loss of Load Expectation Study Report" at 5. Available at: https://www.misoenergy.org/api/documents/getbymediaid/80578

forward-looking PRM values, through 2028. Over the planning period MISO examined in the 2018-2019 LOLE study, the UCAP PRM remained relatively constant between 8.3-8.4 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, which would override the PRM otherwise determined by MISO. None of the NSP System states have established a PRM separate from MISO.

B. Zonal Capacity Obligation

Additionally, MISO makes an annual determination regarding the amount of capacity required within each of MISO's Zones, called the Local Clearing Requirement (LCR). The LCR is determined as a function of each Zone's Local Reliability Requirement (LRR) and its Capacity Import Limit (CIL). The LRR represents the necessary resource requirement in order for a Zone to achieve an LOLE of 0.1 day per year, without relying on resources outside of the Zone. Each Zone, having a smaller footprint than the overall MISO footprint does not benefit from the same level of peak load diversity as does the larger, more diverse MISO footprint. Thus, it can be expected that a Zone's LLR is greater than the sum of its LSEs' MISO footprint obligations. If a Zone within which an LSE operates has import capacity, however, the resulting LCR is reduced. As a result, LSEs usually plan their minimum system needs based on the MISO-wide PRM rather than the zonal requirement.

For the 2018-2019 planning year, Zone 1 was assigned an LRR of 114.8 percent, which, in capacity terms equates to an LRR of 20.2 GW. However, when accounting for Zone 1's CIL of 4.4 GW, Zone 1's LCR is 15.8 GW. This is less than the MISO footprint PRM of 18.4 GW. Thus, Zone 1's import capabilities allow LSEs within Zone 1, including the Company, to plan to the MISO-wide UCAP PRM of 8.4 percent rather than the higher LRR value.

C. Capacity Obligations Derived From Forecasted Demands

After determining the relevant PRM, each LSE can derive its MISO-wide and zonal capacity obligation from its 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).

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

The NSP System CPD factor measures how closely our system peak matches the MISO system peak. A coincidence factor of 95 percent indicates that we expect to experience load levels that are approximately 95 percent of our peak load during times when the total MISO system load is peaking. In other words, the timing of our peak and the MISO peak does not match exactly, so we are able to reduce the amount of reserves we carry as a result. After accounting for the coincidence factor, our effective reserve margin drops from 8.4 percent to 2.98 percent. We illustrate this calculation in Figure 3-4 below.

Figure 3-4: MISO Planning Reserve Margin Calculation – NSP System Planning Year June 1, 2018 to May 31, 2019

$$(95\, percent\ coincidence\ factor) x\ (1 + 8.4\, percent) - 1 = 2.98\, percent\ effective\ reserve\ margin\ for\ NSP$$

Putting these pieces together, we used our effective reserve margin, in combination with our annual load forecasts over the planning period, to determine our overall capacity obligation for the same period. For 2020, this calculation results in the following approximate obligation:

Table 3-1: Capacity Obligation Calculation – 2020 Example

Total Capacity Obligation Component	Value
Forecasted load	9.1 GW
NSP Effective Reserve Margin	x (1+ 2.98%)
NSP Obligation	**= 9.4 GW**

Our estimated obligation for all planning period years can be found in the Load and Resources table in Section VI. below.

D. Capacity Accreditation of Resources

After these obligation levels have been determined, we consider the type of resources suitable to meet that requirement. MISO's tariff and business practices set forth procedures to enable various types of resources to be used to achieve our RA requirements. 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.

Resources used to achieve MISO's RA requirements are referred to as "Planning Resources." Planning Resources include the following sub-types:

- *Capacity Resources*: Physical Generation Resources (i.e. physical assets and purchase agreements), External Resources if located outside of MISO's footprint, and DR Resources participating in MISO's energy and operating reserves market, available during emergencies.
- *Load Modifying Resources*: Behind-the-Meter Generation and DR available during emergencies, which reduces the demand for energy supplies coming from the LSE.
- *Energy Efficiency Resources*: 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. Therefore, instead of using installed or nameplate capacity (i.e. ICAP), MISO calculates the unforced capacity value (i.e. UCAP) for each resource to determine its expected contribution to RA. These are calculated differently depending on the resource's dispatchability or variability:

- *Dispatchable generation resources, DR and EE* – MISO assigns a UCAP value for dispatchable generation resources by discounting their installed capacity by an anticipated forced outage rate. Resources where availability depends on other factors are measured differently; for example, MISO has a process to determine the UCAP for DR resources using a documented process of assessing the resource's observed responsiveness and load reduction effectiveness.
- *Variable resources* – MISO assigns variable resources, such as grid-scale solar and wind, a UCAP value that is a function of the individual unit's historical performance during the peak hours of the planning period. 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. If sufficient operating history is not available, MISO assigns a proxy value.

Our modeling selects resources based on their UCAP values, to ensure we maintain adequate capacity on our system over the planning period. Additionally, as discussed below in Section IV, we included a further Reliability Requirement in our planning process to address MISO's evolving processes.

III. DEMAND SIDE MANAGEMENT

DSM programs offer our customers opportunities to lower their energy use and manage their peak demand, in particular through our Conservation Improvement Programs. As noted previously, these programs include both EE and DR. We base our forecasts and potential incremental additions on historic achievements through our programs, as well as external studies about expected and potentially achievable adoption rates.

As previously discussed, we adjusted the customer capacity and energy forecasts in this Resource Plan to distinguish incremental EE from the load forecast. We modeled incremental DR and EE achievements as "Bundles" to be evaluated alongside other resource options. Each Bundle represents a combination of program achievements expected to lead to a certain amount of avoided load or energy per year, at an estimated blended cost.

For EE, these Bundles include measures that work to reduce a customer's overall energy usage throughout the year. The DR Bundles, on the other hand, reflect a customer's commitment to discrete reductions in demand (e.g. on a day when peak load is expected to be high otherwise). These actions are expected to reduce the anticipated annual system peak demand, as well as smooth demand on specific days when weather or other conditions lead to high demand at a certain point in time. In the Order approving our last Resource Plan,[7] the Commission directed that the Company "shall acquire no less than 400 MW of additional DR by 2023." In this Resource Plan, we included one DR Bundle in our modeling for both the Reference Case and Preferred Plan.

We discuss the studies that informed our expected EE and DR levels, our analysis,

[7] *See* E002/RP-15-21 Order Approving Plan with Modifications and Establishing Requirements for Future Resource Plan Filings (January 11, 2017), Order Point 10.

and the changing DSM landscape in more detail in Appendix G1.

IV. RELIABILITY REQUIREMENT

A new planning element we included in this Resource Plan is a Reliability Requirement which, in short, will ensure that we can serve customers with reliable energy every hour of every day.

The need for the Reliability Requirement stems from the inherently variable nature of renewable resources and availability of any time limited resource. Further, as the penetration of these resources increases, their value to meet peak customer needs decreases. Although MISO is beginning to recognize these challenges, its current planning constructs do not yet incorporate any measures to address them. Until MISO determines how best to address these gaps, we believe it is incumbent on us as the utility to take steps to ensure that our system is resilient and that our customers will be reliably served. Fundamentally, we have a responsibility to ensure we have access to a sufficient level of firm dispatchable resources in all grid conditions that can flexibly adapt to variable renewable resource performance to meet our customers' needs.

To develop the Requirement, we analyzed industry insights and data from case studies, including the 2019 polar vortex and normal winter and summer days. From this information, we developed a method determine a threshold level of firm dispatchable resources needed to serve customer loads, that reflects a reasonable level of reliance on MISO resources and DR to meet a portion of the need.

Figure 3-5 below demonstrates the calculation of the Reliability Requirement we applied in our modeling for this Plan.

Figure 3-5: NSP System Reliability Requirement Calculation – 2020 Example

Peak Demand Proxy – 6.4 GW
Minus Firm DR (Winter) Proxy – (0.2) GW
Minus Firm Market Supply Proxy – (0.5) GW

Reliability Requirement - 5.7 GW
(Firm dispatchable resources)

To implement this Requirement, we applied it as a threshold in our Strategist modeling to ensure that our firm dispatchable resources do not fall below this level – even while our Preferred Plan achieves an 80 percent carbon reduction by 2030. In the 2020-2034 planning period, the Requirement ranges from approximately 5.6 GW early in the planning period, to about 6.0 GW by the end of the planning period. We clarify here, however, that while this concept is essential to include until MISO evolves its capacity accreditation constructs, the Requirement as applied in our modeling has little effect for this Resource Plan. The model does not select any firm dispatchable additions as a direct result of the Reliability Requirement until near the end of the planning period, in 2031. This long runway leaves ample time for MISO and its stakeholders to address this aspect of its planning and provide additional direction.

V. EXISTING RESOURCES

Our current generating resources[8] comprise a diverse portfolio including nuclear, coal, wind, biomass, solar, hydro, natural gas and oil-fueled facilities. Physical generating assets owned by the Company have a net maximum capacity of over 9,500 MW, including 850 MW of wind.[9] In addition to these assets, we maintain PPAs representing a net maximum capacity of over 3,700 MW.[10] Together, these provide over 13,200 MW of generation resources, of which over 4,300 MW[11] is supplied by renewables. A total of over 6,000 MW[12] is supplied by carbon-free resources.

A. Renewable Resources

In total, we currently have over 4,300 MW of renewable capacity serving the NSP System, including:[13]

- Over 2,600 MW of wind
- 840 MW of solar, including community solar programs and grid-scale solar[14]
- 680 MW of hydroelectric power[15]
- 160 MW of biomass and landfill gas

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[8] As of July 2019; excludes some resources included in modeling that are expected to be online by the end of 2019.
[9] Maximum capacity represented here reflects capacities included in Strategist modeling. It approximates Net Maximum Capacity, which is defined as the units Gross Maximum Capacity, less any capacity that is used for that unit's station service or auxiliary load.
[10] This total excludes 425 MW of renewable diversity capacity credit from contracts with Manitoba Hydro.
[11] *Id.*
[12] *Id.*
[13] Note: these values are approximate.
[14] Per Docket No. E002/RP-15-21 Order Point 4a (January 11, 2017), our solar acquisitions will exceed the 650 MW through CSG resources or other cost-effective acquisitions. The CSG program is on track to exceed the ordered 650 MW by year ending 2019, per the most recent forecast CSG Monthly Report (filed June 14, 2019) and included in this filing as Appendix N8.
[15] Excluding capacity associated with diversity agreement contracts with Manitoba Hydro.

B. Nuclear

Our Monticello and Prairie Island nuclear plants provide nearly 1,740 MW of clean energy and capacity to our customers and play an important role in achieving our goal of an 80 percent reduction in system carbon emissions by 2030, while maintaining reliability and affordability. The monthly capacity factors of our nuclear facilities are historically 90 percent or higher. Together, our nuclear plants currently provide nearly 30 percent of our energy mix. In terms of production costs (fuel plus O&M), both plants have achieved reductions of more than 20 percent since 2015, with average costs now below $30/MWh.

C. Coal

Our coal fleet includes our Sherco Units 1, 2, and 3 in Becker, Minnesota and the Allen S. King plant in Oak Park Heights, Minnesota. This coal fleet provides almost 2,400 MW of baseload and cycling generating capacity, and supports system reliability. In our last Resource Plan, the Commission approved our proposal to retire Sherco Units 1 and 2 in 2026 and 2023, respectively. These retirements are reflected in our Reference Case discussed below. Our Preferred Plan further proposes to retire the King plant in 2028 and Sherco 3 in 2030, after which coal would no longer be part of our energy mix.

D. Natural Gas (and Oil-Fired) Fleet

Our natural gas fleet consists of both intermediate and peaking generation. We have five owned or contracted intermediate-type generating assets that provide just over 2,400 MW of capacity. We have peaking-type resources located at seven sites, providing another 2,350 MW of capacity. Combined, these facilities provide valuable load following capabilities for our system, cycling as necessary to provide important flexibility to our generation operations and support to our growing renewable resources. Our Reference Case also includes pending and proposed capacity resource additions including MEC as proposed in Docket No. IP6949,E002/PA-18-702, and the Sherco CC that the Commission acknowledged in its Order in our last Resource Plan.[16] These pending resources appear in separate line items in our net resource calculation below.

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[16] The Commission approved our proposed schedule to retire Sherco Units 1 and 2, and found that more likely than not there will be a need for approximately 750 MW of intermediate capacity coinciding with the retirement of Sherco Unit 1 in 2026. *See* In the Matter of Xcel Energy's 2016-2030 Integrated Resource Plan, ORDER APPROVING PLAN WITH MODIFICATIONS AND ESTABLISHING REQUIREMENTS FOR FUTURE RESOURCE PLAN FILINGS, Ordering Point Nos. 7 and 8, Docket No. E002/RP-15-21 (January 11, 2017).

VI. NET RESOURCE SURPLUS/DEFICIT

As described above, our forecast of customers' peak demand and MISO Resource Adequacy requirements are used to determine our overall total generating capacity obligation. From this, we deduct our expected load management achievements and UCAP generating capacity of the various resources we have included in our Reference Case to determine our net generation capacity surplus or deficit. We anticipate a net surplus through 2026 and a deficit thereafter.

Table 3-2: Reference Case Load and Resources,[17] 2020-2034 Planning Period

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
System needs															
Forecasted gross load	10,499	10,559	10,621	10,684	10,755	10,820	10,886	10,954	11,140	11,232	11,320	11,418	11,518	11,619	11,717
Forecasted EE[18] (reduction to load)*	(1,386)	(1,472)	(1,517)	(1,609)	(1,707)	(1,822)	(1,921)	(1,992)	(2,125)	(2,215)	(2,278)	(2,366)	(2,352)	(2,324)	(2,415)
Forecasted net load	**9,112**	**9,087**	**9,103**	**9,075**	**9,048**	**8,998**	**8,965**	**8,963**	**9,014**	**9,016**	**9,042**	**9,052**	**9,166**	**9,295**	**9,301**
MISO System Coincident	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%
Coincident Load	8,657	8,633	8,648	8,621	8,595	8,548	8,517	8,514	8,564	8,565	8,590	8,599	8,708	8,831	8,836
MISO PRM	8.40%	8.40%	8.40%	8.40%	8.40%	8.40%	8.40%	8.40%	8.40%	8.40%	8.40%	8.40%	8.40%	8.40%	8.40%
NSP Obligation	**9,384**	**9,358**	**9,374**	**9,345**	**9,317**	**9,266**	**9,232**	**9,230**	**9,283**	**9,285**	**9,312**	**9,321**	**9,439**	**9,572**	**9,579**
Reference Case resources (UCAP)															
Load Management *(existing)*	940	955	970	989	1,007	1,023	1,038	1,053	1,066	1,054	1,043	1,032	1,021	1,010	1,000
Load Management* *(potential study)*	270	290	312	322	339	380	392	406	421	438	456	476	497	527	550
Coal	2,390	2,390	2,390	2,390	1,699	1,699	1,699	1,017	1,017	1,017	1,017	1,017	1,017	1,017	1,017
Nuclear	1,603	1,603	1,603	1,603	1,603	1,603	1,603	1,603	1,603	1,603	1,603	992	992	992	484
Natural Gas/Oil	3,295	3,295	3,295	3,295	3,141	2,829	2,624	2,136	2,018	2,018	2,018	2,018	1,765	1,765	1,765
MEC*	627	627	627	627	627	627	627	627	627	627	627	627	627	627	627
Sherco CC*	0	0	0	0	0	0	0	727	727	727	727	727	727	727	727
Biomass/RDF	110	110	110	86	86	63	63	63	22	22	22	22	22	22	22
Hydro	877	997	989	989	989	162	162	162	162	162	162	162	156	152	152
Wind	596	650	696	670	659	642	637	622	616	594	593	578	575	511	492
Grid-scale solar	182	182	181	180	179	178	177	176	175	174	174	173	172	171	170
Solar*Rewards Community Solar	335	339	344	348	352	356	360	365	369	373	377	381	385	389	393
Distributed Solar	42	48	55	60	66	72	78	83	89	95	100	105	111	116	121
Existing Resources	**11,267**	**11,486**	**11,571**	**11,559**	**10,746**	**9,634**	**9,460**	**9,040**	**8,913**	**8,905**	**8,920**	**8,311**	**8,066**	**8,026**	**7,521**
Net Resource (Need)/Surplus	**1,884**	**2,128**	**2,196**	**2,213**	**1,429**	**368**	**228**	**(190)**	**(370)**	**(380)**	**(392)**	**(1,010)**	**(1,373)**	**(1,546)**	**(2,058)**

While the Order also addressed next steps for the replacement generation at Sherco, legislation was passed as part of the 2017 Legislative Session that in summary, allows the Company to proceed with the construction of the replacement unit at Sherco in accordance with the parameters specified in the legislation, and without a Certificate of Need. *See* Laws of Minnesota 2017, chapter 5 – H.F. No. 113, section 1.

[17] In addition to existing and approved resources, those indicated with a * include pending or proposed resources that we have included across all Scenarios, including the Reference Case.

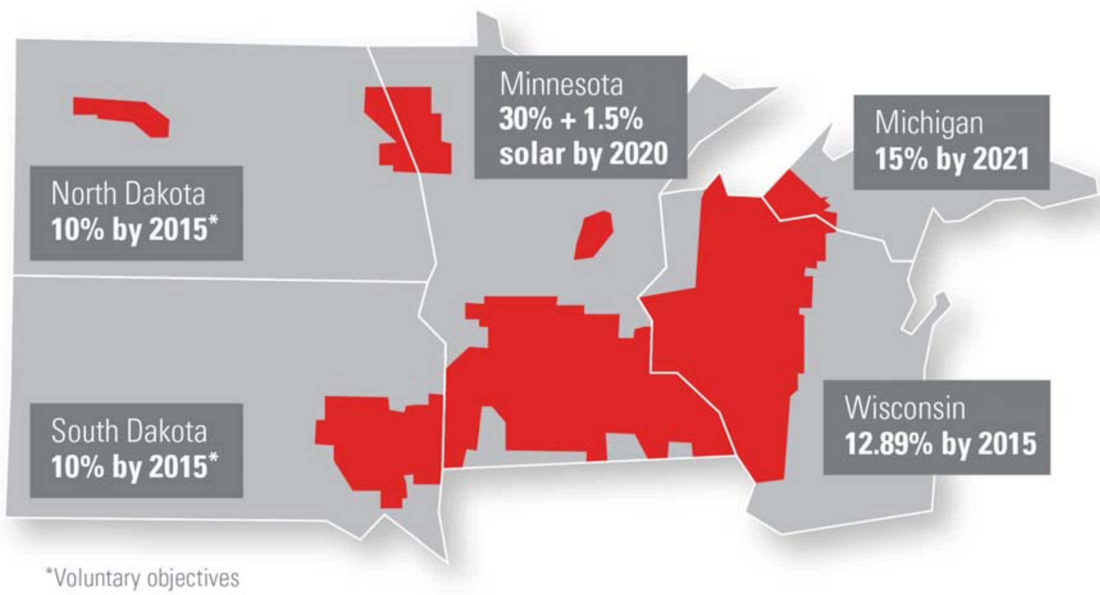
[18] Includes EE savings from historically installed measures, as well as future EE from bundles modeled in this Resource Plan, achieving 2-3% savings levels. Also includes minimal EV and coincidence adjustments.

VII. MEETING RENEWABLE ENERGY REQUIREMENTS AND GOALS

A. Minimum Compliance Requirements

Each of the states in the NSP System has a different public policy with respect to renewable energy requirements or objectives. Figure 3-6 below illustrates each state's renewable energy standard (RES).

Figure 3-6: Renewable Energy Requirements and Objectives – NSP System



Three of our states have renewable standards expressed as a percentage of electric retail sales from qualifying resources by a certain date. Minnesota's RES is the highest, requiring that 30 percent of the Company's energy come from renewables, with at least 24 percent of the electricity we provide to retail customers coming from wind energy by 2020[19] Legislation passed in the 2013 session also established a Solar Energy Standard (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 that 1.5 percent, 10 percent must come from systems with

[19] This requirement is included in the total 30 percent RES, and we are authorized to count a limited amount of solar energy towards an overall 25 percent wind and solar requirement (amounting to 1% of total sales). The SES is assessed separately. Large hydro does not count as a renewable energy source for purpose of the Minnesota RES. Minn. Stat. § 216B.1691.

capacity less than 40 kW.[20] The legislation also established a goal of 10 percent of energy sales from solar by 2030.

North Dakota and South Dakota each have a voluntary objective that includes renewable or recycled energy.[21] Further, our North Dakota regulators have indicated that compliance with the North Dakota Renewable Energy Objective should be accomplished with competitively-priced energy.

To-date we have implemented a strategy to have the entire NSP System comply with, at the very least, the highest of renewable energy requirements across our jurisdictions; in this case, the Minnesota RES. This strategy also places us in compliance with the specific requirements in each of our other jurisdictions. As a result, we have been planning for renewable energy additions, and allocating their benefits, to all of our jurisdictions (with certain exceptions as discussed in the Planning Landscape). As state energy policies continue to evolve, however, we will continue to examine whether this requires a strategy change going forward, and engage our Commissions as needed on that topic.

B. RES Compliance

Given existing and previously approved resources, we project continued compliance with the renewable energy goals and standards in each of our NSP states. The Company currently maintains a set of banked Renewable Energy Credits (RECs) for future compliance.[22] In the past, we have leveraged our REC bank to manage the size, type, 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. Given our recent focus on adding renewable capacity, however, we now generate RECs in excess of our baseline obligations each year. We currently generate sufficient RECs annually from eligible renewable resources to account for over 40 percent of the energy we provide our NSP System customers, which outpaces our annual requirement

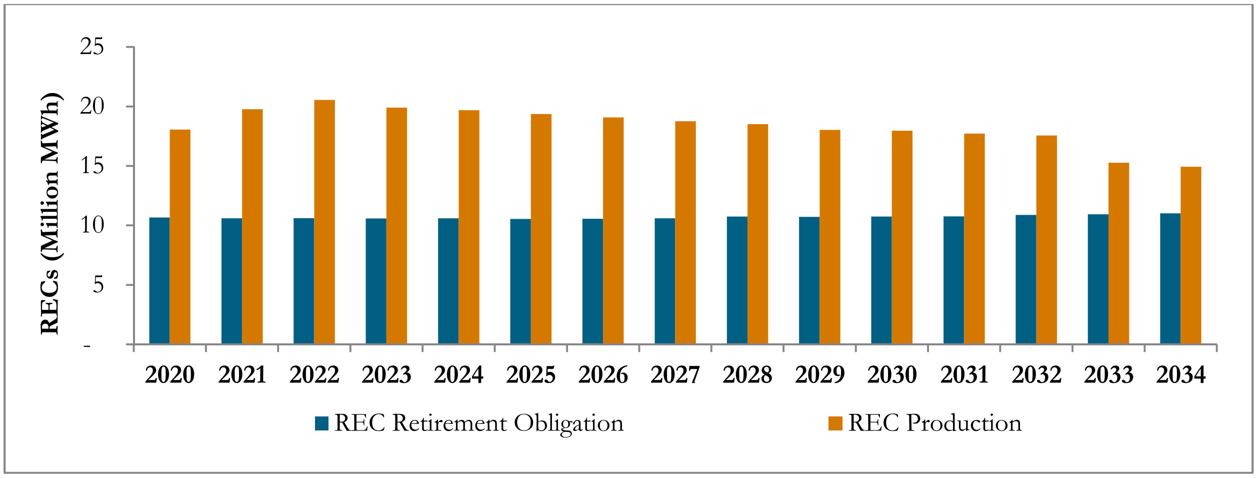
[20] The original legislation set a threshold of 20 kW, but was increased to 40 kW in 2018, per HF3232. *See* "Minnesota Renewable energy Standard: Utility Compliance." Minnesota Department of Commerce (January 2019) at 7. Available at: https://www.leg.state.mn.us/docs/2019/mandated/190330.pdf

[21] 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.

[22] A REC is an accounting device designed to reflect the renewable energy attributes of a particular MWh of renewable energy generation. RECs are the currency for compliance with state renewable targets.

Figure 3-7 below illustrates annually generated RECs across the NSP System in the Reference Case scenario. In this scenario, we will have sufficient RECs to comply with the current renewable energy goals and standards of all of our NSP jurisdictions through 2034, even without securing additional renewable resources.

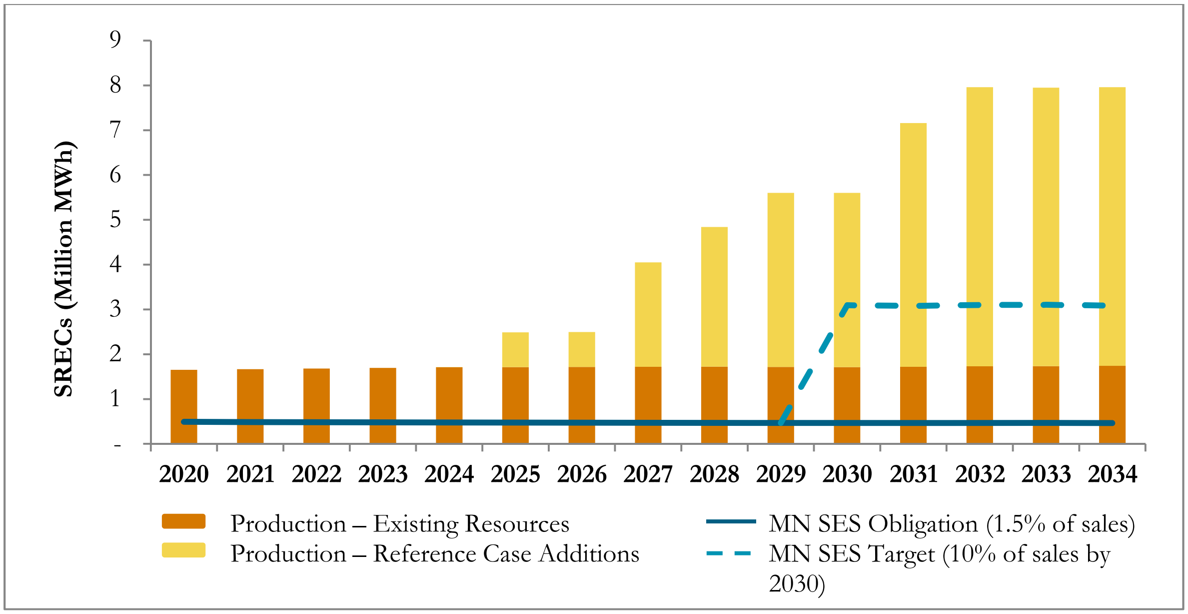
Figure 3-7: REC Production and Retirement Obligations for NSP System – Existing Resources Only



C. SES Compliance

As previously mentioned, Minnesota law requires us to provide our customers with solar-generated energy equal to at least 1.5 percent of our annual customer demand by 2020, and a goal of 10 percent by 2030. We have developed a portfolio of programs to provide solar options to residential and commercial customers, and have also grown our utility-scale solar profile. As a result, we expect to meet the SES requirements through the planning period, per our Reference Case. We also expect the solar capacity additions included in our Reference Case to provide sufficient energy to meet the 10 percent goal by 2030. Figure 3-8 below demonstrates our annual estimated SREC production relative to Minnesota requirements and goals, for the Reference Case scenario.

Figure 3-8: NSP System SREC Production and Minnesota Annual Requirements



We discuss our renewable energy standard compliance further in Appendix N4: Renewable Energy Compliance Positions.

VIII. ENERGY POLICY AND COMPANY GOALS

As demonstrated, we believe that we are well positioned to meet minimum system needs. At least through 2024, we expect that we will be able to meet those needs with existing and already-approved resources. However, in 2018, we committed to an ambitious carbon reduction vision, to achieve 80 percent below 2005 carbon emissions levels by 2030 and 100 percent carbon-free energy by 2050. We are committed to achieving this goal, and as such, have modeled our Reference Case, Preferred Plan, and all other scenarios using our 80 percent carbon reduction target as a guidepost.

IX. REFERENCE CASE

We incorporate all of the aforementioned elements into the Strategist modeling tool, which allows us to 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 develop starting assumptions that reflect their expert opinion of likely future conditions. We then test the robustness of the plans through sensitivity analysis by individually changing key assumptions and re-running the plans under these changed assumptions. Our analysis resulted in the following Reference Case Expansion Plan, depicted in Tables 3-3 and 3-4 below:

Table 3-3: Reference Case Annual Expansion Plan (UCAP)[23]

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Grid-Scale Solar	0	0	0	0	0	250	0	500	250	250	0	500	250	0	0
Battery	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CC	0	0	0	0	0	0	0	727	0	0	0	0	0	0	0
Firm Dispatch-able	0	0	0	0	0	0	0	0	0	0	0	0	206	330	330
DR	270	20	21	10	17	41	12	14	15	17	19	20	21	22	23
EE	115	130	116	133	143	145	154	157	155	140	138	136	129	126	126
Wind	0	0	0	20	7	11	10	11	2	17	2	9	5	82	247
Distributed Solar	154	22	22	21	21	21	21	20	20	20	20	20	20	20	19
Total	**540**	**172**	**159**	**184**	**188**	**468**	**196**	**1,453**	**442**	**443**	**179**	**685**	**630**	**579**	**745**

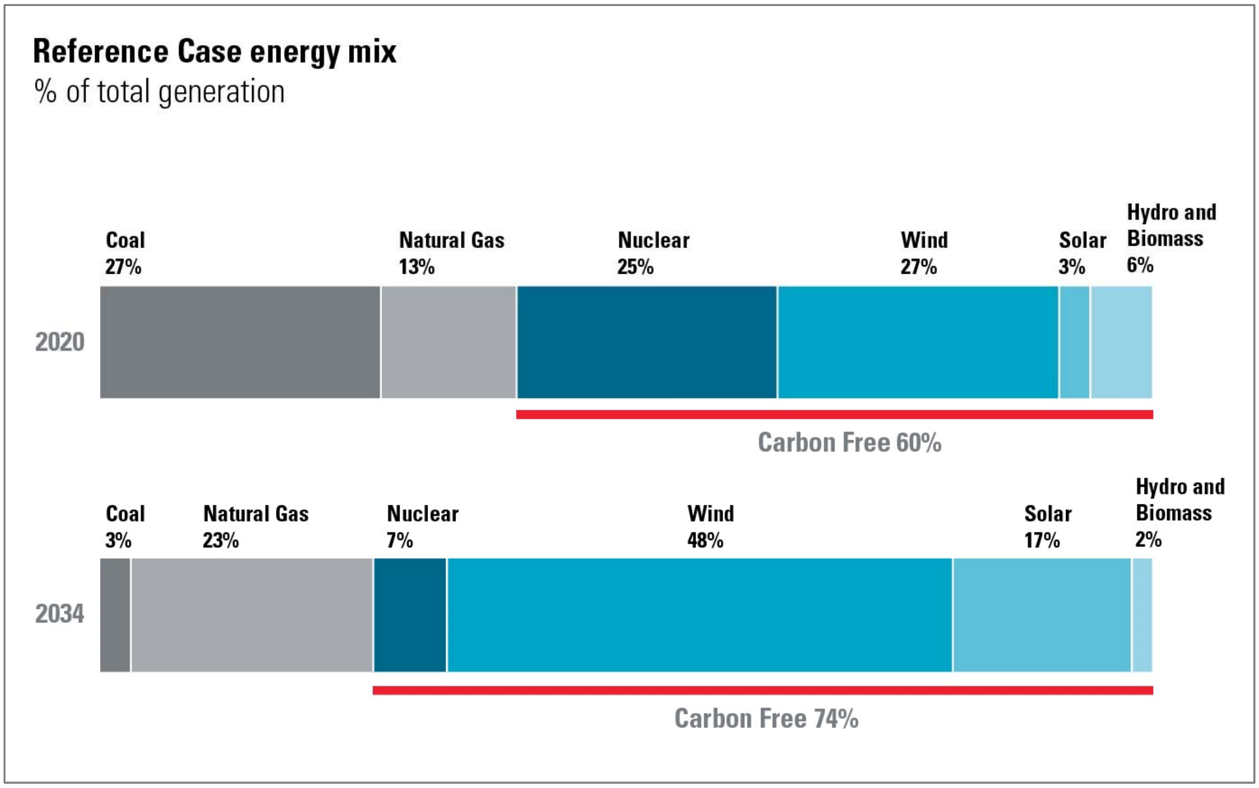
Table 3-4: Reference Case Annual Expansion Plan (ICAP)[24]

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Grid-Scale Solar	0	0	0	0	0	500	0	1000	500	500	0	1000	500	0	0
Battery	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CC	0	0	0	0	0	0	0	835	0	0	0	0	0	0	0
Firm Dispatch-able	0	0	0	0	0	0	0	0	0	0	0	0	232	374	374
DR	270	20	21	10	17	41	12	14	15	17	19	20	21	22	23
EE	115	130	116	133	143	145	154	157	155	140	138	136	129	126	126
Wind	0	0	0	126	45	70	66	72	10	107	16	56	31	523	1581
Distributed Solar	154	22	22	21	21	21	21	20	20	20	20	20	20	20	19
Total	540	172	159	290	226	777	252	2,098	700	784	193	1,232	932	1,065	2,123

The Reference Case presented here would result in the following energy mix:

[23] Note: This table includes CC, EE, DR, and Distributed Solar resources that are also reflected in the Load and Resources Table.
[24] Note: This table shows ICAP values of the resources indicated in Table 3-4 above.

Figure 3-9: Reference Case Energy Mix in 2020 and 2034



We outline and discuss the starting assumptions, scenarios, and sensitivities that formed our Strategist analysis, and resulted in our Preferred Plan, below and in Appendices F2 and F3.

CHAPTER 4
THE PREFERRED PLAN

The Preferred Plan we propose in this 2020-2034 Upper Midwest Resource Plan reflects extensive collaboration with stakeholders as well as independent expert analysis. It supports our states' clean energy goals and the Company's goal of reducing carbon emissions 80 percent by 2030 – and our ultimate vision of 100 percent carbon-free energy by 2050.

Key components of our Preferred Plan include:

- Retiring nearly 2,400 MW of remaining coal-fired capacity by 2030, including previously approved Sherco 1 and 2 retirements and newly proposed accelerated retirement timelines for Sherco 3 and King. We also plan to implement seasonal dispatch at Sherco 2 prior to its retirement.
- Adding thousands of megawatts of new renewable resources, including substantial solar additions and replacement of expiring wind PPAs.
- Continuing to operate our nuclear plants at least until the end of their licenses, and extending operation of Monticello to 2040, as these resources anchor the grid in around the clock carbon-free energy.
- Significantly increasing our EE and DR resources, which will reduce our overall system demand.

Maintaining grid reliability and resilience through this transformation – as we must – will require firm and dispatchable load supporting resources and potentially significant transmission development. Accordingly, in order to meet reliability needs and support renewable integration as we retire legacy coal units, our Plan includes continued operation of our nuclear units (including a proposed 10-year extension of Monticello), acquisition of the MEC CC, and construction of a CC at Sherco, which we proposed in our last Resource Plan.

At the same time, we believe there may are exciting opportunities to pilot batteries, DER, and other clean, innovative technologies in the Upper Midwest. With respect to DR, in particular, we are seeking the flexibility to evaluate and pursue the required incremental DR through a variety of means and technologies that may go beyond conventional DR.

We have also sought to retain strategic flexibility by deferring decisions on certain generating units such as Prairie Island, which can be addressed in the next planning cycle. Doing so leaves room for innovation and allows for reassessment of technologies, costs, and capabilities before making substantial investments. It is also consistent with our longstanding belief that a deliberate and well-thought-out fleet transition is critical to facilitating successful community and employee transitions.

Finally, our Preferred Plan comes at a reasonable cost to our customers – with estimated rate impacts that are at, or below, the rate of inflation. In other words, we can achieve industry-leading reduction to CO_2 emissions at a cost that is consistent with the expected national average increase in electricity prices.

In summary, the course we have charted in this Preferred Plan drives toward our goal of achieving significant carbon reductions by 2030 and positions us to deliver on our longer term vision of a carbon-free electricity mix by 2050 – all without sacrificing our ability to deliver the reliable and affordable power that our customers count on every day. In this section we discuss: (1) our primary planning objectives and how they are reflected in our Preferred Plan, (2) the key components of the Plan and the actions we intend to take to achieve it, (3) the estimated customer cost impacts of our Preferred Plan, and (4) how this Plan meets the Commission's public interest objectives. We take each in turn.

I. PLANNING OBJECTIVES

When we began this Resource Plan process more than a year ago, we framed key planning objectives that would set the framework for development of our plan. The objectives are complex. They sometimes overlap and conflict, but each played a critical role in guiding our thinking and analysis which ultimately culminated in a plan that achieves substantial environmental benefits, maintains reliability, keeps costs low, and minimizes risks to our customers.

Figure 4-1: Xcel Energy Integrated Resource Plan Objectives

A. Environmental and Innovation

Environmental benefits and the technological innovations that will help us achieve them are front and center in this Resource Plan process. We have made a bold commitment to achieve 80 percent carbon reduction from 2005 levels by 2030, and have considered this target a modeling pillar for all of our potential scenarios. Our Preferred Plan achieves this goal in several ways. First, our Preferred Plan eliminates coal from our system by 2030, extends our carbon-free Monticello nuclear plant to 2040, adds at least 4,000 MW of new renewable resources, including substantial new solar capacity additions, maintains the wind levels committed to in our previous resource plan, and replaces renewables with renewables when they reach the end of their life.

It is important to note that, because many of these resource additions are not needed for a number of years, maintaining flexibility in how we achieve our carbon goals is essential. We have watched the planning landscape evolve at a remarkable rate over the last decade and we expect the rapid pace of innovation to continue. In fact, we expect technological advancements and innovations will create opportunities that we can seize upon in future procurement processes and integrated resource planning cycles if we retain the flexibility to do so. For example, future technology costs and transmission considerations may influence our mix of wind, solar and other non-emitting resources. Likewise, the need for firm and dispatchable load supporting capacity additions beyond 2030 may be better filled by battery storage and other advanced technology solutions. Where appropriate, we aim to be technology agnostic and open to what is coming next.

B. Reliability

Our responsibility to ensure a reliable electricity supply for our customers is a fundamental underpinning of our Preferred Plan. We therefore developed a Reliability Requirement that establishes a minimum level of firm dispatchable resources that is required to serve our customers' needs in every hour of every day. The Reliability Requirement was developed through analysis of industry trends and careful study of our system's performance (and the broader MISO system's performance) during both winter and summer days when renewables were unavailable, sometimes for lengthy durations. We discuss the development of the Reliability Requirement in greater detail in Appendix J2.

This Requirement does not drive any resource additions in our Preferred Plan until after 2030. Prior to 2030, our Preferred Plan relies on two primary sources to ensure reliability: (1) the MEC and Sherco CCs and (2) our nuclear units. With respect to the CC units, intermediate gas resources efficiently address reliability challenges because they can vary output to adapt as demand for electricity changes over the course of the day and year. The CC units are large rotating machines, so also provide important grid stability benefits and can also play an important role in our blackstart plans.[1] With respect to nuclear generation, our proposed Monticello extension not only represents a carbon-free workhorse of a resource, it also enhances fuel diversity and provides a generation resource that is not subject to seasonal fuel supply limitations.

C. Cost

Along with leading the clean energy transition and enhancing the customer experience, keeping customer costs low is one of Xcel Energy's central, guiding objectives. Since our last Resource Plan, renewable technology costs – and in particular, solar costs – have continued to decline; we expect this trend to continue going forward. Taking advantage of technological advancements is one reason that we can deliver a Preferred Plan that delivers deep carbon reductions for a nominal customer cost of just over one percent Compound Annual Growth Rate (CAGR) over the planning period. And over the long run, our Preferred Plan is expected to yield net present value savings. In comparison to the Reference Case, which does not

[1] As previously discussed, upcoming generation retirements will impact our current blackstart plans (*i.e.,* our ability to restart the system in the event of a catastrophic failure). While we do not propose any specific action related to the system blackstart at this time, we anticipate addressing this in our next Resource Plan or earlier, if system needs dictate the need to do so.

include accelerated coal retirements or an extension of the Monticello nuclear unit, the Preferred Plan yields $203 million of benefits on present value revenue requirements (PVRR) basis and $461 million of benefits on a present value societal costs (PVSC) basis.

D. Risk and Flexibility

Finally, while holding environmental, reliability, and cost objectives in balance, we also seek to mitigate customer risk by ensuring fuel diversity, maintaining appropriate capacity length in our portfolio, and maintaining flexibility in our plans. Portfolio fuel diversity is essential to risk mitigation – especially so, as we transition away from coal. Incorporating a mix of nuclear, load management, intermediate and peaking natural gas capacity, and renewables into our long-term plans ensures that our portfolio is adequately diverse and mitigates the risk associated with overdependence on any one fuel source. Further, the proposed resource additions identified in our Preferred Plan result in a capacity position that is between 500 to 1,000 MW long in any given year. We believe this modest length is prudent, particularly as we propose to substantially increase renewable resources – adding more than 4,000 MW of incremental new renewable capacity, much of which we anticipate will be grid-scale solar – in addition to our already large wind fleet.

Both MISO and independent analyses suggest that capacity accreditation for solar in particular will decline substantially as more capacity is added. We expect MISO will ultimately recognize this conclusion from its ongoing study of issues associated with integration of high levels of renewables in its planning construct.[2] Therefore, what we believe today to be a long capacity position may actually erode over time.

Maintaining a significant amount of flexibility in our future plans is essential to reliably and affordably navigating the transition of our fleet. To that end, we are deferring a decision on pursuing a license extension at the Prairie Island nuclear plant to subsequent resource plans, thereby preserving flexibility to respond to market conditions at that time. We are also optimistic that the firm dispatchable, load supporting resources needed in the post-2030 timeframe could be provided by new non-emitting technologies rather than traditional gas CTs. In addition, as we look to add solar resources to meet capacity needs in the mid to late 2020s, we are also open to allowing other resource types to compete, to ensure that we secure the most cost-effective resource solutions for our customers. As the industry and technology

[2] We discuss MISO's *Renewable Integration Impact Assessment* (RIIA) in more detail in our Baseload Study, provided as Appendix J1.

continue to rapidly evolve we will evaluate opportunities to bring these potential alternative solutions onto our grid.

E. Our Employees and Communities

Underscoring all four of our objectives is our commitment to our employees and the communities within which we operate. We do not make plant closure decisions lightly, and we are committed to supporting our employees at the Sherco and King plants as we prepare to retire these facilities. In the past we have provided career support services to our employees facing plant closures, and we expect to continue providing this support in the future. We also know that the Company is a major presence in terms of employment and local tax revenues in Becker and Oak Park Heights and the surrounding areas. We also have partners at our Sherco site with Liberty Paper and SMMPA (Southern Minnesota Municipal Power Agency). We are currently participating, alongside Minnesota Power, in a Host Community Impact study, to better understand the potential impact of power plant retirements on host communities. A similar study helped inform our work with the communities surrounding our Sherco 1 and 2 Units, and their planned closure as approved in our last Resource Plan. Since that time, we have worked with Becker and Sherburne County, as well as existing and prospective customers to spur economic development in the area, which also includes our plans to build, own, and operate the Sherco CC. As discussed in Appendix O1: Summary of IRP Stakeholder Engagement, we are committed to continue to work with our employees and communities to navigate this transition together.

II. THE PREFERRED PLAN

Our Preferred Plan is the product of an unprecedented stakeholder process that included 13 public workshops, independent expert analysis, and months of analysis and information sharing. As a result of those efforts – as well as the significant engagement of our stakeholder community over the past year, our Preferred Plan is the product of an unusual amount of consensus this early in the Resource Plan process.

Significant consensus has emerged around the following components of our Preferred Plan:

- Elimination of coal-fired generation from our system by 2030,
- Reduced, seasonal dispatch of Sherco Unit 2 until its retirement in 2023,
- Acquisition of at least 3,000 MW of utility-scale solar by 2030,

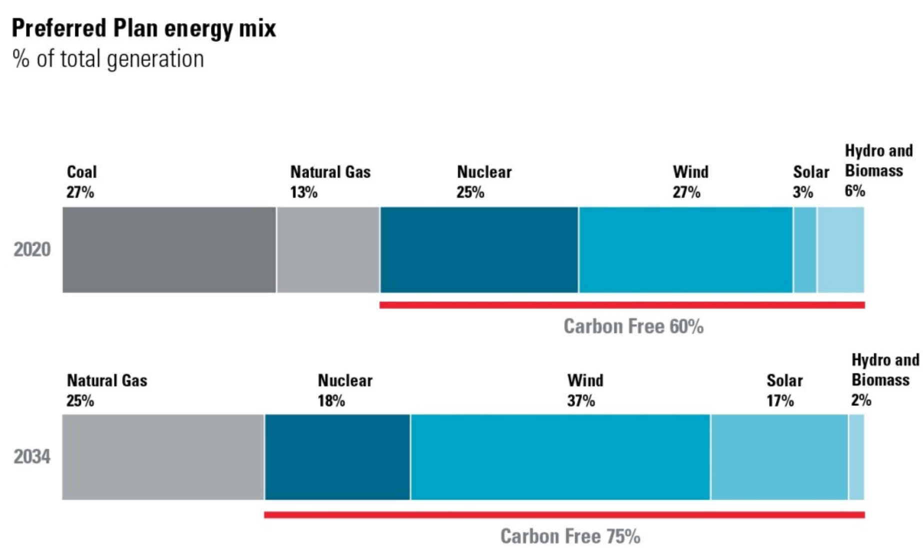
- A substantial increase in EE savings, and
- Support for the Company's proposal to take ownership of the MEC.

Our Preferred Plan builds upon this foundation and includes even more renewable resources, additional DR resources, continued operation of our carbon-free Monticello nuclear plant for an additional 10 years, and a new CC at our Sherco site. In the balance of this section, we present the change in our Energy Mix that will result from our Preferred Plan, and discuss key aspects of the transition below.

A. Transforming Our Energy Mix

From an energy mix perspective, the Preferred Plan eliminates the coal energy contribution and increases the renewable energy contribution by over 20 percent by 2034, rising to approximately 56 percent.

Figure 4-2: Preferred Plan Energy Mix



The fleet transformation underlying our Preferred Plan achieves a nearly 84 percent reduction in CO_2 emissions from 2005 levels by 2030, and maintains at least an 80 percent CO2 reduction through 2034.

Table 4-1 below presents the amount and timing of the resource additions that comprise our Preferred Plan.

Table 4-1: Preferred Plan Resource Additions (MW)

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Grid-Scale Solar	0	0	0	0	0	500	500	1000	500	500	500	0	500	0	0
Battery	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CC	0	0	0	0	0	0	0	835	0	0	0	0	0	0	0
Firm Dispatch-able	0	0	0	0	0	0	0	0	0	0	0	606	0	374	748
DR	270	20	21	10	17	41	12	14	15	17	19	20	21	22	23
EE	115	130	116	133	143	145	154	157	155	140	138	136	129	126	126
Wind	0	0	0	126	45	70	66	72	10	107	16	56	31	523	81
Distributed Solar	154	22	22	21	21	21	21	20	20	20	20	20	20	20	19
Total	**540**	**172**	**159**	**290**	**226**	**777**	**752**	**2,098**	**700**	**784**	**693**	**838**	**700**	**1,065**	**997**

In the next section, we discuss key aspects of our Preferred Plan and our fleet transition in more detail.

B. Fleet Transition

Our 2020-2034 Resource Plan represents a progressive step forward in transitioning our fleet – meaning that the Company will complete its transition away from coal-fired generation in 2030 – a full decade earlier than previously anticipated. In total, we plan to retire approximately 2,400 MW of coal-fired generation in the next decade. This will be an unprecedented period of transition for our system that necessitates a prudent replacement strategy. Our strategy for replacing this capacity includes a significant amount of additional renewable generation supported by natural gas CC resources, continued reliance on nuclear generation, and large EE and DR additions during the planning period.

1. *Renewable Resources*

Substantial renewable additions are a central component of our energy future and a cornerstone of this Preferred Plan. Although the quantities of future wind and solar additions may shift somewhat in concert with technology and market fluctuations, our commitment to renewable energy will not. In total, our Preferred Plan envisions a system that is approaching 60 percent renewable in 2034. High levels of renewables combined with cost-effective gas and nuclear generation will combine to create a safe and reliable system that will withstand the summer and winter extremes of the Upper Midwest. Our Preferred Plan proposes to add at least 4,000 MW of cumulative utility-scale resources by 2034 (the first being in 2025) and approximately 1,200 MW of wind by 2034, to replace wind that would otherwise retire from our system during that period.

With these additions, there would be enough solar generation to power more than 650,000 homes each year. Wind generation also continues to play a prominent role in this Preferred Plan. Xcel Energy has long been one of the nation's leading providers of wind energy, and we are currently engaged in the largest build-out of new wind resources in our Company's history – thanks in large part to the Commission's approval of our last resource plan and our 1,850 MW wind portfolio. By 2034, wind will provide 37 percent of the electricity for our customers in this region, making it the largest component of our overall generation portfolio.

2. *Coal Resources*

Large coal-based generating units have been an important baseload resource to stable grid operations for many decades. As we and other utilities move away from coal for economic, environmental and public policy reasons, we must do so with the maintenance of a resilient and reliable grid at the forefront of our minds.

In our most recent Resource Plan, the Commission approved our proposal to retire our Sherco Units 1 and 2 in 2026 and 2023, respectively. Our proposal to retire these units early was informed by technical analyses that also determined the Sherco CC included in this Preferred Plan is essential to mitigate grid issues. Similarly, our proposal in this Resource Plan to retire our remaining two coals units early – King in 2028 (nine years early), and Sherco 3 in 2030 (ten years early) – is informed by technical and other analyses discussed in our Baseload Study, provided as Appendix J1. As also described in the Economic Modeling Framework Chapter of this Resource Plan, we have included estimated grid reliability mitigation costs into our Strategist modeling underlying the Preferred Plan.

Finally, our Preferred Plan also includes a commitment to offer Sherco Unit 2 into MISO on a seasonal basis until its retirement in 2023 and Commission consideration.

3. *Nuclear Resources*

Our Preferred Plan proposes to operate our Monticello nuclear unit through 2040 (10 years longer than its current license), and continued operation of both of our Prairie Island units through the end of their current licenses (PI Unit 1 to 2033 and PI Unit 2 to 2034).[3] Nuclear is central to achieving our carbon reduction goals while incorporating incremental renewables at a reasonable pace and maintaining reliability.

[3] Given that our operating licenses for Prairie Island run until 2033 and 2034, we believe there is sufficient time to address the future of that plant in upcoming resource plans.

Nuclear is also an important system resource during the winter months, as it does not experience fuel supply issues and has a great track record during cold weather events – making it a critical component of our reliability strategy. Finally, the continued operation of Monticello contributes to the affordability of our plan by leveraging an existing, high-performing asset on our system. We discuss the benefits of nuclear, as well as the performance of our nuclear fleet, in greater detail in Appendix K.

4. *Combined Cycle Resources*

In addition to our carbon-free nuclear baseload, the continuation of dispatchable generation on our system will be vital to our ability to manage the retirement of approximately 2,400 MW of coal-fired generation over the next decade while maintaining reliability. It will also facilitate our ability to successfully integrate large amounts of renewables, because we can ramp the output of these resources up or down in response to our system's changing needs throughout the day as renewable resources generate more or less due to their variable nature. To that end, our Preferred Plan includes our proposed acquisition of MEC,[4] which is a 760 MW two-unit CC, as well as our plan to build the approximately 800 MW Sherco CC located in Becker, Minnesota in the mid-2020s.

As discussed in the pending MEC docket, that plant is already an integral part of our system, as its output is committed to the Company through two Commission-approved PPAs. By securing ownership of the plant, we can mitigate the risk associated with expiration of the first PPA in 2026, thereby achieving additional certainty with respect to capacity and dispatchable energy. As discussed in our last Resource Plan, siting a CC at the existing Sherco site will cost-effectively address grid issues identified by the MISO Attachment Y2 study of the Sherco Unit 1 and 2 retirements. Additionally, the Sherco CC will primarily offset the retirement of other gas units on our system, including the Cottage Grove facility (approximately 250 MW in 2027) and Black Dog 5 (approximately 300 MW in 2032). Replacing this capacity is not only reasonable but operationally necessary in light of the much larger coal retirements planned and the large amounts of variable renewable additions we anticipate in the same period. The Sherco CC will also mitigate impacts to the local community and our employees, and potentially provide improved access to natural gas supplies for communities in Central Minnesota. We discuss the Sherco CC further in Appendix L.

[4] As proposed in Docket No. IP6949,E002/PA-18-702. We will incorporate any Commission decision from that docket into our modeling and supplement the record as necessary.

5. *Firm and Dispatchable Load Supporting Resources*

Reliability is central to resource planning. We are particularly focused on the reliability of our system in this Resource Plan, however, as we embark on a complete transformation of our baseload fleet, and transition to a portfolio of variable renewables that approaches 60 percent of our overall generation. Our transition to cleaner energy will only be successful if we can execute our vision without disrupting our customers' lives and businesses by ensuring a resilient grid that enables us to meet our obligation to provide reliable service.

To this end, our Preferred Plan proposes to begin adding approximately 1,700 MW of cumulative firm dispatchable, load-supporting resources in the 2031 to 2034 timeframe. The need for these dispatchable resources emerges in this later timeframe due to the major plant retirements already discussed, as well as the expiration of several PPAs. Our reliability analysis underlying this Resource Plan demonstrates that these additions are necessary to continue to support grid reliability and resiliency in light of the increased renewables being added to the system and the baseload units being retired.

That said, because these units are not needed until the out-years of our current plan, we have not identified a specific resource type to meet this need. With the expected price declines and technology development between now and the 2030s, we believe storage will be an integral resource used to meet this need. Likewise, we believe the deployment of advanced grid investments could position DR to better compete with traditional generation for this purpose. We are committed to pursuing all of these options not only in the longer term, but also in the near-term in order to leverage this technology as it matures. Generally, by keeping options open and remaining technology agnostic, we can acknowledge the need for a firm resource at the tail end of our plan, but allow the market to advance as we submit future Resource Plans, continue to collaborate with our stakeholders, and engage with the Commission as the need for these resources begins to materialize.

In the meantime, we are analyzing potential locations and sizing of storage solutions as well as the potential values storage assets might provide to the system.

6. *Energy Efficiency and Demand Response*

Demand Side Management (DSM, which collectively is EE and DR) resources empower our customers to control their energy usage and their monthly electric bills. Load control DR programs are an important part of our resource mix as they can be used during periods of peak demand, helping maintain system reliability. EE reduces the consumption of energy all together, which has both system and environmental benefits. Taken together, DSM resources are an important part of maintaining system reliability as well reaching our environmental goals.

The DSM aspects of our Preferred Plan includes average annual energy savings of over 780 GWh in each of 2020-2034, compared to average annual energy savings of 444 GWh in our last Resource Plan. In addition, our Preferred Plan also incorporates an incremental 400 MW of DR by 2023 and grows to over 1,500 MW total by the end of the planning period. Importantly, this Resource Plan also signals a change in how we approach EE. In previous plans, we have treated EE as a reduction to customer load. In this Resource Plan, EE is considered a supply-side resource that the economic modeling considers alongside other resource types.

In our last Resource Plan, the Commission approved 1.5 percent annual EE savings on a go-forward basis. The level of EE we propose in this Plan is based on the 2018 *Minnesota Energy Efficiency Potential Study,* and proposes to achieve savings levels ranging from approximately two percent to 2.5 percent annually. This level of EE achieves more than 800 MW of additional demand savings by 2034 compared to the 1.5 percent level approved in our last Resource Plan.

Finally, consistent with the Commission's Order in our last Resource Plan, our Preferred Plan proposes to add 400 MW of incremental DR by 2023, and grows our total portfolio to over 1,500 MW total by the end of the planning period. When it comes to DR, the Company leads the way in MISO, with 830 MW registered in the current planning year. In our last Resource Plan, the Commission ordered the addition of 400 MW of incremental DR by 2023. As we understood the Commission's reasoning, it sought to add incremental, cost effective DR to avoid near-term reliance on additional combustion turbines (CTs). As can be seen in our analysis, however, no CTs or other firm, dispatchable resource additions are required until the 2031 timeframe as the model instead prefers solar additions in the 2025-2030 timeframe.

That said, we decided to include the DR in our Preferred Plan for several reasons: (1) to be consistent with the Commission's Order in our last Resource Plan, (2) to fill gaps if/when the solar capacity credit declines, (3) to help meet firm dispatchable resource needs in the 2030s, (4) to help support customer programs, and (5) to integrate new and emerging technology and tools. We note that for purposes of our modeling, we have included all of the DR identified in the Brattle study as cost-effective, including expansions to conventional DR programs (i.e., Savers Switch, smart thermostats, and interruptible rates) and a non-conventional smart electric water heater program. Additionally, we included the addition of Auto DR, another non-conventional DR program that automates control of various end-uses like HVAC and lighting.

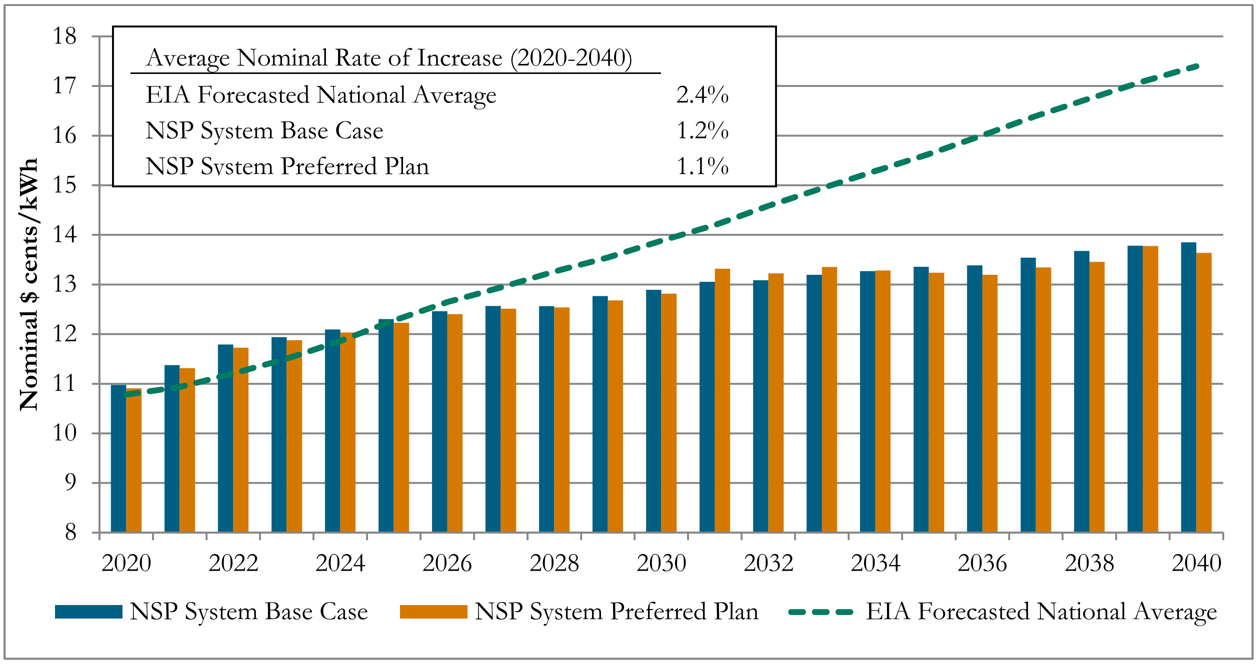
We believe the advancement of our grid, and technology generally, may take the form of less traditional DR, so with this Resource Plan we are requesting the flexibility to evaluate and pursue the required incremental DR through a variety of means and technologies over the coming years. Our objective with this resource type is to bring forward information on several viable options so the Commission, stakeholders, and the Company can engage in an informed exchange. We provide an analysis and detailed discussion of EE and DR in Appendix G1. We also discuss how we applied EE and DR as supply-side resources in our Strategist modeling in Chapter 5. Economic Modeling Framework.

C. Keeping Rates Affordable for Customers

Our Preferred Plan keeps annual cost growth at or below the rate of inflation. In other words, we can achieve significant CO_2 emissions reductions, with cost impacts that are roughly consistent with the expected national average increase in electricity prices.

To show the cost impact of our Preferred Plan over the long-term, we provide as Figure 4-3 below, a CAGR comparison to the national average nominal cost CAGR.

Figure 4-3: Preferred Plan Average Nominal Cost Comparison (NSP System)



* *Notes: National energy cost forecast from Energy Information Administration (EIA) Annual Energy Outlook 2019, Table Energy Supply, Disposition, Prices and Emissions – Reference Case. End use prices, all sector average.*[5] The Preferred Plan and Reference Plan lines include the costs of Solar Rewards*Community.

We derived this long-term projection using a combination of a shorter-range financial forecast and the Strategist model. The modest cost increase associated with our plan is attributable, in large part, to our strategy of deferring resource additions until later in the plan and making use of existing assets on our system. We believe technological improvements will continue to drive the costs of renewables down, which is a key driver in our strategy of proposing significant solar additions in the latter half of the next decade.

We provide our full analysis and discussion regarding customer cost and rate impacts in Chapter 6: Customer Cost and Rate Impacts.

[5] *See* https://www.eia.gov/outlooks/aeo/data/browser/#/?id=8-AEO2019&region=0-0&cases=ref2019&start=2017&end=2050&f=A&linechart=~ref2019-d111618a.70-8-AEO2019&ctype=linechart&sid=ref2015-d021915a.70-8-AEO2015~ref2019-d111618a.70-8-AEO2019&sourcekey=0 The EIA's Annual Energy Outlook was published in January 2019. The report is available at https://www.eia.gov/outlooks/aeo/pdf/aeo2019.pdf.

In the next section, we discuss the actions we plan to take over the next five years, and in the longer term, to achieve our Preferred Plan and deliver on our goals to achieve deep carbon reductions in our electricity mix.

III. ACTION PLANS

A. Five-Year Plan

Our Preferred Plan does not identify any incremental capacity needs through 2024. Thus, our actions in the next five years primarily address previously approved or pending resource additions and retirements, wind repowering and procurement to meet specific customer needs, and continuing to achieve reductions in energy demand and load through ambitious DSM programs. We also plan to make targeted investments in supporting infrastructure to accommodate increased renewable energy and DER on the grid, and to gain operational experience with technologies that may play a larger role on our grid in the future.

Wind. We expect that the 1,850 MW of wind generation resulting from our recent acquisitions and RFPs will achieve commercial operation by 2022. These additions were assumed across all of our scenario analyses. Further, we expect to replace the approximately 170 MW of wind capacity that will expire in the next five years. We are committed to pursuing repowering and/or contract extension opportunities for this capacity, as part of our "no going back" renewables strategy. Further, we intend to pursue incremental renewable resources as needed to meet customer needs in growing customer programs like Renewable*Connect.

Solar. Our Preferred Plan includes significant amounts of large scale solar resources. However, the initial planned addition of 500 MW does not occur until 2025, which is just outside of our five-year Action Plan window. In order to procure this initial tranche of solar, we expect to implement a competitive acquisition process in the 2023 to 2024 timeframe. We expect this timeline will allow us sufficient lead time to acquire these solar resources and bring them online by the end of 2025.

On the distributed solar side, we have included forecasted growth in our plan. If actual distributed solar capacity additions exceed our expectations, we anticipate this will simply displace a portion of our proposed utility-scale solar resources.

Hydro. We anticipate adding 125 MW of energy and capacity through a PPA with Manitoba Hydro in 2021. This incremental contract with Manitoba Hydro is in addition to our existing PPA and diversity exchange and was executed in 2010.

Nuclear. Our Preferred Plan includes a request to operate our Monticello nuclear unit for an additional 10 years beyond its current license. While the license does not end until 2030, we expect to begin a Certificate of Need proceeding with the Commission within the next five years. We also expect to begin working toward license extension with the NRC during this timeframe.

Natural Gas/Oil Peaking. We anticipate extending the life of Blue Lake Units 1-4 through 2020-2023,[6] which provides 153 MW of peaking capacity to the NSP System. Our Preferred Plan further includes our acquisition of MEC, which is currently pending Commission consideration. Finally, we plan to continue development activities associated with the Sherco CC during the next five years.

In addition, as discussed in our last Resource Plan, system retirements will impact our current blackstart plans and we are currently analyzing our blackstart path to determine the best fit for our system needs. While we do not propose any action related to the system blackstart at this time, we anticipate addressing this in our next Resource Plan or earlier, if system needs dictate the need to do so.

Coal. As approved in our last Resource Plan, we will take action with MISO and retire Sherco Unit 2 in 2023, and intend to offer it into MISO on a seasonal basis until that time. Though outside the five-year action window, we are proposing to retire the remainder of our coal units (Sherco 1, Sherco 3 and King) before 2030. As with our previous plant retirements, we plan to begin working with our employees and host communities to prepare for this transition.

Demand Response. Our Preferred Plan proposes to acquire 400 MW of DR resources by 2023, which we intend to evaluate and pursue through a variety of means and technologies over the coming years.

Supporting infrastructure. Aside from the grid-scale and DER additions included in our Plan, sufficient supporting infrastructure is essential to facilitate our fleet transformation, ensure grid resilience and reliability, and to enable greater DER and DR resources on our system. For example, we anticipate completing transmission investments, such as the Huntly-Wilmarth project, in late 2021. We expect further and substantial transmission infrastructure development will be necessary over the long-term, which will involve planning in the near-term. We also are continuing to refine our advanced grid strategy and intend to propose implementation of foundational grid modernization investments – and continue our work to integrate

[6] Pending decision in Docket E,G002/D-19-161

planning processes at all levels of the grid.

Gaining technology experience. As discussed above, we know that energy storage will be essential for our future grid, in order to integrate variable renewable energy without the use of traditional firm dispatchable generation. In the near term, we plan to take steps to gain additional experience with energy storage in the NSP system. For instance, we are co-investing in a microgrid project with Fort McCoy in the NSPW system that will pair solar with storage as a resiliency solution, supplementing traditional diesel backup generators. This project, slated to come online in 2021, will not only support resiliency at Fort McCoy, but will also help us gain valuable experience in maintaining and operating an energy storage facility, especially in the context of new market guidelines in MISO. We anticipate that it will produce income streams to the benefit of all customers through energy price arbitrage, ancillary services, and using the battery as a capacity resource.

Resource treatment across states. We continue to explore options with the North Dakota Public Service Commission to create a resource planning process that can more formally accommodate generation portfolio preferences. We believe additional discussions with all of our state Commissions will be necessary during the five-year action planning period to address differing energy policies and changes in cost allocations that may result.

B. Long-Term Plan

By 2025 we expect we will have achieved approximately 60 percent CO_2 reduction from 2005 levels, per the measures highlighted in our Preferred Plan. In the 2025 and beyond timeframe, there are several key aspects of our system that we will need to address to ensure we can achieve both our 2030 carbon reduction goals, and ultimately, our longer term goals to achieve 100 percent carbon-free electricity. For instance, we anticipate that increasing levels of variable renewable energy and additional baseload unit retirements will necessarily affect the way MISO plans for the broader grid in the future. Notwithstanding the rapid pace of change occurring in our industry, there are several action items on our long-term planning horizon.

New Transmission Infrastructure. Increasing renewable energy on the broader MISO grid is nearly a certainty; wind and solar projects make up over 85 percent of proposed capacity currently in the MISO generator interconnection queue.[7] However, as noted

[7] MISO "Generator Interconnection: Overview." Updated as of June 1, 2019, at: https://cdn.misoenergy.org/GIQ%20Web%20Overview272899.pdf

previously, the queue process is mired with delays and high interconnection cost estimates, in large part due to a lack of available transmission capacity. While generator replacement processes will help us place renewables on our system using existing interconnection rights to an extent, we will need more transmission capacity to come online to effectively achieve the level of renewables we envision on our system – and more broadly within MISO – by 2030 and beyond.

Increasing energy storage on our system. As previously noted we expect that battery energy storage system costs have room to decline over the next several years. We also know that, as variable renewable adoption on the grid increases and more baseload capacity comes offline, we will need a mix of low and non-emitting technologies that can address renewable variability and ensure reliability cost effectively for customers. Battery energy storage holds substantial promise for meeting these needs, and given expected cost declines, we anticipate that we will be able to install cost effective energy storage on the NSP System in the future.

Prairie Island. Our Preferred Plan continues the operation of both Units to the end of their current operating licenses – 2033 for Unit 1 and 2034 for Unit 2. Our baseload scenario modeling results presented in the next Chapter show that there may be value in extending the life of this plant. However, given our operating licenses extend nearly to the end of the planning period, we do not yet need to begin pursuing relicensing. Therefore, we plan to continue working with our stakeholders and evaluate Prairie Island in the context of our future system in subsequent resource planning cycles, rather than locking into a decision at this time. In the meantime, however, Prairie Island continues to serve an important function on the grid and in providing cost-effective and carbon-free baseload power through the planning period.

North Dakota CT. As discussed further in Part IV below, the Company agreed to take steps to locate a natural gas CT in the state of North Dakota, to be operational by December 31, 2025. We remain committed to locating more generation in North Dakota in the future, and we expect to address this resource in our next Resource Plan.

Meeting Statewide Statutory Environmental Goals. Minnesota's Next Generation Energy Act contains a goal for statewide carbon reductions of 80 percent (from 2005 levels) by 2050. While the statewide goal is for all sectors, the Preferred Plan we propose in this Resource Plan achieves over 80 percent reduction by 2030. We know that the electric sector has a unique role to play in achieving the statewide goals. E3's Minnesota PATHWAYS Report, included as Appendix P3, indicates that reducing carbon emissions in the electricity sector enables beneficial electrification to further mitigate emissions in other sectors – in particular the transportation and building sectors. As we discuss in this Resource Plan, our path to achieving 80 percent carbon reduction from 2005 levels in our system relies on retiring baseload coal units, increasing renewable energy, extending nuclear operating licenses, and implementing incremental DSM, and including energy storage. To be sure, all electric utility systems are different and will encounter different challenges on their path to carbon reduction – and there remain challenges to maintaining that level of carbon reduction if current barriers (e.g. transmission constraints or lack of cost effective long-duration storage options) are not mitigated. However, the analysis findings that led us to our current Preferred Plan give us confidence that the electric sector as a whole can help achieve Minnesota's 80 percent carbon reduction by 2050 goal. We further discuss our outlook regarding this statewide goal and potential barriers in Appendix H.

Meeting Company Goals to Achieve 100 Percent Carbon Free Electricity by 2050. As noted throughout this Resource Plan, our Preferred Plan charts a path toward achieving our 2030 carbon reduction goals, and positions us to address our longer term vision of achieving 100 percent carbon-free electricity by 2050. This goal, however, is not one we can achieve cost-effectively or reliably without substantial technological breakthroughs. This includes, in particular, carbon-free dispatchable energy resources that will help us balance variable renewables' output relative to customer demand. Significant research and development is required to bring potential new technologies to commercialization stage; these could include solutions such as longer-duration battery energy storage, other types of energy storage, hydrogen-fired generation, advanced nuclear technologies, carbon capture and storage, and others.[8] We continue to monitor potential emerging technologies and are excited to see what applications will emerge to help make our vision a reality in the long term.

IV. NORTH DAKOTA PLAN

As discussed in the Planning Landscape, we plan and operate a single Upper Midwest system that serves customers in five states. Consistent with the terms of the Settlement in Case No. PU-07-776, since 2008 we have filed our Upper Midwest Resource Plans with the North Dakota Commission, and included in each of them an analysis of a Resource Plan scenario compliant with Federal and North Dakota laws only. As with the previous 2016-2030 Upper Midwest Resource Plan, the current Plan refers to this scenario as simply the "North Dakota Plan."

[8] Selected emerging technologies are discussed further in Appendix F6.

A. Plan Components

Our Preferred Plan for our Upper Midwest system is designed to support the Company's goal of an 80 percent reduction in carbon emissions by 2030. Our 2030 goal is not driven by a particular policy directive from one of our jurisdictions. We believe planning to meet this goal is in the best interest of all our customers. Therefore, this objective is reflected in our North Dakota Plan. The North Dakota Plan differs from the Preferred Plan in the following ways:

1. All CO_2 costs have been removed;
2. Incremental Demand Response (DR) was removed; and
3. Community Solar Garden (CSG) program costs are excluded.

When we developed our Preferred Plan we included the externality and regulatory costs of CO_2 approved by the Minnesota Public Utilities Commission. Removing the CO_2 in the North Dakota Plan had only minor impacts as shown below:

Table 4-2: Expansion Plan Comparisons
Preferred Plan – North Dakota Plan – Summary of Differences

Preferred Plan

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	Total
Large Scale Solar	0	0	0	0	0	500	500	1000	500	500	500	0	500	0	0	4,000
Battery	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CC	0	0	0	0	0	0	0	835	0	0	0	0	0	0	0	835
Firm Dispatchable	0	0	0	0	0	0	0	0	0	0	0	606	0	374	748	1,728
DR	270	20	21	10	17	41	12	14	15	17	19	20	21	22	23	542
EE	115	130	116	133	143	145	154	157	155	140	138	136	129	126	126	2,041
Wind	0	0	0	126	45	70	66	72	10	107	16	56	31	523	81	1,202
Distributed Solar	154	22	22	21	21	21	21	20	20	20	20	20	20	20	19	442

North Dakota Plan

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	Total
Large Scale Solar	0	0	0	0	0	500	500	500	0	1000	1000	0	500	0	0	4,000
Battery	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CC	0	0	0	0	0	0	0	835	0	0	0	0	0	0	0	835
Firm Dispatchable	0	0	0	0	0	0	0	0	0	0	0	606	0	374	748	1,728
DR	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EE	115	130	116	133	143	145	154	157	155	140	138	136	129	126	126	2,041
Wind	0	0	0	126	45	70	66	72	10	107	16	56	31	523	81	1,202
Distributed Solar	154	22	22	21	21	21	21	20	20	20	20	20	20	20	19	442

Difference - North Dakota Plan Compared to Preferred Plan

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	Total
Large Scale Solar	0	0	0	0	0	0	0	-500	-500	500	500	0	0	0	0	0
Battery	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Firm Dispatchable	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DR	-270	-20	-21	-10	-17	-41	-12	-14	-15	-17	-19	-20	-21	-22	-23	-542
EE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Distributed Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

In the modeling for the North Dakota Plan, solar additions for 2027-2029 in the Preferred Plan are delayed to 2029-2030. As discussed previously, our Preferred Plan also includes a large incremental addition of DR in recognition of the Minnesota Commission's Order in our last Resource Plan requiring 400 MW of additional DR by 2023. While we expect most of these DR programs to be implemented in Minnesota, as we continue to develop additional DR programs for our system we would consider proposing to add cost-effective DR programs for our North Dakota customers as well.

The exclusion of the costs of CSG does not impact the resources additions for the North Dakota Plan. Instead, the costs of CSG are allocated so that North Dakota customers pay a market rate for the energy from the CSG resources. The allocation of the costs to North Dakota will also reflect previous cost-recovery decisions that exclude costs related to the disputed resources identified in the rate case Settlement of Case No. PU-12-813 and subsequent cases.

B. Resource Planning Framework Status

On December 21, 2018 we proposed a framework that outlined essential pieces of a North Dakota Resource Plan, including a default presumption that the system would continue to be planned in an integrated fashion.[9] We discussed the proposal at an informal hearing with North Dakota Commissioners in March of this year. The North Dakota Commission confirmed that they are interested in a more formalized resource planning process. We look forward to working with the North Dakota Commission and Staff to further develop a North Dakota planning process.

C. North Dakota Combustion Turbine

Pursuant to the Settlement in Case No. PU-12-813, the Company agreed to take steps to locate a system natural gas CT in the state of North Dakota, to be operational by December 31, 2025. Specifically, Xcel Energy agreed to:

> *…develop, own, and operate (or alternatively, cause to be developed and operated on its behalf through a power purchase agreement or other contractual arrangement) a combustion turbine with a capacity of at least 200 MW in eastern North Dakota, no later than December 31, 2025. The costs of the generating facility will be allocated to all state jurisdictions served by the Company in a manner consistent with other NSP System resources. Attainment of this commitment is contingent on the Company's receipt of all necessary and appropriate permits and regulatory approvals. Further, except as modified by this Section II, all provisions of the 2036 Commitment remain in place, including without limitation, the requirements that the combustion turbine agreed to in this paragraph reasonably 1) addresses a system capacity need and 2) represents a least-cost resource when also considering the local reliability and system benefits of developing thermal generation in North Dakota.*

The five-year Action Plan associated with this 2020-2034 Resource Plan runs through

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[9] *See* North Dakota Case No. PU-12-813.

2024. Thus, the Commission will not find specific mention of a North Dakota natural gas CT addition in the current short-term Action Plan; rather, proposed resource additions in 2025 will be within the Action Plan developed in the next Resource Planning cycle and addressed directly in that filing.

While the longer-term plan for resource additions do not reflect a firm peaking addition until 2031, we acknowledge the above-stated Settlement commitment and will continue to assess NSP System capacity needs over the next couple of years, the likelihood of gaining the necessary approvals in all NSP System states, and the operational feasibility and cost-effectiveness of a peaking plant located in eastern North Dakota. Given the long planning horizons, many things can change in the next 5 to 10 years in terms of energy policy, technology, and economic conditions. We remain committed to locating more generation in the state and a more timely and beneficial option may become evident over time.

V. PUBLIC INTEREST ANALYSIS

Based on our detailed analysis, we conclude that the Preferred Plan is in the public interest. We believe it best balances our goals to ensure reliability, achieve significant carbon reduction, and maintain reasonable costs to 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.[10] Specifically, these Rules require that resource options and resource plans are to be evaluated on their ability to:

- Maintain or improve the adequacy and reliability of utility service,
- Keep the customers' bills and the utility 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.

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

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

A. Reliability

Our Preferred Plan is designed to allow us to continue to provide safe and reliable service to our customers as we take steps to achieve deep carbon reductions in our electricity mix. We know that as we, and other utilities in Minnesota, the Upper Midwest, and the broader MISO market retire baseload units and continue to add substantial variable renewable generation capacity to the grid, planning processes will need to adapt to ensure a reliable and stable grid. We have done the work to understand potential grid impacts from the orderly fleet transition we propose. We have also developed a Reliability Requirement that will ensure we continue to serve our customers' energy needs every hour of every day in the interim until MISO updates its planning construct to recognize the changes underway. We discuss the work we have done to we meet our obligation to provide reliable service in our Baseload Study, provided as Appendix J1.

Related, in connection with our pursuit of vast new quantities of renewables, we have included the proposed MEC acquisition and planned Sherco CC as resources in our Preferred Plan in order to ensure new renewable resources can be adequately integrated. We also leave open the possibility that future firm, dispatchable needs identified in the Plan could be met with non-emitting alternatives such as DR or energy storage. Finally, we discuss other supporting infrastructure that will support our goals to integrate additional variable renewable energy in Appendix I. By including these various elements, our Preferred Plan positions us to ensure the continued adequacy and reliability of the NSP system throughout the planning period and beyond.

B. Impact to Customer Bills

Affordability is one of the key objectives that framed our analysis. Our Preferred Plan achieves significant carbon reductions while ensuring reliability at a cost in line with expected inflation rates, or an annual cost increase of just over one percent, on average, over the planning period. The fact that we do not need to take any actions in the near-term supports the flexibility that we seek with this plan, which we believe is more beneficial now than ever – given the pace of technological innovation and cost reductions we have observed and expect to continue into the future. Therefore, we believe that our Preferred Plan will keep our rates as low as practicable, given future market and other uncertainties as we have described in this Plan.

C. Environmental Effects

Xcel Energy is leading the nation with an ambitious goal of serving our customers with a completely carbon-free resource mix by 2050 – and on our way to reaching this goal, reducing our carbon emissions by 80 percent from 2005 levels by 2030. Our Preferred Plan is a critical step in planning to meet these ambitious carbon reduction goals, while also keeping in mind the socioeconomic impacts of retiring large baseload generation units. We have proposed to close all of our remaining coal units by the end of 2030, which will significantly reduce the amount of carbon attributable to our system. At the same time, we are also planning to vastly expand the amount of renewable energy capacity on our system, and continue to operate Monticello through 2040 – both of which will provide substantial amounts of clean energy to serve our customers. All of these actions work to ensure we achieve our environmental goals and carbon-free vision.[11]

D. Socioeconomic Impacts

We recognize that plant closures can have a significant impact on our plant employees and the communities that have hosted our plants for many years – and we bore this in mind when developing our Preferred Plan. By announcing our plans to retire Sherco 3 and King far in advance of proposed retirement dates, employees will have time to build additional skills and transition to other parts of the Company, if desired. Like we have in the past, we will work with these employees to support their transitions. We will also continue working with the host communities and other stakeholders around those communities. We are currently working, in conjunction with CEE and Minnesota Power, to understand the socioeconomic effects of the plants and their closure on host communities. This commitment is evidenced in the work we have been doing in the Sherco area, after closure of our Sherco Units 1 and 2 was approved in our last Resource Plan. Among others things, we plan to develop our own gas CC plant on the Sherco site. We have been working to draw new development to the area, and with existing and prospective large industrial customers to locate facilities in the area, which will help to offset tax and other impacts from the closure of the coal units. These efforts will generate socioeconomic benefits through facility construction and ongoing operations. Our clean energy efforts also generate socioeconomic benefits, both in preserving key nuclear jobs through the Monticello

[11] Note that resources we include our Preferred Plan meets and exceeds Minnesota greenhouse gas reduction goals under 216H.02, the renewable energy standard under 216B.1691 and the solar energy standard under 216B.1691, 2f.

life extension, and spurring a large amount of new renewable construction over the planning period.

E. Flexibility to Respond to Change

Our Preferred Plan positions the Company well in the current planning landscape – meeting near-term needs and creating flexibility for the future. As we have described, planning constructs, policies, and technology costs are all creating uncertainty, which lead us to prioritize strategic flexibility in our plans to preserve the most value for our customers. For example, even though our modeling results show that extending the operating life of Prairie Island would be cost-effective under today's market conditions, we also know those conditions can change rapidly. Thus, we have deferred a decision regarding Prairie Island extension until the next Resource Plan. We also have said that we are open to meeting our firm and dispatchable capacity needs in the out-years of our Plan with options other than natural gas units, to the extent technologies sufficiently develop and are economically-favorable at that time. This flexibility enhances our ability to respond to changes in our planning landscape that would affect our operations during the planning period and preserves some agility for us to respond and adapt to these factors

F. 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 factors beyond our control. For example, the Reliability Requirement we developed and incorporated into our modeling ensures that we have planned for adequate firm and dispatchable energy to meet our customers' needs until current planning constructs adapt.

Our Preferred Plan represents the best option to meet customers' needs in light of the planning landscape for the planning period, presents the best path forward for the Company, our customers, and the energy future of our Upper Midwest system, and is thus in the public interest.

VI. CONCLUSION

The Preferred Plan we propose in this 2020-2034 Upper Midwest Resource Plan reflects extensive collaboration with stakeholders as well as independent expert analysis. Our Preferred Plan proposes to eliminate coal, add even more renewables, and continue our industry-leading EE and DR programs, all while preserving reliability and affordability for our customers. It also meets the varied interests of our five-state Upper Midwest region. And by planning ahead and charting an orderly, gradual transition of our generation fleet, we believe we can achieve all of these goals while managing the impacts to our host communities and employees, preserving the reliability and stability of our system, and maintaining affordability for our customers. For these reasons, and those discussed throughout this filing, we believe our Preferred Plan is in the public interest and merits Commission approval.

CHAPTER 5
ECONOMIC MODELING FRAMEWORK

We have used the Strategist Resource Planning model to perform our economic analyses since 2000. We use Strategist as our primary resource planning software to estimate the costs of various resource expansion plan options, evaluate specific capacity alternatives, and measure the potential risks of new environmental legislation and other policy scenarios. Strategist results are a decision support tool to guide development and selection of a Preferred Plan and test the robustness of the Plan under a variety of assumptions and sensitivities.

To ultimately identify and refine our Preferred Plan, we created 15 scenarios that examined different combinations and timing of baseload unit retirements, and the resulting size, type, and timing of new resources we would need to add in order to continue meeting customers' needs and achieve our 2030 carbon reduction goals. We refer to these scenarios as "baseload study scenarios."

As we developed the various baseload study scenarios, we also conducted DR and EE Bundle analyses. This is the first Resource Plan in which DR and EE Bundles are considered supply-side resources, and as such, we had to undertake iterative analysis alongside our scenario analysis to analyze these options appropriately. Finally, after this analysis was completed, we used the outcomes and sensitivity tests to select and refine a Preferred Plan.

We discuss our assumptions, scenarios, sensitivities and how these inputs guided selection of our Preferred Plan in more detail below.

I. ASSUMPTIONS

There are several assumptions included in our baseline data inputs that are common across all scenarios studied. These factors may, in some cases, be varied within sensitivities, but are largely kept constant across the default study of each scenario.

Important starting assumptions in our analysis include:

Load Forecast. The Company employs standard probabilistic analyses to determine our load and energy demand forecasts. Our resource planning process takes the 50 percent probability level forecasts for both peak demand and energy requirements as an input, we provide a detailed description of our load forecasting methodology as Appendix F1.

In the past, these forecasts have included adjustments to account for the effects of EE as a load modifier. In order to accommodate modeling EE as a supply-side resource in this Resource Planning process, we have not included any going forward EE impacts in the load forecast for the 2020-2034 period. These energy and demand savings are now included in the three EE Bundles that we evaluate as supply-side resources.

We also incorporated an effective planning reserve margin of 2.98 percent, per MISO requirements. As discussed in Chapter 3, MISO instituted an 8.4 percent planning reserve margin requirement in the 2018-2019 planning year, and our system has a 95 percent MISO system coincident factor. Thus, our effective reserve margin is calculated in the following manner:

Figure 5-1: Effective Reserve Margin Used in Strategist Modeling

$$(95\, percent\ coincidence\ factor)\ x\ (1 + 8.4\, percent)\ -\ 1 \\ =\ 2.98\, percent\ effective\ reserve\ margin$$

Existing Fleet. We develop forecasts to model our existing fleet's 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 future changes where applicable. Additional operational and performance assumptions include:

- Retirement of Sherco Units 1 and 2 in 2026 and 2023, respectively, as approved in our last Resource Plan;
- Remaining coal units are dispatched economically beginning in 2028, reflecting our expectations that MISO transitions to a multi-day commitment approach that more efficiently commits resources in accordance with load serving needs over a longer time horizon;
- 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 (e.g. for nuclear units in scenarios that include life extension);
- Continuation of our existing PPAs until their contractual termination dates, and
- Continued operation of the Company's owned hydroelectric resources based on historical performance.

Additional cost –related assumptions include:

- Costs are escalated based on corporate estimates of expected inflation rates,
- Costs associated with early retirement of the existing baseload coal units (King and Sherco 3), as well as costs for early retirement or re-licensing the nuclear plants were developed for use in the Baseload Study modeling.

Renewable Energy. In addition to the 1,850 MW of wind we are in the process of adding to the NSP System since our last Resource Plan, we have assumed:

- Currently approved and/or operating renewable facilities (including both those facilities we plan to own and those we plan to contract) are assumed to be replaced at their end of life or contract expiration with the equivalent amount of similar energy from generic wind and solar resources (i.e. wind would replace wind, solar would replace solar). We refer to this as "no going back;"
- Accreditation of wind resources based on the 2018-2019 Planning Year 15.6 percent MISO ELCC, accreditation of solar resources at the default 50 percent ELCC. For modeling purposes we assume these values remain the same throughout the modeling period;
- No extension of the federal production tax credit (PTC) or investment tax credit (ITC)[1] past the expiration dates as per current law.

Markets. We run scenarios in Strategist both with "markets on" (i.e. where we can buy and sell energy in the MISO wholesale market) and "markets off" (i.e. where we cannot sell to the market, but purchases are still modeled). We use the "markets on" view as a default assumption because this is more reflective of our realistic operations. Sensitivities with markets off help us test the effects of this assumption on the various scenarios.

Wholesale electricity price forecasts. Our electric power market prices are developed from fundamentally-based forecasts from external analysts Wood Mackenzie, CERA and PIRA. The forecasts we receive from these third party analysts provide monthly average on- and off-peak market pricing at the Minn Hub. We then use that market data to create an hourly shape for each month, based on the amount of thermal generation dispatched on our system. The methodology results in lower hourly locational marginal prices (LMPs) during times when a significant amount of renewable energy is on the system and higher hourly LMPs when amounts of available renewable energy are lower. Shaping the hourly prices in this manner provides a more conservative view of potential benefits we may realize from selling excess generation to the market.

[1] The ITC reverts to 10% in 2022 and beyond, per current law.

Purchase and sales limits. In our Strategist model, we include a limit as to the amount of energy that we are able to either purchase from or sell into the MISO market. This limit was developed using results from the 2018 MISO Transmission Expansion Plan (MTEP) model results and evaluating maximum levels of market interaction achieved in that modeling. For 2020-2023 we assume a market interaction limit of 1,800 MW which grows to 2,300 MW after 2023, based on the anticipated in service of the Cardinal to Hickory Creek transmission line which is expected to increase transmission outlet in our region.

Emissions rates and costs. Emission rates for existing and planned resources are consistent with historical and expected performance. We assume the following costs[2] and apply them to emitting resources as relevant:

- Achievement of an 80 percent reduction in CO_2 serving retail customers, as measured from 2005 levels, by 2030. The overall carbon emissions are allowed to increase slightly from these levels at the retirement dates of the nuclear fleet, which vary by scenario;
- \$ 25.00 per ton CO_2 as a regulatory cost, starting in 2025 and escalating at inflation, with the high CO_2 externality value used prior to 2025. The societal value of CO_2 as an externality and other combinations of externality and regulatory costs were included as sensitivity cases;
- The Minnesota Commission's high externality values for other specified emissions.

Generic Resources. Strategist uses generically-defined resources to meet future demand when our already existing and approved resources are not sufficient in a given year. Generic resources are modeled as incremental units of a certain installed capacity size, but these sizes are chosen based on the amount of UCAP, or the MISO accredited capacity value the units would yield. For example, although the generic unit size for solar is rather large (500 MW installed capacity), the resource adequacy or MISO capacity credit value we would expect to receive for a plant of that size is half that (250 MW), which is more comparable to a generic thermal or storage plant we may assess. Similarly, wind UCAP values are discounted to 15.6 percent of ICAP.

[2] Note: As further discussed below, these costs are not used in evaluating the cost of our Preferred Plan for North Dakota. See our discussion regarding the North Dakota Plan in Chapter 4: Preferred Plan.

Generic units ICAP values included in modeling are as follows:[3]

- 331 MW gas-fired combustion turbine peaking unit (CT),
- 206 MW gas-fired combustion turbine peaking unit (CT),
- 856 MW gas-fired combined cycle intermediate unit (CC),
- 331 MW energy storage project, with costs and performance comparable to lithium-ion battery technology,
- 750 MW wind project
- 500 MW grid-scale single-axis tracking solar project
- 100 MW distributed solar project

Appendix F2: Strategist Modeling Assumptions & Inputs, provides more detail on Strategist assumptions. Please see Appendix F6: Resource Options, for additional discussion on supply-side resource options included in the analysis.

Customer Programs. Incremental customer programs for DR and EE were included as potential resources in the Strategist model. The derivation of these three DR and three EE "Bundles" are described in Appendix F6.

It is important to note that these Bundles represent generic DSM additions and therefore may not perfectly align with the size and timing of actual DR or EE additions to the system in the future. These Bundles were developed immediately after receiving third party studies for incorporation into modeling, without the benefit of time to develop detailed implementation plans to achieve the levels of DSM in each Bundle. Therefore, for incremental DR resource additions in particular, while the size and timing of the first Bundle generally achieves the ordered 400 MW by 2023, the actual implementation plans which detail the specific size, type, and timing of incremental additions will likely differ. Procurement plans are illustrated in Appendix G1: Demand Side Management.

DER is modeled with base and high adoptions assumptions, using similar levels as provided in our 2018 IDP filing. We discuss our DER forecasts in Appendix F1: Load and Distributed Energy Resource Forecasting.

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

II. SCENARIOS

As noted above, we created 15 scenarios to examine combinations and timing of baseload unit retirements, and the resulting size, type, and timing of new resources we would need to add in order to continue meeting customers' needs and achieve our 2030 carbon reduction goals. We describe key parameters of these scenarios below.

A. Reference Case Scenario

We describe the development of our Reference Case in Chapter 3: Minimum System Needs. The Reference Case (Scenario 1) is an extension of our 2015 Resource Plan, in that all of the baseload units retire at their currently scheduled retirement dates, and serves as our starting point. The approved 1,850 MW wind portfolio that is in progress is included, along with generic wind and solar units added to the plan to ensure that we do not fall below the current level of renewables we have on our system (i.e. a "no going back" portfolio). Additional renewable units are evaluated and optimized in the modeling and added where economic. In the original phases of the modeling, the DR and EE Bundles were evaluated as optimized economic alternatives, as were distributed solar, storage, and thermal CT and CC resources. The Sherco CC unit and owned MEC CC unit were included in the Expansion Plan. Firm peaking resources were included in the plan as needed to maintain the Reliability Requirement criteria.

To determine the optimal strategy regarding the future of the baseload fleet, we developed additional scenarios with varying combinations of baseload resource retirement dates. The resulting system needs were then met with a Strategist model-optimized portfolio of new resources. Internal finance, energy supply, and nuclear subject matte experts worked to develop a robust set of assumptions and potential retirement dates for the baseload units. These input assumptions include: ongoing capital expenditures, O&M expenses and decommissioning and/or life extension costs. We also incorporated the planning level estimates from the MISO Y2 studies performed as part of our Baseload Study that informed our Preferred Plan. See Appendix J1 for more details regarding this study. The scenarios we evaluated can be generally grouped into families, as described below.

B. Early Coal Family

This family of scenarios is designed to evaluate the economics (i.e. revenue requirement impacts) of retiring King and/or Sherco 3 early. We did not study life extension for coal facilities. For the early coal retirement scenarios, the early retirement date for King was assumed to be the end of 2028, and for Sherco 3 the early date was the end of 2030. We chose these retirement dates because they generally allow an orderly and staged transition, with a major coal retirement every two to three years. In the all early coal scenarios, for example, the retirement schedule is Sherco 2 in 2023, Sherco 1 in 2026, King in 2028 and Sherco 3 in 2030.

- Scenario 2 **(Early King)** – King is retired at the end of 2028. Sherco 3 and the nuclear units are unchanged.
- Scenario 3 **(Early Sherco 3**) – Sherco 3 is retired at the end of 2030. King and the nuclear units are unchanged.
- Scenario 4 **(Early All Coal)** – King is retired at the end of 2028, Sherco 3 is retired at the end of 2030, and the nuclear units are unchanged.

C. Early Nuclear Family

This family of scenarios is designed to test the economics of retiring Monticello and/or Prairie Island early, either alone or together, and with the combination of early coal retirements. For the early nuclear retirement scenarios, the early retirement date for Monticello was assumed to be the end of 2026 and for Prairie Island 1 and 2 it was the end of 2024 and 2025, respectively. We chose these retirement dates as we felt they best balanced the need for adequate lead time to enable an early major nuclear retirement with the desire to evaluate retirement scenarios that occur well ahead of the existing retirement dates in the 2030s.

- Scenario 5 **(Early Monticello)** – Monticello is retired at the end of 2026. Coal and Prairie Island is unchanged.
- Scenario 6 **(Early Prairie Island)** – Prairie Island is fully retired by the end of 2025. Coal and Monticello is unchanged.
- Scenario 7 **(Early All Nuclear)** – Prairie Island and Monticello are both retired early per the years above, the coal units are unchanged.
- Scenario 8 **(Early All Baseload)** – All baseload units, including coal and nuclear, are retired early per the years indicated above.

D. Extend Nuclear Family

This family of scenarios is designed to test the economics of re-licensing Monticello and/or Prairie Island and extending operational life by 10 years over the current retirement dates. For the extend nuclear scenarios, the revised date for Monticello was assumed to be the end of 2040 and for Prairie Island 1 and 2 was the end of 2043 and 2044, respectively.

- Scenario 9 (**Early Coal, Extend Monticello)** – All coal was retired at the early dates and Monticello is extended for 10 years. Prairie Island is unchanged.
- Scenario 10 (**Early King, Extend Monticello)** – King was retired at the early date and Monticello is extended for 10 years. Sherco 3 and Prairie Island are unchanged.
- Scenario 11**(Early Coal, Extend Prairie Island)** – All coal was retired at the early dates and Prairie Island is extended for 10 years. Monticello is unchanged.
- Scenario 12 **(Early Coal, Extend All Nuclear)** – All coal was retired at the early dates and both Monticello and Prairie Island are extended for 10 years.
- Scenario 13 (**Extend Monticello)** –Monticello is extended for 10 years. King, Sherco 3 and Prairie Island are unchanged.
- Scenario 14 **(Extend Prairie Island)** – Prairie Island is extended for 10 years. King, Sherco 3 and Monticello are unchanged.
- Scenario 15 **(Extend All Nuclear)** –Both Monticello and Prairie Island are extended for 10 years. King and Sherco 3 are unchanged.

III. FUTURES SCENARIOS AND SENSITIVITIES

To determine how changes in our assumptions impact the costs or characteristics of different plans, we have historically evaluated how the plan responds to changes in individual input assumptions. This testing helps us assess the "robustness" of each scenario in the face of future uncertainty, meaning that we want to test how resilient the scenario is to changes in one or more key assumptions. Generally, if a given plan is extremely sensitive to changes in assumptions, it would not represent a prudent course of action for the Company to pursue, because it would subject our customers to excessive risk. While we believe there is value in evaluating the individual sensitivities, and have provided a comprehensive analysis of those sensitivities in Appendix F3, we took a slightly different approach to stress test our results in this particular Resource Plan.

A. Futures Scenarios

Consistent with the MISO MTEP Process, we adopted a scenario-based planning approach to our sensitivity analysis that we have incorporated for the first time in this Resource Plan. Since many of the input assumption variables in our modeling are correlated, we believe there is more value in looking at a combination of variable sensitivities as opposed to "one-off" sensitivity runs. Evaluating one sensitivity at a time may isolate the impacts of the variable in question, but may not necessarily reflect a realistic future scenario.

We developed four Futures Scenarios, using the 2018 MTEP Futures as guideposts. The first two Futures Scenarios (Base PVSC and Base PVRR) represent our base assumptions, with and without carbon costs, as we have consistently provided this view as part of previous Resource Plans and are required to provide the PVRR view for our North Dakota stakeholders. The High Electrification and High Distributed Solar cases represent our new approach, in which we adjusted multiple sensitivities in each Futures Scenario to assess the combined effect of these changes. While there are certainly many assumptions we could have adjusted, we focused on the four most important variables which include fuel price forecasts, load forecasts (or variables impacting the load forecast like distributed solar), carbon and externality costs, and new resource capital costs. The assumptions made for each Futures Scenario can be seen in Table 5-1 below:

Table 5-1: 2019 Resource Plan Futures Scenarios

Futures Scenario	Description	Gas, Power, Coal Prices	Load Forecast	Carbon & Externality Costs	New Resource Capital Costs
Base Scenario (PVSC)	Base Case with Carbon Costs, Similar to MISO MTEP Continued Fleet Change (CFC) Scenario	Base	Base 50/50	High/High	Base
No Carbon (PVRR)	No Carbon Costs	Base	Base 50/50	**None**	Base
High Electrification & Low Tech Costs (PVSC)	Similar to MISO MTEP Accelerated Fleet Change (AFC) Scenario	**High**	**High Electrification Forecast**	High/High	**Low**
High Distributed Solar Deployment, Low Tech Costs (PVSC)	Similar to MISO MTEP Limited Fleet Change (LFC) Scenario	**Low**	**High DG Solar Forecast & Higher EE Levels**	High/High	**Low**

Note: bolded and underlined parameters indicate assumptions that have been modified from the Base Scenario

For the High Electrification Scenario, we examine a case in which higher load levels are expected to stimulate higher fuel demand and consequently higher overall fuel prices. To construct this Scenario, we used a high electrification forecast provided by E3, informed by their Minnesota PATHWAYS study provided as Appendix P3 to this Resource Plan, to assess the impacts of high load, high fuel price, and a low technology cost environment.

Conversely, for the High Distributed Solar Deployment Scenario, lower load levels driven by higher levels of offsetting distributed solar could reasonably be expected to drive down fuel demand and result in lower overall fuel prices. To construct this Scenario, we used an internally developed high customer adoption based distributed solar forecast to assess the impacts of low load, low fuel price and low technology cost environment. We also forced in all three EE Bundles to further reduce the load forecast and evaluate a future that truly stresses our baseload decision options.

In both the High Electrification and the High Distributed Solar Scenarios, we assumed low new resource capital costs. We believe this is an appropriate assumption to test, because trends have indicated that the market has previously underestimated realized cost reductions in renewables and other new technologies, and we feel this could continue to occur going forward. Likewise, in both these Futures Scenarios, we included carbon and externality costs, consistent with resource planning principles in Minnesota.

Figure 5-2: Peak Demand, Net of EE Impacts, by Futures Scenario (MW)

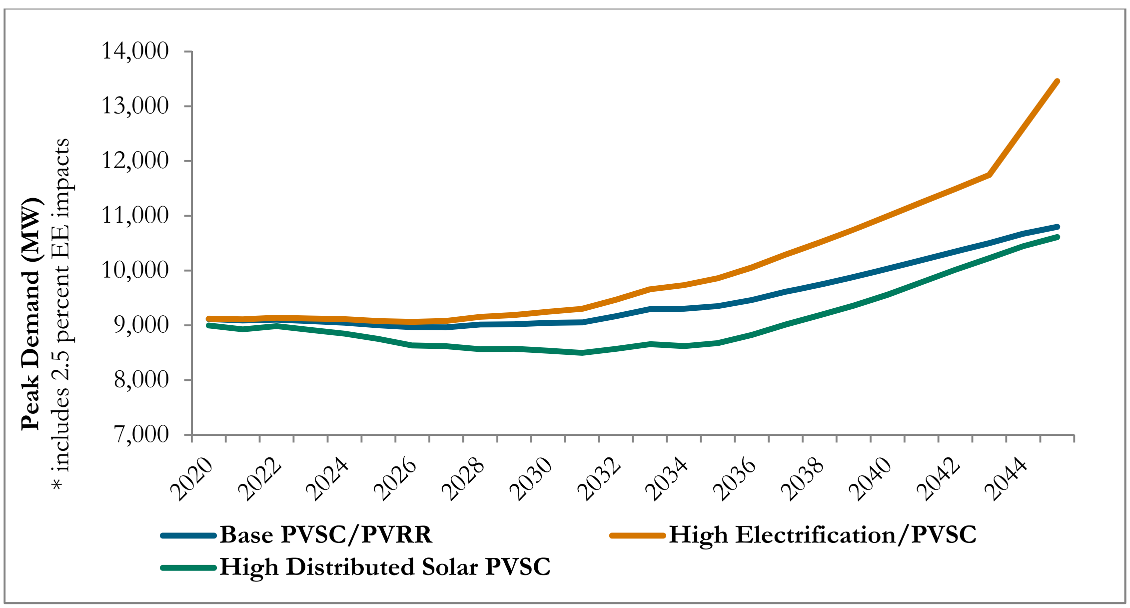


Figure 5-3: Fuel Price Assumptions, by Futures Scenario

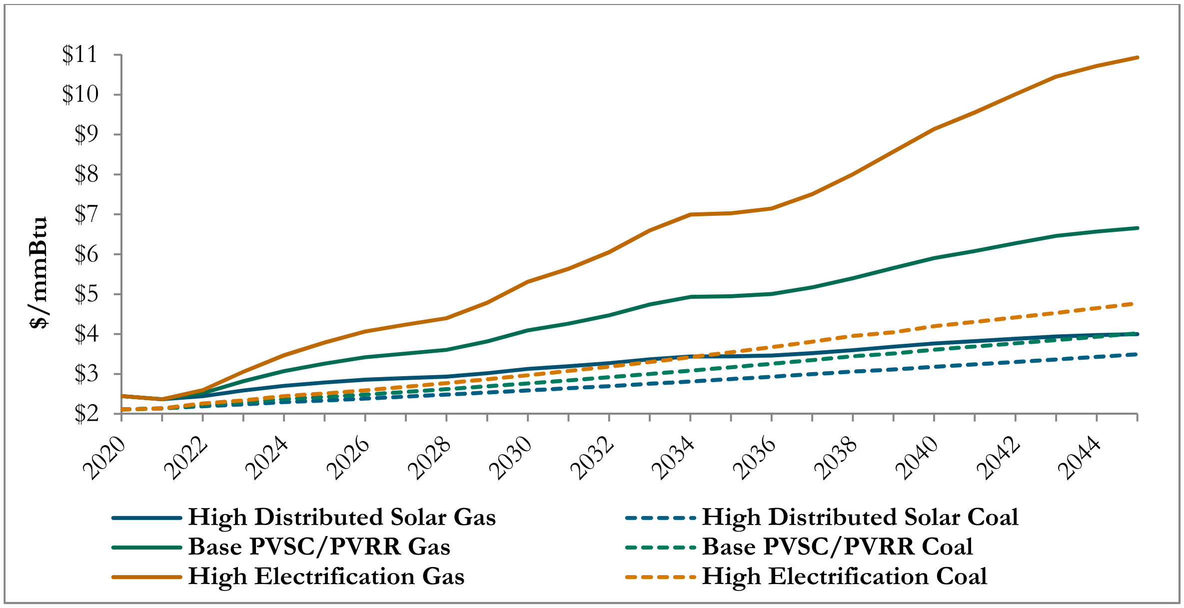


Figure 5-4: New Resource Cost Assumptions, by Futures Scenario ($/MWh; $/kW-mo)

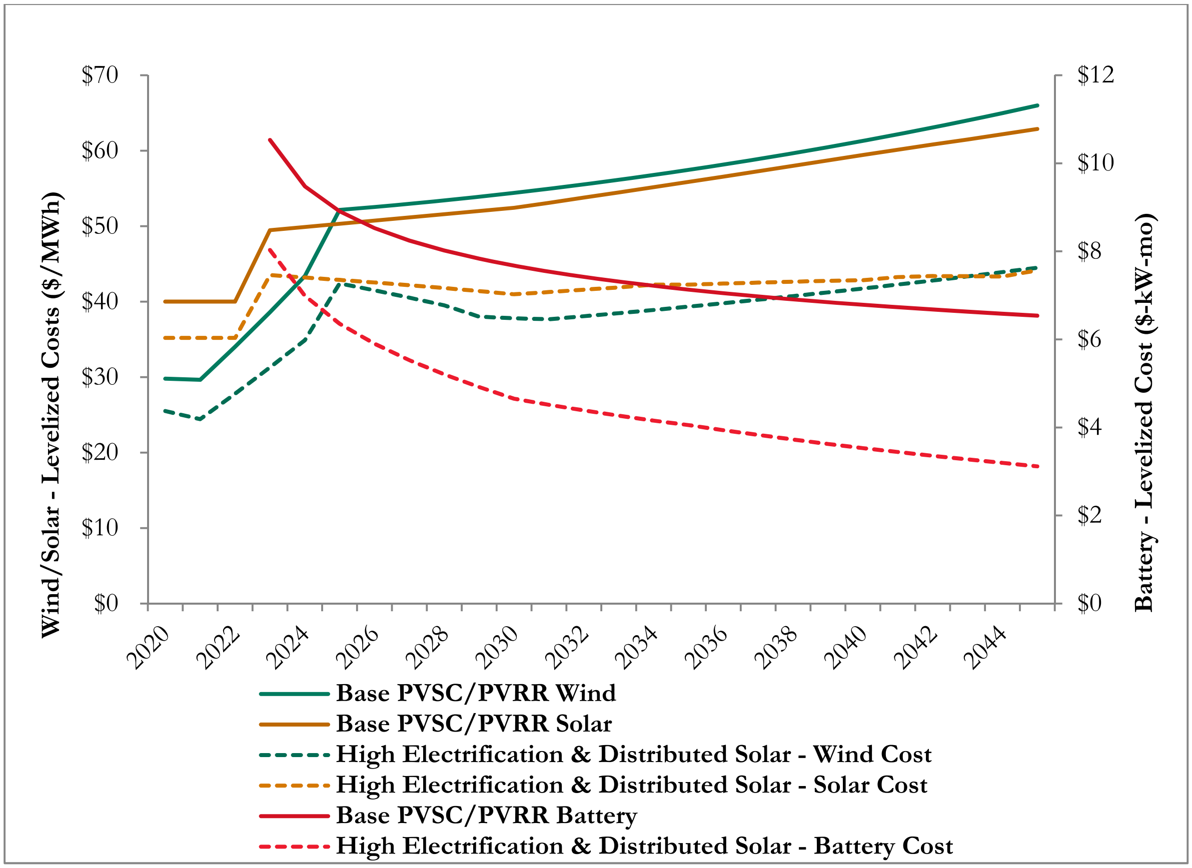
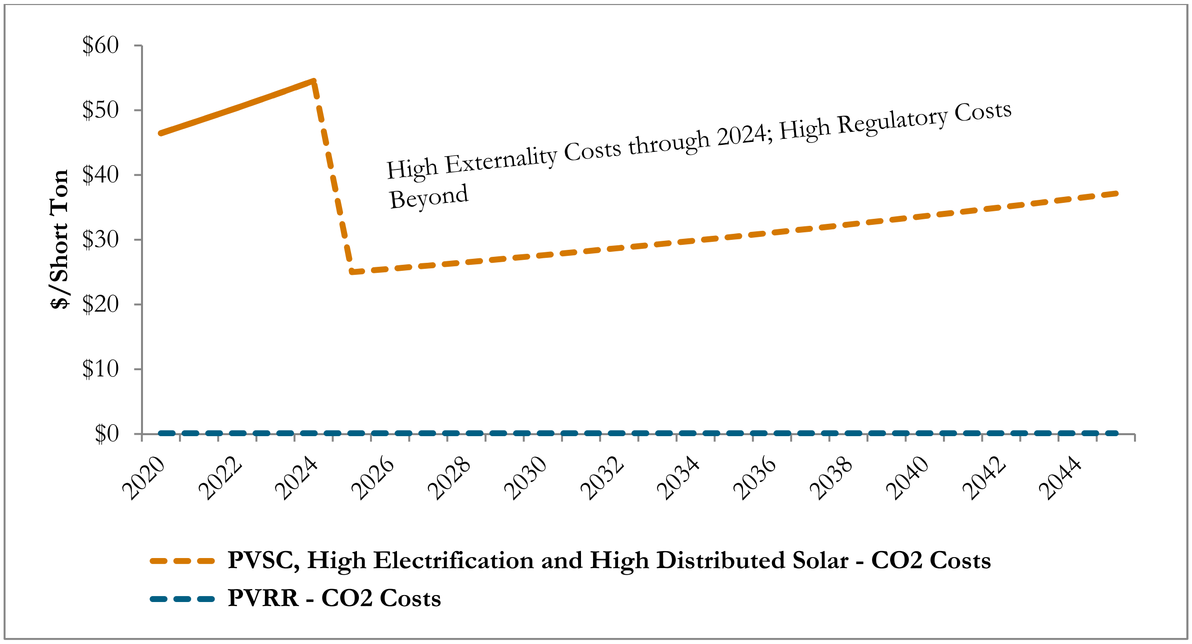


Figure 5-5: Carbon Emissions Cost Assumptions
($/Short Ton)



It is important to note that these Futures Scenarios were designed to test the performance of our baseload retirement decisions under plausible future states. These Futures Scenarios are not, however, intended to test which future is overall least cost for our system. We do not have full control over the level of distributed solar or electrification growth on our system, and have no control over variables such as fuel prices and new resource capital costs. As demonstrated in the next section, the Futures Scenario analysis shows that our Preferred Plan baseload decisions to retire all coal by 2030 and extend Monticello are likely to yield customer benefits relative to the Reference Case, even in a future where multiple key assumptions change simultaneously.

B. Traditional Sensitivities

While our primary focus has shifted to Futures Scenarios as opposed to the traditional single sensitivities, we still believe the individual sensitivities provide insights on potential plan performance. Therefore, consistent with previous Resource Plans, we tested the following individual sensitivities. Detailed results for these sensitivities can be found in Appendix F3.

- *Load.* The low load sensitivity includes high customer adoption-based DER growth and higher EE savings (i.e. it includes all three EE Bundles), which reduces load. The high load sensitivity includes high electrification load.

- *Fuel Price/Market Costs*. High and low price sensitivities were performed by adjusting the growth rate up and down, respectively, by 50 percent from the base forecast starting in year 2022.
- *CO_2 Values*. To examine the effect of CO_2 pricing, we tested high and low cost sensitivities. We also performed a sensitivity evaluating no CO_2 cost. The PVSC Base Case CO_2 values are based on the high externality cost values for CO_2 as determined by the Minnesota Commission through 2024.[4] The PVSC Base Case values starting in 2025 are based on the "high" end of the range of regulated costs.[5] Below is the list of carbon sensitivities.
  - Low Externality
  - Low Externality, Low Regulatory
  - Mid Externality, Mid Regulatory
  - High Externality
  - PVRR, or No Externality or Regulatory
- *Externalities*. Criteria pollutants values are derived from the high and low values for each of the three geographic locations in the Minnesota Commission Order,[6] with existing plants assigned the appropriate area and generic units assigned to "rural." The midpoint externality costs are the average of the low and high values. The high, low and midpoint externality costs are used in conjunction with the CO_2 sensitivities described above.
- *Resource Costs*. For wind, solar and battery energy storage we use NREL's *Annual Technology Baseline* (ATB) 2018 report to provide high and low technology cost sensitivity inputs. For wind and solar, we use the costs projected by the ATB directly. For batteries, we take a slightly different approach. Low and high battery costs are based the percent difference in the NREL ATB base, low and high battery cost forecasts, with this percent difference applied to the Company's base battery cost forecast. We did not adjust capital costs for thermal resources such as the generic CC or CTs, so all scenarios include our base cost assumptions for those resources.
- *Markets Sales Off*. As previously discussed, we assume that markets are "on" for each scenario. The "markets off" sensitivity represents a view in which we

[4] Minnesota Commission Order Updating Environmental Cost Values in Docket No. E999/CI-14-643 issued January 3, 2018.) at 31.
[5] Minnesota Commission Order Establishing 2018 and 2019 Estimate of Future Carbon Dioxide Regulation Costs in Docket Nos. E999/CI-07-1199 and E999/DI-17-53 issued June 11, 2018) at 12.
[6] Minnesota Commission Order Updating Environmental Cost Values in Docket No. E999/CI-14-643 issued January 3, 2018.

cannot access the market to sell energy outside our system.

IV. STRATEGIST ANALYSIS AND RESULTS

After identifying the scenarios and sensitivities for analysis, we used Strategist to identify the expansion plans for each of the 15 primary scenarios, and their resulting cost and emissions impacts. We faced a number of challenges as we tested the full capabilities of the model and attempted to be responsive to stakeholder requests to include a robust set of supply-side and demand-side resource options for consideration. As described below, we undertook an extensive process which attempted to balance the inclusion of a comprehensive set of resource options with the model's limitations, to arrive at a plan that demonstrates a high level of diligence and investigation. This analysis was performed iteratively in several rounds, as we refined the process and results, with each round informing modeling parameters for subsequent rounds. Achieving an appropriate balance between resource options and modeling runtime efficiency required the following adjustments, which are described in more detail in the sections below:

- Removal of our generic distributed solar resource options, with the understanding that if future DG solar growth exceeds our embedded assumptions, it can simply displace utility scale solar additions identified in the Preferred Plan.
- Shortening the modeling period to end in 2025, from the original 2057 end date.
- Testing EE and DR selection via optimizations, evaluating different combinations of the three EE and three DR Bundles for cost effectiveness, and then locking the optimal mix of Bundles in final optimizations.
- Manually inserting CT additions as a proxy placeholder for the firm, dispatchable resource needs driven by the Reliability Requirement. In reality, because these additions happen in the post-2030 timeframe, we expect the need will be met by a combination of firm dispatchable resource options. These may include battery storage, pumped hydro, DR, natural gas, and/or others.

A. Initial Full Optimization

In the first initial round of modeling, all technology alternatives (wind, solar, distributed solar, storage, DR, EE, CC, CT) were made available to the model and we developed a fully optimized expansion plan for each scenario through the end of the available years in Strategist (2057). We found that this stretched the capabilities of the Strategist tool. Due to the large number of alternatives, these runs took a significant amount of time to complete; on average, five days of processing time per scenario. Further, the results were significantly truncated.[7] In these initial plans, no DR, EE, or distributed solar alternatives were selected for any of the scenarios. Although this set of initial runs was not reliable enough for drawing final conclusions, due to the truncation issues, we identified several refinements for the next round of modeling.

First, when comparing utility-scale solar and distributed solar, the model did not select any distributed solar. We reviewed the modeling data for these two alternatives and it was clear that, because both utility-scale and distributed solar have identical capacity accreditation[8] values and similar capacity factors, the model would only ever select the lower cost utility-scale solar. For modeling purposes, therefore, we removed distributed solar from the optimization in order to improve model runtime and reduce the number of truncated results. We note that this does not imply distributed solar is not a resource we anticipate will be added to our system – only that from a modeling perspective, distributed solar will not appear as cost-effective relative to utility-scale solar in the modeling process, and retaining both types of resources in the model for future runs would reduce the quality and runtime of the modeling process. As we have explained, any growth in distributed solar we experience on our system beyond what is in our embedded forecasts will simply serve to displace some of the utility-scale additions identified in our Preferred Plan.

Truncation challenges also informed the duration through which we modeled our plans. While our initial runs experienced truncation issues fairly early (beginning in the late 2020's), the further out we attempted to optimize portfolios, the more truncation occurred and the slower the simulation became. Based on this observation, we determined it was prudent to shorten the modeling period, using 2045 as the end year rather than 2057. We believed that this, in combination with adding 10 years of "end effects" in the modeling, would inform plans through the planning period (2020-2034) that were more robust and valid than the longer simulation would provide. Additionally, the availability, cost and performance assumptions for technologies become increasingly subjective far into the future, and we would not adequately account for new technologies that may develop within that timeframe.[9] Thus the results of modeling in that extended period would not be particularly robust and would likely misstate the resource mix and cost required to

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[7] Truncation occurs when the Strategist model has more viable plans for a given year than the internal memory is able to store. The total collection of plans is sorted by accumulated cost up to that year, and the highest cost plans are discarded and not analyzed further. The Company's model is set to a maximum of 2,500 saved plans per year.
[8] I.e. Effective Load Carrying Capability, or ELCC.
[9] We note that an independent analysis from consultant E3 highlighted similar concerns and also conducts expansion plan modeling to 2045.

meet the Company's longer term vision of 100 percent carbon-free energy by 2050.

Further, including the DR and EE Bundles in full model optimizations proved to be a significant challenge for the Strategist model runtime efficiency. Given that the initial full optimizations resulted in no DSM being selected, we decided to pursue an alternative modeling path. For the next round of modeling, the first DR and the first EE Bundle were forced into the plans to test if "seeding" the model with these Bundles would lead to the second or third Bundles being chosen within the economic optimization.

B. Revised Targeted Optimization

The model revisions discussed above resulted in a somewhat improved modeling process, shortening runtimes and reducing truncation. However, the second round of modeling still took over two days per simulation, and displayed significant truncation, such that we determined additional refinements were needed. This process did, however, help us derive more information from our model runs that informed the final stages of the modeling process.

First, in almost all 15 scenarios, once the first DR and EE Bundles were forced in, the second EE Bundle was selected economically. No additional DR was selected. This result indicated that there was indeed a modeling bias (most likely due to truncation) that prevented selection of DR and EE, as defined by the Bundles, in the fully optimized results. We concluded that some other method of "manual" testing would be necessary to determine these resources' true cost-effectiveness.

Additionally, some of the scenario outcomes in this revised modeling process relied almost entirely on non-dispatchable or use-limited resources (wind, solar, storage) for the full capacity expansion plan. At this point, resource planning consulted with operations and engineering, and worked together to develop and implement a modeling element that would ensure the portfolio resulting from each scenario retained sufficient firm dispatchable generation to reliably serve customer capacity and energy requirements. We describe the Reliability Requirement in Appendix J2.

To incorporate the Reliability Requirement into the modeling, we added firm dispatchable load supporting resources, represented currently with CT resources as a proxy, to the expansion plan in specific years[10] to ensure the portfolio maintained the minimum level of firm dispatchable, load supporting resources as defined by the Reliability Requirement. Given the manual addition of firm dispatchable resources,

[10] Applicable years vary by scenario.

we also reduced the number of new resource alternatives available in certain years to further improve model run times. We believe this did not sacrifice or reduce the model's ability to find optimal solutions for the expansion plan. As an example, the large CC unit option was removed as an alternative in years where the incremental capacity need relative to the previous year was small. This targeted "pruning" of alternatives yielded faster run times and less truncation.

Accounting for all the aforementioned factors, we repeated scenario modeling while including: (1) the Reliability Requirement, (2) the targeted resource "pruning" and (3) one DR and one EE Bundle forced in, while still allowing the incremental DSM Bundles to be selected in the optimization. The second EE Bundle was almost always selected, while no additional DR was selected. Additionally, early coal retirement and nuclear extension scenarios emerged as potential preferred options, as they showed favorable PVSC and PVRR, when compared to other scenarios.

C. Energy Efficiency and Demand Response Analysis

In the next phase of modeling, we worked to refine the DR and EE analysis to identify the most cost effective Bundle combinations. After reviewing initial modeling results, we were confident that two Bundles of EE would likely be selected across all scenarios but wanted to conduct an additional round of tests to confirm. Given we observed strong PVSC and PVRR performance of early coal retirement and extended nuclear scenarios in previous rounds of modeling, we initially conducted DR and EE testing using Scenario 9 (Early King and Sherco 3 retirement with Monticello Extension) and Scenario 10 (Early King retirement with Monticello Extension) as a test. To adequately analyze the Bundles, we developed PVSC and PVRR matrices by selecting a scenario and performing optimizations that included each permutation of the three DR and three EE Bundles. This manual process eliminated the potential for DR and EE truncation, thus allowing us to conduct a robust analysis of each option.

We show results for Scenario 9 as an example below, and note that in both cases the 0 DR/2 EE combination returns the lowest PVSC and PVRR results.

Table 5-2: Scenario 9 (Preferred Plan) DR and EE Cost Effectiveness Analyses ($2019 millions)

PVSC				
	0 DR	1 DR	2 DR	3 DR
0 EE	$48,486	$48,203	$48,502	$48,745
1 EE	$45,390	$45,670	$45,947	$46,152
2 EE	$45,173	$45,512	$45,726	$45,910
3 EE	$45,847	$46,166	$46,389	$46,596

PVSC Deltas (as compared to 0 DR/2 EE)				
	0 DR	1 DR	2 DR	3 DR
0 EE	$3,313	$3,030	$3,329	$3,572
1 EE	$217	$497	$774	$979
2 EE	-	$339	$553	$737
3 EE	$674	$993	$1,217	$1,423

PVRR				
	0 DR	1 DR	2 DR	3 DR
0 EE	$40,029	$40,216	$40,478	$40,653
1 EE	$37,657	$37,910	$38,182	$38,344
2 EE	$37,476	$37,784	$37,925	$38,143
3 EE	$38,374	$38,589	$38,802	$39,009

PVRR Deltas (as compared to 0 DR/2 EE)				
	0 DR	1 DR	2 DR	3 DR
0 EE	$2,554	$2,741	$3,003	$3,177
1 EE	$181	$435	$706	$869
2 EE	-	$308	$450	$668
3 EE	$899	$1,113	$1,327	$1,533

Based on this result, subsequent model runs for the baseload analysis locked in 0 DR Bundles and two EE Bundles, and removed consideration of the remaining DR and EE Bundles from the optimization process. As discussed further in Section V and elsewhere in this Resource Plan however, we ultimately included the first Bundle of DR as part of the Expansion Plan.

D. Final Scenario Analysis

The last round of baseload scenario modeling incorporated the results of the previous rounds into defining and executing a final analysis, which we used to draw conclusions on the relative economics and operational performance of the 15 baseload scenarios. For the final model runs, two EE Bundles were manually added to the plans, and the remaining Bundles were removed from the optimization, per our previous findings that they would not be selected. The Reliability Requirement was included as a constraint, and the number and timing of alternatives were reduced as previously described, in order to improve model run performance without sacrificing the ability to effectively optimize remaining resource options. We then created expansion plans for all 15 scenarios, using PVSC assumptions, and completed the full set of sensitivities.[11]

[11] Minn. Stat. § 216B.2423

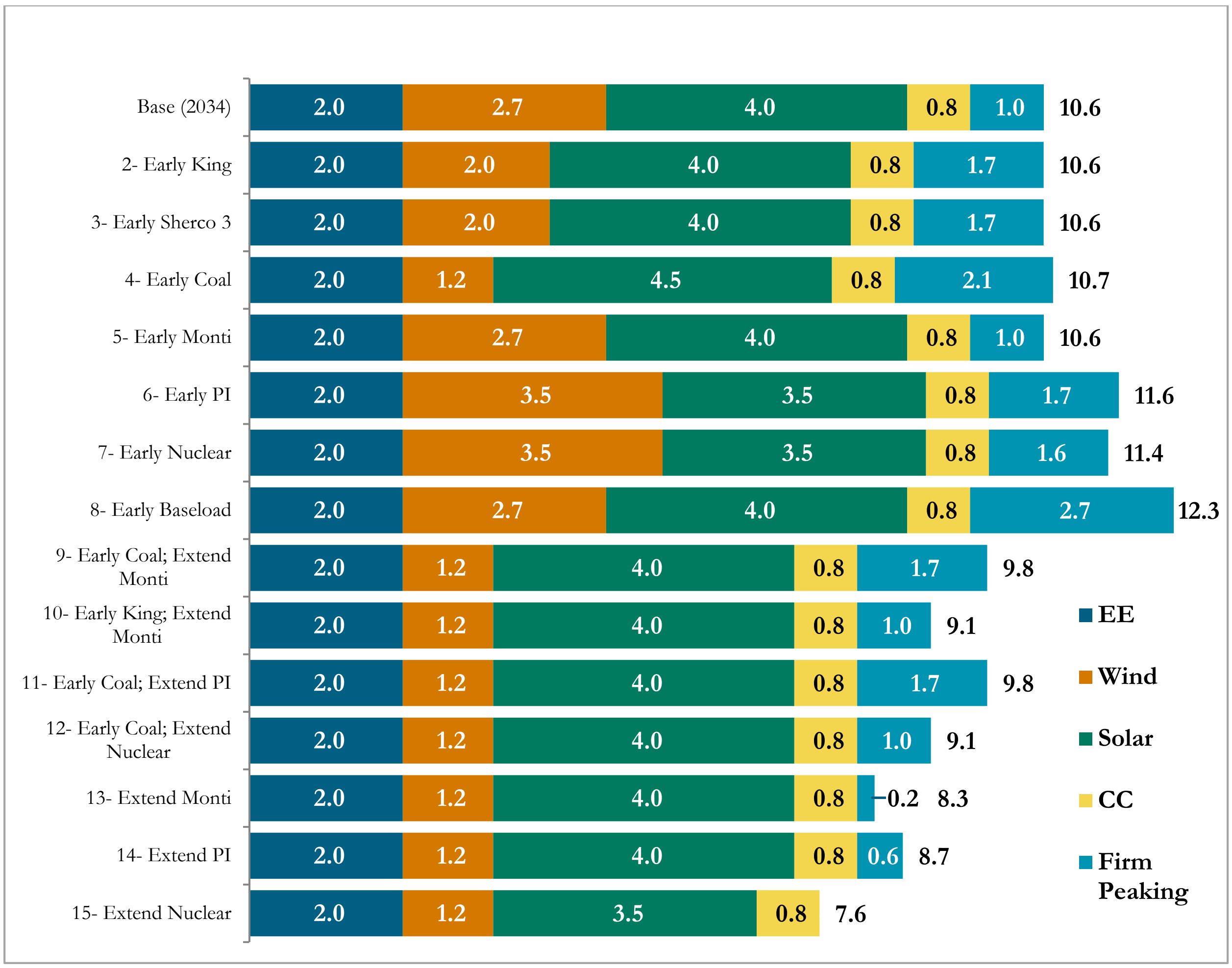
E. Modeling Results and Conclusions

Completing baseload scenario runs, as described above, allows us to examine Scenario outcomes side-by-side, to evaluate their benefits and drawbacks. Among other factors, we examine each Scenario's resource expansion profile and carbon emissions outcomes, present value costs, and several indicators of risk.

1. Capacity Additions and Emissions Reductions

The cumulative expansion plan additions through the planning period for the 15 scenarios are shown below in Figure 5-6.

Figure 5-6: Expansion Plans by Scenario (GW, Cumulative Nameplate Capacity Resource Additions by Fuel Type)

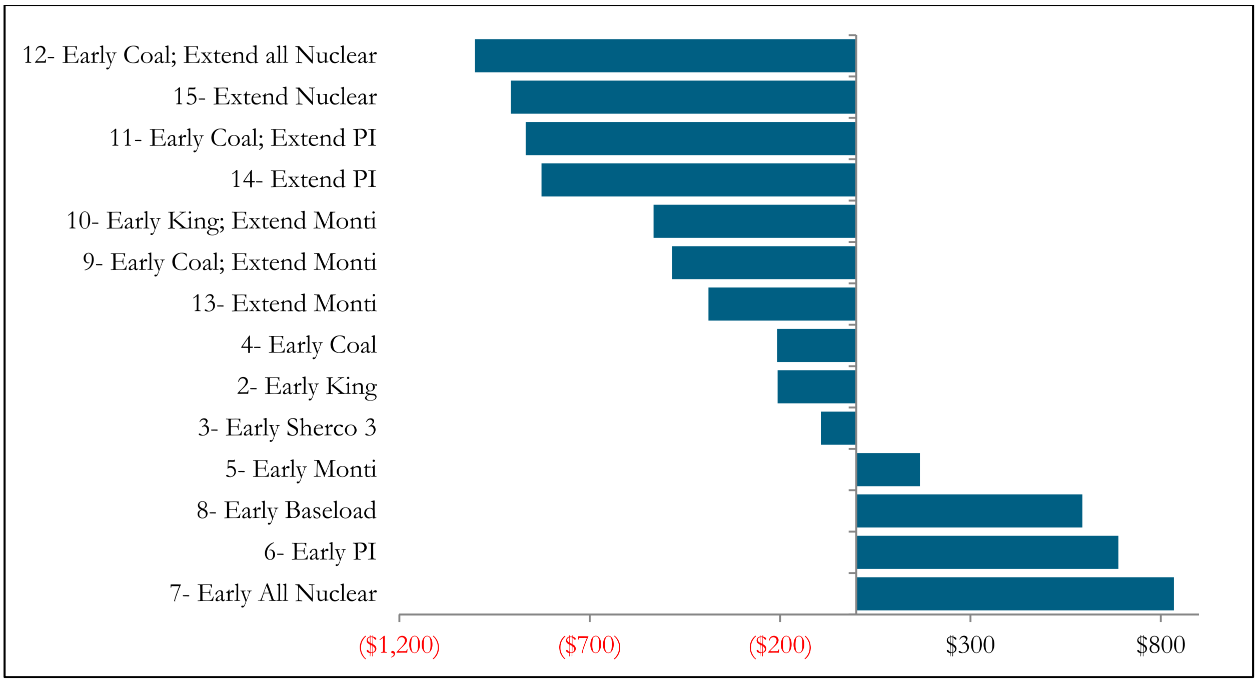


As the 80 percent carbon emissions reduction target was included as a modeling parameter, all the scenarios achieve this goal and remain under the emissions threshold from 2030 throughout the planning period. There is minimal variability between Scenarios on this measure, other than the timeframe in which they first reach 80 percent reduction levels.

2. *Present Value Costs*

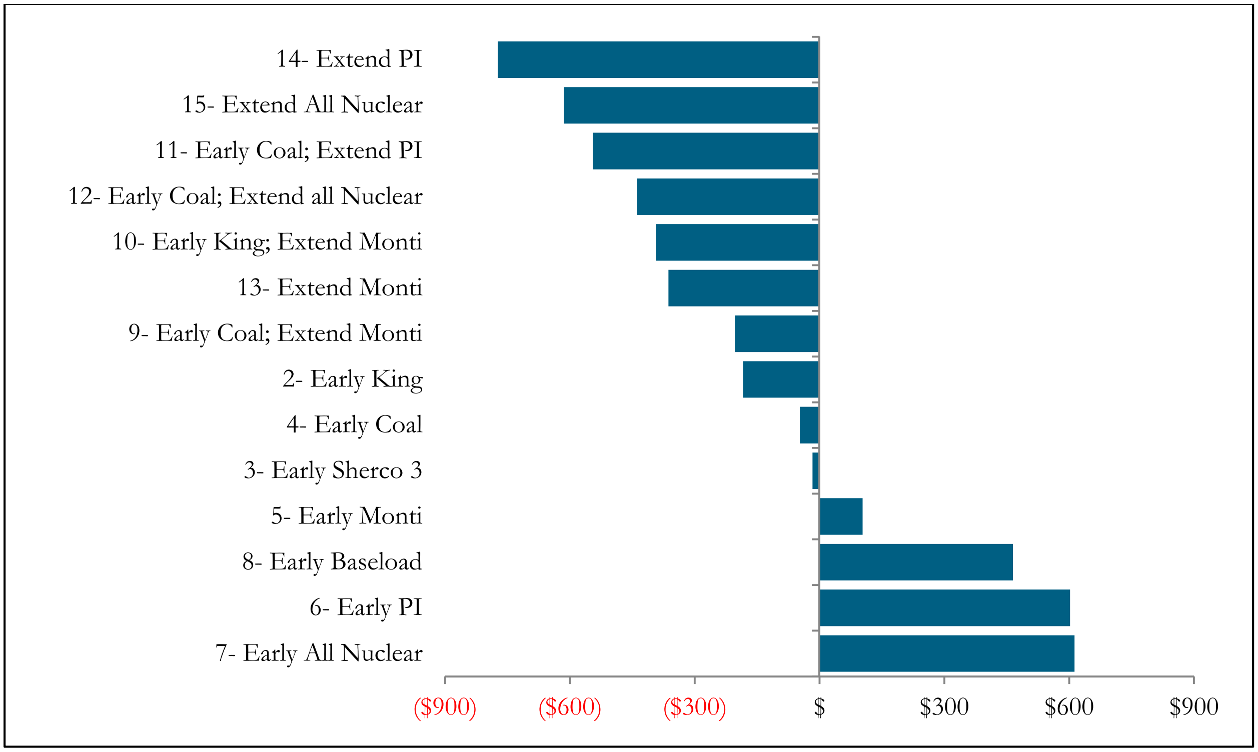
In general, plans that favored early coal retirements and nuclear extensions were the lowest cost plans, both in terms of PVSC and PVRR. The results for the 15 scenarios from the final modeling runs are shown below in Figures 5-7 and 5-8. The figures show the net present value (NPV) delta of modeled costs compared to Scenario 1 (the Reference Scenario), with negative values representing customer savings relative to the Reference Scenario and positive values representing increased costs.[12]

Figure 5-7: Scenario PVSC Deltas from Reference Case ($2019 millions)



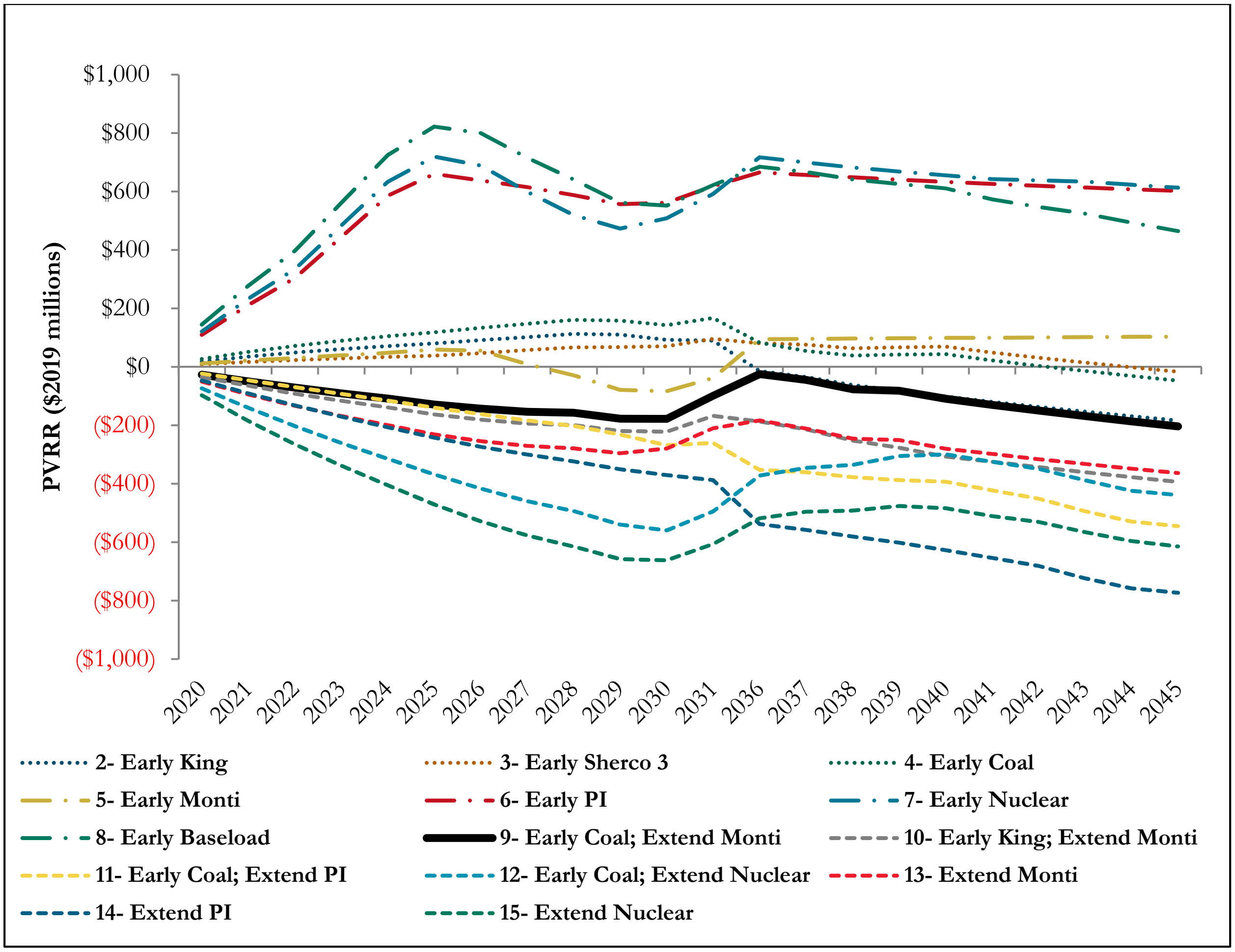
[12] Note that these PVRR and PVSC deltas shown depict NPV for 2020-2045.

Figure 5-8: Scenario PVRR Deltas from Reference Case ($2019 millions)



In addition to evaluating the total NPV of each scenario, we also examine the timing of the relative costs and benefits. Examining NPV over a time series helps us make relative comparisons of changes in costs or benefits at key "transition points" of the plans (such as retirement or extension dates, significant renewable additions, etc.). The cumulative total PVRR costs or savings for each of the scenarios are shown below in Figure 5-9. Each line on the chart illustrates the running total of the annual PVRR costs or benefits by year for a specific scenario, compared to the Reference Case. The end point of the lines in 2045 corresponds to the final PVRR deltas shown in Figure 5-8 above.

Figure 5-9: Cumulative PVRR Cost or Savings Deltas by Scenario, Compared to the Reference Plan ($2019 million)



In addition to PVSC and PVRR, the Company completed sensitivity analyses for all 15 scenarios. The results of these analyses are shown in Appendix F3.

3. *Additional Risk Metrics for Baseload Scenario Evaluation*

While present value costs are one factor we use to inform our Preferred Plan, we also consider other factors and elements of risk exposure for each potential Scenario. Consistent with the Resource Plan objectives presented in Chapter 4, we evaluated each scenario with regard to achieving our cost, environmental, risk and reliability goals. It is essential that our Preferred Plan meets our carbon reduction goals while also ensuring that the system remains reliable and the plan remains affordable for customers. Likewise, it is important we evaluate various risks, because forecasting into the future is inherently uncertain and we want to ensure our selected Plan remains robust, even if some key factors change. We describe the objective risk measures we used to evaluate the scenarios in Table 5-3 below.

Table 5-3: Scenario Modeling Portfolio Risk Metrics

Objective	Metric	Definition
Cost	Base PVRR and Base PVSC	Traditional NPV measure of total 2020-2045 PVRR or PVSC costs to determine least cost plan. Plans showing cost savings are preferred.
	Worst Case Futures Scenario Cost	Measure of worst case potential cost outcomes across the four Futures Scenarios so provides insight into plan cost risk. Plans still showing cost savings in worst case Futures Scenario are preferred.
Risk	Energy Risk	Measures the absolute value of average annual total market interaction (purchases plus sales plus dump energy) associated with each plan, to assess market energy risk exposure. Plans with lower market energy exposure are preferred.
	Capacity Risk	Measures average annual net capacity position associated with each plan, to assess market capacity risk exposure. Typically, plans with lower net capacity positions are considered favorable, and our rankings reflect that. However, we also take into account certain factors that are specific to this Resource Plan, which affect the weight we place on this metric. These are discussed further below in Section V.
Environmental	Carbon Emissions Reduction	All plans achieve acceptable levels of carbon reduction, as a result of including an 80 percent carbon reduction (relative to 2005 levels) constraint in modeling.
Reliability	Firm, Dispatchable Resource to Peak Load Ratio	All plans achieve acceptable levels of reliability, measured by the amount of firm, dispatchable resources available, as a result of including the Reliability Requirement in modeling.

As noted, all scenarios meet the environmental and reliability objectives, given these targets are included as constraints in our modeling. Thus, our Scenario evaluation focuses on the cost and risk objective metrics noted above.

V. PREFERRED PLAN SELECTION AND ASSESSMENT

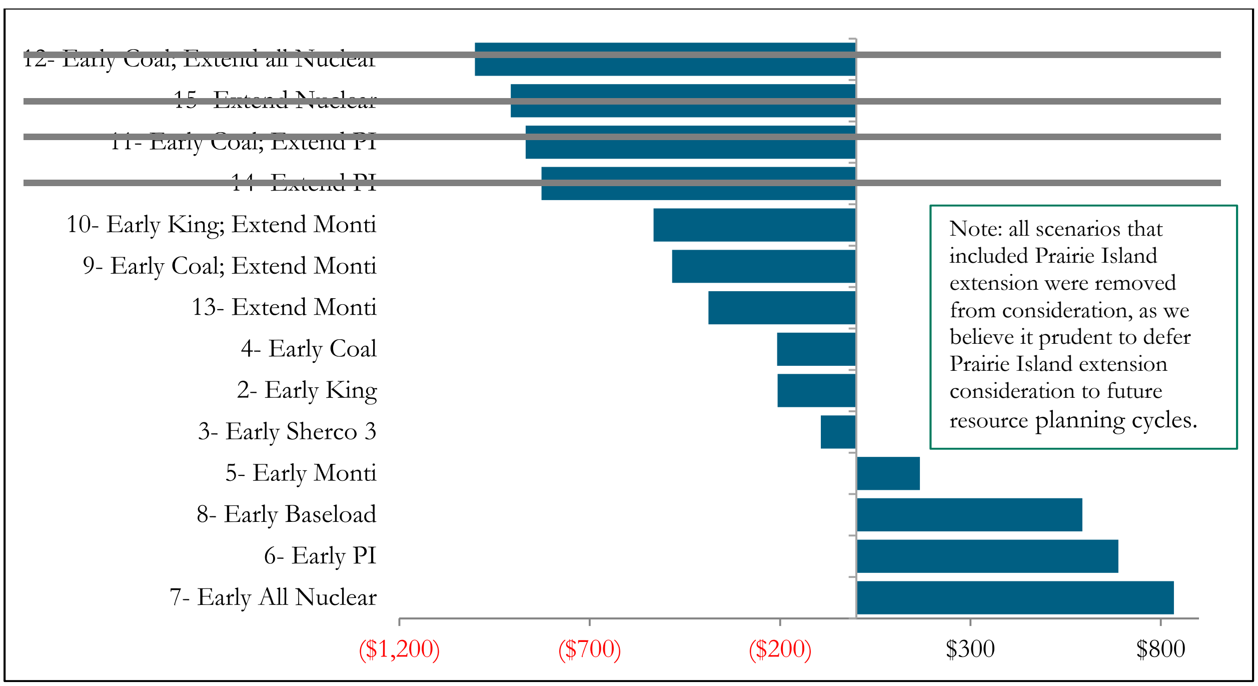
As described previously in this Chapter and in Chapter 4, we evaluated the PVRR and PVSC results of our 15 baseload scenarios, and how effectively each potential plan would meet our planning objectives, to determine which Scenario should form the basis of the Preferred Plan. Based on these outcomes, we selected baseload Scenario 9. Our plan charts the path toward achieving ambitious carbon reduction goals, reflects substantial stakeholder input and consensus, and ensures reliability and affordability for our customers. The baseload aspects of this plan include an early King retirement in 2028, Sherco 3 early retirement in 2030 and extension of our Monticello nuclear facility to 2040. We also took into account additional considerations regarding DR when finalizing the Preferred Plan. We discuss more detail regarding how we selected and evaluated our Preferred Plan below.

A. Baseload Study Analysis Results

From a modeling perspective, the PVSC and PVRR results are primary indicators of the various scenarios' economic favorability. Figures 5-8 and 5-9 shown above indicate that the nuclear extension scenarios paired with early coal retirements yielded the most attractive customer value relative to the Reference Case.

We note that while Baseload Scenario 9 was not the least cost of our 15 scenarios, several lesser cost scenarios included an extension of Prairie Island's operating license. However, as discussed previously, Prairie Island's license does not expire until the 2033-3034 timeframe just outside the planning period, and we believe there is risk avoidance value in deferring a decision on Prairie Island extension until a future Resource Planning process. As a result, we eliminated from consideration cases that include a Prairie Island extension, as shown below.

Figure 5-10: Scenario PVSC Deltas from Reference Case, PI Extension Cases Eliminated ($2019 millions)



After screening out the baseload scenarios that include Prairie Island extension, we evaluated the remaining scenarios using the cost and risk metrics discussed previously, including savings or costs achieved in a "worst-case" Futures Scenario, and average energy and capacity exposure. Of the remaining baseload scenarios available for selection, Scenarios 9 (Early Coal; Extend Monti), and 10 (Early King; Extend Monti) achieve the most favorable risk profile overall.

Further, Minn. Stat. § 216B.2422, subd. 2(c) requires that we "include the least cost plan for meeting 50 and 75 percent of all energy needs from both new and refurbished generating facilities through a combination of conservation and renewable energy resources." The Preferred Plan (Scenario 9 - Early Coal; Extend Monti) satisfies the statute's first requirement (50 percent of energy needs from conservation or renewables) because it is economically optimized and meets approximately 64 percent of energy needs with renewables and conservation. Our baseload scenario analysis satisfies this statute's second requirement (75 percent of energy needs from conservation or renewables), as Scenario 4 (Early Coal) yields the least cost plan for meeting at least 75 percent of all energy needs from both new and refurbished generating facilities through a combination of conservation and renewable energy resources. Because this scenario does not include a nuclear extension, it enables greater levels of renewable additions than the Preferred Plan that meet or exceed the 75 percent threshold.

B. Early Retirement of Sherco 3 by 2030

Excluding the Prairie Island extension scenarios, Scenarios 9 and 10 become the optimal least cost options. Both Scenarios 9 and 10 assume an early King retirement and Monticello extension; however, Scenario 9 includes an early Sherco 3 retirement while Scenario 10 does not. Both Scenarios are beneficial on a PVSC and PVRR basis, and are the most resilient of the remaining scenarios to the potential worst case evaluated, continuing to maintain customer benefits relative to the Reference case.

Given the proximity of overall customer savings and risk considerations between Scenario 9 and 10, we ultimately considered which case would fit best with our strategic objectives and our understanding of stakeholder interests. We selected Scenario 9 as our Preferred Plan, which includes the retirement of all remaining coal units. Scenario 9 provides the best fit for our carbon goals and helps mitigate the potential for regulatory or legislative action around carbon costs or carbon reduction levels. Further, general market trends toward increasing levels and decreasing costs of renewables, low natural gas prices, the need for more flexible resources, and other factors are expected to make it more and more difficult for coal resources to operate in an efficient and economic manner beyond 2030. Finally, our interactions with customers, stakeholders, and shareholders alike have shown increasing interest in achievement of carbon reductions and other environmental solutions. From a financial risk perspective, we believe it is beneficial for the Company to reduce carbon risk exposure, and we view transitioning our generation fleet away from coal assets is one of the best ways to achieve that goal.

C. Demand Response Adjustment to Scenario 9

As noted previously, the model optimization exercise did not select any of the DR Bundles provided as options. However, the Order approving our last Resource Plan included direction to add 400 MW of incremental DR resources. Therefore, the final step in developing our Preferred Plan was to include DR Bundle 1 as part of Scenario 9. This addition increases our net long capacity position, where after 2025, our position remains long by a range of 500-1,000 MW through the remainder of the planning period. As mentioned previously, we typically view a long capacity position as less favorable; however, we believe this is an acceptable path forward given alignment with our risk mitigation planning objective, discussed further below.

D. Futures Scenarios Results

As previously discussed, a final step in our analysis process evaluated the performance of the Preferred Plan under the Futures Scenarios. Table 5-4 below provides a summary of the Futures Scenario results. Under all of these Futures Scenarios, the Preferred Plan provides savings relative to the Reference Case,[13] which suggests that the Plan is robust under a range of potential future conditions.

Table 5-4: Preferred Plan NPV Savings under Different Futures Scenarios ($2019 millions)

	Base PVSC	Base PVRR	High Electrification Scenario PVSC	High Distributed Solar Scenario PVSC
Delta	***(461)***	***(203)***	***(81)***	***(51)***

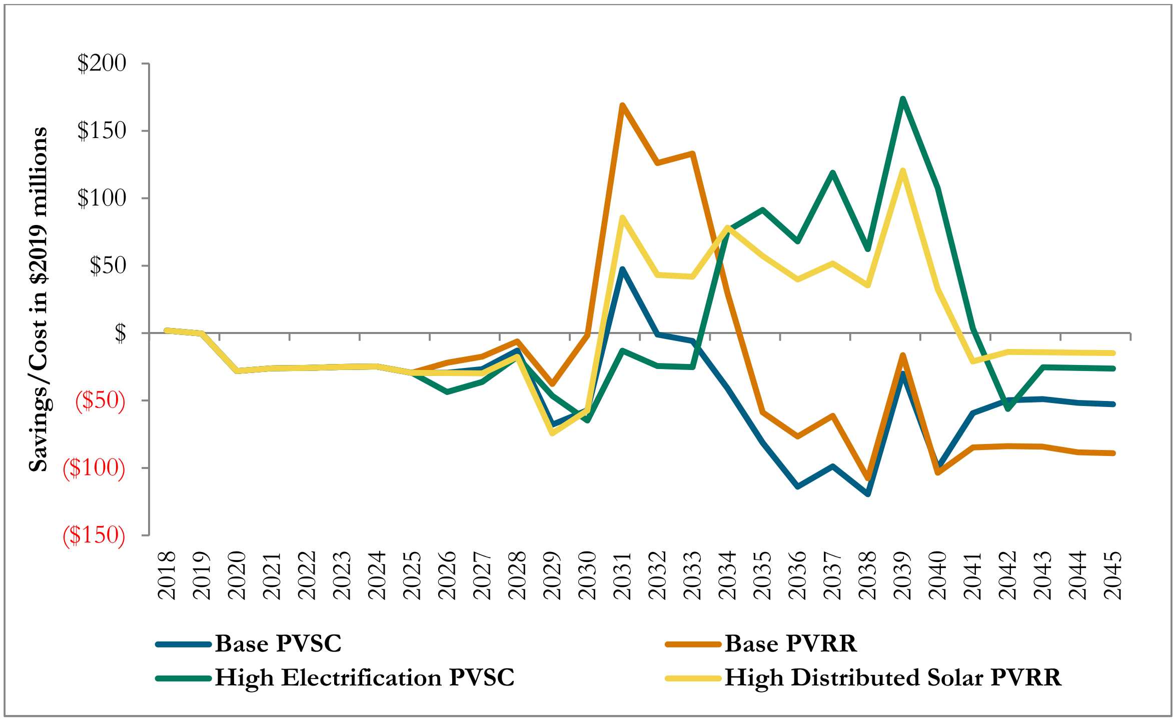
As demonstrated in the baseload scenario analysis and in Table 5-4, the Preferred Plan yields customer value of $203 million in the base PVRR and $461 million in the base PVSC scenarios. Early coal retirements paired with the Monticello extension yield

[13] Note: Each NPV result compares the Preferred Plan with Future Scenarios assumptions applied to the Reference Case with those same assumptions applied.

benefits to customers particularly when carbon costs are included. In both the High Electrification and the High Distributed Solar Futures Scenarios, customer value is marginally reduced from the Base PVRR and PVSC scenarios with $81 million of savings in the High Electrification Scenario and $51 million of savings in the High Distributed Solar Scenario.

As shown in Figure 5-11 below, the Preferred Plan consistently results in customer savings relative to the Reference Case in all Future Scenarios through 2030. At that time, however, the Base PVSC and PVRR scenarios diverge from the High Electrification and High Distributed Solar Scenarios mainly in the 2030 timeframe. A number of factors impact the annual deltas in these Scenarios and drive the divergence. Assumed low new resource capital costs in the Electrification and High Distributed Solar Scenarios likely functions as the biggest driver in upward cost pressure on the Preferred Plan in the 2030s, as in those Scenarios Monticello can be replaced with cheaper renewables. Even under these conditions,, however, the results demonstrate that over the entire planning period and across multiple Futures Scenarios, the Preferred Plan provides overall customer savings relative to the Reference Case. This demonstrates that the Plan is robust and beneficial to customers, yielding savings under a host of potential future conditions.

Figure 5-11: Preferred Plan Annual Costs or Savings Compared to the Reference Case, by Scenario ($2019 millions)



The expansion plans for the Preferred Plan under all of the Futures Scenarios analyses are provided below. In the High Electrification Scenario, higher load growth drives incremental solar and firm dispatchable resource additions above what is included in the Base PVSC/PVRR expansion plans. Specifically, the High Electrification Scenario yields an additional 1,000 MW of solar and 748 MW of firm dispatchable additions. In the High Distributed Solar Scenario, utility-scale solar is displaced by incremental distributed solar, as well as additional EE resources, per the inclusion of the third EE Bundle. Total large solar additions are decreased from 4,000 MW in the base scenarios to 2,500 MW total in the High Distributed Solar Scenario.

Table 5-5: Preferred Plan Base Expansion Plan (MW)

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	Total
Grid-scale Solar	0	0	0	0	0	500	500	1000	500	500	500	0	500	0	0	**4,000**
Battery	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
CC	0	0	0	0	0	0	0	835	0	0	0	0	0	0	0	**835**
Firm Dispatchable	0	0	0	0	0	0	0	0	0	0	0	606	0	374	748	**1,728**
DR	270	20	21	10	17	41	12	14	15	17	19	20	21	22	23	**542**
EE	115	130	116	133	143	145	154	157	155	140	138	136	129	126	126	**2,041**
Wind	0	0	0	126	45	70	66	72	10	107	16	56	31	523	81	**1,202**
Distributed Solar	154	22	22	21	21	21	21	20	20	20	20	20	20	20	19	**442**

Table 5-6: High Electrification Scenario Expansion Plan (MW)

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	Total
Grid-scale Solar	0	0	0	0	0	500	500	1000	500	500	500	500	500	0	500	**5,000**
Battery	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
CC	0	0	0	0	0	0	0	835	0	0	0	0	0	0	0	**835**
Firm Dispatchable	0	0	0	0	0	0	0	0	0	374	0	606	374	374	748	**2,476**
DR	270	20	21	10	17	41	12	14	15	17	19	20	21	22	23	**542**
EE	115	130	116	133	143	145	154	157	155	140	138	136	129	126	126	**2,041**
Wind	0	0	0	126	45	70	66	72	10	107	16	56	31	523	81	**1,202**
Distributed Solar	154	22	22	21	21	21	21	20	20	20	20	20	20	20	19	**442**

Table 5-7: High Distributed Solar Scenario Expansion Plan (MW)

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	Total
Grid-scale Solar	0	0	0	0	0	500	0	500	500	0	0	500	500	0	0	**2,500**
Battery	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
CC	0	0	0	0	0	0	0	835	0	0	0	0	0	0	0	**835**
Firm Dispatchable	0	0	0	0	0	0	0	0	0	0	0	606	0	374	748	**1,728**
DR	270	20	21	10	17	41	12	14	15	17	19	20	21	22	23	**542**
EE	151	171	152	174	186	189	202	207	203	185	183	181	171	167	166	**2,687**
Wind	0	0	0	126	45	70	66	72	10	107	16	56	31	523	81	**1,202**
Distributed Solar	154	166	9	11	9	14	93	19	127	27	62	64	67	70	72	**964**

For simplicity, the table below shows cumulative expansion plan additions by resource type. It is important to note that while DR, EE and battery storage are reflected as separate categories, and no incremental additions for these resources are shown, they would be considered to fill any firm dispatchable needs identified in the expansion plans. Similarly, evolving economics and value could also shift the mix of wind and solar additions.

Table 5-8: Cumulative 2020-2034 Additions by Resource Type and Scenario (MW)

	Base Preferred Case	**High Electrification**	**High Distributed Solar**
Large Scale Solar	4,000	5,000	2,500
Battery	0	0	0
CC	835	835	835
Firm Dispatchable	1,728	2,476	1,728
DR	542	542	542
EE	2,041	2,041	2,687
Wind	1,202	1,202	1,202
Distributed Solar	442	442	964

E. Preferred Plan Benefits

We believe our analysis supports selection of Scenario 9, including the early retirement of all of our coal resources by 2030 and extension of Monticello nuclear facility to 2040, as our Preferred Plan. While all of our scenarios meet the carbon goal and Reliability Requirement we established, we believe cost and risk considerations elevate Scenario 9 above the rest as an appropriate path forward.

1. Cost

As demonstrated in our modeling analysis, the Preferred Plan achieves customer value, not only under the our Base PVSC ($461 million) and PVRR ($204 million) analysis but also under more challenging future conditions as evidenced in our High Electrification ($81 million) and High Distributed Solar ($51 million) Futures Scenario analysis. In addition, the Preferred Plan yields customer value under all of the individual sensitivities run, even in the Futures Scenario that results in the worst case customer savings outcome (High Distributed Solar Scenario). Lastly, from a customer rate impact perspective, the Preferred Plan results in annual rate increases of just over one (1) percent, which is below the rate of inflation.[14] Altogether, we believe the Preferred Plan delivers tangible customer savings while taking industry-leading steps towards a carbon free future.

2. Risk

In addition to beneficial cost outcomes, the Preferred Plan addresses major risks by maintaining portfolio diversity, retaining optionality and effectively managing market exposure. The Plan incorporates significant capacity additions to replace retiring resources, consisting of a diverse portfolio of DSM, nuclear extension, solar, wind, and firm dispatchable resource additions. Ensuring we do not become too dependent on a single fuel source mitigates risk. In addition, deferring a decision on a potential Prairie Island license extension affords us additional flexibility to reevaluate in future resource planning cycles, as technology costs and other key assumptions can change quickly.

We also evaluate factors such as energy market exposure and portfolio length. All of our baseload scenarios show high levels of market interaction, driven in part by significant renewable additions; but our selected Plan minimizes them relative to other scenarios and attempts to carefully balance and pace renewable additions with other resources. Further, we typically try to achieve a closer supply-demand balance than

[14] As noted in Chapter 4: Preferred Plan and discussed further in Chapter 6: Customer Rate and Cost Impacts

any of our baseload scenarios offer, although the 500-1000 MW of length in any scenario is relatively minimal compared to our overall system. We believe our Preferred Plan's portfolio length is warranted at this time, however, and creates an effective hedge for our customers against two key risk factors:

- *Capital Investment Wind Down At Retiring Plants.* The retirement of all 2,400 MW of our coal assets, in addition to a few other units by 2030 exposes our customers to some risk as we wind down operations and reduce capital spend at these plants. In the event of an early outage, excess capacity will give us the option to flex the retirement dates as needed if we find that a capital investment is not in our customers' best interests at that time.
- *Renewable and Use-Limited Resource Capacity Accreditation.* Solar capacity accreditation is assumed at 50 percent credit in all years of our modeling. We expect this to change as MISO changes its approach to forward capacity accreditation – recognizing that as solar penetration increases in the footprint, the accredited value of solar will decline. The same also applies for use-limited resources like DR. We discuss this emerging MISO recognition in the Baseload Study provided as Appendix J1, in conjunction with the Reliability Requirement in Appendix J2, and in discussion of our Supporting Infrastructure – Transmission & Distribution, provided as Appendix I.

VI. CONCLUSION

Considering the above we believe our modeling and analysis fully supports selection of the Preferred Plan, and strikes a strong balance in meeting our planning objectives, in service of our customers' needs. The plan sets us on a path to deliver tangible savings to our customers, while transitioning our system to meet both our 2030 carbon reduction objectives and longer term carbon-free goals.

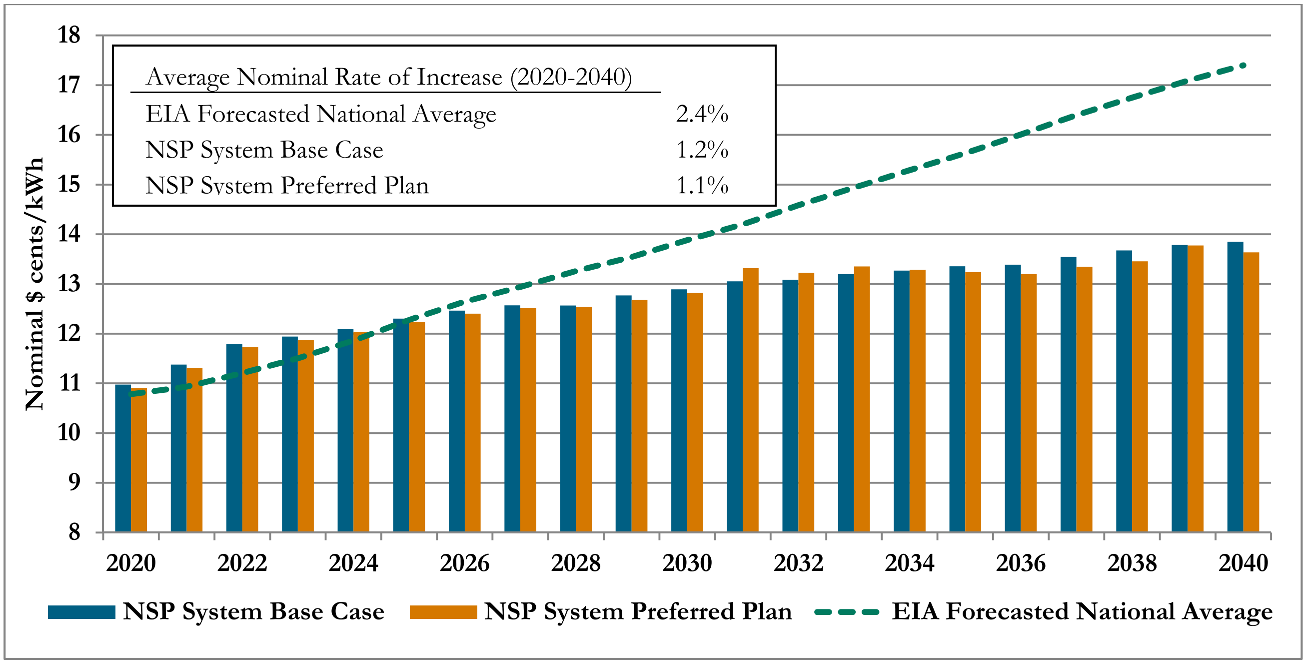
CHAPTER 6
CUSTOMER RATE AND COST IMPACTS

Overall, our Preferred Plan results in an estimated average annual increase in revenue requirements less than the Reference Case and just over one (1) percent overall. In other words, we can achieve significant CO_2 emissions reductions, with cost impacts that are roughly half of the expected national average increase in electricity prices.

Both the Reference Case and the Preferred Plan are designed to meet the Company's goal of reducing carbon emissions 80 percent by 2030, compared to 2005 levels. We did not do the full rate impact calculations discussed in this Chapter on a resource portfolio that does not meet our 80 percent carbon reduction by 2030 goal, we did run a "no 80 by 30" portfolio in our Strategist model and and confirmed that the impacts are in line with our Preferred Plan. In other words, our carbon goals do not materially increase costs for our customers.

To show the cost impact of our proposal over the long-term, we provide a Compound Average Growth Rate (CAGR) comparison of our Preferred Plan compared to the national average nominal cost CAGR for the NSP System in Figure 6-1 and Minnesota in Figure 6-2.

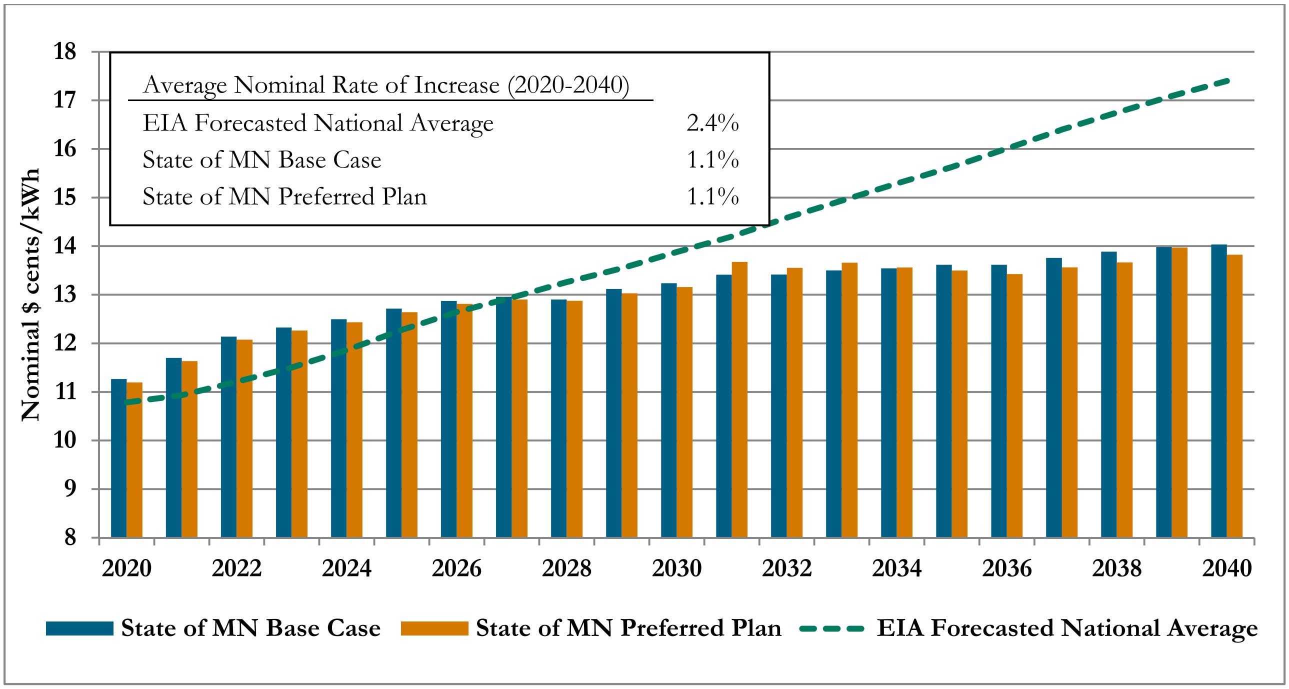
Figure 6-1: Preferred Plan Average Nominal Cost Comparison (NSP System)



* *Notes: National energy cost forecast from Energy Information Administration (EIA) Annual Energy Outlook 2019, Table Energy Supply, Disposition, Prices and Emissions – Reference Case. End use prices, all sector average.*[1] The Preferred Plan and Reference Plan lines include the costs of Solar Rewards*Community.

[1] *See* https://www.eia.gov/outlooks/aeo/data/browser/#/?id=8-AEO2019&region=0-0&cases=ref2019&start=2017&end=2050&f=A&linechart=~ref2019-d111618a.70-8-AEO2019&ctype=linechart&sid=ref2015-d021915a.70-8-AEO2015~ref2019-d111618a.70-8-AEO2019&sourcekey=0 The EIA's Annual Energy Outlook was published in January 2019. The report is available at https://www.eia.gov/outlooks/aeo/pdf/aeo2019.pdf.

Figure 6-2: Preferred Plan Average Nominal Cost Comparison (State of Minnesota)



We derived this long-term projection using a combination of a shorter-range financial forecast and the Strategist model.

We note that a detailed analysis of rate impacts in a resource planning process with long-time horizons is difficult to produce due to changes in our rates and resource needs that will occur over time. Because of the simplifying assumptions made in both the calculation methodology and the input variables, these estimated impacts may not correspond with actual rates that the Commission sets for various rate classes in the future. That said, aside from updated inputs to the class cost allocation factors used in this analysis, the methods are the same as those we used in our last Resource Plan.

In this Section, 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 the NSP system, State of Minnesota, and individual State of Minnesota customer class levels. This is generally consistent with the methodology we used in our last Resource Plan.

I. REFERENCE CASE REVENUE REQUIREMENTS 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. This forecast leveraged our detailed five-year financial forecast and a specific approach to identify costs through the end of the planning period (2034) using the CAGR of generation and fuel costs from the Strategist model.[2] Next, we analyzed the annual cost differences by category (i.e. fuel, purchased power, capital expenditures, operating and maintenance costs, taxes, depreciation, etc.) from the Strategist model results for the Reference Case and the Preferred Plan to determine the aggregate system cost impacts and jurisdictional and rate class breakouts.

To determine the overall 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 class allocation principles to calculate impacts on individual Minnesota customer classes. We provide various rate impact analyses and discuss the methodologies below.

II. ESTIMATED RATE IMPACTS AND METHODOLOGY

The primary Strategist model captures only the generation-related portion of the business, or around 50 percent of the total revenue requirements. Developing a total rate forecast beyond 2023 when detailed Company financial models are not available is dependant on making assumptions for capital expenditures and O&M costs for all areas of the business, including generation (both new and existing), transmission, distribution and corporate support services. Many of these assumptions are speculative, and the resulting total rate forecast would be similarly speculative.

A. Methodology

To calculate the rate impacts of the Preferred Plan, we started with the 2018 budget forecast of total revenue requirements for the 2019-2023 period.[3] To estimate customer impacts for the immediate five-year period, we estimated revenue requirements similar to a Jurisdictional Cost of Service (JCOSS) for each year, and then performed an estimated Class Cost of Service (CCOSS) analysis – both of which required us to make a number of assumptions.

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[2] The Strategist model for the Reference Case is the same model used for the Strategist aspect of our Baseload Study, Scenario 1 Reference Case, with the exception that the first Demand Response (DR) bundle was added to the plan, as was also added to the Preferred Plan.
[3] Developed in July 2018 and updated in November 2018.

To determine the JCOSS, we had to make a number of assumptions, including the following:

- Full recovery of the Company's internal five-year forecasts of capital, O&M, and sales,[4]
- Return on Equity (ROE) of 9.20 percent,[5]
- A forecast of debt and equity ratios and debt rates appropriate for the five-year modeling term,
- Estimated historical regulatory adjustments made in rate cases.

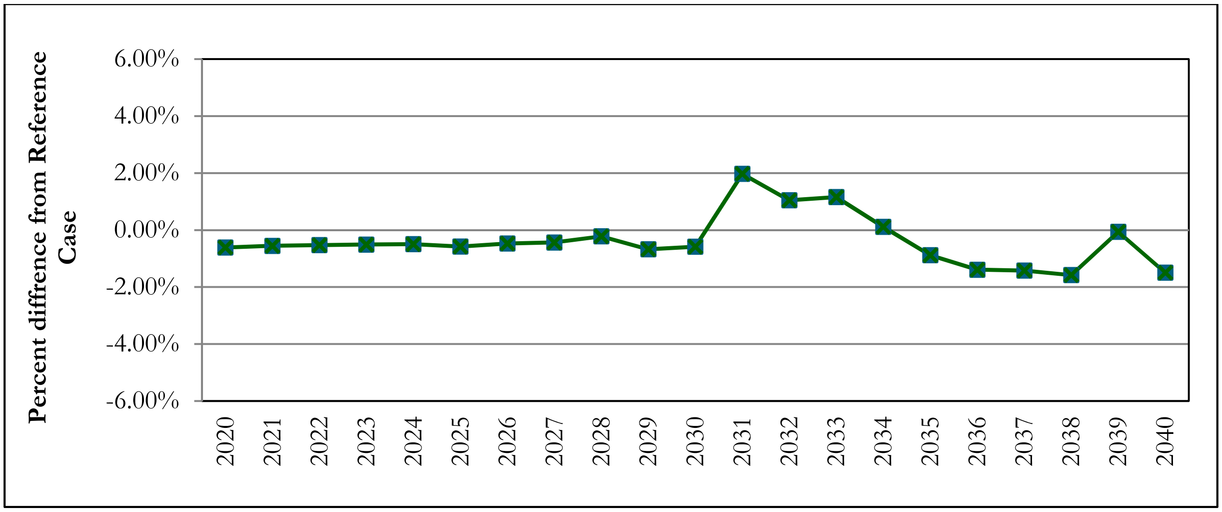
To calculate longer-term rate impacts of the Preferred Plan, we used a combination of the Company's 5-year financial forecast and the Strategist model to project total system revenue requirements for extended periods. For the period beyond 2023, we escalated the capital and O&M costs in the last year of the 5-yr model by the CAGR of the Reference Case as modeled by Strategist.[6] This approach avoids speculation on areas of the business not related to resource planning and modeling, while still using the detailed generation-related information from the Strategist model to create a "business as usual" long term rate projection. Finally, we calculated the annual difference between the Preferred Plan and the Reference Case to estimate the total rate impact of our Preferred Plan.

B. Estimated Overall Rate Impacts

Figure 6-3 below illustrates the State of Minnesota estimated rate impacts of the Preferred Plan compared to the Reference Case over the long-term.

[4] Data as of November 2018.
[5] The Company acknowledges the recent decision in the TCR docket requiring a 9.06% calculation to be used in future filings and will implement that practice once the order is received.
[6] The Reference Case is Resource Plan Scenario 1; see Appendix F2 for additional details.

Figure 6-3: Annual Percent Change in Revenue Requirements (2020-2040) Preferred Plan above Reference Case – State of Minnesota



The modeling includes accelerated depreciation costs associated with the early retirements of Sherco 3 and King. However, consistent with the Commission's actions in the approval of the early shutdown of the Benson biomass plant (Docket No. E002/M-17-530), a regulatory asset is another tool that could be used to accompany these early retirements. The use of a regulatory asset for the remaining costs of these plants, including a cost of capital return on those assets, would be an appropriate alternative to accelerating the depreciation because it would keep the Company whole over the remainder of the plants' remaining lives. This would also serve to smooth the projected rate impacts over the planning period.

C. Key Drivers

The major inflection points in the delta of revenue requirements (and rates) is driven entirely by the differences in the set of resources that comprise each the Preferred Plan and Reference Case; these points coincide with key differences in baseload plant retirement dates between the two cases and the timing of replacement resources. The reduction in revenue requirements associated with the early coal unit retirements helps to offset a portion of the ongoing nuclear revenue requirements in the Preferred Plan in the early 2030s, as discussed in more detail below:

- *Extension of Monticello.* In 2028, costs associated with the 10-year license extension begin to ramp up in the Preferred Plan, and capital revenue requirements and O&M costs continue through 2040. In contrast, the Reference Case does not have ongoing capital and O&M costs for Monticello beyond 2030 as it is retired in that case; this results in an approximate $295 million difference between the two cases in fixed costs for Monticello, beginning in 2031.

- *Retirement of Coal Units.* The Reference Case contains ongoing capital and O&M costs for King and Sherco Unit 3, whereas in the Preferred Plan the costs for King terminate in 2029 and Sherco Unit 3 in 2031 due to early retirement. This results in savings of approximately $45 million in fixed costs in 2029, increasing to $110 million in 2031.

- *Load Supporting Resources.* The Preferred Plan has some load-supporting, dispatchable resources added in the early 2030's associated with the Reliability Requirements Proxy discussed in the Baseload Study in this Resource Plan. With the early retirement of King and Sherco Unit 3, the Preferred Plan has a load supporting, dispatchable resource deficiency of approximately 400 MW in that time frame. The Preferred Plan extension of Monticello helps to offset some of this capacity deficiency. The net cost of the load supporting, dispatchable resources in those years ranges from approximately $35 million to $70 million.

The rate increase seen in 2031-2033 reverses in 2034 and the Preferred Plan remains an annual savings producer thereafter. The cost savings from the Preferred Plan are due to the extension of Monticello, which maintains the NSP system 80 percent carbon reduction after Prairie Island retires, without the need to add significant renewables. In the Reference Case, the model adds 2,250 MW of wind in 2034-35 to maintain the 80 percent carbon reduction level, which adds significant costs.

D. These Estimates are not Directly Comparable to Rate Impact Analysis in a Rate Case

We caution that this information should not be interpreted as directly comparable to the customer rate impact information we would provide as part of a rate case filing for reasons including the following:

- The internal forecast for 2019-2023 is not prepared at the level of detail necessary to support a rate case,

- While the forecast includes typical regulatory adjustments, we have not attempted to remove one-time effects or other one-time adjustments that are not specifically known at this time,

- We have made no assumptions of a rate case filing schedule over this period; the forecast provided assumes full recovery of annual deficiencies, suggesting a full rate case annually, and

- All factors of the Cost of Capital, including debt rates, return on equity, and debt-equity ratios, are subject to change over the period.

III. ESTIMATED RATE IMPACTS BY CLASS PER YEAR

After determining the incremental revenue requirement impacts from the Preferred Plan and Reference Case for the Minnesota jurisdiction, we determined *class* revenue requirement impacts. We provide the estimated impacts below, then discuss the methodology and calculations that we used. The incremental revenue requirement impact of the Preferred Plan versus the Reference Case is shown in column 3 of Table 6-1 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.

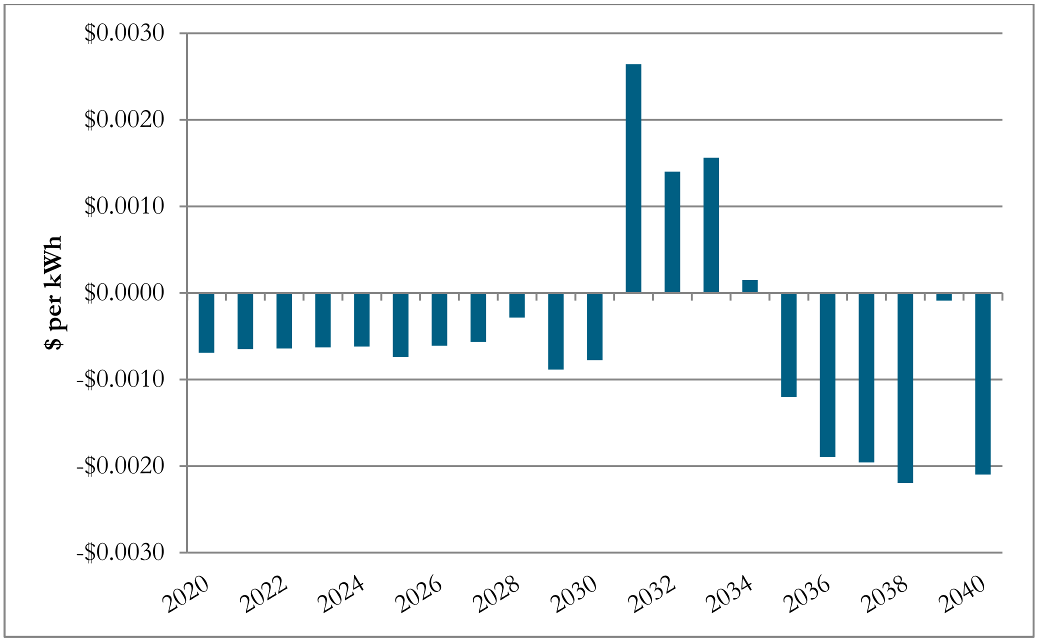
We calculated rate impacts in $ per kWh by dividing each class's revenue requirement in each year by the forecasted sales in each year.

**Table 6-1: Estimated Incremental Impact of Preferred Plan
State of Minnesota – All Customers**

1	2	3	4
Year	**State of MN Total Revenue Req ($000)**	**Incremental Impact of Preferred Resource Plan** ($000)	**Incremental Impact (%)**
2019	$3,241,019		
2020	$3,309,662	-$20,307	-0.61%
2021	$3,407,431	-$18,905	-0.55%
2022	$3,531,080	-$18,646	-0.53%
2023	$3,567,006	-$18,163	-0.51%
2024	$3,614,422	-$17,880	-0.49%
2025	$3,662,468	-$21,259	-0.58%
2026	$3,711,153	-$17,597	-0.47%
2027	$3,760,484	-$16,389	-0.44%
2028	$3,810,472	-$8,389	-0.22%
2029	$3,861,124	-$26,054	-0.67%
2030	$3,912,450	-$22,932	-0.59%
2031	$3,964,457	$78,174	1.97%
2032	$4,017,157	$41,948	1.04%
2033	$4,070,556	$47,089	1.16%
2034	$4,124,665	$4,568	0.11%
2035	$4,179,494	-$36,862	-0.88%
2036	$4,235,052	-$58,945	-1.39%
2037	$4,291,348	-$61,023	-1.42%
2038	$4,348,392	-$68,746	-1.58%
2039	$4,406,195	-$2,809	-0.06%
2040	$4,464,766	-$66,728	-1.49%

We visually portray this information in Figure 6-4 below.

Figure 6-4: Incremental Rate Impact of Preferred Plan
State of Minnesota – All Customers



A. Methodology and Calculations

We determine class revenue requirement impacts by allocating incremental costs to rate classes for each year in the planning period (2020-2034). After costs are allocated, we then calculate revenue requirement impacts for each customer class.

We apply ratemaking treatments to expense items that are impacted by the Resource Plan, as follows:

- Fuel Costs
- Purchased Energy
- Production O&M Expenses
- Property Taxes
- Deferred Income Taxes
- Tax Depreciation and Removal Expense,
- Decommissioning Accruals
- Plant In Service and Associated Depreciation, Construction Work in Progress (CWIP), and Accumulated Deferred Income Taxes

- Bulk Transmission Costs

We discuss our treatment of these expense items for purposes of this rate impact analysis below.

B. Fuel Costs and Purchased Energy

Fuel and purchased energy costs are allocated to classes using the E8760 energy allocator approved in our most recent Minnesota rate case, as provided below:[7]

Table 6-2: E8760 Energy Allocator

MN	Residential	Commercial Non-Demand	C&I Demand	Lighting
100.00%	29.27%	3.04%	67.24%	0.44%

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.

C. Production Expense, Property Taxes, Deferred Income Taxes, Tax Depreciation and Removal Expense and Decommissioning Accrual

These expense items 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.[8] We provide the approved plant stratification analysis that we applied to production O&M expenses for each plant type below:

[7] See Docket No. E002/GR-15-826, *In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota*, FINDINGS OF FACT, CONCLUSIONS, AND ORDER, (June 12, 2017).
[8] *Id.*

Table 6-3: Stratification Analysis by Plant Type

Plant Type	Replacement Value $/kW	Capacity Ratio	Capacity/Demand Percentage	Energy Percentage
Combustion Turbine	$825	$825 / $825	100.0%	0.0%
Fossil	$2,089	$825 / $2,089	39.5%	60.5%
Nuclear	$4,286	$825 / $4,286	19.3%	80.7%
Combined Cycle	$1,079	$825 / $1,079	76.5%	23.5%
Wind	$15,847	$825 / $15,847	5.2%	94.8%
Solar	$8,182	$825 / $8,182	10.1%	89.9%

The plant stratification approach begins by comparing the replacement cost of each type of generation plant (fossil, combined cycle, nuclear, etc.) to the replacement cost of a CT. CT 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 a CT 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.

After production O&M costs originating from each type of generation plant are split into capacity-related and energy-related components based on the percentages shown in Table 6-3 above, those costs that have been classified as being energy-related are allocated to class using the E8760 energy allocator provided in *part 1* above.

The capital costs that have been classified as being capacity- or demand-related are allocated to customer class using the D10S capacity allocator approved by the Commission in our most recent rate case.[9] The D10S allocator is simply each class's load that is coincident with the NSP system peak load. We provide the approved D10S class allocator percentages below:

Table 6-4: D10S Capacity Allocator

MN	Residential	Commercial Non-Demand	C&I Demand	Lighting
100.00%	36.14%	3.28%	60.59%	0.00%

[9] *Id.*

D. Generation Rate Base Costs Including Plant in Service, Depreciation, CWIP and Accumulated Deferred Income Taxes

Rate base related costs from each type of generation plant are also split into energy-related and capacity/demand-related components using the Company's plant stratification analysis approved in our most recent Minnesota rate case.[10] As was true with the expense items listed in *part 2* above, rate base costs classified as being energy-related are allocated to class using the E8760 energy allocator. Likewise, the capital costs that have been classified as being capacity or demand-related are allocated to customer class using the D10S capacity allocator.

E. Bulk Transmission Costs

As ordered by the Minnesota Commission, all rate base and expense items related to bulk transmission are classified as being capacity or demand-related and are allocated to customer class using the Commission-approved D10S capacity allocator.[11]

IV. DETERMINING CLASS RATE IMPACTS

In order to show the estimated impacts of the Preferred Plan on customer rates and bills, we provide a breakdown by customer class for the 2020-2040 period, and in more detail for the immediate five-year 2019-2023 period at the Minnesota customer class levels.

Figure 6-5 below shows the estimated incremental impacts of our Preferred Plan over the long-term by customer class.

[10] *Id.*
[11] *Id.*

Figure 6-5: Incremental Rate Impact of Preferred Plan by Customer Class – State of Minnesota

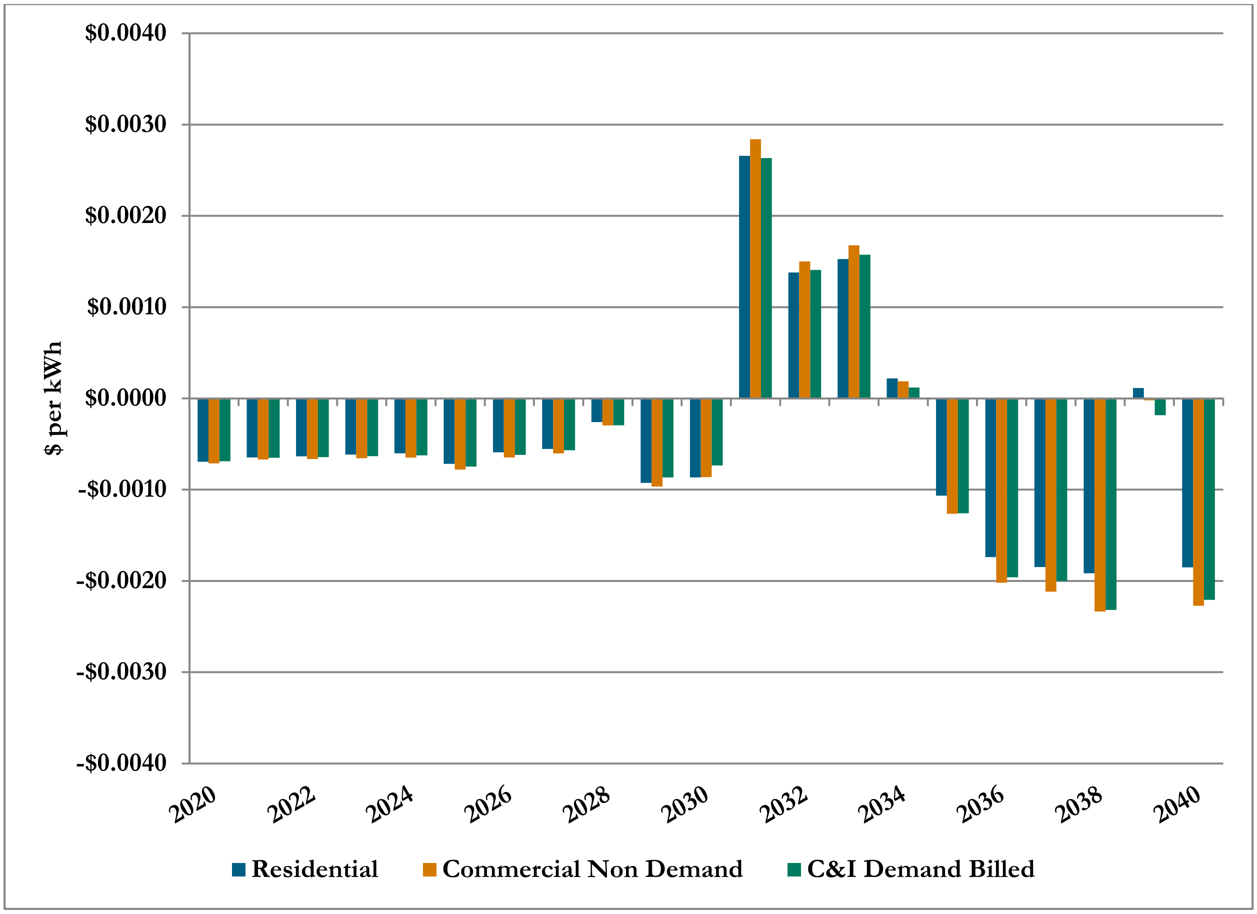


Table 6-5 below provides a more detailed view of near-term estimated rate impacts for Minnesota customer classes.

Table 6-5: Preferred Plan Estimated Rate Impacts by Class per Year

Rate Class Impacts \1	2019	2020	2021	2022	2023	2024	Comp'd Incr/Yr
Residential (avg rate, ¢/kWh)	14.488¢	14.367¢	14.506¢	14.847¢	15.377¢	15.526¢	N/A
Cumul Increase (¢/kWh)		-0.121	0.018	0.359	0.889	1.037	N/A
Cumulative Increase (%)		-0.84%	0.12%	2.48%	6.14%	7.16%	1.39%
$ Impact/Month, @ 650	($0.79)	$0.11	$2.33	$5.78	$6.74	N/A	N/A
Sm Non-Dmd (avg rate, ¢/kWh)	13.218¢	13.218¢	13.167¢	13.511¢	13.946¢	14.599¢	14.855¢
Cumul Increase (¢/kWh)		-0.052	0.293	0.727	1.380	1.636	N/A
Cumulative Increase (%)		-0.39%	2.22%	5.50%	10.44%	12.38%	2.36%
$ Impact/Month, @ 1,000	($0.52)	$2.93	$7.27	$13.80	$16.36	N/A	N/A
Demand (avg rate, ¢/kWh)	9.370¢	9.300¢	9.707¢	10.040¢	10.471¢	10.570¢	N/A
Cumul Increase (¢/kWh)		-0.070	0.336	0.669	1.100	1.199	N/A
Cumulative Increase (%)		-0.75%	3.59%	7.14%	11.74%	12.80%	2.44%
$ Impact/Month, @ 37,500	($26.30)	$126.15	$250.98	$412.56	$449.71	N/A	N/A
Street Ltg (avg rate, ¢/kWh)	25.290¢	25.027¢	24.668¢	24.917¢	25.624¢	26.079¢	N/A
Cumul Increase (¢/kWh)		-0.262	-0.622	-0.372	0.334	0.790	N/A
Cumulative Increase (%)		-1.04%	-2.46%	-1.47%	1.32%	3.12%	0.62%
$ Impact/Month, @ 60	($0.16)	($0.37)	($0.22)	$0.20	$0.47	N/A	N/A

Using the methodologies described above, the incremental costs in the last year of the period (2024) for the Preferred Plan would be expected to increase the average Residential rate by about 1.39 percent on a compounded annual basis through 2024. That is equivalent to a total increase of $6.74 per month above the current rate level.

The impact to the average Large Demand Billed rate would be an increase of about 2.44 percent on a compounded annual basis through 2023, which is equivalent to an increase of 1.199 cents per kWh above the 2019 level.

V. FACTORS IMPACTING NEAR-AND LONG-TERM RATE ESTIMATES

We note that the following factors could have an impact on the estimated rate impacts in the planning period:

Depreciation Expense for Coal Closures. The modeling and estimated rate impacts reflect accelerated depreciation associated with the early retirement of the Allen S. King and Sherco Unit 3 plants. This is consistent with the Company's current method of recovery for Sherco 1 and 2. As noted previously, however, and consistent with the Commission's actions in the approval of the early shutdown of the Benson biomass plant, a regulatory asset is another tool that could be used to accompany these early retirements. An alternative regulatory treatment such as this would impact this analysis.

Generation Ownership: Owned and Purchased Power Agreement resources will have different cost patterns, which will impact this analysis to the extent a resource addition differs in terms of ownership from what was modeled.

Taxes. This analysis is based on present tax conditions. Any tax changes will impact the modeling underlying this analysis and thus the rate impact results.

Nuclear Decommissioning Trust. There are several items regarding the NDT that may have a material impact on costs included in this resource plan.

Pending or Future Regulatory Decisions. Rate case and resource acquisition outcomes have the potential to impact rates and system needs.

Large Customer Changes. The loss or addition of a large business customer has the potential to impact both rates and system needs.