414 Nicollet Mall
Minneapolis, MN 55401

March 29, 2019

—Via Electronic Filing—

Daniel P. Wolf
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101

RE: REPLY COMMENTS
ACQUISITION OF THE MANKATO ENERGY CENTER (MEC)
DOCKET NO. IP6949, E002/PA-18-702

Dear Mr. Wolf:

Northern States Power Company, doing business as Xcel Energy, submits to the Minnesota Public Utilities Commission the enclosed Reply Comments regarding the Company's Petition seeking approval to acquire from Southern Power Company the Mankato Energy Center.

We have electronically filed this document with the Minnesota Public Utilities Commission, and copies have been served on the parties on the attached service lists. Please contact me at bria.e.shea@xcelenergy.com or (612) 330-6064 if you have any questions regarding this filing.

Sincerely,

/s/

BRIA E. SHEA
DIRECTOR, REGULATORY & STRATEGIC ANALYSIS

Enclosures
c: Service List

STATE OF MINNESOTA BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Dan Lipschultz	Vice Chair
Matthew Schuerger	Commissioner
Katie J. Sieben	Commissioner
John A. Tuma	Commissioner

IN THE MATTER OF THE PETITION OF XCEL ENERGY FOR APPROVAL OF THE ACQUISITION OF THE 375 MW MANKATO ENERGY CENTER AND THE 345 MW MANKATO ENERGY CENTER II

DOCKET NO. IP6949, E002/PA-18-702

REPLY COMMENTS

INTRODUCTION

Northern States Power Company, doing business as Xcel Energy, submits to the Minnesota Public Utilities Commission these Reply Comments regarding the Company's Petition seeking approval to acquire from Southern Power Company the Mankato Energy Center.

At the outset, we want to thank the International Brotherhood of Electrical Workers Local Union 949 (IBEW), the Laborers International Union of North America – Laborers District Council of Minnesota and North Dakota (LIUNA), the City of Mankato, Greater Mankato Growth, Inc., Mankato Building and Construction Trades Council, and Southern Power Company for their comments supporting our proposed transaction. While some of these organizations recognized the environmental benefits of the water reclamation project within the plant, and others recognized our constructive approach to partnering with the Local Union in order to drive benefits for our customers and the state—all of these commenters agreed that the proposed transaction will bring benefits to all customers over the long term as well as stability to the facility, the workers, and the region.

We likewise appreciate other stakeholders' review of our Petition, and we respond to the various issues raised in their comments in this reply. We also provide a substantial supplement to our Strategist modeling in response to the Department of Commerce's ("Department") Comments and its observation that our high renewables scenario represents the more likely future in light of our ambitious carbon reduction goals. We now provide a full set of Strategist scenarios and sensitivities that reflect a high-renewable and low-carbon future. We also provide scenarios that limit the plant's operating life to 2050 and 2040, respectively, and provide a number of other scenarios and additional in response to the Department's comments, as well as comments from the Office of Attorney General, the Sierra Club, the Xcel Large Industrials, the City of Minneapolis, and other stakeholders.

Our modeling results demonstrate that, by acquiring MEC, the Company can achieve benefits for its customers under a wide variety of resource planning outcomes. These outcomes include not only a 2054 retirement as proposed in our initial petition, but also an earlier 2050 retirement. In fact, our modeling demonstrates that we expect to achieve $124 million of savings on a present value of revenue requirements (PVRR) basis and $90 million of savings on a present value of societal costs (PVSC) basis by acquiring MEC and running it until just 2050 (four years before the end of its useful life). We have also included a scenario that includes—as an example—the accelerated retirement of two coal units by 2030, and our ownership of MEC in that scenario enables the Company to achieve $51 million in benefits on a PVRR basis and $337 million of benefits on a PVSC basis. These results provide strong support for the Company's proposal to acquire MEC, as they demonstrate that the Company's ownership of MEC reduces the system costs associated with early coal retirements on both a PVSC and PVRR basis and is also likely to displace some of the combustion turbine additions contemplated in previous resource plans. Our MEC proposal, in other words, enables greater resource planning flexibility as we continue our transition away from coal in pursuit of nation-leading carbon reduction goals.

We see other benefits associated with our ownership of MEC beyond just the economic modeling. First, ownership mitigates future risks related to expiration of the MEC I Power Purchase Agreement ("PPA"), and that additional certainty provides a hedge against future capacity costs while also creating opportunities to evaluate accelerated coal retirements. Second, ownership creates broad flexibility with respect to future resource planning that is not provided under a PPA. Any third-party purchaser will likely run both units for the full duration of their useful lives (that is, into and through the 2050s). Xcel Energy's ownership brings the decision of how to run the plant and how long to run it within the control not only of the Company and the Commission but also our stakeholders, who play an integral role in our resource planning process. With this in mind, we also included a Strategist modeling scenario based on an aggressive 2040 retirement date for MEC. Those modeling results show that we can retire the plant a full 14 years earlier than the anticipated operational life for a very modest incremental cost of $25 million on a PVRR basis. We view these results—in combination with the results showing benefits associated with a 2050 retirement—as providing a substantial amount of resource planning flexibility to the Company and our stakeholders as we move into the 2030s and 2040s.

An important input to our modeling results is the purchase price of $650 million. As stated in our initial petition, this price is comparable to other combined cycle purchases we have seen in this region and is only about $100 million more than the present value of our capacity payment obligations under the PPAs. And we are obtaining significantly more from this transaction than just the capacity values contemplated in the PPAs. Based on recent studies from the MISO interconnection queue process, we value the transmission interconnection rights alone to be worth somewhere between $100 million and $370 million on a net present value basis, and these interconnection rights are in addition to the benefits shown in our Strategist modeling. We also expect to receive—at a minimum—between $25 and $35 million in capacity value from MEC between the time the PPAs would otherwise expire and 2050. In total, then, these value streams—when added to the $550 million in capacity payments under the PPAs—amount to approximately $675 million to $955 million in net present value without even taking into account additional value streams associated with the plant such as the value of dispatch/energy. We therefore see consistency among the comparable market data, our Strategist modeling, and our analysis of the value streams associated with the plant—all of which suggest that the purchase price contemplated in our transaction is reasonable.

Finally, we want to clarify at the outset that we had no intention of sidestepping the Integrated Resource Planning process in connection with this transaction. The timing of our MEC petition was driven entirely by Southern Power's decision in late 2018 to sell MEC as part of its broader strategy to raise capital. Following our initial discussions with Southern Power in August of 2018, it became clear that MEC was going to be sold in the coming year. And as the Department notes in its comments, our PPAs contain a right of first offer, allowing the Company to make an offer before Southern Power could put the plant out for bid. In light of that, the Company quickly undertook efforts to explore the costs and benefits associated with our purchase of the plant in comparison to some other third party purchasing the plant and stepping into Southern Power's role under the relevant PPAs. That modeling—along with the modeling in our initial Petition and this Reply—all demonstrate that we can secure benefits by purchasing the plant relative to continuing with a PPA structure. We therefore brought this petition forward and are reaffirming our request for Commission approval.

For these reasons, and those discussed later in these reply comments, we continue to believe that our MEC proposal will result in customer benefits, is in the public interest, and merits Commission approval. We respond to the remaining issues raised by stakeholders in the balance of these reply comments.

Reply Comments

I. TIMING & RELATION TO IRP

Various stakeholders have expressed concern with the timing of our MEC proposal in relation to our upcoming 2019 IRP. As discussed above, the timing of our proposal was driven by the opportunity itself. We learned that Southern Power intended to sell MEC in late 2018, and we had a limited time to evaluate a potential transaction and negotiate an agreement with MEC before they moved forward with selling the plant to a third party. Because MEC was an existing resource on our system, we did not anticipate this transaction in our 2015 IRP; nor did we contemplate it as part of our five-year action plan in that proceeding. This does not preclude the Company from moving forward with the transaction and bringing it to the Commission for approval between IRPs.

Minnesota's integrated resource planning process is critically important to ensuring that the Company's plans are informed by the desires and policies of our customers, stakeholders, the Commission, and the state. We believe it is unreasonable, though, to expect the Company to make acquisition decisions in a changing market and industry in perfect lockstep with an IRP process that takes two years to complete and occurs only a few times each decade. The Company must retain some amount of flexibility to respond to opportunities that were not anticipated in prior IRPs and present themselves between or during IRP proceedings—particularly when those opportunities are expected to benefit customers and are consistent with the Company's general resource planning objectives.

We agree with the Department's view of IRPs as discrete proceedings that happen at a point in time and are generally relied upon until the next one occurs. Indeed, acquisition proceedings nearly always occur outside the IRP process. As part of those acquisition proceedings, the Department typically compares the resource planning analysis in support of the acquisition with the latest IRP analysis. If updates are required, a limited re-analysis is performed. We have performed that re-analysis in this docket (as supplemented in these Reply Comments), and we therefore view this proceeding as similar to the 2013 wind dockets referenced by the Department.

Some parties have recommended that the Commission deny the Company's petition without prejudice and allow (or even require) the Company to re-propose the MEC transaction as part of its upcoming 2019 IRP. This is not possible. We have always understood (and recently reconfirmed) that if closing of this transaction is delayed beyond the termination date of September 27, 2019, Southern would exercise its rights under the Membership Interest Purchase Agreement ("MIPA") to terminate that agreement and then seek an alternative purchaser of the Mankato Energy Center as soon as possible. Under this scenario, we believe it is virtually certain that another third-party power producer would take ownership of MEC, that the plant would remain outside the Commission's oversight, and that it would likely operate well into the 2050s.

Finally, our MEC proposal is consistent with our goal to achieve an 80 percent reduction in carbon emissions by 2030 and 100 percent carbon-free energy by 2050. Our 2030 goal is focused on carbon reduction because we believe this metric better aligns with stakeholder objectives and state policies. It recognizes the contribution of DSM and considers the carbon intensity of generation that remains on our system, both of which are important to evaluating the Company's progress toward a cleaner energy future. We have therefore updated our modeling to include a constraint that limits carbon emissions on our system to 80 percent of 2005 levels by 2030. We have also provided Strategist modeling data that evaluates the impact of retiring MEC in 2050 to better align with the Company's goal of achieving 100% carbon-free energy by 2050. Those Strategist results continue to show significant net savings over the PPA base case even with a 2050 retirement date, as detailed later in these comments.

In fact, we believe the Company's ownership of MEC could facilitate an earlier retirement of the plant compared to third-party ownership. Our modeling shows that we can acquire the plant and retire it earlier than the end of its standard book life—all while achieving customer benefits relative to the status quo. At the same time, we believe our ownership of MEC—and the certainty it brings with respect to capacity in the 2020s and 2030s—will enable the Company to reduce the system impacts associated with retiring one or more existing coal units earlier than currently planned.

MEC, in other words, represents a bridge resource for the Company and our customers. It can facilitate our transition away from coal generation in the 2020s; it serves to mitigate our need for gas peaking resources; and it will provide critical backup generation to facilitate our continued addition of renewable (and intermittent) resources as we pursue our goal of achieving an 80% reduction to carbon emissions by 2030. Finally, it can be cost-effectively retired in the 2040s, as new technology develops and enables our ultimate achievement of 100% carbon-free energy by 2050. We therefore view our proposal as squarely consistent with, and integral to, our nation-leading carbon reduction goals.

II. TRANSACTION PROCESS & COST

Some stakeholders have also expressed concern regarding the process we used to determine that the MEC purchase was in our customers' best interest and the overall cost of the transaction. As a general matter, we agree with the Department's comment that "[o]verall, a well-run bidding process should create the best result for ratepayers in instances where a competitive market exists."[1] We have run such bidding processes to positive effect, for example, in our 1,550 MW wind portfolio docket.

The Company also agrees, however, with the Department's statement that other considerations should be taken into account when evaluating our process for acquiring MEC.[2] These include the fact that the Company did not set out to acquire a new combined cycle resource to address a need that was identified in prior resource plan. Rather, MEC is an existing resource on the Company's system, and it came to our attention in late 2018 that Southern Power intended to sell the plant. In this way, our MEC proposal presented a one-off opportunity to secure ownership over a resource that is already an integral part of our system and that the Commission has approved in prior resource planning and acquisition dockets. There simply was no opportunity to run a competitive bidding process under these circumstances, as Southern Power would have sold the plant to a third party had we not moved forward with the negotiations and agreement that is currently before the Commission.

Additionally, as noted by the Department, the Company has a right of first offer in the MEC II PPA, which was approved by the Commission. Of course, that does not mean the Commission must approve our proposal, but we believe it does mean the Company arrived at the transaction and our proposal in an appropriate fashion that is consistent with prior Commission Orders. It is also important to note that our right of first offer differs significantly from a right of first refusal. It simply provided the Company with the opportunity to make an offer for MEC before Southern Power solicited third-party offers for the plant. It does not give the Company any right to purchase the plant following Southern Power's solicitation of third-party offers.

With respect to the cost of the transaction, we noted in our initial petition that the $650 million purchase price for the plant was within approximately $100 million of just the capacity payments Xcel Energy would owe under the existing PPAs (on a present value basis). We also noted that the purchase price breaks down to $855/kW, and we provided an analysis of comparable transactions that ranged from $827/kW (for the Riverside Energy Center) to $1,333/kW (for the recently approved Nemadji Trail Energy Center). We have since identified three additional transactions involving the acquisition of combined cycle facilities by utilities. These include:

[1] Department Comments at 29.
[2] Department Comments at 29.

- The 2015 acquisition by AltaGas of 523 MW of combined cycle generation for a total cost of $642 million ($1,228/kW);
- The 2015 acquisition by PSEG Power of the 755 MW Keys Energy Center for $850 million ($1,126/kW);
- The 2011 acquisition by American Municipal Power of the 724 MW Fremont facility for $526 million ($726/kW).

Notably, all of those transactions—as well as Riverside and the Fox Energy Center referenced in our initial petition—occurred prior to passage of the TCJA. That is important because the TCJA's reduction to the corporate tax rate effectively increases the value of existing PPAs that have pricing predating the tax change. In other words, any plant with a pre-TCJA PPA in place became substantially more valuable following passage of the TCJA. We would therefore expect to see an increase to the purchase price for these plants if those transactions were to occur in today's tax environment. We believe these market data points are an important factor in determining that the price of our MEC acquisition is reasonable.

We also note that LSP-Cottage Grove, L.P. (LSPCG) filed comments arguing that its facility represents a better purchase opportunity for customers than MEC. That is simply not true. Back in 1994, the Company entered into a 30 year power purchase agreement for the output of the Cottage Grove facility, and the contract is scheduled to expire in September 2027. While it is true that Cottage Grove is also a combined cycle resource under PPA to the Company, there are also a couple key differences that make the Mankato facility a much more valuable resource. First, Cottage Grove and MEC are markedly different facilities in terms of vintage, operational life expectancy, and efficiency; and MEC's more efficient operations contribute to higher customer benefits. Second, and more importantly, the Cottage Grove PPA was structured with higher fixed capacity costs in the front end of the contract and lower fixed capacity costs in the back end. The high front-end capacity payments ended in 2017, and the Company is now making fixed capacity payments for Cottage Grove via the PPA that are *much lower* than what the Company is paying to Southern Power for fixed capacity. In short, then, the Company and its customers have just recently reached the final 10 years of the PPA, when the pricing structure flips strongly in favor of customers who have paid higher capacity payments over the first 20 years of the contract. As a result, the value associated with avoided capacity cost (*i.e.,* avoided PPA payments) for the Cottage Grove facility is materially lower than the $555 million in net present value for avoided capacity payments identified in our MEC petition. In fact, continuation of the current PPA with LSPCG provides our customers with a very low cost capacity resource for the duration of our contract and allows them to enjoy the benefit of the long-term bargain we struck more than 20 years ago.

Some stakeholders have also expressed concern over the $100 million difference between our capacity payment obligations under the PPA and the purchase price, but we are obtaining significantly more from his transaction than just the capacity values contemplated in the PPAs. Based on recent studies from the MISO interconnection queue process, we value the transmission interconnection rights alone to be worth somewhere between $100 million and $370 million on a net present value basis.[3] Moreover, we expect to receive—at a minimum—between $25 and $35 million in capacity value from MEC between the time the PPAs would otherwise expire and 2050. In total, then, these value streams amount to approximately $675 million to $955 million (including the PPA capacity payments) in net present value without even taking into account additional value streams associated with the plant such as the value of dispatch/energy. In short, we believe our purchase price is supported not only by comparable market data but also by our Strategist modeling and an analysis of the value streams associated with the plant.

However, the market data and value streams discussed above are only part of the confirmatory information in support of the MEC purchase price. Our Strategist modeling is another important data point that supports the reasonableness of the MEC purchase price. As already discussed, the existence of long-term PPAs are a critical factor in determining the value of a power plant like MEC because the PPAs represent a fixed revenue stream associated with owning and operating the plant. As discussed in our initial Petition, we used Strategist to compare Company ownership versus continuation of the existing PPAs using highly conservative modeling assumptions for demand response and energy efficiency. In effect, then, our Strategist analysis provides a comparison between the purchase price and benefits associated with ownership versus the benefits and costs under the existing PPAs. The fact that our modeling shows customer benefits associated with ownership under a wide variety of resource planning scenarios demonstrates that the Company is paying a reasonable price for the plant.

[3] Given the status of the MISO queue and recent study results from the February 2017 DPP suggesting that major upgrade costs are likely on the horizon, resources with existing interconnection rights provide substantial value in that they allow the Company to avoid the transmission upgrade costs associated with new greenfield resources. Depending on the specific resource assumed to replace the MEC contracts, the implied value of the 740 MW of MEC resource interconnection rights amounts to somewhere between approximately $100 million (assuming solar replacement at $140/kW) to $370 million (assuming greenfield CC replacement at $500/kW).

III. RISKS & MITIGATION

Stakeholders also expressed concern that the Company's ownership of MEC would shift certain cost risks to customers, whereas the current PPAs assign those risks to Southern (or any future owner of the plant). These include risks associated with stranded assets, decommissioning, plant outages, property taxes, and O&M expenses. We certainly acknowledge that ownership and PPA structures come with different bundles of risks and benefits. We discussed these risks and benefits in detail throughout the course of our 2017 and 2018 wind acquisition proceedings.

PPAs, for instance, are for a specific term (20 years in the case of each MEC unit) that is generally shorter than the useful life of the facility. At expiration, the Company must return to the marketplace to procure replacement energy and capacity a price that will be based on a number of factors such as future capital costs, transmission costs, market prices for electricity, and taxes, among other things. Under utility ownership, by contrast, the Company and its regulators have more flexibility in determining how long to operate the plant and are less exposed to changing market conditions. Through ownership of generating assets, the Company can also reduce its reliance on PPAs, which are viewed by creditors and rating agencies as additional debt on the utility's balance sheets. At the same time, as the Department notes, ownership comes with certain operational and retirement-related risks.

Here, we believe the benefits of owning MEC materially outweigh the risks that coincide with utility ownership. First, we respectfully disagree that the benefits associated with ownership versus the PPAs are similar. Our updated Strategist modeling demonstrates that we expect customers to enjoy well more than $100 million in benefits on a present value of revenue requirements basis. These benefits are significant, particularly in the context of a single-plant transaction involving two units that are already subject to PPAs with the Company. Likewise, there are a number of benefits associated with ownership that are not captured by our Strategist modeling. These include the certainty associated with securing an important capacity resource through the 2020s and 2030s, compared to having the MEC I PPA expire in 2026. Additionally, the Company can achieve additional resource planning flexibility to securing ownership over MEC, allowing the Company (in cooperation with the Commission and our stakeholders) to determine how long MEC should remain part of Minnesota's resource mix, and how it should operate within our generation portfolio. Finally, as discussed above, our Strategist modeling does not account for the $100-$370 million of transmission interconnection rights valued on a net present value basis.

That said, we appreciate the Department's concern that ownership also comes with certain risks that are not necessarily captured by Strategist. We believe two of the identified risks—related to stranded assets and property tax expenses—have already been sufficiently mitigated. With respect to property taxes, we have undertaken substantial efforts to ensure that we will qualify for the same property tax exemptions that applied to Southern' s ownership of MEC. Moreover, we have experience applying for, and receiving, the same exemption at other sites. We therefore do not see any significant risk associated with our ability to receive favorable property tax treatment.

With respect to the risk of stranded assets, we believe our updated Strategist modeling should address many of these concerns by demonstrating that the transaction is cost effective even if we retire the plants earlier than stated in our initial Petition. More specifically, our modeling shows that the combination of Company ownership and a 2050 retirement of the plant still results in $124 million of customer benefits on a PVRR basis and $90 million of customer benefits on a PVSC basis. Even if we were to retire the plant in 2040—a full 14 years earlier than the anticipated operational lives we relied on in our initial petition—the incremental cost is only $25 million on a PVRR basis. This is a very modest incremental cost associated with an aggressive retirement scenario. And should that aggressive scenario ultimately come to pass, the Commission would have full authority to determine how best to deal with the remaining plant balance in an equitable fashion. We therefore believe our modeling results demonstrate that the Company's ownership of MEC will provide the Company—as well as the Commission and our stakeholders—a significant degree of flexibility to determine how long MEC should operate as part of the Company's (and the state's) generation fleet.

With respect to the remaining two risks—operating and decommissioning costs—we believe the estimates used in our modeling are reasonable and in line with both industry standards and the Company's experience in operating similar combined cycle plants. Specifically, the Company worked to ensure that our estimates of O&M and ongoing capital at the facility were in line with our experience operating the High Bridge and Riverside plants on our system. We also validated fixed costs (plant gas, electricity, fixed labor, tax, insurance, etc.) and variable costs (chemicals, consumables, water) using diligence information provided by Southern Power related to its ownership of Mankato. In short, we believe our cost projections are consistent not only with our own experience in the industry and operating similar plants but also with Southern Power's own experience in operating MEC itself.

Some of our stakeholders have questioned the variable cost savings shown in our modeling as a result of taking ownership over MEC, suggesting that this particular category of savings appears to be unreasonably high or lacking support in the record. However, the delta in variable costs between the PPA pricing scheme and Company ownership is likely due to the different way in which costs get categorized under Company ownership versus the PPA pricing structure. In other words, a direct one-to-one comparison of the cost categories between ownership and the PPA pricing structure has limited value in determining the reasonableness of either the PPA costs or the Company's costs of ownership. Instead, we believe total costs (fixed and variable) should be comprehensively assessed when comparing the PPAs to Company ownership, and this is exactly what we have done in our Strategist modeling to support the Company's petition.

That said, if the Commission has concerns regarding our long-term cost assumptions for MEC, it has a variety of tools to deal with those issues. First and foremost, the Commission will maintain oversight of our costs to operate and eventually decommissioning the plant, and always has the authority to evaluate the prudence of those costs in the context of a rate case or similar proceeding. We understand that in making that evaluation, the Commission may look back to our projections in this petition. Likewise, the Commission could order the Company to make compliance filings regarding the operating characteristics of MEC in order to ensure that customers are receiving the approximate level of benefits we project in this petition. This is similar to the Commission's approach in our 1,550 MW wind portfolio and Dakota Range III dockets.[4] These types of reporting requirements and ongoing review should address any concerns regarding our cost projections for owning, operating, and decommissioning MEC. In short, while the Department is correct to point out that certain risks come with ownership, we believe the Commission has ongoing authority to manage those risks on behalf of customers and to ensure that the Company's analysis in this petition proves to be reasonable and appropriate.

IV. FINANCIAL ISSUES

The Department has also recommended three financial adjustments in connection with our petition related to (1) rate recovery for the $96.195 million acquisition adjustment relative to the plant's net book value; (2) a rate recovery true up for 2019 revenue requirements; and (3) rate recovery for the $450,000 in transaction costs. We address each in turn below.

[4] Docket Nos. E002/M-16-777 and E002/M-17-694.

A. Acquisition Adjustment

With respect to the acquisition adjustment, we oppose the Department's recommendation on several grounds. As the outset, we want to be clear that the Company cannot move forward with the transaction if $96 million of our purchase price is deemed unrecoverable. The transaction would not be financially viable, and we would need to exercise our right to exit the agreement under to the conditions precedent for regulatory approvals. In light of this, we believe that evaluation of our proposal should focus on whether the transaction as a whole will result in customer benefits and is in the public interest rather than on a financial adjustment that would override this broader analysis.

We also oppose the policy underlying the Department's recommendation on this issue. While the Department is correct to point out that FERC accounting rules require the Company to record the plant's net book value separately from the remainder of the purchase price (*i.e.,* the "acquisition adjustment"), those rules do not preclude the Company from recovering the total amount of its investment.[5] Nor should they. Market conditions change over time. Fuel and energy prices shift with changing market conditions and so too does the value of generating plants like MEC. This is particularly true when large systemic changes in market conditions occur, such as the passage of the TCJA in 2018, which effectively increased the value of plants that had long-term PPAs in place with pricing that was based on a 35% corporate tax environment. There is little reason, then, to assume that fair market value for a plant should be tied to net book value, and little reason to disincentivize the Company from seeking out beneficial transactions simply because the asset in question is already in service. Indeed, net book value reflects the original cost to construct a plant—not what a plant might be valued at in today's market. A plant's value is a product of its generating characteristics, its expected life, its operating costs, and its projected revenues either from PPAs or expected market sales, among other things.

There is also no Minnesota law or rule prohibiting the Company from recovering the full cost of the MEC transaction. As the Department noted in comments, Minnesota Statute 216B.16, Subd. 6 states in relevant part:

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[5] FERC rules also require the Company to recognize acquisition date accumulated depreciation of MEC consistent with Southern Power's financial statement. And since the transaction was executed, Southern Power—in conformity with GAAP—has classified the plant as "held for sale" and ceased depreciation since that date. We believe this accounting treatment is appropriate and therefore have reflected the same in our calculations of net plant, in conformity with FERC rules.

> In determining the rate base upon which the utility is to be allowed to earn a fair rate of return, the commission shall give due consideration to evidence of the cost of the property when first devoted to public use, <u>to prudent acquisition cost to the public utility less appropriate depreciation on each</u>, to construction work in progress, to offsets in the nature of capital provided by sources other than the investors, and to other expense of a capital nature. <u>For purposes of determining rate base, the commission shall consider the original cost of utility property included in the base and shall make no allowance for its current replacement value</u> (emphasis added).

While the Department emphasizes the last sentence of this provision, we believe it is highly significant that the statute instructs the Commission to consider both "the cost of the property when first devoted to public use" *and* the "prudent acquisition cost to the public utility." In this way, we believe Minnesota law explicitly acknowledges that net book value and fair market value may differ when a utility acquires a plant, and it instructs the Commission that it should consider both when determining rate base. While the final sentence quoted above (and emphasized by the Department) is obviously related, we believe that sets out a general prohibition against marking already owned assets to market for purposes of calculating rate base, which is plainly reasonable and appropriate for a rate-regulated utility.

In the case of MEC, Xcel Energy's actual original cost to acquire the plant is $650 million. While FERC accounting rules may deem a portion of this cost to be an acquisition adjustment, those rules do not change the fact that the Company must actually incur this full cost to acquire the plant. Moreover, our modeling and market analysis incorporate the $650 million purchase price and all of the value inputs associated with MEC, and it demonstrates that we can expect $124 million in PVRR benefits from acquiring the plant relative to continuing on with the PPA structure. This analysis, in other words, plainly shows that the transaction is in the public interest at the full purchase price. It also demonstrates that our acquisition of MEC is very different from a merger or acquisition of another company, where acquisition adjustments are often called into question and where the benefits of the transaction are often speculative and not subject to such rigorous and accepted analysis. As such, there is simply no justification for denying recovery for almost $100 million of that purchase price simply because FERC accounting rules deem it to be an acquisition adjustment.

If the Commission determines that the transaction is in the public interest (as we believe it should), the ultimate rates that incorporate the purchase price must, by definition, be just and reasonable. For this reason, again, we believe the Commission should focus its analysis on whether the transaction as a whole is in the public interest and not on an adjustment that prevents the Company from moving forward with the purchase.

B. 2019 Rate True-Up

Next, the Department recommends rejection of our request for an FCA variance to recover the difference between the 2019 revenue requirement resulting from the transaction and the revenues already in base rates for the capacity portions of the current MEC I and MEC II PPAs. The Department argues that the Company's request is inconsistent with rate recovery practices in Minnesota and with our multi-year rate plan (MYRP) settlement in Docket No. E002/GR-15-826. We respectfully disagree. While both the rate case paradigm and our settlement generally require the Company to weather changes to our cost of service during the course of our MYRP and until filing our next rate case, there are exceptions to this general rule. Passage of the TCJA represents one such exception, and the Commission recently ordered the Company to refund $136 million in 2018 TCJA savings to customers.

We believe our MEC proposal represents another reasonable exception. We did not anticipate Southern deciding to put MEC up for sale when we entered into our MYRP Settlement. We therefore did not factor the costs associated with taking ownership of MEC into any part of our cost of service or the terms of the settlement. When we learned that Southern did intend to sell MEC, we carefully evaluated a potential transaction and concluded that it was likely to result in customers benefits on both a PVRR and PVSC basis, as well as the various other benefits discussed earlier in these comments. We therefore believe the transaction is squarely in the public interest and will benefit our customers, stakeholders, and the state.

We are requesting an FCA variance in order to remain financially whole and to not suffer a penalty as a result of bringing this transaction forward for Commission review. The Department's recommendation, if adopted by the Commission, would dissuade the Company (and other utilities) from seeking out or responding to beneficial transactions in between rate cases. We do not think the public interest is best served by limiting our ability to pursue such opportunities in lockstep with our rate case filing schedule, nor is it served by the Company trying to forecast the number and type of such opportunities that might arise for purposes of forecasting a test year. We therefore reaffirm our request for an FCA variance to recover the difference between the 2019 revenue requirement resulting from the transaction and the revenues already in base rates for the capacity portions of the current MEC I and MEC II PPAs.

C. Transaction Costs

Finally, the Department has recommended that the Commission disallow recovery of our transaction costs, which amount to $450,000. Again, we believe this recommendation serves only to penalize the Company for having brought this transaction forward and to potentially dissuade utilities from seeking out opportunities to benefit customers in between rate cases.

The budget for our 2016 test year in our rate case was developed in mid-2015—well before we commenced discussion regarding the acquisition of MEC. We therefore did not account for the transaction or the associated legal fees when developing the 2016 test-year budget. Moreover, our rate case test-year budget included a total of $3,985,759.86 in legal fees and, of that total, only $5,000 was budgeted for outside legal services for the acquisition of assets like MEC.

Because the transaction costs for the MEC acquisition were not factored into our base rates, we believe it is reasonable and appropriate for the Company to request and recover the costs that are necessary to bring this transaction forward for Commission approval. Again, we believe the Department's recommendation would serve to dissuade the Company and other utilities from pursuing beneficial transaction in between rate cases when the costs of those transactions have not already been factored in the Company's most recent test year.

V. MODELING SUPPLEMENT

The Department raised a number of concerns with the modeling analysis provided in our initial petition. As discussed in our initial petition, the base files included the wind additions approved by the Commission and solar additions consistent with the preferred plan from our last IRP. The Department concluded the "2015 IRP Renewables" scenarios did not provide a good basis for the evaluation of MEC due to the high capacity factors of combined cycles beginning in the mid-2020s. We agree that we intend to add significantly more renewables than included in the 2015 IRP Renewables scenario. Since our last IRP, the pricing of renewables has continued to decline and we have announced aggressive carbon reduction goals.

We included the "High Renewables" scenarios in our initial petition to address these concerns. The Department agreed that the High Renewables scenarios represent a more likely future and utilization of MEC. However, the Department noted three additional concerns with the modeling. First, the Department was concerned that the distribution of hourly market prices in the "markets on" scenarios did not correspond with the likely timing of high and low Locational Marginal Prices (LMPs) in the MISO market. Second, the Department noted that we did not include the mid-point of the Commission's approved externality and future regulatory costs for carbon dioxide. Third, the Department noted that in the High Renewables scenarios we changed the commitment status of the King plant to economic beginning in 2028. We address each of these concerns below.

Finally, several parties recommended that MEC be considered as part of our upcoming IRP to be filed on July 1, 2019. As discussed above, and noted by the Department, resource acquisition proceeding are generally separate and distinct from resource planning proceedings. Moreover, the timing of our petition is driven by Southern Power's decision to sell MEC. However, we do acknowledge that we are making this filing just ahead of our 2019 IRP filing. Our request to delay that filing to July 1 was driven by multiple considerations, as detailed in our request for extension,[6] all of which have made modeling more complex and required additional time. We have held numerous stakeholder workshops on our upcoming IRP filing, including workshops on the assumptions we intend to use and scenarios we intend to consider. Since our initial filing in this proceeding, we have developed DSM and DR bundles, informed by our stakeholder interaction, to include as supply side resource as well as a battery storage alternative and DG solar alternative. We have refined our transmission interconnection costs and developed scenarios to evaluate the early retirement of our remaining coal units. We have developed load forecast sensitivities to evaluate the potential impact on our system of high levels of electrification. We plan to present our preliminary preferred plan at our upcoming April 29, 2019 stakeholder workshop. Given the significant progress we have made in the analysis to be provided in the 2019 IRP and in response to concerns raised by several parties, we provide a significant update and refinement of the modeling analysis provided in our initial petition. We discuss the updated assumptions and results below.

A. Updated Assumptions- Reply to Department

i. Market Assumptions

Our electric power market prices are developed from fundamentally-based forecasts from Wood Mackenzie, CERA and PIRA. The forecast we receive from third parties provide monthly average on- and off-peak market pricing at MN hub. The

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[6] Request for Extension – 2020-2034 Upper Midwest Integrated Resource Plan. October 15, 2018. Docket No. E002/RP-15-21.

Department noted that our average price forecasts fit their expectations. We then use that market data to create an hourly shape for each month based on the amount of thermal units generation dispatched on our system. The methodology results in lower hourly LMPs during times when significant amounts of renewable energy is on the system and higher hourly LMPs when lower amounts of renewable energy is available on our system. While we continue to believe that this methodology is reasonable and provides a conservative estimate of the cost efficiencies to be gained through MISO market interaction, we acknowledge that it may not always correspond well with the timing of high and low LMPs in the MISO market. Therefore, we provide sensitivity for all modeling runs conducted that does not allow for sales into the MISO market. By not allowing market sales, we exclude the potential for increased market revenue due our ownership of MEC. As shown below, this methodology shows that the purchase of MEC will result in benefits of $91 million on a PVRR basis and $128 million on a PVSC basis.

We also note that we updated the market purchases and sales limit to 1,350 MW in 2018, 1,800 MW from 2019-2022, and 2,300 MW in 2023 and beyond consistent with the updated assumption used in the Moraine II PPA extension.[7] When modeling market interactions, we include a limit on the maximum sales that could be made into the MISO market during hours where production exceeds our load serving requirements. Previously, we used a limit of approximately 1350 MWs based on historical data of market transactions. There have been continued investments in the transmission system, including the newly energized Badger-Coulee line connecting La Crosse, WI and Madison, WI. We will continue to evaluate changes to the limit on market transactions in future filings.

In order to develop a better estimate of a market transaction limit, we conducted PROMOD modeling using datasets from the MISO Accelerated Fleet Change MTEP scenario. PROMOD is a nodal, dispatch model that can be used to simulate the dispatch of the resources in MISO. This analysis showed the NSP system executing sales into the market of up to 2,300 MWs per hour in 2027. We have phased this limit in by increasing the limit to 1,800 MWs in 2019, after the Badger-Coulee line is in service, and up to 2,300 in 2023, when then Cardinal to Hickory Creek transmission line is expected to be come online. We believe this updated market limit provides a more accurate representation of our ability to execute market sales in the future.

Our modeling assumptions are included as Attachment A.

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[7] Docket No. E002/M-19-58

ii. *Base assumption for Carbon Dioxide externality and regulatory costs*

As discussed in our initial petition the Base PVSC assumptions included the high carbon dioxide (CO_2) externality costs through 2024 and the high CO_2 regulatory costs in 2025 and beyond – option D as approved by the Commission in its June 11, 2018 *Order*.[8] The June 11, 2018 *Order* required that:

> In all electricity generation resource acquisition proceedings during 2018 and 2019, utilities shall analyze potential resources under a range of assumptions about environmental values, including scenarios that—
>
> A. Incorporate, for all years, the low end of the range of environmental costs for carbon dioxide as approved by the Commission in its January 3, 2018 Order Updating Environmental Costs in Docket No. E999/CI-14-643, *In the Matter of the Further Investigation into Environmental and Socioeconomic Costs Under Minnesota Statutes Section 216B.2422, Subdivision 3*.
>
> B. Incorporate, for all years, the high end of the range of environmental costs for CO_2 as approved by the Commission in its January 3, 2018 order.
>
> C. Incorporate the low end of the range of environmental costs for CO_2 but substituting, for planning years after 2024, the low end of the range of regulatory costs for CO_2 regulations, in lieu of environmental costs.
>
> D. Incorporate the high end of the range of environmental costs for CO_2 but substituting, for planning years after 2024, the high end of the range of regulatory costs for CO_2 regulations, in lieu of environmental costs.
>
> Consistent with the Commission decision in the Order Updating Environmental Costs, utilities shall include at least one scenario that excludes consideration of CO_2 costs.

Since the *Order* declines to prescribe which of these scenarios to use in base assumptions, leaving this to the discretion of each utility, we selected Option D for base assumptions and initially ran just four sensitivities (Options A, B, and C plus a sensitivity that excludes consideration of CO_2 cost).

At the time of the June 11, 2018 *Order,* it was the Company's understanding that Commission direction to utilities was to analyze the impacts of CO_2 costs using just the five scenarios above. The Commission did not order a scenario using midpoints of the high and low ends of the ranges; and in Docket E-000/CI-14-643, the Commission established only Low and High CO_2 externality values, no midpoint

[8] ORDER ESTABLISHING 2018 AND 2019 ESTIMATE OF FUTURE CARBON DIOXIDE REGULATION COSTS, Docket Nos. E999/CI-07-1199 and E999/DI-17-53.

values.[9] However, in our supplemental modeling, the Company added a scenario that uses the midpoint of the approved externality values through 2024 and the midpoint of the approved regulatory costs for 2025 and beyond. The Company is open to additional direction from the Commission on the appropriate CO_2 values to include in base assumptions.

iii. Economic Commitment

The Department noted that the high renewables scenario changed the commitment status of King from must-run to economic in 2028. In our initial petition, we noted that the change in commitment status significantly reduced the capacity factor, and that the specific decisions related to early retirement of coal would be made in the IRP. We provided the High Renewables scenario to shows the impact of the proposed transfer of ownership under a high-renewable and low-carbon future. We have committed to evaluating early coal retirements for King and Sherco 3 by 2030 in our 2019 IRP. As part of our supplemental modeling we provide a scenario that analyzes the system impacts of the ownership transfer of MEC when King is retired in 2028 and Sherco 3 is retired in 2030. Additional updated assumptions used in our supplemental modeling are discussed below.

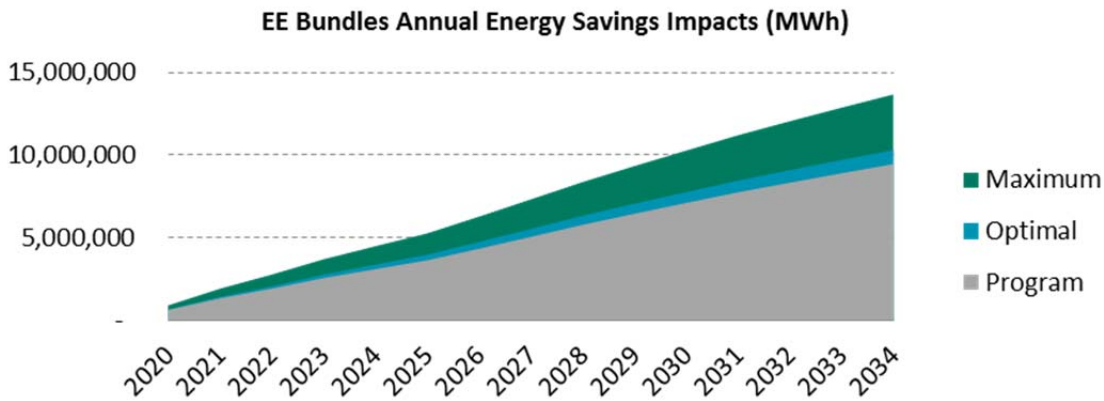
B. Updated Assumptions - Based on Expected 2019 IRP Assumptions

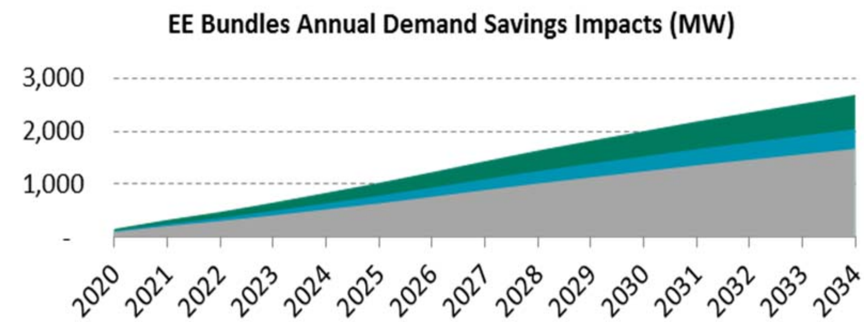
As previously discussed, several parties recommended that MEC be considered as part of our upcoming IRP. The supplemental modeling discussed below analyzes the acquisition of MEC using assumptions developed with input from stakeholders for our upcoming IRP filing. In our view, the Commission does not need to make a specific determination on the amount of demand response, demand side management, renewables additions, and/or baseload retirement dates in this proceeding. The supplemental modeling analysis is provided solely for the purpose of evaluating our proposed purchased in the context of the assumptions to be used the upcoming IRP. In other words, while the modeling continues to focus on the acquisition of MEC, the assumptions have been refined since our initial filing consistent with the work we have done in preparation for our next IRP. The updated analysis confirms that the Mankato acquisition is reasonable and prudent when judged under all of our IRP assumptions. We discuss the updated assumptions in more detail below.

[9] ORDER UPDATING ENVIRONMENTAL COST VALUES, Docket No. E999/CI-14-643. January 3, 2018. Page 30-32.

i. DSM Bundles

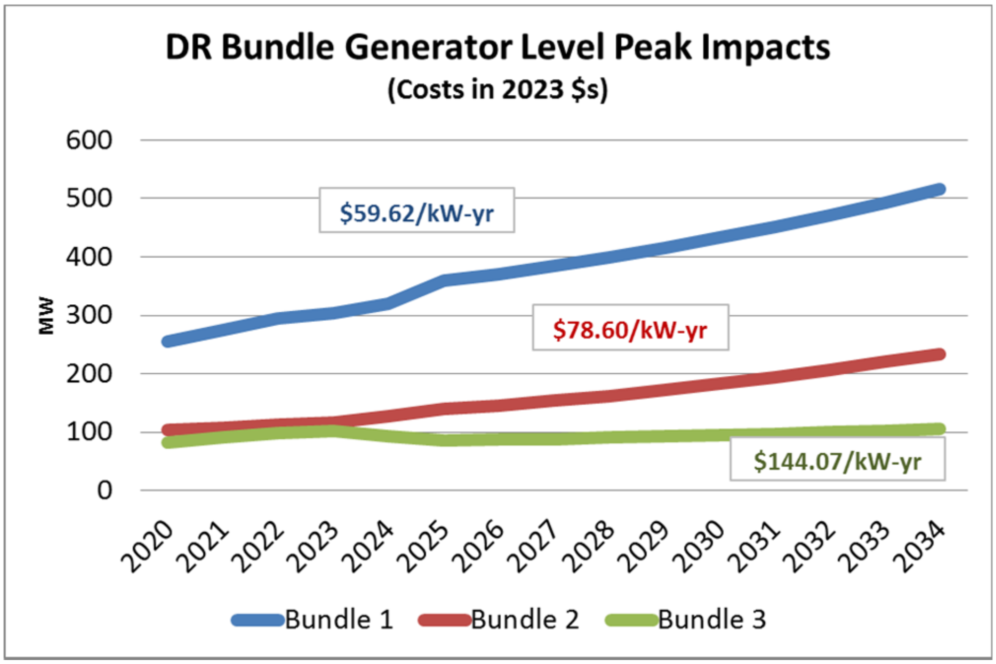
In response to stakeholder feedback through the IRP workshops, the Company developed DSM bundles to be selected in the modeling in the same way other generation resources are selected. Three bundles were developed: Program, Optimal, and Maximum. The Program and Maximum Bundles are based on 2018 Minnesota Statewide DSM Potential Study. The Optimal Bundle was developed by the Company for optimal MW avoidance. The bundles shown below are incremental to each other and are dependent on the bundle before it being selected (i.e. Bundle 2 cannot be selected if Bundle 1 isn't selected). They are included in Strategist as supply-side alternatives. The energy and demand savings impacts of the DSM bundles are shown below.





ii. Demand Response Bundles

Similar to the DSM bundles, Demand Response (DR) bundles were developed so the DR response could be treated as supply side resources in the Strategist modeling. The Base Demand Response Forecast was developed by the Company and is includes existing DR programs. Three incremental Demand Response Bundles were developed based on the Brattle Study that will be filed with IRP. The bundles are incremental to each other and are dependent on the bundle before it being selected (i.e. Bundle 2 cannot be selected if Bundle 1 isn't selected). The DR bundles are included in Strategist as supple-side alternatives. For the supplemental MEC modeling, we forced all three DR bundles into the model in order to comply with the requirement from our last IRP to add an incremental 400 MWs of DR by 2023. All else equal, additional DR reduces the remaining capacity needs of the system. Including all three DR bundles in the model provides a conservative approach to analyzing the benefits of MEC. The impacts to peak demand for each incremental DR bundle are shown below.



iii. Battery Storage

We have developed a Generic Battery Storage alternative to include as a supply side resource in the supplemental Strategist modeling. The costs of the battery storage alternative are based on bids we received in response to the all-source solicitation of our Public Service of Colorado operating company. Responses to our all-source solicitation were received in late 2017. To forecast future costs, we assumed a 10 percent improvement rate on price.

iv. DG solar alternative

In addition to the forecast of distributed solar resources included in our initial filing, we have included a supply-side alternative for distributed commercial solar and distributed residential solar. Large scale solar includes transmission delivery costs, while distributed solar does not.

v. Generic Resource Transmission Delivery Costs

Based on new information coming out of the February 2017 MISO Definitive Planning Phase (DPP) Studies, which was published in March of 2019, we have increased the transmission delivery costs associated with new greenfield generic CC, CT, wind and solar resources. The recent studies have identified significantly higher upgrade costs for projects in the February 2017 study cycle as compared to previous cycles which have prompted the Company to update these assumed costs. The table below compares the old and new cost assumptions. The 2017 DPP results help underscore the value of resources with existing interconnection rights.

Table 1: Transmission Delivery Costs

Resource Type	Old Assumption	New Assumption
CC	\$330	\$500
CT	\$100	\$200
Wind	\$200	\$400
Solar	\$70	\$140

vi. Sensitivity Combinations

In response to stakeholder feedback on the assumptions for our upcoming IRP, we have developed scenarios that combine multiple sensitives. In the MISO Transmission Expansion Plan (MTEP) planning process, futures are developed through a stakeholder process to analyze potential generation expansion plans. We have developed sensitivity combinations similar to the MISO MTEP futures. The combination sensitivities are summarized below.

Table 2: Combination Sensitivities

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	Similar to MISO MTEP Accelerated Fleet Change (AFC) Scenario	**High**	**High Load due to High Electrification Impacts**	High/High	**Low**
High Distributed Solar Deployment, Low Tech Costs	Similar to MISO MTEP Limited Fleet Change (LFC) Scenario	**Low**	**Low Load due to High DG Solar Impacts**	High/High	**Low**

For the 2019 IRP, we also plan to analyze a stress scenario to assess potential impacts of reduced capacity accreditation levels for renewable and use-limited (battery storage, demand response) resources based on effective load carrying capabilities (ELCC) and penetration levels on the NSP system.

C. Supplemental Modeling Results

Several parties noted the Company's goal to achieve an 80 percent reduction in CO_2 emissions by 2030 and aspiration to deliver 100 percent carbon-free electricity to customers by 2050 and questioned whether the acquisition of MEC was consistent with those goals.

As stated in our *Building a Carbon-free Future* report,[10] "achieving the long-term vision of zero-carbon electricity requires technologies that are not cost effective or commercially available today." We expect that technological advances may allow use to obtain value from MEC through its expected book life and beyond 2050. However, in order to analyze the impacts of a shorter book life scenario that assume a 2050 and 2040 retirement of MEC were also evaluated.

[10] See https://www.xcelenergy.com/environment/carbon_reduction_plan.

In addition, our announced goal for 2030 focused on carbon reduction rather than carbon-free generation. We believe the focus on carbon reductions aligns with stakeholder objectives and state policies, allows DSM to contribute to the goal, and considers the carbon intensity of generation that remains on our system. Therefore, in our updated modeling, we have included a constraint that limits the carbon emissions on our system to 80 percent of 2005 levels by 2030. Table 3 provides a summary of the renewables additions under each scenario, which are discussed further below.

Table 3: Renewable Additions by 2030 by Scenario

	MEC Ownership	MEC Ownership and 2040 shutdown	MEC Ownership and 2050 shutdown	MEC Ownership with Early Coal Retirement
Wind Additions (MW)	1,589	1,589	1,589	1,589
Solar Additions (MW)	3,240	3,240	3,240	4,240
Total (MW)	4,828	4,828	4,828	5,828

i. *MEC and Early Coal Retirement*

Table 4: MEC and Early Coal Retirement Cost/Savings ($000s)

	Markets Sales On		Market Sales Off	
Scenario	PVSC	PVRR	PVSC	PVRR
Base (Continuation of PPAs)	-	-	-	-
Base with Early Coal Retirement	($271)	$82	($147)	$89
MEC Ownership with Early Coal Retirement	($337)	($51)	($337)	($98)

As discussed above, we plan to analyze the impact of early coal shutdown for King and Sherco 3 in our upcoming IRP. The analysis above shows the impact of retiring King in 2028 and Sherco 3 in 2030[11] on a present value of societal costs (PVSC) and present value of revenue requirements (PVRR) basis. As compared to a base case

[11] The upcoming IRP will include further analysis of all baseload units and reliability impacts associated with various retirement scenarios.

where the existing MEC PPAs expire, early retirement of King and Sherco 3 result in savings when carbon costs are included and shown in the PVSC column. When carbon costs are not included early coal shutdown results in increased costs as shown in the PVRR column. When early coal retirement is combined with the acquisition of MEC, system costs are reduced on both a PVSC and PVRR basis with market sales on and off. These results underscore the potential value of MEC as a bridge resource that can help facilitate an early coal transition.

ii. Early Retirement of MEC

Table 5: Early Shutdown of MEC

	Markets Sales On		Market Sales Off	
Scenario	PVSC	PVRR	PVSC	PVRR
Base (Continuation of PPAs)	-	-	-	-
MEC Ownership	($122)	($165)	($128)	($91)
MEC Ownership and 2040 shutdown	$121	$25	($31)	$80
MEC Ownership and 2050 shutdown	($90)	($124)	($66)	($28)

As shown above, retiring MEC in 2050 continues to show benefits on both and PVSC and PVRR basis with markets on and off. The benefits of operating MEC into the 2040s will depend on the technology and costs of replacement resources available in that timeframe. The results above show that the cost of the MEC acquisition are largely offset by 2040 allowing for flexibility in determining whether an early retirement of MEC is in the public interest as technology evolves. This analysis provides further support for our acquisition of MEC as consistent with our 2050 aspiration as we can adjust the retirement date to occur before 2050 and still achieve customer savings.

iii. Sensitivity Combinations

As discussed above, we developed sensitivity combinations to inform our analysis in our upcoming 2019 IRP. We analyzed the benefits of MEC under the sensitivity combinations and early retirement of MEC as shown below in Table 6.

Table 6: Sensitivity Combinations with Early MEC Retirement

	Markets Sales On		Market Sales Off	
Scenario	High Electrification & Fuel Costs, Low Tech Costs	High Distributed Solar Deployment, Low Tech Costs and Fuel Costs	High Electrification & Fuel Costs, Low Tech Costs	High Distributed Solar Deployment, Low Tech Costs and Fuel Costs
Base (Continuation of PPAs)	-	-	-	-
Own	($459)	($76)	($459)	($76)
Own 2040	$18	$71	$18	$71
Own 2050	($264)	($29)	($264)	($29)

The benefits of the acquisition of MEC increase under the High Electrification and Fuel Costs, and Low Technology Costs sensitivity combination. The benefits of MEC increase due to the incremental load associated with electrification of the transportation sector and increased heating load. Under the High Distributed Solar Deployment, Low Technology Costs and Fuel Costs sensitivity combination the benefits of decrease somewhat due to the higher deployment of renewable resources. Table 7, below, shows the benefits of the acquisition of MEC under the sensitivity combinations and early coal retirement.

Table 7: Sensitivity Combinations with Early Coal Retirement

	Markets Sales On		Market Sales Off	
	High Electrification & Fuel Costs, Low Tech Costs	High Distributed Solar Deployment, Low Tech Costs and Fuel Costs	High Electrification & Fuel Costs, Low Tech Costs	High Distributed Solar Deployment, Low Tech Costs and Fuel Costs
Base (Continuation of PPAs)	-	-	-	-
Base with Early Coal Retirement	($236)	($204)	($415)	($188)
MEC Ownership with Early Coal Retirement	($624)	($303)	($608)	($305)

As shown above, MEC provides significant system benefits when combined with early coal shutdown under both combination sensitivities.

iv. Additional Sensitivities

Table 8, below, shows the benefits of the acquisition of MEC compared to continuation of the existing PPAs under the sensitivities provided in our initial petition and the addition of a sensitivity that use the midpoint of the Commission approved externality and regulatory costs for carbon emissions. The early coal retirement scenario is compared to a base case where the PPAs continue and the coal units are retired early.

Table 8: Benefits of MEC Ownership – Additional Sensitivities

	Markets On			
	MEC Ownership	MEC Ownership & Early Coal Retirement	MEC Ownership & 2040 Shutdown	MEC Ownership and 2050 Shutdown
Low Fuel/Market Prices	($192)	($170)	($13)	($168)
High Fuel/Market Prices	$5	$14	$372	$32
Low Load	($192)	($146)	($55)	($157)
High Load	($469)	($357)	($150)	($317)
Higher MEC Ongoing Costs	($124)	($68)	$119	($92)
Lower MEC Ongoing Costs	($129)	($73)	$114	($97)
Low Cost Renew Resources	($46)	$0.5	$226	($26)
High Cost Renew Resources	($277)	($203)	($76)	($224)
Low Externality	($121)	($100)	$75	($77)
High Externality	($39)	($100)	$201	$35
Low Ext. and Low Regulatory	($120)	($74)	$75	($91)
No Environmental Costs	($142)	($97)	$41	($106)
Mid Ext and Mid Regulatory	($138)	($85)	$81	($104)

Table 9: Benefits of MEC Ownership – Additional Sensitivities

	Markets Off			
	MEC Ownership	MEC Ownership & Early Coal Retirement	MEC Ownership & 2040 Shutdown	MEC Ownership and 2050 Shutdown
Low Fuel/Market Prices	($281)	($187)	($120)	($236)
High Fuel/Market Prices	($153)	($178)	$165	($80)
Low Load	($52)	($178)	$127	($50)
High Load	($454)	($182)	($196)	($320)
Higher MEC Ongoing Costs	($151)	($193)	($34)	($89)
Lower MEC Ongoing Costs	($187)	($200)	($41)	($125)
Low Cost Renew Resources	($52)	($124.0)	$73	($2)
High Cost Renew Resources	($284)	($328)	($229)	($200)
Low Externality	($19)	($135)	$164	$42
High Externality	$151	($70)	$403	$225
Low Ext. and Low Regulatory	($196)	($171)	($32)	($139)
No Environmental Costs	($68)	($150)	$95	($10)
Mid Ext. and Mid Regulatory	($215)	($180)	($28)	($156)

CONCLUSION

We appreciate the opportunity to provide these Reply Comments. We believe these comments respond to and address the concerns raised by the stakeholders in this docket, and we believe our supplemental modeling continues to demonstrate that our MEC proposal is reasonable, consistent with the public interest, and merits Commission approval.

Dated: March 29, 2019

Northern States Power Company

Strategist Modeling Assumptions

1. Discount Rate and Capital Structure

The discount rate used for levelized cost calculations and the present value of modeled costs is 6.53 percent. The rates shown below were calculated by taking a weighted average of each NSP jurisdiction's last allowed/settled electric retail rate case.

Table 1: Discount Rate and Capital Structure

Discount Rate and Capital Structure				
	Capital Structure	Allowed Return	Before Tax Electric WACC	After Tax Electric WACC
Long-Term Debt	46.16%	4.80%	2.22%	1.60%
Common Equity	52.35%	9.35%	4.90%	4.90%
Short-Term Debt	1.49%	3.65%	0.05%	0.04%
Total			**7.17%**	**6.53%**

2. Inflation Rates

The inflation rates are used for existing resources, generic resources, and other costs related to general inflationary trends in the modeling and are developed using long-term forecasts from Global Insight. The general inflation rate of 2% is from their long-term forecast for "Chained Price Index for Total Personal Consumption Expenditures" published in the second quarter of 2018.

3. Reserve Margin

The reserve margin at the time of MISO's peak is 8.4 percent from the 2018-2019 LOLE Study Report published November 2017. The coincidence factor between the NSP System and MISO system peak is 5 percent. Therefore, the effective reserve margin is:

$$(1 - 5\%) * (1 + 8.4\%) - 1 = 2.98\%.$$

4. CO_2 Costs

The PVSC Base Case CO2 values are based on the high environmental cost values for CO2 through 2024 (page 31 of the Minnesota Public Utilities Commission's Order Updating Environmental Cost Values in Docket No. E999/CI-14-643 issued January 3, 2018.). All prices are converted to 2018 real dollars using the 2017 GPDIPD of 113.416 and then escalate at general inflation thereafter.

The PVSC Base Case values starting in 2025 are based on the "high" end of the range of regulated costs (see page 12 of MPUC Order Establishing 2018 and 2019 Estimate of Future Carbon Dioxide Regulation Costs in Dockets No.E999/CI-07-1199 and E-999/DI-17-53 issued June 11, 2018). All prices escalate at general inflation.

The Order Establishing 2018 and 2019 Estimate of Future Carbon Dioxide Regulation Costs requires four alternative scenarios to be run in addition to the PVSC Base Case. The Order Extending Deadline for Filing Next Resource Plan issued January 30, 2019 also requires a scenario using the midpoint of the Commission's most recently approved externalities and regulatory costs of carbon. The values in the PVSC Base Case and alternative scenarios are set out below.

Table 2: CO2 Costs

CO2 Costs ($ per short ton)						
Year	Low Environmental Cost	High Environmental Cost	Low Environmental/ Regulatory Costs	Mid Environmental/ Regulatory Costs	PVSC - High Environmental/ Regulatory Costs	PVRR - Omitting CO2 Cost Considerations
2018	$9.09	$42.76	$9.09	$25.92	$42.76	$0.00
2019	$9.49	$44.58	$9.49	$27.04	$44.58	$0.00
2020	$9.90	$46.45	$9.90	$28.18	$46.45	$0.00
2021	$10.32	$48.39	$10.32	$29.35	$48.39	$0.00
2022	$10.77	$50.38	$10.77	$30.57	$50.38	$0.00
2023	$11.22	$52.43	$11.22	$31.82	$52.43	$0.00
2024	$11.69	$54.55	$11.69	$33.12	$54.55	$0.00
2025	$12.16	$56.72	$5.00	$15.00	$25.00	$0.00
2026	$12.67	$58.97	$5.10	$15.30	$25.50	$0.00
2027	$13.17	$61.29	$5.20	$15.61	$26.01	$0.00
2028	$13.70	$63.67	$5.31	$15.92	$26.53	$0.00
2029	$14.24	$66.12	$5.41	$16.24	$27.06	$0.00
2030	$14.80	$68.64	$5.52	$16.56	$27.60	$0.00
2031	$15.37	$71.24	$5.63	$16.89	$28.15	$0.00
2032	$15.97	$73.91	$5.74	$17.23	$28.72	$0.00
2033	$16.57	$76.67	$5.86	$17.57	$29.29	$0.00
2034	$17.21	$79.50	$5.98	$17.93	$29.88	$0.00
2035	$17.85	$82.41	$6.09	$18.28	$30.47	$0.00
2036	$18.52	$85.41	$6.22	$18.65	$31.08	$0.00
2037	$19.20	$88.50	$6.34	$19.02	$31.71	$0.00
2038	$19.91	$91.68	$6.47	$19.40	$32.34	$0.00
2039	$20.62	$94.96	$6.60	$19.79	$32.99	$0.00
2040	$21.38	$98.32	$6.73	$20.19	$33.65	$0.00
2041	$22.14	$101.78	$6.86	$20.59	$34.32	$0.00
2042	$22.94	$105.34	$7.00	$21.00	$35.01	$0.00
2043	$23.74	$109.00	$7.14	$21.42	$35.71	$0.00
2044	$24.58	$112.76	$7.28	$21.85	$36.42	$0.00
2045	$25.43	$116.63	$7.43	$22.29	$37.15	$0.00
2046	$26.33	$120.61	$7.58	$22.73	$37.89	$0.00
2047	$27.23	$124.71	$7.73	$23.19	$38.65	$0.00
2048	$28.17	$128.92	$7.88	$23.65	$39.42	$0.00
2049	$29.12	$133.24	$8.04	$24.13	$40.21	$0.00
2050	$30.12	$137.69	$8.20	$24.61	$41.02	$0.00
2051	$31.14	$142.26	$8.37	$25.10	$41.84	$0.00
2052	$32.18	$146.97	$8.53	$25.60	$42.67	$0.00
2053	$33.26	$151.80	$8.71	$26.12	$43.53	$0.00
2054	$34.36	$156.76	$8.88	$26.64	$44.40	$0.00
2055	$35.50	$161.87	$9.06	$27.17	$45.28	$0.00
2056	$36.66	$167.11	$9.24	$27.71	$46.19	$0.00
2057	$37.86	$172.51	$9.42	$28.27	$47.11	$0.00

5. All Other Externality Costs

The values of the criteria pollutants are derived from the high and low values for each of the 3 locations, as determined in the MPUC Order Updating Environmental Cost Values in Docket No. E999/CI-14-643 issued January 3, 2018. The midpoint externality costs are the average of the low and high values. All prices are escalated to 2018 real dollars using the 2017 GPDIPD of 113.416. The high, low and midpoint externality costs will be used in the CO2 sensitivities as described above.

Table 3: Externality Costs

MPUC Low Externality Costs 2018 $ per short ton				
	Urban	Metro Fringe	Rural	<200mi
SO2	$6,116	$4,829	$3,643	$0
NOx	$2,934	$2,622	$2,110	$28
PM2.5	$10,697	$6,856	$3,654	$872
CO	$1.65	$1.17	$0.31	$0.31
Pb	$4,857	$2,562	$624	$624

MPUC High Externality Costs 2018 $ per short ton				
	Urban	Metro Fringe	Rural	<200mi
SO2	$15,288	$12,030	$8,878	$0
NOx	$8,390	$7,798	$6,771	$158
PM2.5	$26,721	$17,091	$8,973	$1,327
CO	$3.51	$2.08	$0.63	$0.63
Pb	$6,011	$3,094	$695	$695

MPUC Midpoint Externality Costs 2018 $ per short ton				
	Urban	Metro Fringe	Rural	<200mi
SO2	$10,702	$8,430	$6,261	$0
NOx	$5,662	$5,210	$4,441	$93
PM2.5	$18,709	$11,974	$6,313	$1,099
CO	$2.58	$1.63	$0.47	$0.47
Pb	$5,434	$2,828	$659	$659

6. Demand and Energy Forecast

The Company’s fall 2018 load forecast is used as the base assumption and assumes that EV impacts grow through 2023 are then held constant for the remaining forecast period. The energy efficiency (EE) forecast included in this forecast assumes impacts at a 75 percent rebate level which equals roughly 1.5 percent of sales through the planning period.

The “Load Forecast with 1.5% EE” shown in Table 4 below will be used in the Reference Case. In all other modeling scenarios, the “1.5% EE” will be removed - the removal of these DSM programs, which have a 14-year life, will impact the load forecast through 2047. In its place, three EE Bundles (discussed below) will be included in Strategist as Proview Alternatives and any number of these bundles (from 0 to all 3) is allowed to be selected as part of the optimization process. The resulting forecast, before the optimized EE bundles are added, is shown below in Table 4 as “Forecast Without 1.5% EE”. The forecasts shown do not include the impact of DG solar, as DG solar is modeled as a resource in Strategist, not a load modifier.

Table 4: Demand and Energy Forecast

Demand and Energy Forecast				
	Demand (MW)		Energy (GWh)	
Year	Forecast with 1.5% EE	Forecast without 1.5% EE	Forecast with 1.5% EE	Forecast without 1.5% EE
2018	9,152	9,152	43,914	43,914
2019	9,136	9,136	43,798	43,798
2020	9,156	9,227	43,865	44,310
2021	9,191	9,333	43,560	44,447
2022	9,251	9,464	43,529	44,860
2023	9,285	9,569	43,394	45,168
2024	9,329	9,684	43,425	45,650
2025	9,354	9,780	43,257	45,919
2026	9,403	9,900	43,281	46,386
2027	9,487	10,055	43,493	47,042
2028	9,593	10,262	44,089	48,093
2029	9,635	10,403	43,972	48,408
2030	9,697	10,567	44,130	49,010
2031	9,740	10,713	44,172	49,496
2032	9,856	10,956	44,661	50,445
2033	10,005	11,211	44,875	51,087
2034	10,137	11,343	45,232	51,443
2035	10,248	11,368	45,534	51,302
2036	10,374	11,408	46,042	51,382
2037	10,482	11,430	46,126	51,006
2038	10,576	11,438	46,287	50,723
2039	10,674	11,449	46,541	50,534
2040	10,777	11,467	46,946	50,505
2041	10,873	11,476	46,975	50,081
2042	10,964	11,481	47,143	49,805
2043	11,057	11,488	47,407	49,626
2044	11,169	11,514	47,823	49,603
2045	11,241	11,500	47,879	49,210
2046	11,328	11,500	48,076	48,964
2047	11,424	11,510	48,372	48,816
2048	11,536	11,536	48,977	48,977
2049	11,626	11,626	48,811	48,811
2050	11,715	11,715	49,042	49,042
2051	11,804	11,804	49,274	49,274
2052	11,893	11,901	49,640	49,640
2053	11,982	11,992	49,736	49,736
2054	12,071	12,083	49,968	49,968
2055	12,160	12,174	50,199	50,199
2056	12,249	12,265	50,567	50,567
2057	12,339	12,356	50,662	50,662

The low load sensitivity includes high customer-adoption-based DG/DER growth and higher EE savings, which reduces load. The high load sensitivity includes high electrification load. These assumptions are show in Table 5 and Table 6 and are incremental/decremental to the base forecast shown in Table 4.

Table 5: High Load Sensitivity

High Electrification		
Year	Energy (GWh)	Demand (MW)
2018	35	8
2019	46	6
2020	59	7
2021	166	20
2022	276	33
2023	390	47
2024	507	62
2025	627	77
2026	785	96
2027	976	117
2028	1,194	141
2029	1,579	171
2030	2,122	207
2031	2,802	250
2032	3,622	302
2033	4,593	362
2034	5,706	430
2035	6,969	509
2036	8,320	592
2037	9,751	681
2038	11,248	772
2039	12,797	866
2040	14,387	961
2041	15,950	1,055
2042	17,472	1,146
2043	18,940	1,245
2044	20,341	1,930
2045	21,665	2,660
2046	22,904	3,318
2047	24,054	3,945
2048	25,112	4,800
2049	26,076	5,056
2050	26,947	5,554
2051	28,051	6,093
2052	29,061	6,564
2053	30,072	7,041
2054	31,083	7,528
2055	32,093	8,021
2056	33,104	8,496
2057	34,115	8,984

**Demand values are coincident to system peak*

Table 6: Low Load Sensitivity

High DER Growth			
Year	Energy (GWh)	ELCC (MW)	Demand (Nameplate MW)
2018	0	0	0
2019	0	0	0
2020	0	0	0
2021	189	72	144
2022	173	66	131
2023	159	60	121
2024	144	55	109
2025	135	51	103
2026	230	87	175
2027	228	87	173
2028	369	140	280
2029	377	143	286
2030	432	164	328
2031	490	186	373
2032	553	210	420
2033	617	235	469
2034	687	261	522
2035	760	289	578
2036	840	319	637
2037	920	350	700
2038	1,007	383	766
2039	1,099	418	836
2040	1,200	455	910
2041	1,225	466	931
2042	1,187	451	902
2043	1,148	437	873
2044	1,112	422	844
2045	1,070	407	814
2046	1,014	385	771
2047	974	370	740
2048	935	354	709
2049	891	339	677
2050	850	323	646
2051	799	304	607
2052	759	287	575
2053	701	266	532
2054	657	249	498
2055	607	230	461
2056	559	211	422
2057	506	192	383

7. Energy Efficiency Bundles

The energy efficiency (EE) "Program" and "Maximum" Bundles are based on the 2018 MN Statewide DSM Potential Study. The "Optimal" Bundle was developed by the Company. The bundles are incremental to the "Forecast without 1.5% EE" shown in Table 4. They are also dependent on the bundle before it being selected (i.e. Bundle 2 cannot be selected if Bundle 1 isn't selected). They are included in Strategist as Proview Alternatives and any number of these bundles (from 0 to all 3) is allowed to be selected as part of the optimization process.

Table 7: Energy Efficiency Bundles

	Energy(MWh)			Demand (MW)			Costs ($000)		
Year	Bundle 1: Program	Bundle 2: Optimal	Bundle 3: Max	Bundle 1: Program	Bundle 2: Optimal	Bundle 3: Max	Bundle 1: Program	Bundle 2: Optimal	Bundle 3: Max
2018	0	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	0	0
2020	621	43	231	97	18	36	100,989	12,598	148,331
2021	1,326	91	493	207	38	77	113,525	13,905	167,221
2022	1,913	148	702	301	60	113	121,239	21,425	177,197
2023	2,555	211	928	407	86	154	133,614	23,931	196,474
2024	3,094	279	1,110	520	116	197	148,406	26,120	217,388
2025	3,629	346	1,289	635	146	241	152,433	26,077	223,293
2026	4,330	414	1,533	759	176	289	160,445	26,236	233,779
2027	5,054	482	1,785	886	206	338	167,718	26,637	242,963
2028	5,785	551	2,040	1,012	235	387	174,161	27,018	249,373
2029	6,454	606	2,280	1,127	259	432	162,170	23,442	233,114
2030	7,110	659	2,516	1,241	283	477	162,170	23,442	233,114
2031	7,753	710	2,748	1,354	307	522	162,170	23,442	233,114
2032	8,339	760	2,960	1,460	329	564	162,170	23,442	233,114
2033	8,909	808	3,168	1,564	352	605	162,170	23,442	233,114
2034	9,464	857	3,370	1,667	374	646	162,170	23,442	233,114
2035	9,250	846	3,294	1,648	370	638	0	0	0
2036	8,739	835	3,073	1,579	366	600	0	0	0
2037	8,088	789	2,829	1,470	347	557	0	0	0
2038	7,450	741	2,590	1,369	327	517	0	0	0
2039	6,841	685	2,372	1,267	304	475	0	0	0
2040	6,197	626	2,144	1,154	278	430	0	0	0
2041	5,543	562	1,919	1,036	250	384	0	0	0
2042	4,871	499	1,685	916	221	337	0	0	0
2043	4,220	434	1,457	796	191	291	0	0	0
2044	3,561	377	1,218	678	165	245	0	0	0
2045	2,912	318	990	562	139	201	0	0	0
2046	2,276	265	761	451	116	156	0	0	0
2047	1,746	212	573	349	93	117	0	0	0
2048	1,216	159	384	248	70	79	0	0	0
2049	686	106	195	146	46	40	0	0	0
2050	156	53	7	45	23	1	0	0	0
2051	0	0	0	0	0	0	0	0	0
2052	0	0	0	0	0	0	0	0	0
2053	0	0	0	0	0	0	0	0	0
2054	0	0	0	0	0	0	0	0	0
2055	0	0	0	0	0	0	0	0	0
2056	0	0	0	0	0	0	0	0	0
2057	0	0	0	0	0	0	0	0	0

***Demand values are coincident to system peak*

8. Demand Response Forecast

The base demand response forecast was developed by the Company and is included in all scenarios and sensitivities. The three demand response “Bundles” are from the Brattle Study. The bundles are incremental to the base demand response forecast and are dependent on the bundle before it being selected (i.e. Bundle 2 cannot be selected if Bundle 1 isn’t selected). They are included in Strategist as Proview Alternatives and any number of these bundles (from 0 to all 3) is allowed to be selected as part of the optimization process. The Reference Case is modeled to be in compliance with the Order from the previous IRP, which would require all three bundles to meet the ordered 400MW of incremental DR by 2023.

Table 8: Demand Response Forecast

Demand (MW) Adjusted For Reserve Margin						Costs ($000)		
Year	Base Demand Response Forecast	Bundle 1	Bundle 2	Bundle 3	Demand Response Needed to Comply with Order	Bundle 1	Bundle 2	Bundle 3
2018	848	0	0	0	848	0	0	0
2019	924	0	0	0	924	0	0	0
2020	940	270	107	89	940	14,380	7,659	11,311
2021	955	290	112	97	955	15,724	8,150	12,587
2022	970	312	116	106	970	17,212	8,676	14,016
2023	989	322	120	110	1,490	18,124	9,137	14,758
2024	1007	339	132	101	1,501	19,512	10,277	13,829
2025	1023	380	145	92	1,503	22,305	11,459	12,858
2026	1038	392	151	93	1,498	23,475	12,207	13,326
2027	1053	406	159	95	1,494	24,786	13,080	13,845
2028	1054	421	168	97	1,489	26,245	14,086	14,418
2029	1042	438	178	99	1,485	27,859	15,231	15,047
2030	1031	456	189	101	1,480	29,637	16,522	15,734
2031	1020	476	201	104	1,476	31,551	17,926	16,467
2032	1009	497	214	106	1,472	33,612	19,451	17,251
2033	998	519	227	109	1,467	35,832	21,109	18,088
2034	988	542	242	112	1,463	38,224	22,911	18,984
2035	978	567	257	116	1,459	40,802	24,870	19,943
2036	968	594	274	119	1,455	43,582	26,999	20,971
2037	972	630	293	125	1,451	46,580	29,313	22,072
2038	963	660	312	129	1,447	49,814	31,829	23,253
2039	954	692	332	133	1,443	53,305	34,564	24,522
2040	945	726	353	138	1,439	57,073	37,537	25,884
2041	937	726	353	138	1,435	58,215	38,288	26,402
2042	929	726	353	138	1,431	59,379	39,054	26,930
2043	921	726	353	138	1,427	60,566	39,835	27,468
2044	913	726	353	138	1,423	61,778	40,632	28,018
2045	906	726	353	138	1,419	63,013	41,444	28,578
2046	898	726	353	138	1,416	64,274	42,273	29,150
2047	891	726	353	138	1,412	65,559	43,118	29,733
2048	884	726	353	138	1,408	66,870	43,981	30,327
2049	876	726	353	138	1,404	68,208	44,860	30,934
2050	869	726	353	138	1,400	69,572	45,758	31,552
2051	862	726	353	138	1,396	70,963	46,673	32,183
2052	854	726	353	138	1,392	72,382	47,606	32,827
2053	847	726	353	138	1,388	73,830	48,558	33,484
2054	839	726	353	138	1,384	75,307	49,530	34,153
2055	832	726	353	138	1,381	76,813	50,520	34,836
2056	825	726	353	138	1,377	78,349	51,531	35,533
2057	817	726	353	138	1,373	79,916	52,561	36,244

**Demand values are coincident to system peak.*

9. Fuel Price Forecasts

The natural gas prices are developed using a blend of market information (New York Mercantile Exchange futures prices) and long-term fundamentally-based forecasts from Wood Mackenzie, Cambridge Energy Research Associates (CERA) and Petroleum Industry Research Associates (PIRA).

Coal price forecasts are developed using two major inputs: the current contract volumes and prices combined with current estimates of required spot volumes and prices to cover non-contracted coal needs. Typically coal volumes and prices are under contract on a plant by plant basis for a one to five year term with annual spot volumes filling the estimated fuel requirements of the coal plant based on recent unit dispatch. The spot coal price forecasts are developed from price forecasts provided by Wood Mackenzie, JD Energy, and John T Boyd Company, as well as price points from recent Request for Proposal (RFP) responses for coal supply. Added to the spot coal forecast, which is just for the coal commodity, are: transportation charges, SO_2 costs, freeze control and dust suppressant, as required.

In addition to resources that exist within the NSP System, the Company is a participant in the MISO Market. Electric power market prices are developed from fundamentally-based forecasts from Wood Mackenzie, CERA and PIRA using a similar methodology as is used for the gas price forecast. The table below shows the market prices under zero CO_2 cost assumptions. The market purchases and sales limit for transaction volume between the Company and MISO is 1,350 MWh/h in 2018, 1,800 MWh/h from 2019-2022, and 2,300 MWh/h for 2023 and beyond.

High and low price sensitivities were performed by adjusting the growth rate up and down by 50 percent from the base forecast starting in year 2022.

Table 9: Fuel and Market Price Forecasts

	Base Price Forecast				Low Price Forecast				High Price Forecast			
	Fuel Price ($/mmBTu)		Market Price ($/MWh)		Fuel Price ($/mmBTu)		Market Price ($/MWh)		Fuel Price ($/mmBTu)		Market Price ($/MWh)	
Year	Generic Coal	Ventura Hub	Minn Hub On-Peak	Minn Hub Off-Peak	Generic Coal	Ventura Hub	Minn Hub On-Peak	Minn Hub Off-Peak	Generic Coal	Ventura Hub	Minn Hub On-Peak	Minn Hub Off-Peak
2018	$2.19	$2.74	$28.60	$21.61	$2.19	$2.74	$28.60	$21.61	$2.19	$2.74	$28.60	$21.61
2019	$2.08	$2.67	$27.10	$21.12	$2.08	$2.67	$27.10	$21.12	$2.08	$2.67	$27.10	$21.12
2020	$2.11	$2.44	$24.36	$18.97	$2.11	$2.44	$24.36	$18.97	$2.11	$2.44	$24.36	$18.97
2021	$2.14	$2.37	$23.37	$17.97	$2.14	$2.37	$23.37	$17.97	$2.14	$2.37	$23.37	$17.97
2022	$2.23	$2.52	$24.93	$19.30	$2.19	$2.44	$24.18	$18.72	$2.26	$2.59	$25.68	$19.88
2023	$2.29	$2.82	$28.39	$22.16	$2.24	$2.59	$26.08	$20.36	$2.34	$3.06	$30.80	$24.04
2024	$2.37	$3.07	$30.69	$23.93	$2.29	$2.70	$27.02	$21.07	$2.45	$3.47	$34.66	$27.03
2025	$2.42	$3.26	$32.82	$25.48	$2.34	$2.79	$28.06	$21.79	$2.51	$3.79	$38.13	$29.61
2026	$2.48	$3.42	$34.50	$27.03	$2.38	$2.85	$28.81	$22.58	$2.59	$4.06	$41.02	$32.14
2027	$2.55	$3.51	$35.03	$27.53	$2.43	$2.89	$28.86	$22.68	$2.68	$4.24	$42.22	$33.19
2028	$2.62	$3.60	$35.52	$27.78	$2.48	$2.93	$28.90	$22.60	$2.77	$4.40	$43.35	$33.90
2029	$2.69	$3.82	$37.34	$29.17	$2.54	$3.02	$29.53	$23.07	$2.87	$4.79	$46.83	$36.59
2030	$2.76	$4.09	$39.20	$30.60	$2.59	$3.13	$29.95	$23.38	$2.97	$5.31	$50.84	$39.69
2031	$2.84	$4.26	$41.18	$32.22	$2.64	$3.19	$30.85	$24.13	$3.07	$5.63	$54.45	$42.60
2032	$2.92	$4.47	$42.61	$33.54	$2.70	$3.27	$31.17	$24.53	$3.18	$6.05	$57.66	$45.38
2033	$3.00	$4.74	$45.01	$35.50	$2.75	$3.37	$31.99	$25.24	$3.30	$6.60	$62.64	$49.41
2034	$3.08	$4.93	$46.64	$37.01	$2.81	$3.44	$32.51	$25.80	$3.42	$6.99	$66.15	$52.51
2035	$3.17	$4.94	$46.91	$37.38	$2.87	$3.44	$32.65	$26.02	$3.54	$7.02	$66.64	$53.11
2036	$3.26	$5.00	$46.72	$37.35	$2.93	$3.46	$32.33	$25.85	$3.67	$7.15	$66.75	$53.37
2037	$3.35	$5.17	$48.19	$38.46	$2.99	$3.52	$32.81	$26.19	$3.81	$7.51	$69.97	$55.84
2038	$3.44	$5.40	$49.56	$40.01	$3.06	$3.60	$33.03	$26.67	$3.95	$8.00	$73.47	$59.32
2039	$3.51	$5.65	$51.50	$41.70	$3.11	$3.68	$33.54	$27.16	$4.05	$8.57	$78.09	$63.23
2040	$3.61	$5.90	$53.12	$43.28	$3.18	$3.76	$33.87	$27.60	$4.20	$9.14	$82.24	$67.00
2041	$3.69	$6.08	$54.73	$44.58	$3.24	$3.82	$34.39	$28.01	$4.31	$9.55	$85.97	$70.04
2042	$3.77	$6.27	$56.47	$46.00	$3.30	$3.88	$34.93	$28.46	$4.42	$10.01	$90.07	$73.38
2043	$3.85	$6.46	$58.13	$47.35	$3.36	$3.94	$35.44	$28.88	$4.53	$10.45	$94.04	$76.61
2044	$3.93	$6.57	$59.12	$48.17	$3.43	$3.97	$35.75	$29.12	$4.65	$10.72	$96.46	$78.59
2045	$4.02	$6.66	$59.90	$48.80	$3.49	$4.00	$35.99	$29.32	$4.77	$10.93	$98.37	$80.14
2046	$4.11	$6.77	$60.93	$49.63	$3.56	$4.03	$36.29	$29.57	$4.89	$11.21	$100.88	$82.19
2047	$4.20	$6.96	$62.70	$51.07	$3.63	$4.09	$36.82	$29.99	$5.02	$11.69	$105.27	$85.75
2048	$4.29	$7.17	$64.55	$52.57	$3.70	$4.15	$37.37	$30.44	$5.15	$12.21	$109.93	$89.54
2049	$4.38	$7.25	$65.25	$53.15	$3.77	$4.17	$37.57	$30.60	$5.29	$12.41	$111.72	$91.01
2050	$4.48	$7.37	$66.39	$54.08	$3.85	$4.21	$37.90	$30.87	$5.43	$12.73	$114.66	$93.38
2051	$4.58	$7.52	$67.67	$55.12	$3.92	$4.25	$38.27	$31.17	$5.57	$13.10	$117.97	$96.08
2052	$4.68	$7.66	$68.99	$56.19	$4.00	$4.29	$38.64	$31.47	$5.72	$13.49	$121.42	$98.90
2053	$4.79	$7.81	$70.33	$57.28	$4.08	$4.33	$39.02	$31.78	$5.87	$13.88	$124.95	$101.77
2054	$4.89	$7.96	$71.68	$58.39	$4.16	$4.38	$39.39	$32.08	$6.03	$14.28	$128.56	$104.71
2055	$5.00	$8.12	$73.07	$59.51	$4.25	$4.42	$39.77	$32.39	$6.18	$14.69	$132.28	$107.74
2056	$5.11	$8.27	$74.48	$60.67	$4.33	$4.46	$40.16	$32.71	$6.34	$15.12	$136.13	$110.87
2057	$5.21	$8.43	$75.92	$61.83	$4.41	$4.50	$40.54	$33.02	$6.49	$15.55	$140.05	$114.06

**Coal prices are delivered prices, while gas and market prices are hub prices.*

10. Surplus Capacity Credit

The surplus capacity credit of up to 500 MW is applied for all twelve months of each year and is priced at the avoided capacity cost of a generic brownfield H-Class combustion turbine on an economic carrying charge basis.

Table 10: Surplus Capacity Credit

Surplus Capacity Credit																				
	2018	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**
$/kw-mo	4.62	4.71	4.81	4.90	5.00	5.10	5.20	5.31	5.41	5.52	5.63	5.74	5.86	5.98	6.10	6.22	6.34	6.47	6.60	6.73
	2038	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**	**2045**	**2046**	**2047**	**2048**	**2049**	**2050**	**2051**	**2052**	**2053**	**2054**	**2055**	**2056**	**2057**
$/kw-mo	6.87	7.00	7.14	7.29	7.43	7.58	7.73	7.89	8.04	8.20	8.37	8.54	8.71	8.88	9.06	9.24	9.42	9.61	9.80	10.00

11. Effective Load Carrying Capability (ELCC) Capacity Credit for Wind, Solar, and Battery Resources

The ELCC for existing wind units is based on current MISO accreditation. The ELCC for generic wind is equal to 15.6% of their nameplate rating per MISO 2017/2018 Wind Capacity Report. The ELCC for generic solar is 50% of the AC nameplate capacity. The ELCC for a generic 4-hour battery is equal to 100% of their AC equivalent capacity.

12. Spinning Reserve Requirement

Spinning reserve is the on-line reserve capacity that is synchronized to the grid to maintain system frequency stability during contingency events and unforeseen load swings. The level of spinning reserve modeled is 137 MW and is based on a 12 month rolling average of spinning reserves carried by the NSP System within MISO.

13. Emergency Energy

Emergency energy is $500/MWh and is used to cover events where there are not enough resources available to meet system energy requirements.

14. Transmission Delivery Costs and Interconnection Costs

Transmission delivery costs for generic resources were developed by the Company. They are based on evaluation of recent and historical MISO studies and queue results. These costs represent “grid upgrades” to ensure deliverability of energy from these facilities to the overall bulk electric system.

Interconnection costs for generic resources are included in the capital costs in Table 14 and represent “behind the fence” costs associated with substation and representative gen-tie construction.

Table 11: Transmission Delivery Costs

Transmission Delivery Costs				
	CC	**CT**	**Wind**	**Solar**
$/kw	500	200	400	140

15. Integration and Congestion Costs

Integration costs are taken from studies conducted by Enernex and apply to new wind and solar resources only. Congestion costs were developed by the Company using the MISO MTEP 2018 models and looking at the average congestion costs between representative wind bus locations and NSP.NSP. Congestion costs are applied to new wind projects only.

Table 12: Integration and Congestion Costs

Integration and Congestion Costs ($/MWh)				
Year	Integration		Congestion	
	Wind	Solar	Wind	Solar
2018	0.00	0.00	0.00	0.00
2019	0.00	0.00	0.00	0.00
2020	0.41	0.41	3.43	0.00
2021	0.42	0.42	3.50	0.00
2022	0.43	0.43	3.57	0.00
2023	0.44	0.44	3.64	0.00
2024	0.45	0.45	3.71	0.00
2025	0.46	0.46	3.79	0.00
2026	0.47	0.47	3.86	0.00
2027	0.48	0.48	3.94	0.00
2028	0.49	0.49	4.02	0.00
2029	0.49	0.49	4.10	0.00
2030	0.50	0.50	4.18	0.00
2031	0.51	0.51	4.27	0.00
2032	0.53	0.53	4.35	0.00
2033	0.54	0.54	4.44	0.00
2034	0.55	0.55	4.53	0.00
2035	0.56	0.56	4.62	0.00
2036	0.57	0.57	4.71	0.00
2037	0.58	0.58	4.80	0.00
2038	0.59	0.59	4.90	0.00
2039	0.60	0.60	5.00	0.00
2040	0.62	0.62	5.10	0.00
2041	0.63	0.63	5.20	0.00
2042	0.64	0.64	5.30	0.00
2043	0.65	0.65	5.41	0.00
2044	0.67	0.67	5.52	0.00
2045	0.68	0.68	5.63	0.00
2046	0.69	0.69	5.74	0.00
2047	0.71	0.71	5.86	0.00
2048	0.72	0.72	5.97	0.00
2049	0.74	0.74	6.09	0.00
2050	0.75	0.75	6.22	0.00
2051	0.77	0.77	6.34	0.00
2052	0.78	0.78	6.47	0.00
2053	0.80	0.80	6.60	0.00
2054	0.81	0.81	6.73	0.00
2055	0.83	0.83	6.86	0.00
2056	0.84	0.84	7.00	0.00
2057	0.86	0.86	7.14	0.00

16. Distributed Generation and Community Solar Gardens

The distributed solar inputs are based on the most recent Company forecasts. Annual additions are modeled assuming a degradation of half a percent annually in generation, and a twenty five year service life. After a “vintage” of additions reach end of life, it is assumed 90% of the capacity is replaced at then-current costs. The Company expects a transition from Solar*Rewards to non-incentivized DG over time due to end of statutory provisions.

Table 13: Distributed Solar Forecast

Distributed Solar (Nameplate MW)				
Year	Solar Rewards	Net Metered	Community Gardens	Total
2018	29	18	246	293
2019	41	27	504	573
2020	49	37	641	727
2021	53	47	649	749
2022	56	58	657	771
2023	57	70	665	792
2024	57	83	673	813
2025	56	96	681	834
2026	56	109	689	854
2027	56	122	697	875
2028	55	135	705	895
2029	55	147	713	915
2030	55	160	720	935
2031	55	172	728	955
2032	54	185	736	975
2033	54	197	744	995
2034	51	212	751	1,014
2035	45	229	759	1,033
2036	39	247	766	1,052
2037	34	262	774	1,070
2038	27	280	781	1,088
2039	16	301	789	1,106
2040	8	319	796	1,123
2041	4	333	804	1,141
2042	0	346	808	1,154
2043	0	358	796	1,154
2044	0	368	781	1,149
2045	0	379	776	1,155
2046	0	389	783	1,171
2047	0	399	789	1,188
2048	0	409	795	1,205
2049	0	419	802	1,221
2050	0	429	808	1,237
2051	0	439	814	1,254
2052	0	449	821	1,270
2053	0	459	827	1,286
2054	0	469	833	1,302
2055	0	479	839	1,318
2056	0	488	845	1,334
2057	0	498	852	1,350

17. Owned Unit Modeled Operating Characteristics and Costs

Company owned units are modeled based upon their tested operating characteristics and projected costs. Below is a list of typical operating and cost inputs for each company owned resource.

a. Retirement Date
b. Maximum Capacity
c. Current Unforced Capacity (UCAP) Ratings
d. Minimum Capacity Rating
e. Seasonal Deration
f. Heat Rate Profiles
g. Variable O&M
h. Fixed O&M
i. Maintenance Schedule
j. Forced Outage Rate
k. Emission rates for SO_2, NO_x, CO_2, Mercury and particulate matter (PM)
l. Contribution to spinning reserve
m. Fuel prices
n. Fuel delivery charges

18. Thermal Power Purchase Agreement (PPA) Operating Characteristics and Costs

PPAs are modeled based upon their tested operating characteristics and contracted costs. Below is a list of typical operating and cost inputs for each thermal PPA.

a. Contract term
b. Maximum Capacity
c. Minimum Capacity Rating
d. Seasonal Deration
e. Heat Rate Profiles
f. Energy Schedule
g. Capacity Payments
h. Energy Payments
i. Maintenance Schedule
j. Forced Outage Rate
k. Emission rates for SO_2, NO_x, CO_2, Mercury and PM
l. Contribution to spinning reserve
m. Fuel prices
n. Fuel delivery charges

19. Renewable Energy (PPAs and Owned) Operating Characteristics and Costs

PPAs are modeled based upon their tested operating characteristics and contracted costs. Company owned units are modeled based upon their tested operating characteristics and projected costs. Below is a list of typical operating and cost inputs for each renewable energy unit.

a. Contract term
b. Name Plate Capacity
c. Accredited Capacity
d. Annual Energy
e. Hourly Patterns
f. Capacity and Energy Payments
g. Integration Costs

Wind hourly patterns are developed through a “Typical Wind Year” process where individual months are selected from the years 2014-2017 to develop a representative typical year. Actual generation data from the selected months is used to develop the profile for each wind farm. For farms where generation data is not complete or not available, data from nearby similar farms is used.

Solar hourly patterns are taken from the ELCC Study from Fall 2013 and updated to reflect the ELCC as stated above.

20. Generic Assumptions

Generic resources are modeled based upon their expected operating characteristics and projected costs. Generic thermal costs are developed by the Company. Generic battery costs are based on Public Service of Colorado All-Source Solicitation bids (Nov 28, 2017) with a 10% annual price improvement rate. Generic renewable costs and capacity factors are from National Renewable Energy Laboratory’s 2018 Annual Technology Baseline data. Utility scale wind and solar costs shown in Tables 16-18 include transmission costs from Table 10 while distributed solar does not.

The Reference Case assumes “no going back” on renewables, meaning that the levels committed to in the preferred plan in the previous IRP are maintained, and renewable resources are replaced “in-kind” when they reach end of life. Starting in 2023, generic solar is added to maintain at a minimum the 2015 IRP Preferred Plan solar levels. In 2023, there is ~ 1,800 GWhs of solar (both utility scale and DG solar) on the system which will grow to ~ 4,500 GWhs by 2028. The company has already procured the levels of wind contemplated in the previous IRP, so no minimum level of generic wind additions are needed. Additional renewables are included as Proview Alternatives.

In addition to base cost data for renewables, low and high costs are used for various sensitivities. Low and high wind and solar costs are based on the National Renewable Energy Laboratory's 2018 Annual Technology Baseline data. Low and high battery costs are based the percent difference in the NREL ATB low / high battery costs compared to the NREL ATB base costs, with this percent difference applied to the Company's base battery cost forecast.

Below is a list of typical operating and cost inputs for each generic resource.

Thermal

a. Retirement Date
b. Maximum Capacity
c. UCAP Ratings
d. Minimum Capacity Rating
e. Seasonal Deration
f. Heat Rate Profiles
g. Variable O&M
h. Fixed O&M
i. Maintenance Schedule
j. Forced Outage Rate
k. Emission rates for SO_2, NO_x, CO_2, Mercury and PM
l. Contribution to spinning reserve
m. Fuel prices
n. Fuel delivery charges

Renewable

a. Contract term
b. Name Plate Capacity
c. Accredited Capacity
d. Annual Energy
e. Hourly Patterns
f. Capacity and Energy Payments
g. Integration Costs

Table 14: Thermal Generic Information (Costs in 2018 Dollars)

Thermal Generic Information					
Resource	**Sherco CC**	**Generic CC**	**Generic CT**	**Generic CT**	**Generic CT**
Technology	7H	7H	7H	7F	7H
Location Type	Brownfield	Greenfield	Brownfield	Brownfield	Greenfield
Cooling Type	Wet	Dry	Dry	Dry	Dry
Book life	40	40	40	40	40
Nameplate Capacity (MW)	835	916	374	232	374
Summer Peak Capacity with Ducts (MW)	750	870	NA	NA	NA
Summer Peak Capacity without Ducts (MW)	576	750	331	206	331
Capital Cost ($000) 2018$	$837,068	$871,168	$174,700	$114,766	$193,500
Electric Transmission Delivery ($000) 2018$	NA	$417,180	NA	NA	$74,804
Ongoing Capital Expenditures ($000-yr) 2018$	$6,200	$6,200	$1,784	$892	$1,784
Gas Demand ($000-yr) 2018$	$15,000	$19,368	$2,165	$1,342	$2,165
Gas Pipeline CIAC ($000) 2018 $	$192,000	NA	NA	NA	NA
Capital Cost ($/kW) 2018$	$1,002	$951	$467	$495	$517
Electric Transmission Delivery ($/kW) 2018$	NA	$455	NA	NA	$200
Ongoing Capital Expenditures ($/kW-yr) 2018$	$7.42	$6.77	$4.77	$3.85	$4.77
Gas Demand ($/kW-yr) 2018$	$17.96	$21.14	$5.79	$5.79	$5.79
Fixed O&M Cost ($000/yr) 2018$	$6,592	$6,592	$1,253	$1,203	$1,253
Variable O&M Cost ($/MWh) 2018$	$1.04	$1.04	$0.99	$1.03	$0.99
Levelized $/kw-mo (All Fixed Costs) $2018	$13.97	$15.10	$5.74	$6.03	$7.83
Summer Heat Rate with Duct Firing (btu/kWh)	NA	6,522	NA	NA	NA
Summer Heat Rate 100% Loading (btu/kWh)	6,359	5,984	9,264	10,025	9,264
Summer Heat Rate 75% Loading (btu/kWh)	6,546	6,546	9,546	10,407	9,546
Summer Heat Rate 50% Loading (btu/kWh)	7,109	7,109	10,376	11,597	10,376
Summer Heat Rate 25% Loading (btu/kWh)	7,671	7,671	11,207	12,787	11,207
Forced Outage Rate	3%	3%	3%	3%	3%
Maintenance (weeks/yr)	5	5	2	2	2
CO2 Emissions (lbs/MMBtu)	118	118	118	118	118
SO2 Emissions (lbs/MWh)	0.00	0.00	0.00	0.00	0.00
NOx Emissions (lbs/MWh)	0.05	0.05	0.90	0.32	0.90
PM10 Emissions (lbs/MWh)	0.02	0.02	0.03	0.03	0.03
Mercury Emissions (lbs/MMWh)	0.00	0.00	0.00	0.00	0.00

Table 15: Renewable Generic Information (Costs in 2018 Dollars)

Renewable Generic Information				
Resource	**Wind**	**Utility Scale Solar**	**Distributed Solar Commercial**	**Distributed Solar Residential**
ELCC Capacity Credit (%)	15.6%	50.0%	50.0%	50.0%
Capacity Factor	50.0%	17.7%	14.0%	14.8%
Book life	25	25	25	25
Electric Transmission Delivery ($/kW)	400	140	0	0

Table 16: Levelized Capacity Costs by In-Service Year

Levelized Capacity Costs by In-Service Year ($/kw-mo)								
COD	CT - 7H Greenfield	CT - 7F Brownfield	CT - 7H Brownfield	CC	Sherco CC	Base Battery	Low Battery	High Battery
2018	$7.83	$6.03	$5.74	$15.10	$13.97			
2019	$7.99	$6.16	$5.85	$15.41	$14.25			
2020	$8.15	$6.28	$5.97	$15.71	$14.53			
2021	$8.31	$6.40	$6.09	$16.03	$14.83			
2022	$8.48	$6.53	$6.21	$16.35	$15.12			
2023	$8.65	$6.66	$6.33	$16.68	$15.42	$10.53	$8.03	$13.71
2024	$8.82	$6.80	$6.46	$17.01	$15.73	$9.48	$6.99	$12.51
2025	$9.00	$6.93	$6.59	$17.35	$16.05	$8.91	$6.35	$11.92
2026	$9.18	$7.07	$6.72	$17.70	$16.37	$8.53	$5.90	$11.41
2027	$9.36	$7.21	$6.85	$18.05	$16.70	$8.24	$5.53	$11.04
2028	$9.55	$7.36	$6.99	$18.41	$17.03	$8.02	$5.20	$10.73
2029	$9.74	$7.50	$7.13	$18.78	$17.37	$7.83	$4.92	$10.49
2030	$9.93	$7.65	$7.27	$19.16	$17.72	$7.68	$4.65	$10.28
2031	$10.13	$7.81	$7.42	$19.54	$18.07	$7.54	$4.51	$10.19
2032	$10.33	$7.96	$7.57	$19.93	$18.43	$7.42	$4.39	$10.13
2033	$10.54	$8.12	$7.72	$20.33	$18.80	$7.31	$4.27	$10.08
2034	$10.75	$8.28	$7.87	$20.74	$19.18	$7.22	$4.16	$10.05
2035	$10.97	$8.45	$8.03	$21.15	$19.56	$7.13	$4.05	$10.02
2036	$11.19	$8.62	$8.19	$21.57	$19.95	$7.05	$3.94	$10.02
2037	$11.41	$8.79	$8.36	$22.00	$20.35	$6.98	$3.83	$10.03
2038	$11.64	$8.97	$8.52	$22.44	$20.76	$6.91	$3.73	$10.05
2039	$11.87	$9.15	$8.69	$22.89	$21.17	$6.85	$3.63	$10.07
2040	$12.11	$9.33	$8.87	$23.35	$21.60	$6.79	$3.53	$10.09
2041	$12.35	$9.52	$9.04	$23.82	$22.03	$6.73	$3.44	$10.11
2042	$12.60	$9.71	$9.22	$24.30	$22.47	$6.68	$3.36	$10.13
2043	$12.85	$9.90	$9.41	$24.78	$22.92	$6.63	$3.28	$10.15
2044	$13.11	$10.10	$9.60	$25.28	$23.38	$6.58	$3.20	$10.17
2045	$13.37	$10.30	$9.79	$25.78	$23.85	$6.54	$3.12	$10.20
2046	$13.64	$10.51	$9.99	$26.30	$24.32	$6.50	$3.10	$10.13
2047	$13.91	$10.72	$10.18	$26.82	$24.81	$6.46	$3.09	$10.07
2048	$14.19	$10.93	$10.39	$27.36	$25.31	$6.42	$3.07	$10.01
2049	$14.47	$11.15	$10.60	$27.91	$25.81	$6.38	$3.06	$9.96
2050	$14.76	$11.37	$10.81	$28.47	$26.33	$6.35	$3.04	$9.91
2051	$15.05	$11.60	$11.02	$29.03	$26.85	$6.31	$3.03	$9.85
2052	$15.36	$11.83	$11.24	$29.62	$27.39	$6.28	$3.01	$9.80
2053	$15.66	$12.07	$11.47	$30.21	$27.94	$6.25	$3.00	$9.76
2054	$15.98	$12.31	$11.70	$30.81	$28.50	$6.22	$2.98	$9.71
2055	$16.30	$12.56	$11.93	$31.43	$29.07	$6.19	$2.97	$9.66
2056	$16.62	$12.81	$12.17	$32.06	$29.65	$6.16	$2.95	$9.62
2057	$16.95	$13.06	$12.42	$32.70	$30.24	$6.13	$2.94	$9.58

Table 17: Base Renewable Levelized Costs by In-Service Year

Levelized Costs by In-Service Year $/MWh (LCOE)				
COD	Wind	Utility Scale Solar	Distributed Solar Commercial	Distributed Solar Residential
2018				
2019				
2020	$29.79	$40.00	$73.92	$97.93
2021	$29.65	$40.00	$71.77	$91.35
2022	$34.04	$40.00	$70.71	$88.46
2023	$38.61	$49.48	$69.59	$87.04
2024	$43.39	$49.90	$68.41	$85.55
2025	$52.15	$50.32	$67.18	$83.98
2026	$52.55	$50.74	$65.88	$82.34
2027	$52.98	$51.17	$64.53	$80.63
2028	$53.42	$51.59	$63.11	$78.83
2029	$53.89	$52.01	$61.62	$76.95
2030	$54.39	$52.43	$60.07	$74.98
2031	$54.95	$53.10	$60.66	$75.15
2032	$55.54	$53.78	$61.25	$75.28
2033	$56.16	$54.47	$61.84	$75.40
2034	$56.80	$55.16	$62.43	$75.49
2035	$57.47	$55.86	$63.02	$75.56
2036	$58.17	$56.57	$63.61	$75.60
2037	$58.91	$57.28	$64.20	$75.61
2038	$59.67	$58.00	$64.78	$75.60
2039	$60.47	$58.72	$65.37	$75.56
2040	$61.30	$59.45	$65.95	$75.49
2041	$62.17	$60.13	$66.88	$76.33
2042	$63.07	$60.81	$67.82	$77.18
2043	$64.01	$61.50	$68.77	$78.04
2044	$64.99	$62.18	$69.74	$78.89
2045	$66.01	$62.87	$70.71	$79.76
2046	$67.07	$63.57	$71.70	$80.62
2047	$68.17	$64.27	$72.70	$81.49
2048	$69.32	$64.97	$73.71	$82.36
2049	$70.52	$65.68	$74.73	$83.24
2050	$71.76	$66.38	$75.76	$84.07
2051	$73.20	$67.71	$77.28	$85.75
2052	$74.66	$69.07	$78.83	$87.47
2053	$76.16	$70.45	$80.40	$89.22
2054	$77.68	$71.86	$82.01	$91.00
2055	$79.23	$73.29	$83.65	$92.82
2056	$80.82	$74.76	$85.32	$94.68
2057	$82.43	$76.25	$87.03	$96.57

*Distributed Solar costs represent at the meter values before grossing up for losses.

Table 18: Low Renewable Levelized Costs by In-Service Year

Low Levelized Costs by In-Service Year $/MWh (LCOE)				
COD	Wind	Utility Scale Solar	Distributed Solar Commercial	Distributed Solar Residential
2018				
2019				
2020	$25.51	$35.18	$56.57	$94.61
2021	$24.43	$35.18	$51.50	$85.46
2022	$27.80	$35.18	$50.18	$81.18
2023	$31.28	$43.52	$48.81	$78.32
2024	$34.89	$43.21	$47.40	$75.38
2025	$42.41	$42.88	$45.95	$72.34
2026	$41.50	$42.54	$44.44	$69.21
2027	$40.53	$42.17	$42.89	$65.98
2028	$39.52	$41.79	$41.28	$62.65
2029	$38.00	$41.39	$39.63	$59.22
2030	$37.80	$40.97	$37.93	$55.69
2031	$37.66	$41.28	$37.65	$53.91
2032	$38.06	$41.58	$37.35	$52.04
2033	$38.48	$41.88	$37.03	$50.07
2034	$38.90	$42.28	$36.68	$48.02
2035	$39.34	$42.25	$36.30	$45.87
2036	$39.80	$42.39	$35.90	$43.62
2037	$40.26	$42.52	$35.47	$41.27
2038	$40.75	$42.64	$35.01	$38.81
2039	$41.24	$42.75	$34.52	$36.25
2040	$41.75	$42.85	$33.99	$33.57
2041	$42.27	$43.27	$34.47	$34.11
2042	$42.80	$43.39	$34.95	$34.64
2043	$43.35	$43.37	$35.44	$35.19
2044	$43.92	$43.33	$35.94	$35.75
2045	$44.50	$44.15	$36.44	$36.31
2046	$45.09	$43.34	$36.95	$36.88
2047	$45.70	$43.39	$37.46	$37.46
2048	$46.32	$43.42	$37.98	$38.05
2049	$46.96	$43.44	$38.50	$38.65
2050	$47.62	$43.97	$39.04	$39.22
2051	$48.57	$44.85	$39.82	$40.00
2052	$49.54	$45.74	$40.61	$40.80
2053	$50.53	$46.66	$41.43	$41.62
2054	$51.54	$47.59	$42.25	$42.45
2055	$52.57	$48.54	$43.10	$43.30
2056	$53.63	$49.51	$43.96	$44.17
2057	$54.70	$50.50	$44.84	$45.05

*Distributed Solar costs represent at the meter values before grossing up for losses.

Table 19: High Renewable Levelized Costs by In-Service Year

High Levelized Costs by In-Service Year $/MWh (LCOE)				
COD	Wind	Utility Scale Solar	Distributed Solar Commercial	Distributed Solar Residential
2018				
2019				
2020	$34.70	$50.52	$88.96	$124.70
2021	$35.40	$50.52	$91.58	$127.20
2022	$40.61	$50.52	$93.41	$128.14
2023	$46.03	$62.48	$95.28	$130.70
2024	$51.64	$63.73	$97.19	$133.32
2025	$61.25	$65.01	$99.13	$135.98
2026	$62.49	$66.31	$101.11	$138.70
2027	$63.76	$67.63	$103.14	$141.48
2028	$65.06	$68.99	$105.20	$144.30
2029	$66.38	$70.37	$107.30	$147.19
2030	$67.72	$71.77	$109.45	$150.13
2031	$69.10	$73.21	$111.64	$153.14
2032	$70.50	$74.67	$113.87	$156.20
2033	$71.93	$76.17	$116.15	$159.32
2034	$73.39	$77.69	$118.47	$162.51
2035	$74.88	$79.24	$120.84	$165.76
2036	$76.39	$80.83	$123.26	$169.08
2037	$77.94	$82.45	$125.72	$172.46
2038	$79.52	$84.09	$128.24	$175.91
2039	$81.13	$85.78	$130.80	$179.42
2040	$82.77	$87.49	$133.42	$183.01
2041	$84.45	$89.24	$136.09	$186.67
2042	$86.16	$91.03	$138.81	$190.41
2043	$87.90	$92.85	$141.58	$194.21
2044	$89.68	$94.70	$144.42	$198.10
2045	$91.49	$96.60	$147.30	$202.06
2046	$93.34	$98.53	$150.25	$206.10
2047	$95.23	$100.50	$153.25	$210.22
2048	$97.15	$102.51	$156.32	$214.43
2049	$99.12	$104.56	$159.45	$218.72
2050	$101.12	$106.65	$162.63	$223.09
2051	$103.14	$108.79	$165.89	$227.55
2052	$105.21	$110.96	$169.21	$232.10
2053	$107.31	$113.18	$172.59	$236.75
2054	$109.46	$115.44	$176.04	$241.48
2055	$111.65	$117.75	$179.56	$246.31
2056	$113.88	$120.11	$183.15	$251.24
2057	$116.16	$122.51	$186.82	$256.26

*Distributed Solar costs represent at the meter values before grossing up for losses.

CERTIFICATE OF SERVICE

I, Jim Erickson, hereby certify that I have this day served copies of the foregoing document on the attached list of persons.

xx by depositing a true and correct copy thereof, properly enveloped with postage paid in the United States mail at Minneapolis, Minnesota

xx electronic filing

Docket No. IP6949, E002/PA-18-702

Dated this 29th day of March 2019

/s/
____
Jim Erickson
Regulatory Administrator

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