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Direct Testimony
Farah L. Mandich

STATE OF NORTH DAKOTA
BEFORE THE
NORTH DAKOTA PUBLIC SERVICE COMMISSION

In the Matter of the Application of Northern States Power Company
for an Advance Determination of Prudence for Repowered Wind Portfolio

Case No. PU-20-____
Exhibit___(FLM-1)

Resource Planning

October 13, 2020

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Prefiled Direct Testimony of Farah Mandich - redacted
Northern States Power Company
Zeviel Simpser - Dorsy & Whitney LLP

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I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND TITLE.

A. My name is Farah L. Mandich. I am a Regulatory Policy Specialist for Northern States Power Company-Minnesota (NSP or Xcel Energy or the Company). The Company provides electric service to customers in Minnesota, North Dakota, and South Dakota (collectively the NSPM States). The Company's affiliate, Northern States Power, a Wisconsin corporation (NSPW), provides electric service to customers in Wisconsin and Michigan. The Company and NSPW, together under the Interchange Agreement, own and operate the five-state integrated NSP System.

Q. PLEASE DESCRIBE YOUR QUALIFICATIONS AND EXPERIENCE.

A. I have worked for Xcel Energy since April 2019 in the Regulatory Affairs department. In this role, I work with cross-functional teams to develop Integrated Resource Plan and resource acquisition filings for NSP.

Prior to joining Xcel Energy, I worked as a Policy Advisor for Southern California Edison, a large investor owned utility in California. In this role, I supported development of Integrated Resource Planning and resource acquisition regulatory filings before the California Public Utilities Commission. My statement of qualifications is provided as Exhibit___(FLM-1), Schedule 1.

Q. WHAT ARE YOUR CURRENT RESPONSIBILITIES?

A. In my current role, I work within the Regulatory Affairs team on the development of resource plans for the five-state integrated Upper Midwest

Northern States Power Company system (NSP System), which provides electric service to customers in North Dakota, South Dakota, Minnesota, Wisconsin, and Michigan. I also work on the development of resource acquisition filings for NSPM, including those filed in Minnesota and North Dakota.

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

A. The purpose of my testimony is to discuss, in detail, the economic impacts of the proposed power repowering of the Border Winds, Grand Meadows Wind, Nobles Wind, and Pleasant Valley Wind facilities in support of the Company's ADP Application (Application). The individual proposed repowering projects are described in the testimony of Company witness Mr. Christopher J. Shaw.

My testimony supports the conclusion that the North Dakota Public Service Commission (Commission) should grant an advance determination of prudence (ADP) for each of the proposed projects. My testimony provides an economic analysis of the proposed projects and the overall benefits they generate.

II. ECONOMIC ANALYSIS

Q. HOW DID THE COMPANY EVALUATE THE ECONOMIC IMPACT OF THE PROPOSED REPOWERING PROJECTS?

A. First, we performed a "pro forma" spreadsheet analysis on each individual project proposed in response to the Company's RFP. Later, after the proposed projects were narrowed down, we analyzed the overall rebuild portfolio (the Wind Repower Portfolio), which includes the four self-build projects that that are the subject of the Application and three additional smaller power purchase agreement (PPA) projects, using EnCompass.

A. Pro Forma Analysis

Q. WHAT IS A PRO FORMA ANALYSIS?

A. Pro forma is a spreadsheet analysis. The pro forma compares the expected costs of each repower proposal to a baseline where the existing (unrepowered) project remains in our portfolio to the end of its expected life and is replaced by a generic wind resource thereafter. Pro forma modeling allowed us to screen projects for expected benefits prior to full resource planning modeling using EnCompass. Further, in recognition of Advocacy Staff's request in the Mower County Wind ADP proceeding (CaseNo. PU-19-310), we also performed a pro forma analysis in which each proposed Company-owned repowering project for which we are requesting an ADP was compared to a baseline where the existing project remains in our portfolio to the end of its expected life and is replaced by market price replacement energy.

Q. WHAT WERE THE RESULTS OF THE PRO FORMA ANALYSES?

A. In the course of this evaluation, we discovered that two of the projects bid in response to the Company's solicitation for rebuild projects were not expected to yield customer benefits at the price and terms provided. These projects were eliminated from further consideration and are not included in the Application. The pro forma analysis indicated that the four projects included with the Application (and the PPA projects that included in the broader Wind Repower Portfolio) are all expected to result in customer benefits.

Q. WHAT CUSTOMER BENEFITS DID THE PRO FORMA ANALYSIS USING GENERIC WIND AS A REPLACEMENT RESOURCE INDICATE FOR THE FOUR SELF-BUILD PROJECTS THAT ARE THE SUBJECT OF THIS APPLICATION?

A. On an aggregate basis, this pro forma analysis showed $138 million in savings for the Company-owned projects. The pro forma analysis indicated that repowering of Border Winds would result in **[TRADE SECRET DATA BEGINS TRADE SECRET DATA ENDS]** million in savings, the repowering of Pleasant Valley Wind would result in **[TRADE SECRET DATA BEGINS TRADE SECRET DATA ENDS]** million in savings, the repowering of Grand Meadow Wind would result in **[TRADE SECRET DATA BEGINS TRADE SECRET DATA ENDS]** million in savings, and the repowering of Nobles wind would result in **[TRADE SECRET DATA BEGINS TRADE SECRET DATA ENDS]** million in savings. These savings are on a present value of revenue requirements (PVRR) basis and do not include carbon dioxide costs, other environmental externality values, or costs for potential future carbon emissions regulations.

Q. WHAT CUSTOMER BENEFITS DID THE PRO FORMA ANALYSIS USING MARKET ENERGY AS A REPLACEMENT RESOURCE INDICATE FOR THE FOUR SELF-BUILD PROJECTS THAT ARE THE SUBJECT OF THIS APPLICATION?

A. On an aggregate basis, this pro forma analysis showed $87.9 million in savings for the Company-owned projects. The pro forma analysis indicated that repowering of Border Winds would result in **[TRADE SECRET DATA BEGINS TRADE SECRET DATA ENDS]** million in savings, the repowering of Pleasant Valley Wind would result in **[TRADE SECRET DATA BEGINS TRADE SECRET DATA BEGINS]** million in savings, the repowering of Grand Meadow Wind would result in **[TRADE SECRET DATA BEGINS TRADE SECRET DATA ENDS]** million in savings, and the repowering of Nobles wind would result in **[TRADE SECRET BEGINS TRADE SECRET DATA ENDS]** million in savings. These savings are on a present value of revenue requirements (PVRR) basis and do not include carbon dioxide costs, other environmental externality values, or costs for potential future carbon emissions regulations.

Q. DID THE COMPANY PERFORM A PRO FORMA ANALYSIS OF THE THREE PPA REPOWERING PROJECTS?

A. Yes, although they are not part of the Application, the three PPA repowering projects went through the same process as the self-build projects, and the pro forma analysis using a generic wind replacement was a crucial step in that process. This pro forma analysis also showed cost savings from the three PPA projects: the Ewington Wind Project PPA repowering would result in **[TRADE SECRET DATA BEGINS TRADE SECRET DATA ENDS]** in savings, the McNeilus Wind PPA repowering would result in **[TRADE SECRET DATA BEGINS TRADE SECRET DATA BEGINS]** in savings, and the Westridge Wind Farm PPA repowering would result in **[TRADE SECRET DATA BEGINS TRADE SECRET DATA BEGINS]** in savings. Table 1 below summarizes the result of the pro forma analyses of all the projects in the Wind Repower Portfolio.

Table 1: Pro Forma Savings Resulting from Repowering Projects

Project Name	Type	Repower Cost Savings $M (wind	Repower Cost Savings $M (market price

		replacement energy) **[TRADE SECRET DATA BEGINS**	replacement energy) **[TRADE SECRET DATA BEGINS**
Border Winds	Self-build		
Grand Meadow Wind	Self-build		
Nobles Wind	Self-build		
Pleasant Valley Wind	Self-build	**TRADE SECRET DATA ENDS]**	**TRADE SECRET DATA ENDS]**
Total for Company-owned	Self-build	($138)	($87.9)
Ewington Wind	PPA	**[TRADE SECRET DATA BEGINS**	**N/A**
McNeilus Wind	PPA		**N/A**
Westridge Wind	PPA	**TRADE SECRET DATA ENDS]**	**N/A**
Total for PPA Projects	PPA	($26.25)	**N/A**

Q. WHAT DOES THE TABLE SHOW?

A. The results of the pro forma analyses shown in the table above demonstrate that each of the four Company-owned wind repowering projects that are the subject of this Application are expected to provide cost saving benefits to the Company's customers regardless of whether the existing resources are assumed to be replaced with generic wind resources or market energy. The cost savings are on a PVRR basis to customers over their life for the entire NSP System.

B. EnCompass Analysis

Q. WHAT IS ENCOMPASS?

A. EnCompass is a resource planning model that the Company used to evaluate the impact of the Wind Repower Portfolio on customers. Encompass is a capacity expansion and production cost model tool that allows the Company to optimize resource expansion plans based on a set of assumptions. Like our previously-used resource planning model, Strategist, EnCompass simulates the operation of the NSP System and estimates the total cost of energy over the life of the project on a present value basis. However, one of the primary differences between EnCompass and Strategist is that Encompass evaluates resource needs and cost on an hourly chronological basis, which better accounts for hourly variations on our system. The Company has largely shifted to using the EnCompass tool, rather than Strategist, to perform capacity-expansion modeling because, as we add more variable and use-limited resources to our system, it becomes increasingly important to ensure we appropriately consider resource needs and costs on an hourly basis.

Q. HOW DID THE COMPANY USE ENCOMPASS TO EVALUATE THE PROPOSED PROJECTS?

A. The last step of our solicitation evaluation process included modeling the portfolio of shortlisted projects in the EnCompass model. We conducted this portfolio analysis to validate that the full portfolio of repowering projects, including both the self-build projects that are the subject of the Application and the PPA projects, would yield customer benefits.

In our pro forma analysis, we already established that each individual project would be expected to provide customer benefits, relative to a future in which the existing plant remained in service until the end of its asset or contract life, and was then replaced with a generic wind resource. However, in a full system planning analysis we may select from a wide variety of resources to replace an expiring resource, or – depending on the loads and resources on the system at the time – it may not need to be replaced at all. Portfolio modeling in the EnCompass tool allows us to simulate our future system and evaluate these tradeoffs.

Q. WHAT MODELLING INPUTS AND ASSUMPTIONS WERE USED IN THE ENCOMPASS MODELLING?

A. We evaluated the Wind Repower Portfolio's economic impact to our system using a Base Case consistent with the plan presented in our most recent Integrated Resource Plan Supplement, filed with the Commission on June 30, 2020.[1] We updated these assumptions through the addition of the Mower County Wind resource in the Base Case in response to the Commission's approval in Case No. PU-19-310, along with other updates since we filed our Supplement Preferred Plan at the end of June. Our complete modeling assumptions are provided as Schedule 2 to my Direct Testimony.

Our analysis takes this Base Case, and then analyzes a change case in which the proposed repowering portfolio replaces the relevant existing resource(s)

[1] *See* Case No. PU-19-220. XCEL ENERGY 2020-2034 UPPER MIDWEST INTEGRATED RESOURCE PLAN SUPPLEMENT (June 30, 2020).

in our overall generation portfolio. The Company's full Upper Midwest system resource portfolio is then re-optimized in order to evaluate whether moving forward with these repowered projects will provide benefits or result in additional costs on a system-wide basis.

Q. WHAT WAS THE RESULT OF THE ENCOMPASS ANALYSIS?

A. We evaluated the overall Wind Repower Portfolio in comparison to the Base Case. The results of the EnCompass analysis shows that the proposed portfolio of repowered projects will result in net savings for our customers, including under sensitivity analyses for high and low gas, coal, and market prices. The results of the EnCompass analysis are set forth in Table 2 below.

Table 2: PVRR Savings Resulting from the Wind Repower Portfolio

Present Value Measure	Cost/(Savings) ($2020 millions)
PVRR (No CO2 Costs)	(163)
Sensitivities	
Low Gas, Coal, and Market Prices	(98)
High Gas, Coal, and Market Prices	(248)

The costs savings in the table above are on a PVRR basis, and do not include carbon dioxide costs, other externality values, or potential future regulatory costs for carbon emissions. These results show that we expect that the Wind Repower Portfolio will result in significant net benefits to our customers.

Q. WHEN WILL THE COST SAVINGS REPRESENTED IN THE TABLE ABOVE OCCUR?

A. To understand how these potential costs or savings accrue over time, we examined total system costs on an annual and cumulative basis. Figures 1 and 2 below portrays the annual (undiscounted) and cumulative system costs impacts of incorporating the Wind Repower Portfolio into our system. Given these results, we expect that all customers will experience benefits from the portfolio in nearly every year, with benefits accruing immediately and more than offsetting a small number of years when costs may increase relative to the Base Case. In short, the portfolio captures substantial customer benefits overall.

Figure 1: Annual Costs/(Savings) Resulting from the Wind Repower Portfolio Case, as Compared to the Base Case

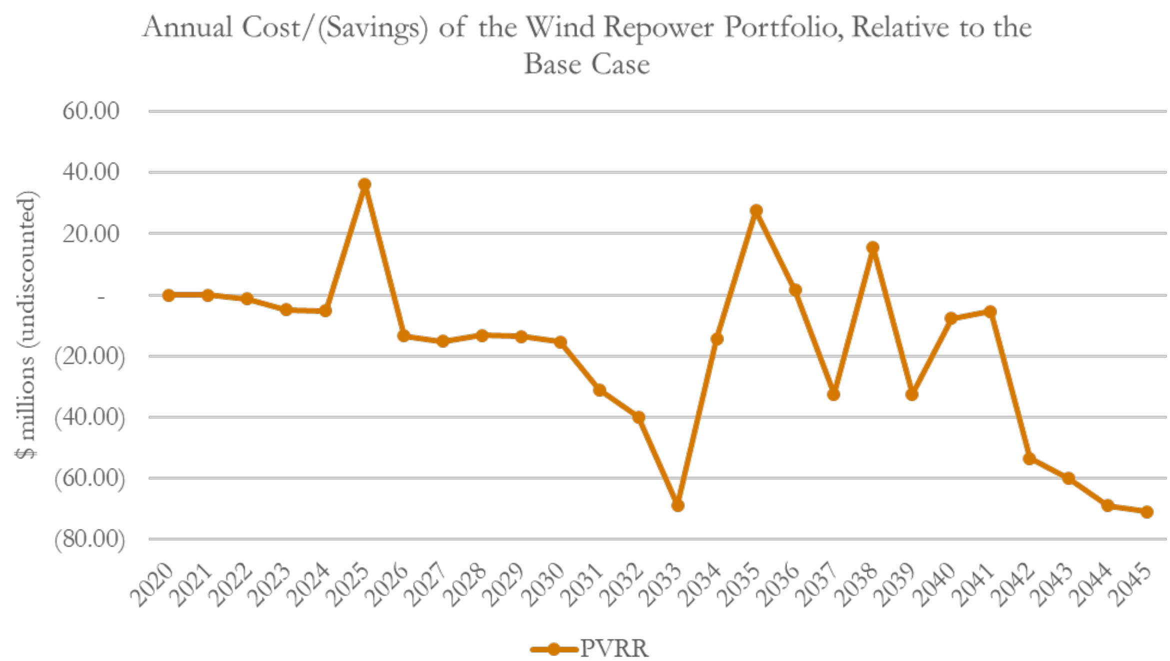
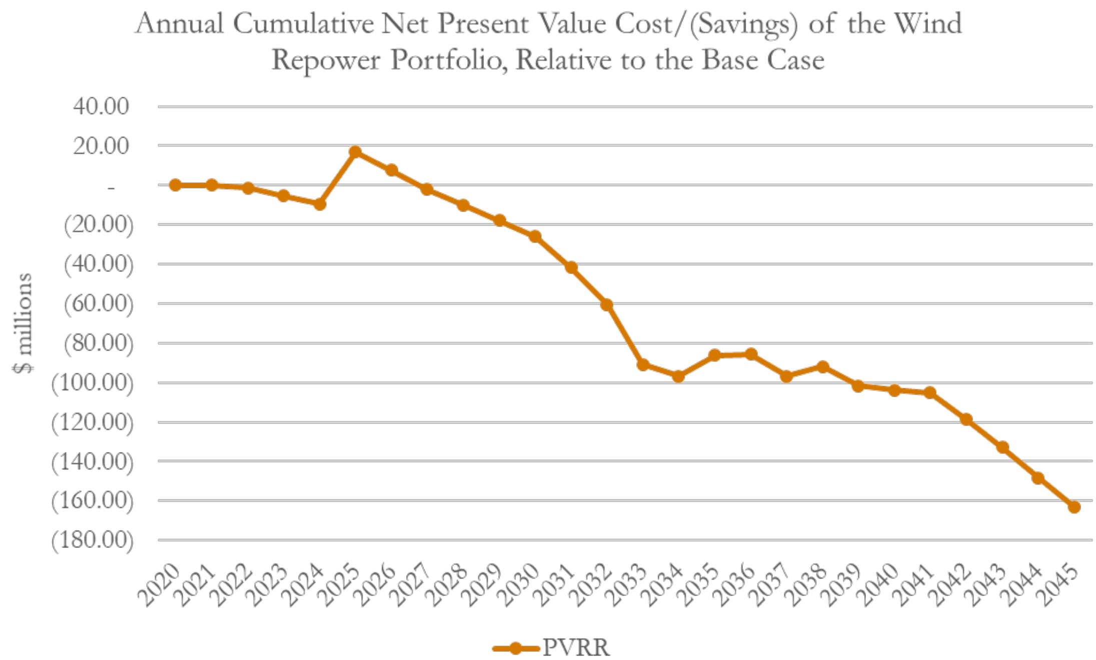


Figure 2: Annual Cumulative Net Present Value Costs/(Savings) Resulting from the Wind Repower Portfolio Case, as Compared to the Base Case



Q. WHAT DO THE FIGURES ABOVE SHOW?

A. The figures show that customers begin experiencing cost savings as soon as 2022, when existing facilities begin to be replaced with new, lower cost repowered projects. Savings then continue to accrue until 2025, where there is a one-year increase in costs, relative to the Base Case. This cost increase is primarily a factor of a difference in PTCs earned on two of the Company's proposed self-build projects and their impacts on ratemaking with respect to our deferred tax asset. Both Border Winds and Pleasant Valley were in-serviced in 2015, and therefore – in the Base Case where the units are not repowered – would have one final year of their existing level of PTC qualification. In the Wind Repower Portfolio Case, these projects would no longer receive that same level of PTCs as of the repower in-service date, which is at the end of 2024. The repowered projects are expected to qualify for partial PTCs for ten additional years as of their COD date; however, the PTCs they will accrue in 2025 are lower than in the Base Case, and thus we see the cost delta increase in that one year. That said, I note part of the cost of partially foregone PTCs in 2025 is offset by cost savings the Company will experience as a result of the repowered, higher efficiency wind facilities and resulting reduced market purchases and increased market sales. Also, please note that the remainder of increased costs in 2025 are fully offset by accrued savings in other years by 2027.

After 2025, customers begin accruing savings again in the Wind Repower Portfolio Case, relative to the Base Case. In the near term, these cumulative savings are largely a result of the repowered facilities' increased efficiency, displacing higher cost generation from other resources on the system and increasing market sales. As shown in Figure 2, customer benefits grow to be substantial, on a cumulative basis, through the end of the analysis period. Sharp changes in the savings trends in any given future year are generally driven by either PTCs expiring for the repowered projects in the early 2030's, and/or new generic units in the expansion plan moving up or back a year, relative to the Base Case.

Q. WHAT DO YOU CONCLUDE FROM THIS ANALYSIS?

A. I conclude that the Wind Repower Portfolio will provide material cost savings to the NSP System, including under the high and low-cost sensitivity scenarios. The cost savings will begin as soon as 2022 and, except for 2025, will continue to accumulate.

Q. DOES THE ENCOMPASS MODELLING PROVIDE INFORMATION ON THE INDIVIDUAL PROJECTS THAT ARE THE SUBJECTS OF THE APPLICATION?

A. No, the EnCompass modelling was done on the entire Wind Repower Portfolio, which includes the four self-build projects for which the Company is seeking ADPs in the Application as well as the three additional PPA projects. However, we know that the bulk of the customer savings result from the self-build projects, which are significantly larger than the PPA projects. In addition, as I noted above, the pro forma analysis showed that each of the individual projects in the Wind Repower Portfolio will result in customer savings. Accordingly, the Company is confident that each of the repowering projects for which it is seeking an ADP will provide material benefits to customers.

Q. HISTORICALLY, THE COMPANY HAS PROVIDED A RATE IMPACT ANALYSIS WITH ITS ADP APPLICATIONS. WHY WAS SUCH AN ANALYSIS NOT INCLUDED WITH THIS APPLICATION?

A. Both the pro forma analyses and the EnCompass modelling indicate that the repowering projects will reduce costs and result in customer savings. Accordingly, we concluded that a rate impact analysis was not necessary. However, if the Commission desires such an analysis, we would be happy to provide one during discovery.

III. CONCLUSION

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS.

A. The repowering projects for which the Company is seeking ADPs are prudent. Our pro forma analysis showed that each of the projects will benefit customers and our EnCompass modelling of the overall Wind Repower Portfolio showed that it will provide substantial cost saving benefits for customers. We estimate that the Wind Repower Portfolio will save customers approximately $163 million on a PVRR basis. The four projects for which we are seeking ADPs are prudent and reasonable, and the Commission should grant ADPs for each of them.

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

A. Yes, it does.

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF NORTH DAKOTA

NORTHERN STATES POWER COMPANY ADVANCE DETERMINATION OF PRUDENCE – REPOWERED WIND PORTFOLIO	CASE NO. PU-20-__

VERIFICATION

STATE OF MINNESOTA)
)SS.
COUNTY OF HENNEPIN

Farah L. Mandich, being first duly sworn on oath, deposes and says that she is a Regulatory Policy Specialist for Applicant Northern States Power Company, a Minnesota corporation, in the above-captioned matter, that the testimony submitted in the above-captioned matter under her name was prepared under her direction, that she knows the contents thereof, and that the same is true and correct to the best of her knowledge and belief.

____
Farah L. Mandich

Subscribed and sworn to before me on this 12 day of October, 2020

MICHAEL S SORNBERGER
NOTARY PUBLIC - MINNESOTA
My Commission Expires
January 31, 2025

____
Notary Public
My Commission expires: Jan. 31, 2025

Schedule 1
Statement of Qualifications

Farah Ladan Mandich is a Regulatory Policy Specialist for Northern States Power Company – Minnesota. She is responsible for developing resource planning and resource acquisition regulatory filings for NSP-M. Mandich joined Xcel Energy in April 2019 in this role.

Prior to joining Xcel Energy, Mandich was a Policy Advisor at Southern California Edison (SCE), a large investor owned utility in California. In this role, she supported development of Integrated Resource Planning and resource acquisition regulatory filings before the California Public Utilities Commission. Before working on California regulatory issues, Mandich was a Knowledge Specialist in global consultancy McKinsey & Company's Electric Power & Natural Gas practice, where she served as a subject matter expert to both US and international clients on North American renewable energy markets.

Mandich received her Bachelor of Science in Economics from Texas Christian University and her Master of Public Policy from the University of Michigan's Gerald R. Ford School of Public Policy.

MODELING ASSUMPTIONS AND INPUTS

Since filing our initial Resource Plan in July 2019 in Case No. PU-19-220, the Company has made several changes to its modeling approaches, inputs, and assumptions for the purposes of developing our Supplement Preferred Plan.

Topic	Assumption	Change from Initial IRP Filing
Modeling constraints		
Carbon emissions constraint	▪ No constraint; baseload scenarios may not meet 80 percent reduction goal	▪ Removed modeling constraint of 80 percent carbon reduction by 2030
"No Going Back" wind replacement capacity	▪ No assumption that existing wind will be replaced when plants or contracts reach end of life	▪ Removed wind replacement capacity from baseline modeling
Reliability Requirement	▪ Modeling does not include 5.7 GW firm, dispatchable capacity floor; model optimizes resources to develop expansion plans	▪ Removed reliability requirement from baseline modeling

Topic	Assumption	Change from Initial IRP Filing
Near term wind availability constraint	▪ No generic wind option made available for model to select before 2026	▪ Generic wind available to select in modeling for each year
Market sales limit	▪ Limits market sales to 25 percent of retail load in EnCompass modeling	▪ Not applicable; no market sales limit capability in Strategist
Market and technology assumptions		
Market hourly price shaping	▪ Shaped hourly market prices based on retail load	▪ Hourly market price shaped based on thermal load
Fuel price forecasts	▪ Updated to Fall 2019 forecast vintage	▪ Changed from vintage available prior to previous filing
Technology price forecasts for wind, solar, and storage	▪ Used National Renewable Energy Labs (NREL) *Annual Technology Baseline (ATB) 2019* assumptions	▪ Updated from 2018 ATB to 2019 ATB for wind and solar ▪ Shifted from using internal price assumptions to 2019 ATB for storage

Topic	Assumption	Change from Initial IRP Filing
Wind resource production	▪ Used 2019 NREL ATB price inputs for Technology Resource Group (TRG) 2	▪ Previously used 2018 ATB price assumptions for TRG 1, which reflected a higher capacity factor expectation
Solar resource production	▪ Assumed 22 percent capacity factor in first year, with 0.5 percent per year degradation	▪ Previously assumed 17.7 percent levelized capacity factor
Renewable transmission interconnect cost	▪ Wind: $500/kW ▪ Solar: $200/kW	▪ Wind: Increased from $400/kW for greenfield wind ▪ Solar: Increased from $140/kW
Solar capacity accreditation	▪ 50 percent ELCC to 2023, declining to 30 percent in 2033 at a rate of 2 percent per year	▪ 50 percent ELCC for the full analysis period

Topic	Assumption	Change from Initial IRP Filing
Wind capacity accreditation	▪ 16.7 percent ELCC throughout the planning period	▪ 15.6 percent ELCC throughout the planning period
Effective Reserve Margin	▪ Reserve margin updated to 3.46 percent, based on latest MISO LOLE Study (2020-2021)	▪ 2.98 percent effective reserve margin
Upper Midwest System Assumptions		
Unit retirement dates	▪ All existing unit retirement years with end of financial life	▪ Selected units used differing retirement dates for resource planning purposes
Seasonal coal dispatch	▪ King and Sherco 2 do not dispatch from March-May and September-November, through 2023	▪ No units were modeled with seasonal dispatch
Load forecasts	▪ Updated to fall 2019 internal forecast vintage	▪ Changed from fall 2018 internal forecast

Topic	Assumption	Change from Initial IRP Filing
DER forecasts	▪ Updated to latest vintage for each technology	▪ Changed from vintage available prior to previous filing
EV adoption forecasts	▪ Updated to latest vintage, aligned with most recent forecasts used in IDP	▪ Changed from vintage available prior to previous filing
Nuclear budgets	▪ Updated to most recent vintage for Nuclear Decommissioning Trust, Operations and Maintenance and Capital Expenditure budgets	▪ Changed from vintage available prior to previous filing

In addition to these modifications for the IRP Supplement, we have made several additional model updates for the instant docket, to account for inclusion of resources that have been recently approved by the North Dakota Public Service Commission (NDPSC) and/or Minnesota Public Utilities Commission (MPUC). These changes include:

- Adjusting the Mower County Wind resource to reflect both the ND PSC and MPUC approval of our repowering and purchase proposal;[1]
- The addition of a 100 MW Deuel Harvest Wind and 80 MW Elk Creek Solar PPAs that support our Minnesota Renewable*Connect program expansion (the costs of which will recovered directly from participating customers in Minnesota);
- Updating baseline revenue requirement assumptions for the four Company-owned wind projects considered in this proposal;

[1] Per Case No. PU-19-310.

- Updating baseline cost and operational assumptions for the third-party wind projects proposed; and
- Updating how we model curtailments; whereas we previously only assigned energy costs to generation net of curtailment, we now also account for costs of energy that is ultimately curtailed.

As a result of these updates, the Base Case expansion plan used as a comparison point for assessing the repowering projects' economic costs/benefits is slightly altered relative to the IRP's Supplement Preferred Plan; specifically, some wind and firm peaking units move forward or back in the timeline and one solar unit is deferred to a future year outside the planning period. The Wind Repowering Base Case expansion plan is detailed below.

Wind Repowering Base Case

Wind Repower Base Case (MW)	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Firm Peaking	-	-	-	-	-	-	-	-	-	-	374	748	748	374	374
CC	-	-	-	-	-	-	-	835	-	-	-	-	-	-	-
Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	1,500	750
Solar	-	-	-	-	-	500	500	-	-	1,500	500	-	-	-	-
DR	33	132	67	62	47	41	12	14	15	17	19	20	21	22	24
EE	115	130	116	133	143	145	154	157	155	140	138	136	129	126	126
Distributed Solar	173	72	87	68	25	16	15	15	15	15	15	15	15	15	15
TOTAL	**321**	**334**	**269**	**263**	**214**	**702**	**681**	**1,022**	**185**	**1,672**	**1,045**	**919**	**912**	**2,037**	**1,288**

A. Discount Rate and Capital Structure

The discount rate used for levelized cost calculations and the present value of modeled costs is 6.47 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 IV-1: Discount Rate and Capital Structure[2]

Discount Rate and Capital Structure				
	Capital Structure	Allowed Return	Before Tax Electric WACC	After Tax Electric WACC
Long-Term Debt	45.72%	4.79%	2.19%	1.58%
Common Equity	52.39%	9.25%	4.85%	4.85%
Short-Term Debt	1.89%	3.55%	0.07%	0.05%
Total			**7.10%**	**6.47%**

B. 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 percent is from their long-term forecast for "Chained Price Index for Total Personal Consumption Expenditures" published in the second quarter of 2018.

C. Reserve Margin

The reserve margin at the time of MISO's peak is 8.9 percent from the 2020-2021 LOLE Study Report, published November 2019. The coincidence factor between the NSP System and MISO system peak is 95 percent. Therefore, the effective reserve margin is:

$$(95\ percent\ coincidence\ factor) x\ (1 + 8.9\ percent) - 1 = \mathbf{3.46}\ percent\ effective\ reserve\ margin\ for\ NSP$$

D. CO_2 Costs

The Present Value of Societal Cost (PVSC) Base Case CO_2 values are based on the high environmental cost values for CO_2 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 Gross Domestic Product Implicit Price Deflator (GDPIPD) of 113.416 and then escalated 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

[2] Note: the Tables in this Schedule retain their numbering from our most recent Integrated Resource Plan.

of Future Carbon Dioxide Regulation Costs in Dockets No. E999/CI-07-1199 and E999/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 IV-2: CO_2 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

E. All Other Externality Costs

The values of the criteria pollutants are derived from the high and low values for each of the three locations, as determined in the Minnesota Commission 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 GDPIPD of 113.416. The high, low and midpoint externality costs will be used in the CO_2 sensitivities as described above.

Table IV-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

F. Demand and Energy Forecast

The Company's fall 2019 load forecast is used as the base assumption and assumes that EV impacts growth continues throughout the forecast period. The energy efficiency (EE) forecast included in the base forecast developed by the Company's Load Forecasting department assumes somewhat less energy efficiency (EE) savings levels than those included in our initial Resource Plan's Preferred Plan. Please see Attachment A Section II for more information.

The "Load Forecast with EE" shown in Table IV-4 below is the starting point for the load inputs. In all modeling scenarios, the "EE" is removed – the removal of these EE program effects, which have a 14-year life, impacts the load forecast through 2048. In the initial filing, the three EE Bundles (discussed below) were optimized as Proview Alternatives. For this supplemental filing, the first two EE Bundles are included in all scenarios. The resulting forecast, before the optimized EE bundles are added, is shown below in Table IV-4 as "Forecast Without EE." The forecasts shown do not include the impact of DG solar, as DG solar is modeled as a resource, not a load modifier.

Table IV-4: Demand and Energy Forecast

Demand and Energy Forecast				
	Demand (MW)		Energy (GWh)	
Year	Forecast with EE	Forecast without EE	Forecast with EE	Forecast without EE
2018	9,152	9,152	43,914	43,914
2019	9,084	9,084	43,558	43,558
2020	9,099	9,230	43,170	43,806
2021	9,079	9,312	42,741	44,018
2022	9,126	9,462	42,628	44,549
2023	9,165	9,604	42,440	45,004
2024	9,184	9,728	42,339	45,555
2025	9,238	9,849	42,324	45,976
2026	9,311	9,992	42,470	46,565
2027	9,414	10,164	42,757	47,296
2028	9,504	10,327	43,221	48,216
2029	9,525	10,416	43,006	48,432
2030	9,605	10,566	43,224	49,093
2031	9,679	10,710	43,420	49,734
2032	9,775	10,880	43,903	50,678
2033	9,979	11,058	44,532	51,299
2034	10,190	11,246	45,426	52,203
2035	10,343	11,269	46,158	52,299
2036	10,502	11,325	47,028	52,527
2037	10,673	11,393	47,647	52,503
2038	10,803	11,420	48,209	52,422
2039	10,936	11,449	48,833	52,394
2040	11,073	11,518	49,603	52,729
2041	11,209	11,585	50,055	52,737
2042	11,338	11,645	50,635	52,873
2043	11,467	11,701	51,267	53,048
2044	11,614	11,780	52,023	53,374
2045	11,722	11,818	52,468	53,375
2046	11,839	11,865	53,010	53,473
2047	11,951	11,903	53,545	53,547
2048	12,021	11,998	54,150	54,160
2049	12,045	12,045	54,202	54,202
2050	12,097	12,097	54,407	54,407
2051	12,149	12,149	54,611	54,611
2052	12,199	12,199	54,947	54,947
2053	12,252	12,252	55,022	55,022
2054	12,305	12,305	55,226	55,226
2055	12,357	12,357	55,431	55,431
2056	12,409	12,409	55,765	55,765
2057	12,461	12,461	55,840	55,840

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 shown in Table IV-5 and Table IV-6 and are incremental/decremental to the forecast shown in Table IV-4.

Table IV-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	592	65
2026	692	77
2027	812	85
2028	939	98
2029	1,202	118
2030	1,578	162
2031	2,028	205
2032	2,538	251
2033	3,137	305
2034	3,857	367
2035	4,716	438
2036	5,657	515
2037	6,672	596
2038	7,741	679
2039	8,851	766
2040	9,996	854
2041	11,114	940
2042	12,199	1,025
2043	13,241	1,118
2044	14,229	1,796
2045	15,159	2,520
2046	16,037	3,173
2047	16,877	3,796
2048	17,696	4,647
2049	18,660	4,908
2050	19,530	5,407
2051	20,634	5,947
2052	21,645	6,418
2053	22,656	6,896
2054	23,666	7,384
2055	24,677	7,877
2056	25,688	8,352
2057	26,699	8,840

**Demand values are coincident to system peak*

Table IV- 6: Low Load Sensitivity

High DER Growth		
Year	Energy (GWh)	Demand (Nameplate MW)
2018	0	0
2019	0	0
2020	0	0
2021	207	122
2022	180	106
2023	159	94
2024	270	159
2025	258	152
2026	423	250
2027	423	250
2028	635	374
2029	641	379
2030	740	437
2031	826	487
2032	913	538
2033	996	588
2034	1,082	639
2035	1,167	689
2036	1,256	739
2037	1,338	790
2038	1,423	840
2039	1,509	891
2040	1,598	941
2041	1,631	963
2042	1,580	933
2043	1,529	903
2044	1,482	872
2045	1,425	842
2046	1,350	797
2047	1,296	765
2048	1,245	733
2049	1,187	701
2050	1,131	668
2051	1,063	628
2052	1,009	594
2053	932	550
2054	872	515
2055	807	476
2056	742	437
2057	671	396

G. Energy Efficiency Bundles

The EE "Program" and "Maximum" Bundles are based on the Minnesota DOC's Minnesota Energy Efficiency Potential Study: 2020-2029 published December 4, 2018. The "Optimal" Bundle was developed by the Company. The bundles are decremental (reducing energy and demand) to the "Forecast without EE" shown in Table IV-4.

Table IV- 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*

H. 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 Potential Study provided as Appendix G2. The Bundles are incremental to the base demand response forecast. In the initial filing, the three DR Bundles were optimized as Proview Alternatives. For this Supplement, the first DR Bundle is included in all scenarios.

Table IV-8: Demand Response Forecast

Demand (MW) Adjusted For Reserve Margin					Costs ($000)		
Year	Base Demand Response Forecast	Bundle 1	Bundle 2	Bundle 3	Bundle 1	Bundle 2	Bundle 3
2018	852	0	0	0	0	0	0
2019	928	0	0	0	0	0	0
2020	1012	33	107	90	1,752	7,659	11,311
2021	1027	165	112	98	8,917	8,150	12,587
2022	1041	232	117	107	12,748	8,676	14,016
2023	1055	294	121	110	16,489	9,137	14,758
2024	1066	341	133	101	19,512	10,277	13,829
2025	1072	382	145	92	22,305	11,459	12,858
2026	1077	394	152	93	23,475	12,207	13,326
2027	1078	407	159	95	24,786	13,080	13,845
2028	1077	423	168	97	26,245	14,086	14,418
2029	1071	440	178	99	27,859	15,231	15,047
2030	1059	458	190	102	29,637	16,522	15,734
2031	1048	478	202	104	31,551	17,926	16,467
2032	1037	499	215	107	33,612	19,451	17,251
2033	1026	521	228	110	35,832	21,109	18,088
2034	1016	545	243	113	38,224	22,911	18,984
2035	1005	570	259	116	40,802	24,870	19,943
2036	995	596	275	120	43,582	26,999	20,971
2037	985	624	293	123	46,580	29,313	22,072
2038	976	654	312	127	49,814	31,829	23,253
2039	966	686	332	132	53,305	34,564	24,522
2040	957	720	353	136	57,073	37,537	25,884
2041	948	720	353	136	58,215	38,288	26,402
2042	939	720	353	136	59,379	39,054	26,930
2043	930	720	353	136	60,566	39,835	27,468
2044	922	720	353	136	61,778	40,632	28,018
2045	914	720	353	136	63,013	41,444	28,578
2046	906	720	353	136	64,274	42,273	29,150
2047	898	720	353	136	65,559	43,118	29,733
2048	890	720	353	136	66,870	43,981	30,327
2049	882	720	353	136	68,208	44,860	30,934
2050	875	720	353	136	69,572	45,758	31,552
2051	868	720	353	136	70,963	46,673	32,183
2052	860	720	353	136	72,382	47,606	32,827
2053	853	720	353	136	73,830	48,558	33,484
2054	847	720	353	136	75,307	49,530	34,153
2055	840	720	353	136	76,813	50,520	34,836
2056	833	720	353	136	78,349	51,531	35,533
2057	827	720	353	136	79,916	52,561	36,244

**Demand values are coincident to system peak.*

I. Fuel Price Forecasts

Natural gas price forecasts are developed using a blend of market information (New York Mercantile Exchange, or NYMEX, 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. Table IV-9 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 when the long-term fundamentally-based forecasts are blended with market information (NYMEX futures prices).

Table IV-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	$2.60	$26.93	$20.98	$2.08	$2.60	$26.93	$20.98	$2.08	$2.60	$26.93	$20.98
2020	$2.11	$2.26	$25.78	$20.13	$2.11	$2.26	$25.78	$20.13	$2.11	$2.26	$25.78	$20.13
2021	$2.14	$2.23	$25.32	$19.06	$2.14	$2.23	$25.32	$19.06	$2.14	$2.23	$25.32	$19.06
2022	$2.19	$2.33	$26.92	$20.45	$2.17	$2.28	$26.33	$20.00	$2.24	$2.38	$27.52	$20.90
2023	$2.25	$2.45	$29.31	$22.19	$2.19	$2.34	$27.96	$21.17	$2.36	$2.57	$30.68	$23.23
2024	$2.30	$2.58	$30.00	$23.20	$2.22	$2.40	$27.94	$21.60	$2.46	$2.76	$32.16	$24.87
2025	$2.35	$2.79	$31.47	$24.36	$2.24	$2.50	$28.17	$21.80	$2.57	$3.11	$35.04	$27.12
2026	$2.40	$2.98	$32.30	$24.99	$2.27	$2.58	$28.01	$21.67	$2.69	$3.42	$37.09	$28.70
2027	$2.45	$3.12	$33.35	$26.71	$2.29	$2.64	$28.28	$22.64	$2.81	$3.66	$39.16	$31.36
2028	$2.51	$3.26	$34.09	$26.97	$2.32	$2.71	$28.25	$22.35	$2.93	$3.92	$40.92	$32.38
2029	$2.57	$3.44	$35.21	$28.25	$2.34	$2.78	$28.42	$22.79	$3.07	$4.24	$43.38	$34.80
2030	$2.62	$3.70	$38.27	$30.69	$2.37	$2.88	$29.83	$23.92	$3.20	$4.71	$48.76	$39.09
2031	$2.68	$3.87	$39.33	$32.07	$2.40	$2.95	$29.97	$24.44	$3.35	$5.04	$51.22	$41.77
2032	$2.75	$4.02	$39.75	$33.14	$2.43	$3.01	$29.71	$24.77	$3.51	$5.34	$52.76	$43.99
2033	$2.81	$4.10	$39.93	$33.46	$2.45	$3.03	$29.58	$24.79	$3.67	$5.48	$53.47	$44.80
2034	$2.87	$4.20	$41.13	$34.56	$2.48	$3.07	$30.08	$25.28	$3.83	$5.70	$55.76	$46.86
2035	$2.94	$4.35	$42.15	$35.66	$2.51	$3.13	$30.32	$25.65	$4.00	$6.00	$58.12	$49.17
2036	$2.99	$4.47	$42.79	$36.60	$2.53	$3.17	$30.37	$25.97	$4.14	$6.24	$59.80	$51.13
2037	$3.07	$4.65	$44.00	$38.21	$2.56	$3.24	$30.61	$26.58	$4.36	$6.63	$62.69	$54.44
2038	$3.14	$4.86	$44.95	$39.45	$2.60	$3.31	$30.60	$26.85	$4.58	$7.08	$65.43	$57.42
2039	$3.23	$5.04	$45.82	$40.48	$2.63	$3.37	$30.63	$27.06	$4.83	$7.47	$67.88	$59.98
2040	$3.31	$5.22	$46.61	$41.48	$2.66	$3.43	$30.61	$27.25	$5.06	$7.87	$70.25	$62.53
2041	$3.37	$5.32	$46.52	$41.48	$2.69	$3.46	$30.27	$26.99	$5.26	$8.10	$70.79	$63.12
2042	$3.45	$5.47	$47.61	$42.64	$2.72	$3.51	$30.57	$27.38	$5.51	$8.43	$73.40	$65.74
2043	$3.53	$5.62	$48.37	$43.71	$2.75	$3.56	$30.64	$27.69	$5.77	$8.78	$75.56	$68.28
2044	$3.62	$5.78	$49.72	$44.99	$2.79	$3.61	$31.04	$28.09	$6.05	$9.17	$78.79	$71.29
2045	$3.70	$5.99	$51.23	$46.37	$2.82	$3.68	$31.45	$28.46	$6.31	$9.65	$82.57	$74.73
2046	$3.78	$6.17	$52.49	$47.53	$2.85	$3.73	$31.74	$28.74	$6.59	$10.09	$85.85	$77.73
2047	$3.86	$6.29	$53.27	$48.57	$2.88	$3.77	$31.89	$29.08	$6.88	$10.40	$87.98	$80.22
2048	$3.95	$6.46	$54.39	$49.88	$2.91	$3.82	$32.15	$29.49	$7.20	$10.80	$90.96	$83.42
2049	$4.04	$6.66	$55.69	$50.92	$2.95	$3.88	$32.43	$29.65	$7.53	$11.30	$94.52	$86.43
2050	$4.13	$6.77	$56.64	$51.71	$2.98	$3.91	$32.70	$29.85	$7.87	$11.60	$96.97	$88.53
2051	$4.22	$6.96	$58.23	$53.16	$3.01	$3.96	$33.16	$30.27	$8.21	$12.08	$101.05	$92.24
2052	$4.31	$7.13	$59.62	$54.42	$3.04	$4.01	$33.56	$30.63	$8.57	$12.51	$104.64	$95.53
2053	$4.41	$7.29	$61.00	$55.68	$3.08	$4.06	$33.94	$30.99	$8.94	$12.95	$108.29	$98.85
2054	$4.50	$7.46	$62.38	$56.95	$3.11	$4.10	$34.33	$31.34	$9.33	$13.39	$111.97	$102.21
2055	$4.60	$7.62	$63.76	$58.21	$3.14	$4.15	$34.71	$31.69	$9.73	$13.83	$115.69	$105.61
2056	$4.69	$7.79	$65.15	$59.47	$3.17	$4.19	$35.09	$32.03	$10.12	$14.28	$119.45	$109.05
2057	$4.79	$7.95	$66.53	$60.73	$3.21	$4.24	$35.46	$32.37	$10.52	$14.74	$123.26	$112.52

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

J. Baseload Retirement "Leave Behind" Costs

Based on the MISO Y2 retirement studies performed on existing coal and nuclear resources, the Company developed transmission reinforcement or "leave behind" estimates, which reflect costs required to mitigate localized grid impacts of the retirement of major baseload resources. The reinforcement costs are included as a one-time charge based on the timing of the resource retirement.

Specifically, we have included the following proxy leave behind costs related to our baseload resource retirements as estimated from the MISO studies. We applied these costs in the modeling as soon as the resource is retired, over a three-year period, to reflect the estimated local transmission reinforcement costs assumed to be required upon retirement. All numbers below are in real dollar terms ($2020).

- King: $48 million
- Sherco 3: $48 million
- Monticello: $96 million
- Prairie Island 1: $96 million
- Prairie Island 2: $96 million

K. 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 IV-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	4.57	4.66	4.75	4.85	4.95	5.05	5.15	5.25	5.35	5.46	5.57	5.68	5.80	5.91	6.03	6.15	6.27	6.40	6.53	6.66
	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055	2056	2057
$/kw-mo	6.79	6.93	7.07	7.21	7.35	7.50	7.65	7.80	7.96	8.12	8.28	8.44	8.61	8.79	8.96	9.14	9.32	9.51	9.70	9.89

L. Effective Load Carrying Capability 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 16.7 percent of their nameplate rating per MISO 2020/2021 Wind Capacity Report. The ELCC for generic solar is based on the values provided in MISO's MTEP 2019 in Appendix E,[3] and is 50 percent of the alternating current (AC) nameplate capacity through 2023, declining 2 percent annually to 30 percent by 2033 where it remains for the rest of the forecast period. The ELCC assigned for a generic 4-hour battery is equal to 100 percent of the AC equivalent capacity. The ELCC used for hybrid options are the same as the individual components.

M. Spinning Reserve Requirement

Spinning reserve is the online 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.

N. Emergency Energy

Emergency energy is used to cover events where there are not enough resources or market purchase energy available to meet system energy requirements. In Strategist, this is set to $500/MWh. Encompass uses the default value of $10,000/MWh. The primary reason for this difference is the way the models utilize this input. In Strategist's dispatch approach, the emergency energy is determined after the dispatch, when all resources have been utilized and an energy shortfall still exists. In EnCompass, emergency energy is a "soft constraint" that allows emergency energy to "dispatch" as a last resort resource, in order for the model to find a feasible solution. The EnCompass price is set to a high level to ensure that all other available resources – including those that may have a very high effective $/MWh cost resulting from startup costs spread over a very small required run time – are utilized before emergency energy.

O. 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.

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[3] Available at: https://cdn.misoenergy.org//MTEP19%20Appendix%20E-Futures%20Assumptions382958.pdf

We note additionally that interconnection costs for generic resources are included in the capital costs in Table IV-14 in Part U of this section and represent "behind the fence" costs associated with substation and representative gen-tie construction.

Table IV-11: Transmission Delivery Costs

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

P. 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 not included in the model.

Table IV-12: Integration Costs

Integration Costs ($/MWh)		
Year	Wind	Solar
2018	0.00	0.00
2019	0.00	0.00
2020	0.41	0.41
2021	0.42	0.42
2022	0.43	0.43
2023	0.44	0.44
2024	0.45	0.45
2025	0.46	0.46
2026	0.47	0.47
2027	0.48	0.48
2028	0.49	0.49
2029	0.49	0.49
2030	0.50	0.50
2031	0.51	0.51
2032	0.53	0.53
2033	0.54	0.54
2034	0.55	0.55
2035	0.56	0.56
2036	0.57	0.57
2037	0.58	0.58
2038	0.59	0.59
2039	0.60	0.60
2040	0.62	0.62
2041	0.63	0.63
2042	0.64	0.64
2043	0.65	0.65
2044	0.67	0.67
2045	0.68	0.68
2046	0.69	0.69
2047	0.71	0.71
2048	0.72	0.72
2049	0.74	0.74
2050	0.75	0.75
2051	0.77	0.77
2052	0.78	0.78
2053	0.80	0.80
2054	0.81	0.81
2055	0.83	0.83
2056	0.84	0.84
2057	0.86	0.86

Q. Distributed Solar Generation and Community Solar Gardens

The distributed solar and Community Solar Gardens inputs are based on the most recent Company forecasts. Distributed Solar is modeled assuming a degradation of half a percent annually in generation. Community Solar Gardens 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.

Table IV-13: Distributed Solar Forecast

Distributed Solar (Nameplate MW)			
Year	Solar Rewards	Community Gardens	Total
2018	29	246	274
2019	61	504	565
2020	80	658	738
2021	95	714	809
2022	109	787	897
2023	123	841	964
2024	138	852	989
2025	152	853	1,005
2026	166	854	1,020
2027	180	855	1,035
2028	194	857	1,050
2029	208	858	1,066
2030	222	859	1,080
2031	236	860	1,095
2032	249	861	1,110
2033	263	862	1,125
2034	276	863	1,140
2035	290	864	1,154
2036	303	866	1,169
2037	317	867	1,184
2038	330	868	1,198
2039	343	869	1,212
2040	357	870	1,227
2041	370	871	1,241
2042	383	869	1,252
2043	396	852	1,247
2044	409	830	1,239
2045	421	818	1,239
2046	434	814	1,248
2047	447	808	1,255
2048	460	805	1,264
2049	472	805	1,277
2050	491	806	1,297
2051	504	807	1,311
2052	518	808	1,326
2053	531	809	1,340
2054	545	810	1,355
2055	559	811	1,369
2056	572	812	1,384
2057	586	812	1,398

R. 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

S. Thermal 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

T. 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 and solar hourly patterns are developed through a "Typical Meteorological Year" process where individual months are selected from the years 2017-2020 to develop a representative typical year. Actual generation data from the selected months is used to develop the profile for each unit. For units where generation data is not complete or not available, data from a nearby similar unit is used.

U. Generic Assumptions

Generic resources are modeled based upon their expected operating characteristics and projected costs. Generic thermal costs are developed by the Company. Generic renewable and battery costs are based on data from the NREL 2019 ATB. Utility-scale wind and solar costs shown in Tables IV-18 through IV-20 include transmission costs from Table IV-11 while DG/distributed solar does not.

The modeling no longer assumes "no going back" on renewables, which was the replacement of renewable resources for a similar resource when they reached the end of their life, but rather allows all renewable additions to be optimized.

In addition to base cost data for renewables, low and high costs are used for various sensitivities. Low and high wind, solar, and battery costs are also based on the 2019 ATB data. 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 IV-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	901	374	232	374
Summer Peak Capacity (MW)	750	856	331	206	331
Capital Cost ($000) 2018$	$837,068	$906,588	$174,700	$114,766	$193,500
Electric Transmission Delivery ($000) 2018$	NA	$410,505	NA	NA	$74,804
Ongoing Capital Expenditures ($000-yr) 2018$	$6,200	$6,200	$1,784	$892	$1,784
Gas Demand ($000-yr) 2018$	$31,725	$19,058	$2,165	$1,342	$2,165
Capital Cost ($/kW) 2018$	$1,002	$1,006	$467	$495	$517
Electric Transmission Delivery ($/kW) 2018$	NA	$455	NA	NA	$200
Ongoing Capital Expenditures ($/kW-yr) 2018$	$7.42	$6.88	$4.77	$3.85	$4.77
Gas Demand ($/kW-yr) 2018$	$37.98	$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	$15.26	$16.06	$5.91	$6.22	$8.06
Summer Heat Rate 100% Loading (btu/kWh)	6,359	6,848	9,264	10,025	9,264
Summer Heat Rate 75% Loading (btu/kWh)	6,547	6,874	9,738	10,581	9,738
Summer Heat Rate 50% Loading (btu/kWh)	6,985	7,334	11,120	12,515	11,120
Summer Heat Rate 25% Loading (btu/kWh)	8,004	8,404	11,558	13,430	11,558
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 IV-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 (%)	16.7%	50% declines to 30%		
Capacity Factor	50.0%	22.0%	18.0%	18.0%
Book life	25	25	25	25
Electric Transmission Delivery ($/kW)	500	200	0	0

Table IV-16: Storage Generic Information (Costs in 2018 Dollars)

Storage Generic Information	
Resource	**Battery**
Technology	Li Ion
Location Type	NA
Book life	40
Nameplate Capacity (MW)	321
Summer Peak Capacity (MW)	321
Storage Volume (hrs)	4
Cycle Efficiency (%)	85
Equivalent Full Cycles per Year	250
Electric Transmission Delivery ($000) 2018$	0
Levelized $/kw-mo (All Fixed Costs) $2023	$18.18

Table IV-17: Levelized Capacity Costs by 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	$8.06	$6.22	$5.91	$16.06	$15.26			
2019	$8.22	$6.34	$6.02	$16.38	$15.56			
2020	$8.38	$6.47	$6.15	$16.71	$15.87	$20.04	$17.86	$22.94
2021	$8.55	$6.60	$6.27	$17.05	$16.19	$19.44	$16.81	$23.19
2022	$8.72	$6.73	$6.39	$17.39	$16.51	$18.82	$15.73	$23.45
2023	$8.89	$6.86	$6.52	$17.73	$16.85	$18.18	$14.62	$23.71
2024	$9.07	$7.00	$6.65	$18.09	$17.18	$17.52	$13.47	$23.97
2025	$9.25	$7.14	$6.78	$18.45	$17.53	$16.84	$12.30	$24.24
2026	$9.44	$7.28	$6.92	$18.82	$17.88	$16.63	$11.75	$24.51
2027	$9.63	$7.43	$7.06	$19.20	$18.23	$16.41	$11.18	$24.78
2028	$9.82	$7.58	$7.20	$19.58	$18.60	$16.19	$10.60	$25.06
2029	$10.02	$7.73	$7.34	$19.97	$18.97	$15.95	$10.00	$25.34
2030	$10.22	$7.88	$7.49	$20.37	$19.35	$15.71	$9.38	$25.62
2031	$10.42	$8.04	$7.64	$20.78	$19.74	$15.83	$9.38	$26.06
2032	$10.63	$8.20	$7.79	$21.19	$20.13	$15.94	$9.37	$26.50
2033	$10.84	$8.36	$7.95	$21.62	$20.53	$16.04	$9.36	$26.94
2034	$11.06	$8.53	$8.11	$22.05	$20.94	$16.15	$9.35	$27.40
2035	$11.28	$8.70	$8.27	$22.49	$21.36	$16.26	$9.33	$27.86
2036	$11.50	$8.88	$8.44	$22.94	$21.79	$16.36	$9.31	$28.32
2037	$11.73	$9.05	$8.60	$23.40	$22.23	$16.46	$9.28	$28.80
2038	$11.97	$9.24	$8.78	$23.87	$22.67	$16.56	$9.25	$29.28
2039	$12.21	$9.42	$8.95	$24.34	$23.12	$16.65	$9.21	$29.78
2040	$12.45	$9.61	$9.13	$24.83	$23.59	$16.74	$9.17	$30.27
2041	$12.70	$9.80	$9.31	$25.33	$24.06	$16.83	$9.13	$30.78
2042	$12.96	$10.00	$9.50	$25.83	$24.54	$16.76	$9.00	$30.97
2043	$13.22	$10.20	$9.69	$26.35	$25.03	$16.66	$8.85	$31.12
2044	$13.48	$10.40	$9.88	$26.88	$25.53	$16.55	$8.70	$31.25
2045	$13.75	$10.61	$10.08	$27.42	$26.04	$16.42	$8.53	$31.35
2046	$14.02	$10.82	$10.28	$27.96	$26.56	$16.26	$8.35	$31.41
2047	$14.30	$11.04	$10.49	$28.52	$27.09	$16.08	$8.16	$31.44
2048	$14.59	$11.26	$10.70	$29.09	$27.64	$15.88	$7.95	$31.42
2049	$14.88	$11.48	$10.91	$29.68	$28.19	$15.65	$7.73	$31.35
2050	$15.18	$11.71	$11.13	$30.27	$28.75	$15.39	$7.49	$31.23
2051	$15.48	$11.95	$11.35	$30.88	$29.33	$15.70	$7.64	$31.85
2052	$15.79	$12.19	$11.58	$31.49	$29.91	$16.01	$7.79	$32.49
2053	$16.11	$12.43	$11.81	$32.12	$30.51	$16.33	$7.95	$33.14
2054	$16.43	$12.68	$12.05	$32.76	$31.12	$16.66	$8.10	$33.80
2055	$16.76	$12.93	$12.29	$33.42	$31.75	$16.99	$8.27	$34.48
2056	$17.10	$13.19	$12.54	$34.09	$32.38	$17.33	$8.43	$35.17
2057	$17.44	$13.45	$12.79	$34.77	$33.03	$17.68	$8.60	$35.87

Table IV-18: Base Renewable Levelized Costs by Year

Levelized Costs by First Full Year of Operation $/MWh (LCOE)				
	Wind	Utility Scale Solar	Distributed Solar Commercial	Distributed Solar Residential
2018				
2019				
2020	$28.29	$46.12	$61.16	$92.16
2021	$32.32	$48.12	$64.63	$94.44
2022	$36.53	$53.73	$74.07	$105.71
2023	$40.91	$53.81	$73.54	$102.31
2024	$36.03	$53.87	$72.96	$98.77
2025	$50.24	$53.93	$72.35	$95.07
2026	$50.28	$53.97	$71.70	$91.23
2027	$50.32	$53.99	$71.00	$87.23
2028	$50.36	$54.01	$70.26	$83.07
2029	$50.41	$54.00	$69.47	$78.75
2030	$50.46	$53.98	$68.64	$74.26
2031	$51.13	$54.60	$69.31	$74.25
2032	$51.81	$55.21	$69.97	$74.23
2033	$52.50	$55.83	$70.64	$74.17
2034	$53.19	$56.45	$71.31	$74.08
2035	$53.89	$57.07	$71.98	$73.96
2036	$54.60	$57.70	$72.65	$73.81
2037	$55.31	$58.32	$73.32	$73.62
2038	$56.03	$58.96	$73.98	$73.40
2039	$56.76	$59.59	$74.65	$73.15
2040	$57.49	$60.23	$75.31	$72.86
2041	$58.23	$60.94	$75.87	$73.52
2042	$58.98	$61.66	$76.42	$74.18
2043	$59.73	$62.38	$76.97	$74.84
2044	$60.49	$63.10	$77.51	$75.49
2045	$61.26	$63.83	$78.04	$76.15
2046	$62.03	$64.57	$78.56	$77.43
2047	$62.81	$65.31	$79.08	$78.73
2048	$63.60	$66.05	$79.58	$80.05
2049	$64.39	$66.80	$80.08	$81.40
2050	$65.19	$67.55	$80.56	$82.76
2051	$66.49	$68.90	$82.17	$84.42
2052	$67.82	$70.28	$83.81	$86.11
2053	$69.17	$71.69	$85.49	$87.83
2054	$70.56	$73.12	$87.20	$89.59
2055	$71.97	$74.58	$88.94	$91.38
2056	$73.41	$76.08	$90.72	$93.20
2057	$74.88	$77.60	$92.54	$95.07

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

Table IV-19: Low Renewable Levelized Costs by Year

Low Levelized Costs by First Full Year of Operation $/MWh (LCOE)				
	Wind	Utility Scale Solar	Distributed Solar Commercial	Distributed Solar Residential
2018				
2019				
2020	$25.70	$40.39	$46.57	$80.57
2021	$28.96	$41.44	$44.77	$80.58
2022	$32.43	$45.30	$50.58	$87.80
2023	$36.12	$44.66	$49.46	$82.47
2024	$30.57	$43.99	$48.30	$76.99
2025	$44.15	$43.29	$47.11	$71.34
2026	$43.59	$42.57	$45.87	$65.52
2027	$43.05	$41.82	$44.59	$59.54
2028	$42.55	$41.04	$43.26	$53.38
2029	$42.07	$40.23	$41.89	$47.05
2030	$41.62	$39.40	$40.48	$40.54
2031	$42.10	$39.43	$40.22	$40.29
2032	$42.57	$39.45	$39.94	$40.02
2033	$43.05	$39.46	$39.63	$39.73
2034	$43.53	$39.45	$39.30	$39.41
2035	$44.01	$39.43	$38.95	$39.06
2036	$44.50	$39.59	$38.57	$38.69
2037	$44.98	$39.74	$38.16	$38.29
2038	$45.47	$39.88	$37.72	$37.86
2039	$45.96	$40.01	$37.25	$37.41
2040	$46.45	$40.14	$36.75	$36.92
2041	$46.94	$40.51	$37.10	$37.03
2042	$47.43	$40.89	$37.46	$37.13
2043	$47.92	$41.26	$37.81	$37.22
2044	$48.41	$41.63	$38.17	$37.31
2045	$48.90	$42.01	$37.15	$37.38
2046	$49.40	$42.47	$37.76	$37.91
2047	$49.89	$42.93	$38.38	$38.45
2048	$50.38	$43.40	$39.01	$39.00
2049	$50.88	$43.87	$39.65	$39.55
2050	$51.37	$44.34	$40.30	$40.11
2051	$52.40	$45.23	$41.10	$40.92
2052	$53.44	$46.13	$41.93	$41.74
2053	$54.51	$47.06	$42.76	$42.57
2054	$55.60	$48.00	$43.62	$43.42
2055	$56.71	$48.96	$44.49	$44.29
2056	$57.85	$49.94	$45.38	$45.18
2057	$59.01	$50.94	$46.29	$46.08

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

Table IV-20: High Renewable Levelized Costs by Year

High Levelized Costs by First Full Year of Operation $/MWh (LCOE)				
	Wind	Utility Scale Solar	Distributed Solar Commercial	Distributed Solar Residential
2018				
2019				
2020	$31.34	$47.98	$68.45	$98.01
2021	$36.42	$50.93	$73.59	$105.38
2022	$41.69	$58.00	$86.61	$124.02
2023	$47.16	$59.16	$88.34	$126.50
2024	$43.38	$60.35	$90.11	$129.03
2025	$58.71	$61.55	$91.91	$131.61
2026	$59.88	$62.79	$93.75	$134.24
2027	$61.08	$64.04	$95.63	$136.93
2028	$62.30	$65.32	$97.54	$139.67
2029	$63.55	$66.63	$99.49	$142.46
2030	$64.82	$67.96	$101.48	$145.31
2031	$66.11	$69.32	$103.51	$148.22
2032	$67.43	$70.71	$105.58	$151.18
2033	$68.78	$72.12	$107.69	$154.20
2034	$70.16	$73.56	$109.85	$157.29
2035	$71.56	$75.03	$112.04	$160.43
2036	$72.99	$76.53	$114.28	$163.64
2037	$74.45	$78.07	$116.57	$166.91
2038	$75.94	$79.63	$118.90	$170.25
2039	$77.46	$81.22	$121.28	$173.66
2040	$79.01	$82.84	$123.70	$177.13
2041	$80.59	$84.50	$126.18	$180.67
2042	$82.20	$86.19	$128.70	$184.29
2043	$83.85	$87.91	$131.28	$187.97
2044	$85.52	$89.67	$133.90	$191.73
2045	$87.23	$91.47	$136.58	$195.57
2046	$88.98	$93.30	$139.31	$199.48
2047	$90.76	$95.16	$142.10	$203.47
2048	$92.57	$97.06	$144.94	$207.54
2049	$94.43	$99.01	$147.84	$211.69
2050	$96.31	$100.99	$150.79	$215.92
2051	$98.24	$103.01	$153.81	$220.24
2052	$100.20	$105.07	$156.89	$224.65
2053	$102.21	$107.17	$160.02	$229.14
2054	$104.25	$109.31	$163.23	$233.72
2055	$106.34	$111.50	$166.49	$238.40
2056	$108.46	$113.73	$169.82	$243.16
2057	$110.63	$116.00	$173.22	$248.03

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

V. Market Purchases and Sales Carbon Rate

In order to estimate emissions rates associated with market purchases, the Company assumes an annual average carbon emissions pounds/MWh rate, as shown in the table below. These estimates were developed using MISO's MTEP Futures modeling results. Market sales emissions rates reflect an average emissions rate for our system resources and vary according to each individual scenario and sensitivity capacity expansion portfolio.

Table IV-21: Market Purchase Carbon Rate

Market Purchase CO2 Rate																				
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
lbs/MWh	1372	1307	1241	1176	1110	1045	1042	1039	1036	1034	1031	1018	1006	993	980	968	955	943	930	917
	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055	2056	2057
lbs/MWh	905	892	880	867	854	842	829	817	804	792	779	766	754	741	729	716	703	691	678	666

W. Sherco CC Size Alternatives

In its October 17, 2019 hearing in this docket, the Commission directed the Company to model different size alternatives for the planned Sherco CC. The Company developed three size alternatives – two smaller units and one larger unit – to test in sensitivity modeling. Cost and performance assumptions for each of these alternatives are detailed in Table IV-22 below.

Table IV-22: Sherco CC Alternatives

Thermal Generic Information				
Resource	**Sherco CC**	**7HA.01 1x1**	**7HA.02 1x1**	**7HA.02 2x1**
Technology	7H	7H	7H	7F
Location Type	Brownfield	Brownfield	Brownfield	Brownfield
Cooling Type	Wet	Wet	Wet	Wet
Book life	40	40	40	40
Nameplate Capacity (MW)	835	405	592	1202
Summer Peak Capacity (MW)	750	395	576	1170
Capital Cost ($000) 2018$	$837,068	$473,751	$629,206	$941,199
Electric Transmission Delivery ($000) 2018$	NA	NA	NA	NA
Ongoing Capital Expenditures ($000-yr) 2018$	$6,200	$4,190	$4,190	$8,775
Gas Demand ($000-yr) 2018$	$31,723	$31,723	$31,723	$31,723
Capital Cost ($/kW) 2018$	$1,002	$1,171	$1,064	$783
Electric Transmission Delivery ($/kW) 2018$	NA	NA	NA	NA
Ongoing Capital Expenditures ($/kW-yr) 2018$	$7.43	$10.35	$7.08	$7.30
Gas Demand ($/kW-yr) 2018$	$37.99	$78.41	$53.63	$26.38
Fixed O&M Cost ($000/yr) 2018$	$6,592	$7,150	$7,150	$8,647
Variable O&M Cost ($/MWh) 2018$	$1.04	$1.72	$1.72	$1.09
Levelized $/kw-mo (All Fixed Costs) $2018	$15.26	$18.36	$14.11	$10.95
Summer Heat Rate 100% Loading (btu/kWh)	6,359	6,322	6,208	6,452
Summer Heat Rate 75% Loading (btu/kWh)	6,547	6,419	6,257	6,403
Summer Heat Rate 50% Loading (btu/kWh)	6,985	6,681	6,516	6,812
Summer Heat Rate 25% Loading (btu/kWh)	8,004	7,553	7,388	7,479
Forced Outage Rate	3%	3%	3%	3%
Maintenance (weeks/yr)	5	5	5	5
CO2 Emissions (lbs/MMBtu)	118	118	118	118
SO2 Emissions (lbs/MWh)	0.00	0.00	0.00	0.00
NOx Emissions (lbs/MWh)	0.05	0.05	0.05	0.05
PM10 Emissions (lbs/MWh)	0.02	0.02	0.02	0.02
Mercury Emissions (lbs/MMWh)	0.00	0.00	0.00	0.00