DIRECT TESTIMONY AND SCHEDULE
PHILIP JOSEPH "P.J." MARTIN

STATE OF NORTH DAKOTA
BEFORE THE
NORTH DAKOTA PUBLIC SERVICE COMMISSION

NORTHERN STATES POWER COMPANY
ADVANCE PRUDENCE – 151.2 MW
DAKOTA RANGE III WIND FACILITY

CASE NO. PU-18-___

Resource Planning Testimony

Exhibit ___ (PJM-1)

December 27, 2018

3 PU-18-430 Filed 12/27/2018 Pages: 30
Prefiled Direct Testimony of Philip Joseph Martin - redacted
Northern States Power Company

TABLE OF CONTENTS

SCHEDULE

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND TITLE.

A. My name is Philip Joseph "P.J." Martin. I am the Director, Resource Planning, for Northern States Power Company – Minnesota (NSP or Xcel Energy or the Company).

Q. PLEASE DESCRIBE YOUR QUALIFICATIONS AND EXPERIENCE.

A. I have worked for Xcel Energy since August of 2015 in the areas of Strategic Asset Planning and Resource Planning. In my first role at Xcel Energy in the Strategic Asset Planning group, I focused primarily on business planning for the four operating companies at Xcel Energy. I assumed my current role as Director, Resource Planning in October of 2016.

Prior to joining Xcel Energy, I worked as a Portfolio Director and Energy Trader at ACES Power Marketing. In these roles, I engaged in trading and wholesale portfolio management activities on behalf of electric cooperatives, municipal utilities, IPPs, banks, and other customers. I also supported long-term planning and risk management efforts for these customers in the Midcontinent Independent System Operator, Inc. (MISO), PJM Interconnection, LLC, SERC, and other markets across the U.S.

Q. WHAT ARE YOUR CURRENT RESPONSIBILITIES?

A. In my current role, I am responsible for the direction of electric resource planning for the five-state integrated Northern States Power Company system (NSP System), which provides electric service to customers in North Dakota, South Dakota, Minnesota, Wisconsin, and Michigan. This includes assisting the Company in making reasonable and prudent acquisition decisions for electric generation resources. Among other things, I oversee our resource planning efforts using Strategist to conduct economic evaluations of potential resource additions, and oversee bid processes for new resource acquisitions.

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 purchase agreement (PPA) between the Company and Dakota Range III, LLP for new wind energy generation from a 151.2 megawatt (MW) facility (Dakota Range III). My testimony supports the conclusion that the North Dakota Public Service Commission (Commission) should grant an advance determination of prudence (ADP) for the proposed transaction. My testimony provides an economic analysis of the proposed transaction and the overall ratepayer benefits it generates.

II. ECONOMIC ANALYSIS

Q. HOW DID THE COMPANY EVALUATE THE COST-EFFECTIVENESS OF THE DAKOTA RANGE III TRANSACTION?

A. The Company principally used the Strategist resource planning model (Strategist) to aid in its economic analysis.

Q. WHAT IS STRATEGIST?

A. Strategist is a modeling program that simulates the operation of the NSP System and estimates the total cost of energy over the life of a project on a present value basis. Strategist can be used to test results under a range of input assumptions, also known as sensitivities. The Company uses this tool, which is industry standard, for the majority of its resource planning efforts.

Q. HOW DID THE COMPANY USE STRATEGIST TO ANALYZE THE PROPOSED DAKOTA RANGE III PROJECT?

A. For this analysis, the Company simulated the operation of the NSP System through 2057, with and without the addition of the 151.2 MW Dakota Range III wind facility. The Company's analysis assumes the addition of the 1,850 MWs of wind deemed prudent under the Commission's December 6, 2018, Order Approving Settlement in Case Nos. PU-17-120 and PU-17-132.

Q. IN GENERAL, WHAT IS THE SOURCE OF THE SAVINGS ASSOCIATED WITH DAKOTA RANGE III?

A. Wind generation has no fuel costs so the marginal cost to produce the next unit of energy is zero. In other words, after capital and on-going O&M costs are accounted for, there are no costs for a wind generator to produce the next MWh of energy. As a result, MISO generally provides for wind production ahead of other, marginally-priced generation. Therefore, when the energy from the proposed project is produced, it will displace energy production from other Company resources or purchased energy from the MISO market. This displacement of other generation or market purchases largely drives the benefits shown in the Company's modeling results.

Q. WHAT WAS THE RESULT OF THE ECONOMIC ANALYSIS PERFORMED USING THE STRATEGIST TOOL?

A. The results of the Strategist analysis provide the incremental effect of the addition of the Dakota Range III project and show that this new wind resource will result in net savings for customers under all sensitivity tests conducted. Table 1, below, shows the present value of revenue requirement (PVRR) savings.

Table 1: Incremental PVRR Savings from Reference Case ($millions)

	2018 PVRR
Fixed Cost/Expansion Plan Cost/(Savings)	(16)
VOM Cost/(Savings)	(3)
Fuel Cost/(Savings)	(43)
Dakota Range III PPA Cost	71
Market Cost/(Savings)	(29)
PPA Starts/Own Start Fuel Cost/(Savings)	(1)
Total Cost/(Savings)	(22)

Q. WHAT DOES TABLE 1 DEMONSTRATE?

A. Table 1 indicates that the proposed wind project provides cost benefits to customers. Table 1 also shows that reductions in system costs net of the costs of the PPA result in savings under the PVRR analysis, resulting in an overall savings on a PVRR basis for the Dakota Range III project. I note that this is exclusive of the demand allocator impacts of the C&I Customer discussed later in my testimony.

Q. WHAT ASSUMPTIONS DID THE COMPANY MAKE IN DEVELOPING THIS ANALYSIS?

A. In light of resource additions being added to the NSP System, there will be periods of time where the generation on the Company's system exceeds our native load-serving requirement. During these periods, the Company is likely to make energy sales into the MISO market. Revenues from these sales will be credited to customers through the Company's Fuel Cost Rider (FCR). Therefore, assumptions regarding the likely value of the potential energy sales into the MISO market are an important factor in predicting the likely rate impact of the proposed Dakota Range III PPA. The Company, therefore, analyzed the benefits of Dakota Range III under three different energy market assumptions. First, interactions with the MISO energy market are modeled under the base or reference case assumptions. Second, under the "markets off, no dump credit" sensitivity, market interactions are turned off and no value is given to any generation in excess of load serving requirements. Third, under the "market off, dump credit" sensitivity, energy in excess of load serving requirements is given half of the forecasted market energy price. A detailed description of the Strategist assumptions is included in Schedule 1 to my Direct Testimony.

Table 2: Sensitivity PVRR Savings from Reference Case ($millions)

	PVRR	B_LOW GAS	C_HIGH GAS	D_LOW LOAD	E_HIGH LOAD	F_MKTS OFF, NO DUMP CREDIT	G_MKTS OFF, DUMP CREDIT
Ref Case	45,233	43,642	48,177	41,984	48,701	46,610	46,086
DAK PPA	45,211	43,629	48,142	41,979	48,673	46,604	46,055
Delta	(22)	(13)	(36)	(5)	(28)	(6)	(31)

Further, savings shown in Figure 1, below, assume the Company is able to take advantage of the MISO energy market to make energy purchases and sales. As the Company will take advantage of MISO energy market transactions when in the interest of customers, we believe that modeling the availability of the MISO energy market provides a better indicator of the likely rate impacts to customers of the addition of Dakota Range III.

However, the Company included a limit on the maximum amount of market sales based on the historical data. Due to this limit on market sales, a significant amount of the wind generation due to the addition of Dakota Range III is "dumped" and does not receive any value.

While the Company has used the same limit in the past, this assumption is likely overly conservative. MISO expects the Zone 1 export limit to increase by approximately 2,500 MWs for the 2019-2020 planning year due to additional transmission lines going into service. Consequently, we expect less dump energy than the Company has included in the modeling, which will result in more benefits than shown below in Figure 1.

Q. WHAT OTHER SENSITIVITIES DID THE COMPANY MODEL IN DEVELOPING THE ANALYSIS?

A. In addition to the sensitivities related to market interactions, discussed above, the Company also performed sensitivities related to natural gas prices and forecasted load to further test the cost effectiveness of Dakota Range III with the results also presented in Table 2, above.

Q. PLEASE DESCRIBE THE NATURAL GAS PRICES SENSITIVITY.

A. The Company's natural gas price forecast is based on a blend of the latest market information and long-term fundamental-based forecasts acquired from third parties. The Company has included a low and high natural gas sensitivity to evaluate the impacts of variations in natural gas prices on the proposed transaction.

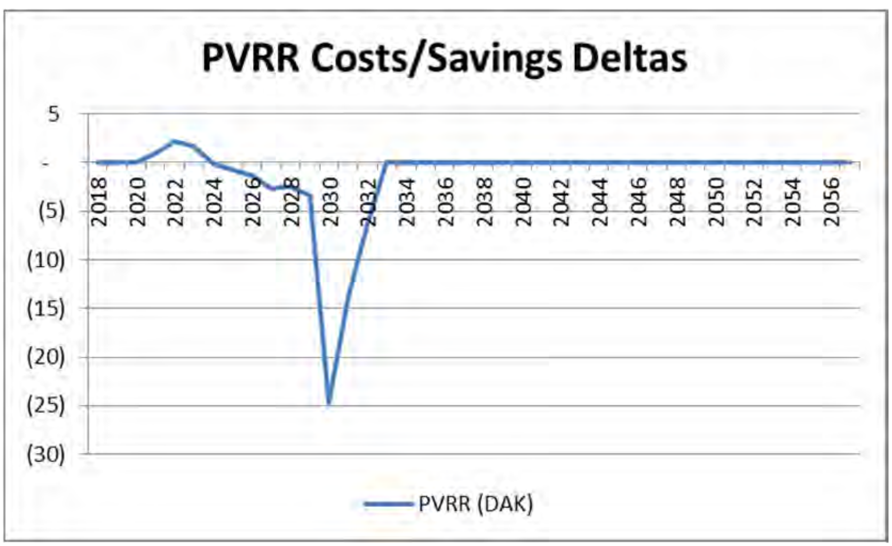
Q. PLEASE DESCRIBE THE FORECASTED LOAD SENSITIVITY.

A. The modeling includes the most recent load forecast, which was developed in the fall of 2018. The high and low load sensitivities were developed by increasing and decreasing forecasted load one standard deviation from the median forecast.

Q. DID THE COMPANY ANALYZE HOW THESE COST SAVINGS EVOLVE OVER THE LIFE OF THE PROJECT?

A. Yes. To understand how the costs (savings) change over time, Figure 1 below visually portrays the annual costs (savings) impacts of the total portfolio as compared to the Reference Case for the PVRR base assumptions.

Figure 1: Annual PVRR Net Costs (Savings) in $millions



Q. WHAT DOES FIGURE 1 DEMONSTRATE?

A. Figure 1 demonstrates that the addition of Dakota Range III creates a net cost in 2021-2024 due to the overly-conservative limiter on sales used in the modeling assumption. However, the Company expects that market sales made possible by transmission expansions coming on-line in 2018 should fully mitigate these minor cost increases and result in net savings to North Dakota customers. Additionally, by utilizing this low-cost wind, the Company is able to lower its overall fuel costs thereby benefitting customers regardless of market sales.

Notwithstanding the conservative modeling assumptions, Strategist still indicates that over the duration of the 12-year PPA term, customers receive significant rate benefits from avoided fuel costs beginning in 2025, as shown in Figure 1. The savings shown in the early 2030s result from one-year deferrals of several combustion turbine additions caused by the addition of Dakota Range III. Figure 1 also shows no change in costs or savings past the 12-year term of the PPA; however, if the term of the agreement was longer and assuming the same PPA pricing, the Company believes that savings would continue as the addition of the Dakota Range III resource could result in additional capacity deferments and the Company would be displacing higher cost energy out in time.

Q. IN ADDITION TO RATE BENEFITS FROM AVOIDED FUEL COSTS, DO NORTH DAKOTA CUSTOMERS BENEFIT FROM THE DAKOTA RANGE III PPA IN OTHER WAYS?

A. Yes. As discussed in the Direct Testimony of Company witness Ms. Bria Shea, North Dakota customers will benefit from the impact that the increased Minnesota load from the addition of the C&I Customer has on the allocation of NSP System costs through shifts in the percentages of system costs paid for by North Dakota under the 12CP demand allocator. Table 3, below, shows the estimated North Dakota dollar impact resulting from the demand allocator shift caused by the addition of the C&I Customer ratably, **[TRADE SECRET BEGINS . . .**

. . . TRADE SECRET ENDS]. The table demonstrates this impact on an incremental basis, showing the impact of 10 MW of load in year one; 75 MW of load by year five; and 150 MW of load by year ten of the agreement on the Company's North Dakota cost of service.

[TRADE SECRET BEGINS . . .

. . . TRADE SECRET ENDS]

Q. WHAT IS THE ESTIMATED IMPACT OF ADDING DAKOTA RANGE III ON THE RATES PAID BY THE COMPANY'S NORTH DAKOTA CUSTOMERS?

A. Based on the results of the Company's Strategist modeling, the Company expects that soon after initial operation, customers' overall bills will be lower as a result of the acquisition of the proposed resource, exclusive of the demand allocator impacts discussed above and in the Direct Testimony of Ms. Shea. Based on the results of the Company's Strategist modeling, beginning in 2025, the cost of the proposed wind project will be more than offset by decreases in the cost of fuel purchases and increases in revenues from market sales.

Q. PLEASE EXPLAIN HOW YOU REACHED THAT CONCLUSION.

A. To develop the rate impact analysis, the Company began with the incremental impact of Dakota Range III as determined by the Strategist modeling that was conducted. Specifically, the Company used the outputs from the PVRR sensitivity, which include market interactions. As discussed earlier in my testimony, it is likely that the Company will be able to make more market sales than reflect in the modeling which will increase the benefits of the Dakota Range III addition.

Using the annual system-wide costs impact form Strategist, the Company then applied a jurisdictional allocator based on a current sales forecast to determine the costs allocated to the North Dakota jurisdiction. The jurisdictional costs were then allocated to classes based on class cost of service study allocation factors approved in the Company's last North Dakota rate case order.

Q. HOW WILL THESE CHANGES IN REVENUE REQUIREMENTS BE REFLECTED ON NORTH DAKOTA CUSTOMERS' BILLS?

A. Table 4, below, shows the forecasted incremental impact on average monthly bills in North Dakota.

Table 4: ND Estimated Impact on Average Monthly Bills

Year	Residential	Commercial Non Demand	C&I Demand Billed
2021	$0.02	$0.03	$0.82
2022	$0.04	$0.06	$1.62
2023	$0.03	$0.05	$1.23
2024	$0.00	$0.00	$0.06

*Customer kWh usage and rate impacts for C&I demand billed customers varies significantly.

III. CONCLUSION

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

A. Yes, it does.

I. 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 in Table 1 were calculated by taking a weighted average of NSP jurisdictions from the April 2018 Corporate Assumptions Memo.

Table 1: Capital Structure

	Capital Structure	Allowed Return	Before Tax Electric WACC	After Tax Electric WACC
Long-Term Debt	45.60%	4.87%	2.22%	1.32%
Common Equity	52.50%	9.39%	4.93%	4.93%
Short-Term Debt	1.90%	2.85%	0.05%	0.05%
Total			**7.20%**	**6.30%**

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 is from the "Chained Price Index for Total Personal Consumption Expenditures" published in the second quarter of 2018.

- General inflation – The inflation rate used for construction (capital) costs and any other escalation factor related to general inflationary trends is 2.0%.

3. Reserve Margin

The reserve margin at the time of MISO's peak is 8.4 percent. The coincidence factor between the NSP System and MISO system peak is 5 percent. Therefore, the effective reserve margin is:

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

Table 2: Reserve Margin

Reserve Margin	
Coincidence Factor	5.00%
MISO Coincident Peak Reserve Margin %	8.40%
Effective RM Based on Non-coincident Peak	2.98%

4. Demand and Energy Forecast

The Fall 2018 Load Forecast developed by the Xcel Energy Load Forecasting group is used. The forecast is shown with no DG solar reduction, as solar was modeled as a resource.

Table 3: Fall 2018 Demand and Energy Forecast

Demand (MW)					Energy (GWh)				
Year	Model Output	W/ Hist DSM, Building Code Adj	w DSM/Eff Adjustments	Final w EV Adjustments	Year	Model Output	W/ Hist DSM, Building Code Adj	w DSM/Eff Adjustments	Final w EV Adjustments
2018	10,415	9,241	9,151	9,152	2018	50,447	44,348	43,909	43,914
2019	10,424	9,313	9,131	9,136	2019	50,530	44,649	43,772	43,798
2020	10,499	9,399	9,146	9,156	2020	50,847	45,129	43,800	43,865
2021	10,559	9,497	9,173	9,191	2021	50,746	45,223	43,449	43,560
2022	10,621	9,623	9,226	9,251	2022	50,844	45,598	43,375	43,529
2023	10,684	9,719	9,251	9,285	2023	50,991	45,857	43,186	43,394
2024	10,755	9,831	9,291	9,329	2024	51,326	46,318	43,189	43,425
2025	10,842	9,949	9,338	9,376	2025	51,333	46,589	43,021	43,257
2026	10,939	10,101	9,418	9,456	2026	51,483	47,061	43,044	43,281
2027	11,038	10,287	9,533	9,571	2027	51,699	47,722	43,256	43,493
2028	11,140	10,494	9,669	9,706	2028	52,079	48,780	43,852	44,089
2029	11,232	10,634	9,737	9,775	2029	52,105	49,097	43,735	43,972
2030	11,320	10,795	9,827	9,864	2030	52,279	49,704	43,893	44,130
2031	11,418	10,940	9,899	9,937	2031	52,516	50,195	43,935	44,172
2032	11,518	11,065	10,044	10,082	2032	52,895	50,712	44,424	44,661
2033	11,619	11,204	10,201	10,239	2033	52,931	50,918	44,639	44,875
2034	11,717	11,333	10,331	10,369	2034	53,112	51,274	44,995	45,232
2035	11,813	11,443	10,441	10,478	2035	53,346	51,577	45,298	45,534
2036	11,912	11,568	10,566	10,604	2036	53,746	52,103	45,806	46,042
2037	12,006	11,675	10,672	10,710	2037	53,750	52,169	45,890	46,126
2038	12,100	11,769	10,766	10,804	2038	53,911	52,329	46,050	46,287
2039	12,197	11,867	10,864	10,902	2039	54,165	52,584	46,305	46,541
2040	12,301	11,970	10,968	11,005	2040	54,589	53,007	46,709	46,946
2041	12,396	12,065	11,063	11,101	2041	54,599	53,018	46,739	46,975
2042	12,488	12,157	11,155	11,192	2042	54,767	53,186	46,907	47,143
2043	12,581	12,250	11,248	11,285	2043	55,031	53,450	47,171	47,407
2044	12,693	12,362	11,360	11,398	2044	55,467	53,884	47,587	47,823
2045	12,765	12,434	11,432	11,469	2045	55,503	53,921	47,642	47,879
2046	12,851	12,520	11,518	11,556	2046	55,700	54,119	47,840	48,076
2047	12,947	12,616	11,614	11,652	2047	55,996	54,415	48,136	48,372
2048	13,035	12,705	11,703	11,741	2048	56,359	55,038	48,740	48,977
2049	13,124	12,794	11,792	11,830	2049	56,435	54,854	48,575	48,811
2050	13,213	12,883	11,881	11,919	2050	56,667	55,085	48,806	49,042
2051	13,302	12,972	11,970	12,008	2051	56,899	55,316	49,037	49,274
2052	13,391	13,062	12,059	12,097	2052	57,288	55,700	49,403	49,640
2053	13,480	13,151	12,148	12,186	2053	57,362	55,779	49,500	49,736
2054	13,595	13,265	12,263	12,301	2054	57,812	56,228	49,949	50,185
2055	13,684	13,355	12,352	12,390	2055	58,043	56,459	50,180	50,417
2056	13,773	13,444	12,441	12,479	2056	58,436	56,847	50,549	50,786
2057	13,862	13,533	12,531	12,568	2057	58,507	56,922	50,643	50,880

5. DSM Forecast

The DSM forecast corresponds to what was used in the 2018v2.0 Load Forecast and assumes impacts expected at a 75 percent rebate level which equals roughly 1.5 percent of sales through the planning period and is what is embedded in the 2018v2 Load Forecast.

Table 4: DSM Forecast

Year	Energy (MWh)	Demand (MW)
2018	439	114
2019	877	229
2020	1,330	316
2021	1,774	402
2022	2,223	489
2023	2,671	576
2024	3,129	663
2025	3,568	750
2026	4,017	837
2027	4,465	924
2028	4,928	1,011
2029	5,362	1,097
2030	5,811	1,184
2031	6,259	1,271
2032	6,287	1,244
2033	6,279	1,216
2034	6,279	1,216
2035	6,279	1,216
2036	6,297	1,216
2037	6,279	1,216
2038	6,279	1,216
2039	6,279	1,216
2040	6,297	1,216
2041	6,279	1,216
2042	6,279	1,216
2043	6,279	1,216
2044	6,297	1,216
2045	6,279	1,216
2046	6,279	1,216
2047	6,279	1,216
2048	6,297	1,216
2049	6,279	1,216
2050	6,279	1,216
2051	6,279	1,216
2052	6,297	1,216
2053	6,279	1,216
2054	6,279	1,216
2055	6,279	1,216
2056	6,297	1,216
2057	6,279	1,216

6. Demand Response Forecast

The Load Management Forecast used was developed by the Xcel Energy Load Research group, 2018v4 vintage plus 406 MW of incremental generic DR starting in 2023. The table below shows the July demand.

Table 5: 2018 Load Management Forecast

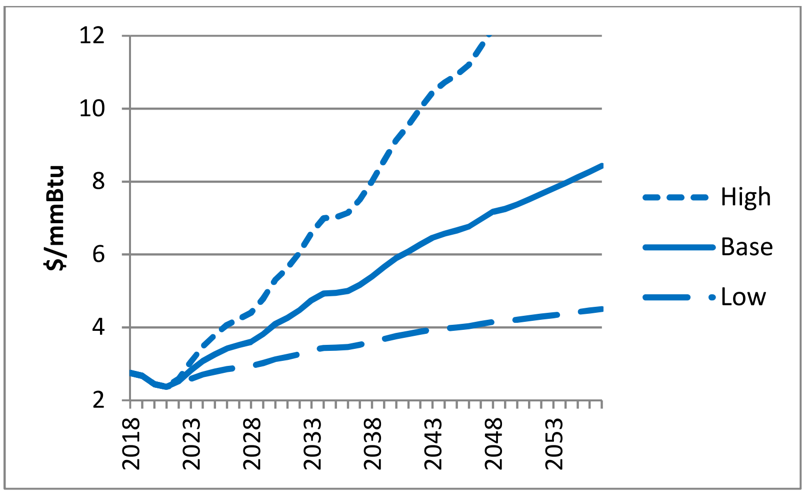
DR Forecast	
Year	July Demand (MW)
2018	899
2019	916
2020	932
2021	948
2022	962
2023	1,409
2024	1,413
2025	1,418
2026	1,423
2027	1,418
2028	1,408
2029	1,398
2030	1,388
2031	1,378
2032	1,369
2033	1,360
2034	1,351
2035	1,343
2036	1,335
2037	1,327
2038	1,319
2039	1,312
2040	1,304
2041	1,297
2042	1,291
2043	1,284
2044	1,277
2045	1,271
2046	1,265
2047	1,259
2048	1,252
2049	1,246
2050	1,240
2051	1,233
2052	1,227
2053	1,221
2054	1,214
2055	1,208
2056	1,202
2057	1,196

7. Natural Gas Price Forecasts

Henry Hub 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).

Gas Prices as of October 18, 2018, were used. High and low gas price sensitivities were performed by adjusting the growth rate up and down by 50 percent from the base natural gas cost forecast starting in year 2022.

Figure 1: Ventura Natural Gas Price Forecast and Sensitivities



8. Natural Gas Transportation Costs

Gas transportation variable costs include the gas transportation charges and the Fuel Lost & Unaccounted (FL&U) for all of the pipelines the gas flows through from the Ventura Hub to the generators facility. The FL&U charge is stated as a percentage of the gas expected to be consumed by the plant, effectively increasing the gas used to operate the plant, and is at the price of gas commodity being delivered to the plant. Table 10 contains gas transportation charges for generic thermal resources.

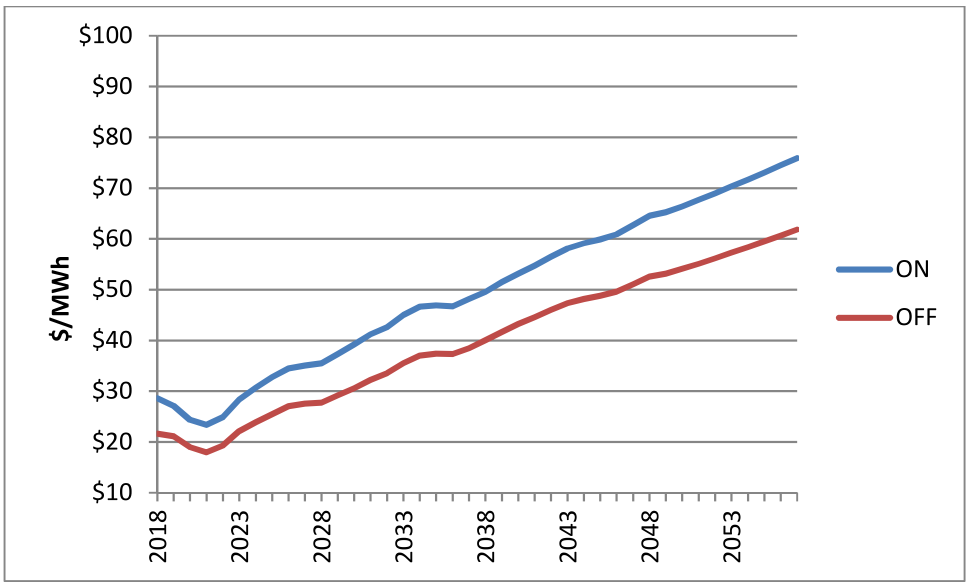
9. Natural Gas Demand Charges

Gas demand charges are fixed annual payments applied to resources to guarantee that natural gas will be available (normally called "firm gas"). Typically, firm gas is obtained to meet the needs of the winter peak as enough gas is normally available during the summer. Table 10 contains gas demand charges for generic thermal resources.

10. Electric Power Market Prices

In addition to resources that exist within the NSP System, the Company is a participant in the MISO Market. Electric power market power prices are developed from fundamentally-based forecasts from Wood Mackenzie, CERA, and PIRA. Figure 2 below shows the market prices under zero cost CO_2 assumptions.

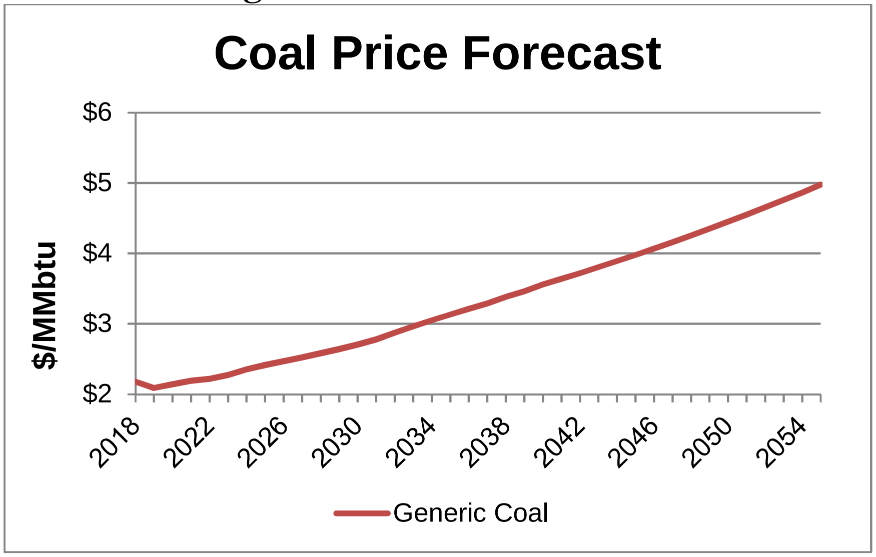
Figure 2: Minn Hub Average On and Off Peak Market Price



11. Coal Price Forecast

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. 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. Layered on top of the coal prices are transportation charges, SO_2 costs, freeze control, and dust suppressant, as required.

Figure 3: Coal Price Forecast



12. Transmission Delivery Costs

Generic 2x1 combined cycle (CC), generic combustion turbine (CT), generic wind, and generic solar have assumed transmission delivery costs. The table below shows the transmission delivery costs on a $/kW basis. The CC and CT costs were developed based on the average of several potential sites in Minnesota. The general site locations were investigated by Transmission Access for impacts to the transmission grid and expected resulting upgrade costs

Table 6: Transmission Delivery Costs

	$/kw
CC	$ 330
CT	$ 100
Wind	$ 200
Solar	$ 70

13. Interconnection Costs

Estimates of interconnection costs of the generic resources were included in the capital cost estimates.

14. Effective Load Carrying Capability (ELCC) Capacity Credit for Wind Resources

Existing wind units is based on current MISO accreditation. New wind additions are given a capacity credit equal to 15.6 percent of their nameplate rating per MISO 2017/2018 Wind Capacity Report.

15. ELCC Capacity Credit for Utility Scale Solar Photovoltaic (PV) Resources

Utility scale generic solar PV additions used in modeling the alternative plans were given a capacity credit equal to 50 percent of the AC nameplate capacity.

16. 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 182 MW and is based on a 12 month rolling average of spinning reserves carried by the NSP System within MISO.

17. Emergency Energy Costs

Emergency Energy Costs were assigned in the Strategist model if there were not enough resources available to meet energy requirements. The cost was set at $500/MWh.

18. Wind Integration Costs

Wind integration costs were priced based upon the results of the NSP System Wind Integration Cost Study. Wind integration costs contain five components:

1. MISO Contingency Reserves
2. MISO Regulating Reserves
3. MISO Revenue Sufficiency Guarantee Charges
4. Coal Cycling Costs
5. Gas Storage Costs

Table 7: Wind Integration Costs

Year	Integration $/MWh		Coal Cycling $/MWh	
	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	0.00	0.00
2021	0.42	0.42	0.00	0.00
2022	0.43	0.43	0.00	0.00
2023	0.44	0.44	0.00	0.00
2024	0.44	0.44	0.00	0.00
2025	0.45	0.45	0.00	0.00
2026	0.46	0.46	0.00	0.00
2027	0.47	0.47	0.00	0.00
2028	0.48	0.48	0.00	0.00
2029	0.49	0.49	0.00	0.00
2030	0.50	0.50	0.00	0.00
2031	0.51	0.51	0.00	0.00
2032	0.52	0.52	0.00	0.00
2033	0.53	0.53	0.00	0.00
2034	0.54	0.54	0.00	0.00
2035	0.55	0.55	0.00	0.00
2036	0.56	0.56	0.00	0.00
2037	0.57	0.57	0.00	0.00
2038	0.59	0.59	0.00	0.00
2039	0.60	0.60	0.00	0.00
2040	0.61	0.61	0.00	0.00
2041	0.62	0.62	0.00	0.00
2042	0.63	0.63	0.00	0.00
2043	0.65	0.65	0.00	0.00
2044	0.66	0.66	0.00	0.00
2045	0.67	0.67	0.00	0.00
2046	0.69	0.69	0.00	0.00
2047	0.70	0.70	0.00	0.00
2048	0.71	0.71	0.00	0.00
2049	0.73	0.73	0.00	0.00
2050	0.74	0.74	0.00	0.00
2051	0.76	0.76	0.00	0.00
2052	0.77	0.77	0.00	0.00
2053	0.79	0.79	0.00	0.00
2054	0.80	0.80	0.00	0.00
2055	0.82	0.82	0.00	0.00
2056	0.84	0.84	0.00	0.00
2057	0.85	0.85	0.00	0.00

19. Wind Congestion Costs

Wind Congestion Costs were developed internally by Resource Planning using the MISO MTEP 2018 models and looking at the average congestion costs between representative wind bus locations and NSP.NSP. From the study, we included a congestion cost of $3.43 per MWh in 2020, escalating at 2% thereafter for all new wind projects.

Table 8: Wind Congestion Costs

	Wind Congestion $/MWh	
	Existing Resources	New Resources
2018	-	-
2019	-	-
2020	-	3.43
2021	-	3.50
2022	-	3.57
2023	-	3.64
2024	-	3.71
2025	-	3.79
2026	-	3.86
2027	-	3.94
2028	-	4.02
2029	-	4.10
2030	-	4.18
2031	-	4.27
2032	-	4.35
2033	-	4.44
2034	-	4.53
2035	-	4.62
2036	-	4.71
2037	-	4.80
2038	-	4.90
2039	-	5.00
2040	-	5.10
2041	-	5.20
2042	-	5.30
2043	-	5.41
2044	-	5.52
2045	-	5.63
2046	-	5.74
2047	-	5.86
2048	-	5.97
2049	-	6.09
2050	-	6.22
2051	-	6.34
2052	-	6.47
2053	-	6.60
2054		6.73
2055		6.86
2056		7.00
2057		7.14

20. Distributed Generation and Community Solar Gardens

The small solar inputs are based on the most recent Company forecast.

21. Assumption and Sensitivity Descriptions

The modeling uses the following assumptions and sensitivities. The Base Assumptions are combined with the Sensitivities to test the modeling results for critical variables.

Table 9: Assumption and Sensitivity Descriptions

Base Assumptions	Assumption Description
PVRR Base	This assumption optimizes under the PVRR Base Assumption, which does not include Regulated CO_2 Costs, Externality Costs, and the Surplus Capacity Credit. All Strategist outputs, except the Markets Off sensitivity, assume the modeling of MISO Energy Market interactions. The following sensitivities were ran using the PVRR assumption as the starting point: Low Gas, High Gas, Low Load, High Load, Markets off no dump, Markets off with dump, 3% Esc costs, 1% esc. costs.

Sensitivities	Sensitivity Description
Low Gas Price	This sensitivity decreases the annual year-over-year percent change in natural gas prices by 50% starting in year 2022.
High Gas Price	This sensitivity increases the annual year-over-year percent change in natural gas prices by 50% starting in year 2022.
Low Load	This sensitivity uses a minus one standard deviation from the base demand and energy forecast.
High Load	This sensitivity uses a plus one standard deviation from the base demand and energy forecast.
Markets Off No Dump Credit	This sensitivity removes the modeling of the Company's hourly sales in the MISO Energy Market. No credit was applied for dump energy.
Markets Off With Dump Credit	This sensitivity removes the modeling of the Company's hourly purchases in the MISO Energy Market and allows for a credit of one half of the all hours market price for dump energy.
3% esc ongoing costs	MEC ongoing costs to escalate by 3% annually, vs. the 20% base inflation assumption.
1% Esc ongoing costs	MEC ongoing costs to escalate by 1% annually, vs. the 20% base inflation assumption.

22. Owned Unit Modeled Operating Characteristics and Costs

Company owned units were modeled based upon their tested operating characteristics and historical or 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

23. 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

24. Renewable Energy PPAs and Owned Operating Characteristics and Costs

PPAs are modeled based upon their tested operating characteristics and contracted costs. Company owned units were modeled based upon their tested operating characteristics and historical or projected costs. Below is a list of typical operating and cost inputs for each renewable energy PPA and owned 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 were developed through a "Typical Wind Year" process where individual months were selected from the years 2014-2017 to develop a typical year. Actual generation data from the selected months were used to develop the profiles for each wind farm. For farms where generation data was not complete or not available, data from nearby similar farms were used.

Solar hourly patterns were taken from the ELCC Study from Fall 2013 and updated to reflect the ELCC as stated above. The fixed panel pattern is an average of the four orientations and three years (2008-2010) of data and single-axis tracking pattern is an average of three years of data.

25. Generic Assumptions

Generic resources were modeled based upon their expected operating characteristics and projected costs. Below is a list of typical operating and cost inputs for each generic resource.

<u>Thermal</u>

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

<u>Renewable</u>

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

Tables 10-11 below show the assumptions for the generic thermal and renewable resources.

Table 10: Thermal Generic Information (Costs in 2018 Dollars)

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)	916	916	374	232	374
Summer Peak Capacity with Ducts (MW)	870	870	NA	NA	NA
Summer Peak Capacity without Ducts (MW)	643	643	331	228	331
Capital Cost ($/kW)	$914	$951	$446	$495	$445
Electric Transmission Delivery ($/kW)	NA	$301	NA	NA	$100
Ongoing Capital Expenditures ($/kW-yr)	$6.77	$6.77	$4.77	$3.85	$3.85
Gas Demand ($/kW-yr) 2018$	$32.56	$21.14	NA	NA	$2.07
Fixed O&M Cost ($000/yr) 2018$	$2,605	$3,105	$422	$736	$668
Variable O&M Cost ($/MWh)	$1.42	$1.42	$4.90	$4.90	$4.90
Levelized $/kw-mo (All Fixed Costs) $2018	$12.04	$12.71	$4.62	$5.13	$5.58
Heat Rate with Duct Firing (btu/kWh)	6,494	6,818	NA	NA	NA
Heat Rate 100% Loading (btu/kWh)	6,331	6,647	9,042	9,791	9,042
Heat Rate 75% Loading (btu/kWh)	6,464	6,787	9,474	10,234	9,474
Heat Rate 50% Loading (btu/kWh)	6,876	7,220	10,833	12,006	10,833
Heat Rate 25% Loading (btu/kWh)	7,831	8,222	11,279	12,835	11,279
Forced Outage Rate	3%	3%	3%	3%	3%
Maintenance (weeks/yr)	5	5	2	2	2

Table 11: Renewable Generic ECC Costs - $/MWh

GENERIC WIND		
Year	PTC	ECC ($/MWH)
2023	60%	33.06
2024	40%	37.72
2025	0%	46.48
2026	0%	46.76
2027	0%	47.07
2028	0%	47.39
2029	0%	47.74
2030	0%	48.11
2031	0%	48.55
2032	0%	49.00
2033	0%	49.49
2034	0%	50.00
2035	0%	50.53
2036	0%	51.09
2037	0%	51.68
2038	0%	52.30
2039	0%	52.95
2040	0%	53.63
2041	0%	54.34
2042	0%	55.08
2043	0%	55.86
2044	0%	56.67
2045	0%	57.53
2046	0%	58.41
2047	0%	59.34
2048	0%	60.32
2049	0%	61.33
2050	0%	62.39
2051	0%	63.64
2052	0%	64.91
2053	0%	66.21
2054	0%	67.53
2055	0%	68.88
2056	0%	70.26
2057	0%	71.66

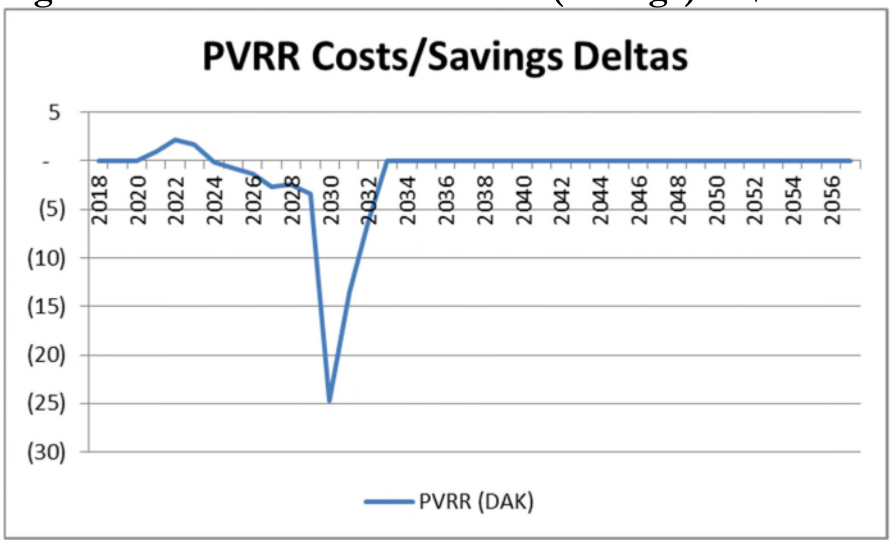
GENERIC SOLAR		
Year	ITC	ECC ($/MWH)
2023	30%	43.45
2024	30%	43.75
2025	10%	44.05
2026	10%	44.34
2027	10%	44.64
2028	10%	44.93
2029	10%	45.22
2030	10%	45.50
2031	10%	46.04
2032	10%	46.58
2033	10%	47.12
2034	10%	47.66
2035	10%	48.21
2036	10%	48.77
2037	10%	49.32
2038	10%	49.88
2039	10%	50.44
2040	10%	51.01
2041	10%	51.52
2042	10%	52.02
2043	10%	52.53
2044	10%	53.04
2045	10%	53.55
2046	10%	54.06
2047	10%	54.57
2048	10%	55.08
2049	10%	55.58
2050	10%	56.09
2051	10%	57.21
2052	10%	58.36
2053	10%	59.52
2054	10%	60.71
2055	10%	61.93
2056	10%	63.17
2057	10%	64.43

II. Strategist Modeling Outputs

1. Annual Net Costs and Savings

The PVRR Base annual costs and savings for the proposed Dakota Range PPA is shown below in Figure 4.

Figure 4: Annual PVRR Net Costs (Savings) in $millions



**BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF NORTH DAKOTA**

NORTHERN STATES POWER COMPANY
ADVANCE PRUDENCE – 151.2 MW
DAKOTA RANGE III WIND FACILITY

CASE NO. PU-18-___

VERIFICATION

STATE OF MINNESOTA)
)ss.
COUNTY OF HENNEPIN

Philip Joseph Martin, being first duly sworn on oath, deposes and says that he is the Director of Resource Planning and Bidding for Xcel Energy Services Inc. on behalf of Applicant Northern States Power Company, a Minnesota corporation, in the above-captioned matter, that the testimony and schedule submitted in the above-captioned matter under his name were prepared under his direction, that he knows the contents thereof, and that the same is true and correct to the best of his knowledge and belief.

Philip Joseph Martin

Subscribed and sworn to before me on this 21st day of December, 2018.

ODISHA FIELDS
Notary Public
Minnesota
My Commission Expires
Jan 31, 2022

Notary Public
My Commission Expires: Jan 31, 2022