Excerpt from North Dakota Case No. PU-17-372, *Northern States Power Company Advance Prudence - Acquisition of 302.4 MW Wind Generation Application*, Supplement (March 23, 2018)

C. Updated Economic Modeling

We updated the inputs to the Strategist resource planning model to reflect the TCJA impacts and cost reductions discussed above. In addition, we updated three other assumptions impacted by the TCJA, including the weighted average cost of capital, the tax impact on the revenue requirements of new generic resource investments, and the capacity credit.[2] All other assumptions are the same as those discussed in our initial Application.

As discussed in our initial Application, the Strategist planning model simulates the operation of the NSP System and estimates the cost to serve load through the life of the project. We use the model to test results under a range of input assumptions. To assess their impact on customer costs, we simulated the operation of the NSP System through 2053, with and without the addition of the 302.4 MW Dakota Range wind project proposed in this filing. All of our analysis assumes the addition of the 1,550 MWs of wind generation currently before the Commission in Case No. PU-17-120.[3] Therefore, the results of the Strategist analysis provide the incremental savings due solely to the addition of the Dakota Range project. The results of the updated Strategist analysis continue to show that this new wind resource will result in net savings for our customers under all sensitivity tests conducted.

Table 1, below, shows the updated present value of revenue requirement (PVRR) savings as well as the PVRR savings from our original analysis.

[2] The capacity credit corresponds to the cost of a generic CT.

[3] On March 19, 2018, the Company and Advocacy Staff requested that the Commission postpone further consideration of the 1,550 MW Wind Portfolio until such time as the Company can update its economic analysis to include the impacts of the TCJA.

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

	PVRR						
	Base	Markets Off	Low Gas Price	High Gas Price	+5% Cap Factor	-5% Cap Factor	Preferred Plan Renewables
Reference Case	0	0	0	0	0	0	0
Dakota Range - orig.	(182)	(132)	(106)	(274)	(245)	(119)	(133)
Dakota Range - suppl.	(167)	(118)	(91)	(259)	(229)	(105)	(122)

As shown above, the proposed wind project continues to provide significant benefits in all scenarios. The $167 million PVRR savings in the Base Case shown above compares to an initially projected PVRR savings of $ 182 million.

To illustrate how the costs (savings) change over time, Figure 1 below charts both the original and the supplemental filing annual costs (savings) impacts of the Dakota Range project as compared to the Reference Case for the PVRR Base assumptions.

Figure 1: Annual Costs (Savings) Compared to Reference Case

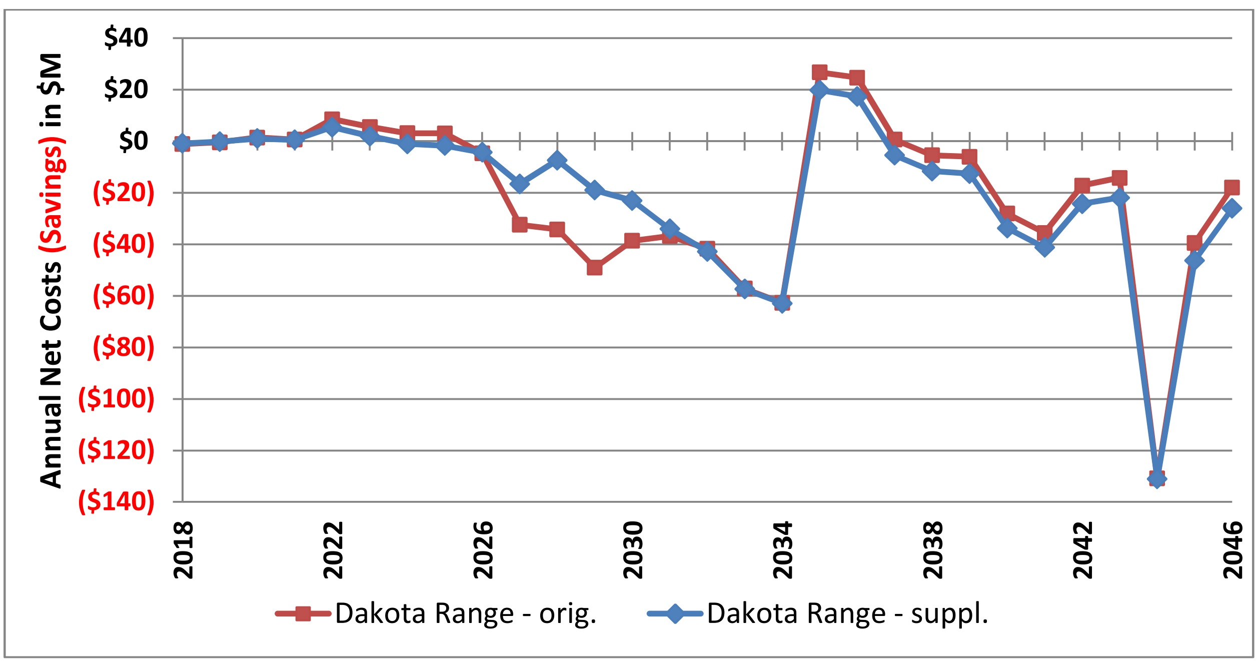

Table 2 shows the original and updated forecasted incremental annual revenue requirement impact of the wind additions through 2027. The values in the table reflect incremental costs or savings as compared to the Reference Case where Dakota Range is not included.

Table 2: Incremental System Revenue Requirement Impact Proposed Project – Initial
($millions)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
New Ownership Wind, 300MW	(0.8)	(0.1)	1.0	2.0	20.6	20.3	19.7	20.1	19.9	21.2
Capacity Cost Savings	0.0	0.0	0.0	0.0	(0.0)	(0.0)	(0.0)	0.0	0.0	(15.4)
Production Cost Savings	0.0	0.0	0.0	(0.8)	(12.8)	(13.2)	(8.8)	(14.1)	(6.4)	(1.1)
MISO Purchases	0.0	0.0	0.0	(0.6)	(2.2)	(2.5)	(6.8)	(3.4)	(6.7)	(11.0)
MISO Sales	0.0	0.0	0.0	(0.5)	(5.9)	(8.5)	(11.1)	(10.4)	(17.4)	(16.7)
Wind Congestion Costs*	0.0	0.0	0.0	0.3	3.4	3.5	3.6	3.6	3.7	3.8
Wind Integration Costs	0.0	0.0	0.0	0.0	0.6	0.6	0.6	0.6	0.6	0.6
Wind Coal Cycling Costs	0.0	0.0	0.0	0.1	1.7	1.8	1.8	1.8	1.9	1.9
Net Costs	**(0.8)**	**(0.1)**	**1.0**	**0.5**	**5.4**	**2.0**	**(1.0)**	**(1.7)**	**(4.3)**	**(16.6)**

Table 3: Incremental System Revenue Requirement Impact Proposed Project – Supplemental

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
New Ownership Wind, 300MW	(0.8)	(0.1)	1.0	2.0	20.6	20.3	19.7	20.1	19.9	21.2
Capacity Cost Savings	0.0	0.0	0.0	0.0	(0.0)	(0.0)	(0.0)	0.0	0.0	(15.4)
Production Cost Savings	0.0	0.0	0.0	(0.8)	(12.8)	(13.2)	(8.8)	(14.1)	(6.4)	(1.1)
MISO Purchases	0.0	0.0	0.0	(0.6)	(2.2)	(2.5)	(6.8)	(3.4)	(6.7)	(11.0)
MISO Sales	0.0	0.0	0.0	(0.5)	(5.9)	(8.5)	(11.1)	(10.4)	(17.4)	(16.7)
Wind Congestion Costs*	0.0	0.0	0.0	0.3	3.4	3.5	3.6	3.6	3.7	3.8
Wind Integration Costs	0.0	0.0	0.0	0.0	0.6	0.6	0.6	0.6	0.6	0.6
Wind Coal Cycling Costs	0.0	0.0	0.0	0.1	1.7	1.8	1.8	1.8	1.9	1.9
Net Costs	**(0.8)**	**(0.1)**	**1.0**	**0.5**	**5.4**	**2.0**	**(1.0)**	**(1.7)**	**(4.3)**	**(16.6)**

* Congestion Costs reflected as cost adder to wind generation rather than lower generator LMP.

Table 3, below, shows the updated forecasted incremental impact on average monthly bills in North Dakota. It is important to note that the recovery mechanism used to recover the costs of this wind addition will impact the actual timing of the recovery and the actual class allocation. We have provided an estimated impact below.

Table 3: Updated ND Forecasted Incremental Impact on Monthly Bills

Year	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Residential	($0.01)	($0.00)	$0.02	$0.01	$0.09	$0.01	($0.01)	($0.02)	($0.06)	($0.29)
Commercial Non Demand	($0.02)	($0.00)	$0.02	$0.01	$0.12	$0.01	($0.02)	($0.03)	($0.08)	($0.35)
C&I Demand	($0.68)	($0.11)	$0.88	$0.43	$4.41	$0.15	($0.94)	($1.45)	($3.57)	($12.21)
Lighting	($0.01)	($0.00)	$0.01	$0.00	$0.04	($0.01)	($0.03)	($0.03)	($0.06)	($0.03)