Table of Contents

I. STRATEGIST RESOURCE PLANNING MODEL OVERVIEW

Strategist is a resource planning software model developed and sold by Ventyx Corporation which has been used by Xcel Energy in our Resource Plans since 2000. Strategist is used to estimate the costs of various resource expansion plans, to evaluate specific capacity alternatives and measure the potential risks of new environmental legislation and other policy scenarios. Strategist results are not of themselves the final decision maker in terms of selecting the preferred plan, but are used as a decision support tool to guide development of a preferred plan and test the robustness of the plan under a variety of scenarios. Modeling is not the same as decision making.

The model consists of four primary components:

- *Load Module* (LFA) that contains Xcel Energy's load forecast, load management, and conservation programs. This module produces long-range estimates of the Company's net energy requirements and peak capacity requirement.
- *Generation Module* (GAF) that contains the operating costs and performance characteristics for our thermal units, renewable resources, and transactions. This module uses an hourly dispatch simulation to estimate how demand will be met and what the associated costs and emissions will be.
- *Capital Project Module* (CER) that estimates the revenue requirement for capital projects such as new generating resources. This module calculates key financial values such as rate base, depreciation, taxes, and rate of return for existing and future capital projects.
- *Expansion Planning Module* (Proview) that uses a dynamic programming algorithm to derive the least cost expansion plan under the assumptions used. This module calculates the customer and societal costs for thousands of different resource combinations to arrive at the least cost plan.

Strategist simulates the operation of our system over a 40-year planning period, taking into account our demand and energy forecast, required reserve margin, new resources we are committed to adding, and planned retirements. The model proceeds one year at a time, simulating the hourly system dispatch, and tracking generation, system costs, and emissions. When Strategist reaches a year in which peak demand plus required reserve margin exceeds available resources, the Proview module will add various combinations of generic resources to meet the required reserves and track total system costs for each combination. At the end of the model run, Strategist identifies the least cost expansion plan as well as any sub-optimal plans evaluated during the simulation.

For each expansion plan, Strategist calculates fuel consumption, fuel costs, O&M costs, emission rates, capital costs, and total revenue requirement. The total system costs are reported as the Net Present Value of Societal Costs (PVSC). This value is the sum of all operating, depreciation, return on rate base, and tax costs, less any revenues from sales discounted back to 2014 using the Company's most recently authorized weighted after tax cost of capital of 6.62 percent.

Although Strategist can be run for shorter periods of time, this tends to underestimate the end value of longer-lived resources (such as owned thermal resources) to customers by effectively chopping off the benefits to be accrued over the true useful life of the resource.

Strategist has been used for many years by utilities, consultants, and state public utility commissions to evaluate a variety of long-term resource planning issues. The software's longevity and market penetration are the result of the confidence end users have in its capabilities. The software includes significant detail on system load and generation characteristics as well as detailed modeling capability for capital projects. Model results can be analyzed down to unit-level performance for each month over the 40-year time horizon. This level of granularity allows the user to build a model that closely mimics the actual system and allows for robust quality checks on the model output.

By using Strategist, we can explore how our plan will meet customer needs under a variety of conditions at a reasonable cost. We work with internal and external subject matter experts to characterize our current system and to develop starting assumptions that accurately reflect the expert opinion of likely future conditions. We then test the robustness of the plans through sensitivity analysis by individually changing key assumptions (such as future fuel prices) and rerunning the plans under these changed assumptions. Thus, Strategist tests our plans under a number of possible futures and allows us to select a robust plan that meets our current and expected future legal and regulatory requirements.

A. Comparison to Other Models and Limitations

Strategist does have some limitations. Although it uses hourly information, it is not a chronological model. Hourly patterns for energy demand are rearranged into load duration curves and thermal dispatch simulations are based on these curves. Also, Strategist uses a simplified approach to wind and solar patterns – we model a typical week for each calendar month that is repeated to fill the month and carried forward to future years' calendar month. These simplifications allow the model to quickly simulate operation of the system, which is critical to being able to analyze the many thousands of potential plans required to determine the true least cost alternative.

As a tradeoff, the model loses the ability to capture some granular operational details (such as ramp rates on our generating units), perform stochastic analysis (such as randomizing wind production), or include transmission constraints. There are other models, such as ProMod, that are more sophisticated in their ability to dispatch chronologically or simulate transmission congestion impacts, but these models typically take many hours to simulate a single year and are not usable for resource selection purposes. Strategist is a robust dispatch and costing tool that is well suited to analyzing the implications of the broad planning decisions made in resource planning proceedings.

B. Modeling Assumptions – Overview

Although the planning period in this report covers 2016-2030, our Strategist analysis covers 2014-2053 and our reported PVSC values correspond to this time period. The longer time interval allows us to better estimate the costs and benefits of the long-lived resources proposed in this plan.

Important starting assumptions in our analysis include:

1. Forecast Assumptions
    - We develop plans to meet the 50 percent probability level of forecasted peak demand, and the 50 percent probability level of forecasted energy requirements. We incorporate a reserve margin requirement to ensure that a plan developed to meet expected values has enough flexibility to meet lower probability extreme events. The forecast has been offset by demand side management (DSM) savings levels of 1.5 percent energy savings to evaluate each of these levels.

2. Existing Fleet Assumptions
    - Forecasts for cost and performance assumptions (such as variable operations and maintenance (O&M), heat rate,[1] forced outage rate,

---

[1] We provide additional heat rate data in Attachment A to this Appendix, pursuant to the Commission's Order in Docket No. E999/CI-06-159 (In the Matter of Commission Investigation and Determination under

maintenance requirements, etc.) developed based on historical data analysis with adjustments for known changes, if applicable.[2]

- Costs escalated based on corporate estimates of expected inflation rates.
- Retirement of our Prairie Island nuclear generating station at the end of its current license renewals (2033, 2034), and retirement of Monticello at the end of its current license (2030).
- Retirement of other facilities at their current expected end of life if within the Resource Planning period, unless we have specifically included costs of life extension.[3]
- Continuation of our existing power purchase contracts until their contractual termination dates.
- Continued operation of Xcel Energy's owned hydroelectric resources based on historical performance.

3. Renewable Energy Assumptions
    - Addition of 750 MW of wind through 2016 as already approved by regulators.
    - Generic addition of 400 MW of wind in 2020 to ensure meeting the state carbon reduction goals.
    - Accreditation of wind resources based on Midcontinent Independent System Operation, Inc., (MISO) planning reserve credit allocation (currently 14.4 percent).
    - No extension of the Federal Production Tax Credit or 30 percent Investment Tax Credit (ITC) past the expiration dates as per current law.
    - 187 MW of utility scale solar added in 2016.
    - Distributed and utility-scale solar additions sufficient to meet the 1.5 percent standard by 2020. Distributed solar additions continue through

---

the Electricity Title, Section XII, of the Federal Energy Policy Act of 2005), which required the Company to file information on the fossil fuel efficiency (heat rate) of our generation units and actions we are taking to increase the fuel efficiency of those units.

[2] We provide information in Attachment B with respect the Company's accounting for possible effects of drought and high water temperature on generating plant availability in our modeling.

[3] The one exception to this assumption is with regard to our Sherco 1 and 2 units. These facilities reach the end of their book lives in 2023. However, the plan for these facilities is a key part of this Resource Plan so our modeling assumes they retire after 2030 under the starting assumptions. Multiple alternative plans are also analyzed in detail.

2030 at the same annual MW level as are planned for 2020 (annual additions grow through 2020 and then remain flat).

4. Markets Assumptions
   - Due to the uncertainty surrounding the United States Environmental Protection Agency's (EPA) proposed 111(d) rule and the impact on both market price forecasts and assigned carbon content of market purchases, the starting assumption was to run the Strategist model with economy purchases off. A sensitivity with economy purchases on was run to test the impacts of this assumption on the various plans.

5. Emissions Assumptions
   - Emission rates for existing and planned resources were assumed consistent with historical and expected performance.
   - A starting assumption of $21.50 per ton carbon dioxide (CO_2) as a regulatory cost, starting in 2019 and escalating at inflation. The societal value of carbon as an externality was included as a sensitivity case (more detail in the Sensitivity Analysis section, below).
   - The Commission's high externality values for specified emissions.
   - Sulfur oxides (SOx) assumed zero regulatory cost due to large surplus of allowances and weak sales market. Zero externality cost per Commission policy.
   - Nitrogen Oxides (NOx) modeled as an externality cost.

6. Generic Thermal Alternatives
   - Strategist uses generically defined resources to meet future demand when existing resources fall short. The Company used the following generic resources as model inputs for this Resource Plan:
     - 226 MW gas-fired Combustion Turbine peaking unit (CT)
     - 100 MW gas-fired CT peaking unit
     - 786 MW gas-fired Combined Cycle intermediate unit (CC)
     - 290 MW gas-fired CC intermediate unit
     - 500 MW Super Critical Pulverized Coal base load unit, with an alternate version including 90 percent carbon capture and storage
     - 50 MW Bubbling Fluidized Bed Biomass unit, burning wood waste
     - 200 MW Wind project, with Production Tax Credit (PTC) for 2016, without PTC afterwards

- 50 MW Solar project, single-axis tracking, with ITC for 2016, without ITC afterwards

Cost and performance data for these units are based on a consultant's estimates and internal company data. Availability dates are selected based on our estimates of the lead time needed for regulatory approvals, financing, permitting and construction. A more complete description of the key Strategist assumptions used is provided below.

C. Modeling Assumptions – Detail

1. Capital Structure and Discount Rate

The rates shown in Table 1 were calculated by taking a weighted average of Minnesota (85 percent) and Wisconsin (15 percent) information from the January 2014 Corporate Assumptions Memo. The after tax weighted average cost of capital of 6.62 percent is used to calculate the capital revenue requirements of generic resources. It is also used as the discount rate to determine the present value of revenue requirements.

Table 1: Capital Structure

	Capital Structure	Allowed Return	Before tax Elec. WACC	After tax Elec. WACC
L-T Debt	45.24%	5.12%	2.33%	1.37%
Common Equity	52.56%	9.89%	5.24%	5.24%
S-T Debt	2.20%	0.64%	0.01%	0.01%
Total			7.58%	6.62%

2. Inflation Rates

The inflation rates are developed based on the long-term forecasts from Global Insight of labor and non-labor inflation rates.

- Variable O&M inflation – 50 percent labor and 50 percent non-labor inflation – 1.80 percent
- Fixed O&M inflation – 75 percent labor and 25 percent non-labor inflation – 2.18 percent
- General inflation – 40 percent labor and 60 percent non-labor inflation – 1.66 percent

3. Reserve Margin

The reserve margin at the time of MISO's peak is 7.1 percent. The coincidence factor between the NSP System and MISO system peak is 5 percent. Therefore, the effective reserve margin is:

$$(1 - 5\%) * (1 + 7.1\%) - 1 = 1.75\%.$$

Table 2: Reserve Margin

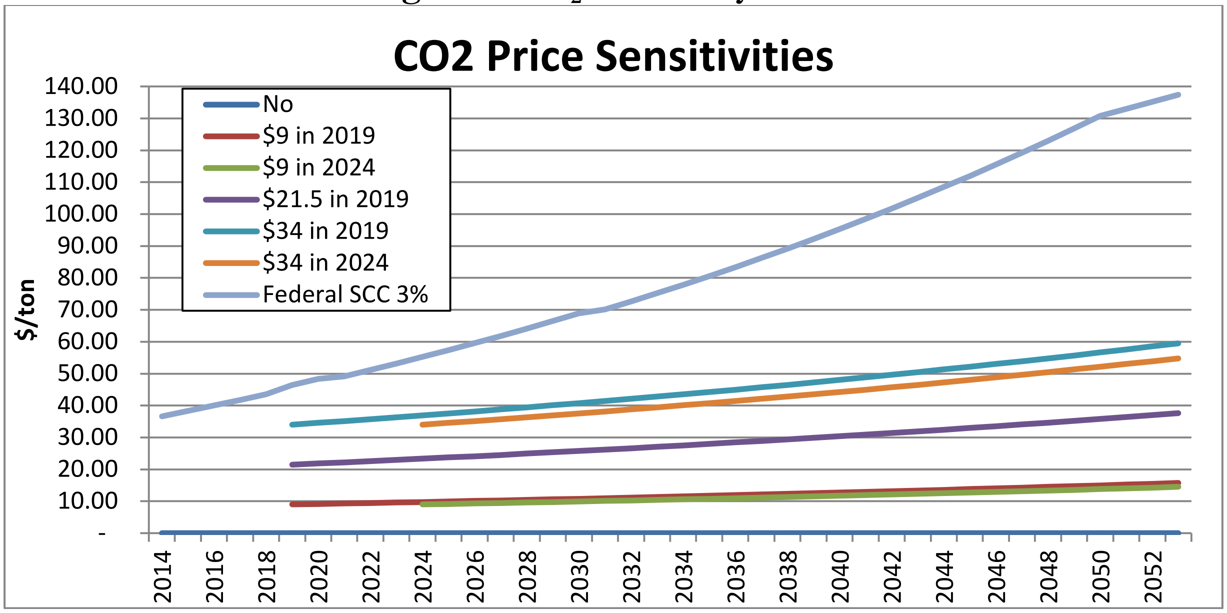
Reserve Margin	
Coincidence Factor	5.00%
MISO Coincident Peak Reserve Margin %	7.10%
Effective RM Based on Non-coincident Peak	1.75%

4. CO_2 Price Forecasts

Figure 1 shows the annual CO_2 prices for the various CO_2 sensitivities that were used in the analysis. The base assumption is $21.50/ton starting in 2019 which is the average of $9/ton and $34/ton. The range of CO_2 costs is drawn from the Minnesota Public Utilties Commission's decision in Docket No. E999/CI-1199. This docket also recommended extending the applicable effective date to 2019. All prices escalate at inflation.

The analysis has a sensitivity that uses the Social Cost of Carbon (SCC) developed and published by the Federal Government. The SCC sensitivity uses the 3.0 percent Average Discount Rate values from the November 2013 revised Technical Support Document (TSD). Since the values in the TSD are in year 2007 dollars per metric ton, they were converted to nominal dollars per short ton. The modeling escalates the SCC at inflation. After converting, the year 2015 price is $38.31/short ton and the year 2053 price is $137.42/short ton.

Figure 1: CO_2 Sensitivity Prices



5. Externality Prices

Externality prices are based on the high values from the Minnesota Public Utilities Commission's Notice of Comment Period on Updated Environmental Externality Values issued May 22, 2014 (Docket Nos. E999/CI-93-583 and E999/CI-00-1636) and are shown in Table 3 below. Prices are shown in 2014 dollars and escalate at inflation.

Table 3: Externality Prices

MPUC Updated Externality Prices				
2014 $/ton				
	Urban	Metro Fringe	Rural	<200mi
NOx	$1,430	$389	$149	$149
PM10	$9,391	$4,220	$1,250	$1,250
CO	$3	$2	$1	$1
Pb	$5,666	$2,917	$655	$655

6. Demand and Energy Forecast

The Fall 2014 Load Forecast, developed by the Xcel Energy Load Forecasting group, was used in the Resource Plan. The table below shows the annual energy and demand. High and low sensitivities were also performed. The growth rates for peak demand and annual sales (unadjusted for DSM or Solar) were decreased by 50 percent for the low load sensitivity and increased by 50 percent for the high load sensitivity.

Table 4: Demand and Energy Forecast

	Demand (MW)				Energy (GWh)		
Year	Model Output	W/ Hist DSM, Building Code Adj	Final w DSM/Eff Adjustments	Year	Model Output	W/ Hist DSM, Building Code	Final w DSM/Eff Adjustments
2014	9,894	8,851	8,776	2014	50,353	45,119	44,682
2015	10,494	9,466	9,325	2015	51,186	46,054	45,210
2016	10,624	9,656	9,442	2016	51,806	46,930	45,635
2017	10,723	9,812	9,525	2017	52,057	47,518	45,775
2018	10,824	9,972	9,597	2018	52,382	48,199	46,008
2019	10,914	10,118	9,649	2019	52,705	48,824	46,185
2020	11,008	10,241	9,674	2020	53,170	49,457	46,362
2021	11,091	10,364	9,694	2021	53,438	49,868	46,325
2022	11,178	10,518	9,754	2022	53,664	50,460	46,520
2023	11,259	10,614	9,748	2023	53,971	50,826	46,488
2024	11,348	10,715	9,766	2024	54,395	51,322	46,659
2025	11,428	10,817	9,798	2025	54,651	51,778	46,810
2026	11,513	10,947	9,868	2026	54,867	52,261	47,083
2027	11,594	11,086	9,962	2027	55,152	52,889	47,520
2028	11,682	11,222	10,136	2028	55,591	53,639	48,522
2029	11,763	11,268	10,151	2029	55,878	53,811	48,566
2030	11,855	11,367	10,251	2030	56,160	54,215	48,779

Figure 2: High and Low Energy Sensitivities

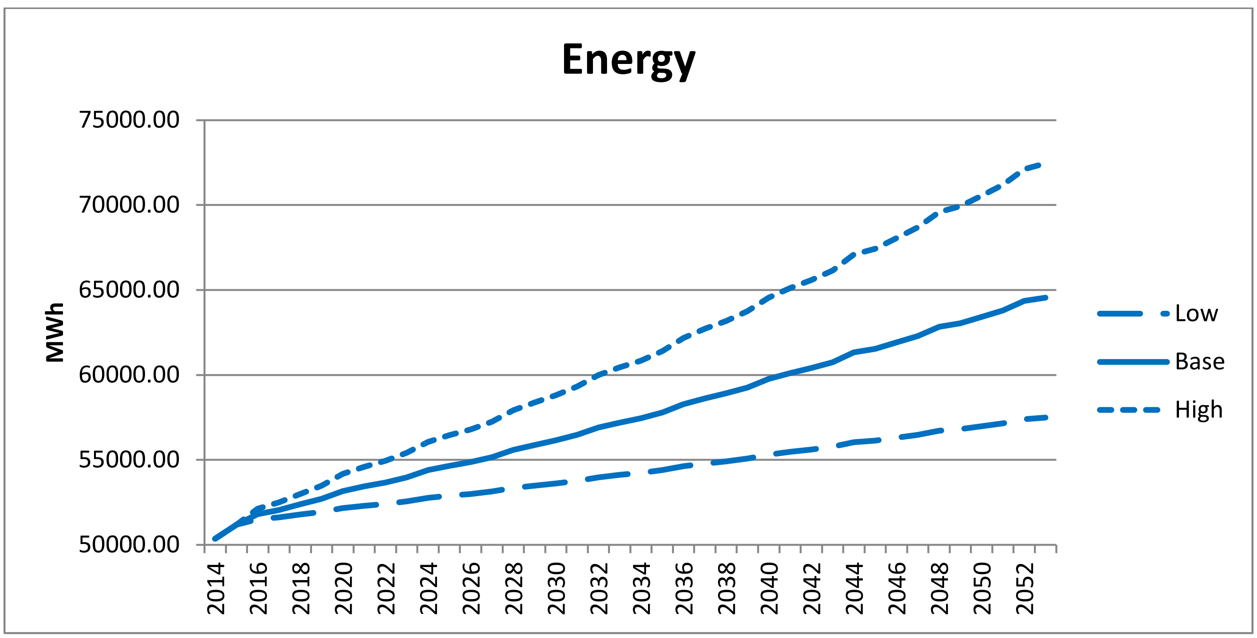
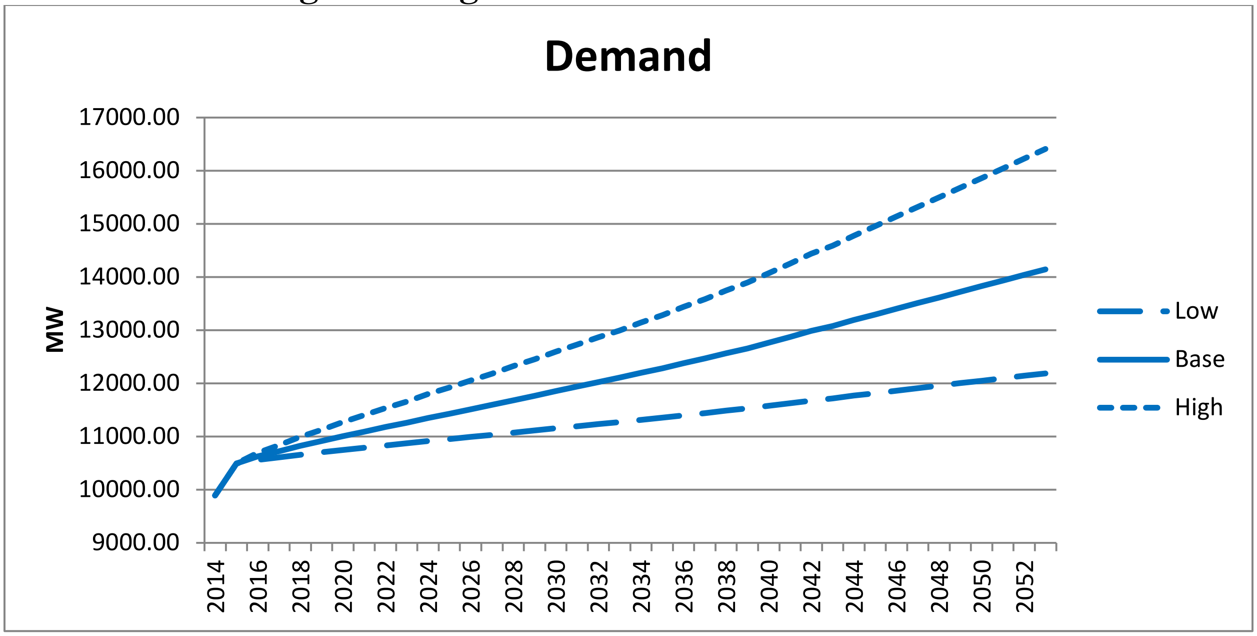


Figure 3: High and Low Demand Sensitivities



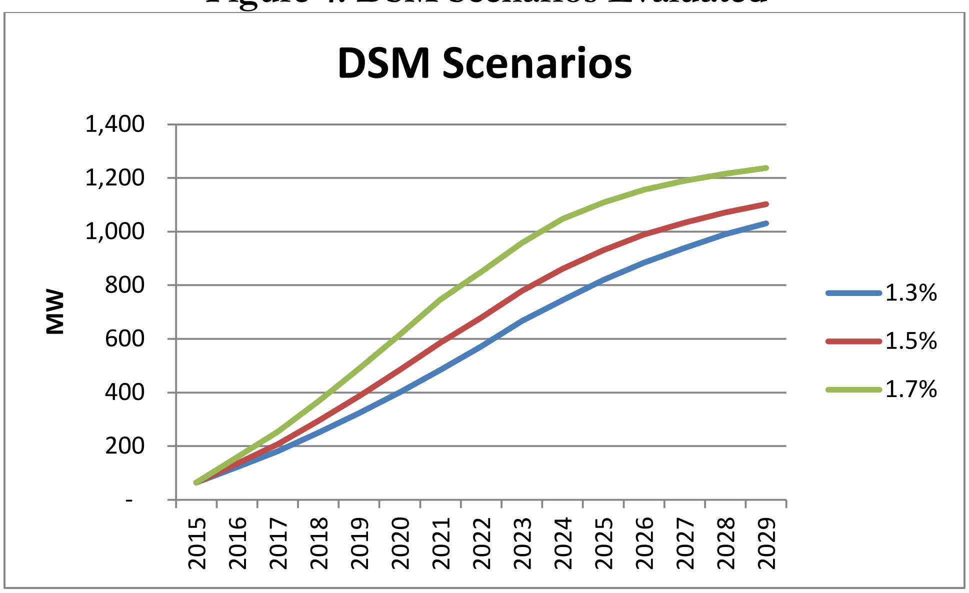
7. DSM Forecasts

The goals for both 2014 and 2015 are as filed in our most recent DSM Triennial Plan (2013-2015) Docket No. E,G002/CIP-12-447. Beginning in 2016, a scenario based on a March 2014 update to the 2011 Minnesota DSM Potential Study was used. This scenario assumes impacts expected at a 75 percent rebate level for DSM. The annual average of impact from this scenario equals roughly 1.5 percent of the sales metric used in the DSM Plans and has been called the "1.5 percent scenario." This scenario was analyzed along with a "1.3 percent scenario" and a "1.7 percent scenario." Figure 4 below shows the MW values of the three scenarios evaluated. The various DSM scenarios begin in 2016 and live through 2029.

Table 5: Base DSM Forecast (with 1.5 percent scenario beginning 2016)

Year	Energy (MWh)	Demand (MW)
2014	438	75
2015	845	141
2016	1,295	214
2017	1,743	287
2018	2,191	375
2019	2,639	469
2020	3,095	567
2021	3,543	670
2022	3,941	764
2023	4,338	866
2024	4,663	949
2025	4,968	1,019
2026	5,178	1,079
2027	5,369	1,124
2028	5,117	1,087
2029	5,246	1,116
2030	5,436	1,116

Figure 4: DSM Scenarios Evaluated



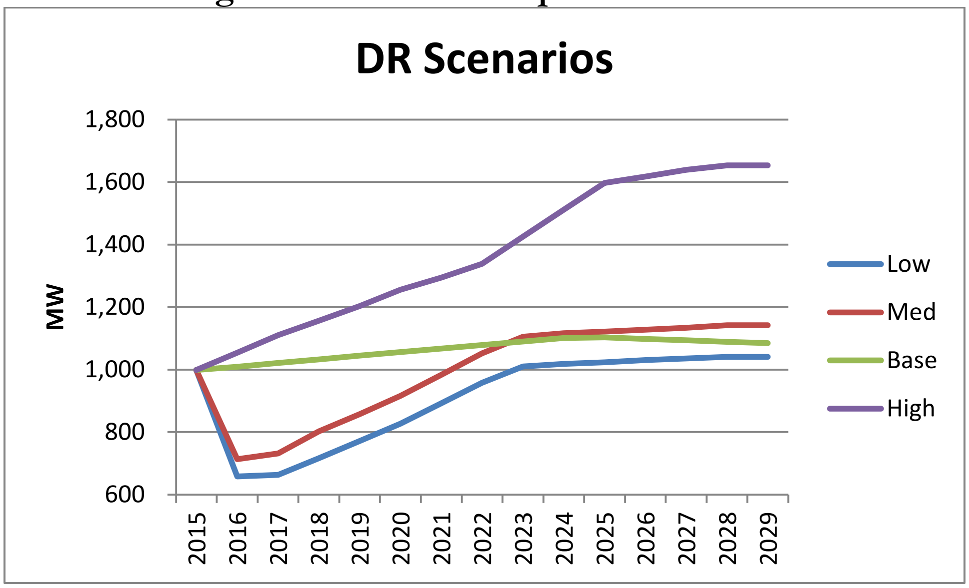
8. Demand Response Forecast

The 2014 Load Management Forecast developed by the Xcel Energy Load Research group was used in the Resource Plan. The table below shows the July demand. In addition to the Load Management Forecast (LMF), three additional demand response scenarios were evaluated. These scenarios were based on findings from a study performed by The Brattle Group. These scenarios and the LMF are shown in Figure 5 below.

Table 6: Load Management Forecast

July Demand (MW)	2015	2016	2017	2018	2019	2020	2021	2022
LMF	933	942	953	964	975	986	996	1,007
July Demand (MW)	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
LMF	1,017	1,028	1,030	1,025	1,021	1,017	1,013	1,009

Figure 5: Demand Response Scenarios

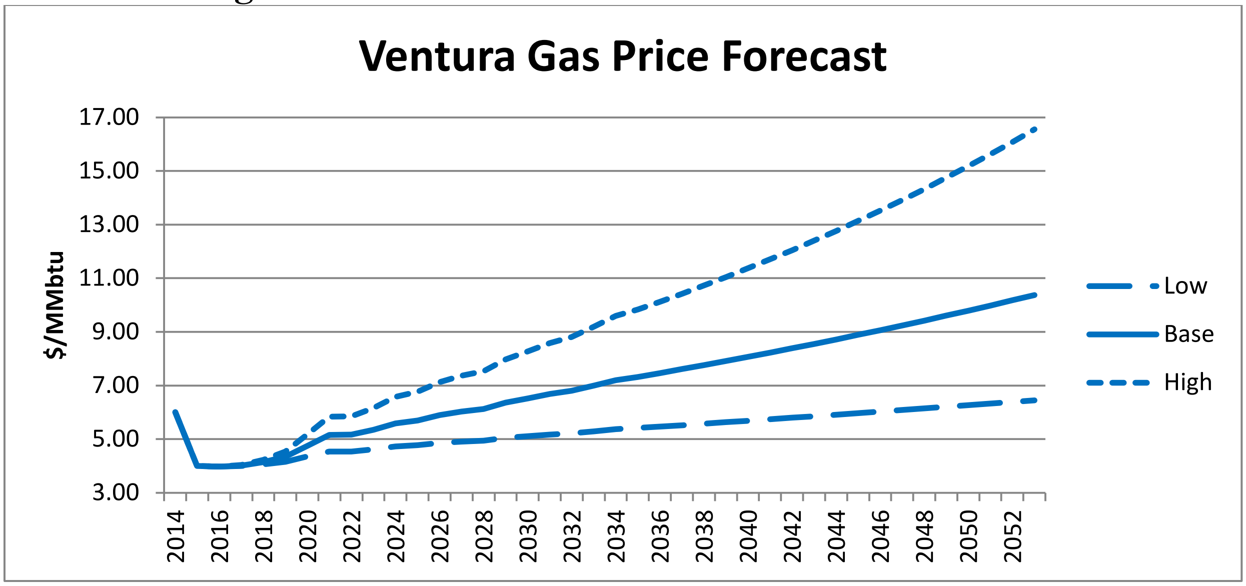


9. Gas Price Forecasts

Henry Hub natural gas prices are developed using a blend of the latest 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 from September 8, 2014 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.

Figure 6: Ventura Gas Price Forecast and Sensitivities



10. 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 13 contains gas transportation charges for generic thermal resources.

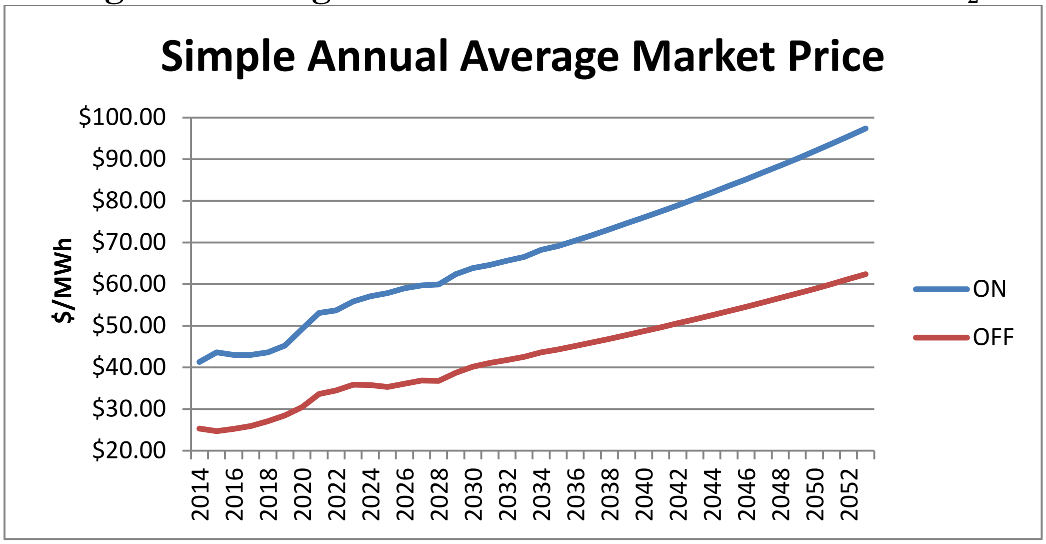
11. Gas Demand Charges

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 13 contains gas demand charges for generic thermal resources.

12. Market Prices

In addition to resources that exist within the NSP System, the Company has access to markets located outside its service territory. Market power prices are developed using a blend of market information from the Intercontinental Exchange for near-term prices and long-term fundamentally-based forecasts from Wood Mackenzie, CERA and PIRA. Figure 9 below shows the market prices under no CO_2 assumptions.

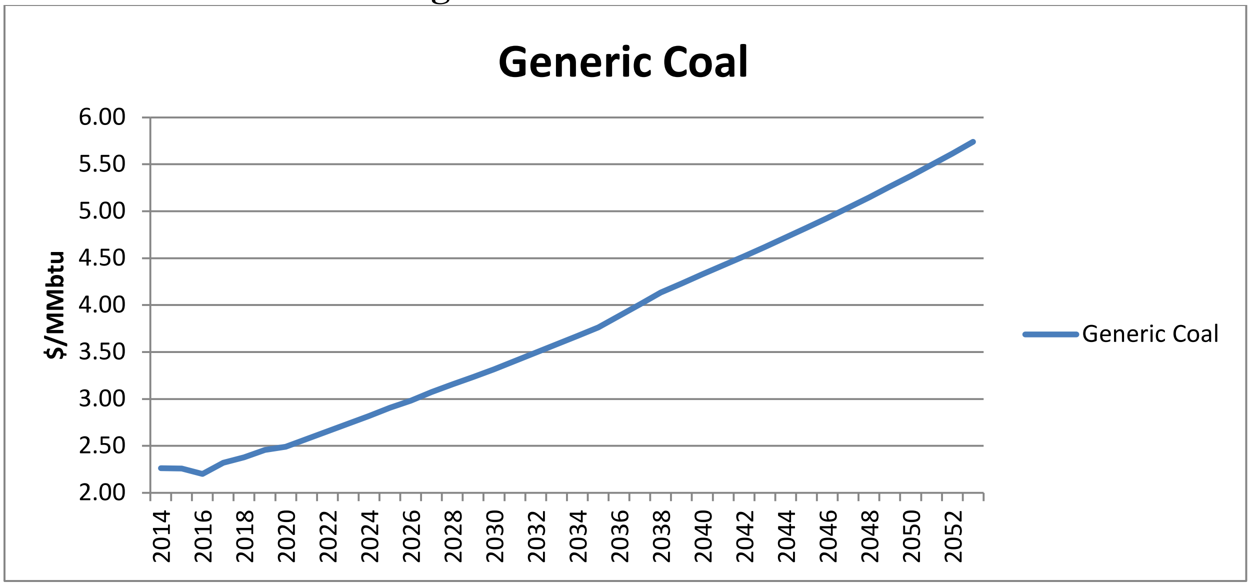
Figure 7: Average On and Off Peak Market Price-No CO_2



13. Coal Price Forecasts

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 8: Coal Price Forecast



14. Surplus Capacity Credit

The credit is applied for all twelve months of each year and is priced at the avoided capacity cost of a generic combustion turbine.

Table 7: Surplus Capacity Credit

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
$/kw-mo	4.60	4.71	4.81	4.92	5.03	5.14	5.26	5.37	5.50	5.62
	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
$/kw-mo	5.74	5.87	6.00	6.14	6.28	6.42	6.56	6.71	6.86	7.01
	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
$/kw-mo	7.17	7.33	7.49	7.66	7.83	8.00	8.18	8.37	8.55	8.75
	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053
$/kw-mo	8.94	9.14	9.35	9.55	9.77	9.99	10.21	10.44	10.67	10.91

15. Transmission Delivery Costs

Generic 2x1 combined cycle, generic CTs, 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 the Minnesota. The general site locations were investigated by Transmission Access for impacts to the transmission grid and expected resulting upgrade costs. The averages were $152/kW for combustion turbines and $406/kW for 2X1 combined cycles. Wind costs were based on 25 percent of capital construction costs, which were based on transmission analyses for the Buffalo Ridge area. Solar costs were developed from inputs from the Transmission Access group that indicated cost of around $150/kWac based on utility scale projects that are connecting at the 115kV transmission level.

Table 8: Transmission Delivery Costs

	$/kw
CC	$ 406.0
CT	$ 152.2
Solar	$ 150.0
Wind	$ 437.5

16. Interconnection Costs

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

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

Existing wind units is based on current MISO accreditation. New wind additions were given a capacity credit equal to 14.8 percent of their nameplate rating per MISO 2012/2013 Wind Capacity Report.

18. 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 52.3 percent of the AC nameplate capacity. This value is from the May 2013 ELCC Study. In this study, it was estimated what capacity accreditation solar might receive based on the methodology that MISO prescribes under its Resource Adequacy Business Practices Manual.

19. 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 94 MW and is based on a recent 12 month rolling average of spinning reserves carried by the NSP System within MISO.

20. 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 escalating at inflation which is about $150/MWh more than an oil unit with an assumed heat rate of 15 MMBtu/MWh. Emergency energy occurs only in rare instances.

21. Dump Energy / Wind Curtailment

Estimates of wind curtailment were represented in the Strategist model by the "dump energy" variable. Dump energy occurs whenever generation cannot be reduced enough to balance with load, a situation that occurs primarily due to the non-dispatchable nature of wind generation resources combined with minimum turn-down capabilities of must-run units under low load hours. In the NSP System, it is assumed that the excess generation can be sold into the MISO market. To approximate the price the excess energy could be sold for, 50 percent of the all-hours average market price modeled in Strategist was used.

22. 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

The complete Wind Integration Study is included in Appendix M. The results of the study as used in Strategist are shown below.

Table 9: Wind Integration Costs

	Wind Integration $/MWh		Coal Cycling $/MWh	
	Existing Resources	New Resources	Existing Resources	New Resources
2014	0.39	0.40	0.72	1.20
2015	0.40	0.41	0.73	1.22
2016	0.41	0.42	0.75	1.24
2017	0.41	0.42	0.76	1.26
2018	0.42	0.43	0.77	1.28
2019	0.43	0.44	0.78	1.31
2020	0.43	0.45	0.80	1.33
2021	0.44	0.45	0.81	1.35
2022	0.45	0.46	0.82	1.37
2023	0.46	0.47	0.84	1.39
2024	0.46	0.48	0.85	1.42
2025	0.47	0.48	0.87	1.44
2026	0.48	0.49	0.88	1.47
2027	0.49	0.50	0.89	1.49
2028	0.50	0.51	0.91	1.51
2029	0.50	0.51	0.92	1.54
2030	0.51	0.52	0.94	1.56

23. 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

Table 10 below shows company owned unit retirement date, installed capacity (ICAP), UCAP (calculated by Resource Planning), and long term UCAP (2017) based on a five-year average of historical equivalent forced outage rates on demand.

Table 10: Thermal Owned Unit Information

Unit	Retirement Date	ICAP	RP Current UCAP	Long Term UCAP
AS KING 1	12/31/2037	541	514	519
BLACKDOG 3	5/31/2015	92	83	83
BLACKDOG 4	5/31/2015	166	135	135
SHERCO 1	12/31/2040	709	695	694
SHERCO 2	12/31/2030	694	676	667
SHERCO 3	12/31/2030	527	491	515
MONTI 1	* 9/30/2030	624	593	608
P ISLAND 1	8/31/2033	522	518	520
P ISLAND 2	10/31/2034	516	508	516
BDOG_CC 52	12/31/2031	285	189	247
HB_CC 1	5/31/2048	544	525	515
RS_CC 1	3/31/2049	470	445	443
ANSON 2	12/31/2030	93	88	83
ANSON 3	12/31/2030	93	80	76
ANSON 4	5/31/2035	149	145	144
BLUELAKE 7	5/31/2035	154	151	154
BLUELAKE 8	5/31/2035	155	146	150
FLAMBEAU 1	12/31/2018	13	12	11
GRANITE 1	12/31/2023	13	9	9
GRANITE 2	12/31/2023	14	12	12
GRANITE 3	12/31/2023	14	11	12
GRANITE 4	12/31/2023	13	10	11
INVERHIL 1	12/31/2026	48	40	41
INVERHIL 2	12/31/2026	48	45	46
INVERHIL 3	12/31/2026	48	44	44
INVERHIL 4	12/31/2026	48	41	40
INVERHIL 5	12/31/2026	47	38	41
INVERHIL 6	12/31/2026	48	42	39
KEY CITY 2	3/31/2015	16	16	16
KEY CITY 3	3/31/2015	16	13	13
KEY CITY 4	3/31/2015	17	16	16
WHEATON 1	12/31/2025	46	38	40
WHEATON 2	12/31/2025	55	42	48
WHEATON 3	12/31/2025	46	40	42
WHEATON 4	12/31/2025	47	38	45
BAYFRONT 4	12/31/2023	20	19	19
BLUELAKE 1	12/31/2023	39	35	35
BLUELAKE 2	12/31/2023	39	39	39
BLUELAKE 3	12/31/2023	38	38	38
BLUELAKE 4	12/31/2023	41	41	41
FCH ISLD 3	12/31/2023	-	-	56
FCH ISLD 4	12/31/2023	61	59	56
WHEATON 5	12/31/2025	53	42	42
WHEATON 6	12/31/2025	51	33	31
INVERDSL 78	8/31/2017	-	-	-
BAYFRONT 5	12/31/2023	21	20	20
BAYFRONT 6	12/31/2023	26	25	25
FCH ISLD 12	12/31/2023	16	15	15
RED WING 12	12/31/2027	21	19	20
WILMARTH 12	12/31/2027	19	17	17

**Assumed retirement of 12/31/2030 for modeling purposes.*

24. 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

Table 11 below shows each thermal PPA's type, expiration date and maximum capacity:

Table 11: Thermal PPA Information

Name of Contract	Type	Strategist Expiration Date	Max Capacity (MW)
LS Power - Cottage Grove	CC	9/30/2027	262.0
Mankato Energy Center	CC	7/31/2026	357.0
Invenergy 1	CT	3/31/2025	179.0
Invenergy 2	CT	3/31/2025	179.0
Minnkota Power Cooperative (Coyote)	COAL	10/31/2015	100.0
Laurentian	BIO	12/31/2026	35.0
Koda Energy	BIO	5/31/2019	12.0
Fibrominn	BIO	8/31/2028	55.0
St Paul Cogen	BIO	4/30/2023	25.0
Burnsville (MN Methane)	LND	3/31/2020	4.7
PineBend	LND	12/31/2025	12.0
Gunderson	LND	NA	1.1
Barron	RDF	12/31/2022	1.9
HERC	RDF	12/31/2017	33.7
Diamond K Diary	DGT	12/31/2023	0.4
Greenwhey	DGT	NA	3.2
Heller Dairy	DGT	NA	0.5

25. 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 2009-2014 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 Fall 2013 update to the May 2013 ELCC study. 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.

Table 12 below shows the type, retirement date, and nameplate capacity for each owned and PPA renewable.

Table 12: Owned and PPA Renewable Information

Name of Contract/Unit	Type	Owned or PPA	Retirement Date	Nameplate Capacity (MW)
Byllesby	Hydro	PPA	2/28/2021	2.36
Hastings	Hydro	PPA	6/30/2033	4
StCloud	Hydro	PPA	10/31/2021	8.8
EauGalle	Hydro	PPA	7/31/2026	0.3
DG Hydro	Hydro	PPA		0.43
LCO_Hydro	Hydro	PPA	12/31/2021	3.1
Neshonoc	Hydro	PPA	12/31/2020	0.4
Rapidan	Hydro	PPA	4/30/2017	5
SAF_Hydr	Hydro	PPA	12/31/2031	9.2
WTC_Angelo Dam	Hydro	PPA	3/31/2024	0.205
Hennipine Island-St. Anthony Falls	Hydro	Owned		13.9
WI Owned Hydro Grouped	Hydro	Owned		260.2
Manitoba	Hydro	PPA	4/30/2015	500
Manitoba	Hydro	PPA	4/30/2021	375
Manitoba	Hydro	PPA	4/30/2025	500
Slayton	Solar	PPA	1/31/2033	1.66
StJohns	Solar	PPA	5/31/2030	0.4
Existing DG	Solar	PPA		4.81 (2020)
New DG	Solar	PPA		67.74 (2020)
Utility Scale Solar	Solar	PPA		187 (2017)
Solar Gardens Community	Solar	PPA		30.01 (2020)
Adams	Wind	PPA	3/31/2031	19.8
Agassiz	Wind	PPA	2/28/2031	1.98
BigBlue	Wind	PPA	12/31/2032	36
Boeve	Wind	PPA	8/31/2028	1.9
Carlton	Wind	PPA	9/30/2024	1.65
Chanaram	Wind	PPA	12/31/2023	85.5
Cisco	Wind	PPA	5/31/2028	8
CommWndNorth	Wind	PPA	5/31/2031	30
CommWndSouth	Wind	PPA	12/31/2032	30.75
Courtnay	Wind	PPA	12/31/2035	200
Danielsn	Wind	PPA	3/31/2031	19.8
DG Wind	Wind	PPA	12/31/2031	5.73
Ewington	Wind	PPA	5/31/2028	19.95
Fenton1	Wind	PPA	11/30/2032	205.5
Fey	Wind	PPA	9/30/2028	1.9
FPL Mower County	Wind	PPA	12/31/2026	98.9
GrantCo	Wind	PPA	8/31/2030	20

Table 12: Owned and PPA Renewable Information (Continued)

Name of Contract/Unit	Type	Owned or PPA	Retirement Date	Nameplate Capacity (MW)
Hilltop	Wind	PPA	2/28/2029	2
Jeffers	Wind	PPA	10/31/2028	50
JJN	Wind	PPA	12/31/2029	1.5
KasBros	Wind	PPA	12/31/2031	1.5
KBrink	Wind	PPA	2/28/2028	1.9
LkBnton1	Wind	PPA	12/31/2028	105.75
LkBnton2	Wind	PPA	5/31/2025	103.5
Metro	Wind	PPA	2/28/2031	0.66
MNDakota	Wind	PPA	12/31/2022	150
Moraine1	Wind	PPA	12/31/2018	51
Moraine2	Wind	PPA	2/28/2019	49.5
NAELakot	Wind	PPA	4/30/2034	11.25
NAEShak	Wind	PPA	10/31/2033	1.65
NAEShakH	Wind	PPA	4/30/2034	11.88
Odell	Wind	PPA	12/31/2035	200
Olsen	Wind	PPA	12/31/2031	1.5
Prairie Rose	Wind	PPA	12/31/2032	200
Ridgewind	Wind	PPA	1/31/2031	25.3
Rock Ridge	Wind	PPA	4/30/2021	1.8
Shanes	Wind	PPA	8/31/2026	2
South Ridge	Wind	PPA	4/30/2021	1.8
StOlaf	Wind	PPA	10/31/2028	1.65
Tholen	Wind	PPA	9/30/2025	13.2
Uilk	Wind	PPA	1/31/2030	4.5
Valley View	Wind	PPA	11/30/2031	10
Velva	Wind	PPA	1/31/2026	11.88
Wind Current	Wind	PPA	5/31/2028	1.9
Wind Power Partners	Wind	PPA	5/31/2019	25
Windvest	Wind	PPA	4/30/2021	1.8
Winona	Wind	PPA	10/31/2031	1.5
WoodStkH	Wind	PPA	4/30/2034	10.2
WoodStkM	Wind	PPA	6/30/2030	0.75
East Ridge group	Wind	PPA	4/30/2026	10
Garwin McNeilus group	Wind	PPA	2/28/2028	36.75
Minwind group	Wind	PPA	2/28/2025	11.55
Norgaard North	Wind	PPA	5/31/2026	5
Norgaard South	Wind	PPA	5/31/2026	3.75
Ruthton Ridge Group	Wind	PPA	1/31/2031	15.84
North Shaokatan	Wind	PPA	2/28/2031	11.88
Stahl Wind group	Wind	PPA	1/31/2025	8.25
Viking Wind group	Wind	PPA	12/31/2018	12
Westridge Group	Wind	PPA	12/31/2028	9.5
Border	Wind	Owned		150
GrandMed	Wind	Owned		100.5
Nobles	Wind	Owned		201
PlsntVly	Wind	Owned		200

26. 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.

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

Tables 13-15 below show the assumptions for the generic thermal and renewable resources.

Table 13: Thermal Generic Information (Costs in 2014 Dollars)

Resource	Coal	Coal w/ Seq	2x1 CC	1x1 CC	CT	Small CT	Biomass
Nameplate Capacity (MW)	511	511	778.3	291.1	229.9	103.4	50
Summer Peak Capacity with Ducts (MW)	NA	NA	766.3	NA	NA	NA	NA
Summer Peak Capacity without Ducts (MW	485	485	649.8	290.2	226.1	100.8	50
Cooling Type	Dry	Dry	Dry	Dry	NA	Wet	Wet
Capital Cost ($/kw)	3,621	5,287	926	1,167	602	1,515	4,558
Electric Transmission Delivery ($/kw)	NA	NA	406	NA	152	NA	NA
Gas Demand ($/kw-yr)	0	0	8.44	11.28	0	0	0
Book life	30	30	40	40	30	30	30
Fixed O&M Cost ($000/yr)	16,343	24,598	7,510	4,139	591	853	5,183
Variable O&M Cost ($/MWh)	2.80	10.56	3.08	1.75	2.27	1.81	4.68
Ongoing Capital Expenditures ($/kw-yr)	9.59	23.42	4.32	4.79	5.87	1.86	14.13
Heat Rate with Duct Firing (btu/kWh)	NA	NA	7725	NA	NA	NA	NA
Heat Rate 100% Loading (btu/kWh)	9,156	12,096	6,822	7,830	9,942	8,867	14,421
Heat Rate 75% Loading (btu/kWh)	9,190	12,565	6,905	8,010	11,048	9,688	14,580
Heat Rate 50% Loading (btu/kWh)	9,710	13,600	6,943	8,583	14,601	11,161	15,570
Heat Rate 25% Loading (btu/kWh)	11,245	17,140	7,583	9,798	NA	15,067	18,650
Forced Outage Rate	6%	7%	3%	3%	3%	2%	4%
Maintenance (weeks/year)	2	5	5	4	2	2	7
CO_2 Emissions (lbs/MMBtu)	216	9	118	118	118	118	211
SO_2 Emissions (lbs/MWh)	0.447	0.371	0.005	0.005	0.007	0.007	0.577
NO_x Emissions (lbs/MWh)	0.45	0.62	0.06	0.05	0.30	0.08	1.01
PM10 Emissions (lbs/MWh)	0.14	0.14	0.01	0.01	0.01	0.01	0.43
Mercury Emissions (lbs/Million MWh)	0.00007	0.00010	0.00000	0.00000	0.00000	0.00000	0.00017

Table 14: Renewable Generic Information (Costs in 2014 Dollars)

Resource	PTC Wind	Non-PTC Wind	30% ITC Solar	10% ITC Solar
Nameplate Capacity (MW)	200	200	50	50
ELCC Capacity Credit (MW)	29.6	29.6	26.15	26.15
Capital Cost ($/kw)	$1,700	$1,700	$1,563	$1,140
Electric Transmission Delivery ($/kw)	$150	$150	$85	$62
Book life	25	25	25	25
Fixed O&M Cost ($000/yr)	$1,828	$1,828	$1,235	$1,235
Variable O&M Cost ($/MWh)	$0.63	$0.63	$0.00	$0.00
Ongoing Capital Expenditures ($000/yr)	$2,466	$2,466	$0	$0
Land Lease Payments ($000/yr)	$1,172	$1,172	$0	$0

Table 15: Renewable Generic ECC Costs

Year	PTC Wind	Non-PTC Wind	30% ITC Solar	10% ITC Solar
2014	25.71	45.46	75.00	95.00
2015	26.28	46.48	75.00	95.00
2016	26.87	47.52	75.00	95.00
2017	27.48	48.58	75.00	95.00
2018	28.09	49.67	75.00	95.00
2019	28.72	50.78	75.00	95.00
2020	29.36	51.92	75.00	95.00
2021	30.02	53.08	75.00	95.00
2022	30.69	54.27	75.00	95.00
2023	31.38	55.49	75.00	95.00
2024	32.08	56.73	75.00	95.00
2025	32.80	58.00	75.00	95.00
2026	33.54	59.30	75.00	95.00
2027	34.29	60.63	75.00	95.00
2028	35.06	61.99	75.00	95.00
2029	35.84	63.38	75.00	95.00
2030	36.65	64.80	75.00	95.00

II. THERMAL EXPANSION ALTERNATIVE DEVELOPMENT

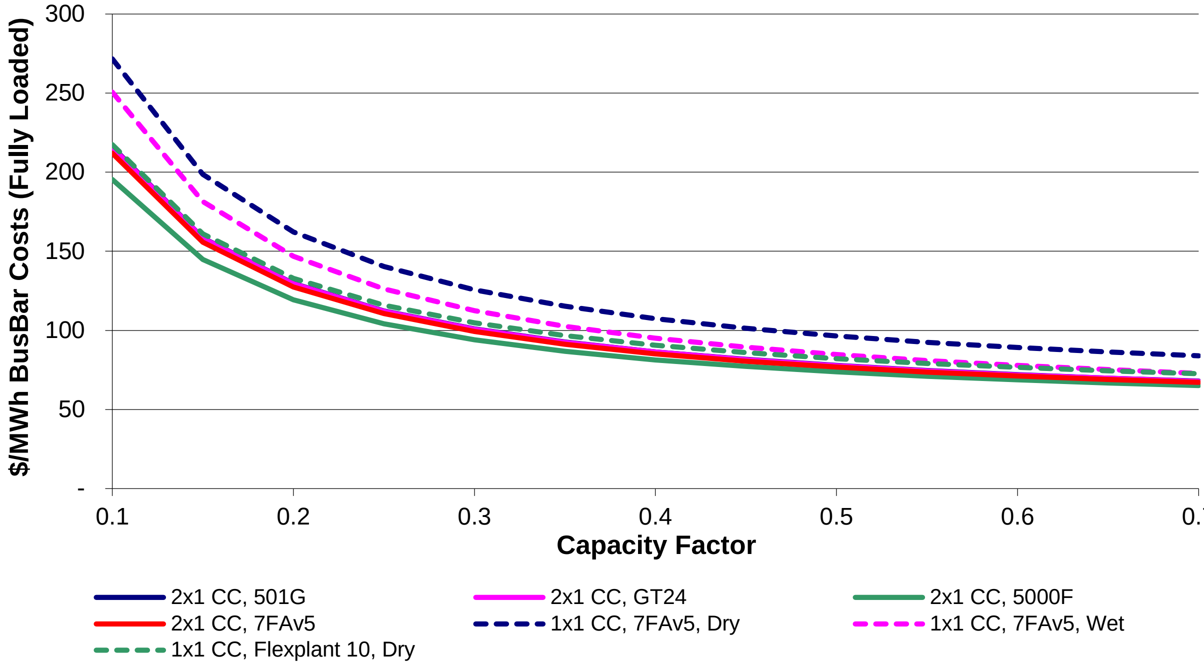
A. Thermal Technology Screening Process

The Company began the selection process for identifying candidate thermal expansion alternatives by developing initial generic cost and operating estimates for a wide variety of technologies that could be theoretically available to meet system needs. It is important to emphasize that these are generic estimates, meaning that while they include all major cost and performance characteristics of each technology appropriate for the region's climate, they do not reflect a specific site location. At a high level, the categories developed are:

- *Coal:* Supercritical coal with and without carbon capture; Circulating fluidized bed, IGCC with and without carbon capture.
- *Large Combined Cycle:* 600-800 MW class, four different vendors / systems, all 2x1 configuration.
- *Small Combined Cycle:* 300-400 MW class, three different vendors / systems, all 1x1 configuration.
- *Large Combustion Turbine:* 200-300 MW class, eight different vendors / systems, including two single-large-unit systems and two six-small-unit systems, all with dual-fuel or gas-only options.
- *Small Combustion Turbine:* 50-100 MW class, eight different vendors / systems, including dual-fuel or gas-only options.
- *Internal Combustion Engine:* 55 MW six-unit configuration, natural gas fuel.
- *Biomass:* 50 MW fluidized bed.

From this initial pool of approximately 30 different thermal technologies, a screening tool was developed to narrow the options down to the top alternatives within each category. The tool calculates a levelized bus-bar cost in $/MWh for each alternative over the full range of potential expected capacity factors. By looking at the relative costs over the realistic dispatch range for each alternative, some alternatives clearly emerge as the most robust option in the category. An example of the output of this screening tool when applied to natural gas combined cycle options is shown below in Figure 9.

Figure 9: Intermediate Dispatch Range Combined Cycles



This same type of output was developed for each of the categories over the expected range of operation. After initial screening, the potential thermal alternatives were narrowed down to the following candidates:

- 226 MW gas-fired CT peaking unit
- 100 MW gas-fired CT peaking unit
- 786 MW gas-fired CC intermediate unit
- 290 MW gas-fired CC intermediate unit
- 500 MW Super Critical Pulverized Coal base load unit, with an alternate version including 90 percent carbon capture and storage
- 50 MW Bubbling Fluidized Bed Biomass unit, burning wood waste

B. Thermal Technology Evaluation

Early in the plan development process, we began testing the candidate technologies in the Strategist planning model under a wide range of situations. Optimized (least cost) plans were developed for alternative Sherco shutdown scenarios (run through 2030, shutdown 1 unit, shutdown 2 units) and under a variety of input sensitivities (varying fuel prices, load forecasts, etc.). As the results were analyzed, it became apparent that of the thermal options, only the large CC and large CT alternatives were being selected under all the cases. All other thermal alternatives failed to appear in the economic expansion plans under the wide variety of screening scenarios studied. A final screening tool was developed with just the candidate thermal alternatives to investigate this finding. As can be seen in Figures 12 through 14 below, under any dispatch level, either the solid green (large CC) or solid light-blue (large CT) are the lowest cost under the screening tool methodology. This served to validate the Strategist results and for further plan development efforts, both to enhance run time as well as to avoid exceeding the maximum number of states saved by the model (truncation errors), the modeling focused solely on the large CT and large CC as thermal expansion alternatives.

Figure 10: Baseload

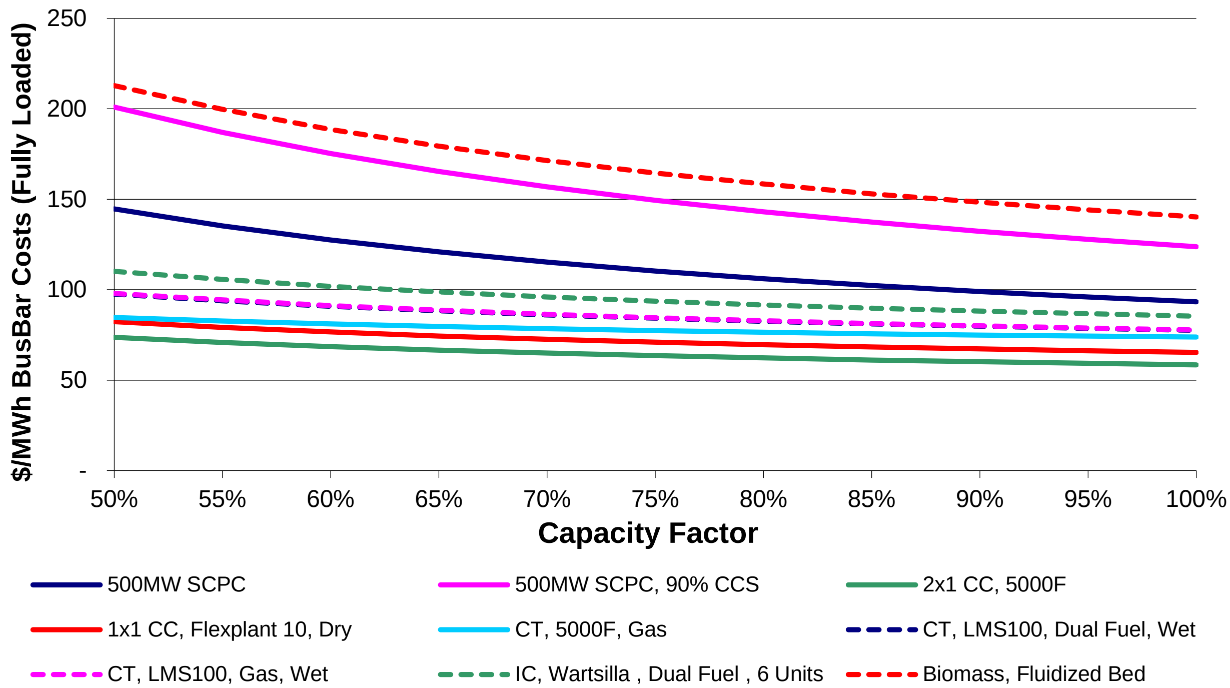


Figure 11: Intermediate Dispatch Range

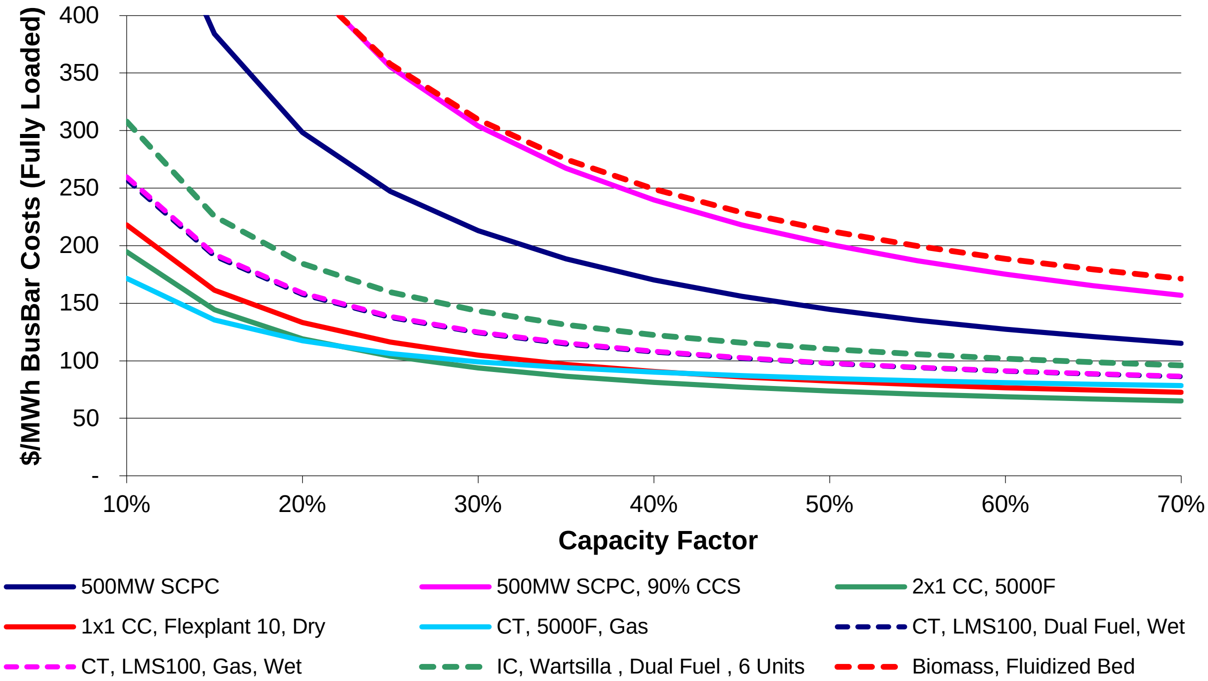
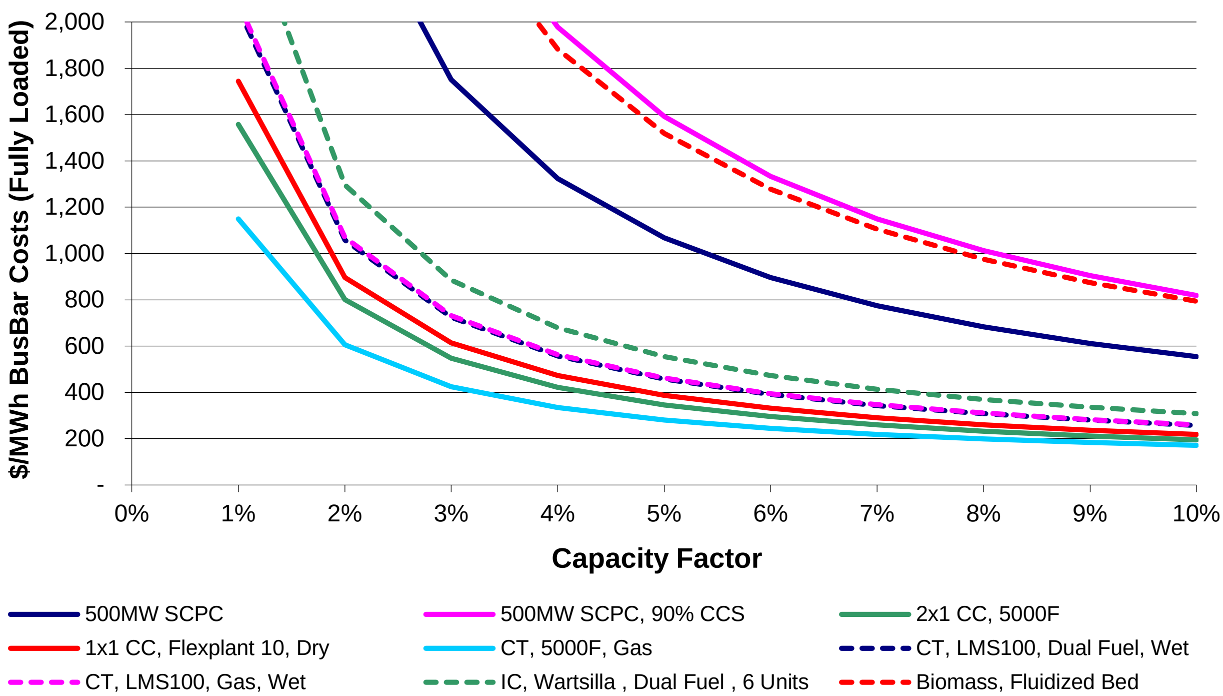


Figure 12: Peaking



C. Combined Cycle and Combustion Turbine Refinement

As it became apparent that the CT and CC thermal alternatives would play a prominent role in any thermal expansion plan, the Company began work to refine the estimates for these alternatives to better represent the specifics of the region and expected technology costs. Several potential greenfield and brownfield sites were investigated in more depth, both for CC and CT options, and a better understanding of potential fuel supply issues, transmission impacts, and construction cost differentials was obtained.

For the CT alternative, the Company developed more detailed estimates of gas supply and transmission grid impacts for the greenfield option, and developed estimates for brownfield units located at the Black Dog site (used as a proxy for typical brownfield costs). To develop the final generic CT data, the Company averaged the costs of the brownfield and greenfield options to develop what we consider to be a more representative view of the "typical" expected cost of future CT resources. It is likely that future CT additions procured through competitive bidding processes will consist of both brownfield and some greenfield projects, and the "blended" generic cost estimate reflects this likely mix better than choosing a single one of either project type. The final generic CT cost estimates and performance characteristics are described in Table 13 of this Appendix.

Unlike CTs, which would be expected to have a reasonable opportunity to build on potential brownfield, siting a large new combined cycle in the 700-800 MW range is a much more challenging prospect. In surveying potential sites in the NSP System, it was found that there are very limited brownfield development sites that would have access to the required fuel delivery and transmission connections without significant upgrade costs, and that in most cases the brownfield project would be more expensive than developing a suitable greenfield site. Thus, for the final generic CC alternative, the Company used a greenfield option exclusively. Generic transmission upgrade and interconnection costs and gas delivery costs were developed by Company subject-matter-experts that are deemed to be representative of a well-chosen suitable new site. The final generic CC cost estimates and performance characteristics are described in Table 13 of this Appendix.

III. RENEWABLE EXPANSION ALTERNATIVE DEVELOPMENT

A. Wind Resources

The Company recently completed an extensive wind PPA bid process that resulted in a large sample of bid offers for federal PTC eligible wind projects with in-service dates in the 2015-2017 timeframe. These offers represent a strong signal of the market price for PTC wind. Using this data, the Company calibrated its internally developed financial model for owned wind projects to reproduce PTC-adjusted prices comparable to the market signal. Although the model is an ownership (i.e. revenue requirements) model, it also has the ability to convert the revenue requirement stream into an Economic Carrying Charge (ECC) equivalent, which is how wind is represented in the Strategist modeling. The modeled ECC was used for the price of PTC wind used in the scenarios that include an assumption for utilizing an extension of the wind PTC.

For most scenarios that included wind additions through the study period, and as a "base" assumption, it was assumed that the PTC was not extended. The financial model was adjusted to not include the PTC benefit, but kept the other inputs (i.e. capital cost, O&M, capacity factor) constant. The ECC representation of the non-PTC wind was used for the Strategist wind cost inputs for all years post-2016, except in the specifically noted scenarios where a PTC extension is contemplated. The final ECC costs for PTC and non-PTC wind are included in Table 16 below.

B. Utility-Scale Solar Resources

Similar to wind, the Company recently completed an extensive solar RFP bid process that resulted in a large sample of bid offers for federal ITC eligible utility-scale solar projects with in-service dates in the 2015-2017 timeframe. These offers averaged around $75/MWh levelized over the life of the PPAs, which is what was used for ITC-eligible utility-scale solar in 2017.

To derive a long-term forecast for utility-scale solar costs, the Company simply adjusted the costs by the expected change in ITC post-2016 (30 percent to 10 percent) as shown in the formula below:

$$\frac{90\%}{70\%} = \frac{x}{\$75}$$

The result of this ratio is approximately $95/MWh. As solar technology is still not fully mature, and costs are expected to decline and conversion efficiency to improve, it was assumed that the $95/MWh price holds throughout the study period. In effect, the assumption is that fundamental cost driver improvements will offset inflation.

C. Distributed Solar Resources

It was assumed that distributed solar, including the Company's Solar*Rewards (S*R) program, Made in Minnesota program, and Solar*Rewards Community (S*RC), are net metered at incentive levels commensurate with 2014 levels through 2020 ($80/MWh for S*R and S*RC, $204/MWh for MIM). After 2020, it was assumed that distributed solar switches to a buy-all/sell-all model, priced at $155/MWh flat.

Table 16: Renewable Pricing ($/MWh)

Renewable Pricing ($/MWh)

	Wind w/ PTC	Wind w/o PTC	Solar w/ ITC	Solar w/o ITC
2016	26.87		75.00	95.00
2017	27.47	48.58	75.00	95.00
2018	28.09	49.67	75.00	95.00
2019	28.72	50.78	75.00	95.00
2020	29.36	51.92	75.00	95.00
2021	30.02	53.08	75.00	95.00
2022	30.69	54.27	75.00	95.00
2023	31.38	55.49	75.00	95.00
2024	32.08	56.73	75.00	95.00
2025	32.80	58.00	75.00	95.00
2026	33.54	59.30	75.00	95.00
2027	34.29	60.63	75.00	95.00
2028	35.06	61.99	75.00	95.00
2029	35.84	63.38	75.00	95.00
2030	36.65	64.80	75.00	95.00

IV. RENEWABLE EXPANSION PLAN DEVELOPMENT

A. Methodology

Due to their relatively small firm capacity contribution relative to their all-in costs (as compared to thermal resources), the Strategist model will typically not pick either wind or solar resources to fill capacity needs in the optimization simulations. As a modeling construct, the only viable way to have Strategist pick them it to set renewables as "superfluous units" – in other words, allow Strategist to look at whether renewable additions are cost-effective on an energy basis only, and consider adding them whether a capacity need exists or not. In practicality, this creates an almost unmanageable simulation as the number of alternative plans Strategist has to evaluate increases almost exponentially in every year and rapidly overwhelms the processing capability of the software. For this reason, except in the case of a relatively small and focused analysis, it is often a better modeling practice to evaluate renewables in more of a scenario approach (developing and evaluating plans with and without renewables).

In addition, many of the primary scenarios for this plan call for specific additions of renewables to meet certain targets related to the scenario. For these reasons, a deterministic approach was taken to renewable additions.

B. Wind Resources

All scenarios include the 75 0MW of approved RFP wind, as well as a generic 400 MW addition in 2020 to meet carbon targets. Other scenarios, primarily the "Preferred Plan" and the "Sherco unit replacement with varying levels of renewables" scenarios include wind additions that were ratably applied through the study period to minimize cost impacts and meet renewable and carbon emission targets specific to the scenario. Specific resource addition schedules are contained in the technical appendices as well as included and cited elsewhere in this document.

C. Utility-Scale Solar Resources

All scenarios include the 187 MW of proposed ITC-eligible solar from the Company's 2014 Solar RFP. Other scenarios, primarily the "Preferred Plan" and the "Sherco unit replacement with varying levels of renewables" scenarios include solar additions that were ratably applied through the study period to minimize cost impacts and meet renewable and carbon emission targets specific to the scenario. Specific resource addition schedules are contained in the technical appendices as well as included and cited elsewhere in this document.

D. Distributed Solar Resources

It was assumed that distributed solar, including the Company's S*R program, Made in Minnesota program and S*RC will be added through 2020 in increasing amounts at a consistent growth rate such that, when combined with the 187 MW of utility-scale solar, will enable the Company to meet the Solar Energy Standards target of 1.5 percent of non-excluded Minnesota sales by 2020 as well as the small solar carve-out. In the base assumptions, it is assumed that the levels added in 2020 continue to be added each subsequent year of the study period. The schedule of small additions is shown below in Table 17.

Table 17: Distributed Solar Additions (AC MW), Base Case

Distributed Solar Additions (AC MW), Base Case	Solar Rewards	Made In MN Small	Made In MN Large	Solar Gardens
2014	3.9	1.2	3.7	2.5
2015	3.9	1.2	3.7	5.0
2016	3.9	1.2	3.7	5.0
2017	3.9	1.2	3.7	5.0
2018	3.9	1.2	3.7	5.0
2019	3.9	1.2	3.7	5.0
2020	3.9	1.2	3.7	5.0
2021	3.9	1.2	3.7	5.0
2022	3.9	1.2	3.7	5.0
2023	3.9	1.2	3.7	5.0
2024	3.9	1.2	3.7	5.0
2025	3.9	1.2	3.7	5.0
2026	3.9	1.2	3.7	5.0
2027	3.9	1.2	3.7	5.0
2028	3.9	1.2	3.7	5.0
2029	3.9	1.2	3.7	5.0
2030	3.9	1.2	3.7	5.0
	66.5	20.3	62.3	82.5

For the Preferred Plan, the Company is proposing continued sustainable growth in distributed solar past 2020, at a rate that increases annual additions by 20 percent year over year. The resulting schedule of additions for the Preferred Plan is shown below in Table 18. The Made in Minnesota additions show zero after 2020 because the specific program's continuance after that date is uncertain; however, the total amounts are carried forward as combined into the Solar Rewards column.

Table 18: Distributed Solar Additions (AC MW), Preferred Plan

Distributed Solar Additions (AC MW), Preferred Plan	Solar Rewards	Made In MN Small	Made In MN Large	Solar Gardens
2014	3.9	1.2	3.7	2.5
2015	3.9	1.2	3.7	5.0
2016	3.9	1.2	3.7	5.0
2017	3.9	1.2	3.7	5.0
2018	3.9	1.2	3.7	5.0
2019	3.9	1.2	3.7	5.0
2020	3.9	1.2	3.7	5.0
2021	10.5	-	-	6.0
2022	12.6	-	-	7.2
2023	15.2	-	-	8.6
2024	18.2	-	-	10.4
2025	21.8	-	-	12.4
2026	26.2	-	-	14.9
2027	31.4	-	-	17.9
2028	37.7	-	-	21.5
2029	45.2	-	-	25.8
2030	54.3	-	-	31.0
	300.5	8.3	25.7	188.3

V. SCENARIO AND SENSITIVITY SUMMARY

To address the various requirements as identified in the various Statues, Commission Orders, and Intervener requests, we developed numerous scenarios addressing the future of Sherco 1 and 2, as well as the impacts of various levels of renewable energy, energy efficiency and demand response. The scenarios are grouped into 21 major "families," with many families containing several significantly different sub-plans. For the scenario families with multiple plans, the optimal plan from each family was selected to be representative. Optimality was determined using a variety of quantitative and qualitative factors, including PVSC, environmental performance, technical feasibility, and ability to meet the goals of the various constituents (Commission, Legislature, customers, interveners and the Company). Table 19 below lists the various scenario families and sub-plans.

Table 19: 2016-2030 Resource Plan Modeling Scenario Summary[4]

			Strategist Output Code
PRIMARY SHERCO / CARBON / RENEWABLE ALTERNATIVES			
Extend Life (Run both units to 2040)			
		No SCR's and both units retire 2030	1
		Add SCR's to both units (Spring 2024 and 2025) and retire in 2030	1B
Retire SH1 (Retire SH1 YE2023, SH2 SCR 2025)			
		Replace: CC	2
		Replace: CT	3
	Force 50% renewables:		
		Replace 50% Renew: CT + Wind	4A
		Replace 50% Renew: CT + Wind + Solar	4B
		Replace 50% Renew: CT + Wind + Solar + DSM (High Scenario)	4C
	Force 75% renewables:		
		Replace 75% Renew: CT + Wind	5A
		Replace 75% Renew: CT + Wind + Solar	5B
		Replace 75% Renew: CT + Wind + Solar + DSM (High Scenario)	5C
Retire Both Units (Retire SH1 YE2023, SH2 YE2024)			
		Replace: CC	6
		Replace: CT	7
	Force 50% renewables:		
		Replace 50% Renew: CT + Wind	8A
		Replace 50% Renew: CT + Wind + Solar	8B
		Replace 50% Renew: CT + Wind + Solar + DSM (High Scenario)	8C
	Force 75% renewables:		
		Replace 75% Renew: CT + Wind	9A
		Replace 75% Renew: CT + Wind + Solar	9B
		Replace 75% Renew: CT + Wind + Solar + DSM (High Scenario)	9C
Preferred Plan			
		Preferred Plan	10
		Preferred Plan with PTC Extension	10A
		Preferred Plan with Sherco 1 Retirement 2025	10B
		Preferred Plan with Sherco 1 Retirement 2025 and PTC Extension	10C
Convert SH1 Gas Boiler			
		Convert SHC 1 to Gas. Retires 2040	11
Repower SH1 STG as CC, Retire SH2 YE 2024			
		SHC1 4x1 CC, Retire Sherco 2 2025	12
North Dakota Plan			
		No additional renewables beyond currently committed 750MW wind	15
OTHER CASES			
DR alternative portfolios			13 (various)
		No DR (used for cost effectiveness)	A-D
		Low DR capacity	E-H
		Med DR capacity	I-L
		High DR capacity	M-P
		Base DR capacity	Q-T
EE alternative portfolios			14 (various)
		No EE Achievement (used for cost effectiveness)	A-D
		Low EE Achievement	E-H; AE-AH
		Med EE Achievement	I-L; AI-AL
		High EE Achievement	M-P; AM-AP

[4] 2024/2025 represents the earliest reasonably practicable retirement timeframe for Sherco Units 1 and 2.

A. Sensitivity Assumptions

To determine how changes in our assumptions impact the costs or characteristics of different Resource Plans, we examine our plans under a number of sensitivities. If a plan is extremely sensitive to changes in assumptions, it is not a robust course of action for the Company to pursue. Instead, we conceivably could propose an expansion plan that is less sensitive to assumption changes, but slightly more costly than the least-cost scenario under starting assumptions. For this Resource Plan, we tested the following types of scenarios.

- *Load*. The base forecast (unadjusted for DSM) is the 50 percent probability level of forecasted peak demand, and the 50 percent probability level of forecasted energy requirements. To test the sensitivity of our plans to changes in our forecast, we increased the growth rates for peak demand and energy by 50 percent as compared to the starting assumptions for the high load sensitivity. The growth rates for peak demand and annual sales were decreased by 50 percent for the low load sensitivity. The "high load" sensitivity can be considered as indentifying resources that may be needed if we experience a robust economic recovery.
- *Natural Gas costs*. The growth rate for the cost of natural gas was adjusted up and down by 50 percent from the base natural gas cost forecast.
- *Coal costs*. The growth rate for the cost of delivered coal was adjusted up and down by 50 percent from the base coal cost forecast.
- *Renewables*. Costs for incremental solar and wind units were increased by +/- 10 percent.
- *CO_2 Values*. CO_2 planning values were varied down to a low of $9/ton and up to $34/ton, both beginning in 2019. An additional sensitivity of no carbon cost was also performed. Two "late implementation" sensitivity cases were tested: $9 and $24 starting in 2024.
- *Externalities*. The high Commission externality values were used in all cases, but a sensitivity of replacing the regulated cost of carbon with the Federal "Social Cost of Carbon" as an externality was performed.
- *Sherco Costs*. Sensitivities for (1) Sherco 1&2 ongoing capital and fixed O&M costs at +10 percent
- *Markets on*. Market sales (i.e. "economy sales") are off in all cases, as it is the policy of the Company to not plan the system based on speculative sales opportunity. In this sensitivity, economy purchases were turned on, creating a "system integrated with the market" view.
- *North Dakota Assumptions*. To reflect the diverse energy policies among the various states we serve, this sensitivity was included to attempt to represent the

plans' economics under the preferences of the North Dakota Public Service Commission. Specifically, all carbon and externality costs were removed.

- *Remove North Dakota Load.* To reflect the possibility of separating North Dakota from the integrated system at a future date, the demand and energy associated with the North Dakota portion of the load forecast was removed starting in 2014. This sensitivity was only run for selected cases.
- *Combination Sensitivities.* To test the robustness of the plans under a wide range of possible futures, several "linked" sensitivities were performed which are various combinations of the above-described types.

The specific sensitivity cases are shown in Table 20 below.

Table 20: 2016-2030 Resource Plan Modeling Sensitivity Summary

Base CO2 (Mid) Costs	Strategist Output Code
Low Load	A
High Load	B
Low Gas Prices	C
High Gas Prices	D
Low Coal Prices	E
High Coal Prices	F
Low Wind Cost	G
High Wind Cost	H
Low Solar Cost	I
High Solar Cost	J
Low Wind Cost, Low Solar Cost	V
High SHC Costs (FOM, Ongoing Capital), +10%	Q
Markets On	S
Remove ND Load (selected scenarios only)	X
Zero CO2 Costs	
CO2 $0	K
ND Assumptions (No Extern, No CO2 Costs)	T
"Customer impact" (No CapCredit, Extern, CO2 Costs)	U
Low Wind Prices, No CO2 Costs	W
Low Load, No Extern, No CO2 Costs	AT
High Load, No Extern, No CO2 Costs	BT
Low Gas Prices, No Extern, No CO2 Costs	CT
High Gas Prices, No Extern, No CO2 Costs	DT
Low Wind Cost, No Extern, No CO2 Costs	GT
High Wind Cost, No Extern, No CO2 Costs	HT
Low Solar Cost, No Extern, No CO2 Costs	IT
High Solar Cost, No Extern, No CO2 Costs	JT
Other CO2 Sensitivities	
CO2 $9, Start 2019	L
CO2 $34, Start 2019	M
CO2 $9, Start 2024	N
CO2 $34, Start 2024	O
CO2 at Federal SCC 3%	P

B. Scenario Outcomes

A summary of the Strategist model's output Net Present Value Revenue Requirement (PVRR) / PVSC's for the various scenarios and sensitivities is shown below in Tables 21 and 22.

Table 21: PVSC/PVRR Total ($M) for all Scenarios, Sensitivities A-O

PVSC/PVRR Total ($M)

Scenario	Number	BASE	A LOW LOAD	B HIGH LOAD	C LOW GAS PRICE	D HIGH GAS PRICE	E LOW COAL PRICE	F HIGH COAL PRICE	G LOW WIND COST	H HIGH WIND COST	I LOW SOLAR COST	J HIGH SOLAR COST	K ZERO CO2	L LOW CO2	M HIGH CO2	N LATE LOW CO2	O LATE HIGH CO2
Reference Case	1	52,429	49,055	56,075	48,976	57,190	51,884	53,024	52,298	52,560	52,429	52,429	46,039	48,730	55,963	47,875	52,865
Add SCR	1B	52,838	49,383	56,403	49,303	57,518	52,212	53,351	52,626	52,888	52,757	52,757	46,367	49,059	56,290	48,203	53,193
Retire 1 Unit Replace with 2x1 CC	2	52,466	49,089	56,123	48,934	57,322	51,977	52,995	52,335	52,597	52,466	52,466	46,243	48,866	55,905	48,016	52,825
Retire 1 Unit Replace with CTs	3	52,466	49,089	56,123	48,934	57,322	51,977	52,995	52,335	52,597	52,466	52,466	46,243	48,866	55,905	48,016	52,825
Retire 1 Unit Replace with 50% Renewables - Wind	4A	52,432	49,088	56,083	48,979	57,185	51,949	52,954	52,246	52,618	52,432	52,432	46,321	48,897	55,806	48,051	52,740
Retire 1 Unit Replace with 50% Renewables - Wind & Solar	4B	52,329	48,993	55,983	48,900	57,043	51,846	52,852	52,177	52,482	52,282	52,377	46,238	48,806	55,689	47,960	52,627
Retire 1 Unit Replace with 50% Renewables - Wind, Solar, & DSM	4C	52,643	49,333	56,293	49,200	57,379	52,161	53,164	52,490	52,795	52,616	52,669	46,562	49,126	55,998	48,289	52,966
Retire 1 Unit Replace with 75% Renewables - Wind	5A	52,405	49,069	56,050	49,070	56,991	51,929	52,919	52,153	52,658	52,405	52,405	46,426	48,948	55,701	48,106	52,651
Retire 1 Unit Replace with 75% Renewables - Wind & Solar	5B	52,249	48,902	55,891	48,918	56,821	51,771	52,764	52,063	52,435	52,176	52,323	46,267	48,791	55,542	47,949	52,494
Retire 1 Unit Replace with 75% Renewables - Wind, Solar, & DSM	5C	52,560	49,260	56,203	49,216	57,153	52,083	53,073	52,374	52,746	52,507	52,612	46,589	49,108	55,847	48,274	52,830
Retire 2 Unit Replace with 2x1 CCs	6	52,530	49,153	56,188	48,947	57,422	52,107	52,982	52,399	52,661	52,530	52,530	46,554	49,076	55,830	48,234	52,779
Retire 2 Unit Replace with CTs	7	52,534	49,160	56,187	48,949	57,426	52,113	52,982	52,403	52,664	52,534	52,534	46,564	49,085	55,825	48,243	52,776
Retire 2 Units Replace with 50% Renewables - Wind	8A	52,439	49,094	56,078	49,094	57,034	52,016	52,894	52,152	52,725	52,439	52,439	46,689	49,114	55,615	48,280	52,589
Retire 2 Units Replace with 50% Renewables - Wind & Solar	8B	52,266	48,914	55,917	48,934	56,840	51,840	52,724	52,046	52,485	52,182	52,350	46,521	48,943	55,439	48,109	52,415
Retire 2 Units Replace with 50% Renewables - Wind, Solar, & DSM	8C	52,576	49,256	56,221	49,228	57,174	52,150	53,034	52,356	52,795	52,513	52,639	46,837	49,257	55,748	48,431	52,753
Retire 2 Units Replace with 75% Renewables - Wind	9A	52,446	49,107	56,080	49,281	56,795	52,027	52,897	52,060	52,833	52,446	52,446	46,869	49,222	55,524	48,394	52,519
Retire 2 Units Replace with 75% Renewables - Wind & Solar	9B	52,169	48,814	55,806	49,023	56,481	51,749	52,619	51,883	52,455	52,037	52,300	46,614	48,958	55,228	48,130	52,229
Retire 2 Units Replace with 75% Renewables - Wind, Solar, & DSM	9C	52,479	49,163	56,116	49,314	56,821	52,060	52,928	52,193	52,765	52,374	52,584	46,929	49,271	55,537	48,451	52,567
Preferred Plan	10	51,997	48,724	55,589	49,114	55,997	51,483	52,561	51,662	52,332	51,827	52,167	46,319	48,709	55,140	47,892	52,177
Preferred Plan with PTC	10A	51,142	47,873	54,723	48,242	55,169	50,634	51,699	51,008	51,275	50,971	51,312	45,542	47,899	54,250	47,120	51,418
Preferred Plan with Sherco 1 Retire	10B	52,001	48,719	55,607	49,048	56,078	51,536	52,506	51,666	52,336	51,831	52,171	46,458	48,796	55,056	47,983	52,111
Preferred Plan with Sherco 1 Retire & PTC	10C	51,146	47,868	54,741	48,176	55,249	50,687	51,644	51,012	51,280	50,976	51,316	45,682	47,985	54,166	47,211	51,351
Convert 1 Unit to Gas Boiler	11	52,558	49,190	56,217	49,054	57,367	52,068	53,090	52,428	52,689	52,558	52,558	46,359	48,972	55,987	48,122	52,910
Convert 2 Units to 4x1 CC	12	52,659	49,218	55,982	49,090	57,488	52,256	53,081	52,528	52,790	52,659	52,659	46,798	49,282	55,864	48,444	52,833
ND Plan	15	52,518	49,104	56,121	48,826	57,626	51,951	53,144	52,518	52,518	52,518	52,518	45,747	48,593	56,296	47,689	53,006

Table 22: PVSC/PVRR Total ($M) for all Scenarios, Sensitivities P-BT

PVSC/PVRR Total ($M)

Scenario	Number	P SOCIAL COST OF CARBON	Q HIGH SHERCO COSTS	S MARKETS ON	T ND ASSUMPTIONS	U CUSTOMER IMPACT	V LOW WIND & LOW SOLAR	W LOW WIND & ZERO CO2	X ND LOAD REMOVED	CT LOW GAS & ZERO CO2	DT HIGH GAS & ZERO CO2	GT LOW WIND & ZERO CO2	HT HIGH WIND & ZERO CO2	IT LOW SOLAR & ZERO CO2	JT HIGH SOLAR & ZERO CO2	AT LOW LOAD & ZERO CO2	BT HIGH LOAD & ZERO CO2
Reference Case	1	66,899	52,539	51,894	45,895	46,158	52,298	45,908	49,401	42,518	50,626	45,764	46,026	45,895	45,895	42,961	49,105
Add SCR	1B	67,228	52,884	52,222	46,230	46,492	52,626	46,237	49,729	42,853	50,960	46,099	46,361	46,230	46,230	43,296	49,440
Retire 1 Unit Replace with 2x1 CC	2	66,678	52,560	51,932	46,108	46,379	52,335	46,113		42,654	50,932	45,977	46,239	46,108	46,108	43,157	49,324
Retire 1 Unit Replace with CTs	3	66,678	52,560	51,932	46,108	46,379	52,335	46,113		42,654	50,932	45,977	46,239	46,108	46,108	43,157	49,324
Retire 1 Unit Replace with 50% Renewables - Wind	4A	66,465	52,526	51,931	46,187	46,433	52,246	46,135		42,815	50,906	46,001	46,373	46,187	46,187	43,241	49,397
Retire 1 Unit Replace with 50% Renewables - Wind & Solar	4B	66,318	52,423	51,857	46,104	46,395	52,129	46,085		42,759	50,783	45,951	46,257	46,057	46,151	43,155	49,311
Retire 1 Unit Replace with 50% Renewables - Wind, Solar, & DSM	4C	66,621	52,737	52,169	46,429	46,749	52,464	46,410		43,069	51,132	46,276	46,582	46,403	46,455	43,511	49,632
Retire 1 Unit Replace with 75% Renewables - Wind	5A	66,205	52,499	51,948	46,293	46,534	52,153	46,173		43,043	50,844	46,040	46,545	46,293	46,293	43,343	49,496
Retire 1 Unit Replace with 75% Renewables - Wind & Solar	5B	66,041	52,343	51,817	46,134	46,420	51,990	46,081		42,895	50,669	45,948	46,320	46,060	46,207	43,169	49,329
Retire 1 Unit Replace with 75% Renewables - Wind, Solar, & DSM	5C	66,340	52,654	52,130	46,457	46,759	52,321	46,403		43,204	51,014	46,271	46,643	46,404	46,509	43,531	49,652
Retire 2 Unit Replace with 2x1 CCs	6	66,343	52,608	52,139	46,430	46,732	52,399	46,423		42,940	51,280	46,299	46,560	46,430	46,430	43,399	49,590
Retire 2 Unit Replace with CTs	7	66,346	52,612	52,150	46,439	46,745	52,403	46,433		42,952	51,288	46,308	46,570	46,439	46,439	43,402	49,595
Retire 2 Units Replace with 50% Renewables - Wind	8A	65,850	52,517	51,987	46,565	46,810	52,152	46,402		43,297	51,124	46,278	46,851	46,565	46,565	43,601	49,777
Retire 2 Units Replace with 50% Renewables - Wind & Solar	8B	65,650	52,344	51,824	46,397	46,694	51,962	46,301		43,144	50,937	46,177	46,616	46,313	46,481	43,437	49,604
Retire 2 Units Replace with 50% Renewables - Wind, Solar, & DSM	8C	65,951	52,654	52,123	46,714	47,037	52,293	46,618		43,443	51,281	46,494	46,933	46,651	46,777	43,791	49,930
Retire 2 Units Replace with 75% Renewables - Wind	9A	65,542	52,525	52,034	46,747	47,031	52,060	46,483		43,659	51,062	46,360	47,133	46,747	46,747	43,775	49,885
Retire 2 Units Replace with 75% Renewables - Wind & Solar	9B	65,207	52,247	51,770	46,491	46,820	51,751	46,327		43,433	50,767	46,205	46,777	46,359	46,622	43,497	49,635
Retire 2 Units Replace with 75% Renewables - Wind, Solar, & DSM	9C	65,517	52,557	52,084	46,807	47,150	52,088	46,643		43,727	51,113	46,520	47,093	46,702	46,912	43,854	49,954
Preferred Plan	10	65,236	52,107	51,533	46,184	46,434	51,491	45,984	49,038	43,363	50,166	45,849	46,519	46,014	46,354	43,321	49,319
Preferred Plan with PTC	10A	64,257	51,252	50,720	45,410	45,723	50,838	45,409	48,290	42,572	49,421	45,276	45,544	45,240	45,580	42,555	48,521
Preferred Plan with Sherco 1 Retire	10B	65,037	52,095	51,550	46,330	46,588	51,496	46,123	49,058	43,453	50,378	45,994	46,665	46,159	46,500	43,447	49,490
Preferred Plan with Sherco 1 Retire & PTC	10C	64,058	51,240	50,737	45,556	45,877	50,842	45,548	48,310	42,662	49,633	45,422	45,690	45,386	45,726	42,681	48,692
Convert 1 Unit to Gas Boiler	11	66,709	52,661	52,081	46,225	46,481	52,428	46,229		42,801	51,001	46,094	46,355	46,225	46,225	43,263	49,426
Convert 2 Units to 4x1 CC	12	66,311	52,738	52,361	46,673	47,193	52,528	46,668		43,245	51,436	46,542	46,803	46,673	46,673	43,630	49,536
ND Plan	15	67,599	52,628	51,636	45,747	45,991	52,518	45,747		42,103	50,831	45,747	45,747	45,747	45,747	42,803	48,993

VI. ATTACHMENT A: HEAT RATE UPDATED

Heat rate data for the Company's owned generating units is provided publicly in our annual Federal Energy Regulatory Commission (FERC) Financial Report, FERC Form No. 1. We include a copy of the pertinent unit heat rate data from FERC Form No. 1 for 2013 in Table 23 below.

Table 23: 2013 FERC Heat Rates

Unit	Heat Rate
AS King	10,238
Black Dog (Coal)	11,118
Sherco	10,432
Monticello	10,574
Prairie Island	10,627
Black Dog (NG)	8,190
High Bridge	7,113
Riverside	7,368
French Island	21,179
Red Wing	21,885
Wilmarth	21,260

In Docket No. E999/CI-06-159 (In the Matter of Commission Investigation and Determination under the Electricity Title, Section XII, of the Federal Energy Policy Act of 2005), the Minnesota Commission required the Company to file information on the fossil fuel efficiency (heat rate) of our generation units, and actions we are taking to increase the fuel efficiency of those units.

The Company's Performance Monitoring department performs routine heat rate testing and conducts heat balances of its generating units. In addition, testing, assessments, and reporting on boilers, air heaters, cooling towers, and enthalpy drop tests on steam turbines are also conducted. These tools factor into our assessment of the condition of these individual components, as well as how their respective performance levels will impact the overall efficiency of a given generating unit. Table 24 below shows a summary of NSP System heat rate testing from 2010-2014.

Table 24: Heat Rate Tests – 2010-2014

Plant/Unit	Type of Unit Test	Type of Test	Year Tested
Black Dog U5/U2	Combined Cycle	Heat Balance	2010
King U1	Coal Boiler	Heat Rate	2010
Angus U2	Combustion Turbine	Heat Balance	2011
Black Dog U5/U2	Combined Cycle	Heat Rate	2011
Inver Hills U2	Combustion Turbine	Heat Rate	2011
Riverside U7,U9,U10	Combined Cycle	Heat Rate	2011
Sherco U1	Coal Boiler	Heat Balance	2011
Sherco U2	Coal Boiler	Heat Balance	2011
Wheaton U1, U3, U4	Combustion Turbine	Heat Balance	2011
Black Dog U5/U2	Combined Cycle	Heat Balance	2012
Cannon Falls U1,U2	Combustion Turbine	Heat Balance	2012
Sherco U1	Coal Boiler	Heat Balance	2012
High Bridge U7, U8, U9	Combined Cycle	Heat Rate	2012
Riverside U7,U9,U10	Combined Cycle	Heat Balance	2013
High Bridge U7, U8, U9	Combined Cycle	Heat Rate	2013
Sherco U2	Coal Boiler	Heat Balance	2014
Sherco U3	Coal Boiler	Heat Balance	2014

As part of its heat rate testing and reporting protocol, the Performance Monitoring group identifies potential heat rate improvement opportunities and validates actual performance enhancements. The Company does not look at heat rate improvements in isolation when considering plant improvement projects; rather, we perform a collective assessment of potential safety, efficiency, and environmental performance improvements as well as overall economics in developing our generation asset management objectives. Looking forward, the Company plans to continue our proactive cycle of heat rate testing and overall unit assessments at our generation units and implement improvements as opportunities arise.

VII. ATTACHMENT B: WATER AND PLANT OPERATIONS

The Company's generating units are geographically positioned along major Minnesota waterways. The access to water accommodates the thermal needs of these generating units. As such, the Company's plant operations are governed by and comply with all applicable cooling water intake and discharge rules and regulations, which may indirectly affect Strategist modeling as discussed below.

The Clean Water Act Section 316(a) sets thermal limitations for discharges and the criteria and processes for allowing thermal variances. The Company's power plant discharge temperature limits and allowances for thermal emergency provisions are outlined in the plants' National Pollutant Discharge Elimination System (NPDES) permits. Additionally, Xcel Energy has policies which outline the conditions and procedures to implement during periods of energy emergencies that allow for limited thermal variances.

Section 316(b) of the Clean Water Act governs the design and operation of intake structures in order to minimize adverse environmental impacts to aquatic life. EPA issued new rules in August 2014 that will impact all plants that withdraw water for cooling purposes. The new rules require improvements to intake screening technology to minimize the number of aquatic organisms that are killed due to being stuck to the screens (referred to as "impingement). The rules also created a process for the state permitting agency to evaluate and determine if additional improvements are required to minimize the number of smaller organisms that pass through the intake screens and enter the plant cooling water system (referred to as "entrainment"). While the costs associated with the impingement compliance requirements are definable, the costs associated with the entrainment compliance requirements are uncertain.

Timing of the compliance requirements is site-specific and is determined by each site's NPDES permit renewal timeline.

While specific conditions, such as high water discharge temperatures, are not directly modeled in Strategist, the model reflects the impact of reducing plant output due to high water temperatures. Modeling in Strategist includes two methods to account for impacts due to changes in plant operations: each resource is modeled using a unit specific median unforced capacity rating, and the system needs are modeled with a planning reserve margin. By modeling the system needs with a planning reserve margin, the base level of required resources is assumed to be higher than those needed to meet the forecasted peak system demand. By modeling all units with an assumed level of forced outage, the base level of all available resources, modeled in aggregate, is assumed to be sufficient to represent resource availability due to emergency changes in plant operations. Thus the impact of reducing plant output due to high water temperatures is reflected through corrections to both obligation and resource adjustments.

VIII. ATTACHMENT C: ICAP LOAD AND RESOURCES TABLE

The following table shows load and resources using Installed Capacity Rating (ICAP) for the planning period.

Table 25: Load and Resources Tables, 2016-2030 Planning Period

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Forecasted Load	9,442	9,525	9,597	9,649	9,674	9,694	9,754	9,748	9,766	9,798	9,868	9,962	10,136	10,151	10,251
MISO System Coincident	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Coincident Load	9,442	9,525	9,597	9,649	9,674	9,694	9,754	9,748	9,766	9,798	9,868	9,962	10,136	10,151	10,251
MISO Planning Reserve	14.8%	14.8%	14.8%	14.8%	14.8%	14.8%	14.8%	14.8%	14.8%	14.8%	14.8%	14.8%	14.8%	14.8%	14.8%
Obligation	9,607	9,691	9,764	9,818	9,843	9,864	9,925	9,919	9,937	9,969	10,041	10,136	10,313	10,329	10,431
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Load Management	1009	1021	1033	1044	1056	1067	1078	1090	1101	1103	1098	1094	1089	1085	1080
Coal	2471	2471	2471	2471	2471	2471	2471	2471	2471	2471	2471	2471	2471	2471	2471
Nuclear	1767	1767	1767	1767	1767	1767	1767	1767	1767	1767	1767	1767	1767	1767	1767
Natural Gas	3871	3871	3871	3858	3858	3858	3858	3858	3505	3147	2492	2205	1943	1943	1943
Biomass/RDF/ Hydro/Wind	2154	2149	2116	1966	1961	2706	2697	2522	2374	2250	2195	2059	1903	1734	1728
Solar	43	246	258	270	287	300	317	337	361	390	425	467	518	580	654
Existing Resources	11,315	11,525	11,515	11,377	11,400	12,170	12,188	12,044	11,578	11,128	10,448	10,063	9,692	9,580	9,643
Current Position	1,707	1,834	1,751	1,558	1,557	2,306	2,264	2,125	1,641	1,159	407	-74	-621	-749	-787
NEW Natural Gas - CT	0	0	0	0	0	0	0	0	0	904	1356	1582	1808	1808	1808
NEW - Wind	0	0	0	0	0	600	600	800	800	1400	1400	1800	1800	1800	1800
NEW - Solar	0	0	0	0	0	0	0	0	100	500	800	1000	1500	1500	1700
Preferred Plan Resources	11,315	11,525	11,515	11,377	11,400	12,770	12,788	12,844	12,478	13,932	14,004	14,445	14,800	14,688	14,951
Forecasted Position	1,707	1,834	1,751	1,558	1,557	2,906	2,864	2,925	2,541	3,963	3,963	4,308	4,487	4,359	4,521