XCEL - NSP

NSP WIND AND SOLAR INTEGRATION STUDY

FINAL REPORT

October 22, 2018

EnerNex
A CESI Company

in conjunction with

leidos

EnerNex
A CESI Company

CONTENTS – NSP WIND AND SOLAR INTEGRATION STUDY

SECTION 1 INTRODUCTION

As part of the 2015 NSP Integrated Resource Plan, the Company was ordered to obtain a wind integration study. The objective of this study was to estimate the costs of integrating wind generation onto the Company system. These costs are associated with the uncertain and variable nature of wind generation and represent additional costs required to maintain overall system operations and reliability. Results from the study were used in the resource planning and selection process to ensure that wind generation resources continue to be compared on a level playing field with other technologies.

For the upcoming 2019 IRP filing, the Company employed EnerNex to perform another study to examine the impact of wind and solar integration on the NSP system as well. This study analyzed the integration costs under different levels of renewable penetration in three different time periods to assess the impact of major coal retirements and other key changes. EnerNex contracted with Leidos Engineering to perform the PROMOD analysis.

SECTION 2 STUDY ASSUMPTOINS

The following list of study assumptions were made in the study.

Data used in the study is based upon the Continued Fleet Change scenario from MISO MTEP18 database. It was agreed that the use of this database would best represent the NSP system for this study.

The NSP resources are located within the LRZ1 zone of MISO and were identified by Xcel – NSP. LRZ1 has other resources and load serving resources that do not belong to Xcel – NSP however have transmission ties to NSP.

Reserves modeled for all MISO in MTEP18 are 1957 MW. NSP reserves are Operating: 27 MW, Spin: 65 MW, and Supplemental: 71 MW.

Incremental wind and solar included in MTEP 18 forecast will not count as part of NSP incremental wind and solar. The assumption being that the MISO increments consider other 3rd party additions to LRZ1. The incremental wind in this study is specific to the NSP system.

The 62MW Marshal Solar Project is added to MTEP18 database.

The 25 MW MN Solar 1 project is removed from the MTEP18 database.

The Fibrowatt Benson: 1 biomass resource is removed from the MTEP18 database. The facility is shutting down.

The Virginia: ST biomass resource is removed from the MTEP18 database. The facility is shutting down.

The Hibbing: ST biomass resource is removed from the MTEP18 database. The facility is shutting down.

Scenario 1: Year 2022 add incremental NSP wind of 1500 MW, 1000 MW solar, 400 MW DR, add BD6

Scenario 2: Year 2027 builds on Scenario 1 adding incremental NSP wind of 1000 MW, 1000 MW solar, and Sherco CC; retire Sherco 1 & 2

Scenario 3: Year 2032 builds on Scenario 2 adding incremental NSP wind of 500 MW, 1000 MW solar, retire King

Scenario 4: Year 2032 also builds on Scenario 2 adding incremental NSP wind of 1500 MW (500 MW from Scenario 3 plus additional 1000 MW), 3000 MW solar (1000 MW from Scenario 3 plus additional 2000 MW), and Retire all Nuclear. The cases studied are shown in Table 1.

Table 1: Scenarios Studied

Scenario	Year	Wind	Solar	Other Changes
Base	2022	-	-	-
1	2022	+1,500 MW	+1,000 MW	Add 400 MW DR, Add Black Dog 6
2	2027	Scenario 1 +1,000 MW	Scenario 1 +1,000 MW	Retire Sherco 1&2, Add Sherco CC
3	2032	Scenario 2 +500 MW	Scenario 2 +1,000 MW	Retire King
4	2032	Scenario 2 +1,500 MW	Scenario 2 +3,000 MW	Retire All Nuclear

The additional incremental wind and solar resources will be modeled by selecting profiles from the MTEP18 database that are NSP resources in LRZ1. To help minimize congestion each incremental resource will be assigned to an NSP bus capable of handling the increased generation. There are 38 wind profiles and 17 solar profiles in the MTEP18 database from which to select incremental wind and solar profiles. These profiles will be scaled to meet the required capacity for the incremental wind and solar in each scenario.

The MTEP18 database uses wind profiles obtained from the NREL Wind database year 2012. MISO provided the site ID's associated with most of the existing NSP wind plants. Site ID's not identified by MISO were assigned NREL Site ID's by selecting a site close to the PSS/E bus location, shaded ID's in Table 2.

Table 2: NREL Wind Site ID's

NREL Site ID	Wind Plant Name in PROMOD
104639	Adams Community Wind Farm:WT1 12
115771	Agassiz Beach LLC:AB30
88774	Big Blue Wind Farm:WT1 18
98957	Buffalo Ridge I:WT1 26
100238	Buffalo Ridge II:WT1 105
96106	Buffalo Ridge Windplant WPP 19:WT1 73
93199	Chanarambie Station:WT1 57
96604	Community Wind North Farm:WT1
105797	Danielson Wind Farms:WT
92352	East Ridge Wind Project (MN):WT1
91950	Fenton Wind Power Plant:WT1 137
93469	G McNeilus Windfarm:WT1 10_NSP
110282	Grant County Wind Farm (MN):WT1 10
93711	Jeffers Wind Energy Center:WT
95031	Lake Benton I:WT1 143
89269	Lake Benton II:EXIS

98718	Lakota Ridge:NMO1
97410	MinnDakota Wind Project:WT1 100
93963	Moraine Wind:WT1 34
90285	Pleasant Valley WF
90461	Prairie Rose Wind:WT1 119
93697	Ridgewind Wind Project:WT1 11
98959	Shaokatan Hills:6150
92745	Uilk Wind Farm:WT1
91947	Valley View Transmission:WT1 5
120485	Velva Wind Farm:WT1 18
92755	Viking Wind Power Project:1
92752	Woodstock Windfarm:WIND
92751	Chanarambie Wind Farm
88743	Christoffer Wind Energy Project:1
116116	Courtenay Wind Farm:WT1 100
92751	CP Node_NSP_CHARA_TR4
104629	CP Node_NSP_WESTSID1
90700	Ewington Energy Wind Project:WT1 10
92179	Freeborn Wind Resource Project
89068	Grand Meadow Wind Farm:WT1 67
89317	Mower County Wind Farm (FPL):WT1 43
89487	Nobles Wind Project:WT1 134

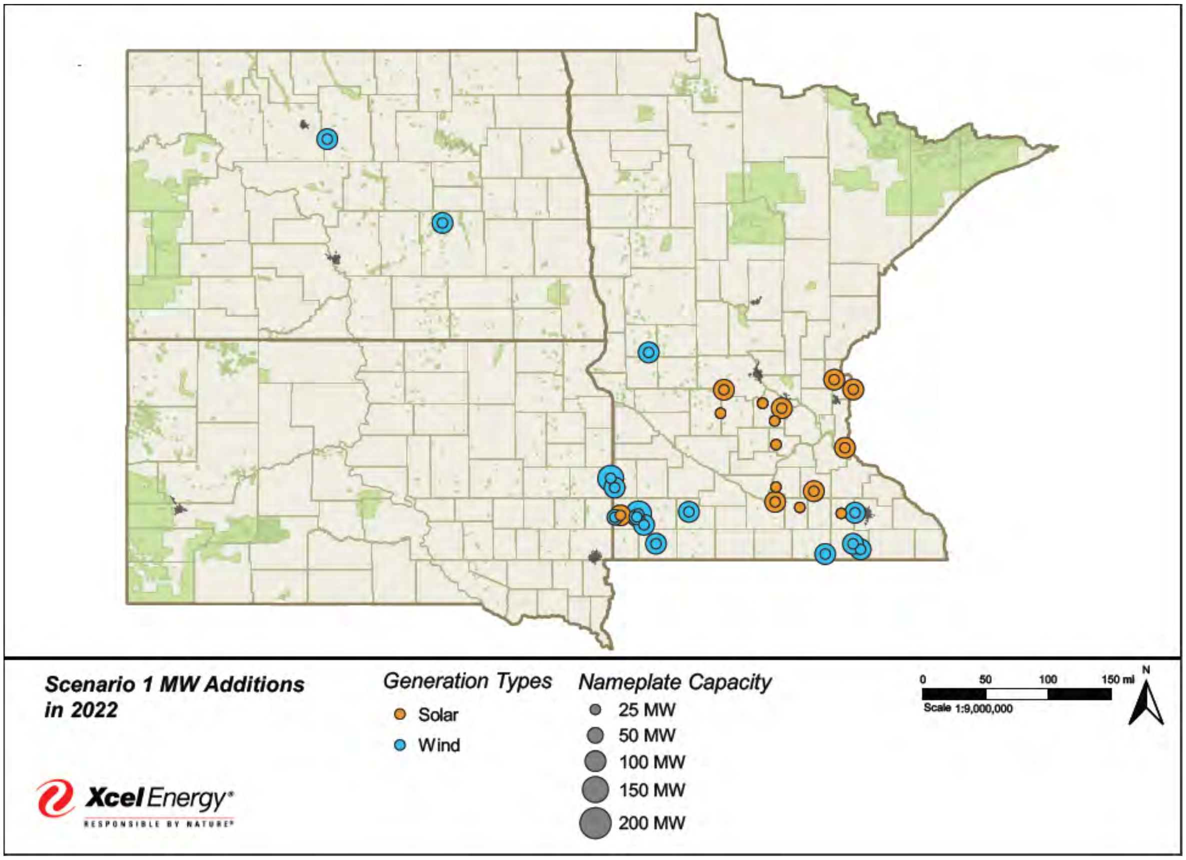

Figure 1: Scenario 1 Wind and Solar PV Site Map

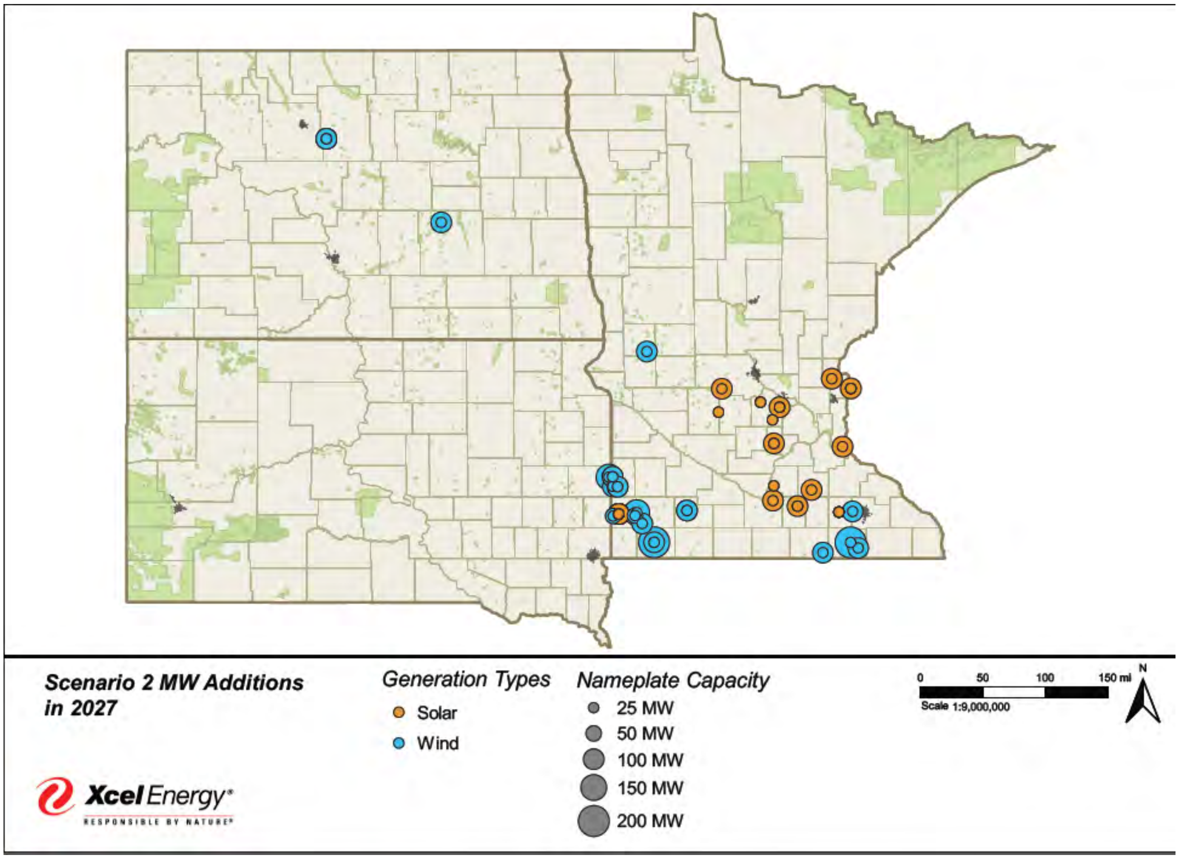

Figure 2: Scenario 2 Wind and Solar PV Site Map

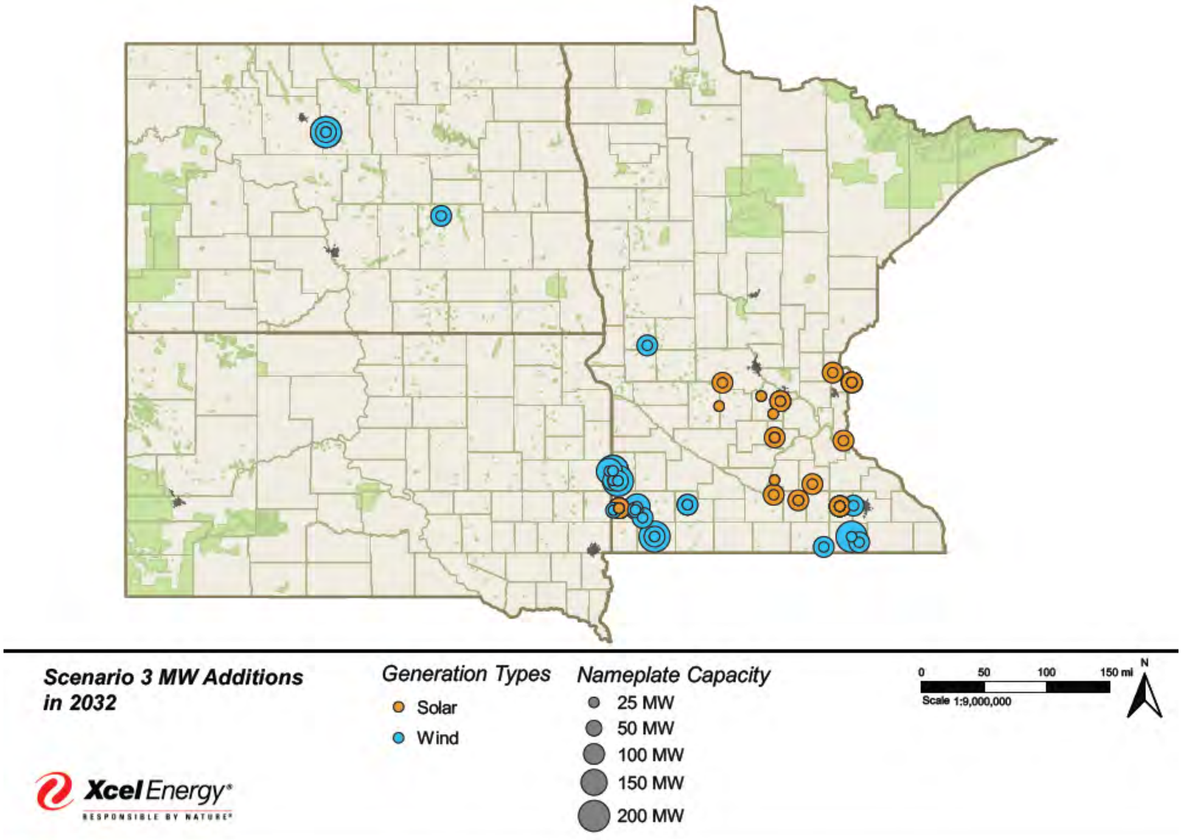

Figure 3: scenario 3 Wind and Solar PV Site Map

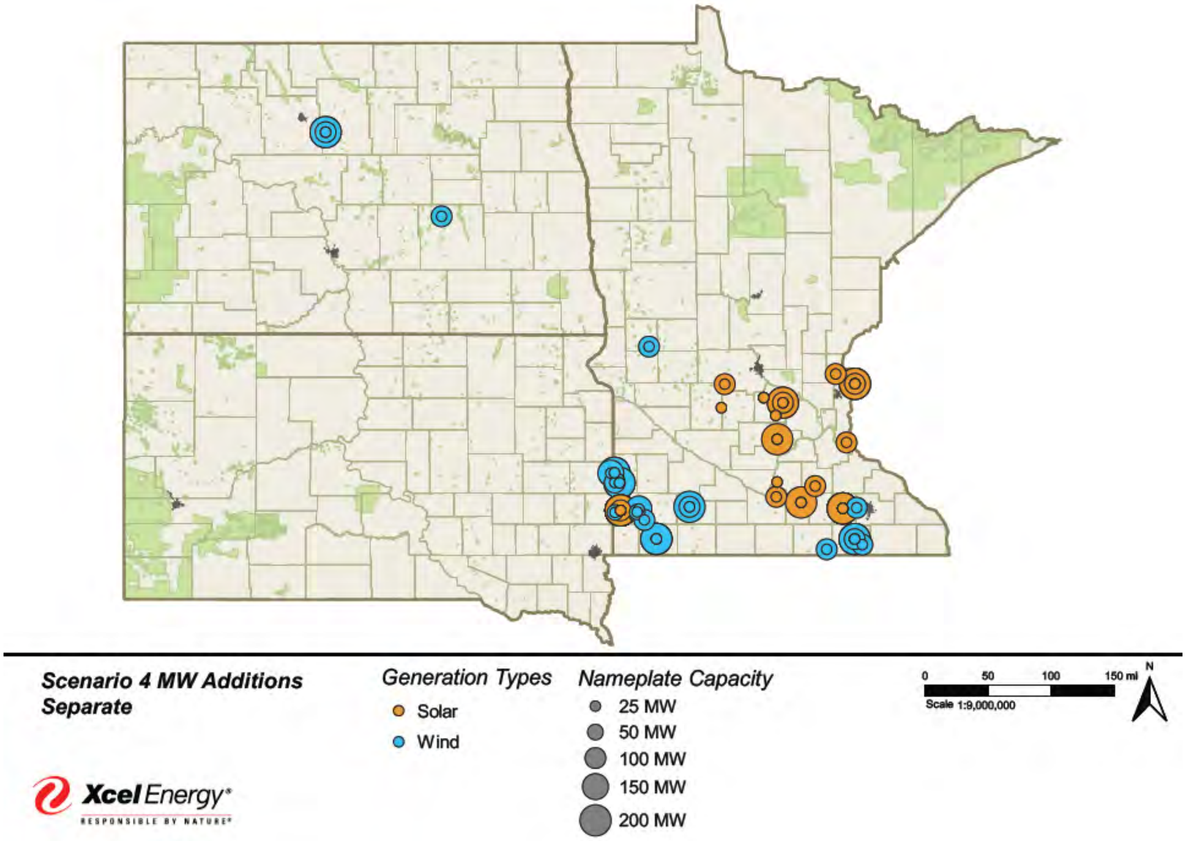

Figure 4: Scenario 4 Wind and Solar PV Site Map

Day ahead forecasts for incremental wind were obtained directly from the NREL Wind database.

Day ahead forecasts for solar and Load were calculated by NSP using a statistical approach using as a basis the actual and forecast data for solar and Load. For solar Northstar and Marshal Plant data from the most recent 12 months were used assuming this would mimic the current level of forecast accuracy. Whenever actual generation profile = 0 MW the forecast for that hour would also be 0 MW. Solar production included generation plus curtailed energy was separated into deciles of 0% -10%, 10% - 20%, etc. A Forecast % adder calculated by taking the difference between Forecast and Gen and dividing by the capacity of solar plant. The associated forecast % is calculated by summing Generation % by capacity of solar facility. The Northstar decile patterns were used to develop forecasts for 100MW facilities. The Marshal Plant decile patterns were used to develop forecasts for 25 MW facilities. Forecast profiles were not allowed to be less than zero or larger than 100% capacity. This method produced Forecast profiles with slightly higher capacity factor than generation profile (over forecast). In the most recent 12 month period both Northstar and Marshal Forecasts had higher capacity factor than Actual generation. The MAPE for the aggregate solar Forecast is better than that for all individual solar plants. This is expected due to geographic diversity of the various solar plants.

SECTION 3 METHODOLOGY

The NSP system is a dispatched by the MISO. Therefore the evaluation of the impact of wind and solar PV on the NSP system requires modeling the MISO and extracting the dispatch costs for the NSP resources. The MISO employs the PROMOD tool in evaluation of its system and developed the MTEP18 database as a model representing the operating companies under its jurisdiction. This study used the MTEP18 database and PROMOD tool in modeling the increase in wind and solar PV penetration on the NSP system. Leidos Engineering performed the PROMOD analysis.

Four scenarios were modeled as described in the assumptions section above. Each scenario applied additional wind and solar PV to the NSP system in addition to the base wind and solar modeled in the MTEP18 database.

Two PROMOD runs were performed for each scenario. The first is a "No error" run (NE) that models a perfect knowledge of actual production for NSP wind and solar resources, with no forecast error assumed. The final production energy profiles for NSP wind and solar generation were used in both the unit commitment decision (similar to Day-ahead market decision) and dispatch optimization (similar to Real-time market). This run also assumes perfect knowledge of the actual NSP load in both commitment and dispatch steps. This run provides the optimal operating dispatch for the NSP resources.

The second PROMOD run is a "Forecast Error" run (FE) that takes into account the day-ahead forecast for wind, solar PV and NSP load. This run performs the unit commitment of the NSP resources based upon the wind, solar PV and NSP load day-ahead forecasts and then performs the dispatch optimization of all resources based upon the actual wind, solar PV and NSP load. The result of this run is different from the first run in that it incorporates the cost of uncertainty due to the wind, solar PV and load forecast errors. For example an over forecast of wind and Solar PV can result in an under commitment of other resources, assuming the load forecast is the same as the actual. An hourly chronological program like PROMOD allows for various combinations of over and under forecasts of wind, solar PV and load throughout the studied year.

The results from the No Error (NE) and Forecast Error runs (FE) are compared for different analysis that will be described later in the report. These include spinning reserve, resource cycling, fuel burn and integration cost due to forecast error.

The data required for modeling wind and solar PV resources in the NSP system was collected with the support of NSP. Wind production and day ahead forecasts were extracted from the NREL wind database using base year 2012. This is consistent with the wind data modeled in the MTEP18 database. Solar production data and the NSP load data were extracted by PROMOD from the MTEP18 database for study year 2022. The Solar and NSP load day ahead forecast were derived statistically from existing solar and NSP load day ahead forecast and actual data. The wind, solar PV and load data were analyzed with results shown in separate presentation.

In order to insure the additional wind and solar PV energy can be integrated into the NSP system a preliminary analysis using proxy wind and solar profiles were used and modeled in PROMOD. Each scenario was set up with the specified generator retirements and incremental renewable generation at transmission buses as designated by NSP. Congestion was measured by flow-gate shadow price ($/MWh), the marginal cost of system dispatch to mitigate congestion. Over 600 flow gates in MTEP 18 were assessed to identify flow gates that become very congested to incremental NSP Renewables. Severe congestion on the Adams 161/69 transformer Adams – Beaver Crk 161 flow-gate was identified in the preliminary analysis of PROMOD runs.. It was then noted that the MTEP18 database being used was lacking an update from the MISO for this transmission line. The upgrade was provided by MISO and implemented in the database for the study.

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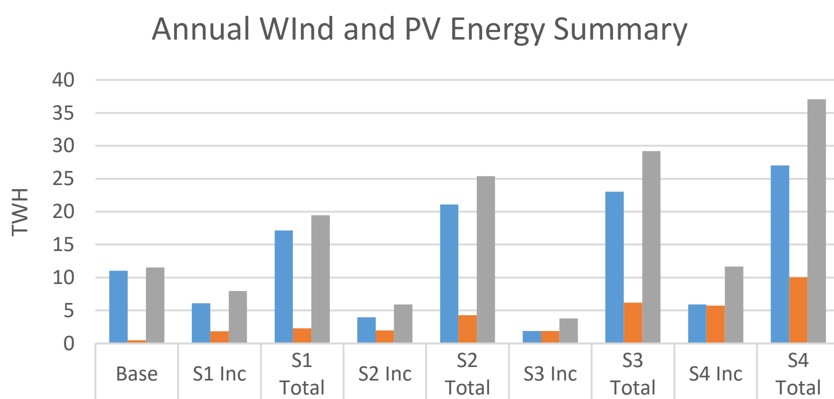
SECTION 4 RENEWABLE CHARACTERIZATION

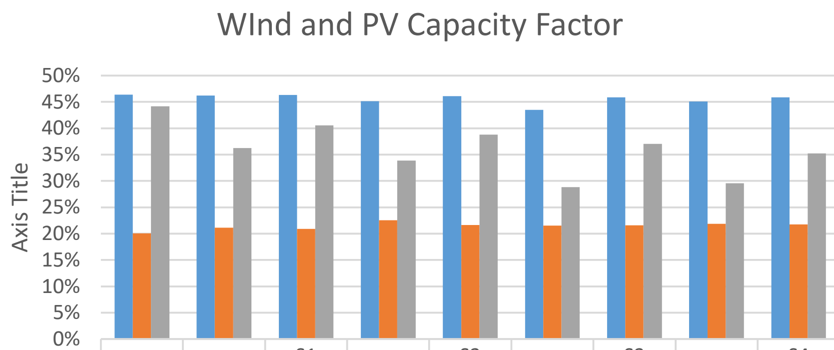
This section provides an analysis of the wind and solar PV modeled in this study. The annual wind and solar PV annual production for each scenario is shown in Figure 5. The total base renewable energy in 2022 is 11.5 TWH of which 11.1 TWH is wind. Scenario 2 models year 2027 builds off of Scenario 1 with total annual renewable energy of 19.5 TWH with wind contributing 17.1 TWH. Scenario 3 and Scenario 4 models year 2032 and are build off of Scenario 2. Scenario 3 has total annual renewable energy of 29.2 TWH of which wind contributes 23 TWH and Scenario 4 has total annual renewable energy of 37.1 TWH of which 27 TWH consists of wind.



	Base	S1 Inc	S1 Total	S2 Inc	S2 Total	S3 Inc	S3 Total	S4 Inc	S4 Total
Wind	11.1	6.1	17.1	4.0	21.1	1.9	23.0	5.9	27.0
PV	0.5	1.9	2.3	2.0	4.3	1.9	6.2	5.7	10.0
Total	11.5	7.9	19.5	5.9	25.4	3.8	29.2	11.7	37.1

Figure 5: Scenario Renewable Annual Energy Summary

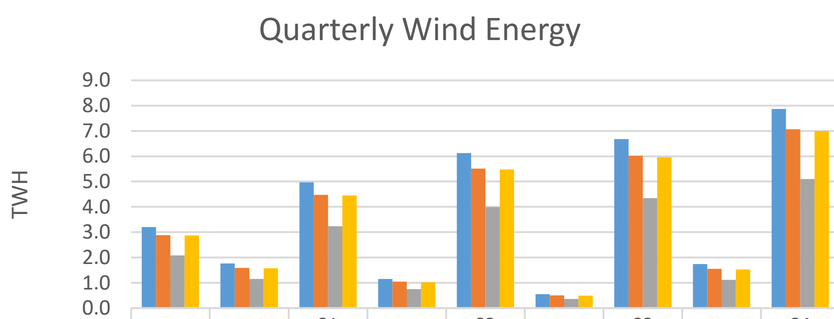
The capacity factors for the aggregated wind and solar PV resources in the study are shown in Figure 6. The Capacity factors for wind in each scenario are in the 46% range with the Base, Scenrio1, Scenario 2, Scenario 3 and Scenario 4 having capacity factors of 46.4%, 46.3%, 46.1%, 45.9% and 45.1% respectively. Solar PV aggregated annual capacity factors for the Base, Scenario1, Scenario 2, Scenario 3 and Scenario 4 are 20.1%, 20.9%, 21.6%, 21.6% and 21.9%.



	Base	S1 Inc	S1 Total	S2 Inc	S2 Total	S3 Inc	S3 Total	S4 Inc	S4 Total
Wind	46.4%	46.2%	46.3%	45.1%	46.1%	43.5%	45.9%	45.1%	45.9%
PV	20.1%	21.1%	20.9%	22.5%	21.6%	21.5%	21.6%	21.9%	21.8%
Total	44.2%	36.2%	40.6%	33.9%	38.8%	28.8%	37.0%	29.6%	35.2%

Figure 6: Scenario Renewable Annual Capacity Factor

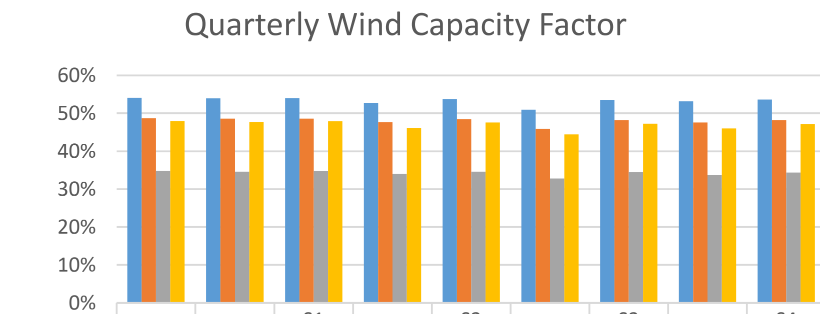
Examining the quarterly renewable energy production, wind energy production is greatest in the January through March months with July through September being the lowest production time in the year. The Wind energy production in the April through June and October through December months are approximately the same Figure 7.



	Base	SI Inc	S1 Total	S2 Inc	S2 Total	S3 Inc	S3 Total	S4 Inc	S4 Total
Jan - Mar	3.206	1.767	4.974	1.152	6.126	0.556	6.682	1.742	7.867
Apr - Jun	2.883	1.592	4.475	1.041	5.516	0.501	6.017	1.558	7.074
Jul - Sep	2.087	1.147	3.234	0.752	3.987	0.363	4.349	1.116	5.102
Oct - Dec	2.875	1.581	4.456	1.019	5.475	0.490	5.965	1.525	6.999

Figure 7: Scenario Quarterly Aggregated Wind Production

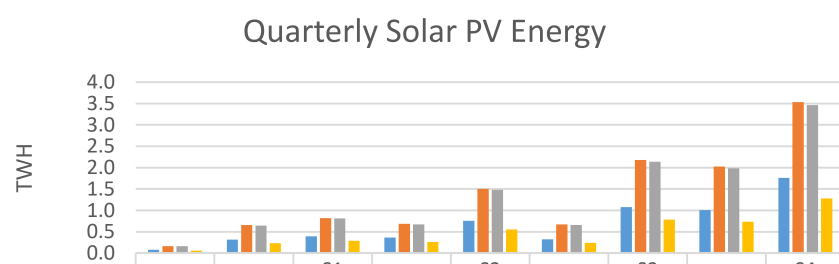
The quarterly wind capacity factors are consistent across all scenarios with capacity factor being the greatest in the January to March months and lowest in the July through September months Figure 8



	Base	SI Inc	S1 Total	S2 Inc	S2 Total	S3 Inc	S3 Total	S4 Inc	S4 Total
Jan - Mar	54%	54%	54%	53%	54%	51%	54%	53%	54%
Apr - Jun	49%	49%	49%	48%	48%	46%	48%	48%	48%
Jul - Sep	35%	35%	35%	34%	35%	33%	34%	34%	34%
Oct - Dec	48%	48%	48%	46%	48%	44%	47%	46%	47%

Figure 8: Scenario Quarterly Aggregated Wind Capacity Factor

The quarterly solar PV production is about the same for the quarters April through June and July through September. The minimum solar PV production occurs in the October through December time period as shown in Figure 9.

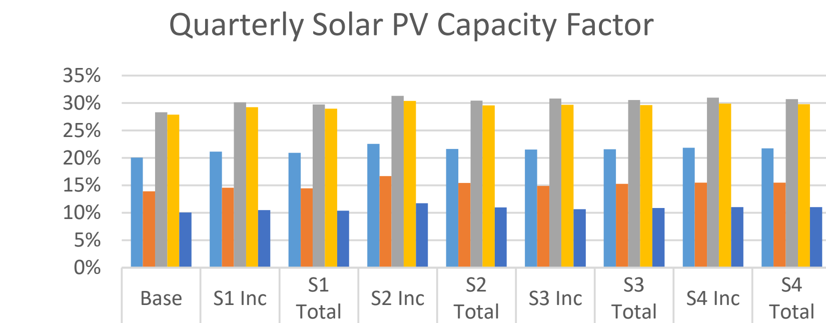


	Base	S1 Inc	S1 Total	S2 Inc	S2 Total	S3 Inc	S3 Total	S4 Inc	S4 Total
Jan - Mar	0.08	0.32	0.39	0.36	0.76	0.32	1.08	1.00	1.76
Apr - Jun	0.16	0.66	0.82	0.68	1.50	0.67	2.18	2.03	3.53
Jul - Sep	0.16	0.65	0.81	0.67	1.48	0.66	2.14	1.98	3.46
Oct - Dec	0.06	0.23	0.29	0.26	0.55	0.24	0.79	0.73	1.28

Jan - Mar   Apr - Jun   Jul - Sep   Oct - Dec

Figure 9: Scenario Quarterly Aggregated Solar PV Production

The quarterly solar PV capacity factor is about the same for the quarters April through June and July through September with a range from 28% to 31%. The minimum solar PV production occurs in the October through December time period with range of 10% to 12% as shown in Figure 10



	Base	S1 Inc	S1 Total	S2 Inc	S2 Total	S3 Inc	S3 Total	S4 Inc	S4 Total
Annual	20%	21%	21%	23%	22%	22%	22%	22%	22%
Jan - Mar	14%	15%	14%	17%	15%	15%	15%	16%	15%
Apr - Jun	28%	30%	30%	31%	30%	31%	31%	31%	31%
Jul - Sep	28%	29%	29%	30%	30%	30%	30%	30%	30%
Oct - Dec	10%	11%	10%	12%	11%	11%	11%	11%	11%

Figure 10: Quarterly Scenario Aggregated Solar PV Capacity Factor

Wind variability was quantified in this study by examining the change in aggregated wind production from one hour to the next. An up – ramp is defined when the present hour is greater than the previous hour and a down – ramp is defined when the present hour is less than the previous hour. This analysis evaluated the hour to hour aggregated changes in wind production over the study year for each scenario. As expected the maximum up and down ramps increase as the penetration of wind increases. The maximum up – ramp range is 879 MW for the Base to 2087 MW hour to hour change in Scenario 4. Similarly calculated the maximum down – ramp range is 1132 MW for the Base to 2770 MW in Scenario 4. Figure 11 shows the plot of the hour to hour changes over the year sorted from high to low. A Histogram shows the up – ramps and down – ramps in Figure 12. Table 3 shows the top 5 up and down ramps for each scenario. Table 4 shows the percent of hours when up – ramps and down – ramps exceed 5% and 10% of the wind rated capacity.

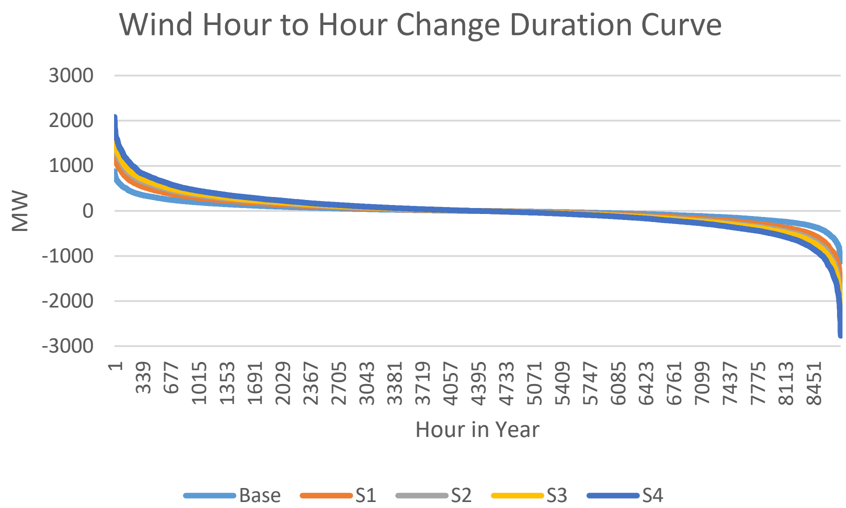


Figure 11: Wind One Hour Ramp Duration Curve

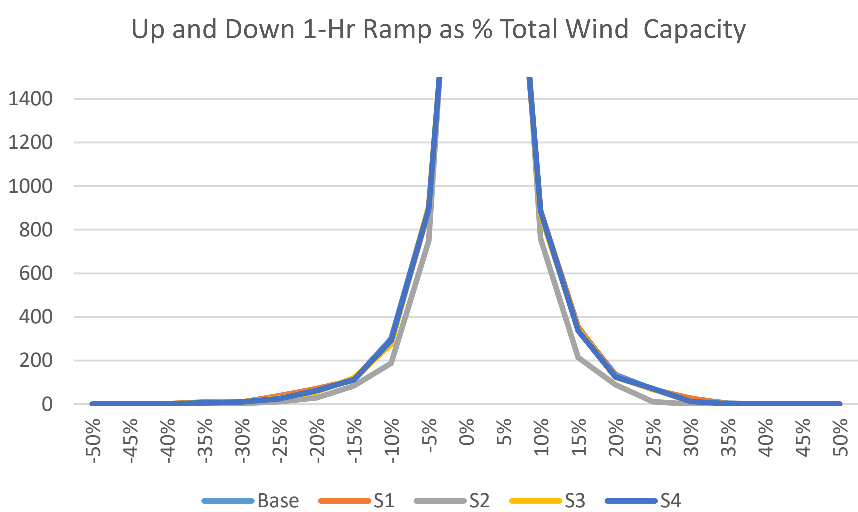


Figure 12: Wind One Hour Ramp Histogram

Table 3: Aggregated Wind One Hour Up and Down Ramp Ranking

Largest MW Up and down ramps										
	Wind Capacity MW	2712		4212		5212		5712		6712
Up	Date	Base	Date	S1	Date	S2	Date	S3	Date	S4
1	06/28/2012 01:00	879	08/30/2012 00:00	1293	08/30/2012 00:00	1648	08/30/2012 00:00	1830	08/30/2012 00:00	2087
2	02/06/2012 23:00	849	11/28/2012 22:00	1276	11/28/2012 22:00	1570	11/28/2012 22:00	1698	11/28/2012 22:00	2024
3	05/03/2012 07:00	838	11/30/2012 23:00	1260	02/06/2012 23:00	1557	02/06/2012 23:00	1662	05/03/2012 07:00	1964
4	08/30/2012 00:00	824	05/03/2012 07:00	1256	11/30/2012 23:00	1487	10/21/2012 00:00	1627	02/06/2012 23:00	1951
5	11/30/2012 23:00	811	02/06/2012 23:00	1239	10/21/2012 00:00	1486	11/30/2012 23:00	1571	10/21/2012 00:00	1866
Down	Date	Base	Date	S1	Date	S2	Date	S3	Date	S4
5	07/23/2012 11:00	1028	07/20/2012 12:00	1570	11/08/2012 15:00	1880	09/16/2012 14:00	2094	11/08/2012 15:00	2444
4	06/28/2012 13:00	1038	06/28/2012 13:00	1580	09/16/2012 14:00	1974	11/08/2012 15:00	2095	09/16/2012 14:00	2519
3	09/16/2012 14:00	1047	09/16/2012 14:00	1632	07/20/2012 12:00	2064	06/06/2012 12:00	2227	06/06/2012 12:00	2639
2	06/06/2012 12:00	1101	06/06/2012 12:00	1733	06/06/2012 12:00	2080	07/20/2012 12:00	2330	07/20/2012 12:00	2686
1	10/21/2012 15:00	1132	10/21/2012 15:00	1742	10/21/2012 15:00	2141	10/21/2012 15:00	2334	10/21/2012 15:00	2770

Table 4: Up – Ramp and Down – Ramp as Percent of Wind Capacity

Number and Percent of ramps in year within +/- % of Rated Capacity					
	Base	**S1**	**S2**	**S3**	**S4**
Hrs -5%	2956	3005	3327	2975	3004
Hrs +5%	2927	2902	3324	2988	2946
% Hrs in Year	**67%**	**67%**	**76%**	**68%**	**68%**
Hrs -10%	3858	3893	4076	3884	3900
Hrs +10%	3804	3788	4082	3858	3831
% Hrs in Year	**87%**	**88%**	**93%**	**88%**	**88%**

Solar PV variability was quantified in this study in a similar way as wind by examining the change in aggregated Solar PV production from one hour to the next. This study evaluated the hour to hour aggregated changes in solar PV production over the study year for each scenario. As expected the maximum up and down ramps increase as the penetration of solar PV increases. The maximum up – ramp range is 94 MW for the Base to 2252 MW hour to hour change in Scenario 4. Similarly calculated the maximum down – ramp range is 93 MW for the Base to 2351 MW in Scenario 4. Figure 13 shows the plot of the hour to hour changes over the year sorted from high to low. Table 3 shows the top 5 up and down ramps for each scenario. A Histogram shows the up – ramps and down – ramps in Figure 14. Table 5 shows the top 5 up and down ramps for each scenario. Table 6 shows the percent of hours when up – ramps and down – ramps exceed 5% and 10% of the solar PV rated capacity.

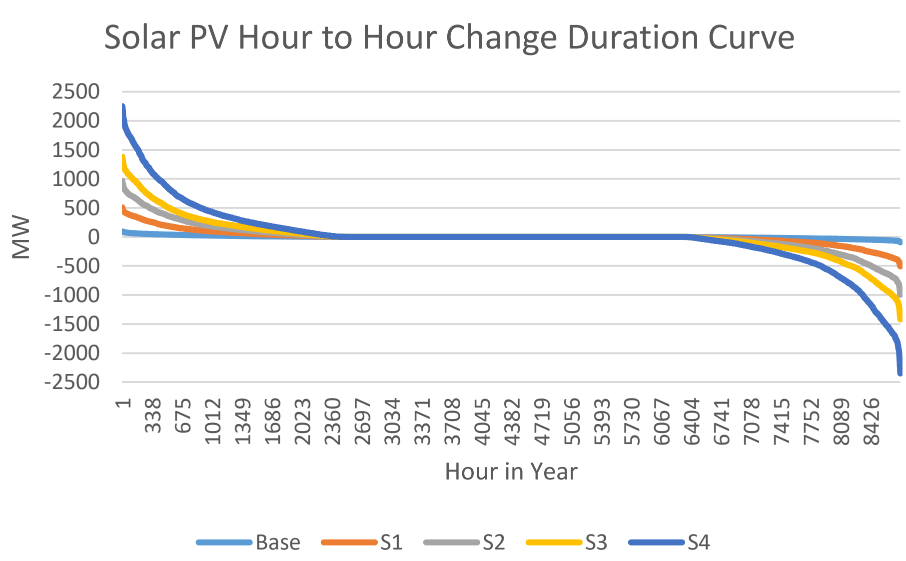


Figure 13: Solar PV One Hour Ramp Duration Curve

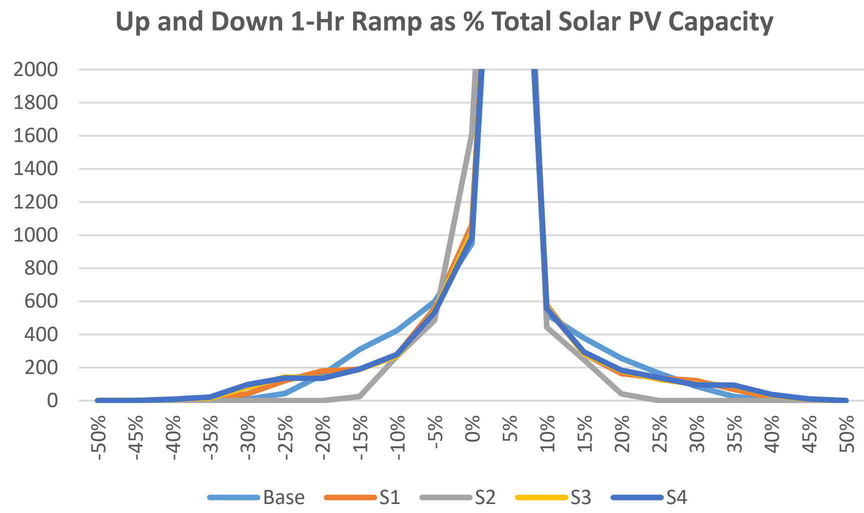


Figure 14: Solar PV One Hour Ramp Histogram

Table 5: Aggregated Solar PV One Hour Up and Down Ramp Ranking

Largest MW up and down ramps										
Solar PV Capacity MW		264		126 4		226 4		3264		5264
Up	Date	Base	Date	S1	Date	S2	Date	S3	Date	S4
1	04/12/2022 09:00	94	04/12/2022 09:00	510	05/03/2022 12:00	966	04/12/2022 09:00	1381	04/12/2022 09:00	2252
2	02/27/2022 10:00	93	04/09/2022 09:00	484	04/08/2022 10:00	952	04/14/2022 09:00	1364	01/21/2022 11:00	2249
3	05/12/2022 09:00	93	04/14/2022 09:00	483	04/12/2022 09:00	934	01/21/2022 11:00	1352	04/14/2022 09:00	2244
4	04/07/2022 10:00	93	04/29/2022 09:00	481	04/14/2022 09:00	925	04/13/2022 09:00	1336	03/12/2022 10:00	2199
5	04/08/2022 10:00	92	04/08/2022 10:00	480	06/13/2022 09:00	922	04/07/2022 10:00	1334	04/13/2022 09:00	2197
Down	Date	Base	Date	S1	Date	S2	Date	S3	Date	S4
5	04/11/2022 20:00	83	02/12/2022 19:00	488	02/14/2022 19:00	938	02/14/2022 19:00	1357	02/14/2022 19:00	2234
4	04/12/2022 20:00	83	04/11/2022 20:00	488	04/12/2022 20:00	940	04/12/2022 20:00	1364	03/17/2022 19:00	2264
3	04/25/2022 15:00	84	04/12/2022 20:00	496	02/13/2022 19:00	984	04/13/2022 20:00	1404	02/13/2022 19:00	2315
2	02/10/2022 19:00	86	02/13/2022 19:00	501	02/12/2022 19:00	989	02/13/2022 19:00	1408	04/13/2022 20:00	2321
1	02/21/2022 19:00	93	02/21/2022 19:00	507	03/17/2022 19:00	995	02/12/2022 19:00	1420	02/12/2022 19:00	2351

Table 6: Up – Ramp and Down – Ramp as Percent of Solar PV Capacity

Number and Percent of 1-Hr Solar PV ramps in year within +/- 5% of Rated Capacity					
	Base	S1	S2	S3	S4
Hrs -5%	947	1062	1612	1016	986
Hrs +5%	4840	4957	5639	4976	4970
% Hrs in Year	66%	69%	83%	68%	68%
Hrs -10%	1544	1620	2097	1556	1518
Hrs +10%	5361	5534	6082	5541	5526
% Hrs in Year	79%	82%	93%	81%	80%

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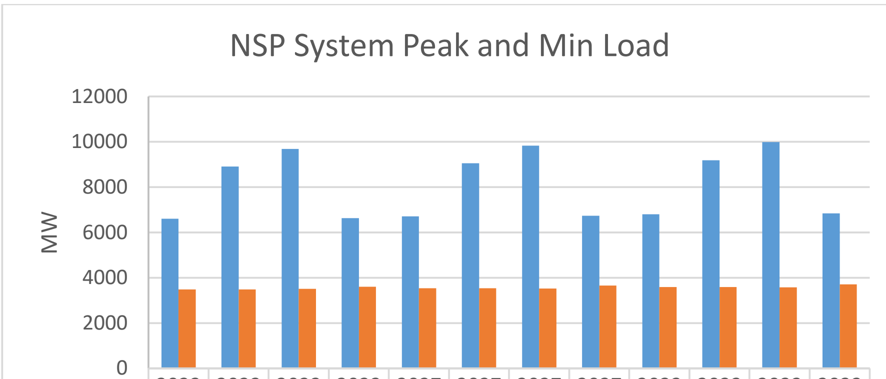
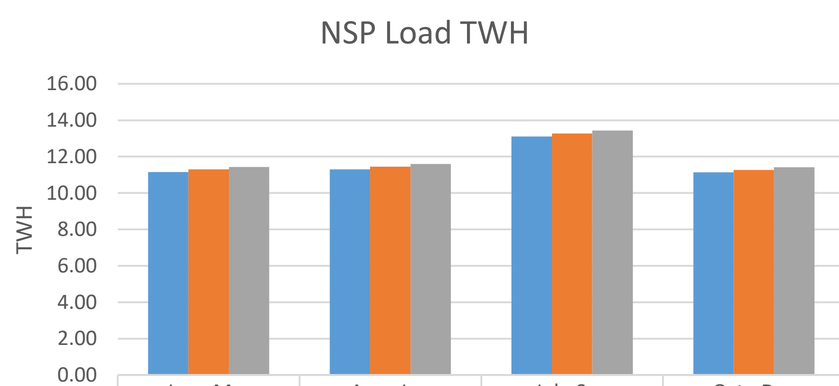
SECTION 5 NSP SYSTEM LOAD

NSP system load for the study years was extracted from the MTEP18 database. Peak load in 2022 is 9686 MW and escalated to 9833 MW in 2027 and again to 9982 MW in 2032. Minimum load in each study year of 2022, 2027 and 2032 is 3482 MW, 3524 MW and 3577 MW respectively. The quarterly NSP system peak and minimum load for each scenario is shown in Figure 15. The annual NSP load demand in TWH in 2022 is 46, 69 TWH, in 2027 load demand is 47.28 TWH and in 2032 load demand is 47.89 TWH as shown in Figure 16. The NSP load factor is shown in Figure 17.



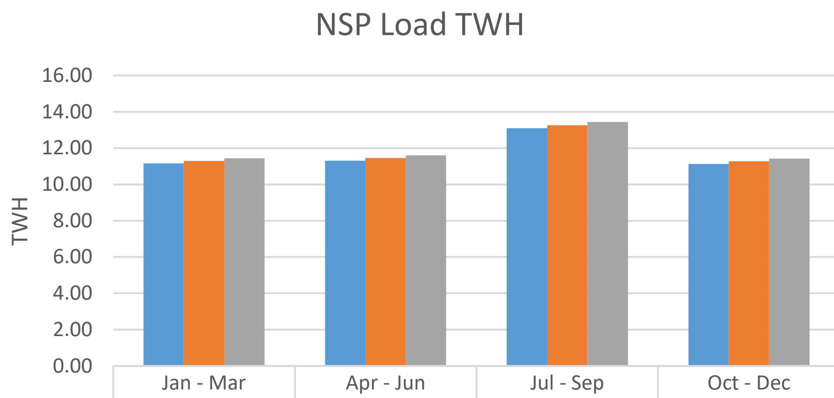
	2022 Jan - Mar	2022 Apr - Jun	2022 Jul - Sep	2022 Oct - Dec	2027 Jan - Mar	2027 Apr - Jun	2027 Jul - Sep	2027 Oct - Dec	2032 Jan - Mar	2032 Apr - Jun	2032 Jul - Sep	2032 Oct - Dec
Max	6603	8911	9686	6635	6703	9046	9833	6736	6805	9183	9982	6838
Min	3488	3482	3514	3599	3541	3535	3524	3653	3595	3589	3577	3709

Figure 15: NSP System Load for Each Scenario



	Jan - Mar	Apr - Jun	Jul - Sep	Oct - Dec
2022	11.15	11.31	13.10	11.13
2027	11.30	11.45	13.27	11.27
2032	11.44	11.60	13.44	11.42

Figure 16: NSP Load Demand by Quarter



	Jan - Mar	Apr - Jun	Jul - Sep	Oct - Dec
2022	11.15	11.31	13.10	11.13
2027	11.30	11.45	13.27	11.27
2032	11.44	11.60	13.44	11.42

Figure 17: NSP Load Factor by Quarter

The NSP load variability, change from hour to hour, was examined in a similar way as the variable wind and solar PV resources. The changes in NSP system load from hour to hour was evaluated and ranked from largest hourly change to smallest Figure 18. In addition the hourly changes were evaluated in a histogram placing the hourly changes into bins representing 25 MW bins, Figure 19. Table 7 shows the five largest and smallest changes in hourly load.

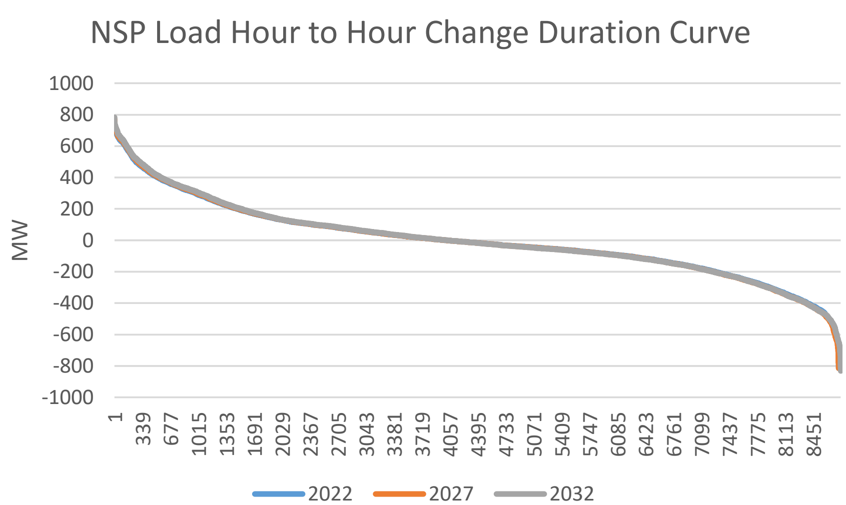


Figure 18: Study Year Load Variability Duration Curve

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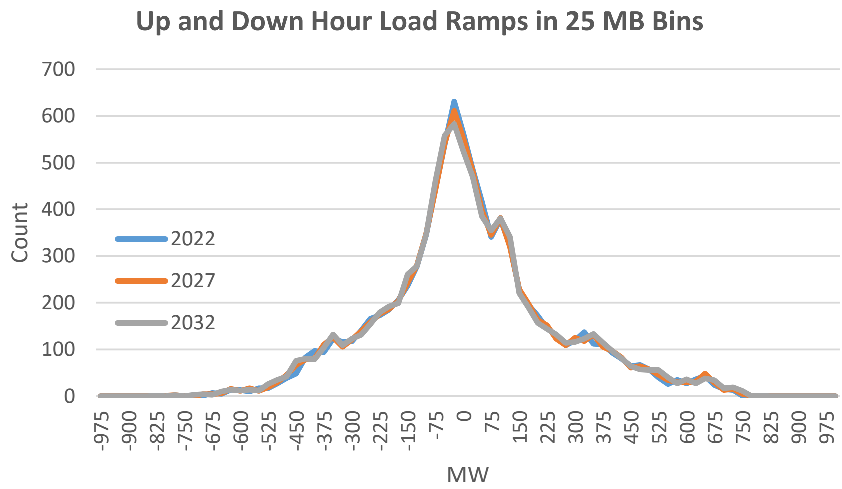

Figure 19: Load Ramp Histogram for each Scenario

Table 7: Five Larges Up and Down Hour Load Change

5 largest up and down ramps						
	Date	Ramp	Date	Ramp	Date	Ramp
Up 1	11/08/2022 08:00	761	11/09/2027 08:00	772	11/09/2032 08:00	783
2	10/03/2022 07:00	729	10/04/2027 07:00	737	10/04/2032 07:00	746
3	11/28/2022 08:00	723	11/29/2027 08:00	734	11/29/2032 08:00	746
4	10/12/2022 07:00	722	10/13/2027 07:00	733	10/13/2032 07:00	743
5	10/24/2022 07:00	720	10/25/2027 07:00	729	12/08/2032 08:00	742
Down 5	07/20/2022 00:00	-692	08/05/2027 00:00	-714	08/05/2032 00:00	-726
4	07/19/2022 00:00	-698	07/20/2027 00:00	-719	07/20/2032 00:00	-733
3	08/04/2022 00:00	-707	08/07/2027 00:00	-777	08/07/2032 00:00	-790
2	08/06/2022 00:00	-766	07/01/2027 01:00	-778	07/01/2032 01:00	-794
1	08/03/2022 23:00	-814	08/04/2027 23:00	-814	08/04/2032 23:00	-832

SECTION 6 NET LOAD

Net load in this section is defined to be the result of subtracting in each hour of the study the amount of wind and solar PV from the NSP system load. This analysis provides further insight into the effects of wind and solar PV on the NSP system making the assumption that the energy produced by wind and solar PV are must take resource and applied to serving system load or off system sale. Table 8 shows for the Base and each Scenario the annual load MWH, Net Load MWH, Renewable MWH, Wind MWH, Solar PV MWH, % of renewable penetration, % of wind penetration, % of solar PV penetration, number of days in the year when renewable energy is greater than load demand, and the number of weeks in the year when renewable energy is greater than load demand. The annual MWH for net load from Scenario 1 to Scenario 4 is reduced by 61%. In Scenario 2 through Scenario 4 there are days when the renewable production exceeds load demand. Additionally in Scenario 4 there are six weeks in the year when renewable production exceeds the weekly NSP demand. Remedial action of curtailment or selling the additional energy can provide mitigation of this excess production.

Table 8: Net Load Characterization for each Scenario

Annual	Base	S1	S2	S3	S4
Load MWH	46,689,259	46,689,259	47,284,693	47,887,784	47,887,784
Net Load MWH	35,879,431	27,300,971	22,008,297	18,637,437	10,736,553
Ren MWH	10,809,828	19,388,288	25,276,396	29,250,347	37,151,231
Wind MWH	10,345,983	17,073,715	20,987,190	23,070,216	27,107,553
PV MWH	463,845	2,314,573	4,289,206	6,180,131	10,043,679
Renewable Penetration % of MWH	23%	42%	53%	61%	78%
Wind Penetration % of MWH	22%	37%	44%	48%	57%
Solar PV Penetration % of MWH	1%	5%	9%	13%	21%
# days Renewable MWH > Load MWH	0	0	19	37	99
# Weeks Renewable MWH > Load MWH	0	0	0	0	6

Net load analysis provided the ability to compare the previously described load analysis to net load. Figure 21 shows the peak and min load and net load by quarter and year. Here it can be seen that renewable configurations in this analysis have a greater effect on minimum load than on the peak load. Another way of observing net load is by examining a histogram counting the number of hour in the year when load or net load falls with a given MW range. The histogram shown in Figure 20 uses the peak load in 2032 and the minimum load in Scenario 4 as boundaries and places in bins sized to 1% of this range. It can be seen in this figure how the NSP net load is modified by the increase in renewable wind and Solar PV.

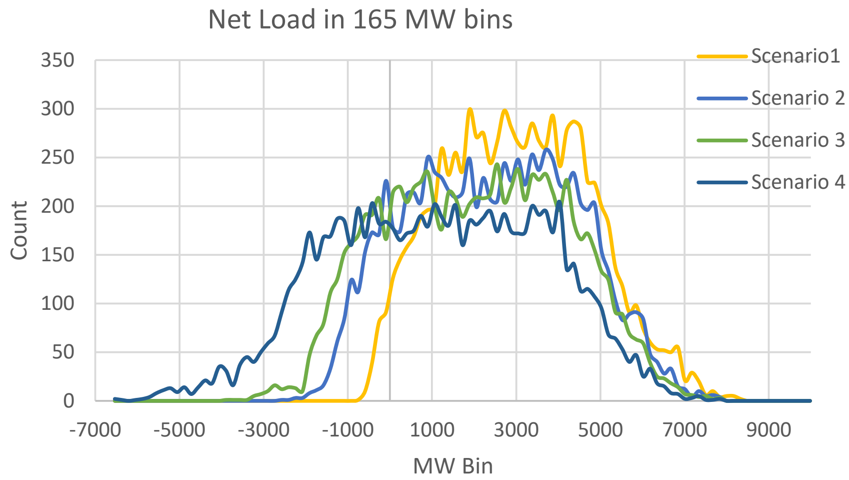

Figure 20: Histogram of Net Load for each study year and Scenario

The analysis of hour to hour net load changes was performed in the same way as load in that the hourly changes were ordered from high to low and plotted in Figure 22, Figure 23, Figure 24 and Figure 25. The hourly load change is plotted to show the differences between the hourly changes in load verses net load. These plots show the number of hour in the year when net load is less than 0 MW, from 179 hours in Scenario 1 to 2988 hours in Scenario 4.

The magnitude and number of hour to hour changes in net load increase in each scenario as penetration increases. This is shown in Figure 26, Figure 27 and Figure 28. The histogram for net load is shown in

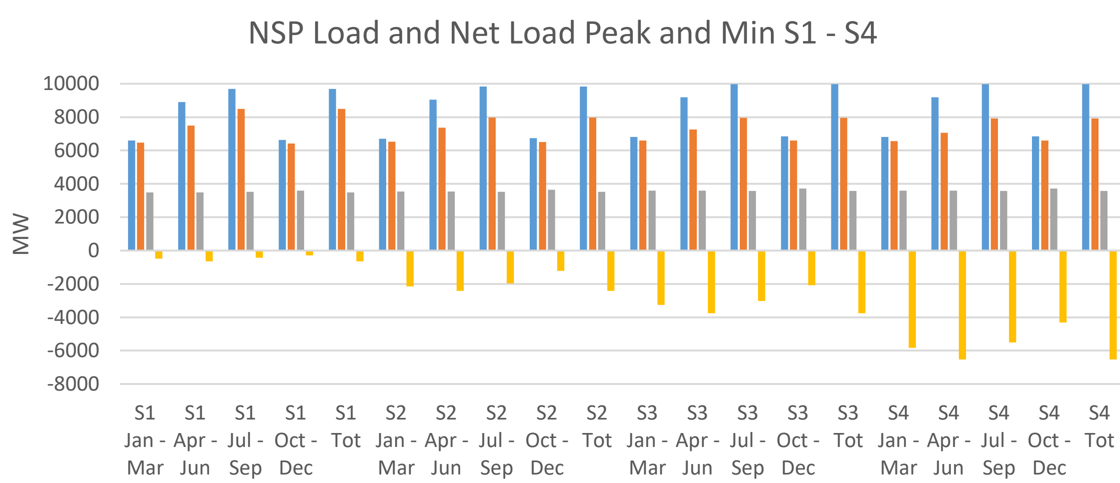

Figure 21: Load and Net Load Peak and Min

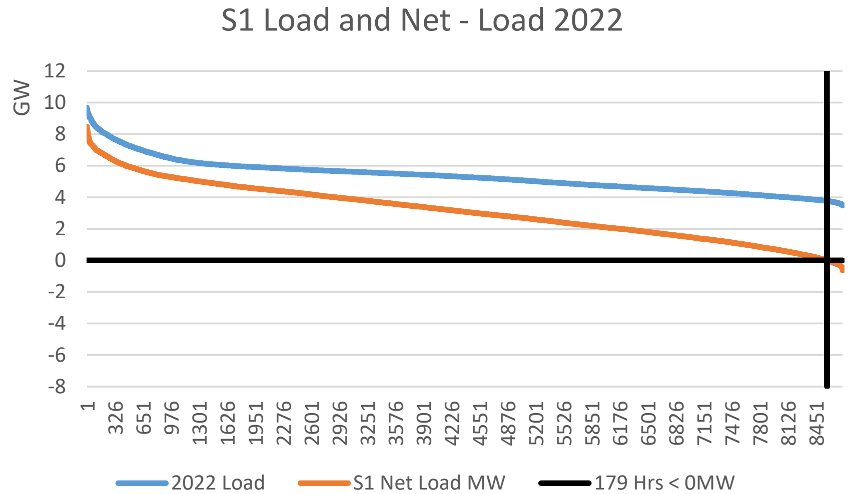

Figure 22: Scenario 1 Load and Net Load Duration Curves

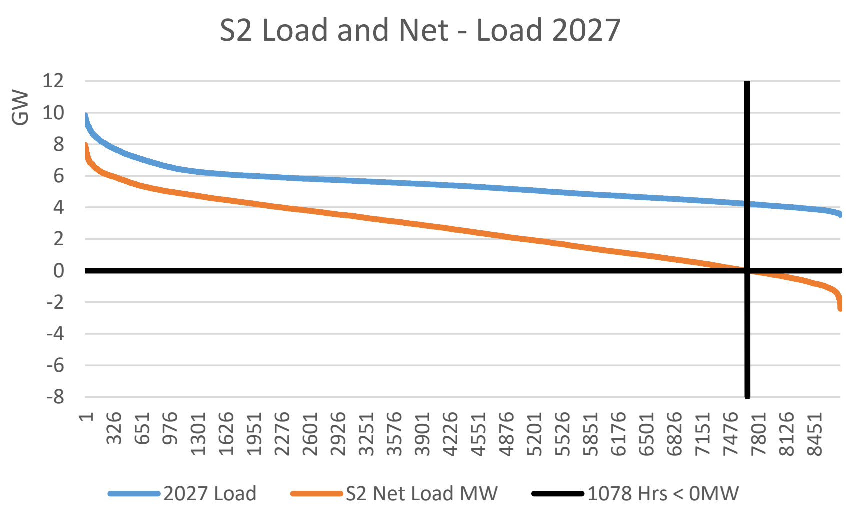

Figure 23: Scenario 2 Load and Net Load Duration Curves

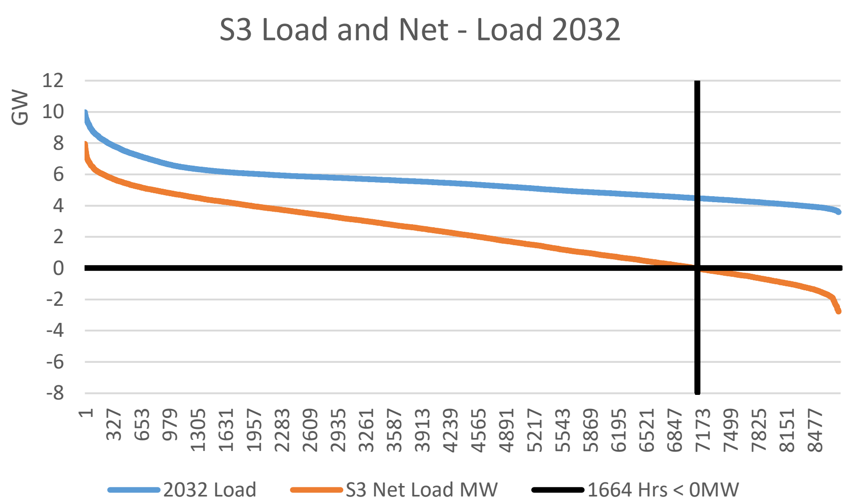

Figure 24: Scenario 3 Load and Net Load Duration Curves

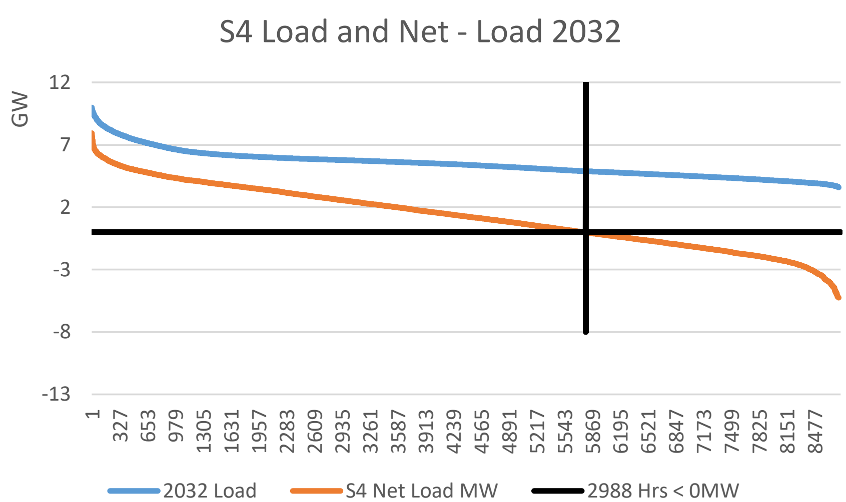

Figure 25: Scenario 4 Load and Net Load Duration Curves

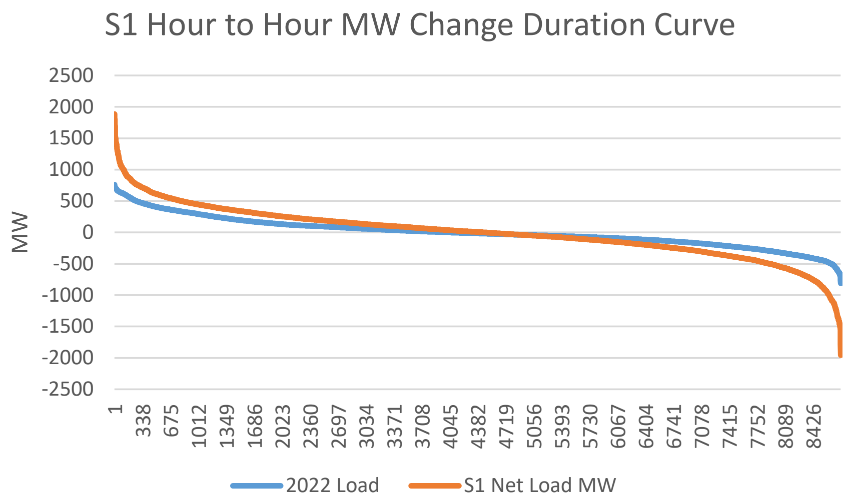

Figure 26: Scenario I Hour to Hour Change Duration Curves

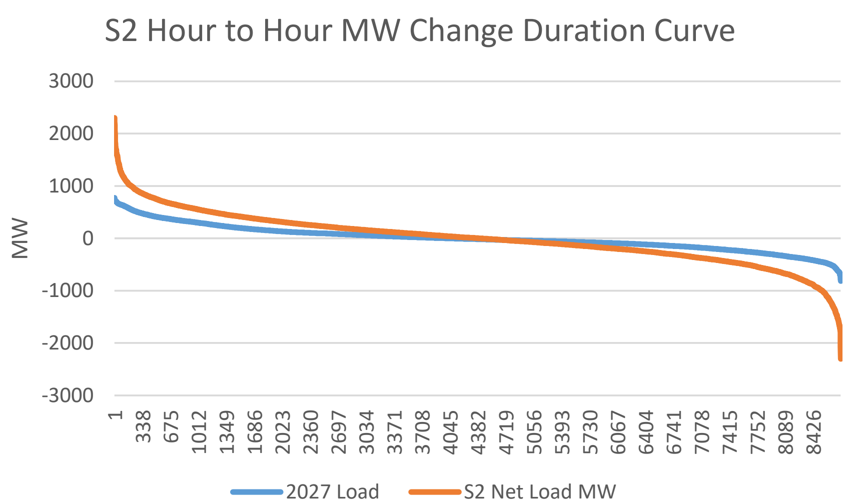

Figure 27: Scenario 2 Hour to Hour Change Duration Curve

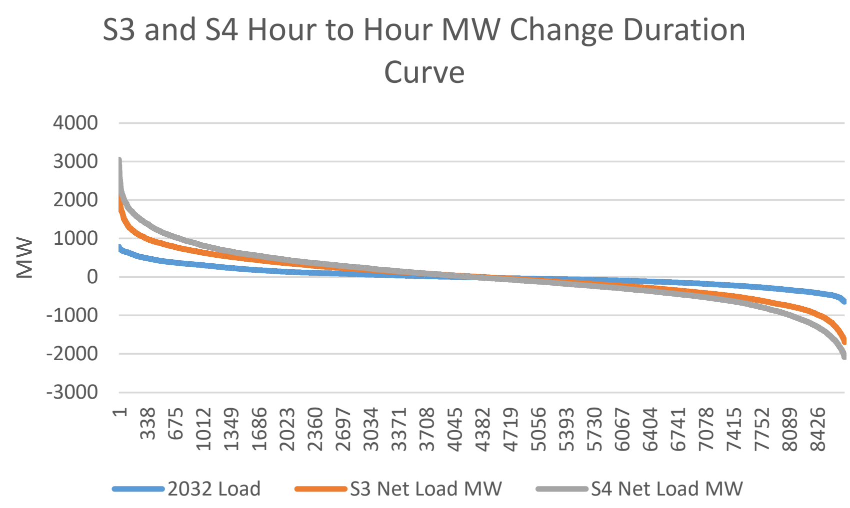

Figure 28: Scenarios 3 and 4 Hour to Hour Change Duration Curve

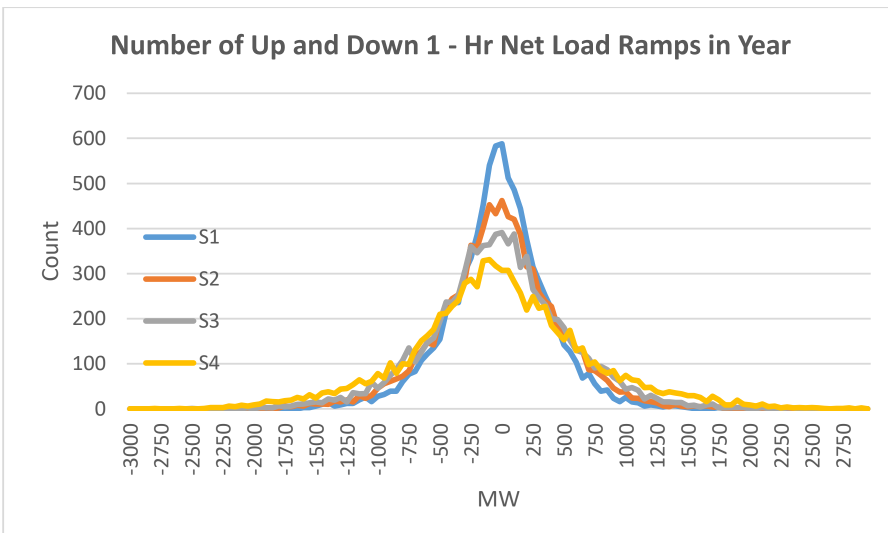

Figure 29: Scenarios 1 through 4 Net Load Hourly Ramps in 50 MW bins

The load and net load analysis provided additional insights into the hour to hour behavior when wind and solar PV is introduced. Plots of individual days and weeks are shown in the final presentation. The tables depicting the days and weeks of interest are shown in the four tables, Table 9, Table 10, Table 11 and Table 12

Table 9: January through March Interesting Days and Weeks

January - March	Base	S1	S2	S3	S4
Max Hr Load MW	6603	6603	6703	6805	6805
Max Hr Load MW Date	01/20/2022 19:00	01/20/2022 19:00	01/21/2027 19:00	01/22/2032 19:00	01/22/2032 19:00
Max Hr Net Load MW	6058	6464	6522	6590	6553
Max Hr Net Load MW Date	01/21/2022 18:00	01/20/2022 19:00	01/21/2027 19:00	01/22/2032 19:00	01/22/2032 19:00
Min Hr Load MW	3488	3488	3541	3595	3595
Min Hr Load MW Date	03/27/2022 04:00	03/27/2022 04:00	03/28/2027 04:00	03/28/2032 04:00	03/28/2032 04:00
Min Hr Net Load MW	1251	-481	-2144	-3261	-5827
Min Hr Net Load MW Date	03/13/2022 03:00	03/20/2022 05:00	03/13/2027 11:00	03/13/2032 11:00	03/13/2032 11:00
Max Week Load MWH	923,921	923,921	936,075	944,342	944,342
Max Week Load MWH Date	01/16/2022 01:00	01/16/2022 01:00	01/17/2027 01:00	01/18/2032 01:00	01/18/2032 01:00
Max Week Net Load MWH	709,374	597,506	518,296	443,318	319,683
Max Week Net Load MWH Date	01/16/2022 01:00	02/13/2022 01:00	02/14/2027 01:00	02/15/2032 01:00	02/15/2032 01:00
Min Week Load MWH	786,878	786,878	795,659	805,739	805,739
Min Week Load MWH Date	03/27/2022 01:00	03/27/2022 01:00	03/28/2027 01:00	03/28/2032 01:00	03/28/2032 01:00
Min Week Net Load MWH	501,000	315,524	178,836	104,853	-53,918
Min Week Net Load MWH Date	01/02/2022 01:00	01/02/2022 01:00	01/03/2027 01:00	01/04/2032 01:00	01/04/2032 01:00

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Table 10: April through Jun Interesting Days and Weeks

April - Jun	Base	S1	S2	S3	S4
Max Hr Load MW	8911	8911	9046	9183	9183
Max Hr Load MW Date	06/29/2022 17:00	06/29/2022 17:00	06/30/2027 17:00	06/29/2032 17:00	06/29/2032 17:00
Max Hr Net Load MW	8099	7485	7365	7250	7062
Max Hr Net Load MW Date	06/21/2022 18:00	06/29/2022 22:00	06/30/2027 22:00	06/29/2032 22:00	06/29/2032 22:00
Min Hr Load MW	3482	3482	3535	3589	3589
Min Hr Load MW Date	04/10/2022 04:00	04/10/2022 04:00	04/11/2027 04:00	04/10/2032 04:00	04/10/2032 04:00
Min Hr Net Load MW	1058	-638	-2418	-3749	-6535
Min Hr Net Load MW Date	04/10/2022 05:00	04/09/2022 10:00	04/10/2027 10:00	04/09/2032 11:00	04/09/2032 11:00
Max Week Load MWH	1,066,489	1,066,489	1,081,782	1,095,569	1,095,569
Max Week Load MWH Date	06/26/2022 01:00	06/26/2022 01:00	06/27/2027 01:00	06/27/2032 01:00	06/27/2032 01:00
Max Week Net Load MWH	867,717	714,510	602,513	523,868	340,510
Max Week Net Load MWH Date	06/26/2022 01:00	06/26/2022 01:00	06/27/2027 01:00	06/27/2032 01:00	06/27/2032 01:00
Min Week Load MWH	779,125	779,125	785,689	795,635	795,635
Min Week Load MWH Date	04/03/2022 01:00	04/03/2022 01:00	04/04/2027 01:00	04/04/2032 01:00	04/04/2032 01:00
Min Week Net Load MWH	507,815	254,625	100,659	6,179	-197,769
Min Week Net Load MWH Date	04/10/2022 01:00	04/03/2022 01:00	04/04/2027 01:00	04/04/2032 01:00	04/04/2032 01:00

Table 11:July through September Interesting Days and Weeks

July - September	Base	S1	S2	S3	S4
Max Hr Load MW	9686	9686	9833	9982	9982
Max Hr Load MW Date	07/04/2022 17:00	07/04/2022 17:00	07/05/2027 17:00	07/05/2032 17:00	07/05/2032 17:00
Max Hr Net Load MW	9177	8484	7967	7963	7925
Max Hr Net Load MW Date	07/04/2022 16:00	07/25/2022 16:00	07/26/2027 16:00	07/20/2032 22:00	07/20/2032 22:00
Min Hr Load MW	3514	3514	3524	3577	3577
Min Hr Load MW Date	09/25/2022 04:00	09/25/2022 04:00	09/26/2027 04:00	09/26/2032 04:00	09/26/2032 04:00
Min Hr Net Load MW	1601	-434	-1960	-3020	-5508
Min Hr Net Load MW Date	09/25/2022 04:00	09/18/2022 05:00	09/19/2027 10:00	09/19/2032 10:00	09/19/2032 11:00
Max Week Load MWH	1,200,141	1,200,141	1,208,446	1,224,129	1,224,129
Max Week Load MWH Date	07/03/2022 01:00	07/03/2022 01:00	07/04/2027 01:00	07/04/2032 01:00	07/04/2032 01:00
Max Week Net Load MWH	1,017,212	901,174	819,052	756,299	604,318
Max Week Net Load MWH Date	07/03/2022 01:00	07/10/2022 01:00	07/11/2027 01:00	07/11/2032 01:00	07/11/2032 01:00
Min Week Load MWH	799,278	799,278	803,100	813,269	813,269
Min Week Load MWH Date	09/25/2022 01:00	09/25/2022 01:00	09/19/2027 01:00	09/19/2032 01:00	09/19/2032 01:00
Min Week Net Load MWH	593,868	385,900	260,208	191,055	16,225
Min Week Net Load MWH Date	09/18/2022 01:00	09/18/2022 01:00	09/19/2027 01:00	09/19/2032 01:00	09/19/2032 01:00

Table 12: October through December Interesting Days and Weeks

October - December	Base	S1	S2	S3	S4
Max Hr Load MW	6635	6635	6736	6838	6838
Max Hr Load MW Date	12/22/2022 19:00	12/22/2022 19:00	12/23/2027 19:00	12/23/2032 19:00	12/23/2032 19:00
Max Hr Net Load MW	6273	6423	6508	6600	6600
Max Hr Net Load MW Date	12/20/2022 19:00	12/19/2022 19:00	12/20/2027 19:00	12/20/2032 19:00	12/20/2032 19:00
Min Hr Load MW	3599	3599	3653	3709	3709
Min Hr Load MW Date	11/06/2022 04:00	11/06/2022 04:00	11/07/2027 04:00	11/07/2032 04:00	11/07/2032 04:00
Min Hr Net Load MW	1296	-294	-1216	-2073	-4317
Min Hr Net Load MW Date	10/16/2022 04:00	11/25/2022 04:00	11/26/2027 04:00	10/16/2032 11:00	10/16/2032 11:00
Max Week Load MWH	905,301	905,301	914,530	926,315	926,315
Max Week Load MWH Date	12/11/2022 01:00	12/11/2022 01:00	12/12/2027 01:00	12/12/2032 01:00	12/12/2032 01:00
Max Week Net Load MWH	750,059	656,938	590,558	565,697	493,018
Max Week Net Load MWH Date	12/11/2022 01:00	12/18/2022 01:00	12/12/2027 01:00	12/12/2032 01:00	12/12/2032 01:00
Min Week Load MWH	792,647	792,647	744,272	753,603	753,603
Min Week Load MWH Date	11/13/2022 01:00	11/13/2022 01:00	12/19/2027 01:00	12/19/2032 01:00	12/19/2032 01:00
Min Week Net Load MWH	492,239	319,565	207,060	151,515	2,015
Min Week Net Load MWH Date	11/13/2022 01:00	11/13/2022 01:00	11/14/2027 01:00	11/14/2032 01:00	11/14/2032 01:00

An example of an interesting day and week is the week with the day April 10. April 10 has a high wind and solar PV production while the load on this day is relatively low. In each scenario as penetration increases the net load decreases. For the day the Base Load is 93,793 MWH the Base net load is 10,642 MW. Scenario 1 net load is 14,642 MWH. Scenario 2 is -28,596 MWH, Scenario 3 is -47,378 MWH, and Scenario 4 is -84,711 MWH. Figure 30, Figure 31, Figure 32, Figure 33 and Figure 34 show the effects of the renewable penetration on the NSP load. In the Base the net load is within the 1000 MW to 2000 MW range while as renewable penetration increases in each scenario there are hours when net load for NSP becomes negative in Scenario 1 and for the full day in Scenario 2, Scenario 3 and Scenario 4.

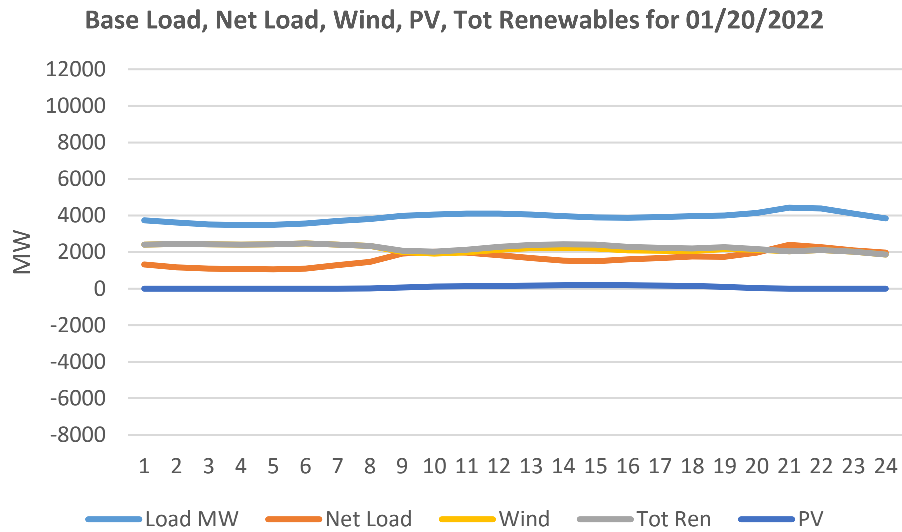

Figure 30: Base Case Interesting Day

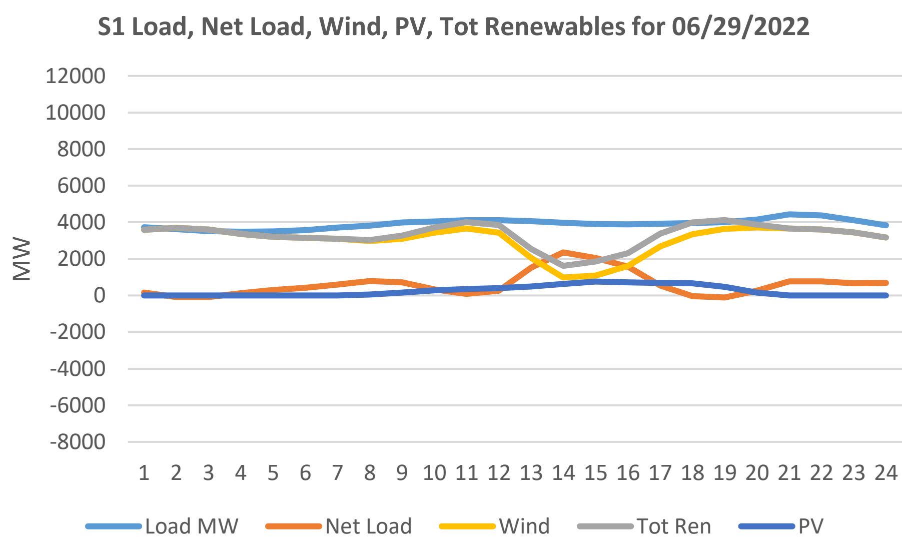

Figure 31: Scenario 1 Interesting Day

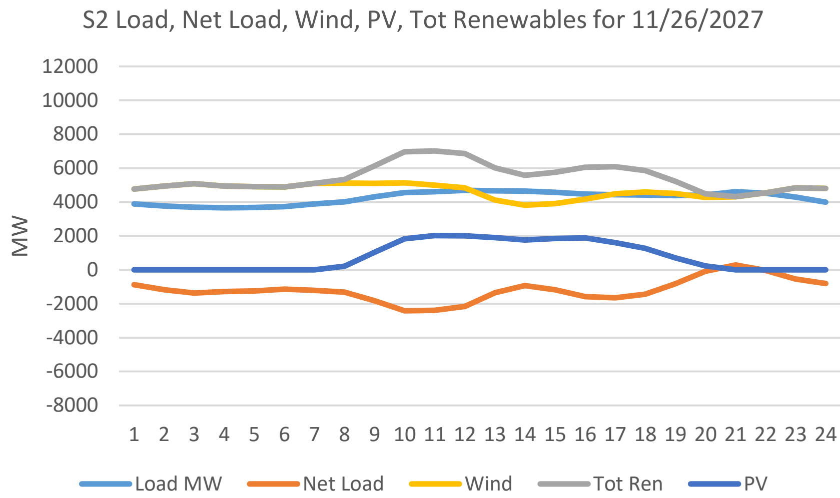

Figure 32: Scenario 2 Interesting Day

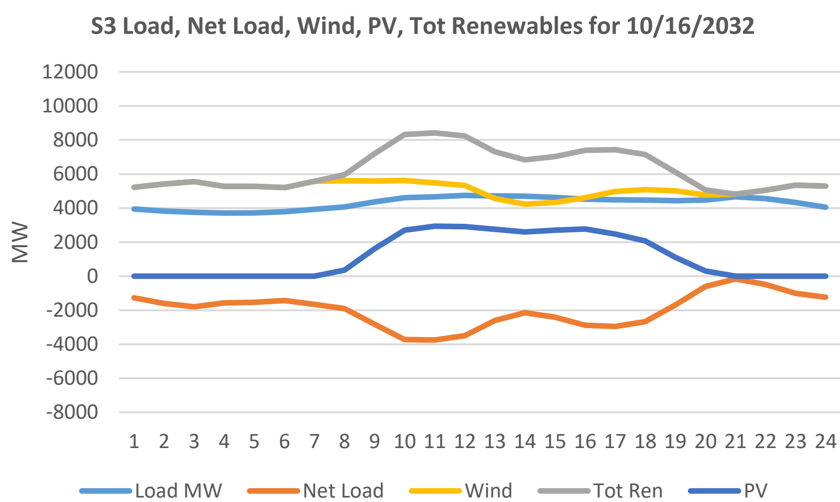

Figure 33: Scenario 3 Interesting Day

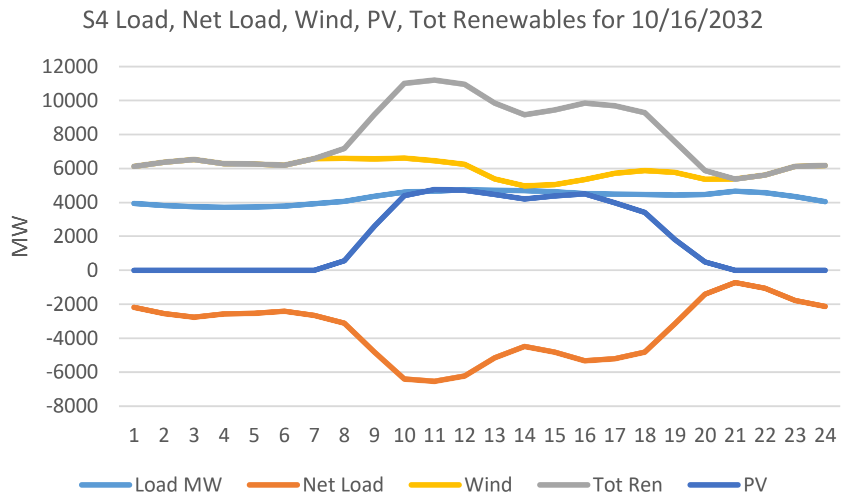

Figure 34: Scenario 4 Interesting Day

SECTION 7 RESERVE

As described in the previous section Net Load shows there is an increase in the hour to hour load change as the penetration of renewables increases. Spinning reserves are typically established to account for these load variations that occur within the hour. Therefore, as the tendency for hour to hour load change increase with renewable penetration, the spinning reserves will also change. The changes in spinning reserves in this study were calculated statistically using the method applied in numerous other studies[1, 2, 3]. The Base Case set NSP Base Reserves at 27 MW, Spin at 65 MW and Supplement at 71 MW. The forecasts used in this analysis were persistence (next hour forecast is the same as present hour) for load and wind. The forecast for solar PV used the average three production values, the hour of, the hour before and the hour after. These forecasts provided a forecast error for the next hour forecast. Associating the forecast error to the level of wind and solar PV production the production levels for these renewable types were placed into histogram bins at 10% production intervals. From each of these bins the standard deviation of the forecast error was calculated and plotted against the production level. A curve fit of the plot results in a quadratic curve. From this curve the statistical standard deviation of the forecast error for wind and solar PV can be calculated. In addition statistically three standard deviations, or three times the calculated standard deviation of forecast error covers 99.7% of the possible forecast errors for wind or solar PV.

Because the Base Case includes renewables, the spinning reserve contribution to renewables was calculated and included in the spinning reserve analysis for each Scenario. The formula for calculating the 10 – minute spinning reserve is based on predictive operating levels of load, wind and solar PV forecast errors and is shown below.

$$3 * \sqrt{\left(\frac{\%Hourly\ Load}{3}\right)^2 + \sigma(HourlyWind)^2 + \sigma(HourlySolarPV)^2} \text{ = 65 MW for the Base Case}$$

The calculated 10-minute spinning reserve changes demonstrate that as renewable penetration increases the average 10-minute spinning reserve requirement also increases. In general the analysis shows the contribution of 10-minute spinning reserves in this study ranges between 0.7% and 0.9% of the renewable rated capacity. Table 13 provides the calculated 10-minute spinning reserve requirements. The spinning reserve contribution of renewables increases from 25 MW in Scenario 1 to 76 MW in Scenario 4 more than doubling the reserve requirement in the Base Case.

[1] https://www.nrel.gov/docs/fy11osti/47078.pdf

[2] https://www.pjm.com/-/media/committees-groups/subcommittees/irs/postings/pris-executive-summary.ashx?la=en
https://www.pjm.com/-/media/committees-groups/subcommittees/irs/postings/pjm-pris-task-3a-part-b-statistical-analysis-and-reserves.ashx?la=en

[3] https://canwea.ca/wp-content/uploads/2016/07/pcwis-section05-statisticalandreserveanalysis.pdf

Table 13: 10 – Minute Spinning Reserves for each Scenario

Average Contribution 10-min Spin Reserve (MW)			
Scenario	Load	Renewable	Total
Base	43	22	65
S1	43	47	90
S2	43	62	105
S3	43	73	116
S4	43	98	141

In order to verify these calculations a post analysis of the PROMOD runs was performed to determine if these levels of reserves were sufficient. The loading of NSP resources for each hour in the study were examined. The Headroom for each on line resource was calculated by subtracting the resource loading in the hour from its available capacity. This value was limited by the respective resource ramping rate. The headroom for all resources was aggregated by hour to provide the total available on line spinning generation. The number of hours in the year when the calculated 10 – minute spinning reserve was exceeded was determined. Table 14 depicts the results of the post analysis. The number of hours in the year when the calculated spinning reserve exceeds the NSP resource headroom, the percent of hours in the year when spinning reserve exceeds the NSP resource headroom, the maximum MW of NSP resources that exceeds the spinning reserve requirement and the hour of maximum deficiency for spinning reserves are shown. The worst case is in Scenario 4 when there is an hour when the NSP system is deficient of 145 MW of spinning reserves. In these hours the NSP system would rely on the MISO for mitigation.

Table 14: Spinning Reserve Post Analysis

10 - Min Spinning Reserve Post Analysis				
	Hours Deficient	**Percent**	**Max Excess MW**	**Max Deficient MW**
Scenario 1	36	0.4%	1,286	43
Scenario 2	65	0.7%	1,235	61
Scenario 3	105	1.2%	1,644	108
Scenario 4	139	1.6%	1,699	145

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SECTION 8 RESULTS

This section provides the PROMOD production costs for the Base Case and Each Scenario. The MTEP 18 PROMOD model includes all RTOs, ISOs, and balancing areas in the Eastern Interconnect. The results extracted from the runs were focused strictly on the NSP system.

There were two sets of PROMOD runs performed in this analysis. The first type (NE) modeled the NSP system without any renewable and load forecast error. This run performed both unit commitment and dispatch steps using the actual values for the hourly wind and solar PV energy and the NSP load. The second type of run (FE) performed the unit commitment using a day-ahead forecast for hourly wind and solar PV energy and NSP load, and then solved the unit dispatch optimization based upon actual values for hourly wind and solar PV energy and NSP load. This second run will have a different production cost than the first due to the forecast used in the commitment stage. An over forecast of wind or solar PV can result in an under commitment of system resources, as would an under forecast of system load. Similarly an under forecast of wind or solar PV would result in an over commitment of system resources. As would an over forecast of system load. Sometimes the over forecast of wind and solar PV is compensated by an under forecast of system load. The hourly chronological production costing model evaluates these combinations of over and under forecast and accounts for the forecast errors in the costs it provides.

Through the study scenarios from 2022 to 2032 the aggregated capacity of gas resources increase. The average annual gas prices modeled in the MTEP18 database are 4.36 $/MMBTU in 2022, 5.47 $/MMBTU in 2027 and 6.49 $/MMBTU in 2032.

The results of the production costs from PROMOD runs include forecast errors unless otherwise stated. Table 15 depicts the annual renewable production (MWH), Conventional resource production (MWH), system cost, cost per MWH, total NSP load MWH, wind and solar curtailment, and the NSP off system energy requirement. The Base Case is the only case where NSP is a net purchaser of power over the year. The average cost in $/MWH increases from 22.99 $/MWH in the Base Case to 42.40 $/MWH in Scenario 4.

The cost of integrating wind and solar PV based upon the forecast error is shown in Table 17. The cost of forecast error due to the integration of wind and solar PV range from 0.09 $/MWH in Scenario 1 to 0.42 $/MWH in scenario 4. The increase in renewable and reduction in traditional generation resulted in lower production costs in Scenario 4. The difference from forecast error is nearly the same in Scenario 3 as in Scenario 4. The % of cost increased over the % if cost increase of scenario 3.

Resource production by fuel type was analyzed over each of the scenarios in Table 18. Gas CT and combined cycle resources increased production as renewable penetration increased. Gas CT production increased in Scenario 1 from 349 TWH to 825 TWH in Scenario 4. Combined cycle production increased in Scenario 1 from 3,485 TWH to 12.368 TWH in Scenario 4. Coal resource production in combination with retirements decreased over the study. While coal capacity decreased from 2,479 MW in Scenario 1, to 1,054 MW in Scenario 2, to 528 MW in Scenario 3 and 4. The capacity factor of the aggregated coal resources increase as the renewable resource penetration increase from 70% in Scenario 1 to 82% in Scenario 4. This increase can be contributed to coal resource retirements that provides production opportunity for the remaining coal resources. There is little difference in production for the other resources modeled.

Table 15: PROMOD Forecast Error Results for NSP

Scenario	Year	Wind (MWH)	Solar PV (MWH)	Other Resource (MWH)	Cost (M$)	NSP ($/MWH)	NSP Load (MWH)	Wind Curt. (MWH)	Solar PV Curt (MWH)	Off System (MWH)
Base 2022	2022	11,081,214	411,372	32,099,679	738.00	22.99	46,689,259	126,579	7,896	-3,231,469
Scenario 1	2022	17,184,813	2,262,501	31,260,438	713.97	22.84	46,689,259	827,958	46,326	3,144,209
Scenario 2	2027	21,459,009	4,238,311	24,555,275	669.01	27.24	47,284,693	1,109,598	104,447	1,753,857
Scenario 3	2032	22,794,690	6,121,946	26,906,024	872.97	32.45	47,887,784	1,575,148	204,112	6,155,616
Scenario 4	2032	26,039,342	7,296,502	17,175,912	728.25	42.40	47,887,784	1,853,498	296,508	473,966

Table 16: PROMOD Forecast Error Results for NSP by Conventional Resource Type

Other Resources (MWH)	CT Gas	Conv. Hydro	ST Coal	CC	CT Oil	Nuclear	CT Other	ST Gas	Total
Base 2022	414,664	797,912	13,754,230	3,798,813	1,146	13,330,759	71	2,085	32,099,679
Scenario 1	348,868	797,920	13,295,512	3,485,308	320	13,330,759	42	1,710	31,260,438
Scenario 2	751,205	798,234	3,222,766	6,891,534	11,594	12,877,915	474	1,554	24,555,275
Scenario 3	608,454	798,278	2,959,974	9,493,506	180	13,044,911	130	621	26,906,054
Scenario 4	825,470	798,280	3,182,140	12,368,017	536	0	390	1,079	17,175,912

Table 17: Integration Cost due to Forecast Error

Average $/MWH	Base 2022	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Perfect Forecast	22.97	22.82	27.15	32.27	42.31
Forecast Error	22.99	22.84	27.24	32.45	42.40
Increase	0.02	0.02	0.10	0.18	0.09
Integration Cost due to Forecast error	na	0.09	0.27	0.55	0.42

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Table 18: Aggregated Fuel Type Production Summary by Scenario

	Fuel Type	CT Gas	ST Gas	CT Other	CC	CT Oil	Hydro	ST Coal	Nuclear	Tot Ren	Tot NSP
S1 NE	**Production MWH**	346,332	1,678	42	3,420,772	145	797,916	13,319,836	13,330,759	18,577,422	49,794,902
	Available Production MWH	13,739,669	39,415	112,313	19,439,326	4,539,785	2,814,588	19,115,350	13,340,041	19,447,315	92,587,800
	Production/Available	2.5%	4.3%	0.0%	17.6%	0.0%	28.3%	69.7%	99.9%	95.5%	53.8%
	Capacity MW	2,142	29	15	2,561	605	321	2,479	1,673	5,476	15,303
S1 FE	**Production MWH**	348,868	1,710	42	3,485,308	320	797,920	13,295,512	13,330,759	18,573,030	49,833,468
	Available Production MWH	13,739,669	39,415	112,313	19,439,326	4,539,785	2,814,588	19,115,350	13,340,041	19,447,315	92,587,801
	Production/Available	2.5%	4.3%	0.0%	17.9%	0.0%	28.3%	69.6%	99.9%	95.5%	53.8%
	Capacity MW	2,142	29	15	2,561	605	321	2,479	1,673	5,476	15,303
S2 NE	**Production MWH**	744,481	1,448	479	6,727,612	11,087	798,224	3,228,928	12,877,915	24,496,397	48,886,571
	Available Production MWH	23,593,662	38,833	117,264	27,223,557	4,629,407	2,814,588	4,338,760	12,877,915	25,697,343	101,331,329
	Production/Available	3.2%	3.7%	0.4%	24.7%	0.2%	28.4%	74.4%	100.0%	95.3%	48.2%
	Capacity MW	**2,937**	5	15	**3,561**	605	321	**1,054**	1,673	**7,476**	**17,648**
S2 FE	**Production MWH**	751,205	1,554	474	6,891,534	11,594	798,234	3,222,766	12,877,915	24,483,275	49,038,550
	Available Production MWH	23,593,662	38,833	117,264	27,223,557	4,629,407	2,814,588	4,338,760	12,877,915	25,697,320	101,331,306
	Production/Available	3.2%	4.0%	0.4%	25.3%	0.3%	28.4%	74.3%	100.0%	95.3%	48.4%
	Capacity MW	**2,937**	5	15	**3,561**	605	321	**1,054**	1,673	**7,476**	**17,648**
S3 NE	**Production MWH**	595,970	508	88	9,136,143	142	798,258	2,977,973	13,044,911	27,164,561	53,718,553
	Available Production MWH	23,860,208	40,202	119,422	34,913,409	307,009	2,816,110	3,909,366	13,044,911	28,916,636	107,927,274
	Production/Available	2.5%	1.3%	0.1%	26.2%	0.0%	28.3%	76.2%	100.0%	93.9%	49.8%
	Capacity MW	**2,973**	5	15	**4,561**	37	321	**528**	1,673	**8,976**	**19,089**
S3 FE	**Production MWH**	608,454	621	130	9,493,506	180	798,278	2,959,974	13,044,911	27,137,376	54,043,430
	Available Production MWH	23,860,208	40,202	119,422	34,913,409	307,009	2,816,110	3,909,366	13,044,911	28,916,636	107,927,274
	Production/Available	2.6%	1.5%	0.1%	27.2%	0.1%	28.3%	75.7%	100.0%	93.8%	50.1%
	Capacity MW	**2,973**	5	15	**4,561**	37	321	**528**	1,673	**8,976**	**19,089**
S4 NE	**Production MWH**	815,004	769	333	12,028,857	417	798,247	3,196,709	0	31,203,106	48,043,442
	Available Production MWH	23,860,208	40,202	119,422	34,913,409	307,009	2,816,110	3,909,366	0	33,308,263	99,273,990
	Production/Available	3.4%	1.9%	0.3%	34.5%	0.1%	28.3%	81.8%	na	93.7%	48.4%
	Capacity MW	**2,973**	5	15	**4,561**	37	321	**528**	0	**11,976**	**20,416**
S4 FE	**Production MWH**	825,470	1,079	390	12,368,017	536	798,280	3,182,140	0	31,158,256	48,334,169
	Available Production MWH	23,860,208	40,202	119,422	34,913,409	307,009	2,816,110	3,909,366	0	33,308,262	99,273,989
	Production/Available	3.5%	2.7%	0.3%	35.4%	0.2%	28.3%	81.4%	na	93.5%	48.7%
	Capacity MW	**2,973**	5	15	**4,561**	37	321	**528**	0	**11,976**	**20,416**

An analysis of unit startups was conducted. In this analysis PROMOD produced hourly output for NSP resources of each different fuel type. The number of startups were counted in each scenario. In general the number of startups across the NSP fleet increases as renewable penetration increases. Coal resources in Scenario 4 show a decrease in startups while CC and Gas CT resources show an increase startups. Table 19 shows the number of resources by fuel type in each scenario. Table 20 shows the increase in unit startups over the year. Table 21 shows the number of resource startups over the year. Table 22 shows the average number of starts per resource type. Additional plots on number of starts can be found in the accompanying presentation.

Table 19: Number of Resources by Fuel Type

Number of Resources					
Type	Base 2022	Scenario 1	Scenario 2	Scenario 3	Scenario 4
CT Gas	27	27	22	18	18
Hydro	19	19	19	19	19
ST Coal	9	9	7	4	4
CC	6	6	8	10	10
CT Oil	11	11	11	2	2
Nuclear	3	3	3	3	0
CT Other	1	1	1	1	1
ST Gas	4	4	1	1	1
Total Resources	80	80	72	58	55

Table 20: Increase in Unit Startups by Fuel Type

Increase in Unit Startups over the year due to Forecast Error					
Type	Base 2022	Scenario 1	Scenario 2	Scenario 3	Scenario 4
CT Gas	17	18	35	52	61
Hydro	-1	1	0	1	-2
ST Coal	-12	-2	-4	-12	-13
CC	0	9	16	-35	-16
CT Oil	1	3	8	0	6
Nuclear	0	0	0	0	0
CT Other	0	0	2	2	4
ST Gas	-6	0	0	0	-4
Total Resources	80	80	72	58	55

Table 21: Resource Startups by Fuel Type

Number of Resource Startups over the Year					
Type	Base 2022	Scenario 1	Scenario 2	Scenario 3	Scenario 4
CT Gas	532	486	737	598	774
Hydro	34	31	33	36	37
ST Coal	263	255	220	161	114
CC	519	488	848	1016	1098
CT Oil	14	7	59	5	12
Nuclear	5	5	5	17	0
CT Other	4	2	9	4	9
ST Gas	27	32	16	7	9
Total startups	1398	1306	1927	1844	2053

Table 22: Average Number of starts by Resource Type

Average Number of Starts per Resource Type					
Type	Base 2022	Scenario 1	Scenario 2	Scenario 3	Scenario 4
CT Gas	20	18	34	33	43
Hydro	2	2	2	2	2
ST Coal	29	28	31	40	29
CC	87	81	106	102	110
CT Oil	1	1	5	3	6
Nuclear	2	2	2	6	na
CT Other	4	2	9	4	9
ST Gas	7	8	16	7	9
All Resources	17	16	27	32	37

Gas Usage was evaluates by comparing the scenario runs with forecast error and without forecast error. The difference in these two runs provide estimations of gas over and underutilization. Over utilization occurs when more gas is burned than anticipated in the forecast while underutilization occurs when less gas is burned. The gas day in this analysis begins at 9:00 am Central Time. The Fuel burned in each run (Forecast Error and No Forecast Error) was computed then compared to determine the gas day for over or under utilization. The number of gas days of over nomination increases as renewable penetration increases. The plots shown are created by ordering the over and under nomination days from low to high. The blip on each curve in Figure 35 shows the number of days a nomination is low or high in each Scenario.

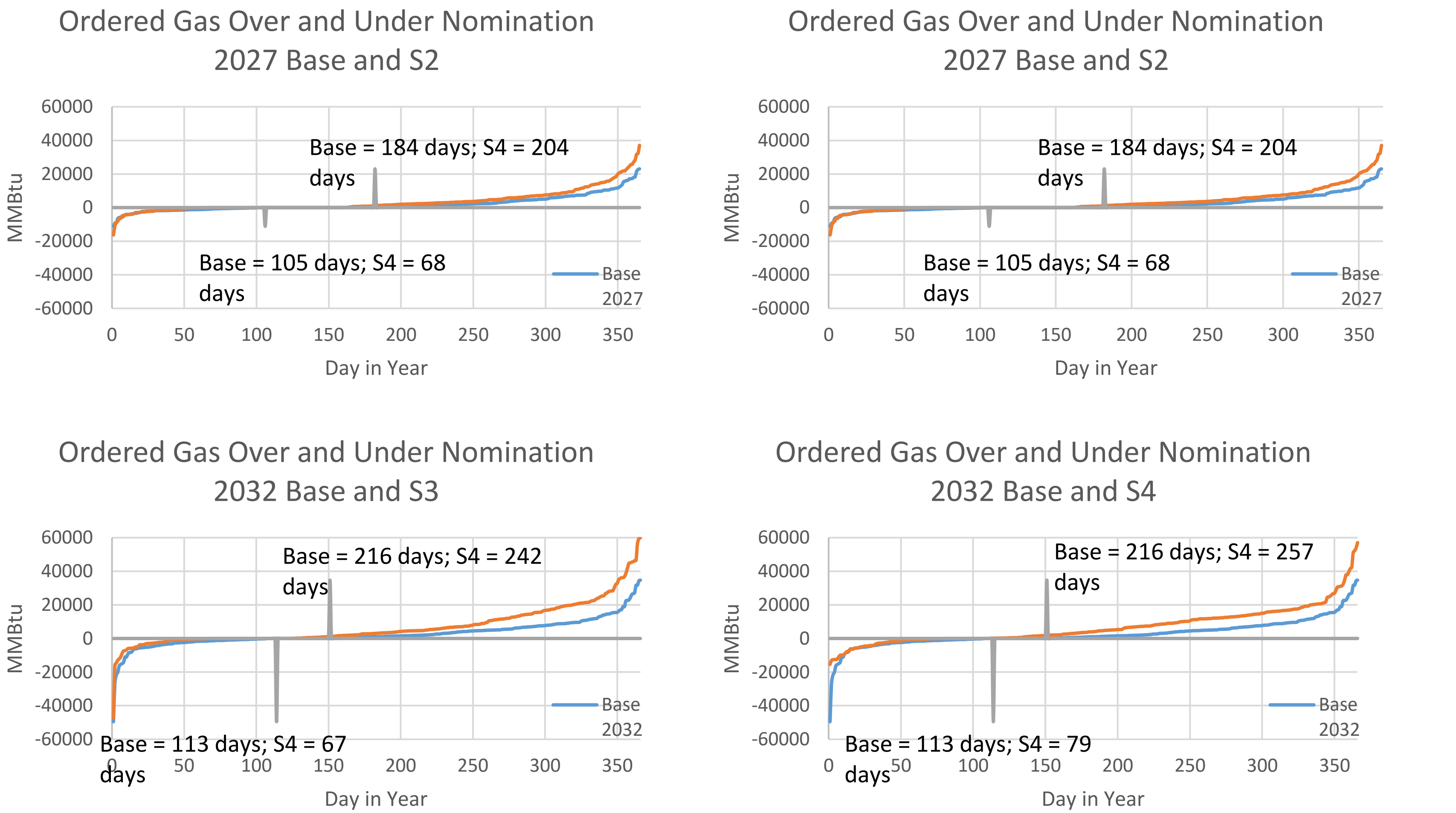

Figure 35: Over and Under Nomination for Gas Day

SECTION 9 CONCLUSIONS

The conclusions as well as findings and recommendations derived from this study are several.

- The average NSP production cost range is $22.99/MWH for the Base 2022 to $42.40/MWH for Scenario 4 (2013).
  - NSP is a net seller of power over the year in all studied scenarios.
  - Integration Cost due to forecast error ranges from 0.09 $/MWH to 0.55 $/MWH from Scenario 1 to Scenario 4.

Table 23: Summary of Project Production and Integration Costs

		Load and Production by Resource Type (GWh)				Production Cost ($/MWh)	Integration Cost Adder ($/MWh)	NSP Net Buyer/ Seller Position
Scenario	Year	NSP Load (GWh)	Wind Generation (GWh)	Solar Generation (GWh)	Other Resources (GWh)			
Base	2022	46,689	11,081	411	32,100	$22.99	---	Buyer
1	2022	46,689	17,185	2,263	31,260	$22.84	$0.09	Seller
2	2027	47,285	21,459	4,238	24,555	$27.24	$0.27	Seller
3	2032	47,888	22,795	6,122	26,906	$32.45	$0.55	Seller
4	2032	47,888	26,039	7,297	17,176	$42.40	$0.42	Seller

- Curtailment of wind and Solar PV increases as penetration increases; wind from 827,958 MWH to 1,853,498 MWH; solar PV from 46,326 MWH to 296,508, Table 24.
  - Wind energy production is greatest in the January through March months
  - Solar PV energy production is greatest in the April through September months.

Table 24: Summary of Projected Curtailment of Wind and Solar Resources

Wind and Solar Curtailment (GWh and % of resource production)				
Scenario	Wind Curtailment (GWh)	% of total Wind Production Curtailed	Solar Curtailment (GWh)	% of total Solar Production Curtailed
Base	126	1.1%	411	1.9%
1	827	4.8%	2,262	2.0%
2	1,109	5.2%	4,238	2.5%
3	1,575	6.9%	6,121	3.3%
4	1,853	7.1%	7,296	4.1%

- The number of hours of low net load increases as penetration increases, Table 25
  - The number of hours in the year when net load is less than 0 MW range from 179 hours in Scenario 1 (2022) to 2988 hours in Scenario 4 (2032).
  - The number of hours when net load is less than minimum load is significant ranging from 5035 hours in Scenario 1 (2022) to 6965 hours in Scenario 4 (2032).

Table 25: Summary of Projected Hours of Low Net Load

Scenario	Number of Hours of Net Load < 0 MW	% of Hours of Net Load < 0 MW	Number of Hours of Net Load < Minimum Load MW	% of Hours of Net Load < Minimum Load MW
1	179	2.0%	5035	57.5%
2	1078	12.3%	5766	65.8%
3	1664	19.0%	6294	71.8%
4	2988	34.1%	6965	79.5%

- Spinning reserves increase as renewable penetration increases from 65MW for the Base (2022) to 141 MW for Scenario 4 (2032), Table 26.
    - With these spinning reserve increases there are a few hours in the year when NSP would rely on MISO for support. 36 hours with in Scenario 1 (2022) and 139 hours in Scenario 4 (2032). The maximum spinning deficiency in an hour being 43 MW and 145 MW respectively.
    - This supports the argument that the MISO operating reserve requirements will need to increase in the future to support the higher levels of renewable penetration.

Table 26: Summary of Projected Spinning Reserve Requirements

	Average Spinning Reserve Requirements (MW)			# of Hours When NSP would Rely on MISO Support(*)
Scenario	Load (MW)	Renewable (MW)	Total (MW)	
Base	43	22	65	
1	43	47	90	36
2	43	62	105	65
3	43	73	116	105
4	43	98	141	139

The number of gas CT and CC resource startups increase as renewable penetration increases, but cost impacts are expected to be minimal,

- Table 27.
    - CT Gas and CC resource types increase production as renewable penetration Increases.
    - Cost impacts directly associated with unit retirements are expected to be minimal.

Table 27: Summary of Projected Annual Count of Resource Start-ups

	Number of Resource Startups over the Year				
	Base	Scenario 1	Scenario 2	Scenario 3*	Scenario 4*
CC	519	488	848	1,016	1,098
CT Gas	532	486	737	598	774
CT Oil	14	7	59	5	12
CT Other	4	2	9	4	9
ST Gas	27	32	16	7	9
ST Coal	263	255	220	161	114
Nuclear	5	5	5	17	0
Hydro	34	31	33	36	37
Total startups	1,398	1,306	1,927	1,844	2,053

(*) Coal Startups decrease largely due to unit retirements

- The number of days with over and under nomination of gas day requirements increase as penetration of renewables increase, but cost impacts are expected to be minimal, Table 28.

Table 28: Summary of Projected Natural Gas Nominations

		Natural Gas Nominations	
Year of Scenario Evaluated	(FE)Annual Production from Gas MWh	Number of days under nomination	Number of days over nomination
2022			
Base	4,215,562	73	152
Scenario 1	3,835,885	62	148
2027			
Base	9,057,391	105	184
Scenario 2	7,644,293	68	204
2032			
Base	12,749,560	113	216
Scenario 3	10,102,581	67	242
Scenario 4	13,194,566	79	257

- Results for NSP show benefits of operating within the MISO
  - This study examined NSP within the MISO as defined in the Continued Fleet Change scenario from the MTEP18 database.
  - Another study that examines NSP system as a standalone system could have different conclusions

PUBLIC DOCUMENT –
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Attachment E provided with the Not Public version of this response contains data classified as trade secret pursuant to Minn. Stat. §13.37 and are marked as "Not Public" in their entirety. Pursuant to Minn. R. 7829.0500, subp. 3, the Company provides the following description of the excised material:

1. **Nature of the Material**: Prepared study.
2. **Authors:** The study was prepared by Excel Engineering.
3. **Importance:** The study contains competitively sensitive data related to project costs.
4. **Date the Information was Prepared**: The study was prepared during the fourth quarter of 2018.

[TRADE SECRET BEGINS

TRADE SECRET ENDS]

Technical and Economic Potential for Combined Heat and Power (CHP) Applications in Xcel Energy's Minnesota Territory

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3002016990

Technical Update, June 2019

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Technical and Economic Potential for Combined Heat and Power (CHP) Applications in Xcel Energy's Minnesota Territory. EPRI, Palo Alto, CA: 2019. 3002016990.

ABSTRACT

Customer-sited fueled distributed generation (DG), often serving both heating and power needs, has served as a reliable source of distributed energy resources. A combination of technology improvements, project economics, policy incentives, and consumer choice in technology and energy service may impact the use of DG in the future. These changing needs and advancements have the potential to disrupt trajectories of load growth, driven by technical and economic decisions in technology adoption. Without adjustments to planning forecasts with respect to the driving factors, the forecasts may not adequately capture the range of load outcomes considered for system planning. The goal of this study is to estimate the technical and economic potential for commercial and industrial (C&I) combined heat and power (CHP) projects in the Minnesota service territory of Xcel Energy. Additionally, the expected market adoption for CHP is projected through 2039 with several sensitivity scenarios. This study serves as an update to a previous study performed in 2014.

Keywords
Distributed generation
Combined heat and power
CHP valuation
Microgrids
Reliability

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1
STUDY OBJECTIVE AND SUMMARY

This goal of this study is to estimate the technical and economic potential for commercial and industrial (C&I) combined heat and power (CHP) projects in the Minnesota service territory of Xcel Energy. Additionally, the expected market adoption for CHP was projected through 2039 with several sensitivity scenarios. This study serves as an update to a previous study performed in 2014.

As a first step, the technical potential for CHP in Xcel Energy's Minnesota territory was analyzed using customer data furnished by Xcel Energy. Data included commercial/industrial segment, maximum demand, and annual energy consumption for customers with maximum demands of 1 MW or larger. Power-to-heat ratios are estimated based on C&I segments and serve as input to the CHPower™[1] model to estimate the technical potential for CHP applications. The resulting technical potential is broken down by segment in Table 1-1.

Table 1-1
Technical Potential in Xcel Energy Minnesota (facilities with at least 1 MW peak demand)

Sector	Sites	Sum of Peak Demand (MW)	Technical Potential (MW)
Commercial	119	289	123
Industrial	120	492	196
Total	**239**	**781**	**319**

The 319 MW of technical potential from 239 sites is relatively small compared to the 941 MW of technical potential from 628 sites in the 2014 study. According to Xcel Energy, this difference was due to a combination of changes in data processing methods and customers implementing distributed energy resources and energy efficiency measures, resulting in lower peak demands.

After establishing the customers with technical potential for CHP, economics were analyzed using the CHPower Model™. Sites with economic potential (simple payback periods of less than 10 years) were broken down by payback period and sector, with the results shown in Table 1-2.

[1] ICF, CHPower Model. Fairfax, Virginia, 2019.

Table 1-2
Economic Potential in Xcel Energy Minnesota CHP, by Sector and Payback Period

	5-7 Years		7-10 Years		Total	
Sector	**Sites**	**Economic Potential (MW)**	**Sites**	**Economic Potential (MW)**	**Sites**	**Economic Potential (MW)**
Commercial	0	0	15	31	15	30
Industrial	<15	99	<15	16	19	115
Total	**<15**	**99**	**<30**	**47**	**34**	**145**

Overall there is an estimated 145 MW of economic potential CHP capacity that could achieve payback periods under 10 years. All of the economic potential came from sites capable of installing CHP sized larger than 1 MW. The economic potential in Minnesota is broken down by size range and payback period in Figure 1-1.

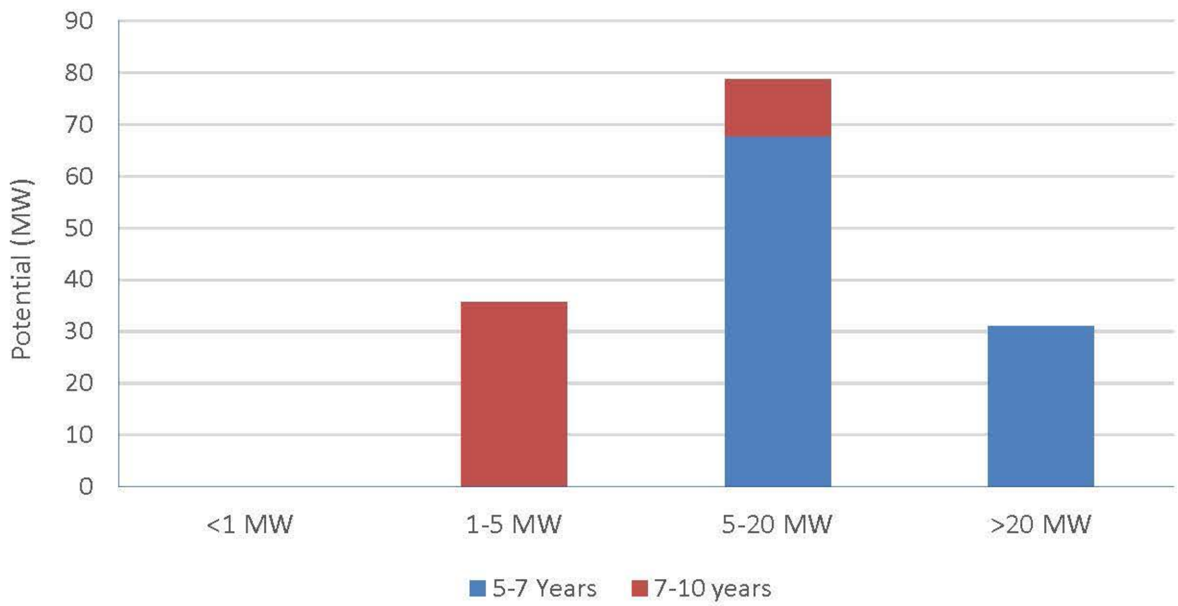

Figure 1-1
Economic Potential in Xcel Energy Minnesota by CHP Size Range and Payback

Out of the 145 MW of economic potential, 114 MW comes from industrial manufacturing facilities that tend to require a payback of less than five years on their energy investments in order to move forward with a project. For most of these customers, some form of large incentive would need to be available or they would need to have a high resilience need before they would consider installing a CHP system.

A market adoption analysis through 2039 was performed, and the base case results show 43 MW of total adoption (see Figure 1-2).

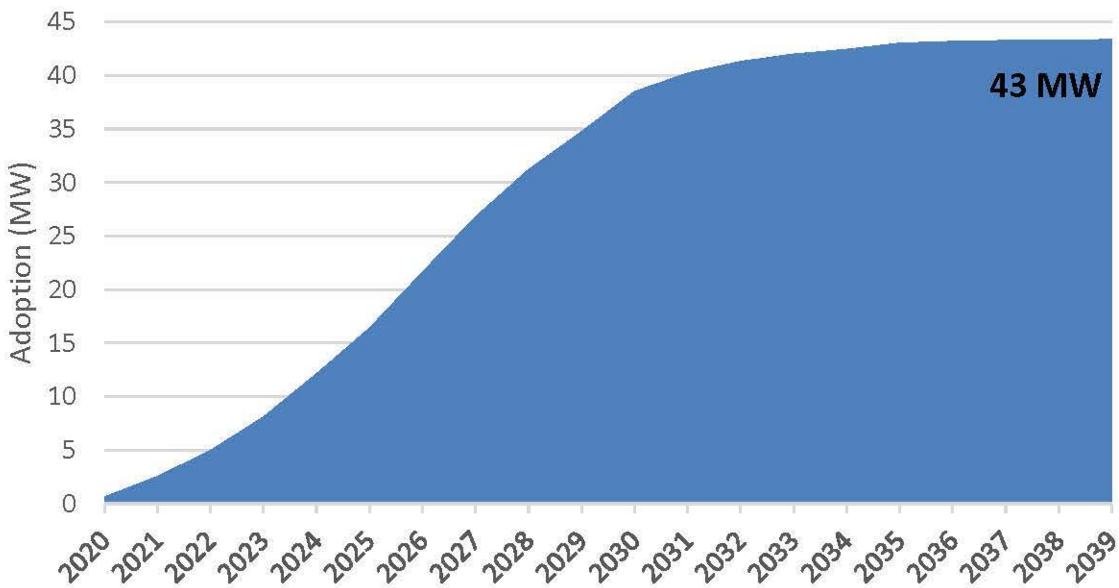

Figure 1-2
Estimated CHP Market Adoption in Minnesota through 2039

Sensitivities

Several sensitivities were performed for this analysis, including capital cost reductions, elimination of standby charges, and alternate electricity and natural gas escalation rates. The results were as follows:

- **Capital cost reduction** – At a 10% capital cost reduction for CHP installations, which mimics the current federal Investment Tax Credit, the overall impact on economic potential and market adoption was fairly minimal. At 30%, the economics for all sites improved, with economic potential increased by 50 MW and expected market adoption increased by 36 MW.
- **Eliminating standby charges** – This improved project economics for all facilities, reducing the payback period for several sites. The economic potential increased by 23 MW, but stronger long-term economics from the elimination of these charges would make facilities more likely to adopt, increasing estimated market adoption by 18 MW.
- **Using EIA escalation rates for electricity and natural gas** – Compared to Xcel Energy's internal forecasts, the EIA escalation rates are less favorable for CHP applications because they have natural gas prices increasing faster than electricity prices – total estimated market adoption decreased by 2 MW.
- **Simulating lower natural gas rates** – Instead of the natural gas escalation rate provided by Xcel Energy, there was no price escalation applied to natural gas rates. This improved CHP project economics, leading to a 9 MW increase in the estimated 20-year market adoption.

For all sensitivity scenarios considered, the total range of CHP market adoption through 2039 was between 41 MW and 79 MW. The results of the estimated 20-year market adoption for each sensitivity scenario are summarized in Table 1-3.

Table 1-3
Market Adoption in Xcel Energy Minnesota CHP, by Sensitivity Scenario

Sensitivity Scenario	Estimated 20-Year Adoption (MW)
Base Case	43
10% Capital Cost Reduction	52
30% Capital Cost Reduction	79
No Standby Charges	61
EIA Escalation Rates	41
Low Natural Gas Prices	52

Finally, the impact on carbon dioxide emissions was examined for both the base case market adoption and the 30% installed cost reduction sensitivity, to show how a relatively large CHP incentive might affect carbon emissions. With the expected CHP adoption, 42,000 tons of CO_2 would be reduced on an annual basis for the base case, compared to 66,000 tons with a 30% capital cost reduction.

Key Takeaways

The following are important findings from the analysis:

- Technical potential: 319 MW across 239 sites.
- Economic potential for base case: 145 MW of CHP, based on Xcel Energy forecasts for electricity/gas escalation, with payback periods ranging from 5 to 10 years.
- Market adoption: 43 MW is anticipated to be adopted through 2039 in the base case, with 39 MW being installed by 2030.
- A 30 percent cost reduction, in the form of a tax credit or grant, would have a large impact on economics, adding 36 MW of expected adoption through 2039, for a total of 79 MW.
- Removing standby rates improves payback periods, adding 18 MW of adoption through 2039.
- CHP installations could lead to a significant reduction in greenhouse gas emissions compared to separate heat and utility power, although emissions will decline over time as the grid becomes cleaner.
- There may be potential benefits to be explored or considered by offering utility-owned CHP systems to large customers with high CHP potential.

2
ASSESSMENT OF DG AND CHP TECHNICAL AND ECONOMIC POTENTIAL IN XCEL ENERGY'S MINNESOTA TERRITORY

As an update to a 2014 assessment of DG and CHP potential, this study aims to provide information on the projected impacts of natural gas-fueled DG and CHP applications in Xcel Energy's service areas, focusing on the large C&I customer base in the Minnesota service territory.

The objectives of the study were to:

- Estimate and analyze technical and economic potential for natural gas distributed generation in C&I end user applications.
- Identify key C&I segments where DG CHP applications could be cost effective for end-users.
- Evaluate the impact of sensitivity scenarios on expected market adoption.
- Present findings and results for the Minnesota service territories.

The focus of this study is on natural gas CHP applications that can utilize waste heat to displace site thermal loads. CHP systems are more efficient and economical than power-only generators. The 2014 study found that natural gas generators in Minnesota were not economical unless they incorporated heat recovery and utilization in a CHP configuration. Additionally, most C&I facilities with significant electric requirements also have a sizable thermal demand that can be served by CHP.

Technical Potential

This study estimated the technical potential for natural gas CHP applications in Xcel Energy's Minnesota service territory. Facility counts and sizes were provided by Xcel Energy, using actual customer data for electric demand (kW) and annual electricity consumption (kWh). This data, along with industry-specific thermal load estimates, is used to approximate the potential size for baseload CHP systems at each customer site. The data was anonymized so that customer names and addresses were not provided. The resulting technical potential estimates are broken down by market sector in Table 2-1.

Table 2-1
Technical Potential in Xcel Energy Minnesota (facilities with at least 1 MW peak demand)

Sector	Sites	Sum of Peak Demand (MW)	Technical Potential (MW)
Commercial	119	289	123
Industrial	120	492	196
Total	**239**	**781**	**319**

The 319 MW of technical potential from 239 sites is relatively small compared to the 941 MW of technical potential from 628 sites in the 2014 study. According to Xcel Energy, this difference was due to a combination of changes in data processing methods and customers implementing distributed energy resources and energy efficiency measures, resulting in lower peak demands.

Based on the economic CHP sizing, over half of these sites could only support CHP systems smaller than 1 MW in size. In this size range, equipment costs are higher on a per-kW basis, so project economics tend to not be as strong. The technical potential in Minnesota (based on economic CHP sizing) is broken down by size range in Table 2-2.

Table 2-2
Technical Potential in Xcel Energy Minnesota by Sector and CHP Size Range

	<1 MW		1-5 MW		5-20 MW		>20 MW	
Sector	**Sites**	**Technical Potential (MW)**	**Sites**	**Technical Potential (MW)**	**Sites**	**Technical Potential (MW)**	**Sites**	**Technical Potential (MW)**
Commercial	76	37	42	75	<15	11	0	0
Industrial	79	29	33	68	<15	68	<15	31
Total	**155**	**66**	**75**	**143**	**<30**	**79**	**<15**	**31**

All of these facilities were analyzed for economic potential, to determine how many sites would be capable of a 10-year or less payback period.

Economic Potential

Installed capital cost, maintenance costs, and performance information for the CHP systems were provided by EPRI from a Request for Information process that was deployed for the recent national study, using typical price and performance data for CHP units across three different size ranges[2]:

1. 100 – 1,000 kW (Medium Commercial/Light Industrial)
2. 1,000 – 5,000 kW (Large Commercial/Medium Industrial)
3. > 5,000 kW (Large Industrial)

The costs were adjusted to reflect inflation rates since the data was provided in 2014.[3] The price and performance data for engines, turbines and fuel cells in these size ranges are shown in Table 2-3.

[2] EPRI Report Natural Gas Distributed Generation Options Cost and Market Benchmarking Assessment 3002004191, October 2014.

[3] 6.1% inflation applied from 2014 to 2018 (US Inflation Calculator, https://www.usinflationcalculator.com); 1.9% 2018 inflation applied annually to 2020 (analysis starts in 2020).

Table 2-3
Price and Performance Data Used in Economic Analysis[4]

	100 - 1,000 kW			1 - 5 MW		5 - 50 MW	
	Engine	Fuel Cell	MT	Engine	Turbine	Engine	Turbine
Installed Cost ($/kW)	$3,310	$6,610	$3,080	$1,980	$2,420	$1,210	$1,380
Maintenance ($/kWh)	0.022	0.028	0.012	0.018	0.020	0.011	0.010
Electric Efficiency (HHV)	29.0%	45.0%	27.0%	37.0%	34.0%	41.0%	32.0%
CHP Efficiency (HHV)	79.0%	83.0%	65.0%	80.0%	68.0%	77.0%	74.0%

The Federal Investment Tax Credit for CHP – scheduled to ramp down from 10% (current rate) to 6% in 2021 and 0% after – was not incorporated into the economic potential results. State average natural gas prices[5] and Xcel Energy's current electricity tariffs were inputs to the model which estimated electricity bills before and after CHP is installed, considering the effect of standby charges, demand charges, and time-of-use components. Then, the installed cost of CHP was compared to the net annual savings when considering maintenance, fuel purchases, and energy bill savings. Economics were analyzed on a site-by-site basis using ICF's CHPower Model™, with the full assumptions and methodology outlined in Appendix A.

Overall, 145 MW of economic potential was found in Xcel Energy's Minnesota service territory, with 99 MW showing payback periods in the range of 5-7 years and the remainder in the range of 7-10 years. Economic potential comes from a mixture of large manufacturing facilities, mining operations, paper mills, chemical plants, commercial office buildings, and other commercial facilities. The results are broken down by sector and payback period range in Table 2-4.

Table 2-4
Economic Potential in Xcel Energy Minnesota by Sector and Payback Period Range

	5-7 Years		7-10 Years		Total	
Sector	Sites	Economic Potential (MW)	Sites	Economic Potential (MW)	Sites	Economic Potential (MW)
Commercial	0	0	15	31	15	30
Industrial	<15	99	<15	16	19	115
Total	**<15**	**99**	**<30**	**47**	**34**	**145**

All of the economic potential comes from sites capable of installing CHP sized larger than 1 MW. While the economics for hospitals and college campuses may not be as strong as large industrial facilities, they have typically been more willing to take on longer payback periods. Industrial facilities tend to require payback periods under five years. For hospitals and college

[4] EPRI Report Natural Gas Distributed Generation Options Cost and Market Benchmarking Assessment 3002004191, October 2014.

[5] The lower of the average industrial gas rate or average citygate price plus $1/MMBtu (EIA average 2017 prices)

campuses, their future is more certain than industrial sites, and they may take on projects with payback periods up to 10 years. Figure 2-1 provides a graphical representation of the economic potential by segment and payback period.

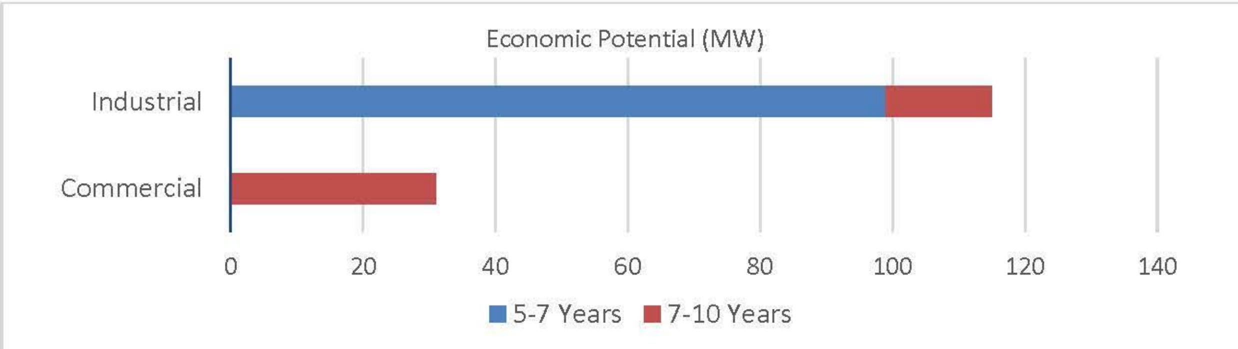

Figure 2-1
Economic Potential in Xcel Energy Minnesota by Sector and Payback Period

The economic potential in Xcel Energy's Minnesota territory is broken down by size range and payback period in Figure 2-2. It should be noted that all of the potential in the >20 MW range comes from fewer than 15 facilities.

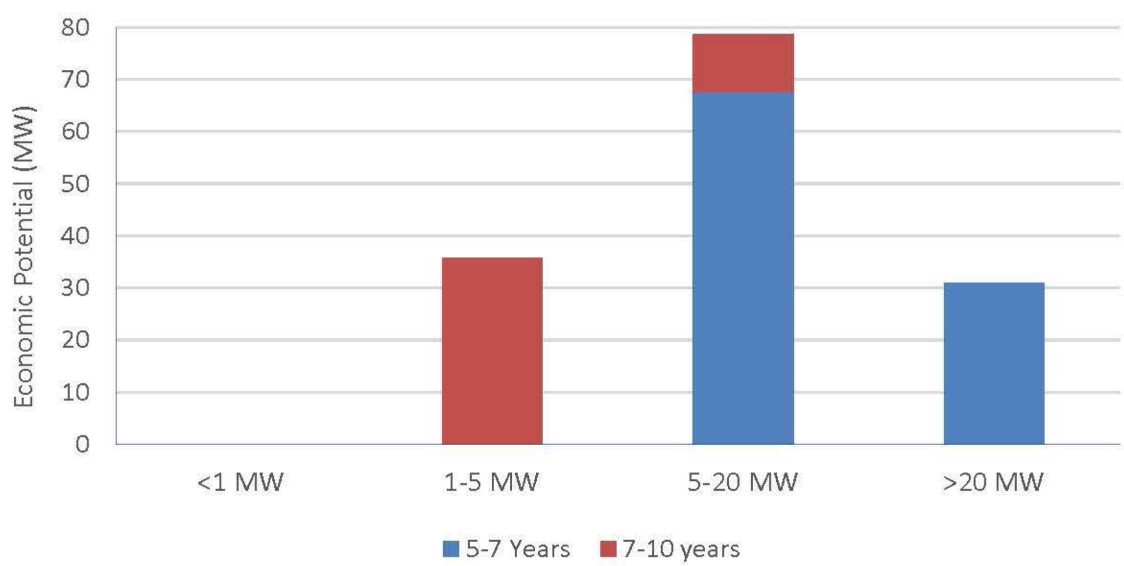

Figure 2-2
Economic Potential in Xcel Energy Minnesota by CHP Size Range and Payback Period

The economic potential analysis showed that project economics are strongest at large, high load factor facilities.

Market Adoption Analysis

The CHPower model™ can estimate the expected adoption of CHP over time. First, market acceptance percentages are applied to each potential installation, based on the sector and payback period. Facility owners in the commercial (and institutional) sectors are more likely to accept projects with longer payback periods compared to industrial facility owners. Market acceptance curves were developed based on a combination of survey results (including the Primen survey used in the 2014 analysis[6]), interviews with current and potential CHP customers, and experience in the marketplace. The market acceptance curves are shown in Figure 2-3.

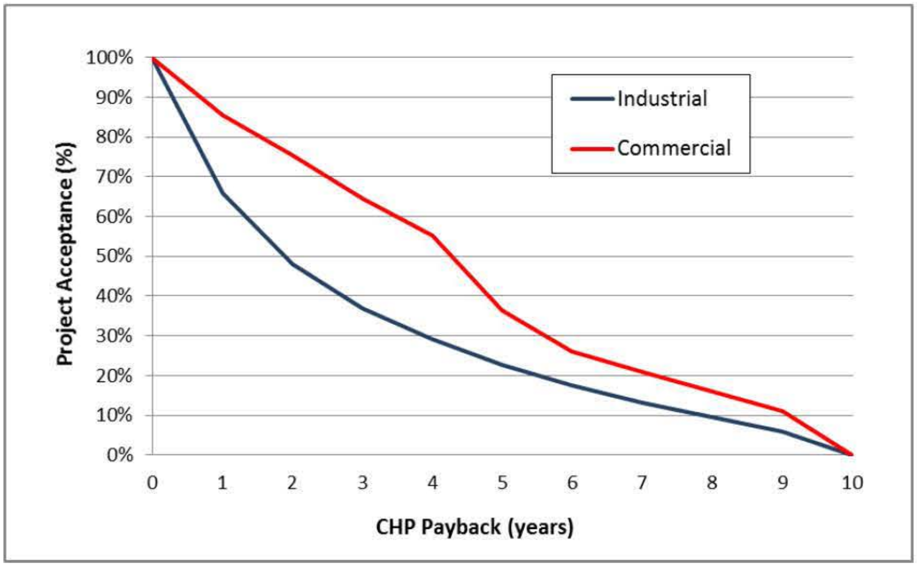

Figure 2-3
Market Acceptance Curves by Payback Period and Sector

The market-accepted potential defines the boundaries of CHP adoption, based on current market conditions. To estimate adoption over time, the model applied a Bass Diffusion model, which includes electricity and natural gas rate escalation with Xcel Energy-provided data, along with industry-specific market growth estimates from the 2018 EIA Annual Energy Outlook.[7] Market adoption was estimated on an annual basis with these changing factors built into the CHPower model calculations. The results for the base case scenario are shown in Figure 2-4, with an estimated 43 MW of CHP adoption from 2020 through 2039.

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[6] *Converting Distributed Energy Prospects into Customers*, Primen, December 2003 (EPRI Number 1010294)

[7] U.S. Energy Information Administration, Annual Energy Outlook, 2018, https://www.eia.gov/outlooks/archive/aeo18/

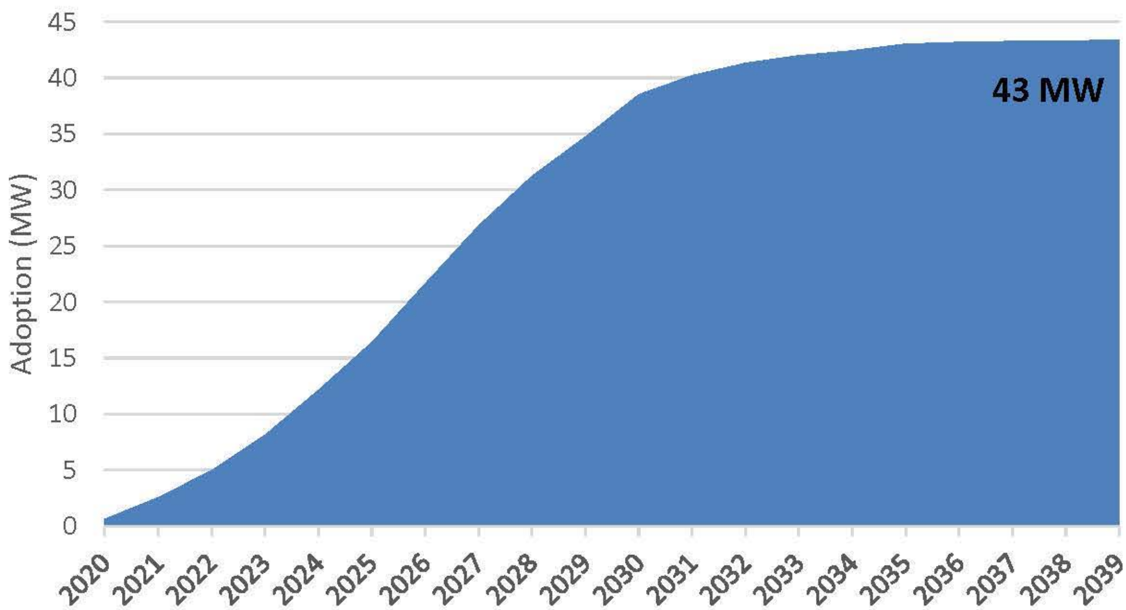

Figure 2-4
Xcel Energy Minnesota Base Case Market Adoption Through 2039

The majority of expected adoption occurs between 2020 and 2030. After 2030, adoption slows due to market limitations and less favorable economics from higher gas prices. Most of this adoption occurs in fewer than 15 sites. Figure 2-5 shows the estimated 20-year adoption by CHP size range. Overall, fewer than 15 sites are expected to adopt CHP, mostly within the 1-5 MW size range.

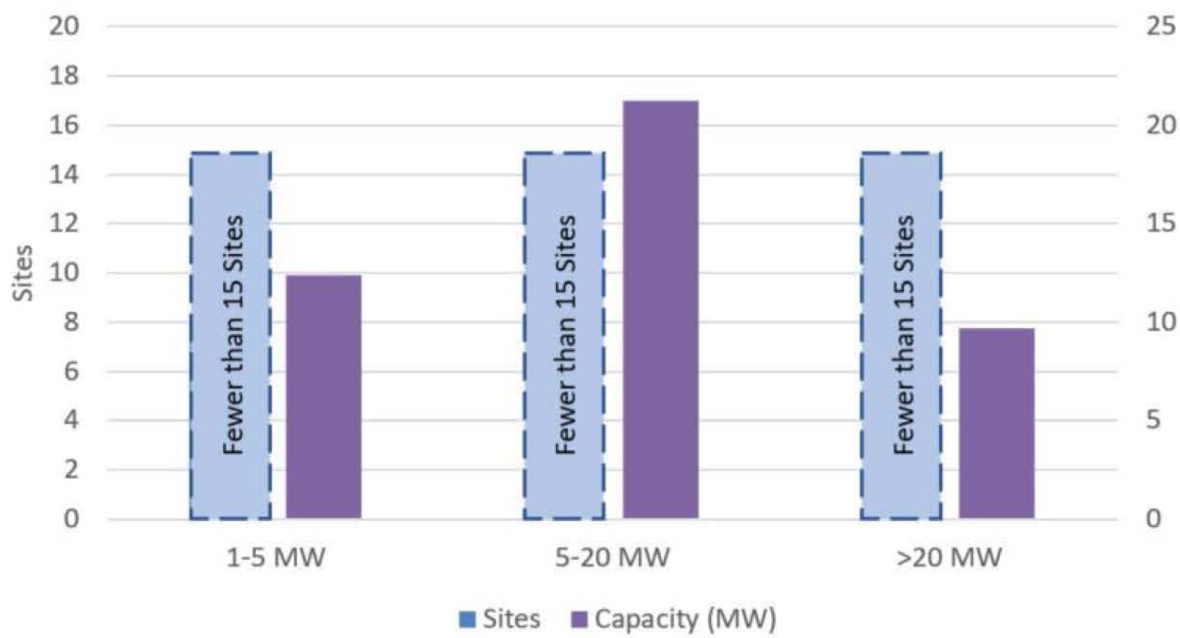

Figure 2-5
Xcel Energy Minnesota Base Case Market Adoption through 2039 by CHP Size Range

Sensitivity Analysis

Five sensitivities were performed for this analysis:

1. capital (installed) costs reduced by 10 percent to show the effect of a CHP incentive
2. capital (installed) costs reduced by 30 percent to show the effect of a larger CHP incentive
3. removal of standby charges
4. using EIA escalation rates for electricity and natural gas
5. removing the escalation of natural gas prices

For each sensitivity, the effects on economic potential and estimated market adoption are shown.

Sensitivity: 10% Installed Cost Reduction

The first sensitivity reduced the installed cost of CHP systems by 10 percent, representing a small government or utility capital incentive. With a 10 percent capital cost reduction, there is a modest increase of 7 MW of economic potential, all found in sites 1-5 MW in size. This new economic potential is found in manufacturing facilities, commercial buildings, colleges/universities, and hotels. While there was not much of an increase in economic potential, the 10 percent cost reduction shortens the payback period of the existing economic potential, moving 65 MW of potential to a payback period under five years (all in sites above 5 MW). The economic potential for this sensitivity is broken down by sector and payback period in Table 2-5.

Table 2-5
Sensitivity: Economic Potential in Xcel Energy Minnesota with 10% CHP Cost Reduction

	<5 Years		5-7 Years		7-10 Years		Total	
Sector	**Sites**	**Economic Potential (MW)**	**Sites**	**Economic Potential (MW)**	**Sites**	**Economic Potential (MW)**	**Sites**	**Economic Potential (MW)**
Commercial	0	0	<15	14	16	21	19	35
Industrial	<15	65	<15	41	<15	11	21	118
Total	**<15**	**65**	**<30**	**55**	**<30**	**32**	**40**	**153**

With a 10 percent capital cost reduction applied, there is a more noticeable change to the total estimated market adoption compared to the total economic potential. Under this sensitivity, expected market adoption increases from 43 MW to 52 MW through 2039, following a similar trend as the base case. The new 20-year market adoption curve with the 10 percent cost reduction can be seen in Figure 2-6.

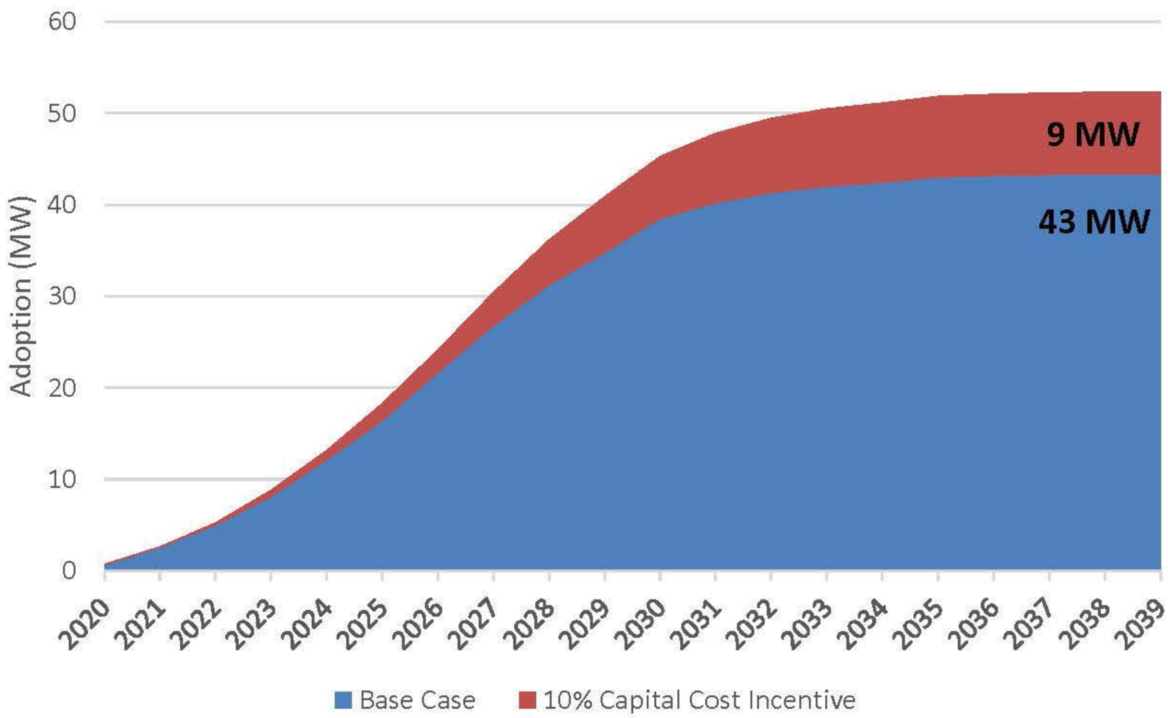

Figure 2-6
Sensitivity: Market Adoption through 2039 with 10% CHP Cost Reduction

Sensitivity: 30% Installed Cost Reduction

The next sensitivity reduced the installed cost of CHP systems by 30 percent, representing incentives similar to those from a larger government or utility capital incentive. With a 30 percent capital cost reduction, there is a much larger impact on economic potential – a total increase of 50 MW. This new economic potential is found in sites 1-5 MW in size across several industrial and commercial sectors. The 30 percent cost reduction also shortens the payback period of much of the existing economic potential. Nearly all of the economic potential at sites larger than 5 MW would now have payback periods under 5 years. The economic potential for this sensitivity is broken down by sector and payback period in Table 2-6.

Table 2-6
Sensitivity: Economic Potential in Xcel Energy Minnesota with 30% CHP Cost Reduction

	<5 Years		5-7 Years		7-10 Years		Total	
Sector	**Sites**	**Economic Potential (MW)**	**Sites**	**Economic Potential (MW)**	**Sites**	**Economic Potential (MW)**	**Sites**	**Economic Potential (MW)**
Commercial	0	0	15	31	16	30	31	61
Industrial	<15	99	<15	16	<15	20	28	134
Total	**<15**	**99**	**<30**	**47**	**<30**	**50**	**59**	**195**

Using a 30 percent capital cost reduction, there is also a large change to the total estimated market adoption. As expected, the additional expected market adoption is more than double that provided by the 10 percent capital cost reduction. Under this sensitivity, expected market adoption increases from 43 MW to 79 MW through 2039, the largest expected market adoption under any of the sensitivities. The new 20-year market adoption curve with the 30 percent cost reduction can be seen in Figure 2-7.

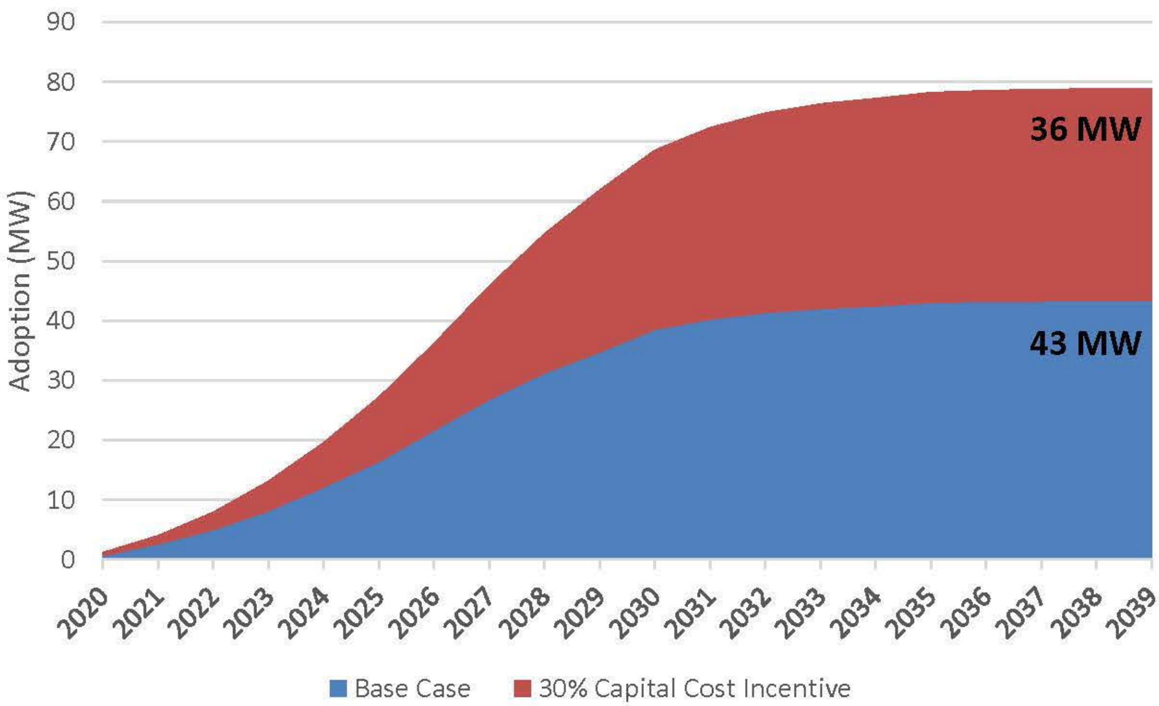

Figure 2-7
Sensitivity: Market Adoption through 2039 with 30% CHP Cost Reduction

Sensitivity: Removal of Standby Charges

Standby charges were modeled using the contract demand charge, assuming all maintenance occurs on a scheduled basis, and no unscheduled downtime or maintenance for the CHP unit that would add additional charges. The contract demand charges, in dollars per kW of CHP system size, are:

- $3.00 per kW for customers receiving service at secondary voltage (assumed to be sites with a maximum demand of less than 3,000 kW),
- $2.20 per kW for customers receiving service at primary voltage (maximum demand of 3,000 – 30,000 kW), or
- $0.65 per kW for customers receiving service at transmission-level voltage (maximum demand of 30,000 kW or higher).

There is a further reduction in standby charges for customers at the sub-transmission level, but for the purposes of this analysis, all customers were assumed to be on either secondary or primary voltage lines.

When the standby charges were removed, economics were improved, resulting in more economic potential and shorter payback periods. 23 MW of economic potential was added in the state, all at sites under 5 MW. Additionally, many of the large industrial facilities over 5 MW that were in the 5-7 year payback range have shifted to <5 year paybacks. The economic potential with no standby charges is presented by segment and payback period in Table 2-7.

Table 2-7
Sensitivity: Economic Potential in Xcel Energy Minnesota with No Standby Charges

	<5 Years		5-7 Years		7-10 Years		Total	
Sector	Sites	Economic Potential (MW)	Sites	Economic Potential (MW)	Sites	Economic Potential (MW)	Sites	Economic Potential (MW)
Commercial	0	0	<15	14	19	25	22	39
Industrial	<15	65	<15	41	<15	23	26	130
Total	**<15**	**65**	**<15**	**55**	<40	**48**	**48**	**169**

The removal of standby charges had a greater impact on market adoption trends than on the economic potential of sites, due to the longer-term benefits of reducing these costs. Under this sensitivity, expected market adoption increases from 43 MW to 61 MW through 2039. The new 20-year market adoption curve without standby rates can be seen in Figure 2-8.

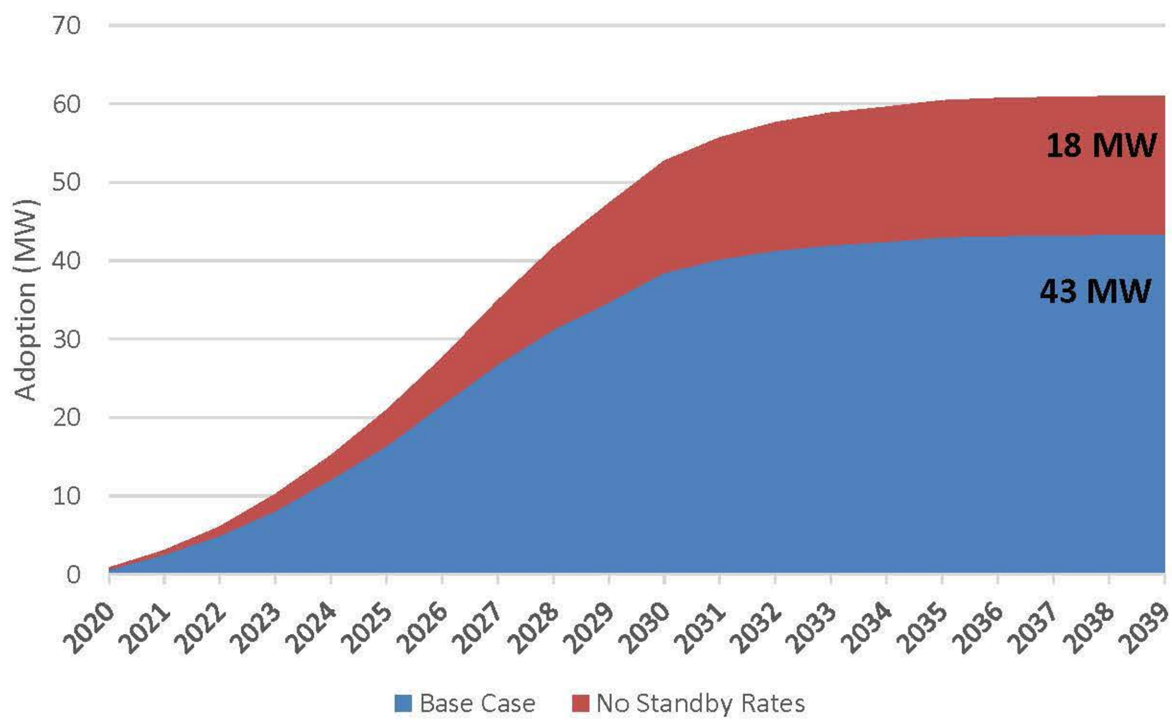

Figure 2-8
Sensitivity: Market Adoption through 2039 with No Standby Charges

Sensitivity: EIA Escalation Rates

Instead of the energy price escalation rates provided by Xcel Energy, the Energy Information Administration's projected escalation rates from the 2019 Annual Energy Outlook were used. With the EIA rates, both electricity (2.23%, compared to 2.70%) and natural gas (3.30%, compared to 4.15%) are projected to escalate at slower rates, leaving little impact on the base case results. This showed in the economic analysis, where there was no change in the economic potential compared to the base case.

However, using the EIA escalation rates did impact the expected 20-year market adoption. Because of the drop in electricity price growth, the economics for CHP projects worsened, leading to a small drop in the estimated adoption. Under this sensitivity, expected market adoption decreased from 43 MW to 41 MW through 2039. The new 20-year market adoption curve with the EIA escalation rates can be seen in Figure 2-9.

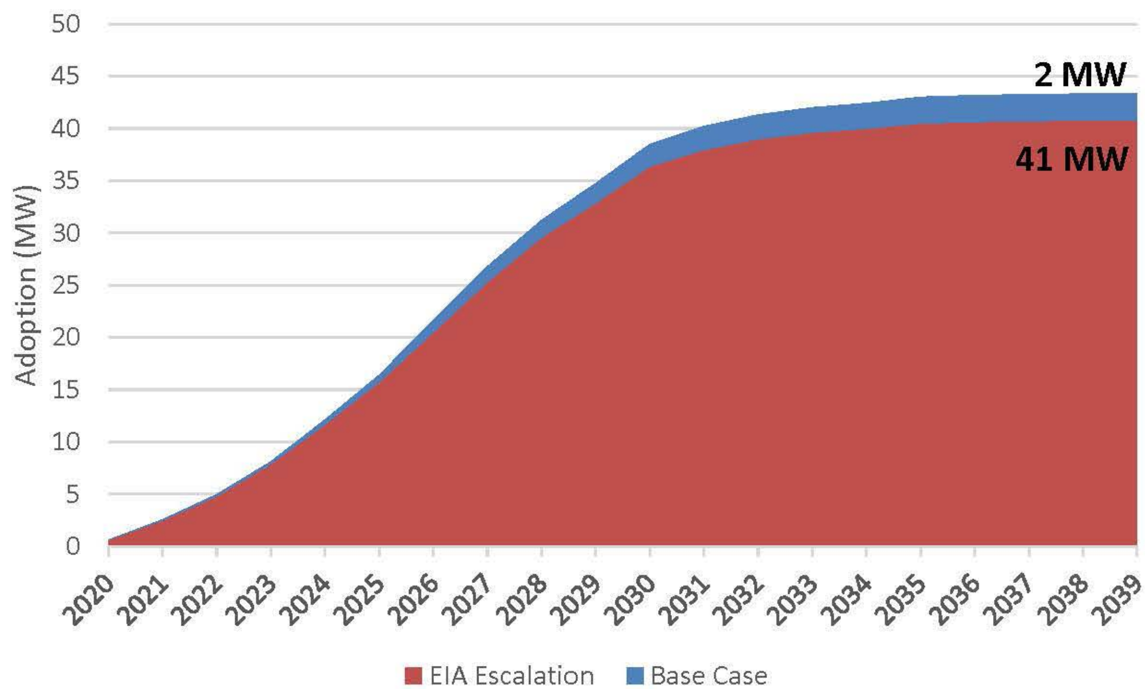

Figure 2-9
Sensitivity: Market Adoption through 2039 with EIA Escalation Rates

Sensitivity: Low Natural Gas Prices

Instead of using the natural gas escalation rate provided by Xcel Energy, there was no price escalation applied to natural gas rates in this sensitivity analysis, to mimic the impact of natural gas prices remaining lower than projected. This had no impact on the economic potential, with no difference in potential from the base case.

However, like with the EIA escalation rates, there was an impact on the expected 20-year market adoption. As expected, with lower gas prices, the economics for CHP projects improves, resulting in a sizeable increase in the estimated adoption. Under this sensitivity, expected market adoption increased from 43 MW to 52 MW in 2039. The new 20-year market adoption curve with low natural gas prices can be seen in Figure 2-10.

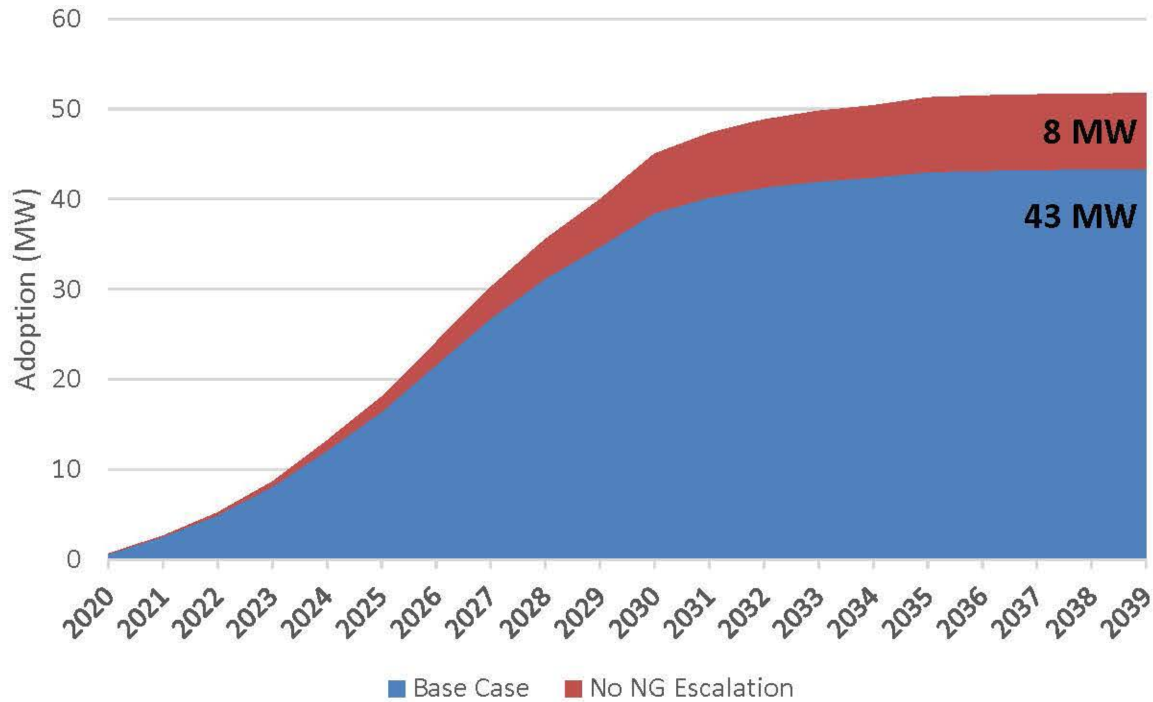

Figure 2-10
Sensitivity: Market Adoption through 2039 with Low Natural Gas Prices

Impact of Adopted CHP on CO_2 Emissions

Efficient CHP systems have a positive impact on CO_2 emissions compared to separate heat and utility power. When a baseload CHP system comes online, demand is reduced and utilities turn down fossil fuel generators in response. For baseload CHP, EPA guidance is to use the eGRID average fossil fuel emissions rate for displaced utility electricity.[8] For Minnesota, the average fossil fuel emissions rate is estimated at 1,854 lbs/MWh. In addition, transmission and distribution line losses produce an average loss of 5.13 percent for delivered electricity. For the customer, natural gas combustion – both for CHP fuel and boiler fuel – produces approximately 117 lbs CO_2 per MMBtu of fuel consumed. However, Xcel Energy recently announced an initiative to become 100 percent carbon-free by 2050, so the grid mix is expected to change significantly over the next twenty years. Between 2030 and 2040, Xcel Energy is expected to retire its coal plants, leaving only natural gas generators to accompany zero-emission nuclear/hydro/renewable resources.

[8] U.S. Environmental Protection Agency, Combined Heat and Power Partnership, Fuel and Carbon Dioxide Emissions Savings Calculation Methodology for Combined Heat and Power Systems, February 2015, https://www.epa.gov/chp/fuel-and-carbon-dioxide-emissions-savings-calculation-methodology-combined-heat-and-power

These factors were combined to develop an estimate of potential emission reductions from expected CHP deployments, both for the base case and the 30% capital cost reduction scenario. The results of this analysis are shown in Figure 2-11. The dotted lines represent the estimated emissions savings using current marginal utility emission rates, while the solid lines represent the estimated emissions savings with Xcel Energy's planned reductions in fossil fuel generation.

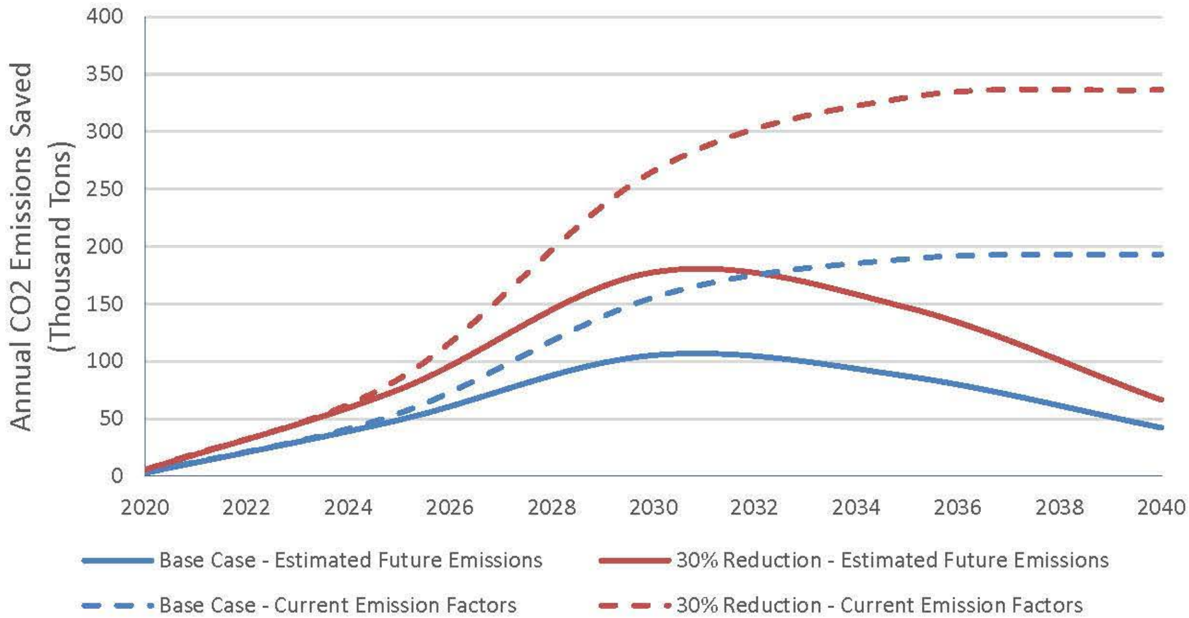

Figure 2-11
Annual Impact of Adopted CHP on Carbon Dioxide Emissions by 2040

Considering the potential impact on CO_2 emissions with 43 MW of base case adoption, an estimated 42,000 tons of CO_2 would be reduced on an annual basis by 2040, down from a maximum of approximately 108,000 tons in 2031. Looking at the increased adoption from deploying a 30 percent cost reduction, a total of 66,000 tons of CO_2 would be avoided on an annual basis by 2040, down from a maximum of 180,000 tons in 2031. While emissions reductions from CHP will be lessened over time compared to Xcel Energy's cleaner grid, there is still expected to be a significant amount of greenhouse gas savings from CHP installations that are installed over the next ten years.

3
CONCLUSION

This study estimates a total of 319 MW of technical potential from 239 sites and 145 MW of economic CHP potential in Xcel Energy's Minnesota service territory. Under current market conditions, large facilities that can install CHP systems over 5 MW in size have the strongest project economics for CHP applications, with payback periods ranging from 5-7 years. Project economics are not attractive for most potential industrial customers, who tend to desire payback periods of five years or less, so CHP adoption is likely to be a relatively slow process in these segments. Under the base case scenario, about 43 MW of adopted CHP is expected through 2039.

When installed costs for CHP systems are reduced by 30 percent, some sites can achieve payback periods below five years, and an additional 36 MW of CHP would likely be adopted through 2039. Removing standby rates has a positive effect on project economics, with an additional 18 MW of expected adoption. Using the EIA's predicted escalation rates for the U.S., the estimated 20-year adoption is reduced from 43 MW to 41 MW. Finally, low natural gas prices over the next 20 years would lead to a modest increase in estimated adoption, from 43 MW to 52 MW.

Overall, the effect of CHP adoption on Xcel Energy's Minnesota territory should be relatively modest in the foreseeable future given current conditions, with economics not strong enough to encourage more widespread adoption. State or utility incentives could speed up adoption, but the ceiling for total economic CHP potential is currently estimated to be less than 150 MW. Even at this relatively modest adoption rate, customers switching to self-generation through CHP can impact current load growth forecasts. There may be potential benefits to be explored or considered by offering utility-owned CHP systems to large customers with high CHP potential. There are a growing number of utilities who are developing rate-based utility owned CHP systems at customer sites to provide customers with energy cost savings on thermal energy, increased resilience, and economic development opportunities.[9]

[9] Utility CHP – A Least Cost Baseload Resource. https://www.icf.com/resources/white-papers/2017/utility-chp-ownership

A
ASSUMPTIONS AND METHODOLOGY FOR CHPOWER MODEL

The CHPower Model

The market analysis of DG/CHP systems was performed using ICF's CHPower Model[10]. This spreadsheet-based model is used to evaluate the technical, economic, and market potential for combined heat and power (CHP) applications across the United States and Canada. The model determines which combination of size, rate schedule, and operating mode is the most economical, and forecasts the commercial and industrial facilities most likely to install CHP systems based on cash flows and simple payback. The model also determines the cumulative CHP market penetration over an analysis timeframe, and provides long-term market forecast for CHP systems operating in commercial, institutional, and industrial sectors. The database of sites for use in the model was provided by Xcel Energy. Figure A-1 illustrates how the CHPower model organizes the key data inputs, performs calculations, and generates the desired outputs.

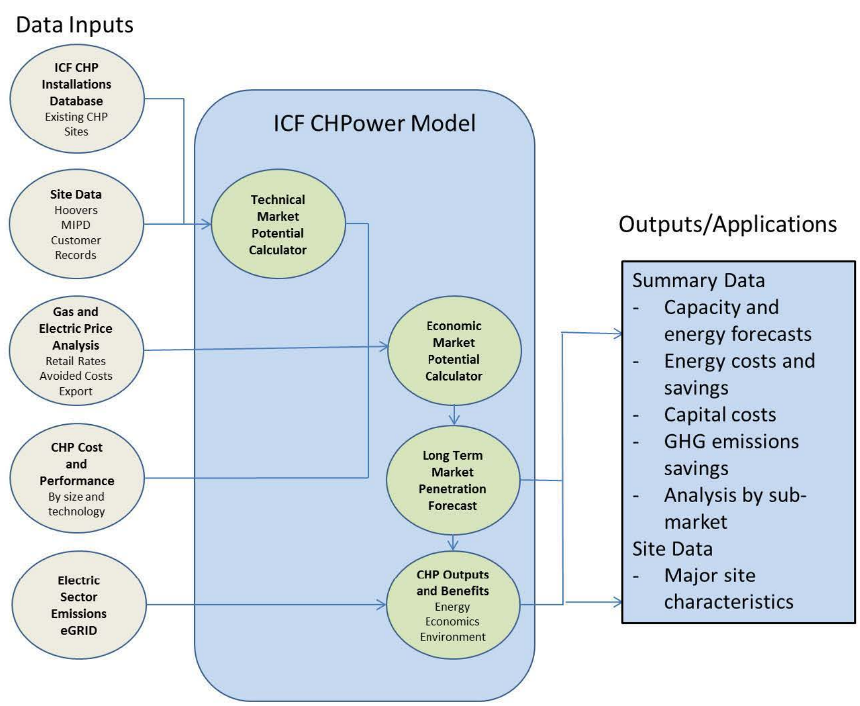

Figure A-1
CHPower Model

[10] ICF, CHPower Model. Fairfax, Virginia, 2019.

The CHPower model has been used for a variety of different geographic, economic, and technical scenarios on projects for utilities, equipment manufacturers, and research organizations. For this effort, the CHPower model was configured to:

- Evaluate the potential for CHP in Xcel Energy's Minnesota and Colorado territory with provided customer data
- Examine the potential for DG/CHP applications at a variety of commercial and industrial sites
- Process the costs and benefits for each DG/CHP unit at each site (versus utility power) and determine the DG/CHP system with the optimal payback period for each site that is analyzed for five different sensitivity scenarios
- Forecast CHP adoption over the 20-year analysis timeframe in Xcel Energy's Minnesota and Colorado territory
- Calculate estimated CO_2 emissions reductions for each site and for each sensitivity over the analysis timeframe

Key Inputs and Assumptions

There are four main components of the model are as follows:

- **Technical Potential Calculator** – Customer data from Xcel Energy was converted into site-by-site estimates of CHP potential using a series of relationships between building type and electric and thermal use.
- **Economic Potential Calculator** – For each site, the simple payback period is calculated based on the appropriate CHP system and energy rates for that system size and application. The payback determines the likelihood that a particular system will be installed by the site.
- **Market Acceptance** – The market acceptance factor or propensity to participate and is based on a national survey of potential CHP customers. The sum of the technical potentials multiplied by the market acceptance factors represents the total market potential – or the estimated quantity of CHP that will ultimately enter the market.
- **Long Term Market Penetration Forecast** – Based on the economic potential estimates, the market penetration over a 10-25 year time horizon is estimated using a diffusion model that provides a realistic representation of how the economic potential will enter the market over time.
- **CHP Outputs and Benefits** – Summary and detailed outputs for each forecast/scenario are characterized including cumulative and annual estimates of market penetration, net effect on gas and electricity consumption, customer economic savings, and emissions both at the site and avoided from the electric power grid.

CHPower has several primary inputs necessary in order to run the model. The key inputs are:

1. Electricity Prices (modeled Xcel Energy rates)
2. Natural Gas Prices (EIA)
3. CHP Technical Potential (Xcel Energy customer data)
4. Market Growth Rates (EIA Annual Energy Outlook (AEO 2018) market sector growth rates)

5. CHP Cost and Performance Assumptions (EPRI)
6. Market Acceptance and Bass Diffusion for expected deployments (ICF)

Key Assumptions Made for Xcel Energy Minnesota

Key assumptions for the DIPSERSE model in this analysis for Xcel Energy are provided in Table A-1, with a comparison to assumptions used in the 2014 analysis.

Table A-1
Assumptions Used for 2019 Analysis (compared to 2014)

Model Inputs	2014 Assumptions/Data	2019 Assumptions/Data
Cost/Performance	2014 EPRI National CHP Assessment	2016 DOE Fact Sheets (or 2014 EPRI Assessment)
Federal ITC	10% reduction for capital costs	10% reduction for capital costs
Discount Rate	7 percent	Simple payback calculation – taxes and depreciation are not applied
Depreciation Schedule	10 year straight line	
Tax Percentage	35 percent	
Property Taxes, Insurance	35 percent	
Natural Gas Pricing	2013 average prices – lower of state average industrial price or city gate price plus $1/MMBtu	2018 average prices – lower of state average industrial price or city gate price plus $1/MMBtu
Natural Gas Escalation	Provided by Xcel Energy	Probided by Xcel Energy
Electricity Pricing	Based on Xcel Energy's latest electricity tariff	Based on Xcel Energy's latest electricity tariff
Electricity Escalation	Provided by Xcel Energy	Provided by Xcel Energy
Standby Service	Contract demand charges for secondary (<3,000 kW) and primary (>3,000 kW) service customers	Contract demand charges for secondary (<3,000 kW) and primary (>3,000 kW) service customers
Value of Backup Power	$0	$0
Part-Load Efficiency	Reductions to 50% of peak load, based on load profile following	DG/CHP sized to operate near full-load, switch to standby during low-load periods
DG Maintenance Escalation	2 percent	N/A (not expected to escalate beyond inflation)
Commercial Load Profiles	Generated from DOE2model building simulations and matched to consumer sites	Annual hours of operation applied to average loads, CHP utilization percentage from load shape
Industrial Load Profiles	Weekday/weekend load shapes collected from representative facilities, matched to consumer sizes	Annual hours of operation applied to average loads, CHP utilization percentage from load shape
CO_2 Emission Reductions	Average Xcel Energy emission rates as of 2014 applied throughout 15-year analysis timeframe	Marginal Xcel Energy emission rates, adjusted over the 20-year analysis period based on plans to reduce fossil fuel generation (100% carbon free by 2050)

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