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

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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

CONTENTS

LIST OF FIGURES

LIST OF TABLES

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.

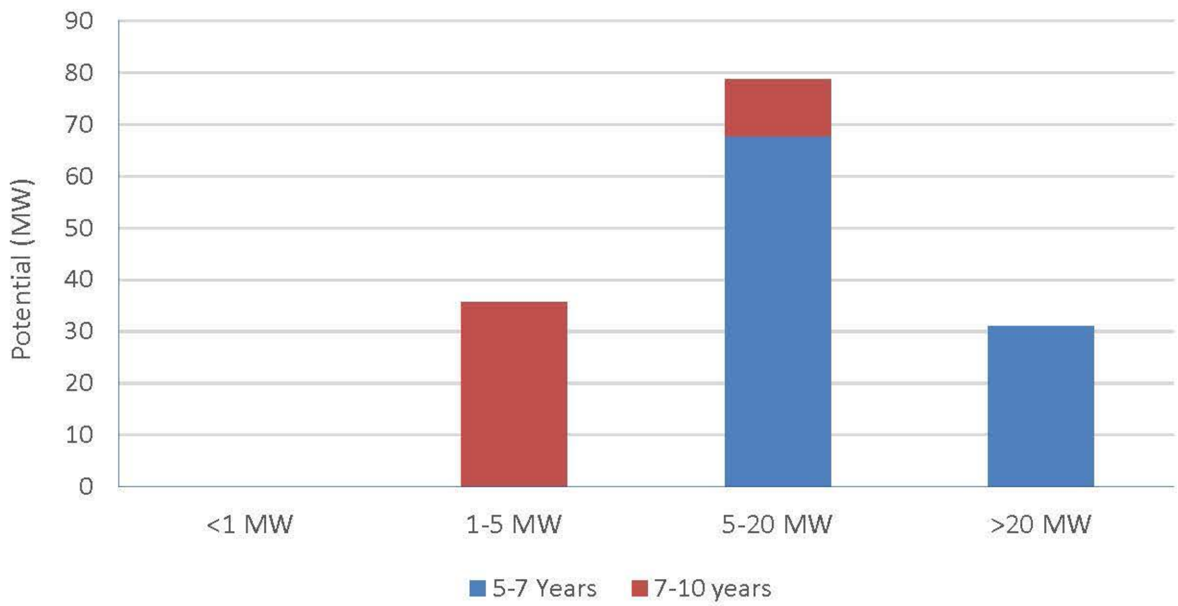

Figure 1-1
Economic Potential in Xcel Energy Minnesota by CHP Size Range and Payback

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).

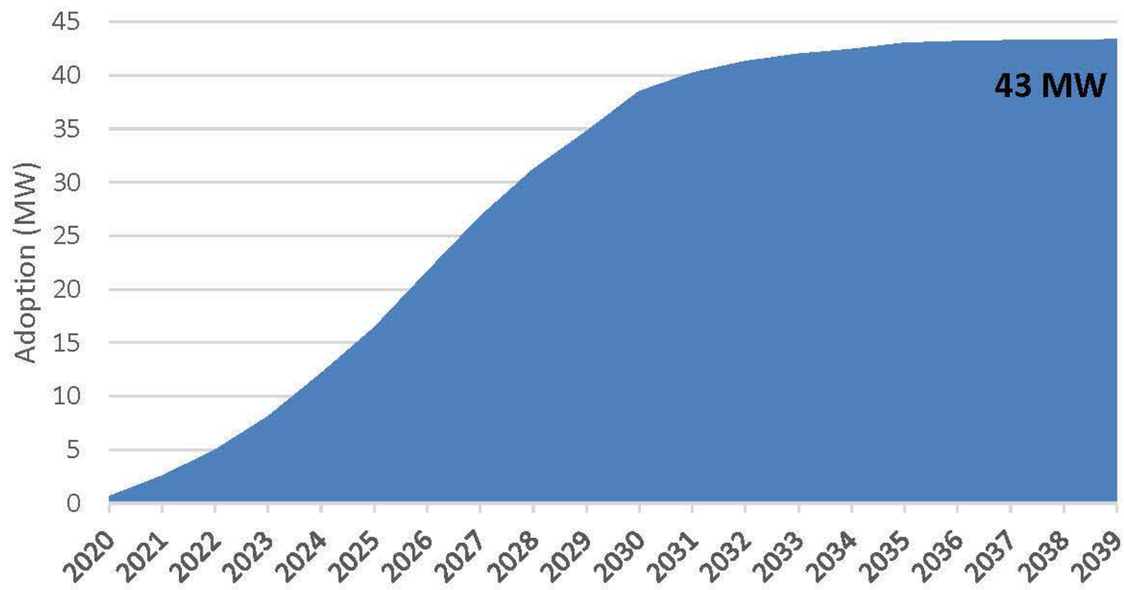

Figure 1-2
Estimated CHP Market Adoption in Minnesota through 2039

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

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[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.

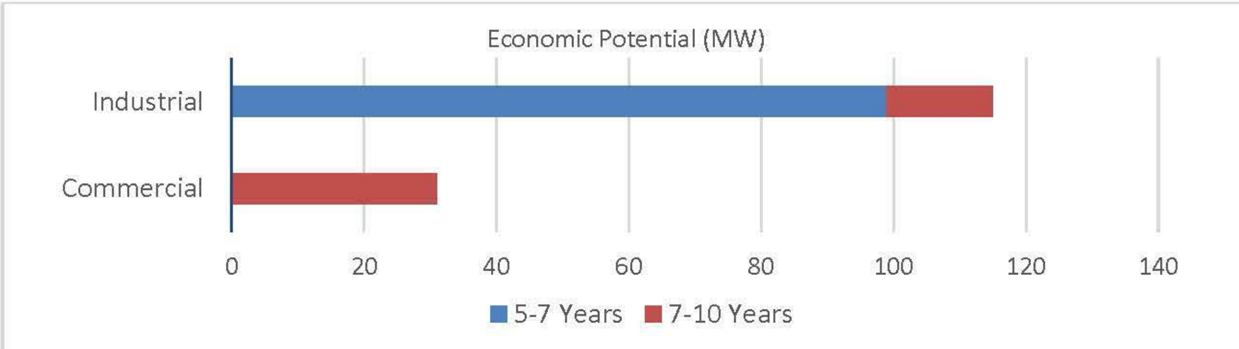

Figure 2-1
Economic Potential in Xcel Energy Minnesota by Sector and Payback Period

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.

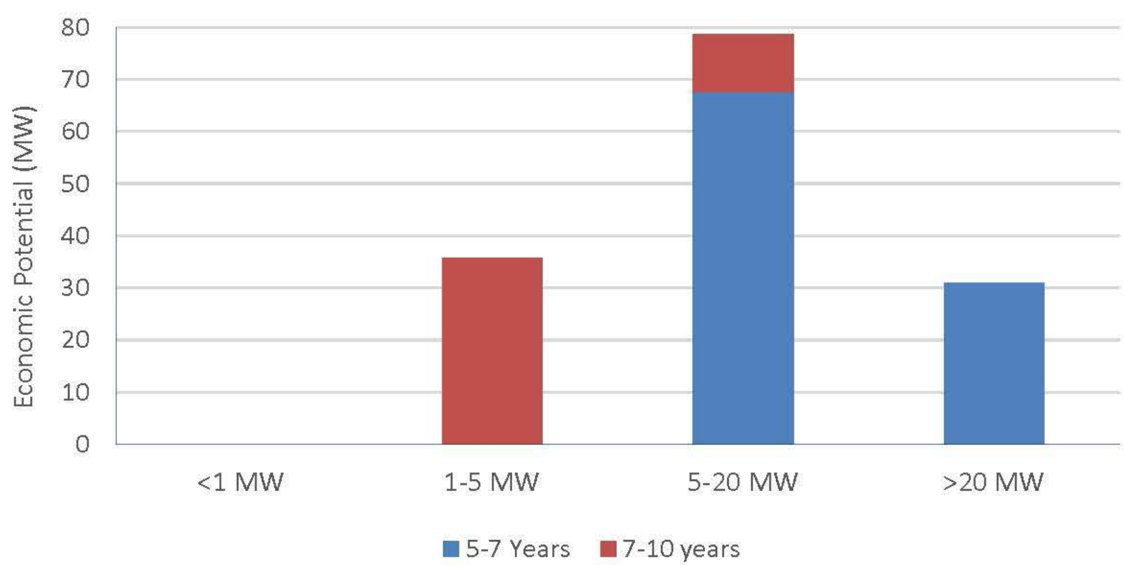

Figure 2-2
Economic Potential in Xcel Energy Minnesota by CHP Size Range and Payback Period

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.

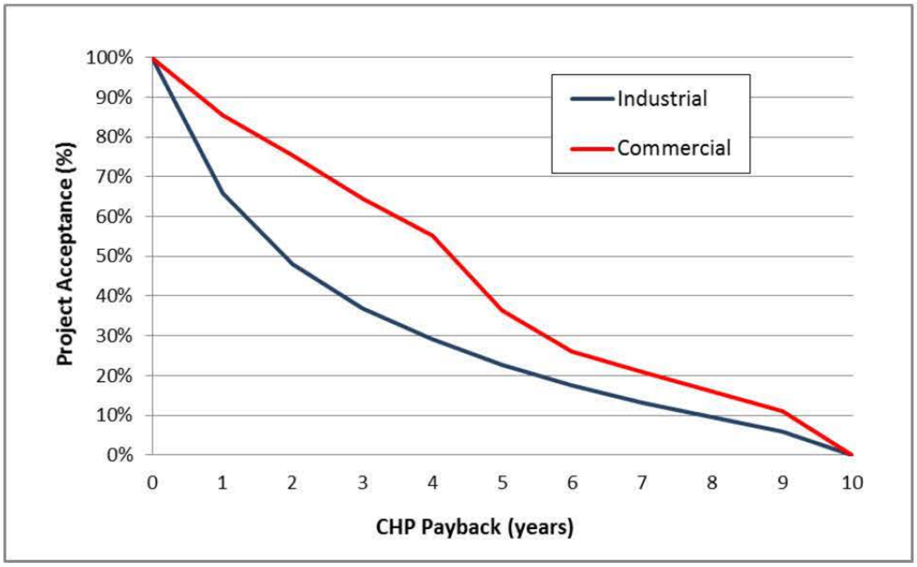

Figure 2-3
Market Acceptance Curves by Payback Period and Sector

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/

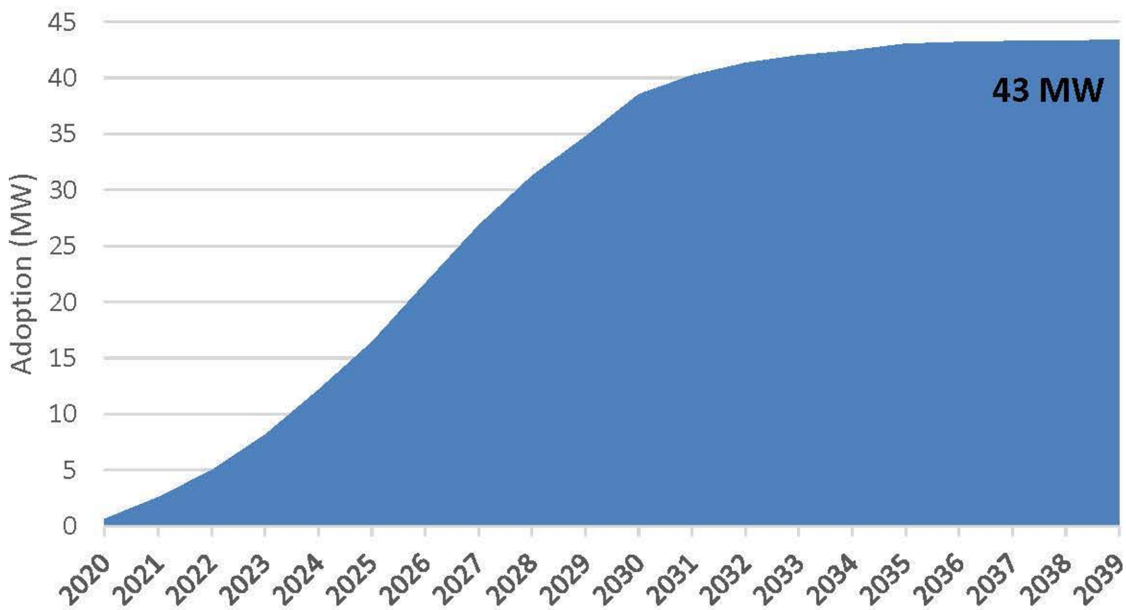

Figure 2-4
Xcel Energy Minnesota Base Case Market Adoption Through 2039

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.

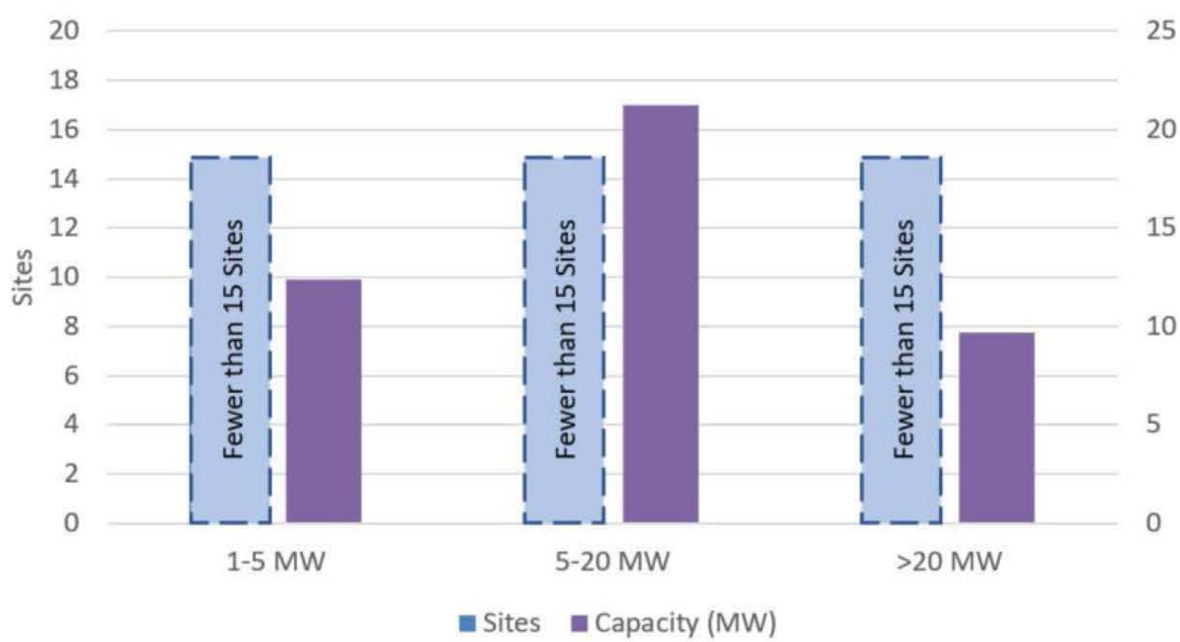

Figure 2-5
Xcel Energy Minnesota Base Case Market Adoption through 2039 by CHP Size Range

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.

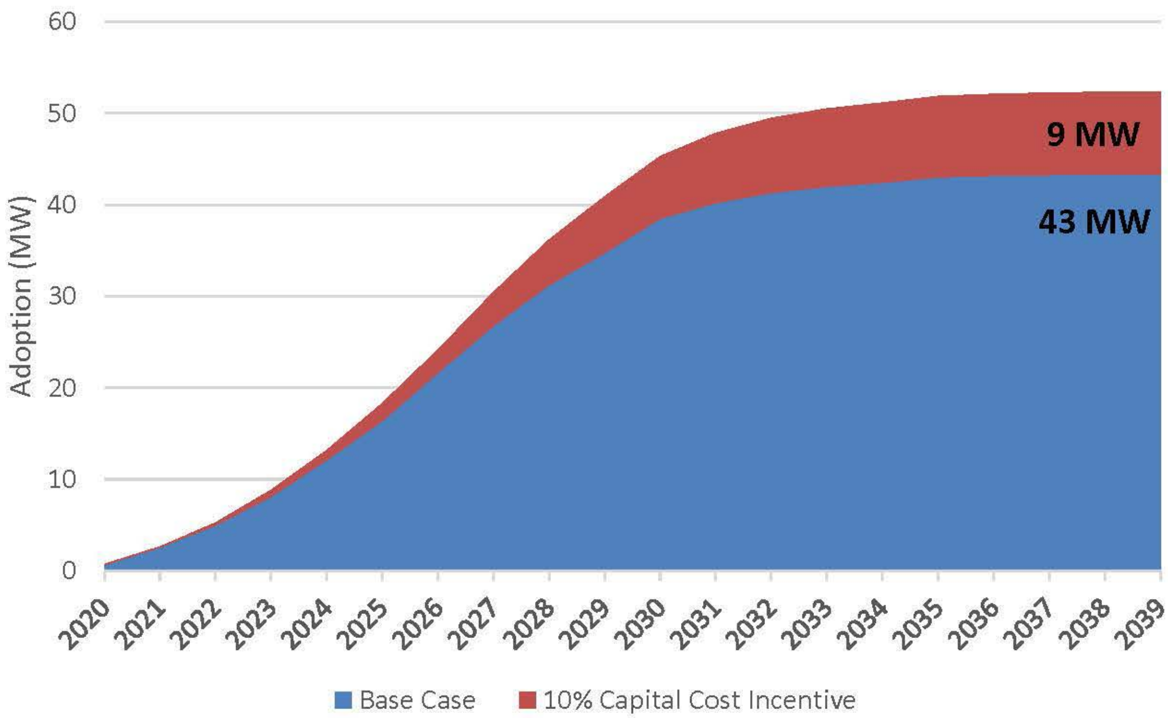

Figure 2-6
Sensitivity: Market Adoption through 2039 with 10% CHP Cost Reduction

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.

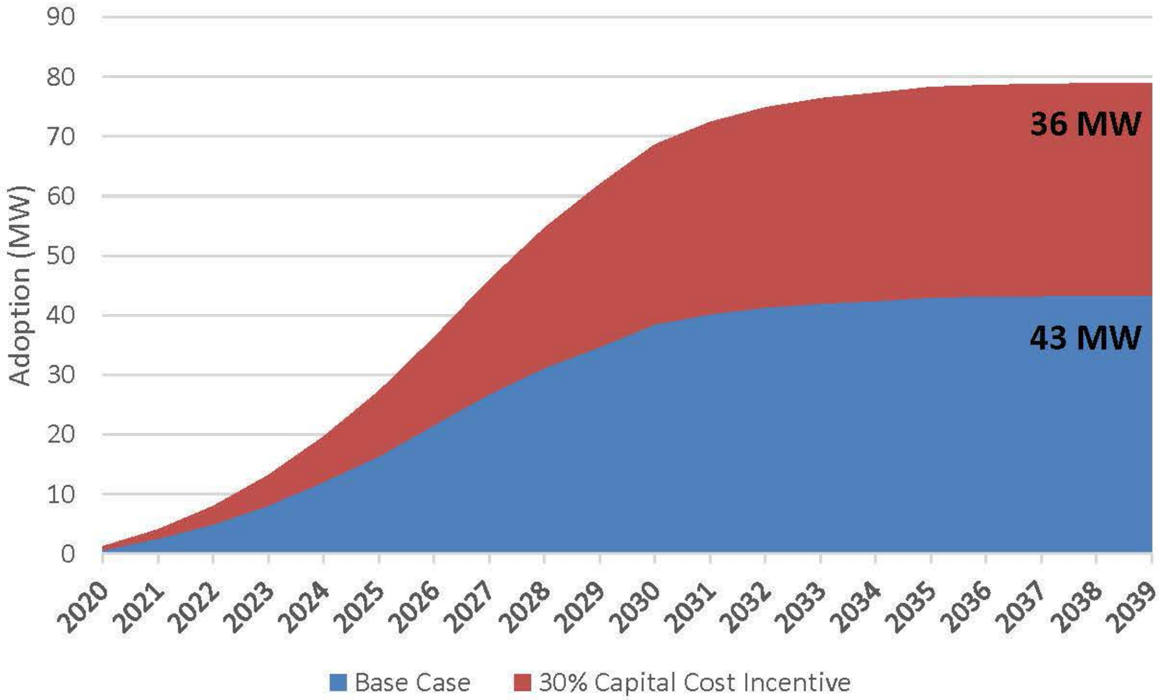

Figure 2-7
Sensitivity: Market Adoption through 2039 with 30% CHP Cost Reduction

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.

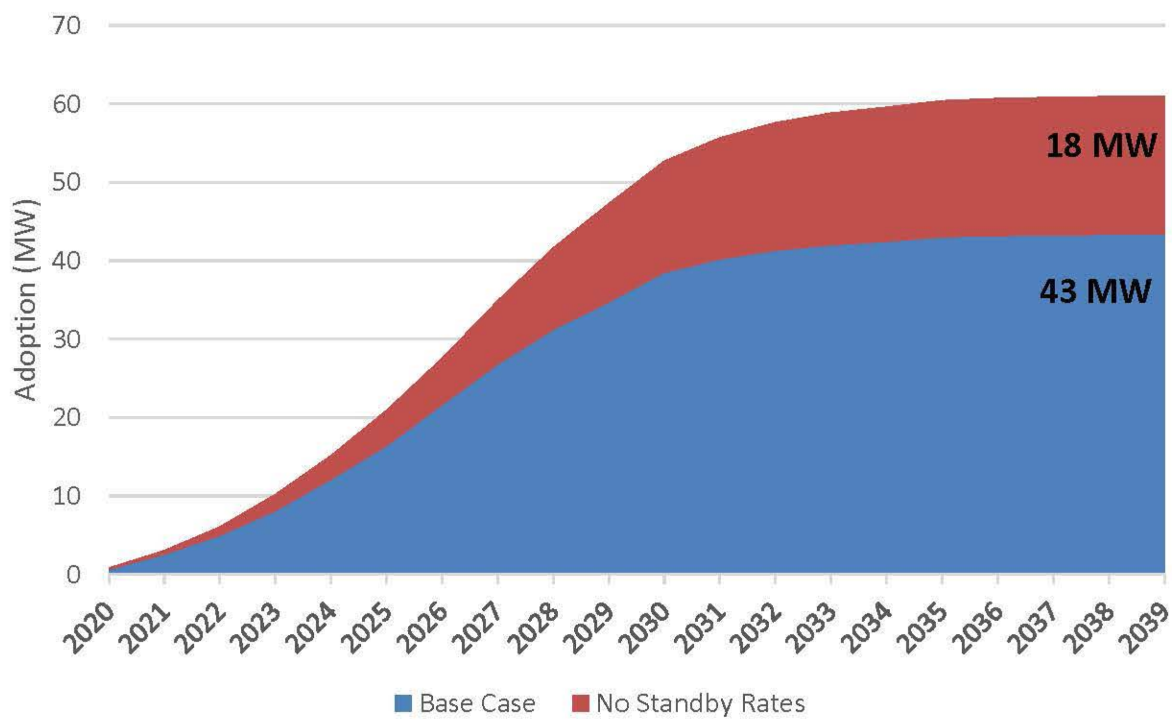

Figure 2-8
Sensitivity: Market Adoption through 2039 with No Standby Charges

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.

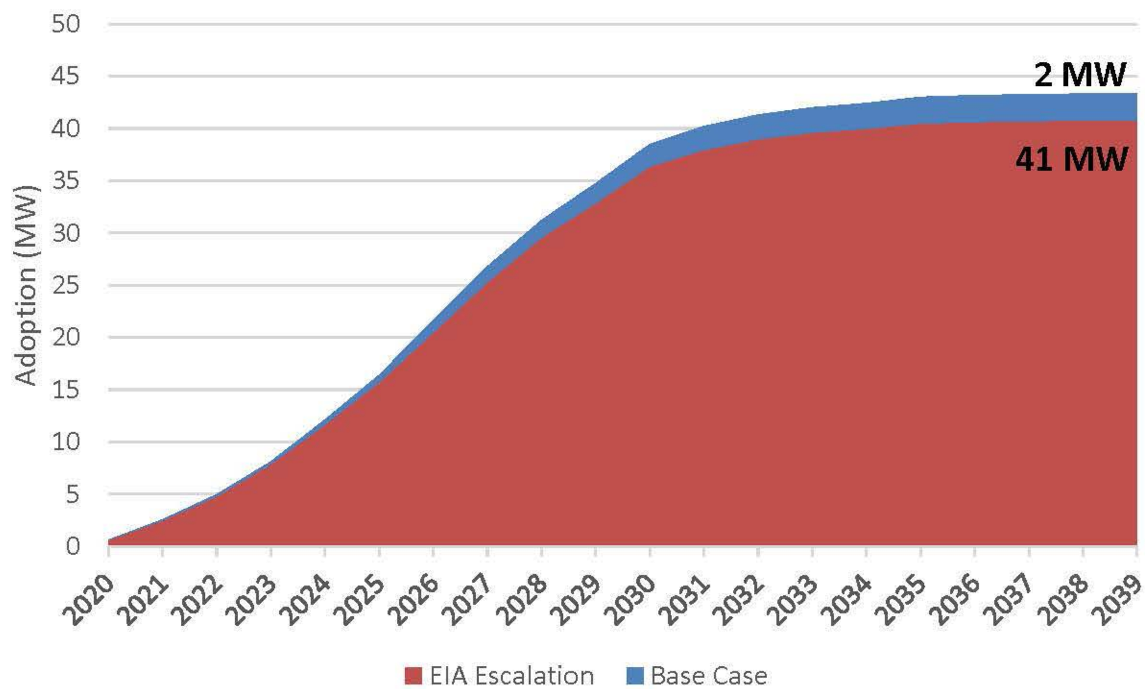

Figure 2-9
Sensitivity: Market Adoption through 2039 with EIA Escalation Rates

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.

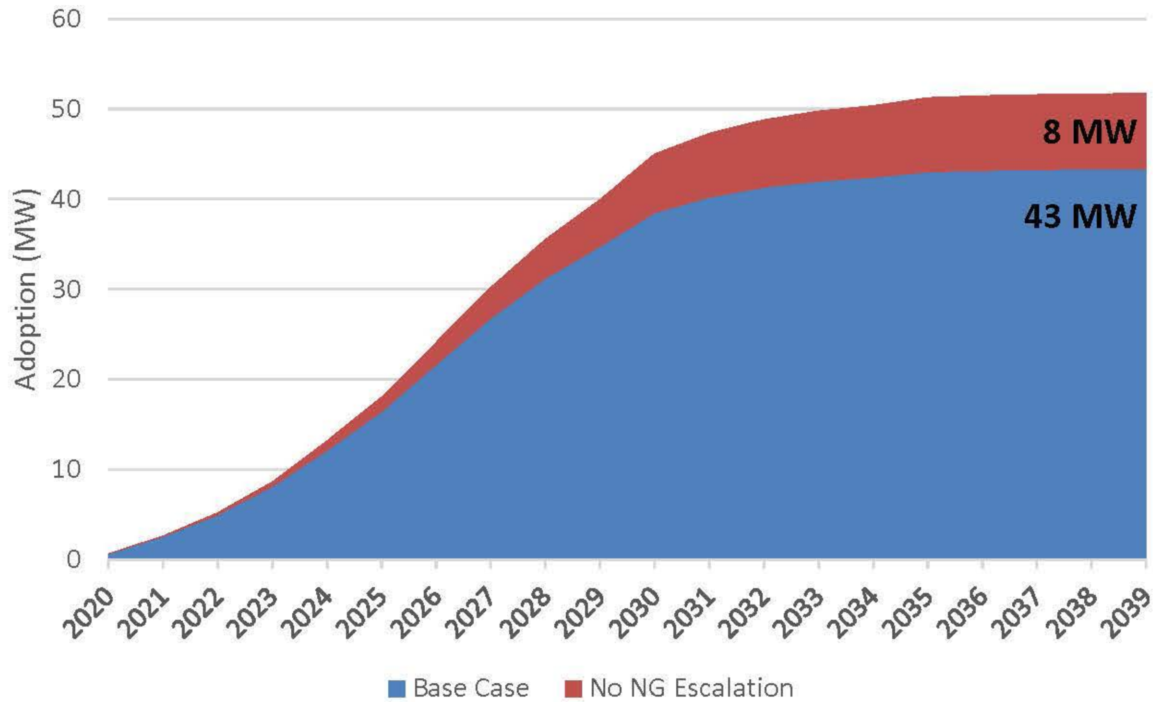

Figure 2-10
Sensitivity: Market Adoption through 2039 with Low Natural Gas Prices

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.

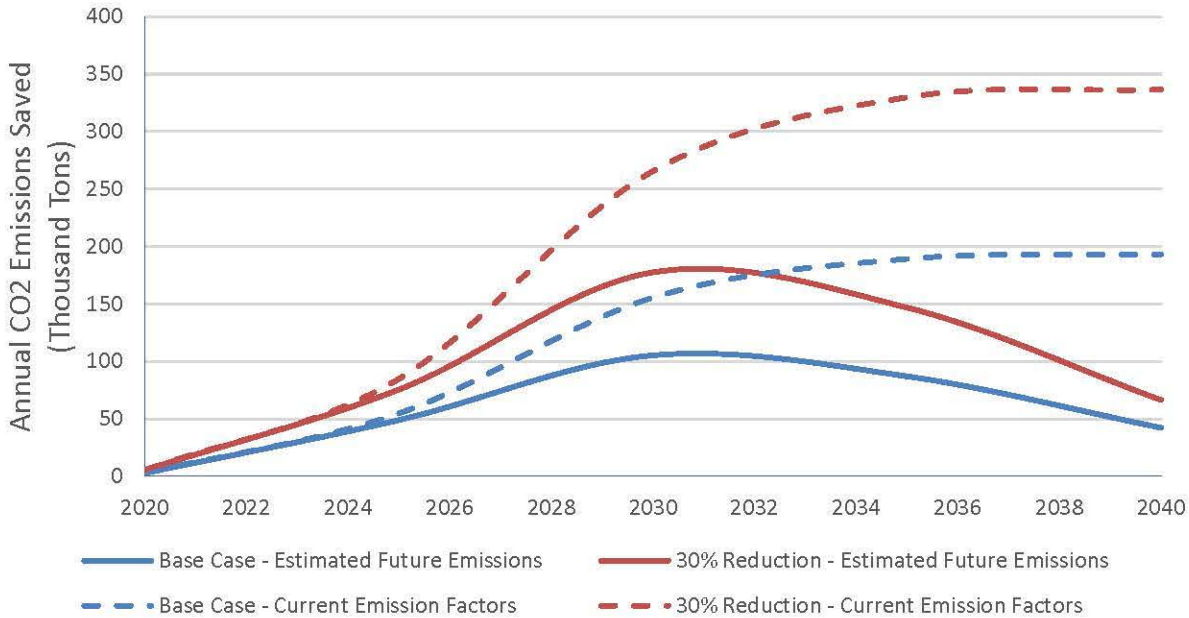

Figure 2-11
Annual Impact of Adopted CHP on Carbon Dioxide Emissions by 2040

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.

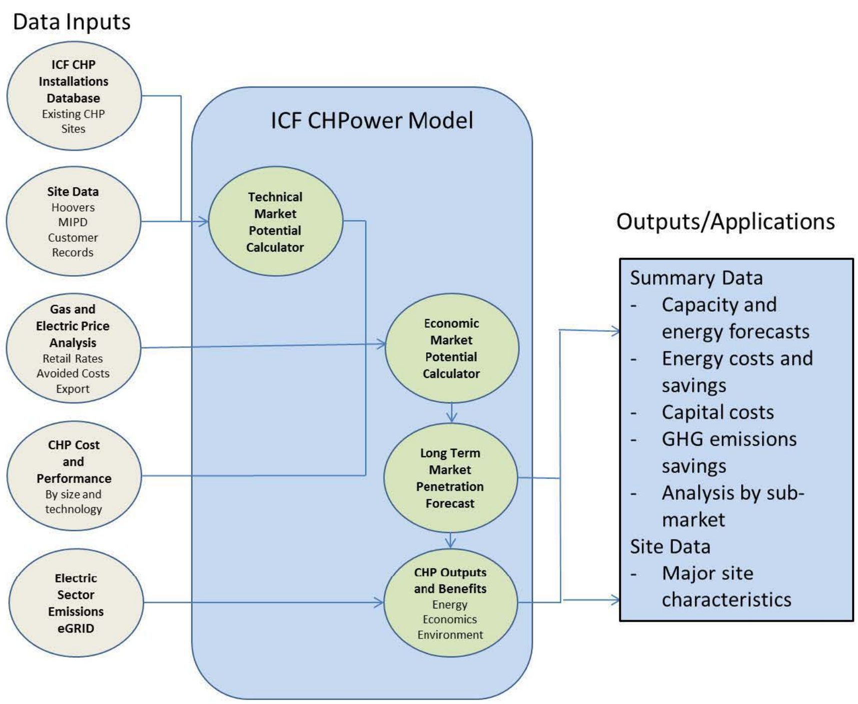

Figure A-1
CHPower Model

[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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