Technical and Economic Potential for DG and CHP Applications in Xcel Energy's Minnesota Territory

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Prepared for:

Xcel Energy

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Executive Summary

Resource Dynamics Corporation (RDC) has analyzed the technical and economic potential for commercial and industrial DG/CHP projects in the Minnesota service territory of Xcel Energy. Overall, 305 MW of economic potential was found, primarily from large industrial facilities, hospitals and colleges/universities. Payback periods ranged from 6 to 10 years.

First, the technical potential for DG/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. Customer names or addresses were not provided. Customers with load factors below 20 percent were not analyzed, as their peaky load profiles tend to indicate poor economics with baseload DG/CHP installations. The resulting technical potential is broken down by segment in Table S-1, using two metrics: average facility demand, and economic DG/CHP sizing. Economic sizing is based on providing baseload electricity and full thermal utilization for industrial sites, and tends to size the unit smaller than average demand.

Table S-1. Technical Potential for Xcel Energy Minnesota (Facilities with at least 1 MW Peak Demand)

Segment	Number of Sites	Sum of Peak Demand (MW)	Technical Potential (MW), based on Average Demand	Technical Potential (MW), with Economically-sized CHP
Chemical and Petroleum/Coal Manufacturing	24	322	230	116
Colleges and Universities	69	232	92	77
Computer and Electronic Product Manufacturing	24	113	65	34
Electrical Equipment, Appliances, Instruments	19	58	28	15
Fabricated Metal Product Manufacturing	18	36	19	10
Food/Beverage/Tobacco Manufacturing	57	182	94	47
Hospitals and Nursing Homes	32	103	52	62
Lodging	15	24	12	15
Machinery,Transportation Equipment, Misc.	30	64	32	17
Office Buildings	190	517	254	381
Forest Products (Wood and Paper)	18	72	46	24
Plastics and Rubber Products	35	71	39	20
Primary Resource Industries	29	225	77	39
Printing and Related Support Activities	21	57	28	14
Retail/Supermarket/Warehouse	47	117	58	71
Grand Total	**628**	**2,193**	**1,125**	**941**

After establishing the sites with technical potential for DG/CHP, economics were analyzed using RDC's DIStributed Power Economic Rationale SElection (DISPERSE) model[1]. Sites with economic potential were broken down by estimated payback period, and the results are shown in Table S-2. Only large industrial facilities, hospitals, universities and hotels showed economic potential in the base case scenario, all for CHP applications that can utilize waste heat for thermal energy.

[1] Resource Dynamics Corporation, DIStributed Power Economic Rationale Selection (DISPERSE) Model. McLean, Virginia, 2014.

Table S-2. Economic Potential for Xcel Energy Minnesota DG/CHP, by Segment and Payback Period

	6-7 year PB		7-10 year PB		~10 year PB		Total	
	Sites	Potential (MW)	Sites	Potential (MW)	Sites	Potential (MW)	Sites	Potential (MW)
Chemical/Petroleum Manufacturing	[TRADE SECRET BEGINS							112
Colleges and Universities								57
Computers and Electronics								12
Fabricated Metal Products								3
Food/Beverage/Tobacco Manufacturing								29
Forest Products (Wood and Paper)								13
Hospitals and Nursing Homes								48
Lodging								5
Primary Resource Industries						TRADE SECRET ENDS]		28
Grand Total	**9**	**133**	**38**	**109**	**32**	**63**	**79**	**305**

All of the economic potential came from sites capable of installing CHP sized larger than 1 MW. While the economics for hospitals and colleges may not be as strong as large industrial facilities, anecdotally they have shown that they are more willing to accept longer payback periods for investments such as CHP systems. The 105 MW of economic potential from colleges and hospitals in the 7-10 year payback range may offer the highest likelihood for market adoption, especially since many manufacturing facilities tend to need 3-year paybacks to justify energy investments. The economic potential for Xcel Energy Minnesota is broken down by size range and payback period in Figure S-1.

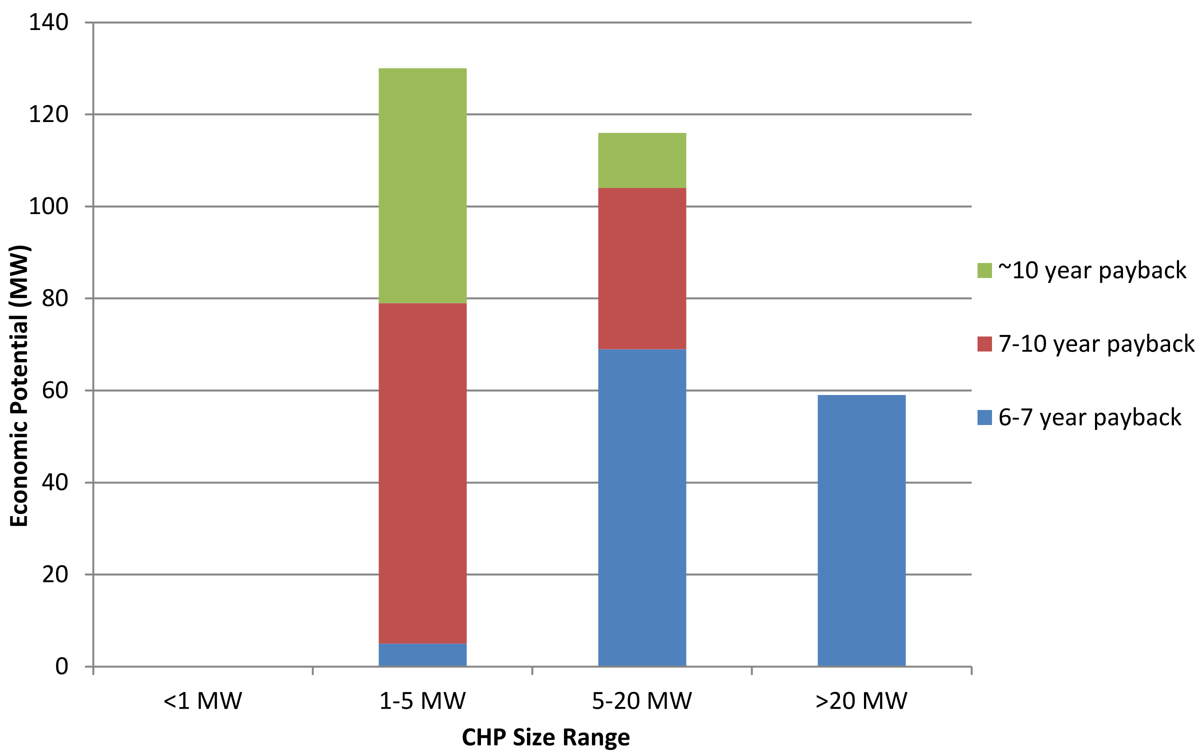

Figure S-1. Economic Potential for Xcel Energy Minnesota by CHP Size Range and Payback

While up to 305 MW of economic potential was found with payback periods of 6-10 years, 200 MW of this potential comes from industrial manufacturing facilities that tend to require 3 year payback periods or less on their energy investments. For most of these customers, some form of large incentive would need to be available before they would consider installing a CHP system. Additionally, two of the Xcel Energy facilities evaluated are already planning to install large CHP systems in the near future, and removing these sites would reduce the total economic potential by close to 75 MW (including all of the potential in the >20 MW size range).

A market adoption analysis through 2040 was performed, and the base case results showed that 100 MW is attainable within 10 years, but it would likely take until 2040 to achieve 200 MW of installed CHP, assuming no market growth. Figure S-2 shows the adoption curves for soft and strong CHP prospects.

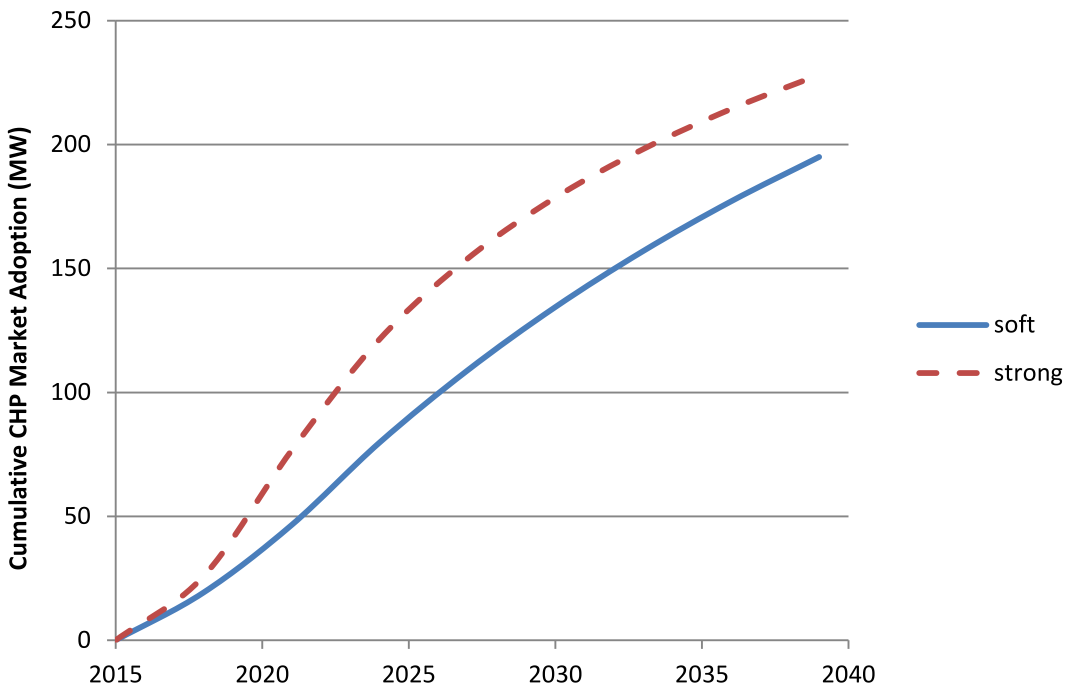

Figure S-2. Estimated DG/CHP Market Adoption Through 2040

Sensitivities

Some sensitivities were also performed in this analysis, including eliminating standby charges, changing the escalation rates for electricity and natural gas, and reducing the installed cost of DG/CHP by 50 percent. The results were as follows:

- **Eliminating standby charges** – this improved project economics for all facilities, typically reducing the payback period by close to one year. This only increased the economic potential by 22 MW (less than 8 percent of base case potential), but stronger economics would make facilities more likely to adopt.

- **Using regional EIA-predicted escalation rates for electricity and natural gas** – compared to Xcel Energy's internal forecasts, the EIA escalation rates are less favorable for DG/CHP applications – sites that saw economic potential in the 6-7 year range shifted to 7-10 years, and economic potential was reduced by over 100 MW.
- **Reducing the installed cost of DG/CHP (simulating a large incentive)** – Increasing incentives of up to 50% of the installed cost were applied – at 40% and below, the overall impact on economic potential and market adoption was fairly minimal, but at 50%, the economics for all high load factor sites (those with significant electric and thermal loads 24 hours a day, 7 days a week) showed economic potential, even those sized smaller than 1 MW. The total economic potential is estimated at 471 MW in this case, with several large sites able to achieve payback periods under five years.

Finally, the impact on carbon dioxide emissions was examined for both the base case market adoption and the 50% installed cost reduction sensitivity, to show how a relatively large CHP incentive might affect carbon emissions. Although CHP units reduce carbon emissions through high overall efficiency, the required costs for incentives are very high per unit of CO2 reduction, relative to other measures such as demand side management.

Key Takeaways

The following are important findings from the analysis:

- Economic potential for base case: 305 MW of CHP, based on Xcel Energy forecasts for electricity/gas escalation, with payback periods ranging from 6 to 10 years.
- Under current market conditions, large industrial facilities that can install CHP systems over 5 MW in size have the most attractive project economics (currently limited to 6-7 year paybacks)
  - Hospitals in the 1-5 MW size range also show some potential but with 7-10 year paybacks, and they may be willing to take on projects with longer payback periods
  - All potential CHP installations have payback periods over 6 years (without incentives, no sites display strong CHP economics)
- Escalation rates are important: using the EIA's predicted escalation rates, the economic potential is reduced to 203 MW
- Removing standby rates improves payback periods by close to 1 year, but adds only 22 MW of additional potential (less than 8% of base case)
- Market adoption scenario: 200 MW is anticipated to be adopted by 2040 in the base case
- A 50 percent cost reduction (simulating an incentive that credits customers with 50 percent of the installed CHP cost) had a large impact on project economics and potential adoption
  - 20%, 30%, 40% and 50% cost reductions for CHP were analyzed
  - At a 50% cost reduction, the market opens up to CHP systems smaller than 1 MW, introducing many smaller facilities into the pool of sites with economic potential
    - Incentive would range from \$550/kW to \$1,400/kW depending on CHP size and technology, with an average incentive of \$800-\$900/kW for adopted projects

- Market adoption would occur significantly faster than the base case
    - 200 MW projected for adoption within 5-10 years with 50% credit
- It would be very difficult to justify a 50% CHP cost reduction incentive through CO_2 emission reductions, based on an analysis showing a high cost per unit of CO_2 reduction

Assessment of DG and CHP Technical and Economic Potential for Xcel Energy's Minnesota Territory

Building off a recent national CHP market assessment[2], EPRI and RDC conducted a study for Xcel Energy to provide information on the projected impacts of natural gas-fueled distributed generation and combined heat and power in the Xcel Energy service area, focusing on the commercial/industrial 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.
- Present findings and results for the Minnesota service territories.

Technical Potential

Using the DISPERSE model, the technical potential was estimated in two different metrics:

1) **Optimistic Technical Potential (Sizing DG/CHP to Average Load)**: Assuming the DG/CHP unit size is equal to the facility's average electric load, which is typically higher than what is found in economic DG/CHP sizing
2) **Conservative Technical Potential (Economic DG/CHP Sizing)**: Strategically sizing the DG/CHP unit for baseload power operation and full thermal utilization for industrial facilities (typically between 25 and 75 percent of a site's maximum electric load) – this provides a conservative estimate of technical potential based on the most economically beneficial DG/CHP sizing.

Facility counts and sizes were provided by Xcel Energy, using actual customer data for maximum electric demand and annual electricity consumption. The resulting technical potential estimates are broken down by market segment in Table 1.

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

Table 1. Technical Potential for Xcel Energy Minnesota (Facilities with at least 1 MW Peak Demand)

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Based on the economic DG/CHP sizing, over half of these sites could only support DG/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 for Xcel Energy Minnesota (based on economic DG/CHP sizing) is broken down by size range in Table 2.

Table 2. Technical Potential for Xcel Energy Minnesota by Segment and Economic CHP Size Range

	100 kW - 1 MW		1 - 5 MW		>5 MW	
Segment	Number of Sites	Technical Potential (MW), Economically-sized CHP	Number of Sites	Technical Potential (MW), Economically-sized CHP	Number of Sites	Technical Potential (MW), Economically-sized CHP
Chemical and Petroleum/Coal Manufacturing	[TRADE SECRET BEGINS					
Colleges and Universities						
Computer and Electronic Product Manufacturing						
Electrical Equipment, Appliances, Instruments						
Fabricated Metal Product Manufacturing						
Food/Beverage/Tobacco Manufacturing						
Hospitals and Nursing Homes						
Lodging						
Machinery, Transportation Equipment, Misc.						
Office Buildings						
Forest Products (Wood and Paper)						
Plastics and Rubber Products						
Primary Resource Industries						
Printing and Related Support Activities						
Retail/Supermarket/Warehouse					TRADE SECRET ENDS]	
Grand Total	**378**	**202**	**223**	**438**	**25**	**217**

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

Economic Potential

Installed capital cost, maintenance costs, and performance information for the DG/CHP systems was 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:

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 price and performance data for engines, turbines and fuel cells in these size ranges are provided in Table 3.

Table 3. Price and Performance Data Used in Economic Analysis

	100 - 1,000 kW			1 - 5 MW		5 - 50 MW	
	Engine	Fuel Cell	MT	Engine	Turbine	Engine	Turbine
Installed Cost ($/kW)	$3,000	$6,000	$2,800	$1,800	$2,200	$1,100	$1,250
Maintenance ($/kWh)	0.02	0.028	0.011	0.016	0.018	0.01	0.009
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 10 percent Federal Investment Tax Credit for CHP was incorporated for all CHP applications analyzed, under the assumption that this program will continue to receive funding. With this incentive, installed costs are effectively reduced by 10 percent in the analysis. State average natural gas prices and Xcel Energy's current electricity tariffs were inputs to the model which determined electricity bills before and after DG/CHP is installed. Escalation rates for electricity and gas were furnished by Xcel Energy, averaging 3.25% for electricity and 3% for natural gas over the 10-year project evaluation period. Economics were analyzed using Resource Dynamics Corporation's DIStributed Power Economic Rationale SElection (DISPERSE) model, with assumptions and methodology outlined in Appendix A.

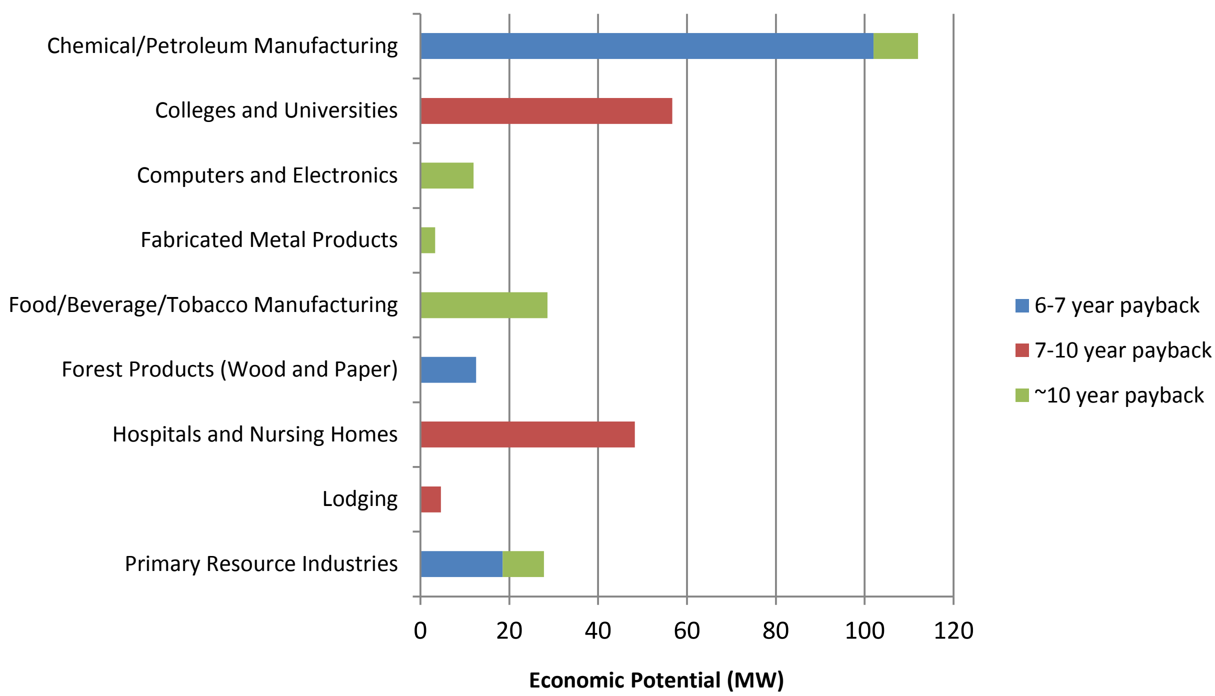
Overall, 305 MW of economic potential was found in Xcel Energy's Minnesota service territory, from a mixture of large industrial facilities, hospitals, colleges and hotels.[3] The results are broken down by segment and payback period range in Table 4.

[3] Another recent study had found more CHP potential for Xcel Energy's Minnesota territory – the studies are compared in Appendix B of this report.

Table 4. Economic Potential for Xcel Energy Minnesota by Segment and Payback Period Range

	6-7 year PB		7-10 year PB		~10 year PB		Total	
	Sites	Potential (MW)	Sites	Potential (MW)	Sites	Potential (MW)	Sites	Potential (MW)
Chemical/Petroleum Manufacturing	[TRADE SECRET BEGINS							112
Colleges and Universities								57
Computers and Electronics								12
Fabricated Metal Products								3
Food/Beverage/Tobacco Manufacturing								29
Forest Products (Wood and Paper)								13
Hospitals and Nursing Homes								48
Lodging								5
Primary Resource Industries					TRADE SECRET ENDS]			28
Grand Total	**9**	**133**	**38**	**109**	**32**	**63**	**79**	**305**

All of the economic potential came from sites capable of installing CHP sized larger than 1 MW. While the economics for hospitals and colleges 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, and usually only take on projects with payback periods of three years or less.[4] For hospitals and colleges, their future is more certain than industrial sites, and they may take on projects with payback periods up to 10 years long. Figure 1 provides a graphical representation of the economic potential by segment.



[4] An example proforma for an industrial food processing facility, showing the annual energy and cash flows evaluated in the DISPERSE model, is provided in Appendix C.

Figure 1. Economic Potential for Xcel Energy Minnesota by Segment and Payback Period Range

The economic potential for Xcel Energy's Minnesota territory is broken down by size range and payback period in Figure 2. It should be noted that all of the potential in the >20 MW range comes **[TRADE SECRET BEINGS TRADE SECRET ENDS].**

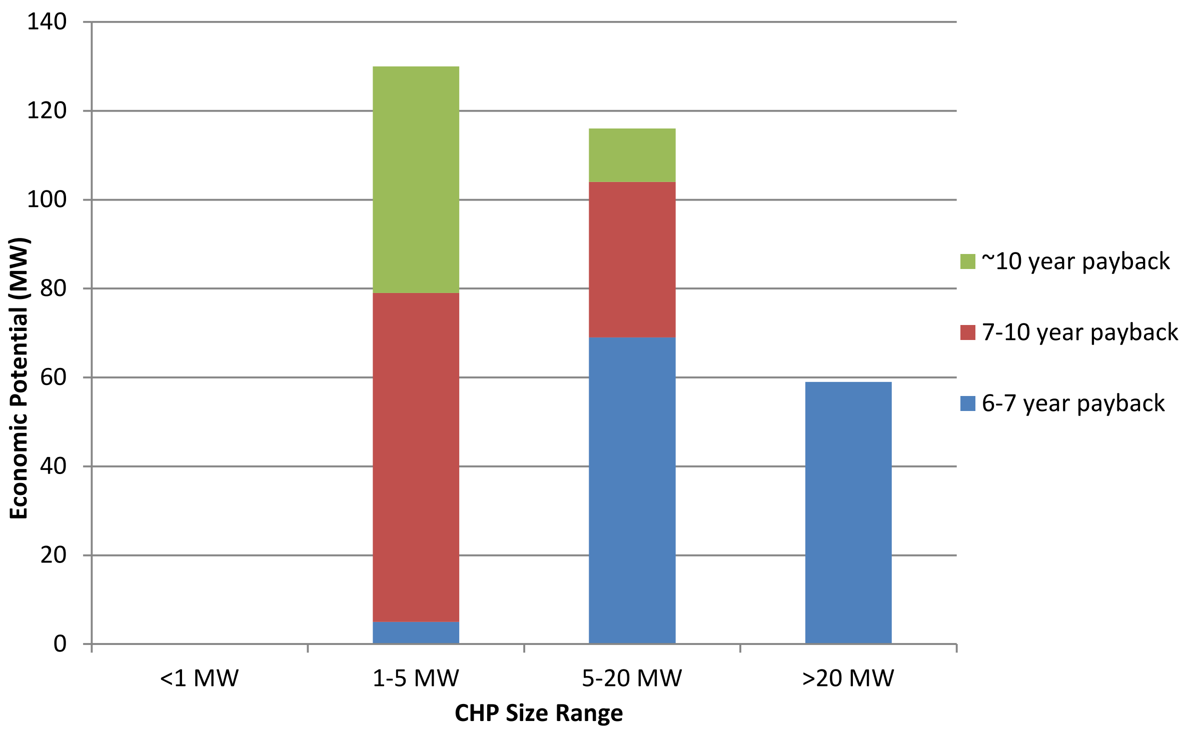


Figure 2. Economic Potential for Xcel Energy Minnesota by CHP Size Range and Payback

Sensitivity Analysis

Three sensitivities were performed for this analysis: 1) removal of standby charges, 2) using EIA escalation rates for electricity and natural gas, and 3) installed costs reduced by 50 percent (showing the effect of a large CHP incentive).

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 DG/CHP unit that would add additional charges. The contract demand charges, in dollars per kW of DG/CHP system size, are:

- $3.22 per kW for customers receiving service at secondary voltage (assumed to be sites with a maximum demand of less than 3,000 kW), or
- $2.32 per kW for customers receiving service at primary voltage (maximum demand of 3,000 kW or greater)

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 predictably improved, resulting in shorter payback periods. Most of the large industrial facilities that were in the 6-7 year payback range have shifted to 5-6 year paybacks, while hospitals with 7-10 year payback periods have shifted to the 6-7 year range. The economic potential with no standby charges is presented by segment and payback period in Table 5.

Table 5. Sensitivity: Economic Potential for Xcel Energy Minnesota with No Standby Charges

	5-6 year PB		6-7 year PB		7-10 year PB		~10 year PB		Total	
	Sites	Potential (MW)	Sites	Potential (MW)	Sites	Potential (MW)	Sites	Potential (MW)	Sites	Potential (MW)
Chemical/Petroleum Manufacturing	[TRADE SECRET BEGINS									112
Colleges and Universities										57
Computers and Electronics										12
Electronic Appliances, Instruments										8
Fabricated Metal Products										3
Food/Beverage/Tobacco Manufacturing										29
Forest Products (Wood and Paper)										18
Hospitals and Nursing Homes										48
Lodging										4
Machinery, Transportation, Misc.										2
Plastics and Rubber Products										6
Primary Resource Industries							TRADE SECRET ENDS]			28
Grand Total	**7**	**120**	**17**	**61**	**55**	**124**	**12**	**22**	**91**	**327**

While economics have improved, the total potential was found to increase by only 22 MW, and facilities were still not able to achieve estimated payback periods below five years.

Sensitivity: EIA Escalation Rates

Instead of the escalation rates provided by Xcel Energy, the Energy Information Administration's projected escalation rates from the 2014 Annual Energy Outlook were used. With the EIA rates, electricity escalates at a slower rate (2.5%, compared to a 3.25% average), and natural gas escalates more quickly (4%, compared to a 3% average), so they are less favorable for DG/CHP projects. This showed in the economic analysis, where significantly less potential was found compared to the base case. The economic potential for this scenario is broken down in Table 6.

Table 6. Sensitivity: Economic Potential for Xcel Energy Minnesota, Using EIA Escalation Rates

	7-10 year PB		~10 year PB		Total	
	Sites	Potential (MW)	Sites	Potential (MW)	Sites	Potential (MW)
Chemical/Petroleum Manufacturing	[TRADE SECRET BEGINS					102
Colleges and Universities						22
Forest Products (Wood and Paper)						13
Hospitals and Nursing Homes						48
Primary Resource Industries				TRADE SECRET ENDS]		19
Grand Total	**24**	**181**	**2**	**22**	**34**	**203**

With this sensitivity, only 203 MW of economic potential was found for Xcel Energy's Minnesota territory, compared to 305 MW in the base case. Smaller industrial sites, colleges and hotels drop off from the economic potential when EIA's escalation rates were used.

Sensitivity: 50% Installed Cost Reduction

The final sensitivity reduced the installed cost of DG/CHP systems by increasing amounts, representing a strong government or utility incentive. With an incentive of 40 percent, some large industrial sites can achieve a payback period of less than five years, but the overall effect on economic potential is minimal, increasing from 305 MW to 356 MW. However, with a 50 percent incentive, smaller facilities that can install CHP systems in the 100 kW – 1 MW range begin to show economic potential, so the effect is much more pronounced. While office buildings and retail stores still do not show potential with a 50 percent incentive, all high load factor (operating with significant loads 24 hours a day, 7 days a week) applications with sufficient thermal loads for CHP show economic potential. Based on the customer data provided by Xcel Energy and RDC's economic CHP sizing analysis, the economic potential would increase to 471 MW. The economic potential for this sensitivity is broken down by segment and payback period in Table 7.

Table 7. Sensitivity: Economic Potential for Xcel Energy Minnesota with 50% CHP Cost Reduction

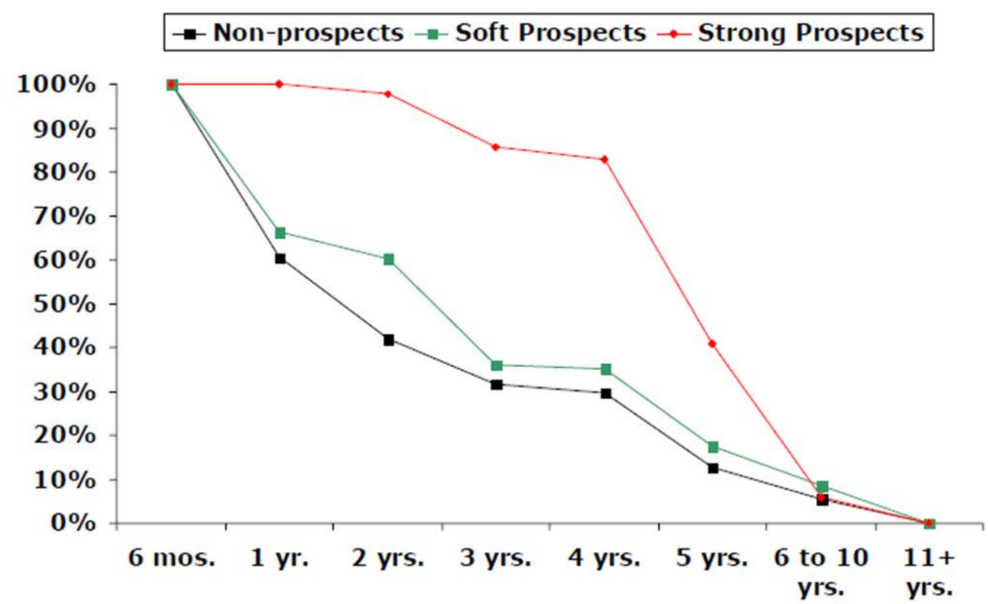
	<5 year PB		5-6 year PB		6-7 year PB		7-10 year PB		Total	
	Sites	Potential (MW)	Sites	Potential (MW)	Sites	Potential (MW)	Sites	Potential (MW)	Sites	Potential (MW)
Chemical/Petroleum Manufacturing	[TRADE SECRET BEGINS									136
Colleges and Universities										77
Computers and Electronics										34
Electronic Appliances, Instruments										15
Fabricated Metal Products										10
Food/Beverage/Tobacco Manufacturing										47
Forest Products (Wood and Paper)										24
Hospitals and Nursing Homes										56
Lodging										10
Machinery, Transportation, Misc.										16
Plastics and Rubber Products										20
Primary Resource Industries										39
Printing										6
Retail/Supermarket/Warehouse								TRADE SECRET ENDS]		2
Grand Total	**11**	**146**	**15**	**56**	**54**	**103**	**281**	**165**	**361**	**471**

Even with a 50 percent cost reduction, many customers (primarily those with potential CHP applications under 1 MW) are still in the 7-10 year payback range, where the likelihood of CHP adoption is minimal. Market adoption scenarios were performed for both the base case and the 50 percent cost reduction case, to estimate the potential for CHP market adoption out to 2040 in Xcel Energy's Minnesota territory.

Market Adoption Analysis

A market adoption analysis for CHP applications in Xcel Energy's Minnesota territory was performed for both the base case and the 50 percent cost reduction sensitivity. The analysis assumes that CHP from reciprocating engines, combustion turbines and microturbines are established technologies, and that owners of large facilities with high electric and thermal demands are aware of CHP as an option. These are known as "soft" prospects, while "strong" prospects are those who are actively evaluating CHP systems. This is the convention that was used in the market study on DG adoption[5], which continues to be used as a standard guideline for evaluating DG/CHP market adoption scenarios.

In the Primen report, the survey results from non-prospects (not considering DG), soft prospects (considering DG), and strong prospects (actively evaluating DG systems) demonstrated the willingness of these groups to move forward with a DG plan if they were to start making a return on their investment after a certain period of time. The survey participants were asked if they would be willing to adopt DG given a specific payback period. The results of the survey are shown in Figure 3.



Source: *Primen's 2003 Distributed Energy Market Survey*

Figure 3. Survey Results: Willingness to Adopt DG/CHP, Given Certain Payback Period (from EPRI)

The survey showed that strong prospects are more willing to accept longer payback periods, but that when it came to the 6-10 year payback range, only 7 percent of survey respondents said they would be willing to adopt. For this analysis, we use the survey results for soft and strong prospects to estimate the percentage of Xcel Energy's customers that would adopt CHP. One adjustment is made, however, to reflect that a 6-7 year payback period, where a customer could see a positive NPV on their investment with a 7% discount rate, is more attractive than a 7-10 year payback period. The percentages used are shown in Table 8.

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

Table 8. DG/CHP Adoption Percentages by Payback Period Range

Payback Period	Soft Prospects	Strong Prospects
0-1 year	100%	100%
1-2 years	67%	99%
2-3 years	60%	97%
3-4 years	37%	91%
4-5 years	37%	86%
5-6 years	18%	40%
6-7 years	10%	15%
7-10 years	5%	5%
10 years	1%	1%

These percentages represent the likelihood of a customer to adopt DG/CHP, but this decision is not continuously being made. To estimate the effects over time, the assumption was made that on average, businesses would seriously evaluate these types of decisions once every three years, as market conditions and economics change. Based on this set of assumptions, about 200 MW of adopted CHP could be expected by 2040 in the base case. However, with a 50 percent reduction in installed costs, 200 MW would be achievable within 10 years and 400 MW would be reached by 2040. The results of the market adoption analysis are presented in Figures 4 and 5.

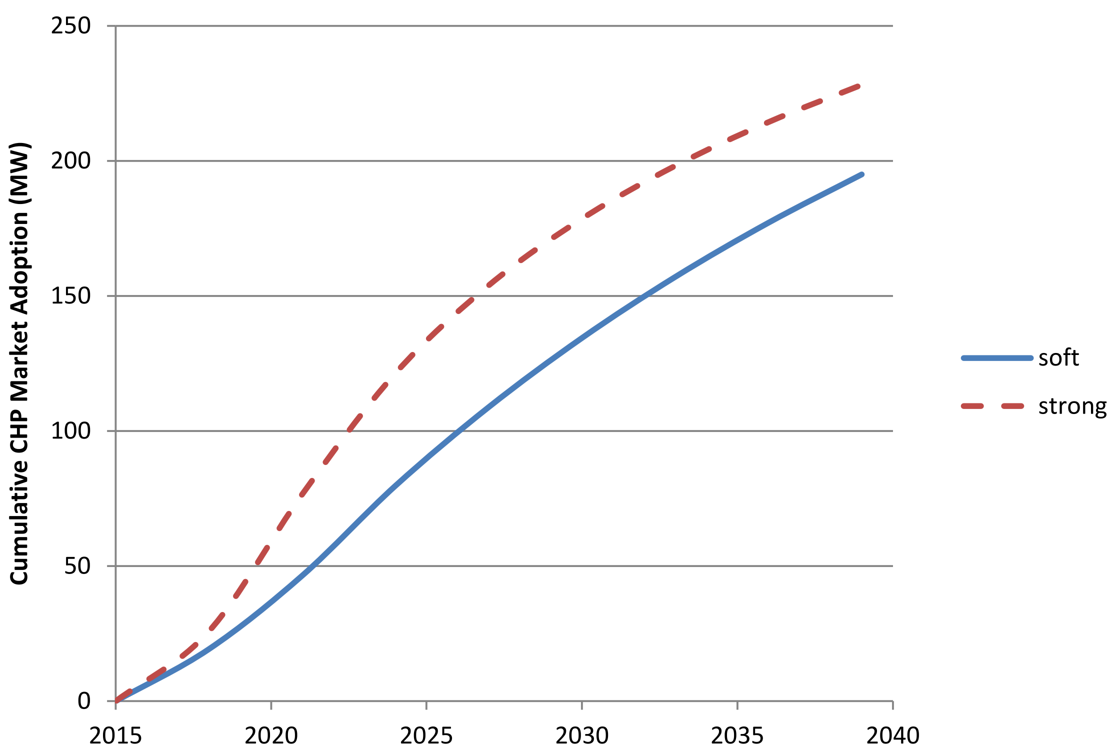


Figure 4. Base Case Market Adoption Through 2040, Soft and Strong Prospects

With the base case assumptions, 134-179 MW of CHP are estimated to come online by 2030, enough to displace between 1,056 and 1,411 GWh of Xcel Energy's electricity sales. If a 50 percent installed cost credit were offered as an incentive, the adoption by 2030 would increase to 287-386 MW of CHP, enough to displace between 2,263 and 3,043 GWh of electricity. Again, the higher adoption assumes all customers are strong prospects and the weaker adoption assumes all customers are soft prospects.

The adoption by 2030 is more than doubled with a 50 percent installed cost credit, but the overall impact on the utility would remain relatively small, while the total cost of the incentive would range from $240 million to $360 million. The soft and strong adoption scenarios for the 50% cost reduction are shown in Figure 5.

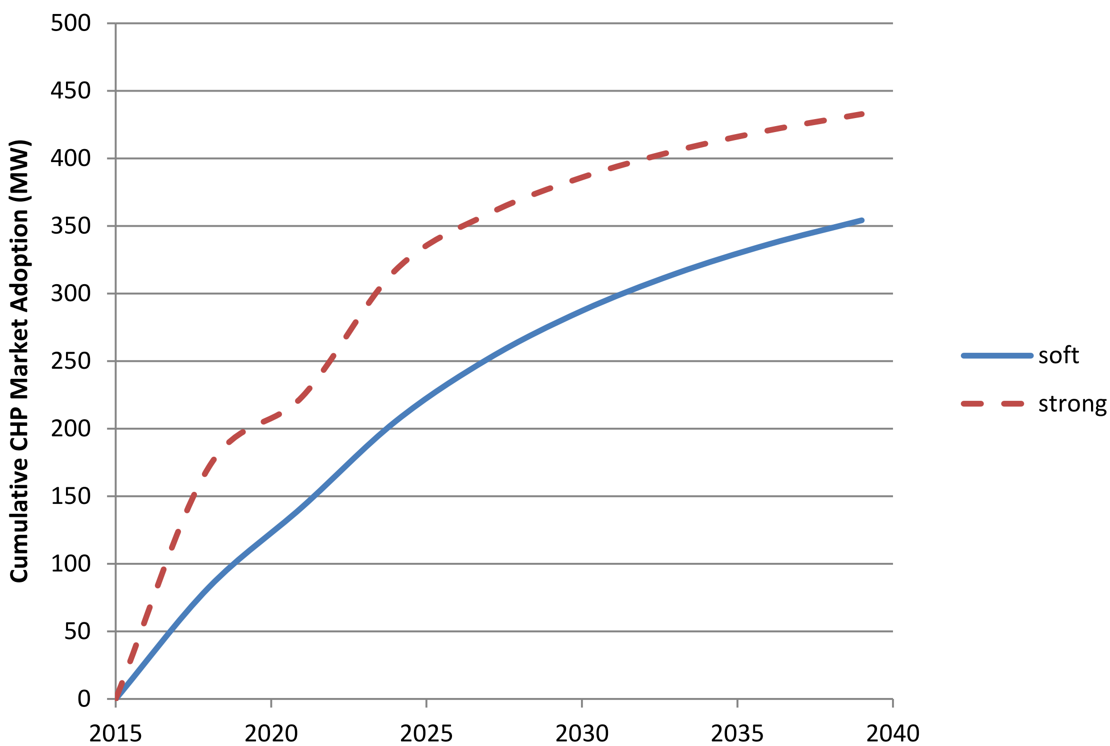


Figure 5. Base Case Market Adoption Through 2040, Soft and Strong Prospects

Impact of Adopted CHP on CO_2 Emissions

Without considering the utilization of waste heat from CHP units, the net effect on greenhouse gas emissions would be negative for all of this adopted CHP. Xcel Energy's operations for their northern territories currently produce CO_2 at an average rate of 1,041 lbs/MWh. When only considering electricity generation, most CHP units produce CO_2 at a rate of about 1,200 lbs/MWh, with large high-efficiency reciprocating engines producing the least at 1,070 lbs/MWh. However, when the effects of thermal recovery are considered, fully utilizing the waste heat to displace an 80 percent efficient natural gas boiler, the result is an overall reduction in greenhouse gas emissions for all CHP units.

Considering the potential impact on CO_2 emissions by 2030, between 169,000 and 488,000 tons of CO_2 would be reduced on an annual basis. Comparatively, Xcel Energy's operations for their northern territories produced 23,400,000 tons of CO_2 in 2013, so the impact of CO_2 emissions by 2030 would be between 0.7 and 2 percent of Xcel Energy's current CO_2 production levels. The 2030 calculations are shown in Table 9.

Table 9. Annual CO_2 Reduction Calculations for 2030

	2030 Estimated CHP Adoption for Xcel Minnesota			
	Base Case		50% Cost Reduction	
	Conservative (soft)	Optimistic (strong)	Conservative (soft)	Optimistic (strong)
Displaced Demand (MW)	134	179	287	386
Displaced Electricity (MWh/yr)	1,056,000	1,411,000	2,263,000	3,043,000
CO2 Reduction (tons)	550,000	734,000	1,178,000	1,584,000
Displaced Thermal (MMBtu/yr)	3,370,000	4,502,000	7,219,000	9,709,000
CO2 Reduction (tons, assumes 80% efficiency)	246,000	329,000	528,000	710,000
CHP Fuel Required (MMBtu/yr)	10,716,000	14,315,000	22,952,000	30,870,000
CO2 Emitted (tons)	627,000	837,000	1,343,000	1,806,000
Total CO2 Reduced/Emitted (tons)	**169,000**	**226,000**	**363,000**	**488,000**

In Figure 6, the annual impact on carbon dioxide emissions is detailed for the four different scenarios through 2030.

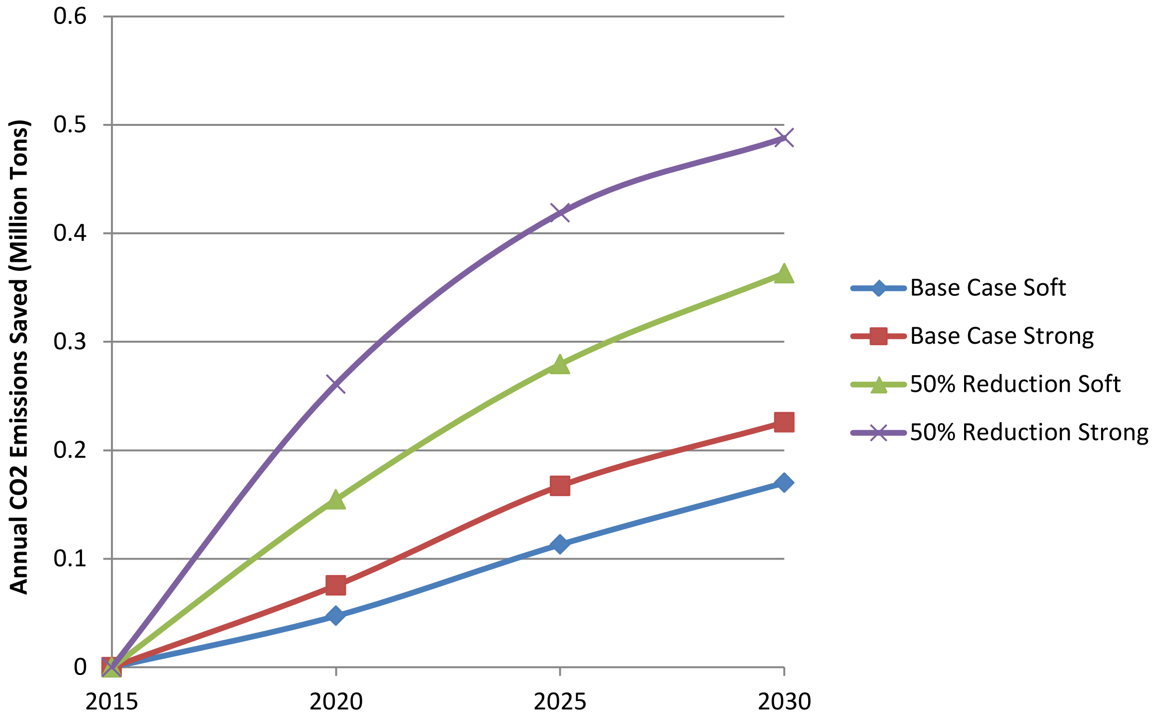


Figure 6. Annual Impact of Adopted CHP on Carbon Dioxide Emissions through 2030

Of particular interest to Xcel Energy is the potential effect of CO_2 emissions over the next ten years, and how favorable CHP incentives could affect that. For example, if the 50 percent CHP incentive were provided, how would it impact CO_2 levels, and what would be the associated value per ton? How does this compare to other CO_2 valuations for Xcel Energy?

When looking at the cumulative effects of adopted CHP, there would be between 1.8 and 2.7 million total tons of CO_2 reduced by 2025, correlating to 220-340 MW of adopted CHP. At an average cost of $1,700 per kW, $850,000 would be needed to provide a 50% incentive for each MW of total CHP adoption ($187-$289 million). This amounts to the incentives providing $104 to $107 per ton of CO_2 reduction, while the current values being planned for Xcel Energy's DSM program are currently $4.32 per ton. The CO_2 reduction benefits of CHP are substantial, but the required incentives for CHP in this analysis yield a much higher cost of CO_2 reduction than other comparable Xcel Energy initiatives.

<u>Summary</u>

A total of 305 MW of economic CHP potential was found for Xcel Energy's Minnesota service territory. Under current market conditions, large industrial facilities that can install CHP systems over 5 MW in size have the strongest project economics for DG/CHP applications, with payback periods in the range of 6-7 years. However, some hospitals and colleges show CHP potential with payback periods of 7-10 years, and they may be more willing to take on projects with longer paybacks. 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 200 MW of adopted CHP is expected by 2040, with 100 MW within the next ten years. These figures include two facilities that are expected to install large CHP systems (over 70 MW combined) within the next couple of years.

Using the EIA's predicted escalation rates for the West North Central region, the total economic potential is reduced from 305 to 202 MW. Removing standby rates has a positive effect on project economics, but the economic potential is only increased by 22 MW compared to the base case, and payback periods below five years are still unattainable. However, when installed costs for CHP systems are reduced by 50 percent, some sites can achieve payback periods below five years, and the total economic potential increases to 470 MW as systems smaller than 1 MW become feasible.

An analysis was performed on the effect of CHP on CO_2 emissions. While utilizing CHP for both electricity and thermal energy produces a net reduction in CO_2 emissions, the total impact is small relative to Xcel Energy's emissions from power generation, and the required funding to support strong CHP adoption would be difficult to justify solely on the basis of CO_2 reductions.

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 DG/CHP potential is currently estimated to be less than 500 MW.

Key Takeaways

The following are important findings from the analysis:

- Economic potential for base case: 305 MW of CHP, based on Xcel Energy forecasts for electricity/gas escalation, with payback periods ranging from 6 to 10 years.
- Under current market conditions, large industrial facilities that can install CHP systems over 5 MW in size have the most attractive project economics (currently limited to 6-7 year paybacks)
    - Hospitals in the 1-5 MW size range also show some potential but with 7-10 year paybacks, and they may be willing to take on projects with longer payback periods
    - All potential CHP installations have payback periods over 6 years (without incentives, no sites display strong CHP economics)
- Escalation rates are important: using the EIA's predicted escalation rates, the economic potential is reduced to 203 MW
- Removing standby rates improves payback periods by close to 1 year, but adds only 22 MW of additional potential (less than 8% of base case)
- Market adoption scenario: 200 MW is anticipated to be adopted by 2040 in the base case
- A 50 percent cost reduction (simulating an incentive that credits customers with 50 percent of the installed CHP cost) had a large impact on project economics and potential adoption

- 20%, 30%, 40% and 50% cost reductions for CHP were analyzed
- At a 50% cost reduction, the market opens up to CHP systems smaller than 1 MW, introducing many smaller facilities into the pool of sites with economic potential
  - Incentive would range from $550/kW to $1,400/kW depending on CHP size and technology, with an average incentive of $800-$900/kW for adopted projects
- Market adoption would occur significantly faster than the base case
  - 200 MW projected for adoption within 5-10 years with 50% credit
- It would be very difficult to justify a 50% CHP cost reduction incentive through CO_2 emission reductions, based on an analysis showing a high cost per unit of CO_2 reduction

Appendix A. Assumptions and Methodology for DISPERSE Model

THE DISPERSE MODEL

The market analysis of DG/CHP systems was performed using the DIStributed Power Economic Rationale SElection (DISPERSE) model[6]. This spreadsheet-based model can estimate the achievable economic potential for distributed generation systems by comparing the cost to obtain, operate, and maintain the DG/CHP system with the cost of utility heat and power. The model determines which combination of size, rate schedule, and operating mode is the most economical. The database of sites comes from publicly Figure A-1 illustrates how the DISPERSE model organizes the key data inputs and generates the desired outputs.

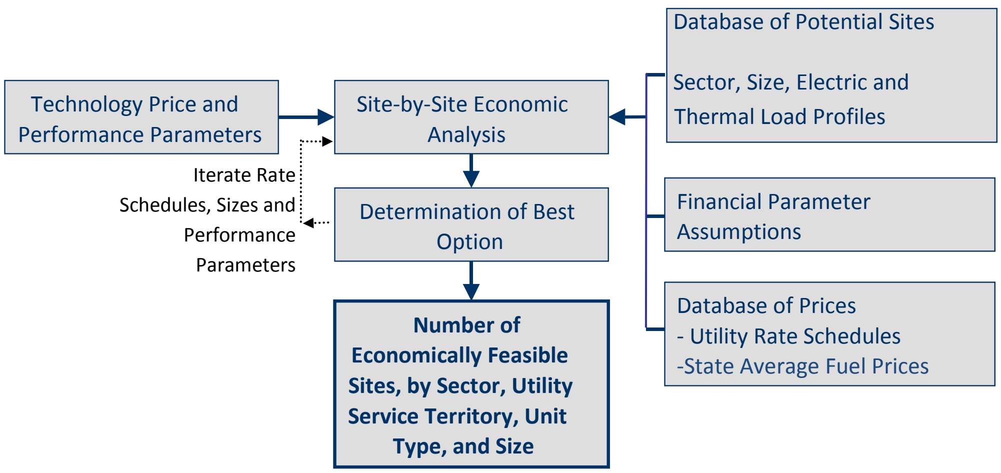


Figure A-1. DISPERSE Model

The DISPERSE model has been developed over the past twenty years, and has been applied on a variety of projects for utilities, equipment manufacturers, and research organizations. For this effort, the DISPERSE model was configured to:

- Evaluate the markets of Xcel Energy's Minnesota 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

[6] Resource Dynamics Corporation, DIStributed Power Economic Rationale Selection (DISPERSE) Model. McLean, Virginia, 2014.

KEY INPUTS AND ASSUMPTIONS

The DISPERSE model performs a life-cycle cost economic analysis, based on the unit life, DG fuel expenses, cost and performance data, electric utility rate schedules, and state fuel prices. The model determines whether any DG/CHP technology option can beat the case in which all power is purchased from the local utility. The best technology option is selected based on the shortest payback period.

This process is repeated hundreds of thousands of times, once for each group of sites within a combination of a DG unit size range/customer sector in the database of sites, to obtain the optimal configuration.

The following key inputs are used by the model:

1. **Technology price and performance parameters**. The model requires data on the mix of technologies that are being analyzed. This data includes each technology's installed cost, fuel type, heat rate, electrical efficiency, usable thermal output, fixed and variable operating and maintenance costs, and other key parameters. Current data for DG/CHP technologies was provided by EPRI.

2. **Building characteristics** Load profiles for building types used in the analysis were generated using DOE2 building models and average weather data. Industrial load profiles are generated from data collected by the contractor and simplified 24-hour load profiles that can be adjusted for different facility sizes based on the number of employees.

3. **Database of natural gas and electricity prices**. Commercial and industrial electricity rate schedules were identified and modeled for Xcel Energy Minnesota, including standby service. Natural gas prices were derived from average state pricing, using the lower of the average industrial price and the average citygate price +$1/MMBtu. Escalation rates for both electricity and natural gas were provided by Xcel Energy for the base case.

4. **Financial parameter assumptions.** A maximum project life of 10 years is generally assumed, reflecting the anticipated life of smaller DG projects and conservative financial planning from customers. The installed cost of the system, maintenance costs, and fuel costs are the primary variables, along with the calculated electricity costs for the building before and after DG is installed. A discount rate of 7 percent is used for all financial calculations.

DETERMINING THE MOST ECONOMIC DG OPTION

The DISPERSE model estimates the most economic technology and unit size that independently meets the electric demand for a particular building type. To do so, the payback period for various DG systems versus grid electricity or other options is calculated. That is, the economics of either generating with DG or purchasing adequate electricity to meet consumption needs is estimated for each combination of building size/type and DG technology size/type. In each case, one technology will offer the most attractive project economics.

In the end, only the most economical DG projects are chosen, and their financial data is compiled from the DISPERSE model's result files.

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.

Model Inputs	Assumptions/Data Used
DG/CHP price, performance, maintenance costs	From EPRI Request for Information Process for 2014 National CHP Assessment
Federal ITC credit (C&I)	10% applied in year zero to all C&I systems
Discount rate (C&I)	7 percent
Depreciation schedule (C&I)	10 year straight line
Tax percentage (C&I)	35 percent
Natural gas pricing - C&I, high load factor	2013 monthly average prices - lower of state average industrial price or city gate price plus $1/MMBtu
Natural gas escalation (C&I)	Average of 3% from 2015-2025, 4% after
Electricity pricing	Based on Xcel Energy's latest electricity tariff
Electricity escalation (C&I)	Average of 3.25% from 2015-2025, 2.5% after
Contract demand charges for standby service	Per kW of contract demand (CHP size): $3.22 for Secondary service (<3,000 kW max demand); $2.32 for Primary service (>3,000 kW max demand)
Value of backup power/avoided interruptions	$0
Part-load efficiency	Engines 25% reduction at 50 percent load, turbines 30% reduction at 50 percent load
DG maintenance escalation	2 percent
Property taxes and insurance	2 percent of depreciated value
Commercial load profiles	Generated from DOE2 model building simulations and matched to customer sizes
Industrial load profiles	Weekday/weekend load shapes collected from representative facilities, matched to customer sizes

For the market adoption scenario, some additional assumptions were made:

- Findings from 2003 Primen study (percentage of customers willing to adopt at certain payback periods) applied to economic DG/CHP potential estimates
- Facility owners decide whether or not to consider or move forward with a DG/CHP installation once every three years
- No market growth considered
- Effect of escalation rates on future project economics are considered (by 2020, CHP economics have improved substantially based on Xcel Energy's forecasted escalation rates)

Appendix B. Differences in Recent Minnesota CHP Studies

	RDC/EPRI (Xcel Energy)	**Minnesota Department of Commerce**
Economic Potential with Payback of 10 years or less	**305 MW, with 132 MW under 7 years**	**487.5 MW, vast majority (462.5 MW) from >20 MW sites with <5 year PB**
Estimated Market Penetration	100 MW around 2025, 200 MW by 2040	2020: 61 MW, 2030: 160 MW, 2040: 187 MW
Sites Evaluated	Actual facilities with 2013 energy and demand requirements	Dun & Bradstreet Hoovers Database, supplemented by Manufacturer's News database, industry directories and government data lists
Natural Gas Escalation	Nominal: 2 percent for first five years, 4 percent for remainder of project (from provided pricing forecast – EIA Outlook for Industrial sector is close to 4%)	Real: 1.3 percent (From EIA Annual Energy Outlook, Electric Power Projections through 2040) – add 1-2 percent for inflation to estimate nominal rate
Electricity Rates	Current Xcel Energy tariff: On-peak energy and demand charges bring average to 8.5-10 cents/kWh before CHP, 10-12 cents/kWh after CHP for most industrial sites	Average avoided electricity prices for Xcel Energy high load customers range from 6.3 cents/kWh (over 20 MW) to 6.7 cents/kWh (1- 5 MW) – Implies that retail rate is between 6.6 and 7.4 cents/kWh)
Standby Rates	Contract Demand: $3.22/kW/month for Secondary customers; $2.32/kW/month for Primary customers – accounts for 3-4 percent of total post-DG bill	Depending on size range, 4-10 percent of average retail electricity price is unrecoverable; however, this is meant to include the effect of TOU and Demand charges in addition to Standby
Electricity Escalation	Nominal: 5 percent for first three years, 2.5 percent for remainder of project (2.5 percent based on regional EIA Annual Energy Outlook for Industrial sector)	Real: 1.1 percent (From EIA Annual Energy Outlook, Electric Power Projections through 2040) – add 1-2 percent for inflation to estimate nominal rate
Taxes	Property taxes and depreciation (income taxes) built into analysis	No income or property taxes used in payback analysis
Equipment Price and Performance	Large combustion turbine: $1,250/kW over 5 MW, 32% electric, 74% CHP, $0.009/kWh ; Large engine: $1,100/kW over 5 MW, 41% electric, 77% CHP, $0.01/kWh	Large combustion turbine: $1,250/kW over 20 MW, 37% electric, 72% CHP, $0.005/kWh –most of the potential came from large facilities with 20+ MW turbines
Federal ITC Credit	10 percent	10 percent

Appendix C. Example Pro Forma for Industrial Customer Installing CHP

Hypothetical Large Xcel Energy Customer Facility with 9.2 MW engine											
(7.0 year payback after taxes)											
	Year										
	0	1	2	3	4	5	6	7	8	9	10
Original Consumption											
Electricity											
Energy (kWh)		159,836,970	159,836,970	159,836,970	159,836,970	159,836,970	159,836,970	159,836,970	159,836,970	159,836,970	159,836,970
Demand (kW)		22,849	22,849	22,849	22,849	22,849	22,849	22,849	22,849	22,849	22,849
Natural Gas (MMBtu)		781,506	781,506	781,506	781,506	781,506	781,506	781,506	781,506	781,506	781,506
Consumption with DG											
Electricity											
Energy (kWh)		78,774,916	78,774,916	78,774,916	78,774,916	78,774,916	78,774,916	78,774,916	78,774,916	78,774,916	78,774,916
Demand (kW)		13,595	13,595	13,595	13,595	13,595	13,595	13,595	13,595	13,595	13,595
Natural Gas (MMBtu)		538,652	538,652	538,652	538,652	538,652	538,652	538,652	538,652	538,652	538,652
DG Unit Operation											
Power Generated (kWh)		81,062,054	81,062,054	81,062,054	81,062,054	81,062,054	81,062,054	81,062,054	81,062,054	81,062,054	81,062,054
Peak Output (kW)		9,254	9,254	9,254	9,254	9,254	9,254	9,254	9,254	9,254	9,254
Fuel Consumption (MMBtu)		674,625	674,625	674,625	674,625	674,625	674,625	674,625	674,625	674,625	674,625
Energy Expenses (excluding DG unit fuel)											
Original Electric Bill		$11,796,538	$12,386,365	$13,005,683	$13,655,967	$13,997,366	$14,347,301	$14,705,983	$15,073,633	$15,450,474	$15,836,735
New Electric Bill		$6,483,656	$6,807,839	$7,148,231	$7,505,642	$7,693,283	$7,885,615	$8,082,756	$8,284,825	$8,491,945	$8,704,244
Net Electric Bill Benefit		***$5,312,882***	***$5,578,526***	***$5,857,452***	***$6,150,325***	***$6,304,083***	***$6,461,685***	***$6,623,227***	***$6,788,808***	***$6,958,528***	***$7,132,491***
Original Boiler Fuel Bill		$4,065,787	$4,147,102	$4,230,045	$4,314,645	$4,400,938	$4,488,957	$4,668,515	$4,855,256	$5,049,466	$5,251,445
New Boiler Fuel Bill		$2,802,339	$2,858,385	$2,915,553	$2,973,864	$3,033,341	$3,094,008	$3,217,768	$3,346,479	$3,480,338	$3,619,552
Net Boiler Fuel Bill Benefit		***$1,263,448***	***$1,288,717***	***$1,314,492***	***$1,340,781***	***$1,367,597***	***$1,394,949***	***$1,450,747***	***$1,508,777***	***$1,569,128***	***$1,631,893***
DG Unit Expense											
Capital Cost (with 10% ITC)	$9,161,123										
Fuel Cost		$4,319,286	$4,405,672	$4,493,785	$4,583,661	$4,675,334	$4,768,841	$4,959,594	$5,157,978	$5,364,297	$5,578,869
Operation & Maintenance		$810,621	$826,833	$843,370	$860,237	$877,442	$894,991	$912,890	$931,148	$949,771	$968,767
Standby Charges (Primary)		$257,622	$270,503	$284,028	$298,230	$305,685	$313,327	$321,161	$329,190	$337,419	$345,855
Customer Benefits											
Avoided Interruptions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Customer Cash Flows											
DG Capital Costs	$9,161,123										
Net Electricity Bill		$5,312,882	$5,578,526	$5,857,452	$6,150,325	$6,304,083	$6,461,685	$6,623,227	$6,788,808	$6,958,528	$7,132,491
Net Natural Gas Bill		$1,263,448	$1,288,717	$1,314,492	$1,340,781	$1,367,597	$1,394,949	$1,450,747	$1,508,777	$1,569,128	$1,631,893
DG Unit Fuel		$4,319,286	$4,405,672	$4,493,785	$4,583,661	$4,675,334	$4,768,841	$4,959,594	$5,157,978	$5,364,297	$5,578,869
DG Unit Maintenance		$810,621	$826,833	$843,370	$860,237	$877,442	$894,991	$912,890	$931,148	$949,771	$968,767
Standby Charges		$257,622	$270,503	$284,028	$298,230	$305,685	$313,327	$321,161	$329,190	$337,419	$345,855
Avoided Interruptions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Cash Flow (Before Tax)	**($9,161,123)**	**$1,188,802**	**$1,364,236**	**$1,550,761**	**$1,748,979**	**$1,813,219**	**$1,879,475**	**$1,880,329**	**$1,879,269**	**$1,876,168**	**$1,870,894**
Net Present Value (NPV):	**$2,523,133**										
Payback Period:	**5.8**	**years**									
IRR:	**12.2%**										
Property Taxes and Insurance		$183,222	$164,900	$146,578	$128,256	$109,933	$91,611	$73,289	$54,967	$36,644	$18,322
Depreciation		$916,112	$916,112	$916,112	$916,112	$916,112	$916,112	$916,112	$916,112	$916,112	$916,112
Depreciated Value	$9,161,123	$8,245,010	$7,328,898	$6,412,786	$5,496,674	$4,580,561	$3,664,449	$2,748,337	$1,832,225	$916,112	$0
Tax Effect		$31,313	$99,128	$170,825	$246,614	$275,511	$305,113	$311,825	$317,866	$323,194	$327,761
Net Cash Flow (After Tax)	**($9,161,123)**	**$974,266**	**$1,100,207**	**$1,233,358**	**$1,374,109**	**$1,427,775**	**$1,482,751**	**$1,495,215**	**$1,506,436**	**$1,516,330**	**$1,524,811**
Net Present Value (NPV):	**$179,286**										
Payback Period:	**7.0**	**years**									
IRR:	**7.4%**										