CHP Stakeholder Comments

Comment Period: Sept. 24 through Oct. 10, 2014

Final Summary Report Prepared For:

Minnesota Department of Commerce - Division of Energy Resources

Prepared By:

Microgrid Institute

Contents

Background

As part of the 2014 Minnesota CHP Stakeholder Engagement process, the Minnesota Department of Commerce, Division of Energy Resources, arranged a comment period from Sept. 24 through Oct. 10, 2014.[1] Commerce invited stakeholders to submit written comments on issues involving CHP in Minnesota, and specifically on the following:

- FVB Energy's proposed CHP policy options
- CHP finance, policy, technical application, and education and training needs
- Alternative mechanisms and approaches to facilitate economically efficient deployment of CHP in Minnesota
- Current barriers and issues hindering CHP projects
- Resource planning, strategic, and regulatory factors affecting CHP options and potential
- Any other CHP issues on which stakeholders would like to comment

Commerce received submissions[2] from the following stakeholder organizations:

BlueGreen Alliance
CenterPoint Energy
Cummins Power Generation
Fresh Energy
Great Plains Institute
Great River Energy
Midwest Cogeneration Association
Minnesota Chamber of Commerce
Minnesota Power
Otter Tail Power
Vergent Power Solutions
Western Lake Superior Sanitary District
Xcel Energy

[1] Commerce scheduled the comment period to coincide with the three weeks separating CHP Stakeholder Meetings #2 (Sept. 3, 2014) and #3 (Sept. 24, 2014); see Appendix A and Commerce Website. http://mn.gov/commerce/energy/topics/clean-energy/distributed-generation/2014-workshops/chp-meetings.jsp

[2] Commerce received 11 comment submissions by Oct. 10, 2014, the official expiration of the comment period, and also accepted two (2) submissions in subsequent days from the Midwest Cogeneration Association and Vergent Power Solutions. Additionally, Xcel Energy submitted the results of a related EPRI study after the comment period expired. This final report is synthesized from all 13 comment submissions plus the EPRI report. Submitted materials are available on the Department of Commerce website.

Comment Summary

Stakeholders submitted comments addressing numerous issues related to CHP development in Minnesota. The comments can be organized into several interrelated topic areas:

- Policy Options
- Capital Costs and Utility Investment Prospects
- Economic Potential and Value Proposition
- Standby Rates
- Training and Education Needs

Note: Copies of all submitted comments are available for public review at the Minnesota Department of Commerce website.[3] This preliminary summary report paraphrases and generalizes comments, and omits figures and citations. Microgrid Institute is solely responsible for any errors or omissions in this summary report.

Policy Options

Comment submissions express various views on CHP policy options proposed by FVB Energy (*e.g.,* to add CHP provisions to Minnesota's Conservation Improvement Program (CIP), or to establish goals for CHP deployment as part of the state's existing renewable portfolio standard (RPS) or as part of a prospective alternative portfolio standard (APS)). Several comments also discuss options to encourage consideration of CHP through utility integrated resource planning (IRP) processes before the Minnesota Public Utilities Commission (PUC).

Some commenters note that various options aren't necessarily mutually exclusive. CenterPoint Energy states that "maximizing CHP could mean pursuing both approaches simultaneously." And Fresh Energy notes that utilities' IRP processes could incorporate CHP analysis at the same time that CIP or other policies encourage CHP: "[W]hile individual proposals may not appear to offer large increases in CHP deployment, a suite of policy options considered together may offer greater potential." The company cautions against disregarding any policy option based solely on its comparative merits versus other, potentially complementary approaches.

Alternative Portfolio Standards:
A few commenters express support for the APS policy option. Great Plains Institute notes that the option shows the highest potential for CHP capacity additions but so far has received comparatively little attention during CHP stakeholder discussions. BlueGreen Alliance observes that CIP policy amendments face limitations and challenges involving industrial companies and their trade unions, while the APS option avoids such issues and represents a more direct approach to encouraging CHP adoption. The Midwest Cogeneration Association suggests that any contemplated portfolio standard program for CHP

[3] http://mn.gov/commerce/energy/topics/clean-energy/distributed-generation/2014-workshops/chp-meetings.jsp

should provide bonus incentives for projects located in "grid-challenged" areas, especially to the degree projects can be dispatched to reduce load during peak periods.

Conservation Improvement Program:
While CenterPoint's submitted comments express opposition to APS and RPS carve-outs for CHP, the company states that it is "open to" CIP policy adjustments for CHP – with some caveats. CenterPoint notes the company's position that CHP projects shouldn't favor gas utilities to the detriment of electric utilities, or vice versa. Also it observes that CHP projects are "unusual and do not occur on a regular basis," suggesting that setting annual CHP goals might be less practical than allowing utilities to apply CHP savings toward their CIP goals. Additionally, CenterPoint asserts that capital cost incentives are more appropriate for CHP than operational incentives, but that if operational incentives are deemed necessary, "then CIP is not the proper source of funding for such incentives." Moreover CenterPoint objects to the incentive levels discussed in FVB Energy's proposals, stating that the hypothetical $0.75/MMBtu incentive exceeds the company's delivery charge ($0.4929/MMBtu) for the customers CenterPoint says are most likely to install CHP systems.

The Midwest Cogeneration Association, on the other hand, disagrees with the FVB Energy proposed methodology for calculating energy savings from topping-cycle CHP, asserting that it's less accurate than other methods and could undervalue actual efficiency achieved. The proposed "tiered" approach, for example, could discourage systems for specific thermal applications that make them inherently incapable of achieving the highest efficiency tiers. Specifically the association "objects to any method that fails to credit a CHP system with 100 percent of its electricity output."

Additionally the Midwest Cogeneration Association supports the FVB Energy proposed option of creating a system of tradable credits (to help alleviate disparities among utility service territories), but it notes that any such trading program should separate emission reduction credits (ERC) from tradable credits, allowing ERCs to be sold separately or retained for compliance. The association also notes that the trading program merits more detailed discussion than it's received so far.

Finally the association suggests that any new CHP CIP provisions should encourage participation by large commercial and industrial customers that otherwise have opted out of CIP. Specifically the association recommends considering streamlined approval processes for customers' self-directed energy efficiency projects, similar to an approach Commonwealth Edison has adopted in Illinois. Additionally the Midwest Cogeneration Association refers to "on-bill" financing options that would allow utilities to finance CHP systems and charge the costs to host customers through their bills over time. The association suggests that such an approach would allow customers to avoid up-front costs and thereby might encourage them to participate in CIP.

Utility Policy Concerns:
The electric utility commenters – Great River Energy, Minnesota Power, Otter Tail Power, and Xcel Energy – expressed opposition to all of the FVB Energy proposed policy options.

Generation and transmission cooperative Great River Energy states that "[e]stablishing a formula for incentives for specific technologies is unprecedented," and that requirements "to derive a specific percentage of energy 'savings' from CHP facilities places an unachievable burden on many of GRE's member cooperatives." In particular Great River Energy objects to an alternative compliance payment option for utilities that don't meet CHP goals, stating that this "troubling" proposal would, in effect, cause GRE members' to pay for CHP projects outside their service territories.

The three investor-owned utilities (IOU) note that CIP is designed to encourage conservation and not energy production, and therefore CIP is an inappropriate framework for CHP investments – with the exception of waste heat recovery projects, which already can qualify under CIP. Minnesota Power states that topping-cycle CHP projects can't be compared with current CIP projects because "[r]educing energy usage is always more cost-effective than adding efficiencies to energy production." Minnesota Power also argues that savings benefits for CIP projects are calculated on a one-year measurement, while CHP projects produce savings measured over many years.

Otter Tail notes that CIP doesn't provide specific requirements for any particular energy efficiency measure, and doing so for CHP would be unprecedented. Also the company adds that while it hasn't included customer CHP projects in CIP, it has provided incentives for waste heat recovery through the separate Custom Grant program for commercial and industrial conservation and efficiency improvements. Otter Tail suggests that a Custom Grant approach "creates a neutral playing field for traditional CIP projects and CHP."

Additionally, Otter Tail Power specifically disagrees with the FVB Energy proposed formula for calculating CHP incentives, stating that it includes administrative costs that aren't comparably considered for other CIP program offerings. "Including only incentive costs in the formula makes an apples to apples comparison … and reduces the incentive amount by half."

Xcel Energy expresses concern about potential cross-subsidy, stating that including topping-cycle CHP applications in CIP would impose cost burdens on residential customers to subsidize investments that primarily benefit commercial and industrial customers. Xcel and Otter Tail both identify potential issues accounting for benefits derived from CHP deployment. Xcel suggests that increasing end-use efficiency by adding CHP would displace natural gas purchases, which could complicate the fair allocation of incentive costs among gas and electric customers. CenterPoint states, however, that solutions "are not difficult to imagine," including a "system-view" approach that evaluates the overall efficiency of energy use at a facility and assigns energy savings to gas and electric utilities on the basis of total energy saved.

Otter Tail notes that using electric utility CIP funds for a natural gas-fired CHP facility would represent "targeted fuel switching" explicitly prohibited by previous Minnesota policies. Allowing funding for CHP projects through CIP would therefore necessitate allowing consideration of other fuel switching options, according to Otter Tail. Moreover, the company asserts that economic CHP potential in its service territory is "virtually non-existent," plus it opposes the proposed remedy for such market disparities – *e.g.,* a statewide system of tradable CHP credits.

Minnesota Power expresses concern that economic CHP projects could be dramatically larger than traditional CIP efficiency projects, with the effect that commensurate treatment for CHP could cause it to dwarf other options in existing CIP budgets, and also that adding a separate tier for CHP within CIP would cause utilities to incur administrative costs even if no projects get built. However, the company suggests that if the state decides to add a new tier to CIP, it should implement that tier as a "generation improvement program," with evaluation criteria designed specifically for evaluating generation projects.

Further, Minnesota Power notes that CHP projects using renewable fuels currently are eligible for cost recovery by utilities, and the company supports giving preference to renewable CHP projects and also supports expanding cost recovery options for CHP projects that aren't currently eligible to meet RPS requirements, arguing that "these projects provide carbon-free efficiency improvements."

Integrated Resource Planning:
Great Plains Institute and the Midwest Cogeneration Association suggest that further stakeholder discussion about CHP policy options could be helpful in the context of utility IRP processes. The Midwest Cogeneration Association supports FVB Energy's proposal to require consideration of CHP in utility IRP, observing that it would help to remedy discrimination against CHP, including third party-owned projects. Xcel Energy reports that its next IRP will include analysis of the costs, benefits, and effects of including higher levels of distributed generation, such as CHP and also photovoltaics and other technologies. Minnesota Power, however, recommends against using IRP processes to evaluate CHP projects. "The IRP planning horizon is 15 years and would require highly generalized assumptions for generic CHP projects many years in the future," the company states.

Finally, the Minnesota Chamber of Commerce observes that no matter what policy options Minnesota might pursue, new fossil fueled CHP plants must be smaller than 50 MW of generating capacity under current law (*Minn. Stat. §216H.03 subd. 3 (2014))*, and that limitation reduces CHP's potential efficiency benefits in the state. Unless the law is changed to exempt CHP projects, the Chamber of Commerce suggests "the current statute will continue to contradict Minnesota's nation-leading energy conservation policies and the federal Public Utility Regulatory Policies Act of 1978."

Capital Costs and Utility Investment Prospects

Many of submitted comments focus on the potential for utility companies to deploy low-cost capital to install CHP systems at the sites of customers who want CHP and whose thermal loads support the investment.

BlueGreen Alliance identifies "upfront capital cost as the most critical barrier" to CHP expansion. Its comments suggest that third-party ownership models – including utility investment – could help overcome that barrier, and the organization encourages resolving questions involving utility financing and operation of CHP systems located at customer sites. The Minnesota Chamber of Commerce observes that utility rate-base investment in CHP could benefit both utilities and customers by allowing utilities to earn regulated returns on distributed generation assets while host customers gain access to economical thermal energy. This approach, the Chamber says, would avoid load loss for utilities and allow customers to focus on investments in their primary business interests. Vergent Power Solutions suggests that gas utilities are "best placed to administer incentive programs for CHP." The company notes however that both electric and gas utilities should be motivated to promote CHP deployment. Fresh Energy recommends gaining additional input from prospective CHP host customers to ensure policies would be acceptable and favorable toward implementing CHP projects.

Third-Party and Customer Financing:
The Western Lake Superior Sanitary District (WLSSD) states that the FVB Energy proposed policy options over-emphasize the economics of IOUs and give utilities too much control over CHP project review, funding, and returns. WLSSD states that many factors influence the way non-IOU organizations evaluate CHP, and suggests that IOUs don't weigh those factors in the same way. Specifically, WLSSD states that its planned CHP facility could help the organization reduce its carbon footprint, increase its sustainability, and control water treatment costs for customers. Thus WLSSD calls for "a healthy balance" of projects operated by utilities and other organizations. "Policy changes need to provide a satisfactory incentive to encourage both utilities and non-utilities to pursue CHP opportunities," WLSSD states.

Further, Cummins Power Generation favors policy options that provide flexibility for commercial and industrial energy users to purchase energy from third parties, and for CHP operators to sell their output in energy markets. Cummins suggests greater flexibility would accelerate and expand CHP opportunities by allowing customers to capture CHP benefits "without the burden of high capital expenditures or liability of maintenance and service."

Utility Financing Issues
Utility commenters express general support for the idea of allowing utility investment in CHP facilities at customer sites. Some of their specific comments and suggestions include the following:

- Great River Energy suggests that clarifying how utilities could invest in CHP might result in greater CHP deployment within existing policy frameworks.
- Otter Tail proposes giving utilities the right of first refusal in ownership of CHP facilities, and limiting the size of third-party and customer-owned CHP systems to the capacity requirements of their thermal hosts.
- CenterPoint emphasizes the need to ensure utility investment in CHP doesn't expose ratepayers to inappropriate risks, and to clarify the nature of projects that would be suited for utility investment.
- Minnesota Power states, "For future company owned CHP projects to be successful, the regulatory framework for evaluating these projects will need to give more consideration to factors besides cost." The company cites as recent example the PUC's disapproval of its plan to put an existing CHP facility into its rate base, on the basis that doing so would marginally increase Minnesota Power's regulated operating costs.

- Xcel notes that utilities don't always have the tax liabilities needed to make them eligible to benefit from tax-credit incentives often used to encourage clean energy investments.

Great Plains Institute recommends further examination of the prospects and implications of utility investment in CHP facilities of various sizes and types, and notes that questions involving utility investment in distributed generation are being considered as part of its "e21 Initiative," which seeks to examine alternative regulatory approaches such as performance benchmarks for earning returns.

Economic Potential and Value Proposition

Most commenters acknowledge potential for economical CHP, with some disagreement regarding the magnitude of market potential as well as CHP valuation methodologies.

Valuing CHP Attributes:
BlueGreen Alliance asserts that CHP's broad range of benefits justify incentives that appropriately assess the value of its environmental, societal, and system attributes. The Minnesota Chamber of Commerce adds that CHP at high load-factor sites can provide local base-load energy supply that supports grid reliability and reduces the need for transmission investments.

The Midwest Cogeneration Association states that opportunities for economical CHP in Minnesota might be underestimated due to utility avoided-cost tariffs calculated on the basis of marginal generation costs as opposed to the costs of adding new generation in the future. The association adds that Minnesota laws allow "only very limited sales of electricity or thermal energy except by utilities." The result, according to the association, is that CHP projects may be sized only to serve the host facility's electricity consumption rather than to also provide power to the utility grid and thereby achieve greater cost effectiveness and efficiency. Accordingly, the Midwest Cogeneration Association recommends further studying the effects on CHP potential of Minnesota policies regarding avoided cost calculations and limits on third-party sales.

Xcel Energy favors a "holistic and balanced approach" to providing incentives that are intended to serve environmental goals. "It is important that the technology options available for reducing emissions are compared against one another, to provide the maximum environmental benefit for the least customer impact," Xcel states. In addition to cost factors, Xcel recommends that comparisons also should value system factors such as dispatchability.

Otter Tail expresses concern that societal benefits included in CHP valuation are difficult to measure, verify, and quantify. Moreover, the company questions FVB Energy's recommended CO_2 equivalent price of \$25 to \$50 per metric ton, and suggests instead using established CO_2 values of \$9 to \$34 per ton.

Assessing CHP Potential:
Fresh Energy recommends ensuring that policies include measures of CHP value that encourage not only large systems for industrial users, but also smaller units for customers of other sizes. Vergent Power

Solutions echoes this recommendation, and adds that "vast" potential exists for CHP applications at apartment buildings, hospitals, office buildings, data centers, and light industrial and processing facilities, many of which might be relatively small in thermal load requirements.

Great Plains Institute encourages more analysis of opportunities at public sector facilities and institutions, including wastewater treatment facilities. Accordingly, WLSSD notes that its planned CHP project would produce a range of benefits, including greenhouse gas reductions and increased use of local renewable energy resources, and suggests that such benefits deserve appropriate valuation when considering economic potential in the context of state policy goals and the interests of Minnesota energy customers.

Advocacy groups Great Plains Institute and BlueGreen Alliance suggest that mapping waste heat sources and "high value" sites in Minnesota could help prioritize CHP development, as well as utility resource planning and environmental compliance planning efforts.

Xcel Energy's comments refer to a study performed by the Electric Power Research Institute (*see Appendix B*) estimating the CHP potential in Xcel's Northern States Power territory. Xcel says the study identifies 305 MW of CHP projects that could achieve payback within six to 10 years. That total, according to Xcel, includes two CHP projects totaling 71 MW now in planning stages, leaving 234 MW of new CHP potential.

Xcel adds that the EPRI study indicates that reducing capital costs by 50 percent increases the total economic CHP potential in the NSP territory by only 15 percent, and that "removing standby rates did not have a huge impact on improving economic potential."

Standby Rates

Several commenters refer to a parallel process at the Minnesota Department of Commerce related to the Minnesota PUC's prospective proceeding on standby rates for distributed generation.

Otter Tail Power briefly summarizes its comments to the Department in that process. First, it notes that the PUC's 2004 order establishing standards for setting standby rates "provides a solid foundation," and that further standby rate design efforts are unnecessary. Second, the company notes that its standby rate design incorporates many of the attributes recommended by presenters at the Department of Commerce's Sept. 11, 2014 meeting. Third, it refers to comments from that meeting that suggest that changes to standby rates wouldn't affect key investment criteria for CHP projects.

Some submitted comments, however, disagree with the assessment that Minnesota's standby rates are sufficient and effective. Midwest Cogeneration Association reports that its members identify instances in which Minnesota utility standby charges are "not cost justified and unfairly discriminate against distributed generation." Cummins Power Generation states that the current standby rate structure "severely limits" CHP potential for small commercial and industrial facilities, and WLSSD adds that uncertainty about standby rates could prevent its proposed CHP project from proceeding. WLSSD notes that current standby rate structures don't support customers' need to anticipate potential standby charges, and they impose fees on the basis of nameplate generating capacity rather than actual customer load patterns and standby energy requirements.

Vergent Power Solutions states that standby rates and exit fees can substantially affect small-scale CHP projects in particular, and accordingly it recommends that such charges should be waived for projects smaller than 500 kW and reduced for projects smaller than 2 MW in size.

Midwest Cogeneration Association encourages the PUC in its generic proceeding to review standby rates on the basis of principles identified by the Energy Resource Center and the Regulatory Assistance Project, namely, that standby charges should be:

- Based on the cost that serving the distributed generation customer poses for the utility;
- Transparent and unbundled to allow for the appropriate allocation of energy, capacity, transmission and distribution, and administrative costs;
- Fair to the utility, the distributed generation facility, and other utility customers – they should not shift costs from one class of customer to another; and
- Structured to encourage partial use customers to efficiently use standby power from the grid.

Training and Education Needs

Some comments provide insight into needs for additional CHP-focused training and education resources in Minnesota. WLSSD notes that many opportunities for CHP may exist, but that customers lack the technical expertise and knowledge to either recognize or exploit those opportunities. WLSSD suggests that making available low-cost (or no-cost) expertise and information resources could help prospective CHP hosts to assess and pursue project opportunities.

Additional comments from stakeholders participating in the Minnesota CHP Stakeholder Engagement process – obtained by telephone survey – suggest that the state's technical workforce is adequately positioned to support CHP project design, construction, operations, and maintenance. However, stakeholders suggest that CHP prospects could benefit from educational capabilities and resources focused on helping energy users assess CHP potential for their facilities, as well as how to manage policy, legal, and finance issues related to project planning and development.

Conclusion: Issues for Consideration

Participants in the Minnesota CHP Stakeholder Engagement process represent a broad cross-section of organizations and individuals in the state's commercial, institutional, and regulatory sectors. Accordingly, they bring a variety of perspectives and experiences to the issues affecting CHP deployment.

Minnesota's utilities express general opposition to CHP policy options that envision new regulatory requirements. Their reasons tend to target the basic assumptions underlying the proposed options – *i.e.,* estimations of market potential, comparative economics, and underlying environmental and energy policy strategies. Additionally, they indicate concerns about unintended consequences – such as potential cross-subsidies, community burdens without commensurate benefits, and policies that favor natural gas companies at the expense of electric companies.

At the same time, however, Minnesota's utilities also acknowledge substantial potential for CHP in some parts of the state. And they support policy changes that would clarify their ability to obtain regulated cost-recovery for investments in CHP assets at customer sites where those investments make sense. In all cases, utilities assert their interest in evaluating CHP potential according to the criteria they consider important, in the context of their fiduciary and public utility obligations.

While acknowledging the legitimacy of those interests, however, potential CHP customers and vendors identify structural barriers in current policies and standards that they suggest unnecessarily complicate CHP projects and inflate project costs. Some stakeholders express concern about policies that focus too much on driving utility investment in onsite power systems. Others assert that energy policy priorities support establishing appropriate price signals for environmental, social, and system attributes, and implementation challenges shouldn't prevent the state from continuing its leadership in promoting conservation and clean energy alternatives to serve customers.

Based on submitted comments and issues discussed during CHP Stakeholder Meeting #3 on Oct. 15, 2014, the Department of Commerce identified the following issues for further examination during Meeting #4, scheduled for Nov. 5, 2014:

- Establishing criteria for evaluating CHP projects and comparing them to alternative solutions
- Identifying "high-value" opportunities to prioritize CHP deployment and resource planning
- Balancing provisions for CHP investment by utilities, customers, and third parties, respectively
- Clarifying the implications of policy options and resolving potential conflicts and unintended consequences
- Developing effective education and assistance tools to facilitate CHP deployment

The Minnesota Department of Commerce welcomes additional input and interaction, and expects to continue the process of CHP stakeholder engagement. In addition to discussion opportunities during additional meetings in the series, the Department expects to arrange a second comment period in the CHP Stakeholder Engagement process. When details about that comment period become available, they will be communicated to stakeholders and publicized via the Department's website.

Appendix A:
CHP Comment Period Invitation
via email to stakeholders, Sept. 25, 2014

A comment period is now open from September 24 through October 10. The Minnesota Department of Commerce invites stakeholders to submit written comments regarding issues and factors affecting CHP deployment in Minnesota. Possible topics for comment may include, but are not limited to:

- FVB Energy's proposed CHP policy options
- CHP finance, policy, technical application, and education and training needs
- Alternative mechanisms and approaches to facilitate economically efficient deployment of CHP in Minnesota
- Current barriers and issues hindering CHP projects
- Resource planning, strategic, and regulatory factors affecting CHP options and potential
- Any other CHP issues that stakeholders would like to comment on

Please submit written comments in PDF format no later than Oct. 10, 2014, to the following email address: cip.contact@state.mn.us

If you have any questions, please contact Jessica Burdette atJessica.burdette@state.mn.us or 651-539-1871 or me via the information in my signature. Thank you!

Adam Zoet
Energy Policy Planner
Minnesota Department of Commerce
85 7th Place East, Suite 500, Saint Paul, MN 55101
P: 651-539-1798

Appendix B:
EPRI Xcel Northern States Power Territory CHP Potential Report summary

Background
Resource Dynamics Corp. (under contract with the Electric Power Research Institute) analyzed the technical and economic potential for commercial and industrial CHP projects in the Minnesota service territory of Xcel Energy.

The report includes data pertaining to maximum demand, annual energy consumption, and commercial and industrial segment for customers with maximum demands of 1 MW or larger. Customers with load factors below 20 percent aren't analyzed, with the reason given that their peaky load profiles tend not to support favorable economics with baseload DG/CHP installations. The full report is available via the Minnesota Department of Commerce website.

Summary
The Resource Dynamics Corp. report identifies several key areas that potentially could impact adoption of CHP in Xcel Energy's service territory through 2040. Specifically, it states that the greatest potential is seen in facilities capable of installing CHP systems larger than 1MW.

A key factor affecting the development of CHP systems is payback period. The report shows 305 MW of economic potential with payback periods of six to 10 years. Institutional sites such as colleges and hospitals have demonstrated a willingness to accept longer payback periods for investments like CHP systems. Given a seven- to 10-year payback, this segment shows an economic potential of 105 MW and perhaps the greatest likelihood for market adoption. Typically industrial facilities require payback on such investments in no more than three years, which suggests they are less likely to adopt CHP.

Examining potential financial structures for CHP projects, the report shows that removing standby rate charges improves project economics for all facilities, improving the payback period by up to one year. This increases total economic CHP potential by 22 MW.

The report also indicates that when incentives of up to 50 percent of the installed cost are applied, all high load-factor sites show economic potential, including those in the 100 kW to 1 MW range. The total economic potential is estimated at 471 MW in this case.

Comparing installation incentives to other incentives in terms of their environmental cost-benefit attributes, the report states that providing a 50 percent installation incentive equates to $104 to $107 per ton of CO_2 reduction. This outweighs the cost of Xcel Energy's DSM program, which is $4.32 per ton.

CHP Market and Segment Profile
According to the report, only large industrial facilities, hospitals, universities, and hotels show economic potential in the base case scenario, all for CHP applications that can utilize waste heat for thermal energy.

The report identifies the greatest economic potential at sites capable of installing CHP sized larger than 1 MW. In terms of total CHP capacity, office buildings showed the largest technical potential for economically sized CHP, followed by chemical/petroleum/coal manufacturing. While the economics for hospitals and colleges might not be as strong as large industrial facilities, they have demonstrated willingness to accept lengthy payback periods for investments such as CHP systems.

Potential CHP Demand

The report identifies 628 sites in Minnesota with peak demand greater than 1 MW that show technical potential for CHP systems. However, based on the economic DG/CHP sizing, less than half could support systems larger than 1 MW.

Reported technical potential for CHP based on economic size range:

Size	**Number of Sites**	**Technical Potential (MW)***
100 kW-1 MW	378	202
1-5 MW	223	348
>5 MW	25	217

**For economically sized CHP*

Under current market conditions, the report states that large industrial facilities that can install CHP systems over 5 MW in size have the most attractive project economics (currently limited to paybacks no longer than seven years.)
Hospitals in the 1 to 5 MW size range also show some potential but with seven- to 10-year paybacks, and they may be willing to take on projects with longer payback periods.

CHP Return on Investment

The report showed 305 MW of economic potential with payback periods of six to 10 years. The 105 MW of economic potential from colleges and hospitals in the seven- to 10-year payback range might offer the highest likelihood for market adoption, especially since many manufacturing facilities require three-year paybacks to justify energy investments.

Using regional EIA-predicted escalation rates for electricity and natural gas are less favorable for DG/CHP applications – sites with economic potential in the six- to seven-year range shifted to seven to 10 years, and economic potential declined by more than 100 MW to 203 MW.

The report shows that removing standby rate charges improves project economics for all facilities, typically reducing the payback period by nearly one year. This only increases the economic potential by 22 MW, but stronger economics would make facilities more likely to adopt CHP. Most of the large industrial facilities in the six- to seven-year payback range shift to five- to six-year paybacks, while hospitals with seven- to 10-year payback periods have shifted to the six- to seven-year range.

The report refers to a 2003 survey “Converting Distributed Energy Prospects into Customers,” performed by Primen Research. The EPRI/Resource Dynamics report selects for analysis this survey’s results for “soft” prospects (aware of CHP as an option) and “strong” prospects (considering DG/CHP) to estimate the percentage of Xcel Energy’s customers that would adopt CHP. The Primen survey results showed that strong prospects may be more willing to accept longer payback periods,

Effects of Incentives on CHP Deployment

The report indicates that when incentives of up to 50 percent of the installed cost are applied, all high load-factor sites (those with significant electric and thermal loads 24 hours a day, seven days a week) show economic potential, even those sized in the 100 kW to 1 MW range. The total economic potential is estimated at 471 MW in this scenario. Incentives of 40 percent or less of installed costs show minimal impact on economic potential and adoption.

The report shows that at the 50 percent cost reduction incentive, the market opens up to CHP systems smaller than 1 MW, with many of these facilities showing economic potential. Additionally, market adoption would occur significantly faster than the base case, with up to 200 MW projected for adoption within five to 10 years. However, the report states that even with a 50 percent cost reduction, many customers (primarily those with potential CHP applications under 1 MW) are still in the seven- to 10-year payback range, where the likelihood of CHP adoption is minimal.

With the base case assumptions, 134 to 179 MW of new CHP capacity is estimated to enter service by 2030, enough to displace between 1,056 and 1,411 GWh of Xcel Energy’s electricity sales. If a 50 percent installed cost incentive were offered, the adoption by 2030 would increase to between 287 and 386 MW of CHP, enough to displace between 2,263 and 3,043 GWh of electricity.

CHP and Emissions Reduction

The report shows an overall reduction in greenhouse gas emissions for all CHP units when the effects of thermal recovery are considered in CHP that fully utilizes the waste heat to displace an 80 percent-efficient natural gas boiler. Considering the cumulative effects of CHP, adopting 220 to 340 MW of new CHP would reduce Xcel’s CO_2 emissions by between 1.8 and 2.7 million total tons by 2025.

The report shows that at an average CHP cost of $1,700 per kW, $850,000 would be needed to provide a 50 percent incentive for each MW of total CHP adoption ($187 to $289 million for the 220 to 340 MW of CHP modeled in the report). This amounts to the incentives providing $104 to $107 per ton of CO_2 reduction. The report compares these figures to the $4.32 per-ton costs for Xcel Energy’s DSM program.