# 8.0 Renewable Energy Standards

## 8.1 Introduction

Minnesota Statutes § 216B.2425, subd. 7, states that in the Biennial Report the utilities shall address necessary transmission upgrades to support development of renewable energy resources required to meet upcoming Renewable Energy Standard milestones. In its May 30, 2008, Order approving the 2007 Biennial Report and Renewable Energy Standards Report, the Commission said, "Future biennial transmission projects reports shall incorporate and address transmission issues related to meeting the standards and milestones of the new renewable energy standards enacted at Minn. Laws 2007, ch. 3."

In the 2007 Biennial Report, the utilities submitted a separate, extensive Renewable Energy Standards Report in response to direction from the Legislature for such a report. The legislation (Minn. Laws 2007, ch. 3, § 2) required the utilities to address specific issues identified in the law. Readers are referred to the 2007 Report for additional detail.

In addition, Minnesota Statutes § 216B.1691, subd. 3, requires the utilities to periodically report to the Commission on their "plans, activities, and progress" with regard to the RES requirements and demonstrate to the Commission their efforts to comply with the standards. In 2008 the Commission opened a separate docket to specifically consider the utilities' efforts to meet the RES requirements. Docket No. is M-08-1163 (*In the Matter of Commission Consideration and Determination on Compliance with Renewable Energy Obligations and Renewable Energy Standards*). As part of that docket, each of the utilities provided extensive information about its individual situation and its efforts to meet the RES. The Commission recognized that its decision in the RES docket did not preclude the Commission or others from requesting additional data, and the utilities are required to submit another compliance report by November 15, 2010.

It is not the intent here to attempt to repeat or even summarize the whole of the data provided in the RES compliance docket. The biennial reporting process focuses on transmission. In response to the Commission's direction, the utilities are reporting on their best estimates for how much renewable generation will be required to meet the Minnesota Renewable Energy Standards in future years and what efforts are underway to ensure that adequate transmission will be available to convey that energy to the necessary market areas.

A Gap Analysis is provided to illustrate the amount of renewable generation that is already available and how much will be required in the future to meet the standard. The utilities also report on the transmission lines that will be relied on to bring renewable energy to their customers to satisfy RES requirements. Further, a brief analysis of two significant issues affecting the utilities' ability to obtain renewable energy – allocation of transmission costs and other states' requirements for renewable energy – is included. Finally, information responsive to the PUC's August 10, 2009, Order in the CapX 2020 Certificate of Need proceeding is provided.

## 8.2 Reporting Utilities

It should be pointed out that the utilities that are required to submit the Biennial Transmission Projects Report are not identical to those that are required to meet the Renewable Energy Standards. The information in this chapter reflects the work of all the utilities that are required to meet RES milestones, regardless of whether they own transmission lines and are required to participate in the Biennial Report. A list of those utilities participating in the Biennial Transmission Projects Report can be found in Chapter 2.0. The utilities participating in this part of the 2009 Biennial Report on renewable energy are the following.

*Investor-owned Utilities*

Interstate Power and Light Company
Minnesota Power
Northern States Power Company, a Minnesota corporation
Otter Tail Power Company

*Generation and Transmission Cooperative Electric Associations*

Basin Electric Power Cooperative
Dairyland Power Cooperative
East River Electric Power Cooperative
Great River Energy
L&O Power Cooperative
Minnkota Power Cooperative

*Municipal Power Agencies*

Central Minnesota Municipal Power Agency
Minnesota Municipal Power Agency
Southern Minnesota Municipal Power Agency
Western Minnesota Municipal Power Agency/Missouri River Energy Services

*Power District*

Heartland Consumers Power District

## 8.3 Compliance Summary

On August 31, 2009, the Commission issued its Order Finding Utilities in Compliance With Reporting Requirements and Objectives of Renewable Energy Obligations – Renewable Energy Standards Statute in Docket No. M-08-1163. The Commission specifically found that twelve of the reporting utilities were in compliance with the 2007 Renewable Energy Objective of one percent, and the other four had made good faith efforts to comply. The Commission found that all sixteen have plans to meet the renewable energy objectives for the years up to and including 2010.

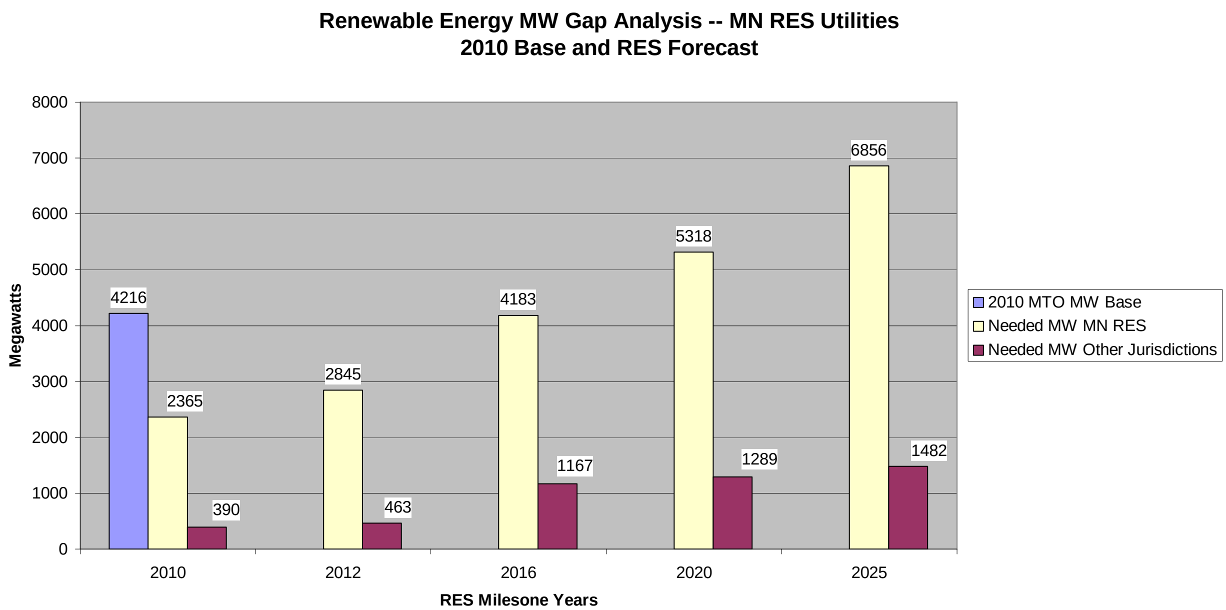
The utilities have made substantial progress with respect to meeting future RES milestones. The present analysis shows that the utilities are on course to meet the RES milestones for 2010, 2012, and 2016. Significantly, the utilities have determined that without the addition of the CapX 2020 Group 1 projects, the transmission system in the 2016 timeframe would not be adequate to meet the combined 2016 Minnesota RES and non-Minnesota RES milestones. The utilities recognize that additional transmission and generation will be necessary for 2020 and beyond in Minnesota, and that other demands for renewable energy will impact Minnesota's compliance status.

## 8.4 Gap Analysis

In the 2007 Renewable Energy Standards Report, updated in a Supplemental Compliance Filing submitted on September 11, 2008, the utilities provided information referred to as a Gap Analysis. A Gap Analysis is an estimate of how many more megawatts of renewable generating capacity will be required beyond what is already available to obtain the required amount of renewable energy that must come from renewable sources at a particular time in the future. It is important to understand, however, the Gap Analysis described here was prepared for transmission planning purposes. This Gap Analysis is not an exercise intended to verify the validity of forecasted energy sales and associated capacity needs. Each utility must verify the validity of its own sales forecast and capacity requirements. This Gap Analysis assumes energy and capacity forecast validity and then incorporates such results into evaluating future transmission needs.

### 2010 Base Capacity and RES/REO Forecast (Bar Chart # 1)

The bar chart on the following page presents a system-wide overview of existing capacity in 2010 (used as a base figure throughout the various milestone periods) and forecasted renewable capacity requirements to meet Minnesota RES as well as non-Minnesota RES/REO needs. Each utility provided its own forecast of Minnesota RES and non-Minnesota RES/REO renewable energy needs, and converted such estimates into capacity based on their own mix of renewable resources (wind, biomass, hydropower) using the most appropriate capacity factors unique to their specific generating resources.




***Definitions**

1. 2010 MW Base Systemwide = RES capacity acquired, actually installed and operational ("in the ground and running") regardless of geographic location. Does not include projects under contract but not yet under construction, and it does not include projects under construction but not yet completed.

2. Needed MW Minnesota RES = Renewable capacity required to meet the RES energy goals for each utility serving customers in Minnesota.

3. Needed MW Other Jurisdictions = Gross non-Minnesota renewable capacity required to meet RES requirements or REO goals in states served by the reporting utility other than Minnesota.

A more specific breakdown of each utility's Minnesota RES and non-Minnesota RES/REO capacity forecast is as follows:

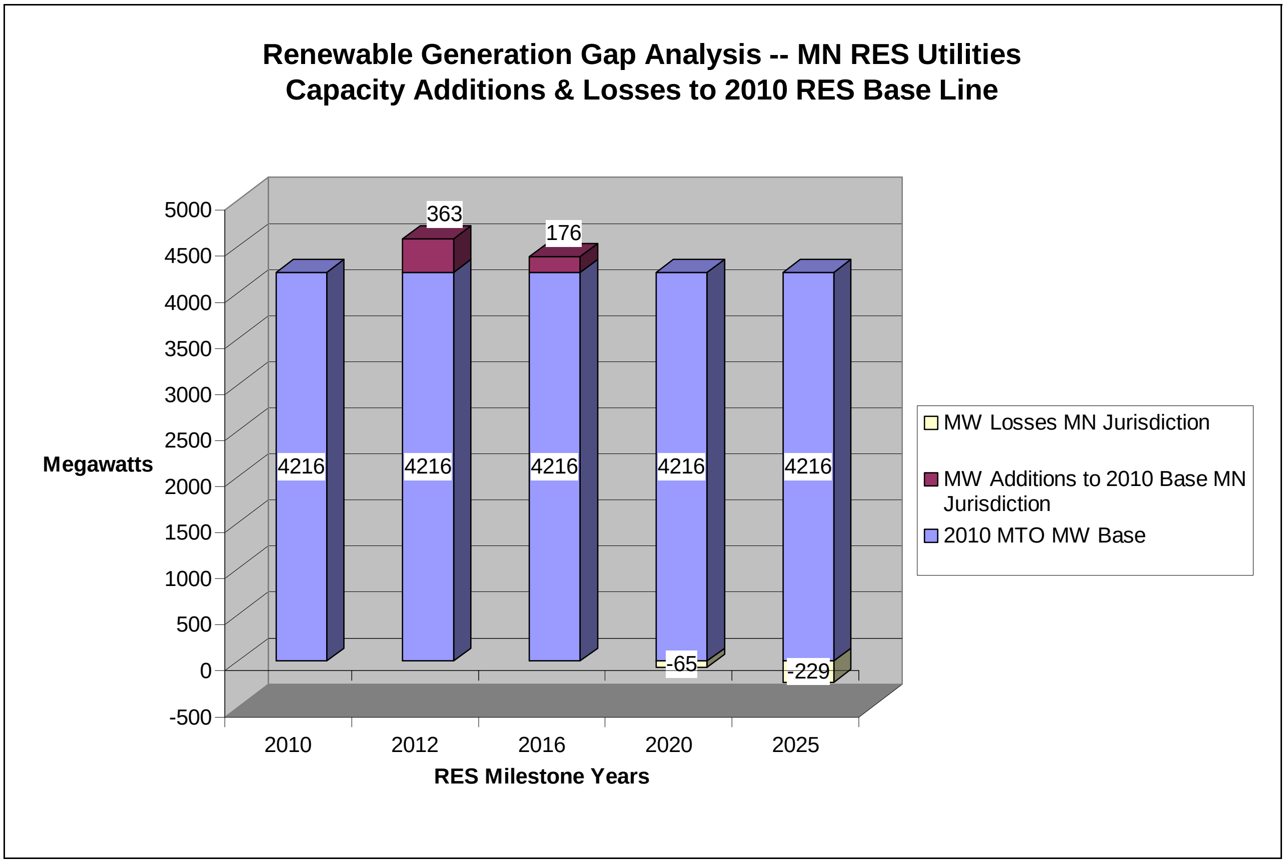
**Table 1. MN & Non-MN RES Forecast (MW)***

| Utility | 2010 | | 2012 | | 2016 | | 2020 | | 2025 | |
|---|---|---|---|---|---|---|---|---|---|---|
| | MN RES | Non -MN RES | MN RES | Non -MN RES | MN RES | Non -MN RES | MN RES | Non -MN RES | MN RES | Non -MN RES |
| Basin** | 3.4 | 45.6 | 53.1 | 92.8 | 90.7 | 306.9 | 120.9 | 333.5 | 181.3 | 358.1 |
| CMMPA | 7.53 | 0 | 13.41 | 0 | 20.32 | 0 | 27.9 | 0 | 37.55 | 0 |
| Dairyland | 13.2 | 74.4 | 23.2 | 130 | 34.9 | 227.1 | 43.6 | 278.5 | 58.3 | 323.7 |
| GRE | 231 | 0.4 | 394 | 0.4 | 587 | 1.6 | 743 | 1.6 | 1,039 | 1.6 |
| Heartland | 9.5 | 0 | 16.5 | 0 | 14.1 | 6.5 | 4.7 | 6.8 | 6.2 | 7.2 |
| IPL | 18 | 50 | 32 | 50 | 49 | 50 | 61 | 50 | 84 | 50 |
| Minnkota | 33 | 0 | 59 | 0 | 90 | 67 | 114 | 72 | 161 | 80 |
| MN Power | 150 | 10 | 291 | 10 | 426 | 17 | 531 | 17 | 683 | 17 |
| MRES | 21.3 | 8.4 | 37.2 | 17.1 | 65.3 | 32.1 | 92.1 | 34.1 | 127.5 | 38.9 |
| SMMPA | 65.23 | 0 | 117.1 | 0 | 180.5 | 0 | 228.9 | 0 | 308 | 0 |
| Otter Tail | 52.2 | 0 | 92.7 | 0 | 140.7 | 69 | 153 | 69 | 190.2 | 69 |
| RPU | 0.9 | 0 | 3.4 | 0 | 7.9 | 0 | 12 | 0 | 12.7 | 0 |
| Xcel | 1,763 | 201.7 | 1,713 | 162.7 | 2,476 | 389.6 | 3,186 | 426.1 | 3,967 | 536.4 |
| **Total** | 2,368 | 390 | 2,846 | 463 | 4,182 | 1,167 | 5,319 | 1,289 | 6,856 | 1,482 |

* Capacity factor assumptions established by each utility.
** Basin Electric numbers include East River Electric and L&O

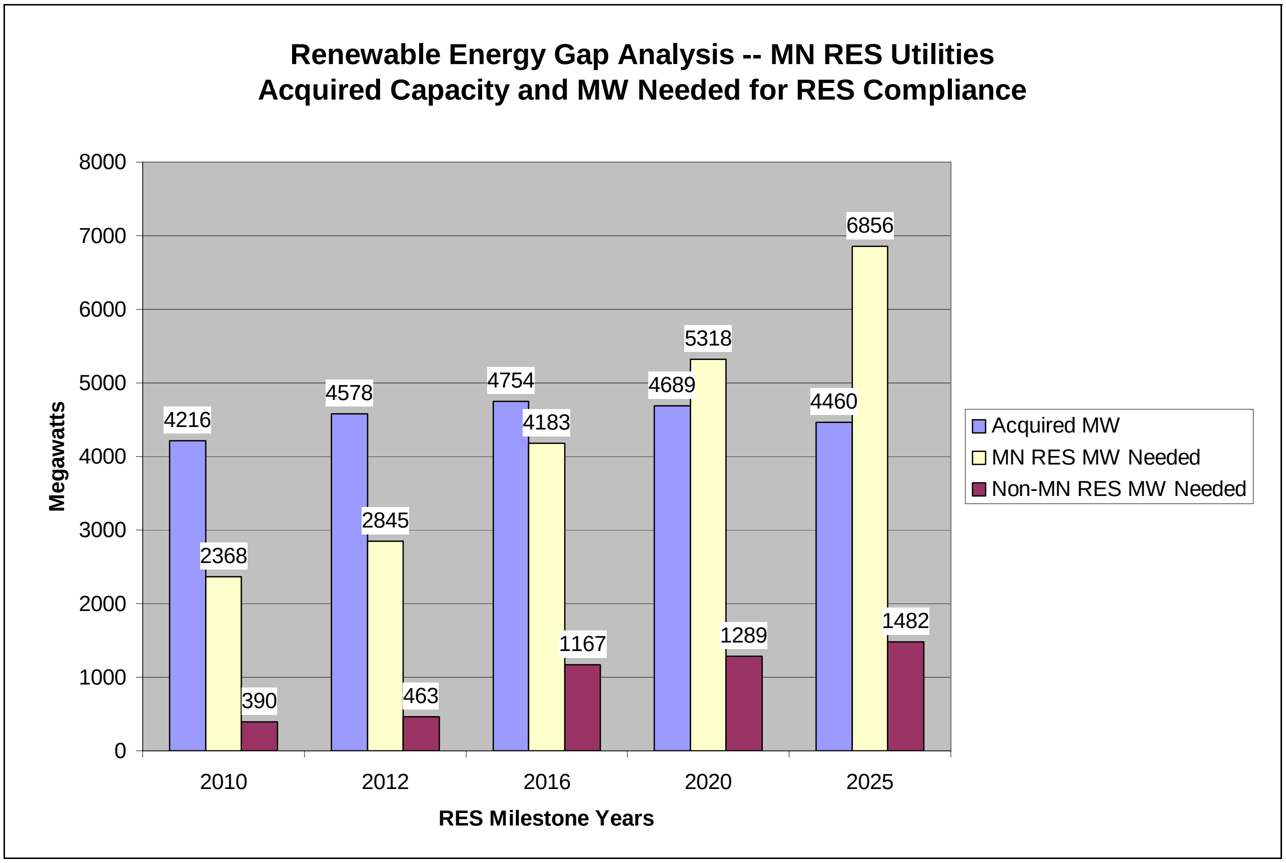
### Capacity Acquisitions & Expirations (Bar Chart # 2)

This bar chart presents a system-wide overview of additional renewable capacity that will be acquired by individual utilities beginning as early as 2012 and capacity that will expire between 2016 and 2025. Such reductions in renewable capacity are attributable primarily due to the expiration of various power purchase agreements for renewable energy generation.



### RES Capacity Acquired and Net RES/REO Need (Bar Chart # 3)

This bar chart represents the total renewable capacity system-wide that will be acquired and lost between 2010 and 2025, as well as the projected total Minnesota RES and non-Minnesota RES/REO needs between 2010 and 2025.



A more specific breakdown of each utility's forecast follows:

**Table 2. RES Capacity Acquired & Net MN RES Capacity Need* (MW)**

| Utility | 2010 | | 2012 | | 2016 | | 2020 | | 2025 | |
|---|---|---|---|---|---|---|---|---|---|---|
| | RES Cap Acq. | MN RES Net | RES Cap Acq. | MN RES Net | RES Cap Acq. | MN RES Net | RES Cap Acq. | MN RES Net | RES Cap Acq. | MN RES Net |
| Basin** | 327.8 | 0 | 479.3 | 0 | 627.8 | 0 | 627.8 | 0 | 620.5 | 0 |
| CMMPA | 19.72 | 0 | 19.72 | 0 | 24.02 | 0 | 44.02 | 0 | 46.42 | 0 |
| Dairyland | 87.7 | 0 | 153.3 | 0 | 262.1 | 0 | 322.1 | 0 | 382.1 | 0 |
| GRE | 216 | 0 | 316 | 0 | 310 | 278 | 299 | 446 | 295 | 745 |
| Heartland | 36 | 0 | 36 | 0 | 36 | 0 | 36 | 0 | 36 | 0 |
| IPL | 23 | 0 | 23 | 0 | 22 | 0 | 20 | 0 | 18 | 0 |
| Minnkota | 359 | 0 | 359 | 0 | 359 | 0 | 359 | 0 | 359 | 0 |
| MN Power | 409 | 0 | 448 | 0 | 420 | 6 | 420 | 111 | 420 | 263 |
| MRES | 82.4 | 0 | 82.4 | 0 | 82.4 | 0 | 82.4 | 9.7 | 82.4 | 45.1 |
| SMMPA | 124.3 | 0 | 125.9 | 0 | 125.9 | 54.6 | 125.9 | 103.1 | 125.9 | 182.1 |
| Otter Tail | 190.2 | 0 | 190.2 | 0 | 190.2 | 0 | 190.2 | 0 | 190.2 | 0 |
| RPU | 7.5 | 0 | 12.5 | 0 | 12.5 | 0 | 12.5 | 0 | 12.5 | 1.87 |
| Xcel | 2,333 | 0 | 2,333 | 620 | 2,282 | 194 | 2,150 | 1,036 | 1,872 | 2,095 |
| **Total** | 4,216 | 0 | 4,578 | 620 | 4,754 | 533 | 4,689 | 1,746 | 4,460 | 3,332 |

* Capacity factor assumptions established by each utility.
** Basin Electric numbers include East River Electric and L&O
*** Some utilities with less than sufficient capacity to meet the MN RES need may use renewable energy credits to fulfill their requirement.

## 8.5 RES Requirements for CapX 2020 Utilities

On August 10, 2009, the Public Utilities Commission issued its Order Granting and Denying Motions for Reconsideration, and Modifying Conditions regarding Certificates of Need for CapX 345-kV Transmission Projects in Docket No. CN-06-1115. In Order Point 7, the Commission directed the utilities to include in the 2009 Biennial Transmission Projects Report certain information relating to renewable energy requirements. Specifically, the utilities were directed to identify the net Minnesota RES capacity need and provide a forecast of the annual non-Minnesota RES or renewable energy objective (REO) capacity required through 2025. This information is included in the Gap Analysis presented above, for more than just the CapX utilities.

In addition to the quantitative capacity data requested by the Commission's Order, the utilities were asked to provide information pertaining to how the capacity data were derived. Specifically, the Order requested the utilities to respond to the following:

- Question 7.A.c.
  Whether an allowance was included for generation capacity to be built in the region for non-CapX purposes;

- Question 7.A. d.
  An explanation of how Minnesota's energy savings goal was incorporated into a utility's capacity forecast; and

- Question 7.A. e.
  A brief discussion of various scenarios regarding the geographic distribution of forecasted capacity needs.

The responses to these questions are set forth in the table below.

| | |
|---|---|
| **CMMPA** | |
| 7.A.c. | CMMPA has no non-Minnesota load and no non-CAPX members, hence no allowance was used for non-CAPX generation capacity additions. |
| 7.A.d. | Energy efficiency gains are included in the load forecast, albeit not higher than .75% in any year of the forecast horizon. |
| 7.A.e. | CMMPA's planned RES capacity would likely be added within the southern/central Minnesota area but, depending on wind capacity factors and the appetite for individual municipal utilities to have generators within their territories, the specific locations are in flux. |
| **Dairyland** | |
| 7.A.c. | If a non-CapX utility proposes a project within Dairyland Power Cooperative's (DPC) transmission system, DPC works with the utility to develop the project. An example of this is the 99 MW Crane Creek Wind Farm being developed by Wisconsin Public Service near Riceville, Iowa. |
| 7.A.d. | Energy efficiency gains are included within DPC's load forecast. The need for renewable energy projects is adjusted according to the load forecast. The challenge of attaining and sustaining 1.5 percent energy savings goals into the future will impact the timing of renewable energy projects. |
| 7.A.e. | DPC's service area encompasses 62 counties in four states (Wisconsin, Minnesota, Iowa and Illinois). Renewable energy projects will be sited based on developer preferences, availability of resources and cost. For example, the wind farms in DPC's system are in Minnesota and Iowa due to the better wind conditions when compared to Wisconsin. |
| **Great River Energy** | |
| 7.A.c. | None included. |
| 7.A.d. | Capacity forecast assumes meeting a 1.5% energy conservation goal through programs that reduce retail sales about 1% and system efficiency improvements that do not reduce retail sales about 0.5%. |
| 7.A.e. | GRE plans to add resources connected to MISO transmission facilities or that can otherwise deliver energy into the MISO market. Specific locations have not been determined and will depend on individual project competitiveness. Most likely they will be in MN, ND, SD, or IA. |

| | |
|---|---|
| **MINNKOTA** | |
| 7.A.c. | No allowance applicable. |
| 7.A.d. | The 1.0 percent and 1.5 percent goal was not incorporated. |
| 7.A.e. | There are numerous scenarios regarding future geographic distribution of interconnection needs. It is difficult to assess which scenarios are most probable but the bulk of such options will occur in North Dakota. |
| | |
| **Minnesota Power** | |
| 7.A.c. | None included. |
| 7.A.d. | The impact of conservation and DSM/CIP programs are assumed implicit within MN Power's energy projections and are incorporated into the price and income coefficients. The effects are therefore quantified in the econometric model specifications of MN Power's retail sales forecast. |
| 7.A.e. | MN Power anticipates additional North Dakota wind facilities with energy delivered to its service territory via the Square Butte to Arrowhead DC line. |
| | |
| **Otter Tail** | |
| 7.A.c. | None included. |
| 7.A.d. | Minnesota's 1.5% energy savings goal was incorporated into the forecast for energy requirements. For 2010, the goal was 1.05% and for 2011 and thereafter the goal was 1.5%. For each year, the conservation was calculated based on the prior three-year average of retail sales. Renewable generation requirements were calculated based on the conserved forecast. |
| 7.A.e. | Of the projected unacquired renewable generation, 8 MW is anticipated to come from a heat recovery unit located in Minnesota. An additional 61 MW of wind will be required in 2025, assuming that Renewable Energy Credits (RECs) are not banked throughout the study period. At this time, Otter Tail anticipates that banked RECs will be allowed, which may delay the need for additional renewable generation. The location of this potential wind resource would likely be in Minnesota, North Dakota, or South Dakota. |
| | |
| **RPU** | |
| 7.A.c. | None included. |
| 7.A.d. | The 1.0 – 1.5% CIP savings goals were incorporated into the SMMPA July 2009 IRP forecast which was used for this report. |
| 7.A.e. | This forecast distributes load growth only on the RPU system and related RPU buses. |
| | |
| **SMMPA** | |
| 7.A.c. | None included. |
| 7.A.d. | SMMPA incorporated the 1-1.5% energy savings goal into the forecast of future resource needs. The load forecast is not adjusted to account for a certain percentage of energy savings, but rather the amount of energy savings is determined as a result of a DSM Screening model and those results are selected on par with supply side options in our EGEAS capacity expansion model. |

| | |
|---|---|
| 7.A.e. | SMMPA currently does not plan to develop Company-owned wind projects but rather will acquire wind resources through power purchase agreements. The use of PPAs limits SMMPA's options to those locations that have been pre-determined by a developer. Geographical location affects the power purchase cost and transmission availability affects the Local Marginal Price. In the past, SMMPA has looked at projects in southeastern Minnesota rather than projects with a higher capacity factor in western Minnesota where transmission is more constrained. |
| | |
| **Xcel Energy** | |
| 7.A.c. | None included. |
| 7.A.d. | The energy forecast is based on historical sales, and then reduced by the projected amount of incremental DSM required in our most recently approved Resource Plan. The DSM forecast used in this energy forecast is 1.16% in 2010 and ramping to 1.3% of retail sales in 2012. |
| 7.A.e. | Xcel Energy's MN RES requires that at least 24% of the energy we provide to MN customers by 2020 must come from wind resources. The best wind resources available in our service territory are in western Minnesota and North and South Dakota. |
| | |

## 8.6 RES Studies

Substantial progress in transmission planning for the Minnesota Renewable Energy Standards has been made since the 2007 Biennial Report was issued. A significant development is the completion and issuance of four significant studies that focused on transmission for meeting the Renewable Energy Standard.

- Corridor Study
- RES Update Study
- CVS Study
- DRG Phase II Study

Each of these studies is briefly described below, and electronic links to these studies are provided. Combined, these studies provide a good assessment of what transmission is likely needed over the next 10 to 15 years, and serve as a blueprint for future transmission development.

These studies, described in more detail below are available on the Minnelectrans website at: http://www.minnelectrans.com/reports.html.

### 8.6.1 Corridor Study

Based on the results of other transmission studies, it was established that one of the most common limiting facilities to generation development in the region was the Minnesota Valley – Blue Lake 230 kV line. This facility is an older transmission line and currently comprises one of the most direct routes from wind-rich southwest Minnesota to the Twin Cities. Due to its positioning in a critical transmission area, the Minnesota Valley – Blue Lake 230 kV line is difficult to remove from service for maintenance or upgrade. With installation of the Twin Cities – Brookings 345 kV line as part of the CapX Group I projects, this largely parallel transmission facility will offload the Minnesota Valley – Blue Lake 230 kV line and provide a window of opportunity for the line to be removed from service.

Given this opportunity, the Corridor Study focused on determining what should be done with the limiting 230 kV line. The Corridor Study was completed in March 2009. The study verified that the Minnesota Valley – Blue Lake 230 kV line limits generation expansion – not only in Minnesota but in points west as well. After verifying the line as a limiting facility the study sought to optimize a mitigation plan for the line. Ultimately, the Corridor Study recommended the existing 230 kV corridor be rebuilt to double-circuit 345 kV (often referred to as the "Corridor Upgrade") and found that doing so would increase generation delivery capability from west central and southwest Minnesota by 2000 MW.

### 8.6.2 RES Update Study

Completed in conjunction with the Corridor Study in March 2009, the RES Update Study sought to examine potential transmission additions that would increase transmission delivery beyond the levels studied in the Corridor Study. In order to aid in timing and deployment considerations, scenarios were studied that examined the Corridor facilities both in service and out of service. This enabled completion of a comprehensive assessment of the impact of various transmission facilities on generation delivery capability in the Upper Midwest to be performed. By dispatching high cost generation throughout the Midwest ISO market footprint, the RES Update Study was designed to align closely with how the transmission system is operated. The RES Update Study primarily investigated three separate scenarios for siting generation – southeast Minnesota, southwest Minnesota and South Dakota, and North Dakota. By looking at generation in these three scenarios, the RES Update Study was able to analyze the full spectrum of wind generation impacts and design transmission facilities that could be pursued as actual generation is located and additional transmission capability is required.

There are two noteworthy findings from the Corridor and RES Update Studies: (1) the realization of a "tipping point" in the ability to sink generation to the Twin Cities, and (2) the need for and benefit of a new 345 kV transmission line from La Crosse to Madison in Wisconsin.

The studies identified that upon completion of the Corridor Upgrade and interconnection of the related 2000 MW of generation, the generators located in the greater Twin Cities area were at the lowest levels they could reliably be operated. Some generators were offline entirely and others were operating at their lowest possible levels. As a result, the interconnection of additional wind generation would require some of these Twin Cities facilities to be taken offline, an action that would impede the ability of the Twin Cities generators to respond to fluctuations in wind generation levels.

This tipping point demonstrated the need for additional transmission facilities to enable the Twin Cities to access additional energy sources during a sudden loss of wind generation. The La Crosse – Madison 345 kV line was determined to be the appropriate solution for this issue. Traveling through an area relatively devoid of high voltage transmission support, and tying together two largely separate transmission systems, the La Crosse – Madison 345 kV line was also shown to significantly increase generation delivery capability. The 1600 MW of capability enabled by the La Crosse – Madison line is located primarily in southeast Minnesota. When combined with the Corridor Upgrade, these two facilities have the potential to enable 3600 MW of new generation to be connected to the transmission system.

### 8.6.3 CVS Study

At the time of the Capacity Validation Study (CVS), which was completed in March 2009, many study efforts were being undertaken throughout the region. Each of these study efforts had its own group of stakeholders that developed separate inputs and assumptions. The significant amount of study work going on was also creating a great deal of uncertainty as to just how the various transmission proposals fit together. To address this, the CVS Study was intended to analyze some of the many transmission facilities being studied under one common set of assumptions. In addition, the CVS Study sought to verify the findings of the Corridor and RES Update studies. By assessing system capability in groups of potential projects (over 200 different project combinations were analyzed), information was gained as to how the various proposals would perform together.

The CVS Study produced two key findings that will inform both future transmission planning study and project development efforts: (1) studying projects together yields more capability than considering individual projects, and (2) sink assumptions (which generation is turned down to account for new generation being studied) has a significant impact on potential outlet capability.

When transmission system upgrades are pursued, they are usually studied individually for their impact, specifically where it relates to generation delivery capability. However, when multiple upgrades are pursued in a given geographical area, they perform together to provide more capability than the simple sum of the individual projects. The CVS Study demonstrated this idea very clearly with the CapX 2020 Group I projects.

The second key finding will inform future studies, as the CVS found that depending upon which generation is assumed to be turned down to allow for the delivery of new generation, vastly different outlet capability can be found. This informs a need to carefully align generation dispatch assumptions in transmission planning studies as closely as possible with how the transmission system is operated in real-time. This finding validated the “economic dispatch” methodology used in the Corridor and RES Update Studies.

### 8.6.4 Dispersed Renewable Generation (DRG) Study

State legislation in 2007 required a statewide study of dispersed renewable generation potential to identify locations in the transmission grid where a total of 1200 MW of relatively-small renewable energy projects could be operated with little or no change to the existing infrastructure. For the purposes of this study, dispersed renewable energy projects are wind, solar and biomass projects that will generate between 10 and 40 MW of power.

The Phase I study goal was to analyze a 2010 model of the transmission system in Minnesota to identify locations in the transmission grid where a total of 600 MW of relatively small-sized renewable energy projects could be operated with little or no changes required to the existing infrastructure. The potential locations studied were based on public input, regional availability of renewable resources, current dispersed generation in the MISO queue, and access to existing transmission. Phase I was completed in June 2008.

Phase II of the study began in October of 2008 and was completed on September 15, 2009. The goal of Phase II was to analyze a 2013 model of the transmission system in Minnesota to identify locations for an additional 600 MW of dispersed renewable energy.

Each study succeeded in identifying 600 MW of projects that could be completed. Phase I managed to do so without any significant transmission upgrades. However, Phase II required significant transmission upgrades in order to accommodate the new generation, even though the generation sites were relatively small and spread throughout the state. Phases I and II both demonstrated that even small generation installations have measurable (and in some cases significant) impacts on the transmission system.

## 8.7 Specific Transmission Lines

Not only does the present assessment establish that there should be enough generation to meet the upcoming milestones through 2016, the utilities have determined that with the addition of the CapX 2020 Group 1 projects, the transmission system in the 2016 timeframe should be adequate to meet the 2016 Minnesota RES milestones.

Beyond 2016, there is a gap between the RES milestone and the identified renewable generation that will be required, and this gap will likely require additional transmission. The Gap Analysis information can be used together with the transmission studies related to renewable energy that were released earlier this year to put together a roadmap for transmission development. In an attempt to project the transmission needs for meeting the Minnesota RES beyond 2016, the following is one potential scenario for transmission development that matches the RES GAP Analysis with the transmission plans that have been identified.

After completion of the CapX 2020 Group I projects, the next most likely transmission addition is the Corridor project. This project is an upgrade of the existing 230 kV line between Granite Falls, Minnesota and Shakopee, Minnesota. As discussed above, the Corridor Study recommended that this line be upgraded to double-circuit 345 kV operation. The initial study results described above indicate that the Corridor project will have the ability to add approximately 2000 MW of generation to the system. This transmission addition has the potential to provide enough transmission to meet the 2020 RES milestone.

At the present time, the utilities are projecting a shortfall of approximately 2100 megawatts of generation by the year 2025, just for meeting the Minnesota Renewable Energy Standard. One possible way that this amount of additional generation could be transmitted would be with the addition of a La Crosse to Madison 345 kV transmission line, which enables a significant amount of new generation capability in southeast Minnesota. This project, in conjunction with the Corridor project, could potentially add 3600 megawatts of capability to the system, which is enough to meet the RES requirements that are presently projected.

## 8.8 Transmission Beyond 2025

At this point, the utilities have not completed a Gap Analysis beyond the 2025 timeframe. However, the transmission planning that was completed as part of the RES study has identified other potential transmission additions that would be helpful in assuring adequate renewable energy to comply with the Minnesota Renewable Energy Standards. Some facilities identified include:

- Fargo – Sioux Falls 345 kV
- Ashley – Hankinson 345 kV
- Lakefield – Adams 345 kV
- Adams – Genoa 345 kV

It is important to consider that the Minnesota RES is only one of the driving factors in developing the necessary transmission to meet the standards. Another factor that will impact the transmission system is the renewable energy goals and requirements of other states. Not all the renewable energy generated in Minnesota can be assumed to be for Minnesota customers. The needs of other states will require additional transmission in Minnesota and elsewhere. This is particularly true if an aggressive federal renewable energy mandate is enacted, such as the 20 percent mandate contemplated in legislation being debated in the U.S. Congress.

Another factor that must be taken into account is load growth. The RES is a percentage of retail sales; as consumption changes, so will the amount of the renewable energy required. In addition, load growth will drive the need for transmission to ensure compliance with national and regional reliability standards.

Still a third factor impacting transmission is new nonrenewable generation. Other forms of generation will be added to the system and in some cases will most likely require additional transmission.

In addition to these other needs, MISO continues to process its interconnection queue for generation additions. As these studies are completed, transmission system additions may be identified. These additions may result in substation modifications or new transmission line additions that are generally unique to the generator interconnection project. The utilities in

Minnesota actively participate in these studies to ensure that the needs of Minnesota are addressed in a reliable and economic manner.

## 8.9 Policy Issues

There are two key policy issues that are having big implications on transmission development.

- Cost allocation
- Market for Renewable Generation Development

### 8.9.1 Cost Allocation

As the Commission is well aware, transmission cost allocation continues to be a complex, controversial, and rapidly changing discussion. There are many forums for which cost allocation discussions are occurring. The Midwest ISO has assembled a Regional Expansion Cost and Benefits (RECB) Task Force to examine more equitable cost allocation methodologies. This effort is being pursued in two phases. The first phase culminated in a filing to change the generator interconnection cost allocation methodology that was conditionally accepted by FERC in its Order Conditionally Accepting Tariff Amendments and Directing Compliance Filing in Docket No. ER09-1431-000, dated October 23, 2009. The first phase was viewed as an interim "stop gap" solution until a second, more long-term solution can be developed by the Task Force. A filing that encompasses a longer-term solution is anticipated no later than July 15, 2010.

In addition to the RECB Task Force, the Organization of MISO States (OMS) is pursuing a cost allocation effort of its own. This effort, known as Cost Allocation and Resource Planning (CARP), is focused on finding a cost allocation methodology that is acceptable to the regulatory bodies of the states in which the Midwest ISO operates. Regulatory and policy maker acceptance is critical in any cost allocation methodology so the CARP effort is a very important process that is necessary to long-term cost allocation resolution.

Aside from these efforts, other cost allocation efforts are also underway. The Upper Midwest Transmission Development Initiative (UMTDI) is considering this issue as it relates to development of transmission capacity for renewable resources in the five-state UMTDI area. FERC has also shown an interest in facilitating cost allocation discussions as it hosted a series of recent Technical Conferences that focused in part on cost allocation. FERC recently issued a Notice of Request for Comments dated October 8, 2009, in Docket No. AD09-8-000 entitled Transmission Planning Processes Under Order No. 890.

Cost allocation is a significant issue across the country and requires serious thought and consideration. Without a clear transmission cost allocation policy, there is risk that necessary transmission may be delayed.

### 8.9.2 Other Demands for Renewable Energy

Another key question that has tremendous implications on the development of the transmission system is to what extent will renewable generation development occur in the Dakotas and

Minnesota that will be used to meet the needs of other regions. For example, will renewable generation that is developed in Minnesota be used to meet renewable energy standards in other states? If so, how remote are those states located from Minnesota? Answers to these questions will have a large impact on the development of the transmission system.

One of the initiatives looking at the implications of these questions is the Upper Midwest Transmission Development Initiative (UMTDI). The planning studies for UMTDI are part of the Midwest ISO Regional Generation Outlet Study (RGOS) Phase I, discussed in Chapter 3. UMTDI is looking at scenarios to determine both the transmission necessary to meet the renewable energy needs of each of the states (ND, SD, MN, IA, WI) participating in UMTDI, as well as accommodating exports from the UMTDI region. The initial results of these studies have identified several 345 kV and 345 kV/765 kV build-out options. The UMTDI initiative is just one example of efforts underway to try and address these critical policy questions. Other studies to identify transmission infrastructure needed to facilitate development of renewable generation include ITC's Green Power Express Study and the SmarTransmission study, both of which are also discussed in Chapter 3.

This policy question could be answered at a Federal level through a national Renewable Portfolio Standard (RPS), or it could be addressed at a more local level such as the UMTDI. Until this policy question is fully addressed, however, it will be difficult to determine the optimum transmission system required to satisfy Minnesota and other renewable energy goals.

## 8.10 Transmission Expansion Scenario to Meet Minnesota RES

In its August 10, 2009, Order (paragraph 7.B.), the PUC also directed the CapX utilities to `develop a proposed transmission expansion plan to meet Minnesota Renewable Energy Standards. Transmission planning is a complex process that involves a myriad of assumptions. These changing assumptions make it difficult to develop a specific transmission plan since any such plan reflects a snapshot in time. Relying on the results of the transmission studies that have been recently completed, as described in Section 8.6 above, and considering recent developments regarding new transmission, the CapX utilities have developed a transmission scenario to meet the Minnesota RES. This scenario is presented in the table on the following page.

The table represents one potential transmission system expansion scenario for supporting the interconnection of renewable generation and sequencing new transmission facilities needed to achieve compliance with the Minnesota Renewable Energy Standards. It includes projects that are complete, transmission projects that are in the permitting phase, and future transmission projects that have been identified in recent transmission planning studies. Many events could occur to change this scenario, including generation location, but it is one conceptual plan for transmission expansion.

**Transmission Expansion Scenario to Meet Minnesota RES**

| Project | Estimated Incremental Addition (MW) | Estimated Total Capacity (MW) | Status | Description |
|---|---|---|---|---|
| 425 Wind | 258 | 425 | In Operation | Small System Upgrades |
| 825 Wind | 400 | 825 | In Operation | Additional small system upgrades, three new 115/161 kV upgrades, and a 90-mile Split Rock-Lakefield 345 kV line. |
| BRIGO | 350 | 1175 | In Operation | Three 115 kV lines (approx. 60 miles total) and 345/115 kV transformer. |
| Blue Lake Upgrade | 600 | 1775 | In Progress | Structural modifications to increase ground clearance of 345 kV line, substation equipment replacement, and capacity upgrades. |
| RIGO | 700 | 2475 | Permit Needed | Two 161 kV lines (approx. 25 miles total) and a 345/161 kV transformer. |
| Twin Cities – Brookings | 700 | 3175 | Permit applied for | 200 mile 345 kV line (approx. half double-circuit). |
| Twin Cities – Fargo | 700 | 3875 | Permit applied for | 250 mile 345 kV line. |
| Corridor Upgrade | 2000 | 5875 | Under study | 125 mile double-circuit 345 kV line. |
| LaCrosse – Madison | 1600 | 7475 | Under study | 150 mile double-circuit 345 kV line. |
| Fargo – Split Rock | 1000 | 8475 | Under study | 300 mile double-circuit 345 kV line. |

## 8.11 Interconnection Issues

In addition to a possible transmission scenario, the PUC in its August Order also directed the CapX utilities to include in the Biennial Report information relating to various interconnection issues implicated under the proposed plan. Relying on the scenario presented in the table on the previous page, and on the studies described in this chapter, and on the Gap Analysis that was developed as part of the RES status, the utilities can provide the following response to the issues presented.

### *Interconnection Capability Approved But Not Yet Used*

The first estimate the Commission requested of the CapX utilities is an estimate of the interconnection capability already approved but not yet used, *i.e.* available to meet forecasted demand. This is a difficult question to answer, as there are many factors that play into determining the capability of the transmission system as well as what generation projects are using the capability. Recent experience would suggest that as the transmission facilities are placed into service for the purposes of renewable energy, they are fully subscribed when they are commissioned. At some point, transmission additions will likely be placed into service without the full capability being subscribed immediately. It is difficult to project when this will occur, but it may occur when the CapX Group 1 projects are placed into service.

The MISO interconnection process also helps address this question. Under the existing MISO interconnection queue, there is not enough transmission capability to accommodate all of the projects that are currently requesting interconnection to the grid. However, not all projects in the MISO queue move forward. As an example, there are many more generation projects that would like to use the capability created by the Brookings line than the line can accommodate, but it is not clear whether all of those projects will move forward.

It must be kept in mind that the existence of transmission capacity does not necessarily mean that it is available to transport renewable energy for purposes of meeting the Minnesota RES. Simply because transmission facilities are built in Minnesota does not mean that Minnesota utilities have a lock on that capacity. The transmission grid is open to all comers, and out-of-state utilities may have access to transmission capacity in the state. Indeed, there are some out of state utilities that have already signed power purchase agreements with wind farms in Minnesota.

### *Annual Generation Interconnection Capability Created by the Proposed Transmission Plan*

The second issue the Commission asked the CapX utilities to address is to provide an estimate of the annual generation interconnection capability created by the transmission plan proposed by the utilities. The transmission expansion scenario presented in the table provides an estimate of potential generation interconnection capability associated with each transmission addition, as well as the total cumulative capability.

### *Size, Type, and Timing Issues Inherent in the Proposed Plan*

The sequencing of the projects identified in the table above was based on the information collected as part of the Gap Analysis and the transmission studies. This is one example of how the system could evolve. Ultimately, the location of specific generation projects as well as other needs (reliability, etc.) could change the sequencing.

### *Geographic Uncertainty in Interconnection Needs*

Transmission planners do not have control over the location of where generation will interconnect to the transmission system. It seems reasonable, however, based on present experience and knowledge, to assume that significant wind development will occur in western and southeastern Minnesota and in the Dakotas. Studies indicate that there are well identified corridors that become constrained for generation additions on a wide area basis. The proposed transmission plan addresses all of these areas of wind development and the transmission constraints.

### *NonInterconnection Benefits*

For the most part, if a transmission facility is added to the system as a result of a robust planning process, these facilities will provide reliability benefits that include reduced line loading on adjacent transmission facilities, better voltage support and the possibility of enhancing the stability of the transmission system. In addition, most transmission system additions result in reduced line losses, which reduce the need for generation capacity and energy. A strong network also provides operating and maintenance flexibility and the capability to support future load serving needs.