INTERIM REPORT

IDENTIFYING MINNESOTA'S ELECTRIC TRANSMISSION INFRASTRUCTURE NEEDS

CAPX 2020

GREAT RIVER ENERGY
MINNESOTA POWER
MISSOURI RIVER ENERGY SERVICES
OTTER TAIL POWER COMPANY
XCEL ENERGY

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Identifying Minnesota's Electric Transmission Infrastructure Needs: An Interim Report

Minnesota's electric transmission infrastructure—a network of high voltage transmission lines of 230 kilovolts and higher—requires major upgrades and expansion over the next 15 years to support customers' growing demand for electricity. To ensure the backbone transmission system is developed and available to serve these growing needs, the five largest Minnesota transmission-owning utilities initiated the CapX 2020 project. CapX 2020 is short for Capital Expenditures by the year 2020.

CapX 2020's mission is to:

- Create a joint vision of required transmission infrastructure investments needed to meet growing demand for electricity in Minnesota and the region; and

- Work to create an environment that allows these projects to be developed in a timely, efficient manner, consistent with the public interest.

Great River Energy, Minnesota Power, Otter Tail Power Company and Xcel Energy jointly formed CapX 2020 in the summer of 2004; Missouri River Energy Services subsequently joined this effort, and other investor-owned utilities, cooperatives, and municipal utilities have been following the initiative.

This Interim Report presents our work to date. Its purpose is to create awareness of the significant need for new transmission investment, to inform stakeholders of our study efforts underway, and to begin a public dialogue on transmission issues. We present this report in the following sections:

- *Our future needs,* presenting forecasts of customer demand over the next 15 years.
- *Our current system,* outlining the characteristics and capacity of our current backbone transmission system.
- *A changed market*, describing how management of the transmission network operates under federal reforms.
- *The CapX 2020 planning effort,* providing an overview of our CapX 2020 study.
- *Our preliminary results,* presenting our findings to date.
- *Next steps,* discussing the continued planning effort and inviting stakeholder dialogue.

Future Needs

A robust bulk electric system supports our national and state economies. Data from the U.S. Department of Energy's Energy Information Administration (EIA) show a parallel between the nation's gross domestic product (GDP) and electricity sales.[1] As the GDP increases or decreases, so does electricity demand.

[1] (http://www.eia.doe.gov/oiaf/aeo/electricity.html).

Utility resource planners foresee continuing growth in the state's population, economy and demand for electricity. Through 2020, Minnesota electric utilities predict an annual average growth in our customers' demand for electricity of 2.49 percent,[2] far above the national forecast of 1.8 percent per year.[3] Meeting this increased demand is expected to require an additional 6,300 megawatts of generating capacity. To provide context for this amount, the largest generating station in Minnesota – the Sherburne County (Sherco) plant near Becker – provides a total of approximately 2,300 megawatts of generating capacity.

In addition to the projected increased need for electric generating capacity, customers' demand for power quality has increased. Sophisticated electrical equipment and new business customers, such as high-speed data processing centers, require highly reliable electricity service. To meet these requirements, transmission and distribution infrastructure must be designed to meet increasingly higher power quality standards.

CapX 2020 provides further background and detail regarding customer requirements and projected demands in Attachment A.

Our Current System

Designed and built in the 1960s and '70s, the high voltage transmission facilities (230 kilovolts and above) act as the supporting structure, or backbone, of the bulk electric system, moving electricity from power plants to load centers. The system is designed to maintain reliability even when faced with various contingencies that arise due to weather or other factors that temporarily may remove a particular transmission facility from service. The majority of these facilities were built in the 1970s, with the last of this class built in connection with construction of Unit 3 at the Sherco power plant, which began operating in 1987.

Utility planners historically designed the regional transmission grid with sufficient capacity and network capability to support the system and meet long-term growth requirements. The grid has served Minnesota well; since 1987, only shorter, lower-voltage transmission lines have been built, typically to meet local, load-serving needs.

Attachment B contains additional information regarding our current transmission system, planning processes and regulatory structure.

A Changed Market

Thirty years ago, when the transmission backbone was designed and built, the region's electric utilities jointly planned the addition of new generation and transmission facilities. In 1992, Congress deregulated the wholesale electric power supply industry, making generation a competitive market while still regulating transmission facilities as the nation's electric

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[2] Demand studies include information from the following utilities: Alliant Energy, Great River Energy, Dairyland Power Cooperative, Minnesota Power, Missouri River Energy Services, Otter Tail Power Company, Southern Minnesota Municipal Power Agency/Rochester Public Utilities and Xcel Energy.
[3] EIA, growth in electric sales for 2002-2025 (http://www.eia.doe.gov/oiaf/aeo/electricity.html)

highway system. A subsequent series of initiatives by the Federal Energy Regulatory Commission (FERC) has provided further change to industry structure.

As a result, the way the electricity industry operates has changed considerably. A key change is the functional separation of transmission from generation to ensure equal access to the grid, which the FERC mandated in 1996. The upshot of this change is that generation and transmission planning must now be performed separately and in a nondiscriminatory manner; transmission planning and development must be prepared to meet the needs of all regional market participants rather than just those of the individual utility or specific generation resource type. Attachment C provides an overview of these changes, including the transition to regional transmission organizations.

THE CAPX 2020 PLANNING EFFORT

It is clear that our current transmission network will be unable to accommodate the required new generation and increased customer demand without significant upgrades and new facilities. To identify projects needed to meet customer needs well into the future, CapX 2020 has undertaken two technical studies on major transmission facilities needs in Minnesota: the Vision Study and the Red River Valley Study. We expect both to be completed in May 2005.

The Vision Study will outline key infrastructure improvements needed to meet future needs under a variety of possible scenarios. Our planners are considering various potential scenarios of generation development to determine what system investments will be required regardless of location of new power plants. With this study, we will identify projects that will meet our customers' and the region's needs. Our goal is to identify the next major transmission backbone investments required to ensure a robust network capable of accommodating growth and providing continued reliable service well into the future. Transmission investments of this magnitude take several years; therefore, the planning process for meeting these needs has begun.

The Red River Valley Study focuses on near-term transmission needs to address known transmission reliability issues in west-central Minnesota. CapX 2020 undertook the Red River Valley Study to build on a recent study by utility transmission planners that revealed this area to be the most immediately vulnerable. Studies show that within the next three years, low voltages along with potential voltage collapse could occur during winter peak conditions. Additionally, the study will address reliability issues in central Minnesota. While more local in nature, this study will produce detailed information capable of supporting a certificate of need for the projects found to be most appropriate.

Concurrent with these technical studies, CapX 2020 is reviewing state processes to determine whether they are able to support development of the required transmission infrastructure in a timely, efficient manner, consistent with the public interest. In particular, CapX 2020 is reviewing current approaches to certification and cost recovery, while also evaluating industry structure, routing and jurisdictional issues. CapX 2020 is committed to working to create an environment that allows needed transmission infrastructure additions and improvements to be developed in a timely, efficient manner consistent with the public interest.

Attachment D provides more detail on these technical studies, while Attachment E summarizes our on-going review of state planning and regulatory issues.

PRELIMINARY RESULTS

Preliminary results from these studies show that the current transmission system will not support the forecasted need for new generation facilities to meet projected customer demand. Absent new investment in transmission facilities, our preliminary analysis anticipates significant line and equipment overloads by 2020, assuming customer requirements develop as projected. These overloads occur under even the most optimistic scenario that has all major transmission lines and equipment in service. Many more overloads occur when other facilities must be removed from service because of storm damage, for routine maintenance or for any other reason.

Under the Vision Study, we are considering several possible scenarios of generation development and the transmission additions needed to serve each. Comparing the resulting plans will allow us to identify the projects needed to reinforce the grid regardless of how generation develops. All told, the study is examining approximately 3,300 miles of additional transmission facilities with an estimated cost of $2.7 billion. While all of these facilities may not be needed to address the customer needs in 2020, CapX 2020 believes it is important to identify for stakeholders the magnitude of investment and projects under review.

Preliminary findings from the Red River Valley study recommend short-term upgrades to ensure reliability in the near future and a long-term system solution. While work has already begun on many of the short-term upgrades, the best long-term alternative includes a new 345 kilovolt line from Fargo, N.D., to St. Cloud, Minn., and a 230 kilovolt line from Bemidji, Minn., to Grand Rapids, Minn. Our further study will confirm whether this project is still the best long-term solution.

NEXT STEPS

CapX 2020 is committed to making the necessary investments to upgrade the grid that delivers power to customers. We agree now is the time to strengthen the electricity system's backbone, before new power plants are constructed and in time to meet customer needs.

Our next steps include:

- Completion of the technical studies in May 2005.
- Dialogue with policymakers and stakeholders regarding the CapX 2020 studies and state process issues.
- Outreach to other transmission providers to share information and collaborate on solutions.

Minnesotans will require access to new generation facilities to meet projected growth. They will need a robust transmission system, one that can provide service reliably into the future, to support the new generation facilities. To meet these needs, significant transmission line upgrades and new transmission construction will be required over the next 15 years. CapX 2020 understands these needs and believes planning and construction must be done wisely, serving the public interest through a deliberate process that includes all stakeholders. We look forward to working with stakeholders to ensure these objectives are met.

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Attachment A
Forecasted Need

Utilities constantly assess how much customer demand for electricity will grow each year and what their generation and transmission capacity must be to ensure a reliable, low-cost, adequate supply of electricity. Most Minnesota utilities calculate their future demand and describe the ways they plan to meet that demand in the resource plans filed with and reviewed by the Minnesota Public Utilities Commission (PUC) every two years.

Resource plans include a utility's 15-year load forecast, its forecast for demand-side management impacts—those load management and conservation programs used to reduce peak demand, encourage energy conservation and improve energy efficiency—as well as how they are meeting other regulatory and legislative requirements. Resource plans are available to the public from the Minnesota PUC. Many utilities also make theirs available on their Web sites.

In addition, Minnesota utilities annually submit reports of their estimated load and capability – how much electricity their customers will demand in the future and what generation facilities they will use to meet that demand – to the North American Electric Reliability Council (NERC) through the Mid-Continent Area Power Pool (MAPP). Through this submission, NERC assesses whether enough electricity is available to meet customer demand during the next season. This report is available on the MAPP Web site at www.mapp.org.

Like resource and generation planning, transmission planning begins with a projection of future customer needs. To this end, the CapX 2020 technical team chose the MAPP 2004 Series, 2009 summer peak model, as the base model to begin scaling loads to the anticipated 2020 load level. To accurately model 2020 loads, the technical team used individual company load growth from the 2004 MAPP Load and Capability Report for the following company control areas: Alliant Energy (west), Xcel Energy (north), Southern Minnesota Municipal Power Agency, Otter Tail Power Company (includes Minnkota Power Cooperative and Missouri River Energy Services) and Dairyland Power Cooperative. Minnesota Power and Great River Energy's loads were scaled based on their most recent resource plan filings.

Table 1 shows the CapX 2020 technical team's projection of future customer needs.

Control area	2009 load level (2004 MAPP Series) (megawatts)	Yearly growth rate (%)	Calculated 2020 load level (megawatts)
ALT (West)	3265.3	1.60%	3888.2
Xcel Energy (North)	9632.6	2.68%	12885.1
MP	1507.3	1.70%	1814.4
SMMPA/RPU	330.0	2.70%	442.4
GRE	2833.5	3.05%	3894.0
OTP/MPC/MRES	1677.2	2.70%	2248.3
DPC	954.7	2.60%	1266.2
Total	20200.6	Ave. = 2.49%	26487.8

Table 1

Thus, electricity use in Minnesota will continue to increase even with consistent investment in energy conservation programs. As shown, Minnesota utilities' forecasts project an average annual growth rate of approximately 2.5 percent through 2020. Based on this growth rate, nearly 6,300 megawatts of new generation will be needed to serve Minnesota customers by 2020.

ATTACHMENT B
OVERVIEW OF CURRENT TRANSMISSION SYSTEM

CURRENT NETWORK
Minnesota's electric transmission system is part of a regional transmission grid operated in coordination with other interconnected transmission systems throughout the Upper Midwest and the entire Eastern United States. The system is managed by regional organizations and control centers that are staffed 24 hours a day, 365 days a year.

Although it originally was designed to reliably deliver power to major electric load centers, such as the Twin Cities metropolitan area, Duluth, Mankato, Rochester, and St. Cloud – and to interconnect utilities so they could back up each other during emergencies – the transmission grid now must do much more. It acts as a regional "highway," providing the physical link between sellers and buyers, facilitating an ever-increasing number of transactions among an increasing number of market participants and over increasing distances. At the same time, the grid continues to serve a critical reliability role.

Diagram 1 provides a simplified overview of the electric system.

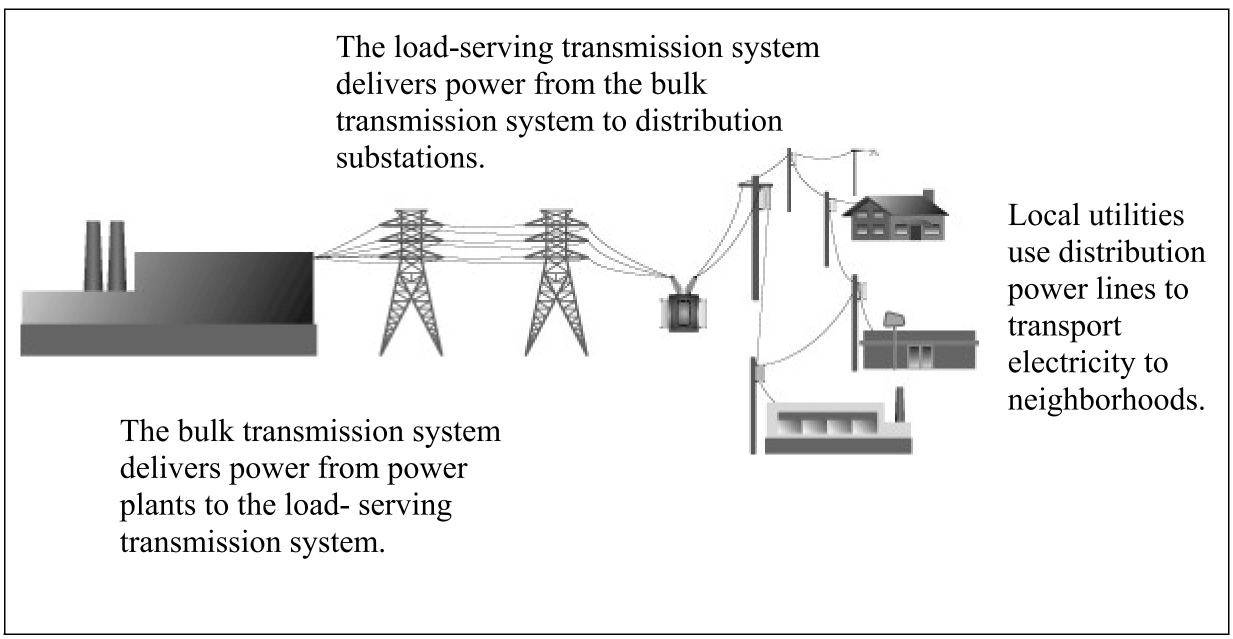

Diagram 1

RECENT TRENDS

According to the May 2002 National Transmission Grid Study by the U.S. Department of Energy (DOE), investment in new transmission facilities declined steadily nationwide for the previous 25 years while growth in demand and additions of new generation have continued. Further, the DOE study states that this disparity between the demand for electricity and the capacity to transport it shows no sign of abating. According to the DOE study, “Construction of high-voltage transmission facilities is expected to increase by only 6 percent (in line miles) during the next 10 years, in contrast to the expected 20 percent increase in electricity demand and generating capacity.”

Minnesota and the surrounding region are not exceptions to this trend. Since 1980, demand for electricity in Minnesota has grown steadily at a rate of 2.64 percent annually. While the current grid has accommodated this growth and generally is adequate to meet today’s needs, this increase in volume has used most of the system’s spare capacity. Utilities have made modest system improvements and investments to meet basic load serving and reliability requirements and optimize the transmission capacity, but they have not been inclined to undertake major transmission construction projects.

CURRENT UTILITY PLANNING PROCESS

Today, regional transmission planning is coordinated by the Mid-Continent Area Power Pool (MAPP), a voluntary association of electric utilities and other electric industry participants, and the Midwest Independent Transmission System Operator Inc. (MISO), a regional transmission organization with functional control over all high-voltage transmission facilities. While MAPP and MISO provide overarching regional processes for transmission planning, plans still begin with the individual electric utilities that own and/or operate transmission facilities.

Each utility employs transmission planners whose principal responsibility is to ensure the safety and reliability of the transmission system for the benefit of all customers. The planners prepare detailed studies, first assessing present and projected electricity demand and then identifying areas on the transmission system that are increasingly inadequate to serve current and future customers. The planning horizon is generally 10 years.

Individual utilities submit their plans to MAPP sub-regional planning groups (SPGs), made up of transmission planners from MAPP member utilities and other stakeholders, including state regulatory agencies and environmental advocacy groups. The SPG process allows utilities to coordinate their plans and collaborate on how best to serve the region. The process considers transmission expansion alternatives, new generation facilities that may be planned for the region, and how additions to the regional transmission system may impact neighboring regions.

SPGs invite public participation into the process, explain their findings to the public and consider the public’s input into the plan and the best route for the proposed transmission lines. The results are sub-regional plans that are “rolled up” into a MAPP regional plan and incorporated into MISO’s overall regional and interregional plans.

Additionally, the state of Minnesota has a biennial transmission planning process. Minnesota law requires each electric transmission-owning utility to file a biennial transmission planning report. State rules prescribe the process of soliciting public input into biennial planning reports, including a requirement for public planning meetings in different parts of the state.

CURRENT REGULATORY STRUCTURE

Regulatory oversight of transmission occurs at several levels and by different regulatory bodies, including:

- The Federal Energy Regulatory Commission (FERC), which has authority over interstate transmission and wholesale transmission rates and regulates regional entities such as MISO.
- Regional transmission organizations (RTOs), such as MISO, which oversee and coordinate regional transmission planning and services to facilitate fair and competitive wholesale markets.
- Regional reliability councils, such as MAPP, which set protocols for grid operations and standards for reliability.
- State public utilities commissions, which set retail rates for public utilities and often decide whether new generation and transmission projects are needed.
- State environmental agencies, which may oversee the new transmission routing.

A series of FERC orders during the past five years has dramatically changed the regulatory landscape for electricity transmission. Continued change, such as the transition to MISO's Day 2 Market with use of regional wholesale electricity markets and significantly different pricing for transmission service, is forthcoming.

Here in Minnesota, state regulatory authority is vested in several agencies, including:

- The Minnesota Public Utilities Commission (PUC), which oversees retail utility rates including transmission investment recovery, transmission planning, and need determinations for certain new transmission projects through the state's certificate of need process.
- The Environmental Quality Board (EQB), which oversees transmission line routing, taking into consideration various environmental issues associated with proposed routes.
- The Minnesota Department of Commerce (DOC), which is charged to be the primary public advocate in proceedings before the PUC. As such, it investigates and evaluates utility proposals and advances recommendations for the PUC to consider.
- The state's Reliability Administrator, housed within the DOC, who is charged by law to develop information regarding the need for transmission and work with stakeholders to ensure the continued reliable provision of electric service within the state.
- The Minnesota Office of Attorney General, which represents residential and small business customers in proceedings before the PUC and also may advance recommendations for the PUC to consider.

State laws and rules govern the processes used by these agencies. In 2001, the Minnesota Legislature adopted a number of changes to the governing statutes in an effort to streamline the regulatory processes over transmission. Both the PUC and EQB undertook rulemaking to implement these statutory changes, the last of which was just recently completed. To date, these new processes have not been significantly used or tested.

ATTACHMENT C
OVERVIEW OF MARKET CHANGES

The federal policy changes of the early 1990s designed to open access to wholesale electricity markets caused significant changes in operation of the transmission grid and led to creation of regional transmission organizations (RTOs). In 1996, the Federal Energy Regulatory Commission (FERC) mandated that electric utilities offer "open access" to their transmission systems. Since 2000, the FERC has strongly encouraged all of its jurisdictional utilities to join RTOs and to transfer to the RTO functional control of the utilities' transmission assets. Non-jurisdictional utilities – such as Minnkota Power Cooperative and Great River Energy – have the option to join an RTO as well, and some have.

The Midwest Independent Transmission System Operator Inc. (MISO), which began operations on Feb. 1, 2002, is the RTO for utilities in large parts of the Midwest and Upper Midwest. MISO is developing rules and systems for users to follow in conducting grid operations in accordance with North American Electric Reliability Council (NERC) standards. It operates with stakeholder input and participation under the FERC's overall direction. MISO controls access to and use of the grid for wholesale transactions for its member companies. Most of Minnesota's transmission system now is operated under the oversight of the MISO umbrella organization.

Placing functional control of jurisdictional utility transmission assets under MISO was a first phase in FERC RTO policy implementation, which was designed to open up access to wholesale electric energy markets. The second phase is to establish an energy transaction market that allocates transmission access based on economic signals rather than physical line-loading procedures. This second, market-based phase of MISO RTO implementation is called the Day 2 Market.

MISO has announced its intention to begin operating a Day 2 market on March 1, 2005. This market will allow MISO to manage congestion on the wholesale electric power system through the use of locational marginal pricing (LMP), which will be the market-clearing price for energy at the location to which the energy is delivered or from which it is received. LMP varies by time and location, based on physical limitations, congestion and loss factors.

The Day 2 Market will consist of two key components:

- Day-ahead energy transactions based on each market participant's forecasted needs and resource availability.
- Real-time transactions that true-up system-wide supply and demand.

Currently, no price signals exist to designate congested or less-congested power delivery routes on the transmission grid. Price signals would encourage market participants to consider the most efficient alternatives to deliver power. Wholesale energy purchase decisions are less efficient than they could be at times under the current system. For example, a utility may have to buy more energy than it needs to secure a certain transmission route.

Another example is that the current system of allocating transmission access also may force cuts to power delivery schedules for established purchases and force a utility to operate one of its more expensive peaking units to meet customer need.

The centralized energy market resulting from MISO's operations is designed to allow for more economically efficient use of existing transmission and generation assets. This, in turn, is expected to produce wholesale and retail consumer savings.

For more information about MISO and the Day 2 Market, visit the MISO Web site at www.midwestiso.org.

For more information about FERC initiatives to restructure the electricity industry, visit the FERC Web site at www.ferc.gov.

ATTACHMENT D
CAPX 2020 PLANNING EFFORT

The CapX 2020 technical team is working on two studies: one to address known reliability issues in the Red River Valley and the other to identify adequate transmission additions to meet the future load growth of the utilities that operate transmission within Minnesota.

RED RIVER VALLEY STUDY

The Red River Valley study continues work started in 2001 to address load-serving reliability concerns in northwestern Minnesota. Initial studies indicated that low voltages along with potential voltage collapse could occur during winter peak conditions. These preliminary studies identified short-term upgrades and long-term system solutions.

Work has begun on many of the short-term upgrades, which include reconductoring, transformer change outs and switched capacitor additions. The best long-term alternative in the original study included a new 345 kilovolt line from Fargo, N.D., to St. Cloud, Minn., and a 230 kilovolt line from Bemidji, Minn., to Grand Rapids, Minn.

The current study will determine whether these long-term solutions remain the best alternatives to address the load-serving and reliability issues in northwestern and central Minnesota in preparation for a certificate of need. The study will involve gathering present load data for the region and performing a steady-state power flow analysis and voltage stability analysis to determine how serious the problem is.

The timeline for completing the Red River Valley study is in Table 2.

Task	Schedule
Model preparation	9/27/04 – 12/9/04
Power flow analysis	12/9/04 – 1/17/05
System improvement analysis	1/17/05 – 3/17/05
Misc. items (economic losses, etc.)	1/18/05 – 4/11/05
Stability analysis	3/17/05 – 4/27/05

Table 2

VISION STUDY

A parallel study will determine transmission needs in Minnesota and the surrounding area to meet the anticipated load growth in the region and the corresponding new generation needed to serve the load. This study will identify transmission solutions that address anticipated load in the year 2020. It also will develop a transmission plan that can address a variety of generation scenarios in the region.

A. BASE MODEL DEVELOPMENT

The CapX 2020 technical team chose the MAPP 2004 Series, 2009 summer peak model, as the base model to begin scaling loads to the anticipated 2020 load level. To accurately model 2020 loads, the technical team used individual company load growth from the 2004 MAPP Load and Capability Report for the following company control areas: Alliant Energy (west), Xcel Energy (north), Southern Minnesota Municipal Power Agency, Otter Tail Power Company (includes Minnkota Power Cooperative and Missouri River Energy Services) and Dairyland Power Cooperative. Minnesota Power and Great River Energy's loads were scaled based on their most recent resource plan filings. The results are in Table 3.

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DPC	954.7	2.60%	1266.2
Total	20200.6	Ave. = 2.49%	26487.8

Table 3

Diagram 3 shows the geographic boundaries of the load being scaled in the study.

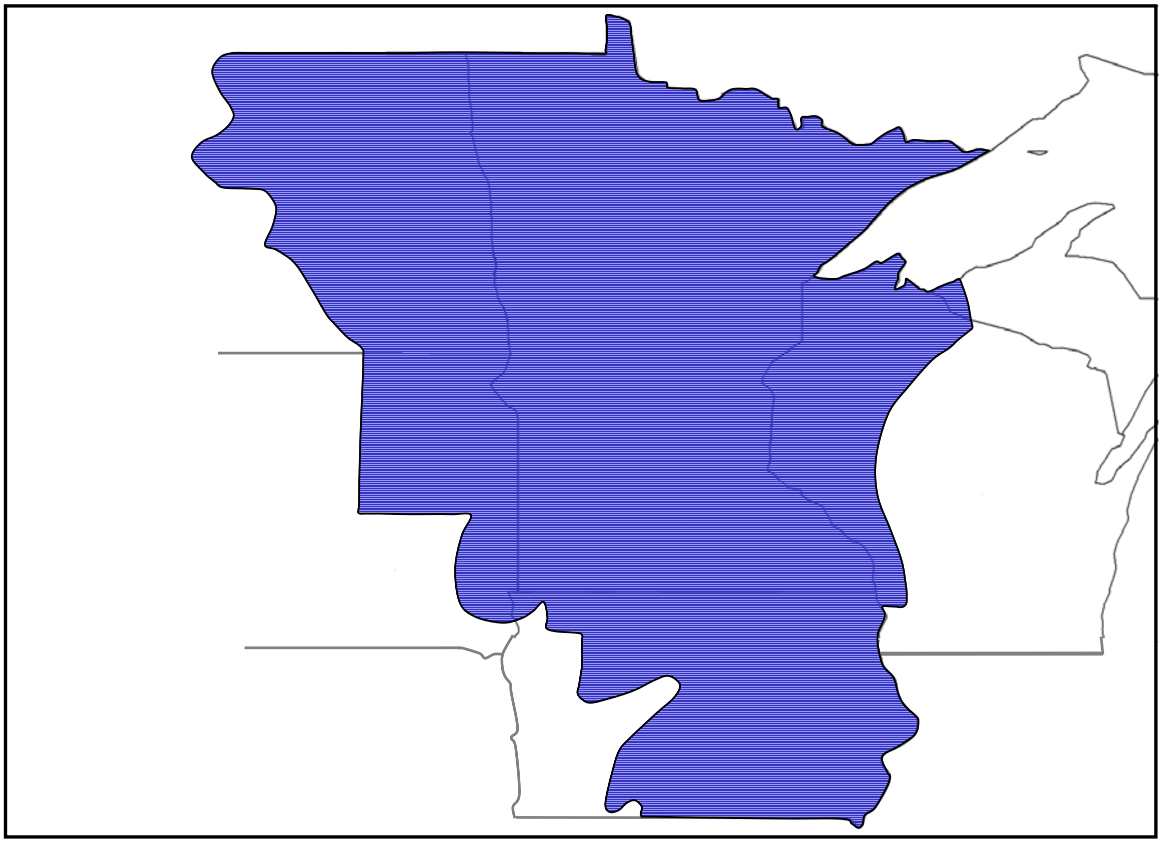

Diagram 3

ATTACHMENT E
STATE PLANNING AND REGULATORY ISSUES

To determine whether current regulatory processes can facilitate the implementation of needed transmission, CapX 2020 is undertaking a review of Minnesota statutes and rules. This effort is intended to determine whether any change would be appropriate to these processes to ensure:

- Reliability.
- That timely additions and upgrades to the transmission grid can be implemented to deliver needed energy and capacity.
- Compliance with state policies, such as a good faith effort to meet the Renewable Energy Objective.
- Access to generation and markets to lower the costs of electricity for customers.
- Consistency with the current regulatory landscape, given significant changes at the federal and regional level.

We present a brief summary of the various issues under review.

INDUSTRY STRUCTURE
As previously noted, significant changes in the industry are underway with the evolution and implementation of regional transmission organizations (RTOs), and the need for significant new transmission investment is great. It is appropriate to consider different approaches and opportunities presented under the RTO structure that may help facilitate the significant investments that will be required. It is possible that investment by individual utilities at the levels anticipated to be required under this effort is not the most efficient or cost-effective approach available and all reasonable possibilities should be explored.

COST RECOVERY
Utilities recover investment in transmission through retail and wholesale rates. Investor-owned utilities' retail rates are regulated by the Minnesota Public Utilities Commission (PUC), while rates of cooperative and municipal utilities are set by their local regulatory/governing bodies. Rates for investor-owned utilities' transmission services to small utilities, such as municipal utilities, are regulated by the Federal Energy Regulatory Commission (FERC).

For investor-owned utilities, recovery of transmission investments generally requires the utility to file with the PUC a general rate case after construction is completed and the transmission lines are in service. General rate cases are 10-month, contested-case processes where all utility costs are reviewed for appropriateness of cost recovery. Rates set in this process would recover all prudent transmission investments, including those made since the time of the last rate case. (The one statutory exception to this process applies to Xcel Energy and allows direct recovery of transmission investments needed to accommodate mandated renewable energy.)

Some concerns with the current cost recovery process exist. They include:

- *Required investments not large enough to drive a general rate proceeding; cost recovery can lag investment.* Transmission investments account for approximately 7 percent of total utility costs, so by themselves they do not justify the time and expense of a general rate case proceeding. However, planning, certification and routing proceedings – and ultimately construction and operation of new transmission projects – can require significant investments prior to cost recovery. Until a general rate case is filed, the costs of incremental transmission investments are incurred by the utility but not recovered in rates. This "regulatory lag" provides a disincentive for significant transmission investment.

- *Cost recovery at authorized returns may not be sufficient to encourage large-scale undertakings with attendant risks of non-certification of facilities or lengthy, contentious proceedings.* The Federal Energy Regulatory Commission (FERC) considers returns to appropriately compensate for investments in transmission, recognizing the nature of these investments. In contrast, state regulation uses a single rate of return to compensate for all electric utility investments – generation, transmission, distribution, customer service and other costs. A single return may not appropriately compensate for the risks associated with large-scale transmission investments, given their unique nature.

- *Current recovery mechanisms do not encourage appropriate decisions between generation and transmission investments.* To some extent, additional generation and transmission are substitutes for each other. In some cases, transmission investments may allow for acquisition of distant resources that can more cost effectively meet customer needs, provide a robust grid, or otherwise strengthen access to markets that help with effective functioning of the wholesale energy markets. Current regulatory and cost recovery mechanisms, however, can favor investment in generation as opposed to transmission, as costs are more likely to be promptly recovered for generation investments.

NEED CERTIFICATION

The criteria for determining whether a proposed transmission facility qualifies for a certificate of need address a variety of issues. These criteria were established by statute in the 1970s, prior to the recent changes in the use and oversight of the transmission grid and do not specify any particular weighting.

These criteria should be reviewed in light of today's environment, as reliability, access to markets and the robust functioning of a wholesale market may be appropriate additional criteria to consider. Such a review should consider whether to add regional considerations to the state's decision-making, as some transmission investments may not be required to specifically serve Minnesota load but rather are needed to address regional reliability issues. Further, it may be appropriate to consider assigning weights to the various criteria to ensure that reliability has priority consideration.

PLANNING

The biennial state transmission planning process established by statute in 2001 and governed by the PUC provides increased and early public participation and is intended to promote overall a more expeditious and less contentious need certification process. Certification as part of the biennial process was intended as an expedited alternative to the certificate-of-need process; however, this approach has not been used and may pose more risk and difficulty than advantages.

The certificate-of-need process has been used for a large-scale project only once, in 2003. The new alternative biennial certification process authorized by the 2001 Legislature has not been tested for smaller-scale projects. Nonetheless, given the anticipated significant need for new transmission in the relatively near future, the question is whether current state processes for permitting transmission facilities are properly designed to accommodate needed infrastructure improvements.

TIMING

The Minnesota certificate-of-need process for transmission requires the PUC to approve or deny a proposal within six months of application (Minn. Stat, 216B.243, subd. 5); the route process requires the Environmental Quality Board (EQB) to decide within 12 months for full process (Minn. Stat. 116C.57, subd. 1) and six months for alternative process (Minn. Stat. 116C.575, subd. 7).

Although both regulatory processes identify a time period in which they are to be completed, as a practical matter the statutory deadlines frequently are inadequate to ensure the processes move along to an expeditious conclusion. There are no consequences if the deadlines are missed, and it is impractical for utilities to challenge missed deadlines. Further, some deadlines may be unrealistic (too long or too short), depending on the nature of the project.

REGIONAL ISSUES

Transmission affects interstate commerce, which is why it is regulated in part by the FERC. Unlike the interstate natural gas pipeline system, however, transmission need and routing decisions are made entirely at the state level. State regulators often are presented with the difficult task of balancing both regional and state needs, while being required to follow only state law. This promotes the state's interest over regional interests. No single forum is charged with looking out for the regional interest.

JURISDICTIONAL ISSUES

As noted above, two state agencies are involved in Minnesota's permitting processes:

- The PUC has jurisdiction over certificates of need for any high-voltage transmission line of 100 kilovolts or more and greater than 10 miles or that crosses a state line, and any high-voltage transmission line greater than 200 kilovolts.
- The EQB has jurisdiction over granting route permits to any high-voltage transmission line greater than 100 kilovolts.

State law (216B.243, subd. 4) allows the agencies to conduct joint hearings “when feasible, more efficient, and may further the public interest.” So far, joint hearings are used only on non-controversial projects.

In addition, FERC rules now require that high-voltage transmission projects be approved through the Midwest Independent Transmission System Operator’s (MISO) regional planning process. So the potential exists for conflicts between the MISO regional plan and decisions of the PUC and EQB regarding facilities solely within Minnesota.

ATTACHMENT F
PRELIMINARY RESULTS

The CapX 2020 technical team assumed that the generation modeled in the 2009 summer model would exist in 2020 and would serve the load modeled in 2009. To address anticipated load growth of 6,300 megawatts, the team solicited information from independent power producers (including wind developers), resource planning entities within various organizations, and the Midwest Independent Transmission System Operator's (MISO's) generation interconnection queue. The team mapped the locations of these resources and identified five generation regions: northern Minnesota, North Dakota and South Dakota, southern Minnesota/northern Iowa, Wisconsin and the Twin Cities metropolitan area. These are shown in Diagram 4.

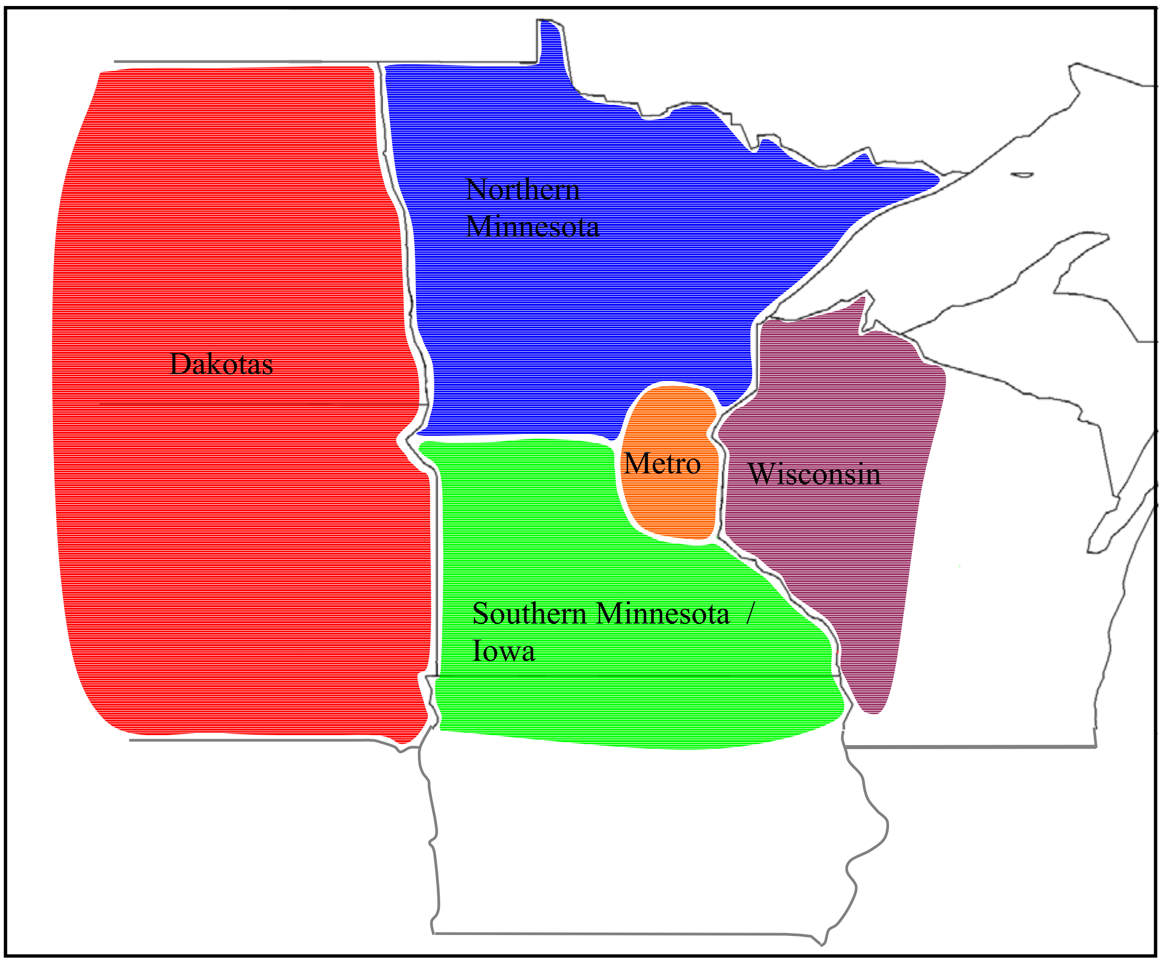

Diagram 4

The CapX 2020 technical team will model three generation scenarios to address the anticipated load growth of 6,300 megawatts by 2020. Each of the scenarios includes sufficient renewable resources to address the Minnesota Renewable Energy Objective of the CapX 2020 participants. The three scenarios include a North/West bias, a Minnesota bias and an Eastern bias. These biases reflect potential generation development that might influence electricity flows on the regional grid and thus the size and location of new transmission infrastructure needed to deliver the generation to customers. Each of the scenarios includes generation resources from several of the regions. See Table 4.

		Scenario	
Generation areas	North /West Bias	Minnesota Bias	Eastern Bias
North MN	1700	1250	550
ND, SD	2100	1000	1600
South MN/ Iowa	1875	1875	2175
Metro	650	2200	1000
Wisconsin	0	0	1000
Total	6325	6325	6325

Table 4

Diagrams 5, 6 and 7 provide geographical representation of the regions for which generation will be modeled in each scenario.

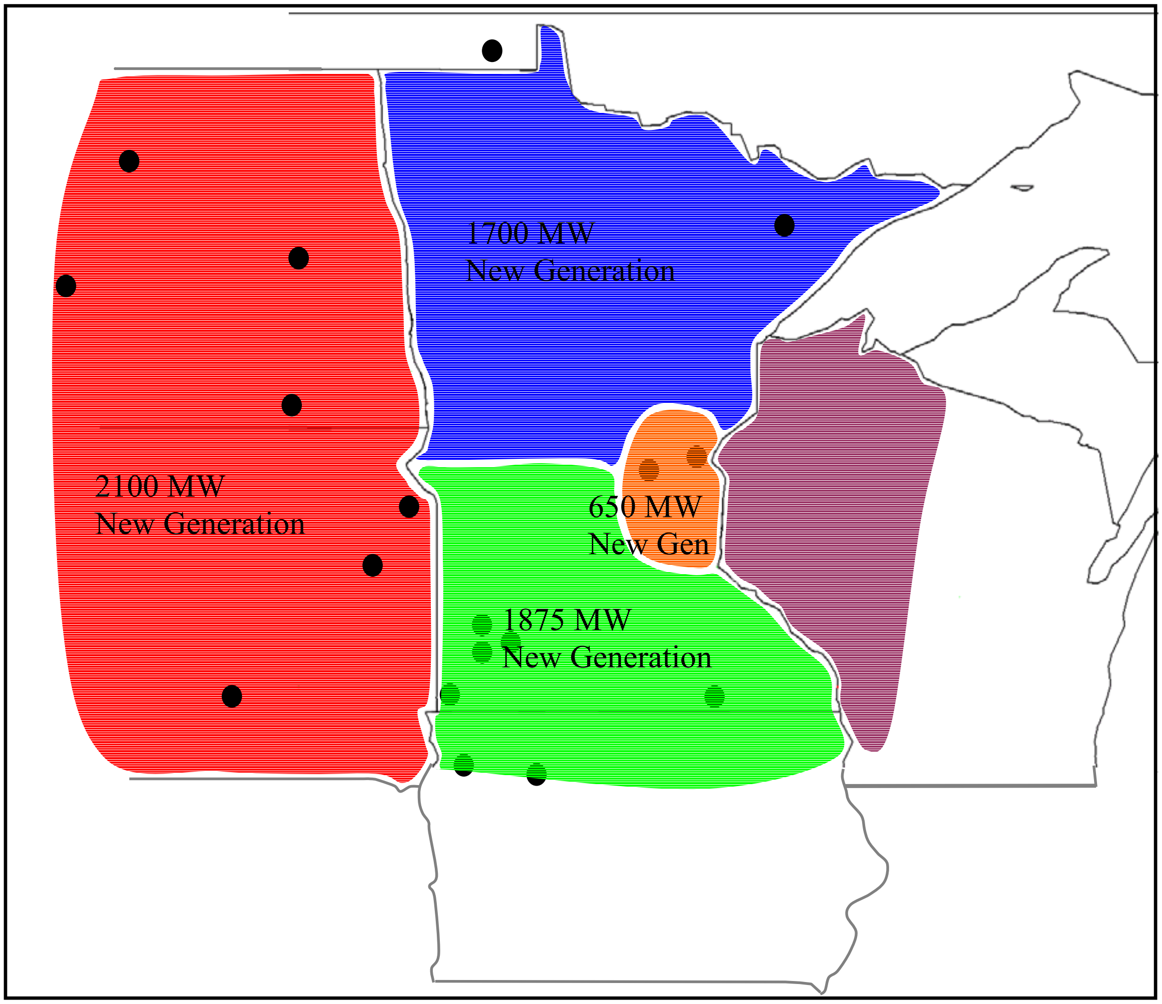

Diagram 5 - North/West Bias

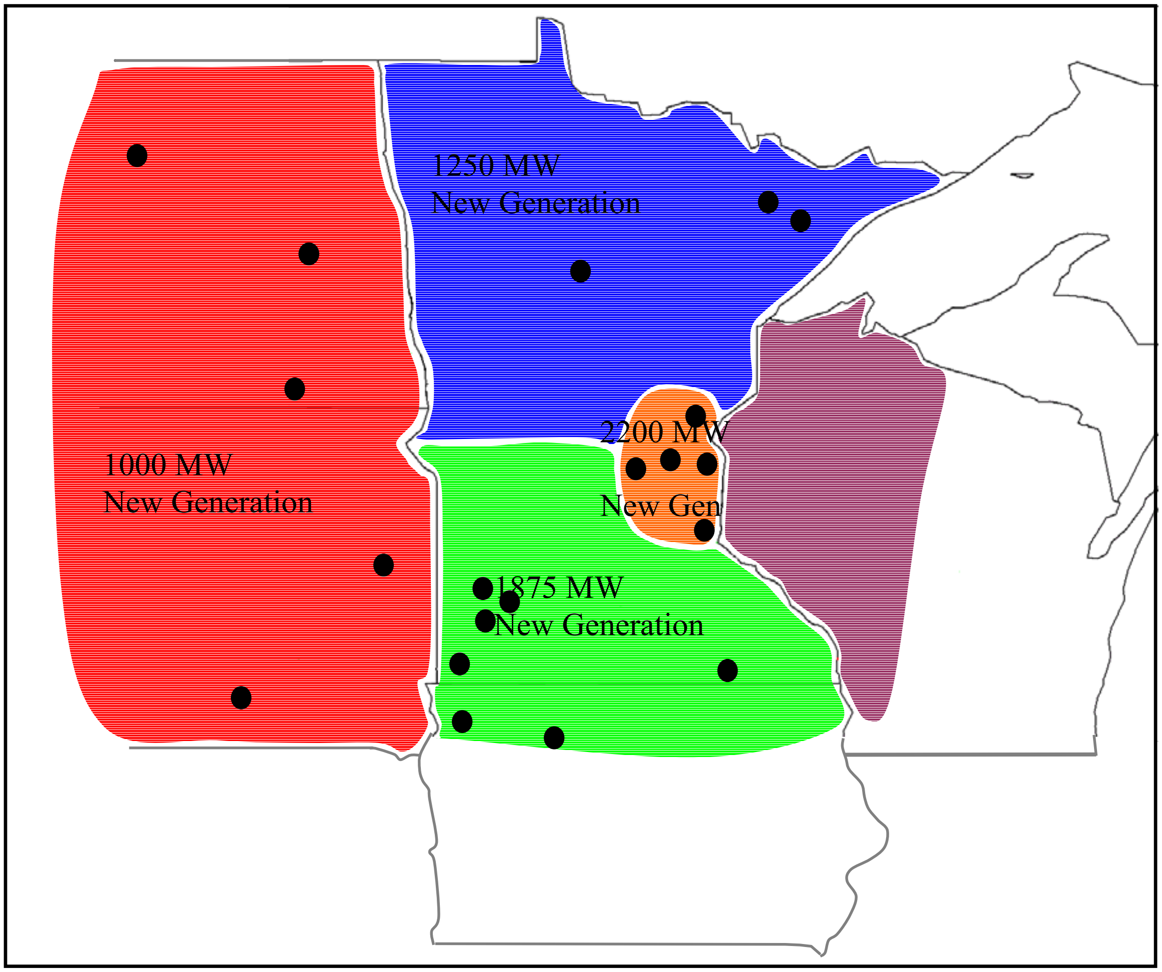

Diagram 6 - Minnesota Bias

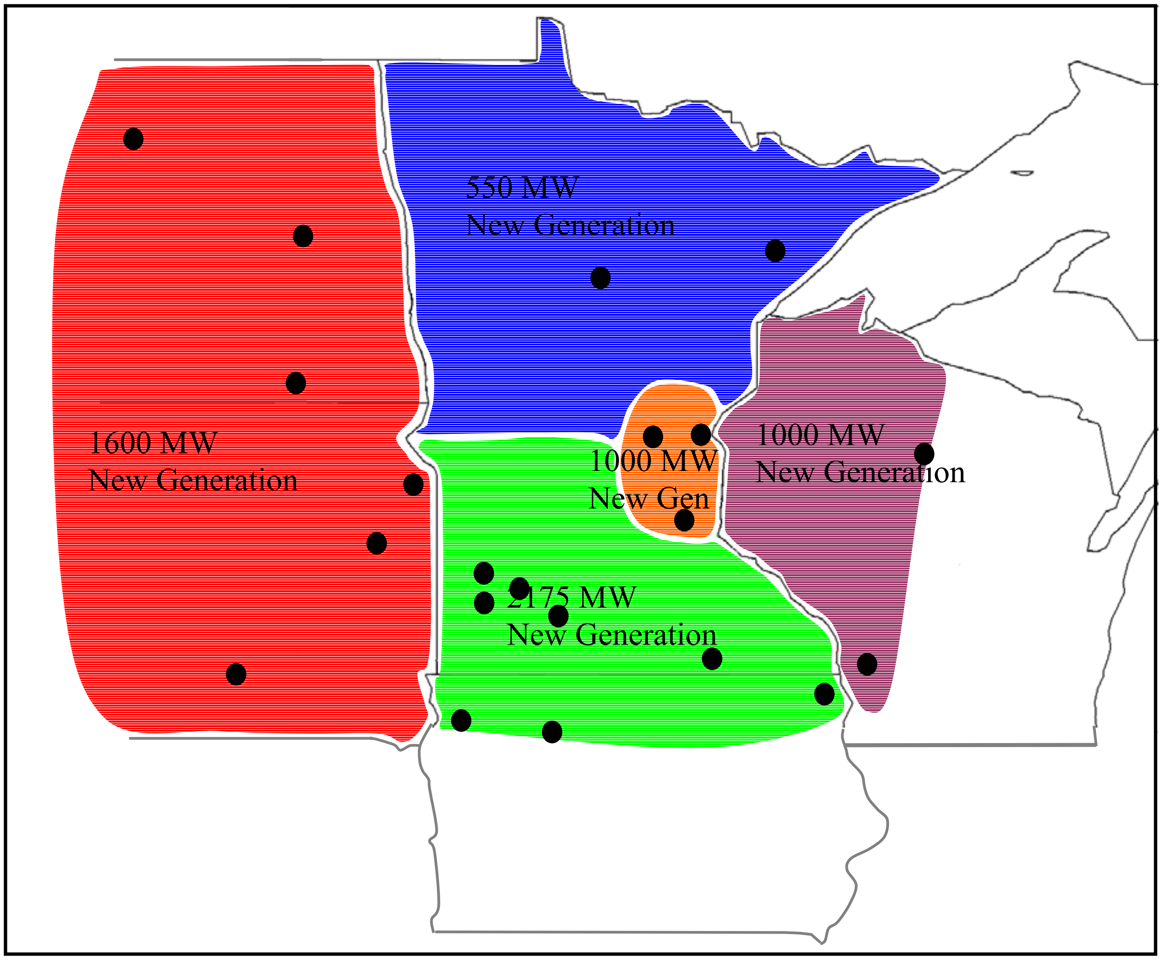

Diagram 7 - Eastern Bias

Transmission improvements identified in the 2003 Minnesota Biennial Transmission Plan are included in the CapX 2020 base model. The plan is available at www.minnelectrans.com.

STUDY ANALYSIS

The technical team will test several transmission solutions for each generation scenario and will perform steady-state power flow analysis (first contingency simulations) to determine which transmission solution eliminates thermal overloads on transmission greater than 100 kilovolts in the region. The team also will perform voltage analysis for each of the transmission solutions.

The technical team plans to incorporate transmission alternatives identified in on-going studies in conjunction with transmission plans identified by various transmission stakeholders. The goal is to identify transmission improvements that bring remote generation to the load-serving centers in the region and develop an expanded transmission backbone that supports continued load growth in the various load centers. The transmission improvements will focus on high voltage solutions (345 kilovolt lines and 500 kilovolt lines) that best address the various generation scenarios, as shown in Diagram 8.

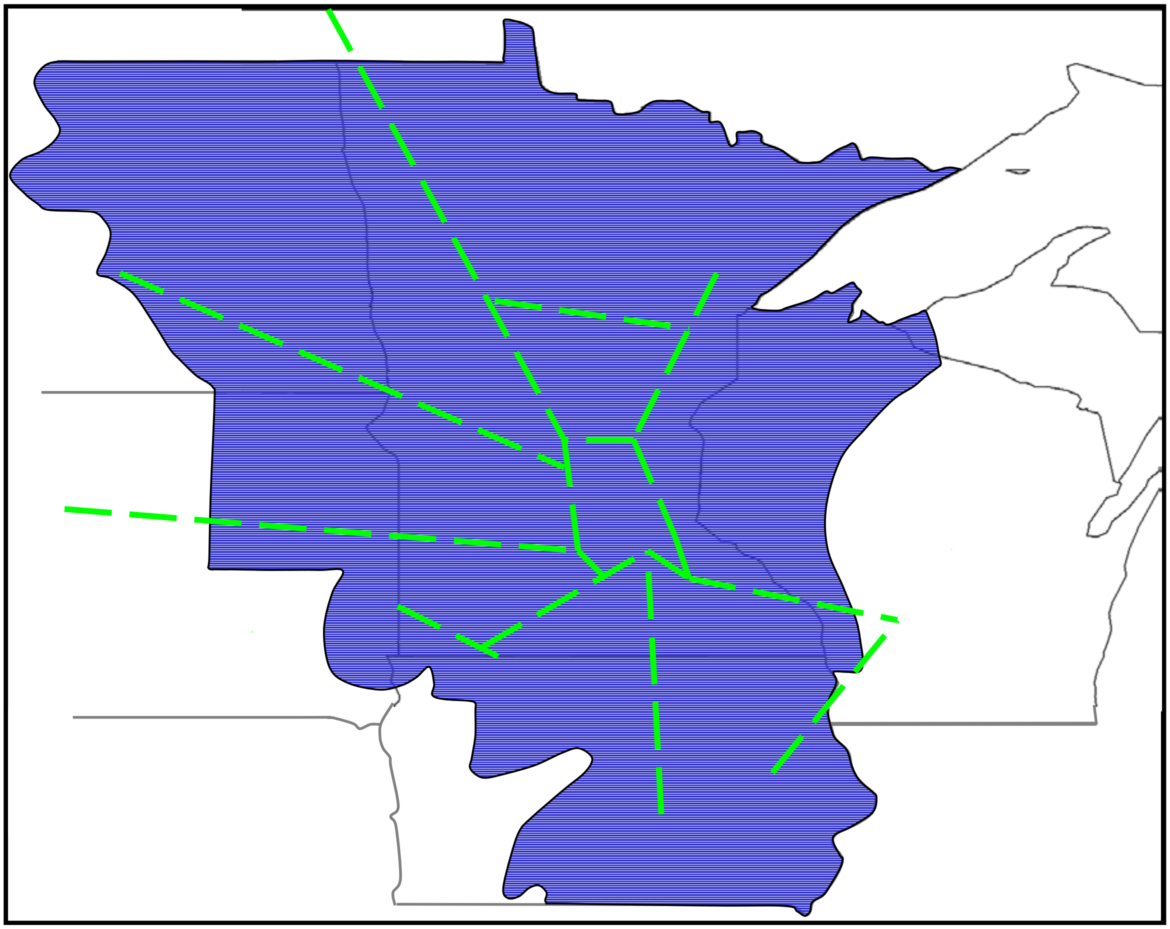

Diagram 8 - Conceptual transmission

INITIAL RESULTS

Preliminary analysis by the CapX 2020 technical team on the three generation scenarios has identified a significant number of transmission overloads if no additional transmission is built to serve the projected 6,300 megawatts in new generation needed by 2020 to meet growth in customer demand. The team currently is simulating the loss of single transmission elements to assist in the determination of transmission alternatives to address violations of North American Electric Reliability Council (NERC) criteria (low voltages and overloaded facilities) that would occur. Table 5 shows overloaded transmission facilities in Base 2020 models.

Scenario	System Intact Overloads	Prior Outage Conditions[4]	Voltage Violations
North/West Bias[5]	42	142	45
Minnesota Bias	42	187	14
Eastern Bias	42	197	33

Table 5

The schedule for completing CapX 2020 Vision study is shown in Table 6.

Task	2004-2005 Schedule
Model Preparation	9/27 – 10/29
Power Flow Analysis	11/1 – 12/17
System Improvement Analysis	1/17 – 3/17
Final Report	May 2005

Table 6

[4] Outages of individual facilities greater than 150 kilovolts were simulated.

[5] Includes the addition of a 345 kilovolt facility from Canada to Minnesota.