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MINNESOTA RESOURCE ASSESSMENT STUDY

PREPARED BY THE
MINNESOTA OFFICE OF ENERGY SECURITY
AND THE RELIABILITY ADMINISTRATOR

office of energy security
Minnesota Department of Commerce

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Minnesota Resource Assessment of the Reliability Administrator

Executive Summary – Major Assumptions and Findings

Until recently, electric resource planning was fairly straightforward. Utilities forecasted how much energy their customers would need by a certain time in the future, with review by state regulators, and then built generation and transmission facilities to serve those needs.

However, beginning in 1996, two federal government-instituted efforts were enacted that dramatically changed the way that utilities provided and planned for energy supply to their customers. First, the federal government established policies that made the nation's transmission grid into an open access electricity carrier where any electricity seller or buyer could transmit their power over transmission lines originally built and operated to serve only local customers.[1] The federal government also created new "independent transmission system operators" (ISOs) to operate this new open-access transmission system and the new energy market. These changes forced utilities and transmission owners to begin to operate their systems and provide services to their customers in much different ways.

Second, more recently, various state governments, including Minnesota, began enacting mandates requiring utilities to meet a certain percentage of their customers' usage with renewable energy.[2] As a result, utilities have made major changes to their energy procurement processes and their generation planning. While the electric industry has been rapidly adapting to these new ways of planning and operating their systems and providing for their customers' needs, Minnesota's economy and citizens continue to rely heavily on electric power for their everyday needs.

Identifying the importance of energy delivery and compliance with new environmental laws, the Legislature charged the Office of the Reliability Administrator (ORA) with formulating an assessment of the State's generation and transmission resources into the future. This report fulfills that Legislative charge and is an assessment of Minnesota's generation and transmission needs through 2025.

Like any resource plan, this state-wide resource assessment had to be based on certain assumptions regarding fuel costs, capital costs, environmental impacts, available resources, etc. The ORA compiled the required assumptions from Integrated Resource Plans, Certificates of Need, Rate Cases, etc. and provided the assumptions to stakeholders for their review and comment. Stakeholders provided many revisions and supplements to the base case assumptions list and well as scenarios to be modeled. The ORA included all feasible assumptions in this report.

As this assessment is a high level, albeit extensive, analysis and forecast of various potential actions that could impact future generation choices, it should not be viewed as a recommendation or a road map for any future generation additions in the same manner as utilities' specific plans

[1] See Federal Energy Regulatory Commission Order 888 (May 10, 1996)
[2] See Minn. Stat. §216B.1691, which was first enacted in 2001.

to procure specific types and sizes of generation resources at specific times. The approval of any generation resource must come after several exhaustive regulatory and environmental proceedings to ascertain the need and appropriate siting conditions for the facility. For this reason, the ORA does not include or make specific statements regarding any proposed generation additions not yet filed or currently pending before the Public Utilities Commission (PUC or Commission) or the Legislature.[3]

Instead, this assessment should be viewed as a tool—a high-level forecasting tool to assist policy makers in answering questions regarding future generation needs under differing scenarios regarding fuel cost changes, environmental cost impacts, generation plant capital cost fluctuations, etc. Examples of such questions may include:

- What would happen to future generation needs if natural gas prices materially increase?
- What would happen to future generation options if Congress enacts a federal Renewable Portfolio Standard?
- What types of generation may be more attractive if carbon legislation of some type was passed?

These are just some of the questions that this assessment can assist policymakers in considering.

Based on the assumptions used in the modeling and the forecasting, the Office of Reliability Administrator offers the following findings from this analysis:

- Overall:
    - Energy demand is likely to grow in the future;
    - While new technologies will have an important impact, they are not likely to be the 'silver bullet' that solves all of our energy issues; and
    - Resource planning will continue to survey long-term periods because of the number of years required to plan, permit and construct facilities.
    - Economies tend to operate in cycles fluctuating between period of strong economic growth and periods of recession. Planners must ensure an adequate and reliable supply of electricity for customers at all usage levels regardless of any short-term economic fluctuations. As such, it is not advisable to base long-term demand or facilities forecasting on short term economic activity that represents only part of a full economic cycle. Rather, forecasting should take into account periods of strong economic growth, with high customer demand, along with recessionary periods when customer demand may be lower.
    - Since the future is unknown, forecasting usually involves testing a number of different scenarios involving high/low facilities/fuels/environmental costs. All of these scenarios are then examined to identify modeling results that are

[3] The ORA did not include the Big Stone II generator, which is pending in litigation, the Prairie Island uprates which pending before the PUC, or the Monticello uprates which are pending before the Nuclear Regulatory Commission (NRC) in its modeling.

common to different scenarios. This information can be very useful in making long term future facilities choices.

- Generation:
  - The size, type, and timing of generation additions are highly dependent upon the assumptions modeled. Assuming compliance with the RES, achievement of the 1.5% DSM goal, and the Base assumptions (as described further in the Report), the following generation resources are anticipated to be needed by 2010, 2015, 2020, and 2025[4]:

Cumulative Generation Additions

Year	Fossil Fuel	Renewables
2010	168 MW	600 MW
2015	1590 MW	2200 MW
2020	3012 MW	3200 MW
2025	4139 MW	4000 MW

Of the total fossil fuel additions shown above, the model added 500 MW from coal generation, 3135 from combined cycle gas generation, and 504 MW from simple cycle gas generation.[5] The Renewable additions are expected to be primarily wind energy, and wind energy additions were used as a proxy for renewables in the analysis, however, biomass, solar, photo-voltaic, etc. may also be included.

  - Even with the RES and CIP mandates fully met, coal will continue to be a main fuel source for generation used in Minnesota under any foreseeable future.

- Transmission:
  - At this time, the state's greatest need is additional transmission facilities, not only to deliver additional renewable power, but for reliability purposes, as discussed on the OES's Dispersed Renewable Generation (DRG) study recently released.[6] The following transmission projects have received Certificates of Need from the Minnesota Public Utilities Commission:

Transmission Line	Voltage	In-Service Date
Bemidji to Grand Rapids	230 kV	2012-2013
Brooking to Hampton	345 kV	2013-2015
Fargo to St. Cloud to Monticello	345 kV	2013-2015
Hampton to La Crosse	345 kV	2013-2015

[4] A discussed further in this Report, these results should not be considered support for or against any particular project.
[5] Nuclear was not considered as a generation option due to the existing moratorium on nuclear generation.
[6] The full reports for both phases of the DRG Study may be found at: www.energy.mn.gov.

- To provide a least-cost, least impact transmission system, new facilities must be studied and approved in cooperation with neighboring states.
- The creation of the open energy market and states' environmental mandates have dramatically changed the operation of the transmission grid, the planning for new transmission facilities and the allocation of costs associated with new transmission facilities
- Many transmission planning processes are currently underway on a state-wide, subregional, regional and national level to forecast future transmission needs to facilitate states', and potentially national, environmental mandates as well as today's open dynamic energy market.
- Distributed generation resources may play some role in allowing additional generation to interconnect to the transmission grid, but that role will be very small unless and until significant transmission upgrades are constructed in order to allow for additional distributed generation opportunities.

I. INTRODUCTION

The quality of life and standard of living enjoyed by the citizens and businesses in Minnesota, the Midwest and the U. S. depend on reliable, reasonably-priced, supplies of energy provided in an environmentally sound manner. Also, Minnesota's economy and citizens continue to rely heavily on electric generation for a variety of needs such as lighting, refrigeration, industrial processes, computers, entertainment, transportation, hospital care, and so on. As demand for electricity grows beyond the capacity of existing generation, more generation must be added to meet the needs of Minnesotans. As these needs are identified, energy policies in Minnesota and nationwide continues to be critically important and present significant challenges in planning for facilities to meet customers' needs while complying with federal and state existing and expected regulations that impact such planning and construction. The potential of greenhouse gas legislation, the integration of renewable generation, and the investments required in transmission infrastructure to accommodate additional generation and policy preferences all present significant issues that must be carefully considered when determining Minnesota's energy future. To assist policy makers in making informed decisions, the Minnesota Legislature passed 2007 Laws, Chapter 136, Art. 4, Sec. 16, which requires the ORA to prepare a Resource Assessment to be submitted to the Minnesota Legislature. Specifically, Section 16 provides:

> The reliability administrator shall conduct an engineering assessment of Minnesota's electricity resource needs through 2025, with a focus on baseload resources. The reliability administrator may contract with an independent entity to conduct all or part of the study. The assessment must consider additional generation and transmission resources necessary to meet the state's renewable energy standard under Laws 2007, chapter 3, section 1, subdivision 2a, and projected energy savings resulting from the implementation of article 2. The assessment, among other activities, must review and evaluate the most recent Minnesota utility demand forecasts, integrated resource plans filed under

> section 216B.2422, and transmission projects reports filed under section 216B.2425, including the assumptions underlying them, and provide independent projections of demand and baseload and nonbaseload generation and transmission resources available to meet projected demand in 2010, 2015, 2020, and 2025. The reliability administrator shall manage the assessment process and shall appoint a technical review committee to review the assessment's proposed methods, assumptions, and preliminary data and results. The reliability administrator must submit a report on the assessment to the chairs and ranking minority members of the senate and house of representatives committees with primary jurisdiction over energy policy. The cost of the assessment is recoverable under section 216C.052, subdivision 2.

The legislation requires this Report to assess the available, and needed, resources (generation and transmission) necessary to serve Minnesota's expected load in the coming decades as well as fulfill the provisions of the Renewable Energy Standard (RES). In order to consistently provide reliable energy service under all weather and other conditions, generation and transmission facilities must be planned for the maximum level of expected load. However, with today's technology, generation and transmission planning must be done separately. That is due to federal rules prohibiting utility practices of combining generation and transmission functions which may impede open energy market competitive transactions. Also, currently no software models are commercially available that can simultaneously optimize transmission and generation. Current models are able to optimize one or the other but not both together. For instance, to forecast future generation needs, transmission is assumed as being sufficient to deliver the level of generation selected by the model in order for the software to solve for generation with certain characteristics and timing. Such models are oftentimes referred to as capacity expansion models. The same applies to transmission models, which assume a particular level of generation to analyze the transmission system.

Many input assumptions are required in order to run a capacity expansion model. These assumptions are discussed below in this Report. These assumptions include costs associated with the construction of additional generation plants, emissions costs, fuel costs, and a forecast of future energy consumption. When this Report was undertaken, the economy was already in recession, and the short-term demand for electricity decreased.

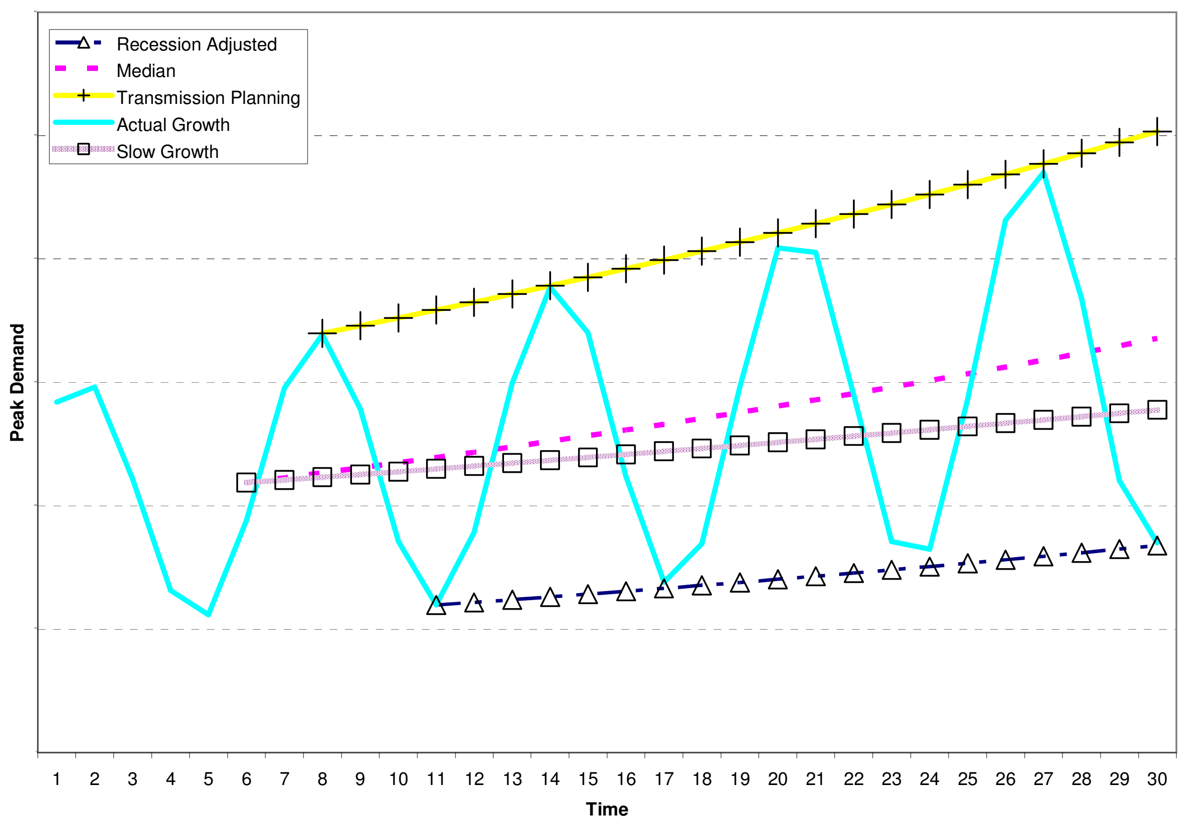
Recently, questions have been raised regarding the effect of the recession and Minnesota's 1.5 percent conservation goal on future demand for electricity. In resource planning, uncertainty is a given. Even in favorable economic times, small and large businesses and even industries may rise and fall (due to circumstances other than economic) and their energy usage rises and falls with them. Policy makers and planners should not attempt to eliminate uncertainty, but rather to account for it by analyzing a variety of futures. This principle applies to forecasting as well as all other major assumptions undertaken in this study. As described in the Report, several contingencies were evaluated using higher and lower costs for capital, fuel, and carbon dioxide (CO_2). Further, the forecast used in the model was adjusted to incorporate different levels of expected energy conservation and efficiency measures. Because of the future energy demand questions raised by the recession, the ORA provides an overview of resource planning and forecasting at the outset of this Report.

Forecast of Demand for Electricity

The study period for this Report is through 2025. This long-term "planning horizon" is advisable in that it usually takes many years to plan, permit and construct energy facilities. Over such long periods, many changes prompted by economic conditions, commodity prices, new legislation, or changes in demand may affect the planning process. The current recession has produced significant interest in the potential effects on the demand for electricity in the long-term.

Recessions have occurred before and will occur again. Prior to the current recession, the economy most recently experienced a recession in 2001. It is important to understand how short-term phenomena such as recessions or weather variations fit in with long-term planning. Below is a graph submitted by the ORA to the Minnesota Public Utilities Commission (PUC) during deliberations in a recent proceeding regarding a proposal to build several 345 kV transmission lines in Minnesota (known as "CapX"). This graph shows the difference between actual demand and several long-term forecasts.

Graph 1: Forecast Comparison



The light blue solid line represents hypothetical actual demand. The demand fluctuates with economic business cycles, weather, and so on. The peaks are years of hot weather and economic growth. The last peak in demand for electricity in Minnesota occurred in the summer of 2006. Currently, we are in a recession (or just coming out of one) with a very cool summer. If history is a guide, demand will once again increase as the recession ends and hotter weather occurs.

Planning for sufficient infrastructure starts with deciding which level of demand is the most appropriate to consider. A typical forecast would result in the dotted pink and purple lines (labeled actual growth and slow growth). If the forecasted growth rate is applied to the peak demand, the result is the yellow line labeled transmission planning. If the forecasted growth rate is applied to the demand during a recession, the result, noted by the dotted dark blue, recession adjusted, line, may jeopardize reliable energy service during economic upswings and at peak economic times. This approach would plan for energy use below both the peak demand and median demand forecasts and thus would assume that Minnesota would not recover from periodic recessions.

Because the goal is to ensure that Minnesota has sufficient capacity not only during periods of recession but also during periods of strong economic growth or hot weather, for transmission planning, ideally, the yellow line would be used. This forecast would ensure that the transmission system is capable of providing reliable service during periods of peak demand, even though the peak demand occurs only a few days a year, or a few days every few years. The ORA acknowledges that off-peak periods may also stress the transmission system and an off-peak forecast, typically calculated as a percentage of the peak, must be examined in a proper transmission study. However, the off-peak analysis is in addition to the peak analysis. That is, due to uncertainty, a variety of scenarios must be studied.

Planning for generation resources is similar to planning for transmission resources, but there are important differences. For generation planning, the dotted pink, or median, forecast is appropriate for the following reasons. First, utilities use a planning reserve margin that requires the utility to have more generation available (or accredited) than the forecasted peak demand. The reserve margin is set so that enough generation is available to meet needs even if some generation is unexpectedly unavailable at the time of peak demand or if demand is higher than expected at peak. Second, some generation resources – whether a few central-station plants or numerous small generation plants – are far more expensive to build and maintain than are transmission resources. Thus, to help ensure that the cost of the electric systems is reasonable, it is important that the transmission and generation resources work in tandem to ensure reliability at reasonable costs. Third, some generation plants generally can be planned, permitted, and constructed in less time than transmission resources; thus it is more likely that new generation resources could be built to respond to additional demand in the intermediate term. Fourth, siting transmission would affect many more individual landowners and residents than building generation.

Using the median forecast, which is based on historical data that includes previous economic downturns, to plan for generation, along with a robust transmission system, ensures that the electric system will be sized appropriately to meet projected needs at reasonable costs. Utilities also regularly evaluate how a resource plan may change based on slow growth. The brown, slow growth, line illustrates a slow growth forecast. That information is important to keep in mind over time as planners assess whether changes are needed to the plan based on actual events.

Fundamental Change in Demand

The ORA expects that this recession, like recessions in the past, will end, and that economic growth and growth in demand for energy will resume. However, the ORA provides the following observations about the potential for fundamental changes in use of electricity.

- *What could fundamental change look like?*

It is possible that there could be fundamental changes in energy use by different types of customers, mainly residential and industrial customers. The June 2009 *Short-Term Energy Outlook* from the Energy Information Administration (EIA) of the U.S. Department of Energy provides the following perspective on the consumption of electricity:

> During the first quarter of 2009, total consumption of electricity fell by an estimated 3 percent compared to the same period last year primarily because of weak industrial consumption. Growth in residential retail sales during the second half of this year is expected to slightly offset continued declines in industrial electricity sales. Total consumption is projected to fall by 1.8 percent for the entire year of 2009 and then rise by 1.2 percent in 2010.

Further, the September 2009 *Short-Term Energy Outlook* stated that:

> Total U.S. electricity consumption fell by 4.4 percent during the first half of the year compared with the same period in 2008, primarily because of the effect of the economic downturn on industrial electricity sales. The expected year-over-year decline in total consumption during the second half of 2009 is smaller, a 2.3-percent decline, as residential sales begin to recover.

According to the EIA, the drop in electricity consumption has primarily been driven by weak industrial consumption, while electricity use by residential customers is expected to continue to rise. This information reflects changes in demand that are typical during a normal recessionary period, rather than a fundamental change in the consumption of electricity. For example, currently some taconite mines on the iron range are temporarily shut down and some retail space across the state remains vacant. This reduction in energy use is due to the drop in demand for the goods and infrastructure (retail goods or steel) provided by taconite mines and retail stores. As the recession ends, the ORA expects that demand for steel and retail goods will increase, retail space will fill and mines will re-open, with the result that growth in energy demand will resume.

While it is possible that not all retail space will be filled, or that taconite mines will not operate at their pre-recession levels, if the recent drop in electrical consumption is reflective of a fundamental change, we would expect to be able to attribute the reduction in consumption to a fundamental change in the industrial base or a change in consumer behavior. The EIA data indicates energy use by residential customers is not the driver for the reduction in demand; in fact, as consumers use electricity for more devices in their homes over time, electric use per residential customer increases. This trend has not shown any evidence of abating at this time. Moreover, the reduction in industrial consumption appears to be driven by a typical business cycle rather than a significant technical innovation resulting in the ability to increase output while decreasing the consumption of electricity, or change in Minnesota's industrial base-the type of goods produced, or some other fundamental change is the consumptions of electricity.

- *What risks does the possibility of a fundamental change in electricity demand pose?*

Planners assess over time whether adjustments must be made to forecasts of electricity demand. An unexpected decrease in demand may mean that utilities would delay the start of a new power plant or other project. It may also mean that there would be excess capacity in the electrical system and that ratepayers would have to pay for some resources that are not needed and may go unused. This cost may be substantial if, for example, a utility adds a new facility and demand for electricity subsequently drops. For example, an investment in a 500 MW facility at a capital cost of 3,000 dollars per MW would result in a capital cost of approximately 1.5 billion dollars. An investment in capital that is unnecessary is a highly undesirable result. In addition, land that could have been used for another purpose would be occupied by unneeded infrastructure.

If an unexpected increase in demand occurs, planners need to act quickly. For an economy to thrive, businesses and consumers must be able to rely on power to keep their production lines running, their call centers operational, their computer systems processing and so forth. Lack of such a fundamental resource may cause companies and residents to consider relocating, securing their own power supply, or adjusting their operations to accommodate an unreliable supply of electricity. All of these options would increase costs to society needlessly. There may also be negative effects on health and safety. The most likely time for a deficiency in resources is during the hottest days of the summer, when young children and the elderly are most susceptible to the heat. An inadequate supply of electricity would result in rolling black outs making areas without electricity more susceptible to crime and more difficult to service in an emergency. In short, the consequences of an inadequate supply of electricity are severe.

Overall assessment of risks of a fundamental change in electricity demand

As noted above, the information available at this time does not indicate that there is a fundamental change in the demand for electricity. Moreover, as noted above, while it is not desirable to err toward either under-building or over-building, the risks of under-building are relatively greater, for society. Therefore, until consumption data demonstrates that a fundamental shift in electricity consumption is occurring, the ORA does not believe it is appropriate to accept the risks of an inadequate supply of electricity by assuming that the demand for electricity will be stagnant or decreasing over time.

Forecast of Demand for Electricity Used in this Report

In this report the ORA used the median forecast of each included utility system, with two adjustments under two scenarios. Under the first scenario, the forecast is reduced to assume that utilities achieve a 1.5 percent annual energy conservation savings. Under the second scenario, the forecast is reduced to assume that utilities achieve a 1.0 percent annual energy conservation savings. These two scenarios provide information about the effects on the need for generation resources under the Minnesota Statute 216B.241, subd. 1c Energy-savings goals, which states in relevant part:

> (b) Each individual utility and association shall have an annual energy-savings goal equivalent to 1.5 percent of gross annual retail energy sales unless modified by the commissioner under paragraph (d).
>
> (d) In its energy conservation improvement plan filing, a utility or association may request the commissioner to adjust its annual energy-savings percentage goal based on its historical conservation investment experience, customer class makeup, load growth, a conservation potential study, or other factors the commissioner determines warrants an adjustment. The commissioner may not approve a plan that provides for an annual energy-savings goal of less than one percent of gross annual retail energy sales from energy conservation improvements.

Objectives of this Study

To manage risk, the ORA evaluated several different scenarios using various input assumptions. The Report provides a discussion of the source of the data, the forecast used, the input assumptions and contingencies, the results of the capacity expansion model runs, and overall conclusion regarding fuel sources used, natural gas and coal consumed, and CO_2 emissions.

The ORA notes that this statewide study, while useful, cannot be considered to be a planning document which guides resource acquisition in the same manner as utilities' specific plans to procure specific types and sizes of generation resources at specific times for reasons discussed in detail in Section II.A of this Report. The largest reason is that electricity does not stop at state borders, a fact which has helped Minnesota sell and buy power to and from other states, helping to reduce costs and ensure reliability of electrical systems. Thus, while this report attempts to isolate the electrical system of Minnesota, such isolation does not accurately portray how the utility systems operate. Moreover, while the statewide study may give insights into areas where utilities might pursue joint ventures to obtain power and the benefits and costs of different policies, there are numerous factors outside the scope of this study which must also be considered by utilities prior to any such joint effort. In addition, as explained below, a highly complex component which cannot be included in this study is the full integration of transmission, generation, fuel transportation, water, and the other infrastructure necessary to pursue specific power resources. With these limits in mind, the goal of this report is to provide an overview of Minnesota's current electrical resources as background for discussion about the future of Minnesota's electric system.

As to technical modeling issues, the ORA notes the following. Conversely to generation resources, to forecast future transmission needs, the amount, type and location of generation must be set in the model in order for the software to analyze the transmission options. Unlike modeling of future generation, using an economic or capacity expansion model for transmission is just the first of many modeling tasks required for transmission.[7]

In addition, since electrons follow the laws of physics, transmission infrastructure changes to one part of the grid, even small changes, can cause (intended or unintended) changes to other parts of the grid, sometimes hundreds of miles away. As a result, to model transmission one must go through rigorous and very complex engineering processes and tests to show how power flows and how it impacts all other parts of the overall transmission grid. All of these processes and tests are needed to ensure that the integrity and reliability of the grid is maintained.

The ORA does not possess significant transmission engineering expertise and resources. Moreover, due to the integrated nature of the transmission system, a statewide study of transmission would not provide highly meaningful information. However, numerous in-depth studies of the entire integrated transmission system, including engineering studies, expected locations of generation facilities, power flows and so forth are currently underway by different utilities, independent transmission system operators and reliability organizations (with such expertise and resources) in a number of venues with a number of scopes and purposes. Studies have been undertaken or are in process using the "footprint" (i.e., physical boundaries) of:

- The state of Minnesota,
- The state of Minnesota plus its surrounding U.S. neighbors--Iowa, North Dakota, South Dakota and Wisconsin,
- The states making up the western (and western portion of the central) sub-regions of the Midwest Independent Transmission System Operator (MISO)—The eastern edge of Montana and South Dakota; most of North Dakota, Minnesota, Iowa and Wisconsin; and the western edges of Illinois and western Indiana,
- The states making up the eastern and eastern portion of the central sub-regions of MISO—northern Missouri, northwest Kentucky, central and eastern Illinois (currently) and Indiana, Michigan, Ohio, and the western edge of Pennsylvania,
- The forty eastern states making up the eastern electric transmission interconnection (Eastern Interconnect)—from the western edge of Montana south through Oklahoma (excluding Texas) and all states east, and
- The forty eastern states making up the Eastern Interconnect in partnership with the Canadian Provinces directly north of the forty states.

[7] The ORA acknowledges that some transmission studies do not require specific information on future generation and thus do not employ a capacity expansion model.

Every study, plan or action encompassing any of these footprints either includes or likely somehow impacts the electric transmission grid, its operations and costs in Minnesota. And, conversely, any impact on the grid in Minnesota likely includes or impacts the grid in other states. All of these impacts and actions are part and parcel of the integrated transmission system in the United States (including the Eastern Interconnection noted above).

As such, for this report, the ORA provides a discussion on each of the major transmission assessments, studies and planning efforts currently underway in the different footprints listed above that will or will likely impact Minnesota in the coming years.

The major efforts to be discussed are:

1. For Minnesota:
    a. the 2004 Xcel Wind Integration Study,
    b. the 2006 Minnesota Wind Integration Study,
    c. the Biennial Transmission Plans,
    d. the RES Transmission Report, and
    e. the Dispersed Renewable Generation Study Phases 1 and 2.
2. For Minnesota and its Neighboring States:
    a. the Upper Midwest Transmission Development Initiative.
3. For the western sub-region of MISO:
    a. the Regional Generation Outlet Study Phase 1.
4. For the eastern sub-region of MISO:
    a. the Regional Generation Outlet Study Phase 2.
5. For the forty states of the Eastern Interconnect:
    a. the Joint Coordinated System Plan,
    b. the Eastern Wind Integration Study, and
    c. the Eastern Interconnection Planning Collaborative Modules A and B.
6. Smart Grid—Collaboration between MISO and member Transmission Owners to: Take steps to ensure continued Transmission "Grid" reliability and energy market operations once retail Smart Grid measures.

II. GENERATION

A. INTRODUCTION

The ORA notes that this statewide study, while useful, cannot be considered to be a planning document in the same manner as utilities' integrated resource plans (IRPs), which are utilities' specific plans to procure specific types and sizes of generation resources at specific times. There are several reasons why a statewide assessment cannot be considered as a plan to acquire specific resources at specific times. First, as discussed further below, while several utilities serve customers in more than one state, their utility system is not subdivided into state jurisdictions; rather, the utility system is operated on a unified basis to provide power in the most efficient manner to all of the utility's customers, regardless of their location. Thus, while this Report attempts to isolate the Minnesota portion of these utility systems, such isolation does not accurately portray how the utility systems operate. Second, procurement of additional resources occurs on a utility-by-utility basis, rather than by any central entity. Thus, while the statewide study may give insights into areas where utilities might pursue joint ventures to obtain power, there are numerous factors outside the scope of this study which must also be considered. Third, a highly complex component which cannot be included in this study is the full integration of transmission, generation, fuel transportation, water, and other infrastructure necessary to pursue specific power resources. With these limits in mind, the goal of this Report is to provide an overview of Minnesota's current electrical resources as background for discussion about the future of Minnesota's electric system.

The ORA began the process of conducting the Assessment in July of 2008. The ORA proposed to assess potential generation additions by using the Strategist capacity expansion model. A capacity expansion model produces a least-cost generation expansion plan based on inputs such as forecasted demand and energy consumption, fuel costs, emissions, existing generation, and options for adding new generation resources, referred to as "expansion unit options." Such models are complex and require numerous assumptions. These models also provide useful information regarding the integration of the generation resources in a utility system.

In July of 2008 the ORA provided documents containing a proposed study scope and proposed assumptions to the stakeholders participating in the ORA meetings. The ORA requested stakeholder feedback on those assumptions and conducted an open stakeholder meeting to garner comments on scope and assumptions. The ORA invited all participants in the ORA meeting to participate in providing feedback, both at the July 2008 ORA meeting, and through written comments. Written comments were received from the following stakeholders:

1. Izaak Walton League, Fresh Energy, and Minnesota Center for Environmental Advocacy (MCEA);
2. Missouri River Energy Services (MRES);
3. Central Minnesota Municipal Power Agency (CMMPA);
4. Byron Starns and James Betrand on behalf of a group of Minnesota Ratepayers;
5. Excelsior Energy;
6. Interstate Power and Light (IPL); and
7. City of Nashwauk Public Utilities Commission.

These stakeholders provided numerous suggestions regarding the input assumptions for the Report. The ORA incorporated as many suggestions as possible into this Report. Provided below is a discussion of the assumptions used and attached as Appendix A are the ORA's scope and assumption documents sent to stakeholders and all of the responses received from stakeholders.

The ORA notes this is the first time an assessment of this kind has been performed for Minnesota. Therefore a considerable amount of time and effort was involved in procuring, rebuilding and testing the model and base case and then performing the scenario runs.[8]

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[8] This study was carried out in addition to the significant amount of ongoing regulatory work that has deadlines imposed by statutes, rules, or Commission Orders or processes, particularly the CapX CN proceeding, numerous wind CN proceedings, power purchase contract proceedings, and rate cases. Thus, as many readers of the Report

B. DATA SOURCE

As a starting point for the data necessary to run the Strategist Capacity Expansion Model, the ORA obtained base case data from the Midwest Independent System Operator (MISO) used in the Midwest Transmission Expansion Plan (MTEP).[9] This data was originally formulated for the 2008 MTEP and reviewed by all of MISO's stakeholders in the process. As part of the MTEP process, MISO analyzes data in three regions, west, central, and east. The data obtained from MISO is for the west region, which includes Minnesota. To tailor the data for a better representation of Minnesota, data from utilities that do not serve Minnesota load were removed from the analysis. Therefore, this Report relies on data for the following utilities: Northern States Power d/b/a Xcel Energy (Xcel), Minnesota Power (MP), Otter Tail Power Company (OTP), Interstate Power and Light (IPL), Great River Energy (GRE), Southern Minnesota Municipal Power Agency (SMMPA), and Hutchinson Utilities Commission. Several stakeholders noted that not all load in Minnesota is represented by the utilities' systems included in the Report. While this observation is correct, it is also true that IPL, Xcel and OTP have significant load that is outside Minnesota and the utility systems included above represent most of the load in Minnesota.[10] Thus, these two factors cancelled each other out to a certain extent. Further, acquiring the data for other utilities that serve load in Minnesota would have been highly time consuming and would not necessarily provide more accurate results. As utilities serve load on a utility-wide basis and not on the basis of jurisdictions located in their respective service territories, separating Minnesota load from out-of-state load would be impractical.[11] The ORA concluded that the above utility systems provided a reasonable representation of Minnesota load, and resources used to serve that load, with the understanding that the data provides only a representation and not an exact picture.

C. FORECAST

The ORA received a number of stakeholder comments regarding the forecast. Several stakeholders suggested that additional contingencies be added to the Report to evaluate the effects that would occur if the 1.5 percent demand-side management (DSM) goal in Minnesota Statute §216B.2401 is not achieved. Specifically, this statute states:

> It is the energy policy of the state of Minnesota to achieve annual energy savings equal to 1.5 percent of annual retail energy sales of electricity and natural gas directly through energy conservation improvement programs and rate design,

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realize, the Offices' resources have been significantly stretched over the past year, which prevented an earlier release of this Report.

[9] The ORA thanks MISO for providing this information.

[10] Utility systems that are capable of generating 100,000 kilowatts or more of electric power and serving the needs of 10,000 retail customers in Minnesota, and are therefore required to file an IRP, that were not included in the Report included: Dairyland Power Cooperative, Basin Electric Power Cooperative, Minnesota Municipal Power Agency (MMPA), Missouri River Energy Services (MRES), and Minnkota Power Cooperative.

[11] The ORA is aware that, since utilities acquire resources to serve their individual systems, this statewide study does not actually reflect the resources that will be needed by Minnesota utilities. However, the ORA followed the requirements of the statute.

> and indirectly through energy codes and appliance standards, programs designed to transform the market or change consumer behavior, energy savings resulting from efficiency improvements to the utility infrastructure and system, and other efforts to promote energy efficiency and energy conservation.

The ORA agrees that this is an important contingency to study. In response the ORA added scenarios which assume that utilities meet only the minimum level of energy savings equal to 1.0 percent of retail sales.

The ORA also received suggestions that the load from the potential use of plug-in hybrid vehicles be included. The ORA notes that the addition of plug-in hybrid vehicles could represent a significant addition to the electric load and a significant change regarding when customers require energy. However, until plug-in hybrid vehicle programs take shape in Minnesota, the effect is too uncertain to model. The ORA agrees, however, that it is worth keeping the load-impact potential of such programs in mind when considering Minnesota's future resource needs.

The ORA also notes that it received information regarding the addition of load due to the construction of the Essar Steel facility. There is still uncertainty regarding the new facility's load profile (how much energy is required at various hours of the day) and thus the ORA chose not to include the potential load in the Report. However, based on the information received by the ORA, the facility is anticipated to have a load profile that is relatively flat (that is, the same energy requirement for each hour) and a potential peak demand of 590 MW by 2020. Clearly, an addition of load this size will require a significant addition of resources to meet anticipated needs.

D. ASSUMPTIONS

In developing initial assumptions, the ORA reviewed MISO's 2008 MTEP, Xcel's IRP, the CN proceeding for the Big Stone II facility, GRE's Elk River peaking facility, and various wind generation CNs. These CNs provide the most recent information regarding CNs for a coal facility, gas facility, and wind facilities, respectively. The ORA then reviewed stakeholder feedback, as well as the report provided by Boston Pacific Company**,** the consultant retained by the PUC in the Big Stone II proceeding to address appropriate modeling assumptions. The ORA provides an explanation below of each assumption type, its source(s) and variations used for sensitivity analyses. Following this discussion are tables showing the assumption values used in various sensitivity scenarios.

1. Study Period

The base year of the study is 2008 with a study period running from January 2008 to December 2025. All values presented in this report are in 2008 dollars unless otherwise noted.

2. *Generation Resources*

As noted above, the ORA relied on data received from MISO for the existing generation resources used in the model. The ORA compared the existing generation in the model provided by MISO to the existing generation compiled in the Minnesota Offices of Energy Security (OES) analysis in the CapX transmission line proceeding, Docket E002 et. al./CN-06-1115, in order to tailor the analysis to the existing generation of Xcel, OTP, IPL, GRE, SMMPA, and Hutchinson as found in the OES's analysis in CapX.

3. *Generation from Wind*

In order to attain the Minnesota Renewable Energy Standard (RES), Minn. Stat. §216B.1691, the ORA forced enough wind generation in the model to meet the RES.[12] The ORA based the wind additions on the *RES Compliance Report* submitted to the Minnesota Legislature in November of 2008. These wind additions are assumed to have a capacity factor (the ratio of the actual output of a power plant over a period of time to its output if it had operated at full capacity the entire time) of 40 percent. Further, the model assumes that 15 percent of the capacity can be counted toward utilities' required reserve margins (the amount of additional capacity that utilities must maintain to ensure reliable electric service). The ORA used the same wind profile MISO used in the 2008 MTEP. MISO developed the wind profile from the 2006 Minnesota Wind Study. An 8,760 hour (one year) wind profile was converted to a 2,016 hour (one week per month) wind profile to match Strategist's 168 hour monthly dispatch.[13] The ORA notes that, while the average capacity factor for wind energy for the year is 40 percent, monthly values can be greater or less than the 40 percent. Finally, the Production Tax Credit is assumed to be $19 per MWh.

4. *Fuel Prices*

The ORA used the natural gas price data provided by Xcel as stakeholder feedback and included as Appendix A. This data is similar to Energy Information Administration (EIA) data that was initially proposed by the Offices, but was updated based on more recent prices from the New York Mercantile Exchange (NYMEX). This approach was also suggested by MRES. Stakeholder feedback on gas prices suggested using a large range of potential prices due to the variability of natural gas prices. The ORA agrees with this recommendation and the ORA ran sensitivity analyses with 20 percent lower, 20 percent higher and 50 percent higher gas prices. The sensitivity analysis with the scenario of 50 percent higher natural gas prices is based on stakeholder requests to further analyze the risk of increases in natural gas prices. The ORA notes that natural gas prices have recently fallen significantly due in large part to the recent economic downturn. While the ORA could have run a scenario with gas prices that were 50 percent lower than the base case, the ORA chose not to do so since planning for natural gas prices to remain at such a low level for a decade is not a realistic contingency in the ORA's view. Below are the gas prices used in the base case:

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[12] When energy savings of 1.5% of retail sales were assumed, 40 wind units of 100-MW each were forced into the model by 2025. When energy savings of 1.0% were assumed 44 wind units of 100-MW each were forced into the model by 2025.

[13] Strategist uses a representative week from each month in order to model the system being represented.

Table 1: Natural Gas Cost (nominal dollars)

Year	$/MMBTU
2008	$9.05
2009	$9.13
2010	$9.22
2011	$8.95
2012	$8.73
2013	$8.60
2014	$8.00
2015	$7.71
2016	$7.91
2017	$8.17
2018	$8.46
2019	$8.84
2020	$9.05
2021	$9.13
2022	$9.43
2023	$9.76
2024	$10.11
2025	$10.34

The ORA did not receive feedback from stakeholders regarding the coal fuel costs as used by MISO. However, the ORA notes that coal prices increased somewhat, although to a lesser extent, in 2008. As a result, the ORA used the coal fuel costs from MISO in the model with a sensitivity analysis using coal at 20 percent higher and 20 percent lower costs. The coal fuel costs used in the base case are below:

Table 2: Coal Fuel Cost (nominal dollars)

Year	\$/MMBTU
2008	\$1.67
2009	\$1.71
2010	\$1.75
2011	\$1.79
2012	\$1.82
2013	\$1.86
2014	\$1.89
2015	\$1.93
2016	\$1.97
2017	\$2.01
2018	\$2.05
2019	\$2.09
2020	\$2.13
2021	\$2.18
2022	\$2.22
2023	\$2.26
2024	\$2.31
2025	\$2.36

5. Greenhouse Gas (GHG) Impacts

The ORA ran the costs of GHG regulation scenarios using four different prices per ton of CO_2: \$4, \$17, \$30, and \$45. The four to thirty dollars is the current range of CO_2 prices approved by the PUC until shortly before the report was completed. Seventeen dollars is the midpoint between \$4 and \$30. The ORA also added the higher \$45 CO_2 price in response to stakeholders' suggestions.

6. Generation Capital Costs

The ORA used the capital costs provided by Xcel in its IRP, which was approved by the Commission in Docket No. E002/RP-07-1572. At \$3,000/kW, the capital costs for coal-fired baseload generation are slightly less than that suggested by MCEA, and more than the amount recommended by the PUC's consultant dated October 21, 2008 in the Big Stone II proceeding in Docket No. E017 et.al/CN-05-619.

The ORA analyzed scenarios where the capital cost of a coal-fired baseload expansion unit was increased and decreased by 20 percent from the \$3,000/kW level giving a range of \$2,400 to \$3,600/kW. Several stakeholders stated their desire to see a set of data taken from a single source. As a result, the ORA used the costs provided by Xcel in Docket No. E002/RP-07-1572 since that information is updated, used for other inputs, and from a single source. The ORA notes that the costs are within the range of that shown in the June 19, 2008 presentation by the Federal Energy Regulatory Commission's (FERC) Office of Enforcement that was provided by Missouri River Energy Systems (MRES) and attached as Appendix A.

Several stakeholders suggested that smaller expansion units should be used. The ORA agree with this recommendation. By using data from Xcel, the ORA was able to decrease the size of the expansion units to the size of those used by Xcel in its resource plan. Below are the generation capital costs assumed in the base case:

Table 3: Capital Costs

Unit	Capacity	$/kW
Coal	500 MW	$3,000.00
CC	627 MW	$1,000.00
CT	168 MW	$750.00
Wind	100 MW	$2,500.00
IGCC w/out sequestration	600 MW	$3,500.00
IGCC w/ sequestration	600 MW	$4,000.00

7. *Wind Integration Costs and Key Assumptions*

Wind generation introduces more uncertainty into operating a power system: it is continuously variable and difficult to precisely predict. Energy from wind generators must be taken "as delivered", which requires the use of other controllable resources to keep the demand and supply of electric energy in balance. There are costs associated with scheduling and operating conventional generating resources to accommodate the variability and the uncertainty of wind generation.

As suggested by MRES, the ORA included the wind integration cost determined in the 2006 Minnesota Wind Integration Study,[14] $4.41 per MWh of wind energy cost and escalated it by 13 percent increase or $4.97/MWh. The wind units modeled have a capacity factor of 40% and accredited capacity of 15%. The wind profile was taken from the 2006 Minnesota Wind Integration Study.

8. *Forced Units*

A resource is said to be "forced" into an expansion planning model when the addition of a resource is required. The ORA initially proposed running three different "futures" or scenarios in which either coal, gas, or wind units would be forced into the model. However, several

[14] Article 2, Section 6 of the 2005 Omnibus Energy Bill required that the Minnesota Public Utilities Commission order all electric utilities covered by the Renewable Energy Objective statute, to contract jointly with an independent firm to study the impacts on reliability and costs of increasing wind capacity to 20 percent of Minnesota retail electric sales by 2020. See the Commission's Order in Docket No. E-999/CI-05-973. The wind integration study may be found at www.energy.mn.gov under the Data & Reports link, or directly at Minnesota Energy : Wind Integration Study.

stakeholders questioned whether such an approach would create useful results or cause confusion. In response to stakeholders' comments, the ORA did not force gas or coal units into the model as initially proposed. However, when ORA did not force wind generation units, but instead allowed the model to choose wind as an expansion option, a modeling error occurred.[15] Therefore, to correct for the modeling error, the ORA had to force the RES-compliant quantity wind into the model with sensitivity scenarios that did not allow any additional wind. The cost of the RES can then be evaluated by comparing the results of the models with and without RES-compliant wind in the model. In addition, the ORA ran a scenario which applied the RES to the entire load served by Minnesota utilities in the model (not just Minnesota load). As noted above, IPL, Xcel and OTP have significant amounts of load outside of Minnesota which may be subject to other state renewable requirements or a national RES. The specific scenarios are discussed in more detail in Section V of this report.

9. Reserve Margin

The Reserve Margin of 15 percent used by MISO in 2008 MTEP was used in the model.

10. Remaining Data from MISO

The ORA used the data obtained from MISO for any inputs not specified above. No changes were made to the data provided by MISO for generation variable costs, generation fixed costs, generation unit maintenance, or generation forced outage rates. MISO used the default data from PowerBase, a separate tool licensed by MISO that contains data necessary to run Strategist, for each of these inputs.

E. RESULTS

The ORA reminds readers that these studies and results are only for the first step in high-level resource assessment and planning purposes. As such, these studies and the report cannot be considered as justification for or against any particular proposal or resource option. Below is a description of results under the following five overall scenarios:

- Scenario I: Achievement of the 1.5 percent DSM goal and compliance with the RES
- Scenario II: No additional wind
- Scenario III: High load (high demand for electricity)
- Scenario IV: High load and no new wind additions
- Scenario V: National RES

As discussed above, each scenario has a number of sensitivity runs, including different levels of CO_2 costs, different capital costs, and different levels of certain fuel costs. The results are reported as the number of units chosen compared to the results of the base case and the change in the present value of societal cost (which represents the costs of the run in today's dollars) for each sensitivity run compared to the base case.

[15] Technically, the model exceeded the limit on the number of "states" or variations in the Strategist model and could not be run to 2025.

SCENARIO I: ACHIEVEMENT OF THE 1.5 PERCENT DSM GOAL AND COMPLIANCE WITH THE RES

1. Base Case

- Assumptions (from above):

Table 8: No Additional Wind Scenario Assumptions

Capital Costs Unit	Capacity	$/kW
Coal	500 MW	$3,000.00
CC	627 MW	$1,000.00
CT	168 MW	$750.00
Wind	100 MW	$2,500.00
IGCC w/out sequestration	600 MW	$3,500.00
IGCC w/ sequestration	600 MW	$4,000.00

Natural Gas Cost			**Coal Fuel Cost**	
Year	$/MMBTU		Year	$/MMBTU
2008	$9.05		2008	$1.67
2009	$9.13		2009	$1.71
2010	$9.22		2010	$1.75
2011	$8.95		2011	$1.79
2012	$8.73		2012	$1.82
2013	$8.60		2013	$1.86
2014	$8.00		2014	$1.89
2015	$7.71		2015	$1.93
2016	$7.91		2016	$1.97
2017	$8.17		2017	$2.01
2018	$8.46		2018	$2.05
2019	$8.84		2019	$2.09
2020	$9.05		2020	$2.13
2021	$9.13		2021	$2.18
2022	$9.43		2022	$2.22
2023	$9.76		2023	$2.26
2024	$10.11		2024	$2.31
2025	$10.34		2025	$2.36

CO_2 Costs	$17 per Ton
100 MW Wind Units Added	40

- Expansion Plan:

YEAR	COAL	CC	IGCC	CT	WIND	IGSQ
2008	0	0	0	0	0	0
2009	0	0	0	1	3	0
2010	0	0	0	0	3	0
2011	0	0	0	0	4	0
2012	0	0	0	1	3	0
2013	0	1	0	0	3	0
2014	0	0	0	0	3	0
2015	0	1	0	0	3	0
2016	0	1	0	0	2	0
2017	0	0	0	0	2	0
2018	0	0	0	1	2	0
2019	0	1	0	0	3	0
2020	0	0	0	0	1	0
2021	0	0	0	0	2	0
2022	0	1	0	0	1	0
2023	0	0	0	0	2	0
2024	1	0	0	0	2	0
2025	0	0	0	0	1	0
	1	5	0	3	40	

2. *Cost of \$4 CO_2 Regulation*

- Base case assumptions with \$4 CO_2 cost instead of \$17.
- Expansion Plan:

YEAR	COAL	CC	IGCC	CT	WIND	IGSQ
2008	0	0	0	0	0	0
2009	0	0	0	1	3	0
2010	0	0	0	0	3	0
2011	0	0	0	0	4	0
2012	0	0	0	1	3	0
2013	0	1	0	0	3	0
2014	0	0	0	0	3	0
2015	0	1	0	0	3	0
2016	0	1	0	0	2	0
2017	0	0	0	0	2	0
2018	0	0	0	1	2	0
2019	0	1	0	0	3	0
2020	0	0	0	0	1	0
2021	0	0	0	0	2	0
2022	0	1	0	0	1	0
2023	0	0	0	0	2	0
2024	1	0	0	0	2	0
2025	0	0	0	0	1	0
	1	5	0	3	40	0

3. *Cost of \$30 CO_2 Regulation*

- Base case assumptions with \$30 CO_2 cost instead of \$17.
- Expansion Plan:

YEAR	COAL	CC	IGCC	CT	WIND	IGSQ
2008	0	0	0	0	0	0
2009	0	0	0	1	3	0
2010	0	0	0	0	3	0
2011	0	0	0	0	4	0
2012	0	0	0	1	3	0
2013	0	1	0	0	3	0
2014	0	0	0	0	3	0
2015	0	1	0	0	3	0
2016	0	1	0	0	2	0
2017	0	0	0	0	2	0
2018	0	0	0	1	2	0
2019	0	0	0	1	3	0
2020	0	0	0	1	1	0
2021	0	1	0	0	2	0
2022	0	0	0	0	1	0
2023	0	1	0	0	2	0
2024	0	0	0	0	2	0
2025	0	0	0	1	1	0
	0	5	0	6	40	0

4. Cost of \$45 CO_2 Regulation

- Base case assumptions with \$45 CO_2 cost instead of \$17.
- Expansion Plan:

YEAR	COAL	CC	IGCC	CT	WIND	IGSQ
2008	0	0	0	0	0	0
2009	0	0	0	1	3	0
2010	0	0	0	0	3	0
2011	0	0	0	0	4	0
2012	0	1	0	0	3	0
2013	0	0	0	0	3	0
2014	0	0	0	0	3	0
2015	0	1	0	1	3	0
2016	0	1	0	0	2	0
2017	0	0	0	0	2	0
2018	0	0	0	1	2	0
2019	0	1	0	0	3	0
2020	0	0	0	0	1	0
2021	0	0	0	0	2	0
2022	0	1	0	0	1	0
2023	0	0	0	0	2	0
2024	0	1	0	0	2	0
2025	0	0	0	0	1	0
	0	6	0	3	40	0

5. 20 Percent Increase in Capital Costs

- Base case assumptions with all capital costs increased by 20 percent.
- Expansion Plan:

YEAR	COAL	CC	IGCC	CT	WIND	IGSQ
2008	0	0	0	0	0	0
2009	0	0	0	1	3	0
2010	0	0	0	0	3	0
2011	0	0	0	0	4	0
2012	0	0	0	1	3	0
2013	0	1	0	0	3	0
2014	0	0	0	0	3	0
2015	0	1	0	0	3	0
2016	0	1	0	0	2	0
2017	0	0	0	0	2	0
2018	0	0	0	1	2	0
2019	0	0	0	1	3	0
2020	0	0	0	1	1	0
2021	0	1	0	0	2	0
2022	0	0	0	0	1	0
2023	0	1	0	0	2	0
2024	0	0	0	0	2	0
2025	0	0	0	1	1	0
	0	5	0	6	40	0

6. *20 Percent Decrease in Capital Costs*

- Base case assumptions with all capital costs decreased by 20 percent.
- Expansion Plan:

YEAR	COAL	CC	IGCC	CT	WIND	IGSQ
2008	0	0	0	0	0	0
2009	0	0	0	1	3	0
2010	0	0	0	0	3	0
2011	0	0	0	0	4	0
2012	0	1	0	0	3	0
2013	0	0	0	0	3	0
2014	0	0	0	0	3	0
2015	0	2	0	0	3	0
2016	0	0	0	0	2	0
2017	1	0	0	0	2	0
2018	0	0	0	0	2	0
2019	0	0	0	0	3	0
2020	1	0	0	0	1	0
2021	0	0	0	0	2	0
2022	1	0	0	0	1	0
2023	0	0	0	0	2	0
2024	0	1	0	0	2	0
2025	0	0	0	0	1	0
	3	4	0	1	40	0

7. *20 Percent Increase in Capital Costs of Coal-Fired Expansion Units Only.*

- Base case assumptions with coal capital costs increased by 20 percent.
- Expansion Plan:

YEAR	COAL	CC	IGCC	CT	WIND	IGSQ
2008	0	0	0	0	0	0
2009	0	0	0	1	3	0
2010	0	0	0	0	3	0
2011	0	0	0	0	4	0
2012	0	0	0	1	3	0
2013	0	1	0	0	3	0
2014	0	0	0	0	3	0
2015	0	1	0	0	3	0
2016	0	1	0	0	2	0
2017	0	0	0	0	2	0
2018	0	0	0	1	2	0
2019	0	0	0	1	3	0
2020	0	0	0	1	1	0
2021	0	1	0	0	2	0
2022	0	0	0	0	1	0
2023	0	1	0	0	2	0
2024	0	0	0	0	2	0
2025	0	0	0	1	1	0
	0	5	0	6	40	0

8. 20 Percent Decrease in Capital Costs of Coal-Fired Expansion Units Only.

- Base case assumptions with coal capital costs decreased by 20 percent.
- Expansion Plan:

YEAR	COAL	CC	IGCC	CT	WIND	IGSQ
2008	0	0	0	0	0	0
2009	0	0	0	1	3	0
2010	0	0	0	0	3	0
2011	0	0	0	0	4	0
2012	0	0	0	1	3	0
2013	0	0	0	1	3	0
2014	1	0	0	0	3	0
2015	0	1	0	0	3	0
2016	1	0	0	0	2	0
2017	0	0	0	0	2	0
2018	0	0	0	1	2	0
2019	1	0	0	0	3	0
2020	0	0	0	0	1	0
2021	0	0	0	1	2	0
2022	1	0	0	0	1	0
2023	0	0	0	1	2	0
2024	1	0	0	0	2	0
2025	0	0	0	0	1	0
	5	1	0	6	40	0

9. *20 Percent Decrease in the Capital Costs of Coal-Fired Expansion Units Only and an Increase in Natural Gas Costs of 20 Percent.*

- Base case assumptions with coal capital costs decreased by 20 percent and natural gas costs increased by 20 percent.
- Expansion Plan:

YEAR	COAL	CC	IGCC	CT	WIND	IGSQ
2008	0	0	0	0	0	0
2009	0	0	0	1	3	0
2010	0	0	0	0	3	0
2011	0	0	0	0	4	0
2012	0	0	0	1	3	0
2013	0	0	0	1	3	0
2014	1	0	0	0	3	0
2015	1	0	0	1	3	0
2016	1	0	0	0	2	0
2017	0	0	0	0	2	0
2018	1	0	0	0	2	0
2019	0	0	0	0	3	0
2020	1	0	0	0	1	0
2021	0	0	0	0	2	0
2022	1	0	0	0	1	0
2023	0	0	0	0	2	0
2024	1	0	0	0	2	0
2025	0	0	0	0	1	0
	7	0	0	4	40	0

10. Coal Fuel Cost Increased by 20 Percent.

- Base case assumptions with an increase in coal fuel costs of 20 percent.
- Expansion Plan:

YEAR	COAL	CC	IGCC	CT	WIND	IGSQ
2008	0	0	0	0	0	0
2009	0	0	0	1	3	0
2010	0	0	0	0	3	0
2011	0	0	0	0	4	0
2012	0	0	0	1	3	0
2013	0	1	0	0	3	0
2014	0	0	0	0	3	0
2015	0	1	0	0	3	0
2016	0	1	0	0	2	0
2017	0	0	0	0	2	0
2018	0	0	0	1	2	0
2019	0	0	0	1	3	0
2020	0	0	0	1	1	0
2021	0	1	0	0	2	0
2022	0	0	0	0	1	0
2023	0	1	0	0	2	0
2024	0	0	0	0	2	0
2025	0	0	0	1	1	0
	0	5	0	6	40	0

11. Coal Fuel Cost Decreased by 20 Percent.

- Base case assumptions with a decrease in coal fuel costs of 20 percent.
- Expansion Plan:

YEAR	COAL	CC	IGCC	CT	WIND	IGSQ
2008	0	0	0	0	0	0
2009	0	0	0	1	3	0
2010	0	0	0	0	3	0
2011	0	0	0	0	4	0
2012	0	0	0	1	3	0
2013	0	1	0	0	3	0
2014	0	0	0	0	3	0
2015	0	1	0	0	3	0
2016	0	1	0	0	2	0
2017	0	0	0	0	2	0
2018	0	0	0	1	2	0
2019	0	1	0	0	3	0
2020	0	0	0	0	1	0
2021	0	0	0	0	2	0
2022	0	1	0	0	1	0
2023	0	0	0	0	2	0
2024	1	0	0	0	2	0
2025	0	0	0	0	1	0
	1	5	0	3	40	0

12. Natural Gas Cost Increased by 20 Percent.

- Base case assumptions with an increase in natural gas fuel costs of 20 percent.
- Expansion Plan:

YEAR	COAL	CC	IGCC	CT	WIND	IGSQ
2008	0	0	0	0	0	0
2009	0	0	0	1	3	0
2010	0	0	0	0	3	0
2011	0	0	0	0	4	0
2012	0	1	0	0	3	0
2013	0	0	0	0	3	0
2014	0	0	0	0	3	0
2015	0	2	0	0	3	0
2016	0	0	0	0	2	0
2017	1	0	0	0	2	0
2018	0	0	0	0	2	0
2019	0	0	0	0	3	0
2020	1	0	0	0	1	0
2021	0	0	0	0	2	0
2022	1	0	0	0	1	0
2023	0	0	0	0	2	0
2024	0	1	0	0	2	0
2025	0	0	0	0	1	0
	3	4	0	1	40	0

13. Natural Gas Cost Decreased by 20 Percent.

- Base case assumptions with a decrease in natural gas fuel costs of 20 percent.
- Expansion Plan:

YEAR	COAL	CC	IGCC	CT	WIND	IGSQ
2008	0	0	0	0	0	0
2009	0	0	0	1	3	0
2010	0	0	0	0	3	0
2011	0	0	0	0	4	0
2012	0	0	0	1	3	0
2013	0	1	0	0	3	0
2014	0	0	0	0	3	0
2015	0	1	0	0	3	0
2016	0	1	0	0	2	0
2017	0	0	0	0	2	0
2018	0	0	0	1	2	0
2019	0	0	0	1	3	0
2020	0	0	0	1	1	0
2021	0	1	0	0	2	0
2022	0	0	0	0	1	0
2023	0	1	0	0	2	0
2024	0	0	0	0	2	0
2025	0	0	0	1	1	0
	0	5	0	6	40	0

14. Natural Gas Cost Increased by 50 Percent.

- Base case assumptions with an increase in natural gas fuel costs of 50 percent.
- Expansion Plan:

YEAR	COAL	CC	IGCC	CT	WIND	IGSQ
2008	0	0	0	0	0	0
2009	0	0	0	1	3	0
2010	0	0	0	0	3	0
2011	0	0	0	0	4	0
2012	0	0	0	1	3	0
2013	0	0	0	1	3	0
2014	1	0	0	0	3	0
2015	0	1	0	0	3	0
2016	1	0	0	0	2	0
2017	0	0	0	0	2	0
2018	0	0	0	1	2	0
2019	1	0	0	0	3	0
2020	0	0	0	0	1	0
2021	0	0	0	1	2	0
2022	1	0	0	0	1	0
2023	0	0	0	1	2	0
2024	1	0	0	0	2	0
2025	0	0	0	0	1	0
	5	1	0	6	40	0

Tables 5 through 7 summarize the results of the different scenarios run on the base case assumptions.

Table 5: Number of 500 MW Coal Units Added 2008-2025

	Base Assumptions	\$4 CO_2	\$30 CO_2	\$45 CO_2	Capital Cost +20%	Capital Cost -20%	Coal K Cost +20%	Coal K Cost -20%	Coal K Cost -20% and NG Cost +20%	Coal Fuel +20%	Coal Fuel -20%	Gas Fuel +20%	Gas Fuel -20%	Gas Fuel +50%
Base Case	1	1	0	0	0	3	0	5	7	0	1	3	0	5

Table 6: Number of 627 MW Combined Cycle Units Added 2008-2025

	Base Assumptions	\$4 CO_2	\$30 CO_2	\$45 CO_2	Capital Cost +20%	Capital Cost -20%	Coal K Cost +20%	Coal K Cost -20%	Coal K Cost -20% and NG Cost +20%	Coal Fuel +20%	Coal Fuel -20%	Gas Fuel +20%	Gas Fuel -20%	Gas Fuel +50%
Base Case	5	5	5	6	5	4	5	4	0	5	5	4	5	1

Table 7: PV Societal Cost - Difference from Base (000s $)

Lower Cost in Bold	
	1.5% DSM and RES
Base	0
$4 CO_2	-20,048,416
$30 CO_2	**19,941,024**
$45 CO_2	**42,937,408**
Capital Cost +20%	2,424,784
Capital Cost -20%	**-2,669,248**
Coal K Cost +20%	**21,184**
Coal K Cost -20%	-490,808
Coal K Cost -20% and NG Cost +20%	1,762,984
Coal Fuel +20%	**3,232,232**
Coal Fuel -20%	-3,287,768
Gas Fuel +20%	**1,693,048**
Gas Fuel -20%	-2,254,560
Gas Fuel +50%	**3,419,664**

Table 7 does not show what expansion plan is least-cost, but what the costs of each plan will be under the differing contingencies. For example, the reason the $4 CO_2 contingency is significantly less expensive that the Base, where a $17 cost was used, is not because the expansion plan selected by the model is less expensive, but because a $4 cost per ton of CO_2 was applied to all generation included existing generation. Thus, the difference in cost is largely attributable to the lower cost per ton of CO_2 emitted as applied to the entire generation fleet.

SCENARIO II: NO ADDITONAL WIND

In order to investigate the cost-effectiveness of the RES and to gain some understanding of the effect of the RES on Minnesota in the future, the ORA ran the base case assumptions as explained in Section IV above, but did not add any additional wind generation. The same contingencies were run on the “no additional wind” scenario.

1. *No Additional Wind Scenario.*

- *Uses Base Case Assumptions without adding additional wind capacity*

Table 8: No Additional Wind Scenario Assumptions

Capital Costs		
Unit	Capacity	$/kW
Coal	500 MW	$3,000.00
CC	627 MW	$1,000.00
CT	168 MW	$750.00
Wind	100 MW	$2,500.00
IGCC w/out sequestration	600 MW	$3,500.00
IGCC w/ sequestration	600 MW	$4,000.00

Natural Gas Cost			**Coal Fuel Cost**	
Year	$/MMBTU		Year	$/MMBTU
2008	$9.05		2008	$1.67
2009	$9.13		2009	$1.71
2010	$9.22		2010	$1.75
2011	$8.95		2011	$1.79
2012	$8.73		2012	$1.82
2013	$8.60		2013	$1.86
2014	$8.00		2014	$1.89
2015	$7.71		2015	$1.93
2016	$7.91		2016	$1.97
2017	$8.17		2017	$2.01
2018	$8.46		2018	$2.05
2019	$8.84		2019	$2.09
2020	$9.05		2020	$2.13
2021	$9.13		2021	$2.18
2022	$9.43		2022	$2.22
2023	$9.76		2023	$2.26
2024	$10.11		2024	$2.31
2025	$10.34		2025	$2.36

CO_2 Costs	$17 per Ton
100 MW Wind Units Added	0

- Expansion Plan:

YEAR	COAL	CC	IGCC	CT	WIND	IGSQ
2008	0	0	0	0	0	0
2009	0	0	0	1	0	0
2010	0	0	0	0	0	0
2011	0	0	0	1	0	0
2012	0	1	0	0	0	0
2013	0	0	0	0	0	0
2014	0	0	0	0	0	0
2015	0	2	0	0	0	0
2016	1	0	0	0	0	0
2017	0	0	0	0	0	0
2018	0	0	0	0	0	0
2019	1	0	0	0	0	0
2020	0	0	0	0	0	0
2021	0	1	0	0	0	0
2022	0	0	0	0	0	0
2023	1	0	0	0	0	0
2024	1	0	0	0	0	0
2025	0	0	0	0	0	0
	4	4	0	2	0	0

2. *Cost of \$4 CO_2 Regulation*

- Base case assumptions with no new wind additions and \$4 CO_2 cost instead of \$17.
- Expansion Plan:

YEAR	COAL	CC	IGCC	CT	WIND	IGSQ
2008	0	0	0	0	0	0
2009	0	0	0	1	0	0
2010	0	0	0	0	0	0
2011	0	0	0	1	0	0
2012	0	1	0	0	0	0
2013	0	0	0	0	0	0
2014	0	0	0	0	0	0
2015	1	1	0	0	0	0
2016	1	0	0	0	0	0
2017	0	0	0	0	0	0
2018	0	0	0	1	0	0
2019	1	0	0	0	0	0
2020	0	0	0	0	0	0
2021	1	0	0	0	0	0
2022	0	0	0	0	0	0
2023	1	0	0	0	0	0
2024	1	0	0	0	0	0
2025	0	0	0	0	0	0
	6	2	0	3	0	0

3. *Cost of \$30 CO_2 Regulation*

- Base case assumptions with no new wind additions and \$30 CO_2 cost instead of \$17.
- Expansion Plan:

YEAR	COAL	CC	IGCC	CT	WIND	IGSQ
2008	0	0	0	0	0	0
2009	0	0	0	1	0	0
2010	0	0	0	0	0	0
2011	0	0	0	1	0	0
2012	0	1	0	0	0	0
2013	0	0	0	0	0	0
2014	0	0	0	0	0	0
2015	0	2	0	0	0	0
2016	0	1	0	0	0	0
2017	0	0	0	0	0	0
2018	0	0	0	0	0	0
2019	0	1	0	0	0	0
2020	0	0	0	0	0	0
2021	0	0	0	0	0	0
2022	0	1	0	0	0	0
2023	0	0	0	0	0	0
2024	0	1	0	0	0	0
2025	0	0	0	1	0	0
	0	7	0	3	0	0

4. Cost of \$45 CO_2 Regulation

- Base case assumptions with no new wind additions and \$45 CO_2 cost instead of \$17.
- Expansion Plan:

YEAR	COAL	CC	IGCC	CT	WIND	IGSQ
2008	0	0	0	0	0	0
2009	0	0	0	1	0	0
2010	0	0	0	0	0	0
2011	0	0	0	1	0	0
2012	0	1	0	0	0	0
2013	0	0	0	0	0	0
2014	0	0	0	0	0	0
2015	0	2	0	0	0	0
2016	0	1	0	0	0	0
2017	0	0	0	0	0	0
2018	0	0	0	0	0	0
2019	0	1	0	0	0	0
2020	0	0	0	0	0	0
2021	0	0	0	0	0	0
2022	0	1	0	0	0	0
2023	0	0	0	0	0	0
2024	0	1	0	0	0	0
2025	0	0	0	1	0	0
	0	7	0	3	0	0

5. *20 Percent Increase in Capital Costs*

- Base case assumptions with no new wind additions and all capital costs increased by 20 percent.
- Expansion Plan:

YEAR	COAL	CC	IGCC	CT	WIND	IGSQ
2008	0	0	0	0	0	0
2009	0	0	0	1	0	0
2010	0	0	0	0	0	0
2011	0	0	0	1	0	0
2012	0	1	0	0	0	0
2013	0	0	0	0	0	0
2014	0	0	0	0	0	0
2015	0	2	0	0	0	0
2016	0	1	0	0	0	0
2017	0	0	0	0	0	0
2018	0	0	0	0	0	0
2019	0	1	0	0	0	0
2020	0	0	0	0	0	0
2021	0	0	0	0	0	0
2022	0	1	0	0	0	0
2023	0	0	0	0	0	0
2024	1	0	0	0	0	0
2025	0	0	0	1	0	0
	1	6	0	3	0	0

6.   20 Percent Decrease in Capital Costs

- Base case assumptions with no new wind additions and all capital costs decreased by 20 percent.
- Expansion Plan:

YEAR	COAL	CC	IGCC	CT	WIND	IGSQ
2008	0	0	0	0	0	0
2009	0	0	0	1	0	0
2010	0	0	0	0	0	0
2011	0	0	0	1	0	0
2012	0	1	0	0	0	0
2013	0	0	0	0	0	0
2014	0	0	0	0	0	0
2015	1	1	0	0	0	0
2016	1	0	0	0	0	0
2017	0	0	0	0	0	0
2018	0	0	0	1	0	0
2019	1	0	0	0	0	0
2020	0	0	0	0	0	0
2021	1	0	0	0	0	0
2022	0	0	0	0	0	0
2023	1	0	0	0	0	0
2024	1	0	0	0	0	0
2025	0	0	0	0	0	0
	6	2	0	3	0	0

7. *20 Percent Increase in Capital Costs of Coal-Fired Expansion Units Only.*

- Base case assumptions with no new wind additions and coal capital costs increased by 20 percent.
- Expansion Plan:

YEAR	COAL	CC	IGCC	CT	WIND	IGSQ
2008	0	0	0	0	0	0
2009	0	0	0	1	0	0
2010	0	0	0	0	0	0
2011	0	0	0	1	0	0
2012	0	1	0	0	0	0
2013	0	0	0	0	0	0
2014	0	0	0	0	0	0
2015	0	2	0	0	0	0
2016	0	1	0	0	0	0
2017	0	0	0	0	0	0
2018	0	0	0	0	0	0
2019	0	1	0	0	0	0
2020	0	0	0	0	0	0
2021	0	0	0	0	0	0
2022	0	1	0	0	0	0
2023	0	0	0	0	0	0
2024	1	0	0	0	0	0
2025	0	0	0	1	0	0
	1	6	0	3	0	0

8. *20 Percent Decrease in Capital Costs of Coal-Fired Expansion Units Only.*

- Base case assumptions with no new wind additions and coal capital costs decreased by 20 percent.
- Expansion Plan:

YEAR	COAL	CC	IGCC	CT	WIND	IGSQ
2008	0	0	0	0	0	0
2009	0	0	0	1	0	0
2010	0	0	0	0	0	0
2011	0	0	0	1	0	0
2012	0	1	0	0	0	0
2013	0	0	0	0	0	0
2014	1	0	0	0	0	0
2015	1	0	0	0	0	0
2016	1	0	0	0	0	0
2017	1	0	0	0	0	0
2018	0	0	0	0	0	0
2019	0	0	0	0	0	0
2020	1	0	0	0	0	0
2021	0	0	0	0	0	0
2022	1	0	0	0	0	0
2023	0	0	0	1	0	0
2024	1	0	0	0	0	0
2025	0	0	0	1	0	0
	7	1	0	4	0	0

9. *20 Percent Decrease in Capital Costs of Coal-Fired Expansion Units Only and an Increase in Natural Gas Costs of 20 Percent.*

- Base case assumptions with no new wind additions and coal capital costs decreased by 20 percent and natural gas costs increased by 20 percent.
- Expansion Plan:

YEAR	COAL	CC	IGCC	CT	WIND	IGSQ
2008	0	0	0	0	0	0
2009	0	0	0	1	0	0
2010	0	0	0	0	0	0
2011	0	0	0	1	0	0
2012	0	1	0	0	0	0
2013	0	0	0	0	0	0
2014	1	0	0	0	0	0
2015	1	0	0	0	0	0
2016	1	0	0	0	0	0
2017	1	0	0	0	0	0
2018	0	0	0	0	0	0
2019	0	0	0	0	0	0
2020	1	0	0	0	0	0
2021	0	0	0	0	0	0
2022	1	0	0	0	0	0
2023	1	0	0	0	0	0
2024	0	0	0	0	0	0
2025	1	0	0	0	0	0
	8	1	0	2	0	0

10. Coal Fuel Cost Increased by 20 Percent.

- Base case assumptions with no new wind additions and an increase in coal fuel costs of 20 percent.
- Expansion Plan:

YEAR	COAL	CC	IGCC	CT	WIND	IGSQ
2008	0	0	0	0	0	0
2009	0	0	0	1	0	0
2010	0	0	0	0	0	0
2011	0	0	0	1	0	0
2012	0	1	0	0	0	0
2013	0	0	0	0	0	0
2014	0	0	0	0	0	0
2015	0	2	0	0	0	0
2016	0	1	0	0	0	0
2017	0	0	0	0	0	0
2018	0	0	0	0	0	0
2019	0	1	0	0	0	0
2020	0	0	0	0	0	0
2021	0	0	0	0	0	0
2022	0	1	0	0	0	0
2023	0	0	0	0	0	0
2024	1	0	0	0	0	0
2025	0	0	0	1	0	0
	1	6	0	3	0	0

11. Coal fuel Cost Decreased by 20 Percent.

- Base case assumptions with no new wind additions and a decrease in coal fuel costs of 20 percent.
- Expansion Plan:

YEAR	COAL	CC	IGCC	CT	WIND	IGSQ
2008	0	0	0	0	0	0
2009	0	0	0	1	0	0
2010	0	0	0	0	0	0
2011	0	0	0	1	0	0
2012	0	1	0	0	0	0
2013	0	0	0	0	0	0
2014	0	0	0	0	0	0
2015	1	1	0	0	0	0
2016	1	0	0	0	0	0
2017	0	0	0	0	0	0
2018	0	0	0	1	0	0
2019	1	0	0	0	0	0
2020	0	0	0	0	0	0
2021	1	0	0	0	0	0
2022	0	0	0	0	0	0
2023	1	0	0	0	0	0
2024	1	0	0	0	0	0
2025	0	0	0	0	0	0
	6	2	0	3	0	0

12. Natural Gas Cost Increased by 20 Percent.

- Base case assumptions with no new wind additions and an increase in natural gas fuel costs of 20 percent.
- Expansion Plan:

YEAR	COAL	CC	IGCC	CT	WIND	IGSQ
2008	0	0	0	0	0	0
2009	0	0	0	1	0	0
2010	0	0	0	0	0	0
2011	0	0	0	1	0	0
2012	0	1	0	0	0	0
2013	0	0	0	0	0	0
2014	0	0	0	0	0	0
2015	1	1	0	0	0	0
2016	1	0	0	0	0	0
2017	0	0	0	0	0	0
2018	0	0	0	1	0	0
2019	1	0	0	0	0	0
2020	0	0	0	0	0	0
2021	1	0	0	0	0	0
2022	0	0	0	0	0	0
2023	1	0	0	0	0	0
2024	1	0	0	0	0	0
2025	0	0	0	0	0	0
	6	2	0	3	0	0

13. Natural Gas Cost Decreased by 20 Percent.

- Base case assumptions with no new wind additions and a decrease in natural gas fuel costs of 20 percent.
- Expansion Plan:

YEAR	COAL	CC	IGCC	CT	WIND	IGSQ
2008	0	0	0	0	0	0
2009	0	0	0	1	0	0
2010	0	0	0	0	0	0
2011	0	0	0	1	0	0
2012	0	0	0	1	0	0
2013	0	0	0	1	0	0
2014	0	1	0	0	0	0
2015	0	1	0	0	0	0
2016	0	1	0	0	0	0
2017	0	0	0	0	0	0
2018	0	1	0	0	0	0
2019	0	0	0	0	0	0
2020	0	0	0	0	0	0
2021	0	1	0	0	0	0
2022	0	0	0	0	0	0
2023	0	1	0	0	0	0
2024	0	0	0	0	0	0
2025	0	0	0	2	0	0
	0	6	0	6	0	0

14. Natural Gas Cost Increased by 50 Percent.

- Base case assumptions with no new wind additions and an increase in natural gas fuel costs of 50 percent.
- Expansion Plan:

YEAR	COAL	CC	IGCC	CT	WIND	IGSQ
2008	0	0	0	0	0	0
2009	0	0	0	1	0	0
2010	0	0	0	0	0	0
2011	0	0	0	1	0	0
2012	0	1	0	0	0	0
2013	0	0	0	0	0	0
2014	1	0	0	0	0	0
2015	1	0	0	0	0	0
2016	1	0	0	0	0	0
2017	1	0	0	0	0	0
2018	0	0	0	0	0	0
2019	0	0	0	0	0	0
2020	1	0	0	0	0	0
2021	0	0	0	0	0	0
2022	1	0	0	0	0	0
2023	1	0	0	0	0	0
2024	0	0	0	0	0	0
2025	1	0	0	0	0	0
	8	1	0	2	0	0

Tables 9 through 10 summarize the results of the different contingencies run on the No Additional Wind scenario.

Table 9: Number of 500 MW Coal Units Added 2008-2025

	Base Assumptions	$4 CO_2	$30 CO_2	$45 CO_2	Capital Cost +20%	Capital Cost - 20%	Coal K Cost +20%	Coal K Cost - 20%	Coal K Cost - 20% and NG Cost +20%	Coal Fuel +20%	Coal Fuel - 20%	Gas Fuel +20%	Gas Fuel - 20%	Gas Fuel +50%
No Additional Wind	4	6	0	0	1	6	1	7	8	1	6	6	0	8

Table 10: Number of 627 MW Combined Cycle Units Added 2008-2025

	Base Assumptions	$4 CO_2	$30 CO_2	$45 CO_2	Capital Cost +20%	Capital Cost - 20%	Coal K Cost +20%	Coal K Cost - 20%	Coal K Cost - 20% and NG Cost +20%	Coal Fuel +20%	Coal Fuel - 20%	Gas Fuel +20%	Gas Fuel - 20%	Gas Fuel +50%
No Additional Wind	4	2	7	7	6	2	6	1	1	6	2	2	6	1

Table 11, below, shows the cost under of the No Additional Wind Scenarios under different contingencies. Table 11 also includes the costs under all contingencies run on the base case so that the cost-effectiveness of the RES can be analyzed. Of the 14 different contingencies analyzed, the RES is cost-effective under eight contingencies.

Table 11: PV Societal Cost - Difference from Base (000s $)

Lower Costs in Bold		
	1.5% DSM and RES	1.5% DSM No RES
BASE ($17 CO_2)	**0**	180,040
$4 CO_2	-20,048,416	**-22,762,904**
$30 CO_2	**19,941,024**	22,487,392
$45 CO_2	**42,937,408**	47,816,488
Capital Cost +20%	2,424,784	**1,208,384**
Capital Cost -20%	**-2,669,248**	-1,503,760
Coal K Cost +20%	**21,184**	534,752
Coal K Cost -20%	-490,808	**-1,263,296**
Coal K Cost -20% and NG Cost +20%	1,762,984	**1,416,392**
Coal Fuel +20%	**3,232,232**	3,826,016
Coal Fuel -20%	-3,287,768	**-3,611,672**
Gas Fuel +20%	**1,693,048**	1,751,656
Gas Fuel -20%	-2,254,560	**-2,883,576**
Gas Fuel +50%	**3,419,664**	3,451,880

SCENARIO III: HIGH LOAD

1. *Base Case with 1.0 Percent DSM instead of 1.5 Percent*

    - *Uses Base Case Assumptions with forecast assuming energy savings equaling 1.0 percent of retail sales instead of 1.5 percent.*

Table 12: High Load Scenario Assumptions

Capital Costs

Unit	Capacity	$/kW
Coal	500 MW	$3,000.00
CC	627 MW	$1,000.00
CT	168 MW	$750.00
Wind	100 MW	$2,500.00
IGCC w/out sequestration	600 MW	$3,500.00
IGCC w/ sequestration	600 MW	$4,000.00

Natural Gas Cost		**Coal Fuel Cost**	
Year	$/MMBTU	Year	$/MMBTU
2008	$9.05	2008	$1.67
2009	$9.13	2009	$1.71
2010	$9.22	2010	$1.75
2011	$8.95	2011	$1.79
2012	$8.73	2012	$1.82
2013	$8.60	2013	$1.86
2014	$8.00	2014	$1.89
2015	$7.71	2015	$1.93
2016	$7.91	2016	$1.97
2017	$8.17	2017	$2.01
2018	$8.46	2018	$2.05
2019	$8.84	2019	$2.09
2020	$9.05	2020	$2.13
2021	$9.13	2021	$2.18
2022	$9.43	2022	$2.22
2023	$9.76	2023	$2.26
2024	$10.11	2024	$2.31
2025	$10.34	2025	$2.36

CO_2 Costs	$17 per Ton
100 MW Wind Units Added	44

- Due to the higher load assumption, 4 additional 100-MW wind generation units were added above the base assumptions for a total of 44. This addition is needed because the RES is determined as a percentage of retail electric sales. Thus, as load increases, the amount of wind generation required to meet the RES must increase.
- Expansion Plan:

YEAR	COAL	CC	IGCC	CT	WIND	IGSQ
2008	0	0	0	0	0	0
2009	0	0	0	1	3	0
2010	0	0	0	1	3	0
2011	0	0	0	1	4	0
2012	0	1	0	0	3	0
2013	0	0	0	0	4	0
2014	0	0	0	0	3	0
2015	0	2	0	0	4	0
2016	0	1	0	0	2	0
2017	0	0	0	0	3	0
2018	0	0	0	0	2	0
2019	0	1	0	0	3	0
2020	0	0	0	0	2	0
2021	0	1	0	0	1	0
2022	0	0	0	0	2	0
2023	0	0	0	0	2	0
2024	0	1	0	0	2	0
2025	0	0	0	0	1	0
	0	7	0	3	44	0

2. *Cost of \$4 CO_2 Regulation*

- Base case assumptions with the forecast adjusted from 1.5 percent to 1.0 percent DSM and \$4 CO_2 cost instead of \$17.
- Expansion Plan:

YEAR	COAL	CC	IGCC	CT	WIND	IGSQ
2008	0	0	0	0	0	0
2009	0	0	0	1	3	0
2010	0	0	0	1	3	0
2011	0	0	0	1	4	0
2012	0	0	0	1	3	0
2013	0	0	0	1	4	0
2014	0	1	0	0	3	0
2015	0	1	0	0	4	0
2016	0	1	0	0	2	0
2017	0	0	0	0	3	0
2018	1	0	0	0	2	0
2019	0	0	0	0	3	0
2020	0	0	0	1	2	0
2021	0	0	0	2	1	0
2022	1	0	0	0	2	0
2023	0	0	0	1	2	0
2024	1	0	0	0	2	0
2025	0	0	0	0	1	0
	3	3	0	9	44	0

3. *Cost of \$30 CO_2 Regulation*

- Base case assumptions with the forecast adjusted from 1.5 percent to 1.0 percent DSM and \$30 CO_2 cost instead of \$17.
- Expansion Plan:

YEAR	COAL	CC	IGCC	CT	WIND	IGSQ
2008	0	0	0	0	0	0
2009	0	0	0	1	3	0
2010	0	0	0	1	3	0
2011	0	0	0	1	4	0
2012	0	1	0	0	3	0
2013	0	0	0	0	4	0
2014	0	0	0	0	3	0
2015	0	2	0	0	4	0
2016	0	1	0	0	2	0
2017	0	0	0	0	3	0
2018	0	0	0	0	2	0
2019	0	1	0	0	3	0
2020	0	0	0	0	2	0
2021	0	1	0	0	1	0
2022	0	0	0	0	2	0
2023	0	0	0	0	2	0
2024	0	1	0	0	2	0
2025	0	0	0	0	1	0
	0	7	0	3	44	0

4. *Cost of \$45 CO_2 Regulation*

- Base case assumptions with the forecast adjusted from 1.5 percent to 1.0 percent DSM and \$45 CO_2 cost instead of \$17.
- Expansion Plan:

YEAR	COAL	CC	IGCC	CT	WIND	IGSQ
2008	0	0	0	0	0	0
2009	0	0	0	1	3	0
2010	0	0	0	1	3	0
2011	0	0	0	1	4	0
2012	0	1	0	0	3	0
2013	0	0	0	0	4	0
2014	0	0	0	0	3	0
2015	0	2	0	0	4	0
2016	0	1	0	0	2	0
2017	0	0	0	0	3	0
2018	0	0	0	0	2	0
2019	0	1	0	0	3	0
2020	0	0	0	0	2	0
2021	0	1	0	0	1	0
2022	0	0	0	0	2	0
2023	0	0	0	0	2	0
2024	0	1	0	0	2	0
2025	0	0	0	0	1	0
	0	7	0	3	44	0

5. *20 Percent Increase in Capital Costs*

- Base case assumptions with the forecast adjusted from 1.5 percent to 1.0 percent DSM and all capital costs increased by 20 percent.
- Expansion Plan:

YEAR	COAL	CC	IGCC	CT	WIND	IGSQ
2008	0	0	0	0	0	0
2009	0	0	0	1	3	0
2010	0	0	0	1	3	0
2011	0	0	0	1	4	0
2012	0	1	0	0	3	0
2013	0	0	0	0	4	0
2014	0	0	0	0	3	0
2015	0	2	0	0	4	0
2016	0	1	0	0	2	0
2017	0	0	0	0	3	0
2018	0	0	0	0	2	0
2019	0	1	0	0	3	0
2020	0	0	0	0	2	0
2021	0	1	0	0	1	0
2022	0	0	0	0	2	0
2023	0	0	0	0	2	0
2024	0	1	0	0	2	0
2025	0	0	0	0	1	0
	0	7	0	3	44	0

6. 20 Percent Decrease in Capital Costs

- Base case assumptions with the forecast adjusted from 1.5 percent to 1.0 percent DSM and all capital costs decreased by 20 percent.
- Expansion Plan:

YEAR	COAL	CC	IGCC	CT	WIND	IGSQ
2008	0	0	0	0	0	0
2009	0	0	0	1	3	0
2010	0	0	0	1	3	0
2011	0	0	0	1	4	0
2012	0	1	0	0	3	0
2013	0	0	0	0	4	0
2014	0	0	0	0	3	0
2015	1	1	0	0	4	0
2016	1	0	0	0	2	0
2017	0	0	0	0	3	0
2018	0	1	0	0	2	0
2019	0	0	0	0	3	0
2020	0	0	0	0	2	0
2021	1	0	0	0	1	0
2022	1	0	0	0	2	0
2023	0	0	0	0	2	0
2024	1	0	0	0	2	0
2025	0	0	0	0	1	0
	5	3	0	3	44	0

7. *20 Percent Increase in Capital Costs of Coal-Fired Expansion Units Only.*

- Base case assumptions with the forecast adjusted from 1.5 percent to 1.0 percent DSM and coal capital costs increased by 20 percent.
- Expansion Plan:

YEAR	COAL	CC	IGCC	CT	WIND	IGSQ
2008	0	0	0	0	0	0
2009	0	0	0	1	3	0
2010	0	0	0	1	3	0
2011	0	0	0	1	4	0
2012	0	1	0	0	3	0
2013	0	0	0	0	4	0
2014	0	0	0	0	3	0
2015	0	2	0	0	4	0
2016	0	1	0	0	2	0
2017	0	0	0	0	3	0
2018	0	0	0	0	2	0
2019	0	1	0	0	3	0
2020	0	0	0	0	2	0
2021	0	1	0	0	1	0
2022	0	0	0	0	2	0
2023	0	0	0	0	2	0
2024	0	1	0	0	2	0
2025	0	0	0	0	1	0
	0	7	0	3	44	0

8. *20 Percent Decrease in Capital Costs of Coal-Fired Expansion Units Only.*

- Base case assumptions with the forecast adjusted from 1.5 percent to 1.0 percent DSM and coal capital costs decreased by 20 percent.
- Expansion Plan:

YEAR	COAL	CC	IGCC	CT	WIND	IGSQ
2008	0	0	0	0	0	0
2009	0	0	0	1	3	0
2010	0	0	0	1	3	0
2011	0	0	0	1	4	0
2012	0	1	0	0	3	0
2013	0	0	0	0	4	0
2014	0	0	0	0	3	0
2015	1	1	0	0	4	0
2016	1	0	0	0	2	0
2017	0	0	0	0	3	0
2018	0	1	0	0	2	0
2019	0	0	0	0	3	0
2020	0	0	0	0	2	0
2021	1	0	0	0	1	0
2022	1	0	0	0	2	0
2023	0	0	0	0	2	0
2024	1	0	0	0	2	0
2025	0	0	0	0	1	0
	5	3	0	3	44	0

9. *20 Percent Decrease in Capital Costs of Coal-Fired Expansion Units Only and an Increase in Natural Gas Costs of 20 Percent.*

- Base case assumptions with the forecast adjusted from 1.5 percent to 1.0 percent DSM and coal capital costs decreased by 20 percent and natural gas costs increased by 20 percent.
- Expansion Plan:

YEAR	COAL	CC	IGCC	CT	WIND	IGSQ
2008	0	0	0	0	0	0
2009	0	0	0	1	3	0
2010	0	0	0	1	3	0
2011	0	0	0	1	4	0
2012	0	0	0	1	3	0
2013	0	0	0	1	4	0
2014	1	0	0	0	3	0
2015	1	0	0	1	4	0
2016	1	0	0	0	2	0
2017	1	0	0	0	3	0
2018	0	0	0	0	2	0
2019	1	0	0	0	3	0
2020	0	0	0	0	2	0
2021	1	0	0	0	1	0
2022	0	0	0	0	2	0
2023	1	0	0	0	2	0
2024	1	0	0	0	2	0
2025	0	0	0	0	1	0
	8	0	0	6	44	0

10. Coal Fuel Cost Increased by 20 Percent.

- Base case assumptions with the forecast adjusted from 1.5 percent to 1.0 percent DSM and an increase in coal fuel costs of 20 percent.
- Expansion Plan:

YEAR	COAL	CC	IGCC	CT	WIND	IGSQ
2008	0	0	0	0	0	0
2009	0	0	0	1	3	0
2010	0	0	0	1	3	0
2011	0	0	0	1	4	0
2012	0	1	0	0	3	0
2013	0	0	0	0	4	0
2014	0	0	0	0	3	0
2015	0	2	0	0	4	0
2016	0	1	0	0	2	0
2017	0	0	0	0	3	0
2018	0	0	0	0	2	0
2019	0	1	0	0	3	0
2020	0	0	0	0	2	0
2021	0	1	0	0	1	0
2022	0	0	0	0	2	0
2023	0	0	0	0	2	0
2024	0	1	0	0	2	0
2025	0	0	0	0	1	0
	0	7	0	3	44	0

11. Coal Fuel Cost Decreased by 20 Percent.

- Base case assumptions with the forecast adjusted from 1.5 percent to 1.0 percent DSM and a decrease in coal fuel costs of 20 percent.
- Expansion Plan:

YEAR	COAL	CC	IGCC	CT	WIND	IGSQ
2008	0	0	0	0	0	0
2009	0	0	0	1	3	0
2010	0	0	0	1	3	0
2011	0	0	0	1	4	0
2012	0	1	0	0	3	0
2013	0	0	0	0	4	0
2014	0	0	0	0	3	0
2015	0	2	0	0	4	0
2016	0	0	0	1	2	0
2017	0	1	0	0	3	0
2018	0	0	0	0	2	0
2019	0	0	0	0	3	0
2020	1	0	0	0	2	0
2021	0	0	0	0	1	0
2022	0	1	0	0	2	0
2023	0	0	0	0	2	0
2024	0	1	0	0	2	0
2025	0	0	0	0	1	0
	1	6	0	4	44	0

12. Natural Gas Cost Increased by 20 Percent.

- Base case assumptions with the forecast adjusted from 1.5 percent to 1.0 percent DSM and an increase in natural gas fuel costs of 20 percent.
- Expansion Plan:

YEAR	COAL	CC	IGCC	CT	WIND	IGSQ
2008	0	0	0	0	0	0
2009	0	0	0	1	3	0
2010	0	0	0	1	3	0
2011	0	0	0	1	4	0
2012	0	0	0	1	3	0
2013	0	0	0	1	4	0
2014	0	1	0	0	3	0
2015	0	1	0	0	4	0
2016	0	1	0	0	2	0
2017	0	0	0	0	3	0
2018	1	0	0	0	2	0
2019	0	0	0	0	3	0
2020	1	0	0	0	2	0
2021	0	0	0	0	1	0
2022	1	0	0	0	2	0
2023	0	0	0	1	2	0
2024	1	0	0	0	2	0
2025	0	0	0	0	1	0
	4	3	0	6	44	0

13. Natural Gas Cost Decreased by 20 Percent.

- Base case assumptions with the forecast adjusted from 1.5 percent to 1.0 percent DSM and a decrease in natural gas fuel costs of 20 percent.
- Expansion Plan:

YEAR	COAL	CC	IGCC	CT	WIND	IGSQ
2008	0	0	0	0	0	0
2009	0	0	0	1	3	0
2010	0	0	0	1	3	0
2011	0	0	0	1	4	0
2012	0	1	0	0	3	0
2013	0	0	0	0	4	0
2014	0	0	0	0	3	0
2015	0	2	0	0	4	0
2016	0	1	0	0	2	0
2017	0	0	0	0	3	0
2018	0	0	0	0	2	0
2019	0	1	0	0	3	0
2020	0	0	0	0	2	0
2021	0	1	0	0	1	0
2022	0	0	0	0	2	0
2023	0	0	0	0	2	0
2024	0	1	0	0	2	0
2025	0	0	0	0	1	0
	0	7	0	3	44	0

14. Natural Gas Cost Increased by 50 Percent.

- Base case assumptions with the forecast adjusted from 1.5 percent to 1.0 percent DSM and an increase in natural gas fuel costs of 50 percent.
- Expansion Plan:

YEAR	COAL	CC	IGCC	CT	WIND	IGSQ
2008	0	0	0	0	0	0
2009	0	0	0	1	3	0
2010	0	0	0	1	3	0
2011	0	0	0	1	4	0
2012	0	1	0	0	3	0
2013	0	0	0	0	4	0
2014	1	0	0	0	3	0
2015	1	0	0	0	4	0
2016	0	1	0	0	2	0
2017	0	0	0	0	3	0
2018	1	0	0	0	2	0
2019	0	0	0	0	3	0
2020	1	0	0	0	2	0
2021	0	0	0	0	1	0
2022	1	0	0	0	2	0
2023	0	0	0	0	2	0
2024	1	0	0	0	2	0
2025	0	0	0	1	1	0
	6	2	0	4	44	0

15. Summary

Tables 13 through 15 summarize the results of the different contingencies run on the High Load scenario.

Table 13: Number of 500 MW Coal Units Added 2008-2025

	Base Assumptions	$4 CO_2$	$30 CO_2$	$45 CO_2$	Capital Cost +20%	Capital Cost -20%	Coal K Cost +20%	Coal K Cost -20%	Coal K Cost -20% and NG Cost +20%	Coal Fuel +20%	Coal Fuel - 20%	Gas Fuel +20%	Gas Fuel - 20%	Gas Fuel +50%
High Load Scenario	0	3	0	0	0	5	0	5	8	0	1	4	0	6

Table 14: Number of 627 MW Combined Cycle Units Added 2008-2025

	Base Assumptions	$4 CO_2$	$30 CO_2$	$45 CO_2$	Capital Cost +20%	Capital Cost - 20%	Coal K Cost +20%	Coal K Cost - 20%	Coal K Cost - 20% and NG Cost +20%	Coal Fuel +20%	Coal Fuel - 20%	Gas Fuel +20%	Gas Fuel - 20%	Gas Fuel +50%
High Load Scenario	7	3	7	7	7	3	7	3	0	7	6	3	7	2

Table 15: PV Societal Cost - Difference from Base (000s $)

	1.0% DSM and RES
BASE ($17 CO_2)	4,453,768
$4 CO_2	-16,007,720
$30 CO_2	24,706,408
$45 CO_2	48,092,968
Capital Cost +20%	7,187,632
Capital Cost -20%	1,412,336
Coal K Cost +20%	4,453,768
Coal K Cost -20%	3,801,656
Coal K Cost -20% and NG Cost +20%	6,340,280
Coal Fuel +20%	7,688,112
Coal Fuel -20%	1,147,104
Gas Fuel +20%	6,300,272
Gas Fuel -20%	1,884,256
Gas Fuel +50%	8,163,504

SCENARIO IV: HIGH LOAD AND NO NEW WIND ADDITIONS.

As in Section V.B, above, in order to assess the cost-effectiveness of the RES and to understand the effect of the RES on Minnesota in the future, the ORA ran a scenario that include a forecast that assumed energy savings of 1.0 percent of retail sales, but did not add any additional wind generation. This scenario is referred to as the "High Load and No New Wind" scenario. The ORA ran the same contingencies on the High Load and No New Wind scenario as on the High Load scenario.

1. High Load and No New Wind

- *Uses Base Case Assumptions with forecast adjusted from 1.5 percent DSM to 1.0 percent DSM.*

Table 16: High Load and No New Wind Scenario Assumptions

Capital Costs

Unit	Capacity	$/kW
Coal	500 MW	$3,000.00
CC	627 MW	$1,000.00
CT	168 MW	$750.00
Wind	100 MW	$2,500.00
IGCC w/out sequestration	600 MW	$3,500.00
IGCC w/ sequestration	600 MW	$4,000.00

Natural Gas Cost / **Coal Fuel Cost**

Year	Natural Gas $/MMBTU	Year	Coal $/MMBTU
2008	$9.05	2008	$1.67
2009	$9.13	2009	$1.71
2010	$9.22	2010	$1.75
2011	$8.95	2011	$1.79
2012	$8.73	2012	$1.82
2013	$8.60	2013	$1.86
2014	$8.00	2014	$1.89
2015	$7.71	2015	$1.93
2016	$7.91	2016	$1.97
2017	$8.17	2017	$2.01
2018	$8.46	2018	$2.05
2019	$8.84	2019	$2.09
2020	$9.05	2020	$2.13
2021	$9.13	2021	$2.18
2022	$9.43	2022	$2.22
2023	$9.76	2023	$2.26
2024	$10.11	2024	$2.31
2025	$10.34	2025	$2.36

CO_2 Costs	$17 per Ton
100 MW Wind Units Added	0

- Expansion Plan:

YEAR	COAL	CC	IGCC	CT	WIND	IGSQ
2008	0	0	0	0	0	0
2009	0	0	0	1	0	0
2010	0	0	0	1	0	0
2011	0	0	0	2	0	0
2012	0	1	0	0	0	0
2013	0	0	0	0	0	0
2014	0	0	0	0	0	0
2015	0	2	0	0	0	0
2016	0	1	0	0	0	0
2017	0	0	0	0	0	0
2018	1	0	0	0	0	0
2019	0	0	0	0	0	0
2020	1	0	0	0	0	0
2021	0	0	0	1	0	0
2022	1	0	0	0	0	0
2023	0	0	0	1	0	0
2024	1	0	0	0	0	0
2025	0	0	0	0	0	0
	4	4	0	6	0	0

2. *Cost of \$4 CO_2 Regulation*

- Base case assumptions with the forecast adjusted to 1.0 percent DSM and no new wind additions and \$4 CO_2 cost instead of \$17.
- Expansion Plan:

YEAR	COAL	CC	IGCC	CT	WIND	IGSQ
2008	0	0	0	0	0	0
2009	0	0	0	1	0	0
2010	0	0	0	1	0	0
2011	0	0	0	2	0	0
2012	0	1	0	0	0	0
2013	0	0	0	0	0	0
2014	0	0	0	0	0	0
2015	1	1	0	0	0	0
2016	1	0	0	0	0	0
2017	1	0	0	0	0	0
2018	0	0	0	0	0	0
2019	1	0	0	0	0	0
2020	0	0	0	0	0	0
2021	0	1	0	0	0	0
2022	0	0	0	0	0	0
2023	1	0	0	0	0	0
2024	1	0	0	0	0	0
2025	0	0	0	0	0	0
	6	3	0	4	0	0

3. *Cost of \$30 CO_2 Regulation*

- Base case assumptions with the forecast adjusted to 1.0 percent DSM and no new wind additions and \$30 CO_2 cost instead of \$17.
- Expansion Plan:

YEAR	COAL	CC	IGCC	CT	WIND	IGSQ
2008	0	0	0	0	0	0
2009	0	0	0	1	0	0
2010	0	0	0	1	0	0
2011	0	0	0	2	0	0
2012	0	1	0	0	0	0
2013	0	0	0	0	0	0
2014	0	0	0	0	0	0
2015	0	2	0	0	0	0
2016	0	1	0	0	0	0
2017	0	0	0	0	0	0
2018	0	1	0	0	0	0
2019	0	0	0	0	0	0
2020	0	1	0	0	0	0
2021	0	0	0	0	0	0
2022	0	1	0	0	0	0
2023	0	0	0	0	0	0
2024	1	0	0	0	0	0
2025	0	0	0	0	0	0
	1	7	0	4	0	0

4. Cost of \$45 CO_2 Regulation

- Base case assumptions with the forecast adjusted to 1.0 percent DSM and no new wind additions and \$45 CO_2 cost instead of \$17.
- Expansion Plan:

YEAR	COAL	CC	IGCC	CT	WIND	IGSQ
2008	0	0	0	0	0	0
2009	0	0	0	1	0	0
2010	0	0	0	1	0	0
2011	0	0	0	2	0	0
2012	0	1	0	0	0	0
2013	0	0	0	0	0	0
2014	0	0	0	0	0	0
2015	0	2	0	0	0	0
2016	0	1	0	0	0	0
2017	0	0	0	0	0	0
2018	0	1	0	0	0	0
2019	0	0	0	0	0	0
2020	0	1	0	0	0	0
2021	0	0	0	0	0	0
2022	0	1	0	0	0	0
2023	0	0	0	0	0	0
2024	0	1	0	0	0	0
2025	0	0	0	0	0	0
	0	8	0	4	0	0

5. 20 Percent Increase in Capital Costs

- Base case assumptions with the forecast adjusted to 1.0 percent DSM and no new wind additions and all capital costs increased by 20 percent.
- Expansion Plan:

YEAR	COAL	CC	IGCC	CT	WIND	IGSQ
2008	0	0	0	0	0	0
2009	0	0	0	1	0	0
2010	0	0	0	1	0	0
2011	0	0	0	2	0	0
2012	0	1	0	0	0	0
2013	0	0	0	0	0	0
2014	0	0	0	0	0	0
2015	0	2	0	0	0	0
2016	0	1	0	0	0	0
2017	0	0	0	0	0	0
2018	0	1	0	0	0	0
2019	0	0	0	0	0	0
2020	0	1	0	0	0	0
2021	0	0	0	0	0	0
2022	1	0	0	0	0	0
2023	0	0	0	0	0	0
2024	0	1	0	0	0	0
2025	0	0	0	0	0	0
	1	7	0	4	0	0

6. 20 Percent Decrease in Capital Costs

- Base case assumptions with the forecast adjusted to 1.0 percent DSM and no new wind additions and all capital costs decreased by 20 percent.
- Expansion Plan:

YEAR	COAL	CC	IGCC	CT	WIND	IGSQ
2008	0	0	0	0	0	0
2009	0	0	0	1	0	0
2010	0	0	0	1	0	0
2011	0	0	0	2	0	0
2012	0	1	0	0	0	0
2013	0	0	0	0	0	0
2014	0	0	0	0	0	0
2015	1	1	0	0	0	0
2016	1	0	0	0	0	0
2017	1	0	0	0	0	0
2018	0	0	0	0	0	0
2019	1	0	0	0	0	0
2020	0	0	0	0	0	0
2021	1	0	0	0	0	0
2022	1	0	0	0	0	0
2023	0	0	0	0	0	0
2024	1	0	0	0	0	0
2025	0	0	0	1	0	0
	7	2	0	5	0	0

7. *20 Percent Increase in Capital Costs of Coal-Fired Expansion Units Only.*

- Base case assumptions with the forecast adjusted to 1.0 percent DSM and no new wind additions and coal capital costs increased by 20 percent.
- Expansion Plan:

YEAR	COAL	CC	IGCC	CT	WIND	IGSQ
2008	0	0	0	0	0	0
2009	0	0	0	1	0	0
2010	0	0	0	1	0	0
2011	0	0	0	2	0	0
2012	0	1	0	0	0	0
2013	0	0	0	0	0	0
2014	0	0	0	0	0	0
2015	0	2	0	0	0	0
2016	0	1	0	0	0	0
2017	0	0	0	0	0	0
2018	0	1	0	0	0	0
2019	0	0	0	0	0	0
2020	0	1	0	0	0	0
2021	0	0	0	0	0	0
2022	0	1	0	0	0	0
2023	0	0	0	0	0	0
2024	1	0	0	0	0	0
2025	0	0	0	0	0	0
	1	7	0	4	0	0

8. 20 Percent Decrease in Capital Costs of Coal-Fired Expansion Units Only.

- Base case assumptions with the forecast adjusted to 1.0 percent DSM and no new wind additions and coal capital costs decreased by 20 percent.
- Expansion Plan:

YEAR	COAL	CC	IGCC	CT	WIND	IGSQ
2008	0	0	0	0	0	0
2009	0	0	0	1	0	0
2010	0	0	0	1	0	0
2011	0	0	0	2	0	0
2012	0	1	0	0	0	0
2013	0	0	0	0	0	0
2014	1	0	0	0	0	0
2015	1	0	0	1	0	0
2016	1	0	0	0	0	0
2017	1	0	0	0	0	0
2018	0	0	0	0	0	0
2019	1	0	0	0	0	0
2020	0	0	0	0	0	0
2021	1	0	0	0	0	0
2022	1	0	0	0	0	0
2023	0	0	0	0	0	0
2024	1	0	0	0	0	0
2025	0	0	0	1	0	0
	8	1	0	6	0	0

9. *20 Percent Decrease in Capital Costs of Coal Fired Expansion Units Only and an Increase in Natural Gas Costs of 20 Percent.*

- Base case assumptions with the forecast adjusted to 1.0 percent DSM and no new wind additions and coal capital costs decreased by 20 percent and natural gas costs increased by 20 percent.
- Expansion Plan:

YEAR	COAL	CC	IGCC	CT	WIND	IGSQ
2008	0	0	0	0	0	0
2009	0	0	0	1	0	0
2010	0	0	0	1	0	0
2011	0	0	0	2	0	0
2012	0	1	0	0	0	0
2013	0	0	0	0	0	0
2014	1	0	0	0	0	0
2015	1	0	0	1	0	0
2016	1	0	0	0	0	0
2017	1	0	0	0	0	0
2018	1	0	0	0	0	0
2019	0	0	0	0	0	0
2020	1	0	0	0	0	0
2021	0	0	0	0	0	0
2022	1	0	0	0	0	0
2023	0	0	0	0	0	0
2024	1	0	0	0	0	0
2025	1	0	0	0	0	0
	9	1	0	5	0	0

10. Coal Fuel Cost Increased by 20 Percent.

- Base case assumptions with the forecast adjusted to 1.0 percent DSM and no new wind additions and an increase in coal fuel costs of 20 percent.
- Expansion Plan:

YEAR	COAL	CC	IGCC	CT	WIND	IGSQ
2008	0	0	0	0	0	0
2009	0	0	0	1	0	0
2010	0	0	0	1	0	0
2011	0	0	0	2	0	0
2012	0	1	0	0	0	0
2013	0	0	0	0	0	0
2014	0	0	0	0	0	0
2015	0	2	0	0	0	0
2016	0	1	0	0	0	0
2017	0	0	0	0	0	0
2018	1	0	0	0	0	0
2019	0	0	0	0	0	0
2020	1	0	0	0	0	0
2021	0	0	0	1	0	0
2022	1	0	0	0	0	0
2023	0	0	0	1	0	0
2024	1	0	0	0	0	0
2025	0	0	0	0	0	0
	4	4	0	6	0	0

11. Coal Fuel Cost Decreased by 20 Percent.

- Base case assumptions with the forecast adjusted to 1.0 percent DSM and no new wind additions and a decrease in coal fuel costs of 20 percent.
- Expansion Plan:

YEAR	COAL	CC	IGCC	CT	WIND	IGSQ
2008	0	0	0	0	0	0
2009	0	0	0	1	0	0
2010	0	0	0	1	0	0
2011	0	0	0	2	0	0
2012	0	1	0	0	0	0
2013	0	0	0	0	0	0
2014	0	0	0	0	0	0
2015	1	1	0	0	0	0
2016	1	0	0	0	0	0
2017	1	0	0	0	0	0
2018	0	0	0	0	0	0
2019	1	0	0	0	0	0
2020	0	0	0	0	0	0
2021	0	1	0	0	0	0
2022	0	0	0	0	0	0
2023	1	0	0	0	0	0
2024	1	0	0	0	0	0
2025	0	0	0	0	0	0
	6	3	0	4	0	0

12. Natural Gas Cost Increased by 20 Percent.

- Base case assumptions with the forecast adjusted to 1.0 percent DSM and no new wind additions and an increase in natural gas fuel costs of 20 percent.
- Expansion Plan:

YEAR	COAL	CC	IGCC	CT	WIND	IGSQ
2008	0	0	0	0	0	0
2009	0	0	0	1	0	0
2010	0	0	0	1	0	0
2011	0	0	0	2	0	0
2012	0	1	0	0	0	0
2013	0	0	0	0	0	0
2014	0	0	0	0	0	0
2015	1	1	0	0	0	0
2016	1	0	0	0	0	0
2017	1	0	0	0	0	0
2018	0	0	0	0	0	0
2019	1	0	0	0	0	0
2020	0	0	0	0	0	0
2021	1	0	0	0	0	0
2022	1	0	0	0	0	0
2023	0	0	0	0	0	0
2024	1	0	0	0	0	0
2025	0	0	0	1	0	0
	7	2	0	5	0	0

13. Natural Gas Cost Decreased by 20 Percent.

- Base case assumptions with the forecast adjusted to 1.0 percent DSM and no new wind additions and a decrease in natural gas fuel costs of 20 percent.
- Expansion Plan:

YEAR	COAL	CC	IGCC	CT	WIND	IGSQ
2008	0	0	0	0	0	0
2009	0	0	0	1	0	0
2010	0	0	0	1	0	0
2011	0	0	0	2	0	0
2012	0	1	0	0	0	0
2013	0	0	0	0	0	0
2014	0	0	0	0	0	0
2015	0	2	0	0	0	0
2016	0	1	0	0	0	0
2017	0	0	0	0	0	0
2018	0	1	0	0	0	0
2019	0	0	0	0	0	0
2020	0	0	0	1	0	0
2021	0	1	0	0	0	0
2022	0	0	0	0	0	0
2023	0	1	0	0	0	0
2024	0	0	0	0	0	0
2025	0	0	0	2	0	0
	0	7	0	7	0	0

14. Natural Gas Cost Increased by 50 Percent.

- Base case assumptions with the forecast adjusted to 1.0 percent DSM and no new wind additions and an increase in natural gas fuel costs of 50 percent.
- Expansion Plan:

YEAR	COAL	CC	IGCC	CT	WIND	IGSQ
2008	0	0	0	0	0	0
2009	0	0	0	1	0	0
2010	0	0	0	1	0	0
2011	0	0	0	2	0	0
2012	0	1	0	0	0	0
2013	0	0	0	0	0	0
2014	1	0	0	0	0	0
2015	1	0	0	1	0	0
2016	1	0	0	0	0	0
2017	1	0	0	0	0	0
2018	0	0	0	0	0	0
2019	1	0	0	0	0	0
2020	0	0	0	0	0	0
2021	1	0	0	0	0	0
2022	1	0	0	0	0	0
2023	0	0	0	0	0	0
2024	1	0	0	0	0	0
2025	0	0	0	1	0	0
	8	1	0	6	0	0

15. Summary

Tables 17 through 19 summarize the results of the different contingencies run on the High Load and No Additional Wind scenario.

Table 17: Number of 500 MW Coal Units Added 2008-2025

	Base Assumptions	$4 CO_2	$30 CO_2	$45 CO_2	Capital Cost +20%	Capital Cost -20%	Coal K Cost +20%	Coal K Cost -20%	Coal K Cost -20% and NG Cost +20%	Coal Fuel +20%	Coal Fuel -20%	Gas Fuel +20%	Gas Fuel -20%	Gas Fuel +50%
High Load and No New Wind Additions	4	6	1	0	1	7	1	8	9	4	6	7	0	8

Table 18: Number of 627 MW Combined Cycle Units Added 2008-2025

	Base Assumptions	$4 CO_2	$30 CO_2	$45 CO_2	Capital Cost +20%	Capital Cost -20%	Coal K Cost +20%	Coal K Cost -20%	Coal K Cost -20% and NG Cost +20%	Coal Fuel +20%	Coal Fuel -20%	Gas Fuel +20%	Gas Fuel -20%	Gas Fuel +50%
High Load and No New Wind Additions	4	3	7	8	7	2	7	1	1	4	3	2	7	1

Table 19: PV Societal Cost - Difference from Base (000s $)

Lower Cost in Bold

	1.0% DSM and RES	1.0% DSM No RES
BASE ($17 CO_2)	**4,453,768**	4,623,296
$4 CO_2	-16,007,720	**-19,037,608**
$30 CO_2	**24,706,408**	27,553,648
$45 CO_2	**48,092,968**	53,427,320
Capital Cost +20%	7,187,632	**5,922,184**
Capital Cost -20%	**1,412,336**	2,655,024
Coal K Cost +20%	**4,453,768**	5,118,400
Coal K Cost -20%	3,801,656	**2,991,224**
Coal K Cost -20% and NG Cost +20%	6,340,280	**6,129,496**
Coal Fuel +20%	**7,688,112**	8,379,328
Coal Fuel -20%	1,147,104	**682,080**
Gas Fuel +20%	**6,300,272**	6,353,808
Gas Fuel -20%	1,884,256	**1,221,920**
Gas Fuel +50%	**8,163,504**	8,354,208

SCENARIO V: NATIONAL RENEWABLE ENERGY STANDARD.

1. Base Case with enough wind to achieve 25 percent of energy from renewables by 2025.

   - Uses Base Case Assumptions with enough wind additions so that 25 percent of energy is produced from renewable sources by 2025. This scenario applies the RES to the out-of-state load that is used in the model as well as the Minnesota load.

Table 20: National RES Scenario Assumptions

Capital Costs

Unit	Capacity	$/kW
Coal	500 MW	$3,000.00
CC	627 MW	$1,000.00
CT	168 MW	$750.00
Wind	100 MW	$2,500.00
IGCC w/out sequestration	600 MW	$3,500.00
IGCC w/ sequestration	600 MW	$4,000.00

Natural Gas Cost		**Coal Fuel Cost**	
Year	$/MMBTU	Year	$/MMBTU
2008	$9.05	2008	$1.67
2009	$9.13	2009	$1.71
2010	$9.22	2010	$1.75
2011	$8.95	2011	$1.79
2012	$8.73	2012	$1.82
2013	$8.60	2013	$1.86
2014	$8.00	2014	$1.89
2015	$7.71	2015	$1.93
2016	$7.91	2016	$1.97
2017	$8.17	2017	$2.01
2018	$8.46	2018	$2.05
2019	$8.84	2019	$2.09
2020	$9.05	2020	$2.13
2021	$9.13	2021	$2.18
2022	$9.43	2022	$2.22
2023	$9.76	2023	$2.26
2024	$10.11	2024	$2.31
2025	$10.34	2025	$2.36

CO_2 Costs	$17 per Ton
100 MW Wind Units Added	61

- Expansion Plan:

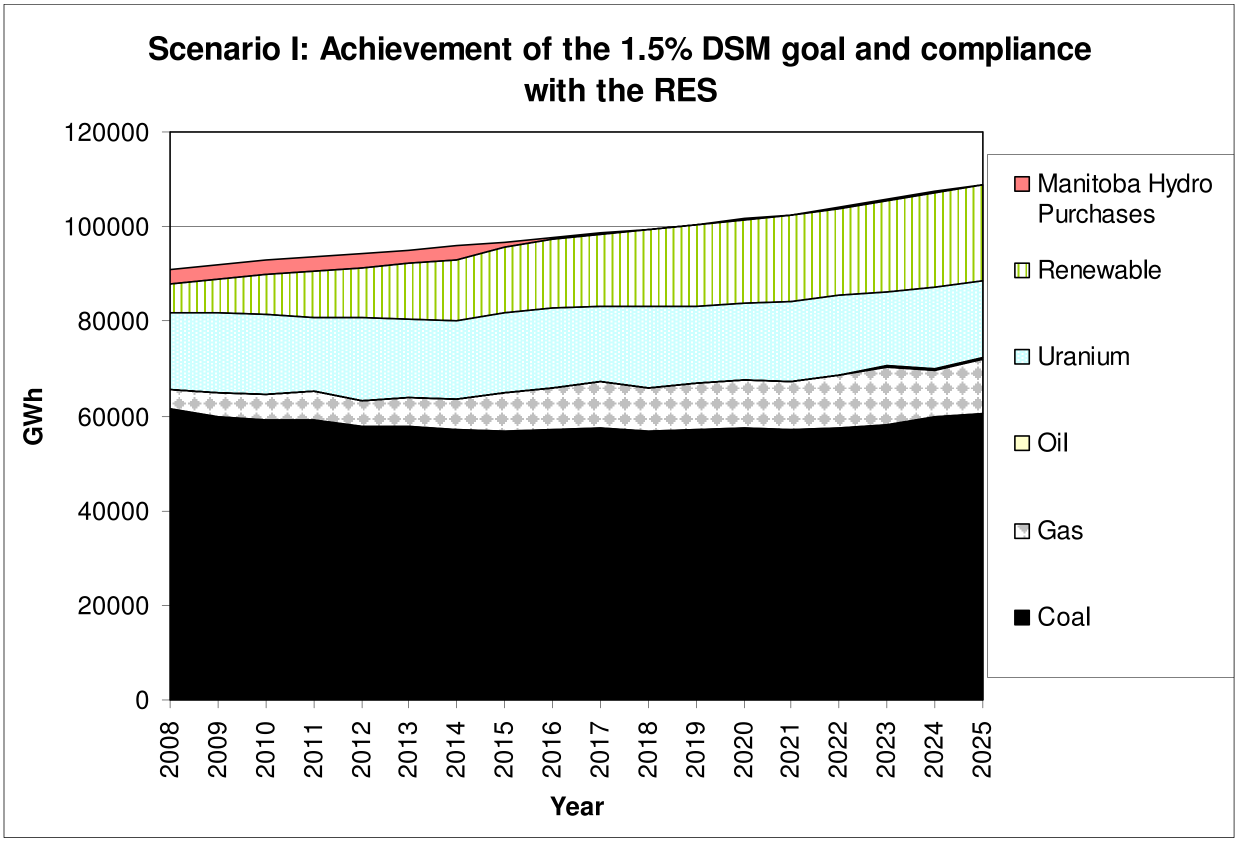
YEAR	COAL	CC	IGCC	CT	WIND	IGSQ
2008	0	0	0	0	0	0
2009	0	0	0	1	4	0
2010	0	0	0	0	4	0
2011	0	0	0	0	5	0
2012	0	1	0	0	5	0
2013	0	0	0	0	4	0
2014	0	0	0	0	4	0
2015	0	1	0	0	4	0
2016	0	1	0	0	4	0
2017	0	0	0	0	3	0
2018	0	1	0	0	3	0
2019	0	0	0	0	4	0
2020	0	0	0	0	3	0
2021	0	0	0	0	3	0
2022	0	1	0	0	2	0
2023	0	0	0	0	3	0
2024	0	1	0	0	3	0
2025	0	0	0	0	3	0
	0	6	0	1	61	0

F. ANALYSIS OF RESULTS

1. GENERATION BY FUEL SOURCE UNDER SELECTED SCENARIOS

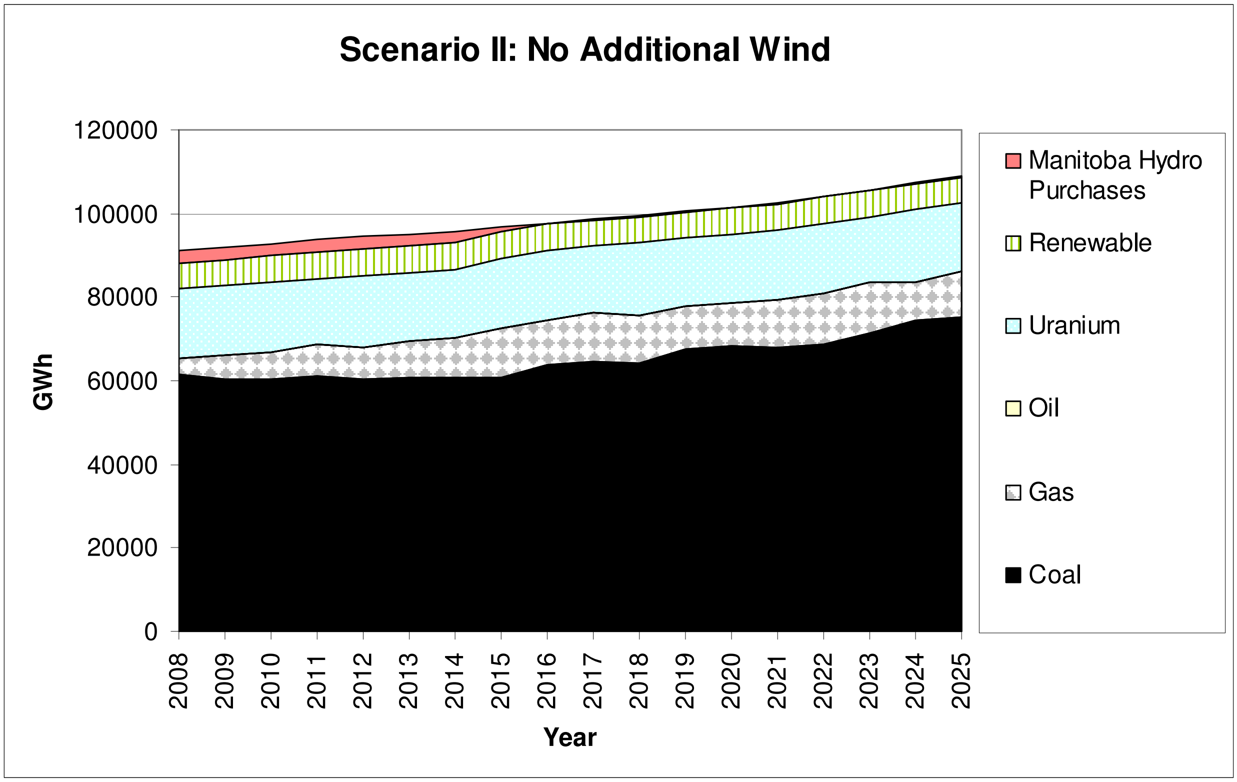
The graphs below show generation by fuel source under selected scenarios and contingences. The scenarios selected were chosen to show the range of outcomes and are as follow: Base Case, No New Wind Additions Scenario, the Base Case with High Natural Gas Costs and Low Coal Generator Capital Costs, the No New Wind Additions Scenario with High Natural Gas Costs and Low Coal Generator Capital Costs, and the National RES scenario. These scenarios and contingencies were chosen to illustrate the effects when either a significant amount of coal baseload was selected or, under the National RES scenarios, no coal baseload was selected.

Graph 2



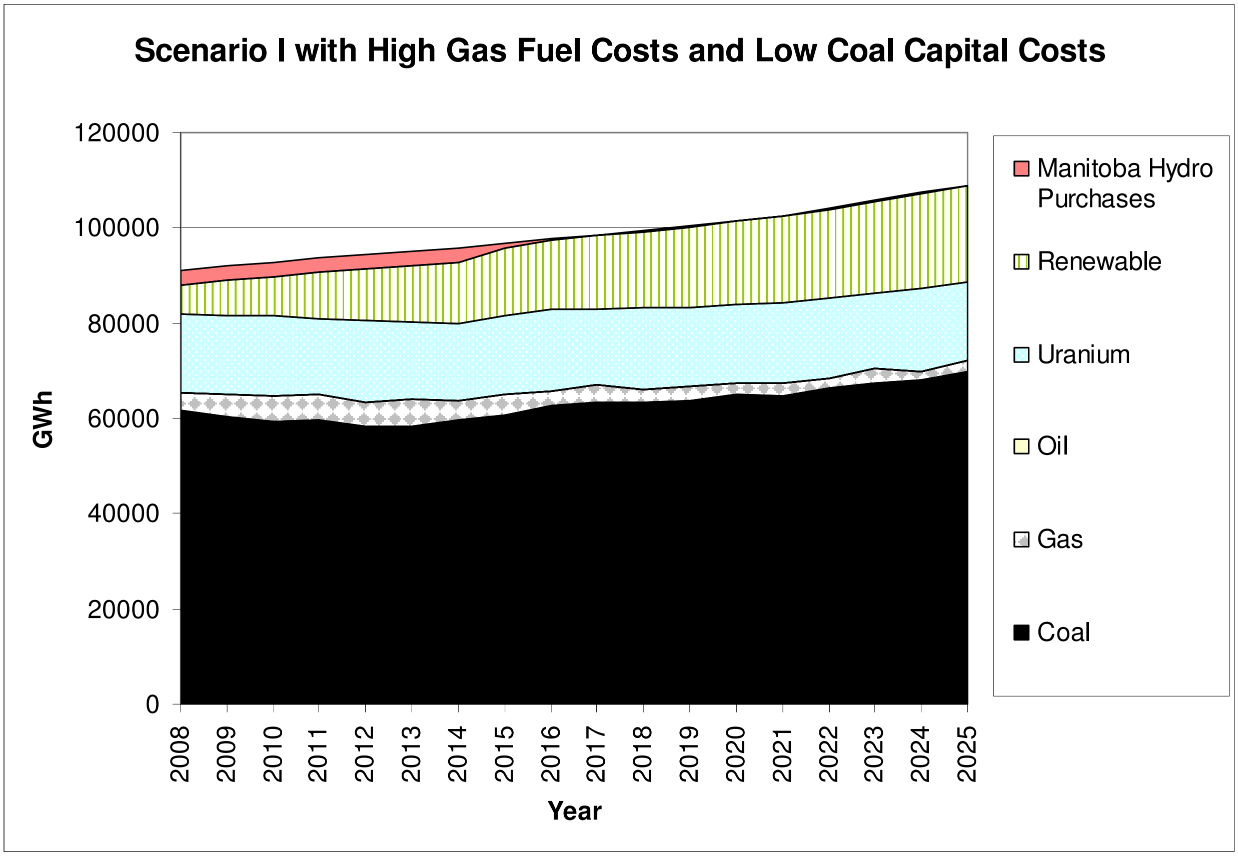
The above graph shows the GWh production over the 2008-2025 study period by fuel source under the Base Case, which assumes 1.5 percent DSM and compliance with the RES. As shown in the graph, generation from coal and uranium remain relatively constant in absolute terms, but decline as a percentage of all generation sources over time, as generation from renewables and natural gas increase.

Graph 3



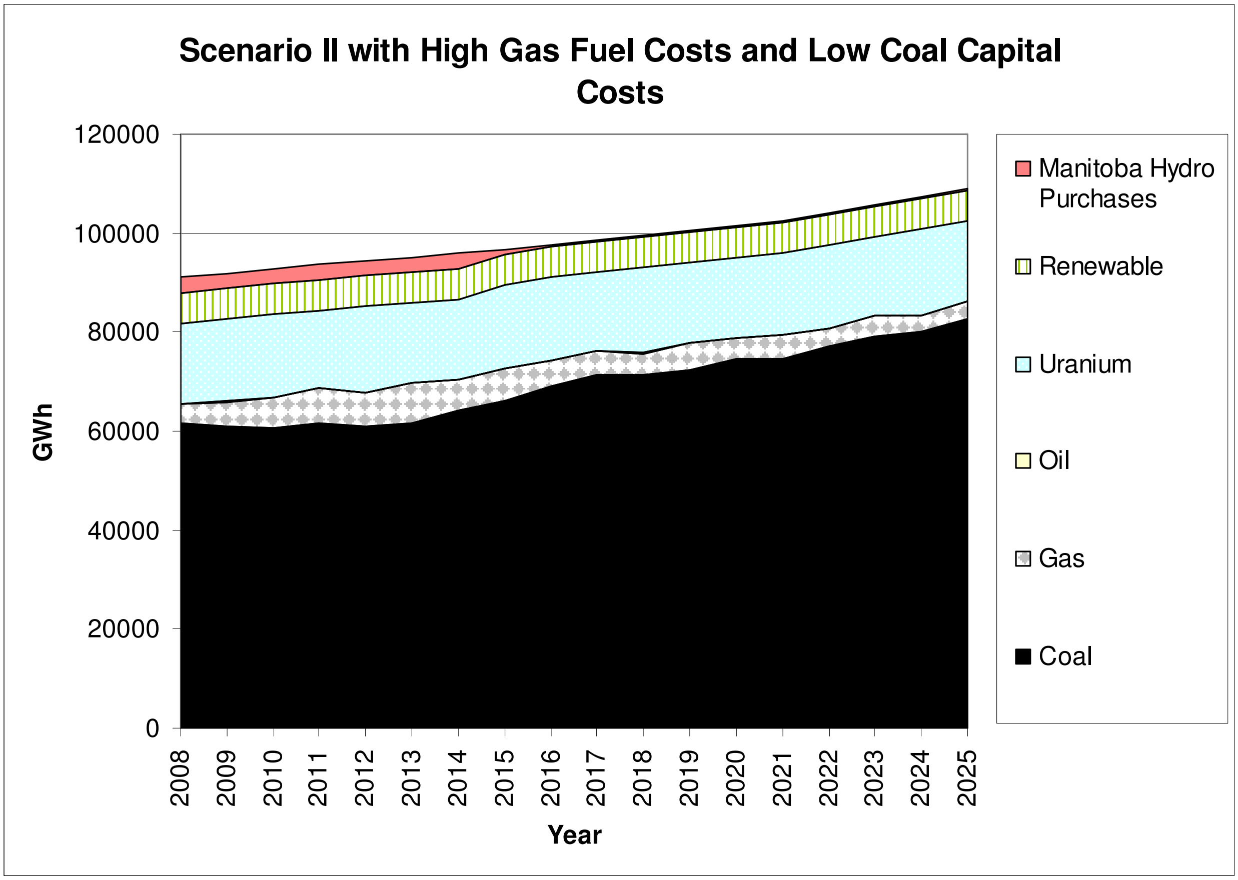
The above graph shows the GWh production over the 2008-2025 study period by fuel source for the No New Wind scenario which assumes 1.5 percent DSM and no new wind additions. As shown in the graph, renewable generation remains constant, whereas the growth in consumption is met through increased generation from coal and natural gas.

Graph 4



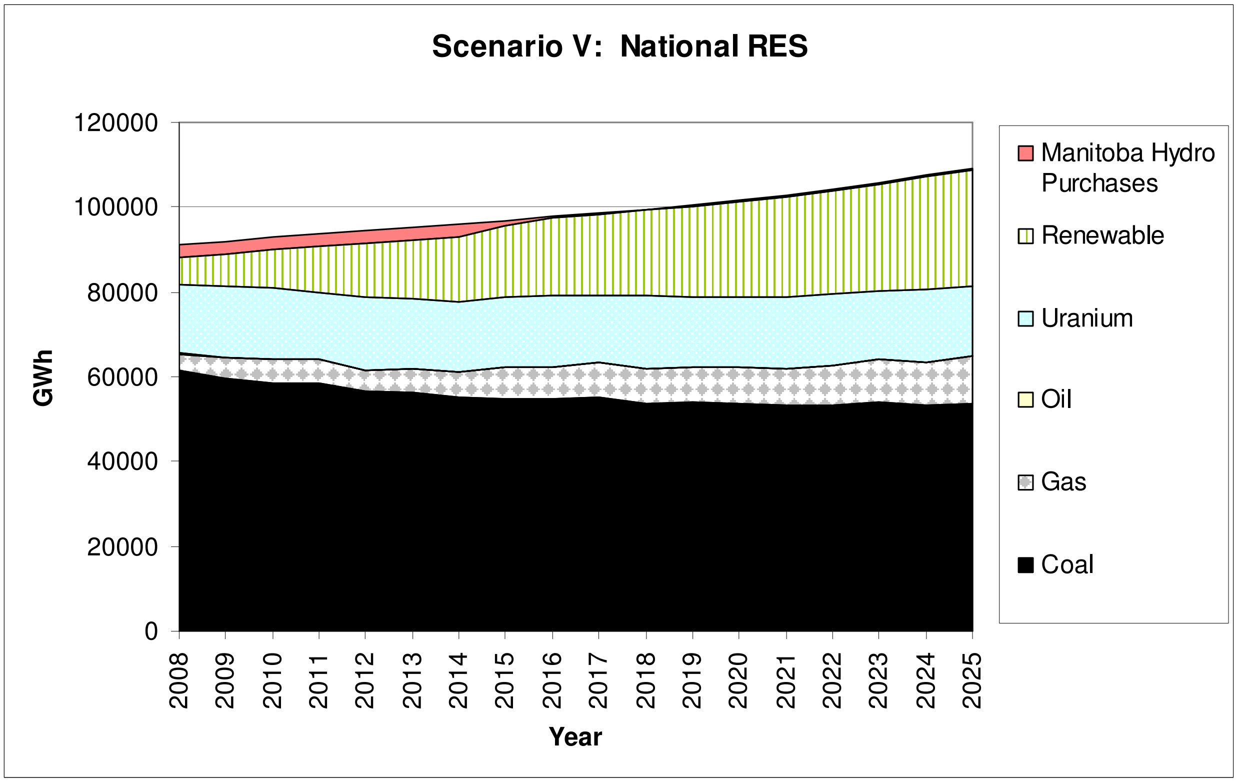
The above graph shows the GWh production over the 2008-2025 study period by fuel source Under the Base Case, which assumes compliance with the RES and 1.5 percent DSM, with the high natural gas fuel costs and low coal capital cost contingencies. As shown in the graph, renewable generation and generation from coal both increase, while generation from natural gas decreases.

Graph 5



The above graph shows the GWh production over the 2008-2025 study period by fuel source under the No Additional Wind scenario, which does not assume compliance with the RES, and the high natural gas fuel cost and low coal capital cost contingencies. As shown in the graph, renewable generation remains constant, generation from natural gas remains relatively constant, and generation from coal increases significantly.

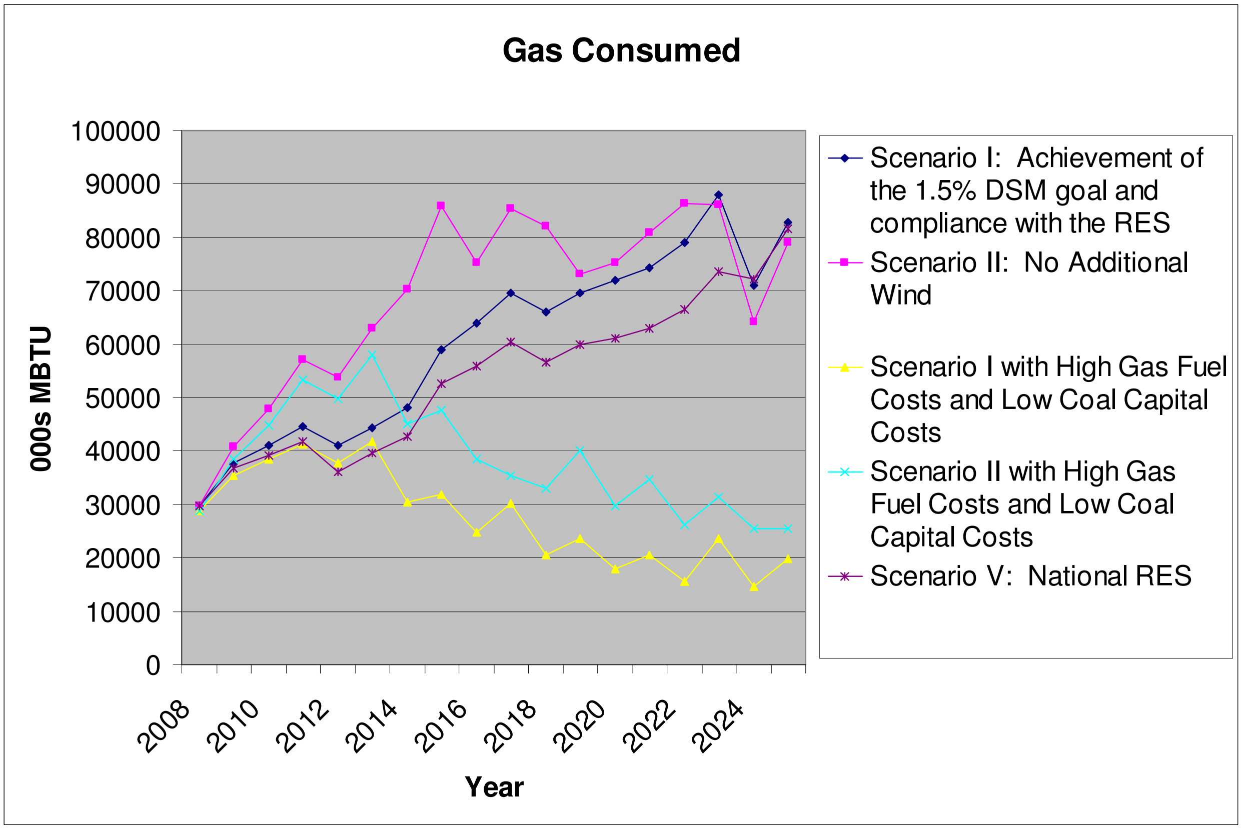
Graph 6



The above graph shows the GWh production over the 2008-2025 study period by fuel source for the National RES scenario. As shown in the graph, renewable generation increases significantly, generation from natural gas also increases, and generation from coal decreases somewhat but still remains the dominant fuel source even after including full compliance with both the DSM goals and the RES.

2. NATURAL GAS CONSUMPTION UNDER SELECTED SCENARIOS

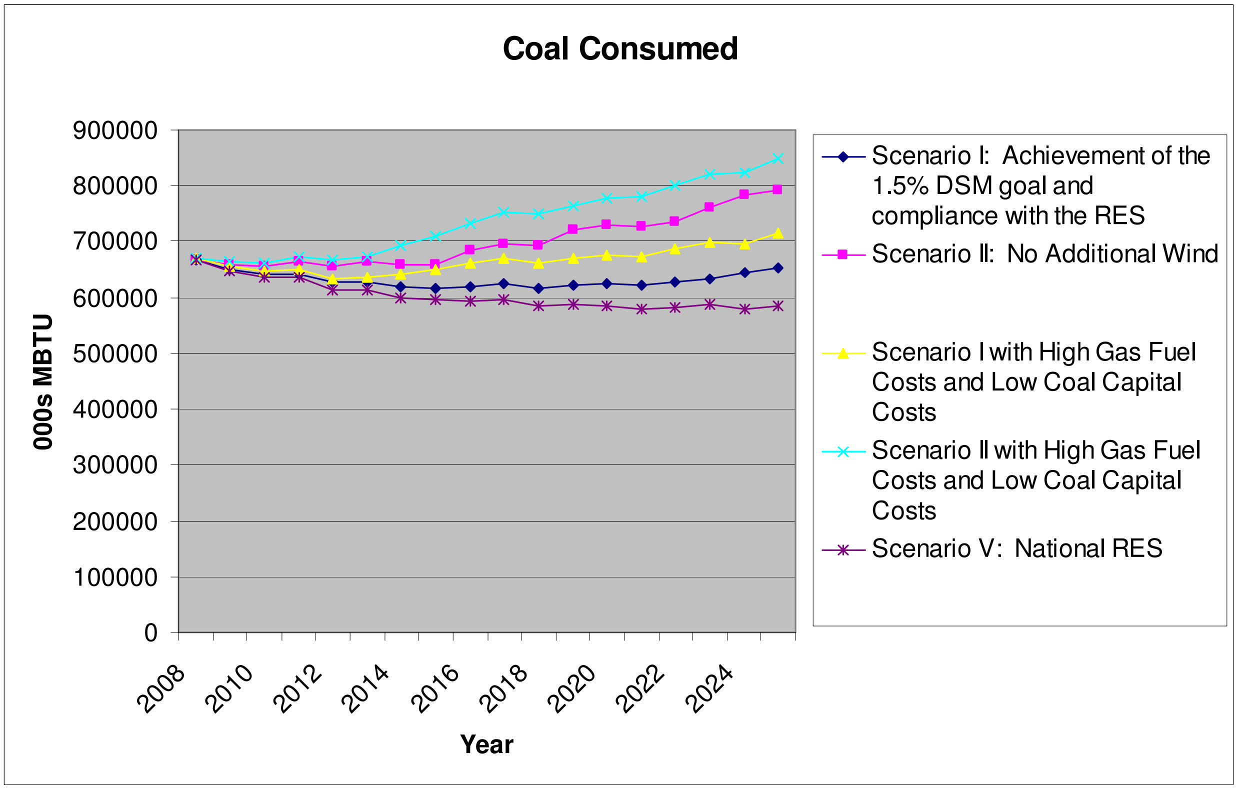
Graph 7



The above graph shows natural gas consumed in thousands of MBTUs for the same five selected scenarios as above in Section A. In the three scenarios in which little baseload coal is selected and significant gas generation is added, gas consumption increases significantly. Where a significant amount of coal generation is added, gas consumption decreases.

3. COAL CONSUMPTION UNDER SELECTED SCENARIOS

Graph 8



The above graph shows coal consumed in thousands of MBTUs for the same five selected scenarios as above in Section A. Coal consumption varies under each scenario, with consumption decreasing under the hypothetical 25 percent Total Company Renewable scenario, remaining relatively constant under scenarios which include Minnesota RES compliance, and increasing significantly if no new wind is added in the system.

G. CONCLUSIONS ON GENERATION

Minnesotans rely heavily on electric generation in their daily lives and businesses, for a variety of needs such as lighting, refrigeration, computers, entertainment, transportation, hospital care, and so on. If demand for electricity grows beyond the capacity of existing generation and as existing generation is replaced, more generation must be added to meet the needs of Minnesotans. The above results indicate that the future of Minnesota's electrical generation will affect, and be affected by, factors such as capital costs, fuel costs, energy conservation, CO_2 costs and costs of other emissions.

The ORA observes the following from the results of this analysis:

- Whether a 1.5 percent or lower 1.0 percent DSM goal in achieved, significant generation additions are anticipated in Minnesota during the 2008-2025 time period. The type of additions added is heavily dependent on the assumptions pertaining to fuel prices, capital costs, and emission costs. The number of 500 MW coal baseload units added varies from zero to nine. The Base Case for Scenario 1, which assumes RES compliance and achievement of a 1.5 percent conservation goal, results in a coal unit addition in 2024. At least one coal unit is added in 38 of the 56 scenarios and contingencies run in the study.

- The RES is cost-effective under 32 of the 56 scenarios and contingencies run in the study, as shown below:

Present Value Societal Cost - Difference from Base (000s $)

Lower Cost in Bold

	Scenario I	Scenario II	Scenario III	Scenario IV
Base Assumptions	**0**	180,040	**4,453,768**	4,623,296
\$4 CO_2	-20,048,416	**-22,762,904**	-16,007,720	**-19,037,608**
\$30 CO_2	**19,941,024**	22,487,392	**24,706,408**	27,553,648
\$45 CO_2	**42,937,408**	47,816,488	**48,092,968**	53,427,320
Capital Cost +20%	2,424,784	**1,208,384**	7,187,632	**5,922,184**
Capital Cost -20%	**-2,669,248**	-1,503,760	**1,412,336**	2,655,024
Coal K Cost +20%	**21,184**	534,752	**4,453,768**	5,118,400
Coal K Cost -20%	-490,808	**-1,263,296**	3,801,656	**2,991,224**
Coal K Cost -20% and NG Cost +20%	1,762,984	**1,416,392**	6,340,280	**6,129,496**
Coal Fuel +20%	**3,232,232**	3,826,016	**7,688,112**	8,379,328
Coal Fuel -20%	-3,287,768	**-3,611,672**	1,147,104	**682,080**
Gas Fuel +20%	**1,693,048**	1,751,656	**6,300,272**	6,353,808
Gas Fuel -20%	-2,254,560	**-2,883,576**	1,884,256	**1,221,920**
Gas Fuel +50%	**3,419,664**	3,451,880	**8,163,504**	8,354,208

- Under many scenarios natural gas consumption would increase significantly as shown in Graph 7. Currently natural-gas-fired generators only provide about six percent of the energy consumed as shown in Graphs 2-6. Under the Base Case, that percentage increases to about 11 percent of the energy consumed.

- Coal consumption varies between scenarios, but as shown in Graph 8, the increase is either moderate or remains level in terms of the MWhs produced. Most energy is currently generated by coal-fired generation as shown in Graphs 2-6 and under every set of contingencies and scenarios, coal continues to be the largest fuel source for generation used in Minnesota.

III. TRANSMISSION

As discussed above in the introduction, in this section of the Report, the ORA provide a brief discussion on each of the major transmission assessments, studies and planning efforts currently underway in Minnesota, the five state, the region, and the eastern U.S. that will or will likely impact Minnesota in the coming years. Each of these studies comprises a very large, detailed body of work. However, for this report, only a very brief high-level discussion is provided of each. Websites are provided for most of the studies where much more information can be attained

1. MINNESOTA STUDIES

1a. Minnesota—2004 Xcel Wind Integration Study

This study was undertaken in 2004 and was one of the first of its kind in the U.S. Minnesota was one of the first States in the U.S. to have a renewable energy focus when it passed its original Renewable Energy Objective, which constituted a goal of 10 percent of the customer usage in the State coming from renewable generation sources by 2015. Since wind generation was, at the time, a new generation technology that, by its nature, impacted the reliability and operation of the transmission system, the ORA performed this study to ascertain the impact (quantified as a cost) to Xcel's transmission system if ten percent of Xcel's load were met with wind generation. The study results concluded that wind generation's impact at that level would add a cost impact of approximately 4.60 cents per MWh of wind energy to mitigate grid reliability concerns stemming from the variability and uncertainty of wind generation, either through employing "load-following" generation using another fuel source to "fill in" when the wind is not blowing or in using the generated energy flowing on the grid to act as "equalizing" or load-following generation. At the time of the study, Xcel indicated that it intended to use this study value in planning and negotiating purchased power agreement with wind generation developers.

1b. Minnesota—2006 Minnesota Wind Integration Study

After the results of the Xcel study (above) were released, interest grew for a study to expand the Xcel study to a study of what wind generation's impact would be on the transmission system covering the entire State. In December 2005 that study began. It was based on improved understanding of modeling the impacts of the variability and the uncertainty of wind generation and included on current information from all of the transmission owners in the state and updated the Xcel information from the first study. The assumptions were the similar (studying the impact of 15, 20, 25 percent of all customers' load in Minnesota being met with wind energy). The study found that expanding the footprint from Xcel's service territory to the entire state allowed for more load-following opportunities by either other generation resources or the broader energy grid. The study concluded that the addition of wind generation to supply 20% of Minnesota retail electric energy sales can be reliably accommodated by the electric power system if sufficient transmission investments are made to support it. The cost of wind generation's impact on the grid was found to range over approximately \$2.11 to \$4.41 per MWh of wind energy. This is a total cost and includes the cost of additional reserves and costs related to the variability and day-ahead forecast error for wind generation.

1c. Minnesota—Biennial Transmission Studies

With the continued acceleration of wind generation development in the state, law and policy makers recognized the need for a formal, transparent, ongoing review and update of Minnesota's lower voltage transmission infrastructure as well as an identification of needed improvements to maintain the reliability of the lower voltage system and the owners' plans for constructing those improvements was recognized. Minnesota law[16] requires any utility that owns or operates electric transmission lines in Minnesota to submit a transmission projects report with the PUC on November 1 of every odd year. The next report is due on November 1, 2009. The main purpose of this transmission planning requirement is to inform the public of transmission issues in the region and to enable regulators and the public to track development of proposed solutions to these transmission issues

Also during the last few years, it became apparent that having to comply with a full CN process for small transmission projects was not warranted. As such, a law was passed to allow utilities to combine their smaller projects into their combined Biennial Transmission Plan on behalf of all of the utilities. Those projects included in the report, that would normally be subject to the requirements of the statutes regarding CNs found in Minn. Stat. 216B.243, could elect to provide evidence of their need within the Biennial Transmission Plan process and receive basically the same approval in the Biennial Transmission docket as the project would have received if it had gone through a full CN proceeding. To date, the PUC has approved the need for two projects through this alternative process.[17]

1d. Minnesota RES Update Transmission Study, Southwest Twin Cities to Granite Falls Upgrade Study, & Capacity Validation Study

The Minnesota utilities have also been assigned study tasks by the legislature. In 2007 the Minnesota transmission owning utilities were directed to analyze and identify specific transmission solutions for interconnection and delivery of the renewable energy resources necessary for the load serving utilities to comply with the requirements of Minnesota's Renewable Energy Objective (now a mandated Standard.) On November 1, 2007 the utilities filed their first report with the PUC. This initial report stated that existing and planned transmission, would be sufficient up until the REO/RES milestone in 2016. However, the initial report noted that further transmission infrastructure additions would be required to meet the future REO/RES milestones.

In March 2009 the Minnesota Transmission Owning Utilities (MTOs) released final reports on a set of studies to identify transmission needed to support the Minnesota Renewable Energy Standard and to support regional reliability. These transmission studies were part of the RES requirements of the Next Generation Act of 2007.

[16] Minnesota Statute 216B.2425
[17] The Tower and Badoura projects were approved by the Commission in the 2005 Biennial Transmission Docket No. E999/TL-05-1739.

Three studies were released in two volumes. The first volume includes the *Southwest Twin Cities – Granite Falls Transmission Upgrade Study* (the Corridor Study) and the *Minnesota RES Update Technical Report* (the RES Study). The Corridor Study confirms that the existing 230 kV line in this corridor is a key limiter to increasing generation delivery between areas west of the Twin Cities and load centers in Minnesota. The RES Study investigates and recommends future transmission alternatives to increase transmission delivery beyond that enabled by the proposed Corridor project.

The second volume contains the *Capacity Validation Study* (the CVS Study). The CVS study examines in aggregate several specific transmission projects (including CapX Group I as proposed, CapX Group I upsized, the Corridor Study facilities, the RES Update Study Facilities, and the Big Stone II transmission) which have been previously studied and proposed individually. The results of this study provide an estimated range of additional generation that can be added by various combinations of transmission projects.

Key findings of the studies include:

- Upgrading the existing 230 kV transmission line between Granite Falls and southwest Twin Cities to a double-circuit 345 kV line (the Corridor) can provide significant new transmission capacity (approximately 2000 MW) and regional reliability benefits in the 2016 time frame. Associated underlying lower voltage system upgrades are also needed.

- Constraints in the grid in western Wisconsin, along with interface loading levels along the Minnesota – Wisconsin border, limits the transmission system's ability to deliver more generation from Minnesota and further points west. Following the Corridor upgrade (and the associated underlying upgrades), a new 345 kV line is needed in Wisconsin from La Crosse to Madison. Adding the Wisconsin line after the Corridor project enables approximately an additional 1600 MW of transmission capacity (about 3600 MW for both projects) and could be important for regional stability at high levels of wind generation.

- The CVS Study results confirm the following transmission project priorities: 1) CapX Group I, 2) the Corridor project, 3) La Crosse to Madison 345 kV, and 4) Upsizing the CapX Group I projects (the timing could support initial construction and operation of Group I as double circuits).

Due to reduced projections for load growth and to greater than expected outlet capability for the studied facilities, it is not yet clear when these lines will move forward in the regulatory process. It is possible that some of the newly identified facilities will move forward based on regional needs.

The studies are posted at http://www.minnelectrans.com/ .

1e. The Dispersed Renewable Generation Study, Phases I and II

The ORA was charged by the legislature in 2007 to perform a two-phase Dispersed Renewable Generation study (DRG Study.) The DRG Study consists of an assessment of the transmission system throughout Minnesota with an eye toward identifying locations where unused transmission capacity may exist that could support the construction of a smaller renewable generation projects (10 to 40 MW) without incurring additional transmission costs. The common name for this study and for the desired available transmission locations became known as the "Sweet Spot" study. The study obligation required that 600 MW of potential DRG sites should be identified in Phase I and an additional 600 MW should be identified in Phase II.

Such a study had never been done before—in Minnesota or anywhere in the U.S. at the time. This study now required transmission staffs from the utilities to share data and to collaborate on detailed engineering studies of large areas of Minnesota's transmission system. The studies benefited from a stellar assembly of national, regional, and state technical experts representing national energy laboratories, wind and community energy advocates, the Midwest ISO, and Minnesota utilities. This Technical Review Committee, appointed and led by the Office of the Reliability Administrator, reviewed and guided the work of the study team.

The Phase I study met the statutory deadline of June 16, 2008 and produced a ground-breaking and informative study showing. through extensive analysis, that even dispersed renewable generation can have substantial impacts on the electric grid. Due to constrained transmission overall in the State, the majority of the locations that were identified in Phase I were in the southeastern and southwestern parts of Minnesota. Since the release of the Phase I report, many of the identified sites have been "claimed" by interconnection requests.

Immediately after the Phase I report was issued, plans began for Phase II, identifying an additional 600 MW of locations dispersed around the State where small (10-40 MW) renewable energy projects could potentially be sited along with identifying transmission upgrades and costs required for that 600 MW. The Phase II study was completed and issued on September 15, 2009, again meeting the statutory deadline. On the same day, a state-wide public webinar was held to present the reports analysis, findings and conclusions.

The Phase II work initially identified that there were limited locations in the state that could accommodate 10-40 MW of generation without incurring some amount of transmission investment. As such, the study team went on to identify and include certain assumed transmission projects in the Phase II study then focused on locations that could potentially accommodate generation without incurring major transmission investments. In fact, several major transmission projects, including major portions of the CapX set of transmission lines, with (costs approaching $1 billion and) estimated in-service dates of 2013 (the date of this Phase II study) were included in the transmission model's base case as well as requiring an additional $121 million in further transmission upgrades to the regional grid were all needed to site this 600 MW. This study does not address the allocation of or responsibility for any such transmission investments.

After adding the proposed transmission projects mentioned above, the Study identified locations in each of the study's five regions of the State (Northwest, Northeast, West-Central, Southwest, Southeast) but stated that siting 600 MW in these (or other locations) would depend, not only on "local" (close to the generation) transmission upgrades, but on larger, regional transmission construction as well. The bottom line of the Phase II study is that, after rigorous expert engineering assessments, the lower and higher voltage transmission grid is essentially constrained in Minnesota when viewed in aggregate statewide.

Again, as with the locations identified in Phase I, if renewable energy developers wish to pursue the use of these locations, the developers must work with the owners of the interconnection transmission and with MISO to ascertain whether the identified areas would, indeed, meet the specifications contained in MISO's FERC-approved tariff and who would be responsible for the required transmission upgrades.

The full reports for both phases of the DRG Study may be found at: www.energy.mn.gov.

2. MINNESOTA AND ITS NEIGHBORING STATES

2a. The Upper Midwest Transmission Development Initiative (UMTDI)

Earlier in 2008, the Governors of Iowa, Minnesota, North Dakota, South Dakota and Wisconsin approved the creation of an interstate collaborative transmission process. Specifically, the collaborative was initiated to foster the development of transmission across the five states primarily for grid reliability and to facilitate the development of renewable energy, specifically wind, in the amount required to fulfill the state renewable energy standards existing within the five states (approximately 15,000 MW). MISO agreed to provide transmission planning and modeling expertise to this effort.

The UMTDI Executive Team, comprised of a Governor's Office Representative and a Public Utilities Commissioner (and support Staff) from each state reviewed a number of options and chose two options for locating renewable generation in general areas throughout the five states. As of this writing, MISO is conducting transmission modeling and testing on the two UMTDI options to identify general transmission requirements to deliver power from the chosen generation areas in the five States to the designated renewable mandate States (primarily Minnesota and Wisconsin.) Further UMTDI information is housed at the Organization of MISO States' website: www.misostates.org.

2b. Upper Great Plains Transmission Development Coalition (UGPTDC)

Before the beginning of other transmission initiatives discussed in this report, a group of utilities, wind developers, and transmission reliability organizations in the Dakotas and Minnesota organized to promote the development of wind generation in the three states and to discuss how wind generation, with its intermittent nature, can be interconnected to the transmission system while still maintaining grid stability and reliability. The UGPTDC continues to meet semi-annually (usually spring and fall) and is monitoring all of the other studies and initiatives now going on with an eye on where they may best direct their group's expertise. Further information may be found at:

3. MISO REGIONAL STUDIES -- WESTERN AND EASTERN REGIONS

Further information on many of the MISO-related studies below may be found on MISO's website at http://www.midwestmarket.org/page/Planning.

3a. Narrowly Constrained Area and Congested Flowgate Studies

MISO has been implementing two separate studies that focus on identifying specific transmission constrained areas across MISO's footprint. The first of the two studies, the Narrowly Constrained Area study began as a response to MISO's Independent Market Monitor (IMM) Each FERC-regulated independent system operator (ISO) has an IMM on-site at the ISO. The IMM is a contractor for FERC and not answerable to the ISO. The IMM's job is to monitor market transactions and the configuration of the market and of the grid to ensure that no situation leads to market manipulation or market power issues by any market participants.

Within the past eighteen months, MISO's IMM, Dr. David Patton, identified certain areas on MISO's transmission footprint in which power flow constraints were sufficiently severe as to potentially impact the market. Dr. Patton was clear that he did not see any evidence of market manipulation or market power but he believed that the cited constrained areas were severe enough to potentially allow such damaging actions in the future.

Upon receiving this report, MISO initiated a study of the constrained areas to ascertain the degree of the constraints, the costs that the constraints impose on the market and the costs associated with adding facilities to relieve the constraints. The study is completed. Proposed projects are in the detailed interconnection study phases with the goal to add these proposed facilities to MISO's annual Midwest Transmission Expansion Plan (MTEP). There are two cited constraints in Minnesota—the east edge of the Buffalo Ridge and between the Twin Cities and Duluth. There is also a constraint in northern Iowa and northwestern Wisconsin that impact Minnesota's grid operations.

The other study, the Congested Flowgate Study (CFS), was instituted by MISO in 2008 as an annual study of currently congested transmission areas. The CFS goes further to also use computer modeling to show if such areas are likely to continue to be congested in 2014. After much testing and stakeholder vetting, MISO released a list of the fourteen most congested flowgates in its footprint. For these flowgates net benefits would be realized if construction steps were taken to alleviate the congestion. Minnesota has the dubious distinction of having the numbers 4 and 5 top congested areas (number 1 is in eastern Ohio, number 2 is in central Illinois and number 3 is just east of Chicago in Indiana on the tip of Lake Michigan.) Minnesota's number 4 congested areas is on the west edge of the state between the cities of Morris and Ortonville and number 5 is close to the southern edge of the state close to Fairmont. MISO and its members are now putting together congestion mitigations plans to identify the best course of action to alleviate these constraints within all of the other transmission planning efforts currently going forward (such as those listed herein).

3b. Regional Generation Outlet Study (RGOS) – Phase I Western Region

Almost half of the states in MISO's footprint have some sort of renewable energy mandate. Rough estimates state that there are requirements for 23,000 MW of renewables just to meet mandated renewable energy standards in Minnesota, Wisconsin, Iowa, Illinois and western Indiana. Each of the states' renewable mandates has different provisions but all will likely require some type of new transmission construction to deliver the renewable power to the customers. As such, around eighteen months ago, concurrently with the above discussed Narrowly Constrained Area Study, MISO embarked on a two-phased study. The Regional Generation Outlet Study, Phase I (RGOS Phase I) has two main tasks. The first task is to identify renewable energy resource areas or zones within each renewable mandate state as well as throughout the MISO footprint. The renewable zones have been identified. Second, these renewable generation zones are then used to analyze the size, type, and timing of transmission facilities that will likely be needed to connect the zones to the load centers sufficiently to fulfill the states' renewable mandates under certain economic conditions. MISO is finishing up the transmission work for Phase I. The RGOS Phase I renewable generation zones were also employed as a start for the UMTDI in choosing the generation zones in the five states (see discussion above.)

3c. Regional Generation Outlet Study (RGOS) – Phase II Eastern Region

Within about the last four months the RGOS Phase II has begun. This study will duplicate the process of RGOS Phase I for the eastern part of MISO's footprint. Rough estimates state that 35,000 MW of renewable energy is needed to satisfy the renewable requirements of the eastern MISO states of western Illinois, western Indiana, northern Missouri, Michigan, Ohio and parts of Pennsylvania and Kentucky. It is too early in the study to provide any findings at the time of this writing.

3d. Regional Wind Integration Studies

In the Spring of 2009 the Midwest ISO launched a wind integration initiative with the goals of ensuring reliability, ensuring an efficient and effective market, and ensuring a level playing field for all market participants.

MISO and its stakeholders are currently working to study and analyze identified issues identify different technical impacts that significant amounts of wind generation can have on the regional transmission grid's safety and reliability and markets. The studies are also investigating how the grid can be controlled and be operated with more flexibility to better accommodate the interconnection of large amounts of wind generation and how to maintain the stability and the reliability of the grid as large amounts of intermittent energy cycle on and off outside of MISO's control.

The Midwest ISO is working with stakeholders to develop high level policy recommendations in the fourth quarter or 2009, develop detailed wind integration business rules in the first quarter of 2010, and then file wind integration tariff changes in the second quarter of 2010.

4. THE EASTERN U. S. ELECTRIC INTERCONNECTION STATES

4a. The Joint Coordinated System Plan 2008 (JCSP 08)

The Joint Coordinated System Plan 2008 (JCSP 08) analysis developed, with participation of most of the major transmission operators in the eastern United States, a conceptual regional transmission and generation system plan for a large portion of the Eastern Interconnection in the United States. This initial effort at interconnect-wide transmission planning focused on two scenarios that expand transmission and generation opportunities out to the year 2024: 1) a Reference Scenario, and 2) a 20% Wind Energy Scenario in support of the U.S. Department of Energy's Eastern Wind Integration and Transmission Study (EWITS).

The JCSP08, completed and release in early 2009, is the first inter-regional planning effort to involve most of the major transmission operators in the Eastern Interconnection. The study represents the collaborative efforts of the Midwest ISO, SPP, PJM, TVA, MAPP and several southeast U.S. transmission operators. The New England and New York areas are also included in the study analysis. Most other transmission studies address much smaller regional footprints.

The study's findings provoked a storm on controversy, particularly among the New England States. Certain Eastern States complained that they did not like the study's premise of only looking at delivering Midwest-sited wind energy to the east coast rather than assuming that renewable energy would be developed locally . The same states have recently released their own regional study touting on-shore and off-shore wind energy to fuel their renewable needs. It is assumed that the JCSP, the New England regional study and all other major such studies will be included in the Eastern Interconnection Planning Coalition study described below.
Further information on the JCSP 08 Study may be found at: http://www.jcspstudy.org/.

4b. The Eastern Wind Integration and Transmission Study (EWITS)

The Eastern Wind Integration and Transmission Study (EWITS) is one of the largest regional wind integration studies to date. The study was initiated in 2008 to analyze the operating impact of up to 20 to 30% of wind energy on the power system in the Eastern Interconnect of the United States. The key tasks in the EWITS Study are wind data development, transmission analysis, and wind integration (operating impacts) analysis.

EWITS has four scenarios of future wind penetrations (three 20% wind energy scenarios and one 30% wind scenario) ranging from using higher capacity factor wind power in the Midwest with more transmission build-out to more emphasis on "local wind". The high capacity factor wind power scenario requires a significant build-out of high voltage transmission to deliver wind power from the Midwest to load centers on the east coast. The "local wind" scenario shows that offshore wind is needed for a 20% wind penetration . Scenario four, with 30% wind energy, requires the large transmission build-out, use of high and low capacity factor on-shore wind power, and significant amounts of offshore wind power.

For all four scenarios, a significant transmission build out is required. Modeling results to date show that 20% wind energy is possible in the Eastern Interconnect. EWITS phase I will be completed in the fourth quarter of 2009. It is anticipated that EWITS will continue to build on the knowledge gained in Phase I with a Phase II study in 2010.

Further information may be found at: http://wind.nrel.gov/public/EWITS/

4c. The Eastern Interconnection Planning Collaborative (EIPC) ("Module A") and The Eastern Interconnection States Planning Council (EISPC) ("Module B")

DOE also noted the concerns of the eastern states regarding the JCSP. When Congress and the President enacted the American Recovery and Reinvestment Act (ARRA) with its accompanying funding, DOE put together a two-part funding opportunity (DE-FOA-0000068). The first part (termed "Module A" by DOE) provides for funding to the ISO's and reliability organizations in the Eastern Interconnection to collaborate on assessing existing transmission facilities in each state and then conduct transmission planning to link or upgrade of otherwise fortify the transmission in each state and region for the benefit of the entire Eastern Interconnection. The Module A Group filed their grant application on September 14, 2009.

The second part of the funding opportunity ("Module B") allows energy leaders in each of the forty Eastern Interconnection states (represented by a state energy regulator and a Governor's representative from each state) to gather as one entity and apply for funding to collaborate on transmission planning throughout the entire forty states. Prior to this time, certain groups of states had collaborated on transmission planning (UMTDI, discussed above, is an example) but collaboration among all of the states had never been attempted before. The states' designees have met several times over the course of the past four months and have developed a formal grant application which was also filed with DOE on September 14, 2009. The states expect that any award monies will be provided by DOE around January 1, 2010. At that time the states will become active in working with and providing guidance to the Module A transmission assessment and planning and, in addition, will conduct other analysis to inform the process. Until funding is made available to the EISPC ("Module B"), more information may be found on the Organization of MISO States website at: www.misostates.org.

5. EMERGING TECHNOLOGIES IMPACTING THE TRANSMISSION SYSTEM

Today, much attention is given to a new wave of energy technologies, technologies which may increase or decrease energy demand, primarily Smart Grid and Plug-In Hybrid Vehicles. Although these new technologies are discussed a great deal, most of that discussion surrounds potential technologies that not only provide real-time information to retail customers but also enable them to modify their immediate behavior to change the amount or timing (or both) of their own energy use. Discussion about the availability and use of such information makes sense because it is the information that is expected to be visible to customers and the general public. What is not so evident is all of the investments and actions required by the retail utilities, wholesale generation and transmission owners and grid operators to enable that end-use "public" information to be available. This section provides a short discussion of the "not so public" requirements of emerging energy technologies.

Traditional energy delivery was fairly simple and straight-forward. Utilities planned as to what energy generation and delivery facilities would be needed for their own customers' needs into the future and constructed those facilities. Also, if utilities found themselves temporarily in need of electricity to serve their customers over the amount provided by their own facilities, specific solicitations had to be made neighboring utilities.

Those straightforward planning methods changed dramatically in the last few years with the advent of federal policies and actions that created independent entities charged with operating an open impartial energy grid and market, coupled with states' enacting public policies regarding energy conservation and renewable energy. These new forces fundamentally changed energy planning and energy provision for retail and wholesale generation and transmission utilities.

Adapting the old acquisition processes and habits of thought to the new energy world plus putting energy planning and procurement on a solid path into the future are the basic underpinnings for all of the above-discussed planning proceedings currently occurring in the state, region and nation. While all of this planning and cost allocation work proceeds, the participants are also keeping in mind this next wave in emerging technologies, primarily "smart grid" and "plug-in hybrid vehicle" technologies. This next generation of technological advances is seen as beneficial in that these individual technologies would enable individual energy customers to increase and decrease their energy use in real time. This customer benefit comes with a price, of course, for customers and their utilities to purchase and install the technologies.

As these new technologies develop and become more widespread, they create the potential for a loosening or even loss of planning and operational capability by utilities and grid operators who still have the charge of maintaining a safe and reliability energy grid. At this time, neither of these advanced technologies has been put into use sufficiently to be able even to guess, let alone forecast with accuracy, customers' responses that could result in potential impacts to overall energy planning, grid operation or the energy market. That, as explained earlier, is why these technologies could not be reasonably factored into all of ORA's modeling discussed in the generation portion of this report. Because the impacts cannot be ascertained, it may be desirable for today's policies to be flexible enough to adapt when the impact of the changes is better defined.

Even though these new technologies' impacts cannot yet be ascertained, retail and wholesale power providers and grid operators are beginning to respond to presumed future challenges arising from future wide-spread use of these new technologies while still providing safe, reliable service. At the present time, energy utilities, wholesale generation and transmission providers and grid operators are embarking on funding investments in advanced computer capabilities and applications, real-time communication devices and equipment retrofits.

Two clear examples are in process currently. At their August 2009 meeting, the Board of Directors of MISO addressed two multi-million dollar requests by MISO. Both requests focus on advancing MISO's and its energy provider members' electronic capabilities in order to enable national and state public policy mandates promoting renewable energy development, energy efficiency, demand response and other measures plus anticipating wide-spread development of new technologies such as smart grid and plug-in hybrid vehicle needs.

The first request resulted in the Board's approval of a proposal made jointly by MISO and several of its utility and transmission owner members to spend $44.5 million, beginning in 2010, to purchase and install 125 phasor measurement units (PMU) and associated phasor data concentrators (PDC) modules in members' substations that would enable the members' and MISO's grid control room operators to monitor power flowing through each of the substations on a real-time basis. This level of specific monitoring has never been required before; however, this advanced level of information will be required as smart grid and plug-in hybrids become more wildly used. Even though such widespread usage may still be years away, MISO and its members are making this move now in order to apply to the DOE to compete for a federal "stimulus" refund of 50 percent of the $44.5 million.

MISO's second funding request is a preliminary multi-million dollar capital-asset request to construct entirely new computer centers to house MISO's expected electronic expansion required in the years to come. This request, spread over three years, is based on expected future computing requirements resulting from today's and tomorrow's public policy energy provision drivers and technologies and is an example of building today the flexibility required to adapt to tomorrow's reality

IV. SUMMARY AND CONCLUSION

The lifestyles and economy enjoyed by the citizens and businesses in Minnesota, the Midwest and the U. S. depend on reliable, reasonably priced, environmentally sensitive energy. Also, Minnesota's economy and citizens continue to rely heavily on electric generation for a variety of needs such as lighting, refrigeration, industrial processes, computers, entertainment, transportation, hospital care, and so on. As demand for electricity grows beyond the capacity of existing generation, more generation must be added to meet the needs of Minnesotans. As these needs are identified, energy policies in Minnesota and nationwide continues to critically important and present significant challenges to plan for facilities to meet customers' needs while complying with federal and state existing and expected regulations that impact such planning and construction. The potential of greenhouse gas legislation, the integration of renewable generation, and the investments required in transmission infrastructure to accommodate additional generation and policy preferences all present significant issues that must be carefully considered when determining Minnesota's energy future. To assist policy makers in making informed decisions, the Minnesota Legislature passed Section 16 of the Next Generation Energy Act of 2007 which requires the Office of the Reliability Administrator (ORA) to prepare a Resource Assessment to be submitted to the Minnesota Legislature. Major findings of the ORA's study include:

<u>GENERATION</u>

- Whether a 1.5 percent or lower 1.0 percent DSM goal in achieved, significant generation additions are anticipated in Minnesota during the 2008-2025 time period. The type of additions added is heavily dependent on the assumptions pertaining to fuel type price, capital costs, and emission costs used. The number of 500 MW coal baseload units added varies from zero to nine. The Base Case for Scenario 1, which assumes RES compliance and achievement of a 1.5 percent conservation goal, results in a coal unit addition in 2024. At least one coal unit is added in 38 of the 56 scenarios and contingencies run in the study.

- The RES is cost-effective under 32 of the 56 scenarios and contingencies run in the study, as shown below:

Present Value Societal Cost - Difference from Base (000s $)

Lower Cost in Bold

	Scenario I	Scenario II	Scenario III	Scenario IV
Base Assumptions	**0**	180,040	**4,453,768**	4,623,296
\$4 CO_2	-20,048,416	**-22,762,904**	-16,007,720	**-19,037,608**
\$30 CO_2	**19,941,024**	22,487,392	**24,706,408**	27,553,648
\$45 CO_2	**42,937,408**	47,816,488	**48,092,968**	53,427,320
Capital Cost +20%	2,424,784	**1,208,384**	7,187,632	**5,922,184**
Capital Cost -20%	**-2,669,248**	-1,503,760	**1,412,336**	2,655,024
Coal K Cost +20%	**21,184**	534,752	**4,453,768**	5,118,400
Coal K Cost -20%	-490,808	**-1,263,296**	3,801,656	**2,991,224**
Coal K Cost -20% and NG Cost +20%	1,762,984	**1,416,392**	6,340,280	**6,129,496**
Coal Fuel +20%	**3,232,232**	3,826,016	**7,688,112**	8,379,328
Coal Fuel -20%	-3,287,768	**-3,611,672**	1,147,104	**682,080**
Gas Fuel +20%	**1,693,048**	1,751,656	**6,300,272**	6,353,808
Gas Fuel -20%	-2,254,560	**-2,883,576**	1,884,256	**1,221,920**
Gas Fuel +50%	**3,419,664**	3,451,880	**8,163,504**	8,354,208

- Under many scenarios natural gas consumption would increase significantly as shown in Graph 7. Currently natural-gas-fired generators only provide about six percent of the energy consumed as shown in Graphs 2-6. Under the Base Case, that percentage increases to about 11 percent of the energy consumed.

- Coal consumption varies between scenarios, but as shown in Graph 8, the increase is either moderate or remains level in terms of the MWhs produced. Most energy is currently generated by coal-fired generation as shown in Graphs 2-6 and under all contingencies and scenarios, coal continues to be the largest fuel source for generation used in Minnesota.

<u>TRANSMISSION</u>

- Additional transmission facilities will be required in Minnesota and the surrounding region to meet the Minnesota’s RES and load growth; and
- To provide a least-cost, least impact transmission system, new facilities must be studied and approved in cooperation with neighboring states.
- The creation of the open energy market and states’ environmental mandates have dramatically changed the operation of the transmission grid as well as planning and allocating the costs of new transmission facilities

- Many transmission planning processes are currently underway on a state-wide, subregional, regional and national level to forecast future transmission needs to facilitate states', and potentially national, environmental mandates as well as today open dynamic energy market.
- The emergence of new energy technologies such as smart grid and plug-in hybrid vehicles is expected to have unplanned detrimental impacts on electric transmission grid reliability and control. To facilitate these new technologies while maintaining transmission reliability, millions of dollars in electronic devices and other measures are currently planned to be installed in the next three years in Midwest transmission facilities.
- Distributed generation resources may play some role in allowing additional generation to interconnect to the transmission grid, but that role will be very small unless and until significant transmission upgrades are constructed in order to allow for additional distributed generation opportunities.

Anyone currently focusing on the topic of energy provision and usage will undoubtedly agree that massive changes are going on today and probably into the future. Such massive changes are fueled by federal and state public policies and other drivers addressing such current challenges as rising energy fuel prices, questions regarding the importation of oil, environmental questions raised by the burning of coal and other fossil fuels, potential impacts of global warming on our future, and more. Industry stakeholders and States are keenly aware of all of these changes, challenges and pressures and, as discussed above, are collaborating on actions and processes to move quickly to meet these challenges and usher in new changes. All of these efforts will naturally come at a cost; the MISO internal funding request and its grant application to DOE are just two examples of the millions and billions that will likely be required over time. However, all of these efforts and all of these costs are required to get through these energy "growing pains" and to establish new, forward looking, reliable and sustainable energy practices in Minnesota, the Midwest and the United States into the future.

/ja

List of Acronyms

CC ....Combined Cycle
CN ....Certificate of Need
CT ....Combustion Turbine
DSM.....................Demand-side management
EIA.......................Energy Information Administration
FERC....................Federal Energy Regulatory Commission
GHG.....................Greenhouse Gas
GRE......................Great River Energy
IPL........................Interstate Power and Light
IRP ....Integrated Resource Plan
kW........................Kilowatt
kWh......................Kilowatt hour
LMP ....Locational Marginal Prices
MCEA..................Minnesota Center for Environmental Advocacy
MISO....................Midwest Independent System Operator
MP........................Minnesota Power
MRES...................Missouri River Energy Services
MTEP...................Midwest Transmission Expansion Plan
MW ....Megawatt
MWh ....Megawatt hour
NYMEX...............New York Mercantile Exchange
OES ....Office of Energy Security
OTP ....Otter Tail Power
PVSC....................Present Value Revenue Requirement
RES ....Renewable Energy Standard
SMMPA ....Southern Minnesota Municipal Power Agency
Xcel ....Northern States Power d/b/a Xcel Energy

Appendix A

Initial Proposed Outline and Assumptions for Minnesota Resource Assessment

I. Data Source

The OES has obtained data from MISO used in the MTEP (MISO Transmission Expansion Plan) process that will be used to run the Strategist Capacity Expansion Model out to the year 2040. The data was reviewed by MISO stakeholders in the MTEP 2008 process. As part of the MTEP process, MISO analyzes data in three regions: West, Central, and East. The data obtained from MISO is for the West region, which includes Minnesota. To tailor the data for a better representation of Minnesota, data from utilities that do not serve load in Minnesota will be removed from the analysis. Therefore, the data that will be relied upon for the Resource Assessment will be MISO data for the following utilities, Alliant West, Great River Energy, Hutchinson, Minnesota Power, Northern States Power, Otter Tail Power, and Southern Minnesota Municipal Power Agency.

II. Proposed Scenarios

A. Forecast

The demand forecast for each of the above named utilities will be verified using the forecast reviewed by the OES in each utility's most recent Integrated Resource Plan. In addition, the inputs from MISO were provided through 2027. This will require a projection of the demand forecast data to 2040 in order to run the various scenarios through 2040.

B. Price Estimates

As explained further below, the OES intends to run contingencies for each major price assumption. The results of each scenario can be further evaluated by analyzing the impacts of contingencies. The OES proposes contingencies of a 20 percent increase and a 20 percent decrease for capital costs and the price of coal and natural gas. The OES proposed to use the Commission established 4 dollar to 30 dollar range for CO2 costs.

C. Scenarios

The OES will primarily rely on MISO's MTEP data to perform several Strategist Runs. Three futures will be developed, each consisting of three scenarios. The futures will include a renewable future, a base load future, and a natural-gas-reliant future. The expansion units available to the model include a 1,200 MW coal unit, a 1,200 MW CC unit, a 320 MW CT unit, a 760 MW IGCC unit with sequestration capability, and a 1,200 MW nuclear unit. Wind units are modeled as 300 MW additions.

1. Renewable Future

The Renewable Future will consist of three scenarios: an RES compliance scenario, an off-ramp scenario, and a no-wind scenario. In the RES compliance scenario, the model will be run to comply with the RES. This scenario is the base for the MISO provided data. MISO also included the wind additions necessary to comply with the 10% renewable requirement in Wisconsin and assumed a 5% renewable requirement in Iowa. The Wind profile used in the data provided by MISO was developed using the Minnesota Wind Study. In the off-ramp scenario, the model will add 300 MW of wind every other year to 2025, an amount less than what is required to comply with the RES. In the no-wind scenario, the model will be run so that no additional wind generation is added. OES notes its expectation that wind will be added, and, therefore, that the no-wind scenario is not a realistic projection of the future; the role of this scenario is to develop a more complete picture regarding expected costs in the upcoming time period.

2. Base Load Future

In the Base Load Future, the model will be run so that a 1,200 MW coal base load unit is selected in 2015 and 2030. Forcing the model to select base load units will allow for a cost comparison to scenarios where no base load or fewer base load units are selected. The Base Load Future will be run using the RES compliance, off-ramp, and no wind scenarios.

3. Natural-Gas-Reliant Future

In the Natural-Gas-Reliant Future, the model will be run so that a 1,200 MW gas-fired CC unit is selected in 2015 and 2030. Forcing the model to select CC units will allow for a cost comparison to scenarios where fewer natural gas fired units are selected.

D. Assumptions

Each of the major assumptions the OES proposes to use in the Strategist model are discussed below. Tables of the inputs for each assumption are attached. In addition, for each assumption a blank table entitled “Suggested Alternative Data” is provided. If a stakeholder would like to suggest data different from that proposed by the OES, the OES requests that the stakeholder provide that data and the foundation for that data in the “Suggested Alternative Data” table.

1. CO2

A value of 17 dollars per ton of CO2 will be used in the base case. This is the mid-point of the 4 to 30 dollar range established by the Commission. CO2 values of 4 and 30 dollars will be run as contingencies. CO_2 costs are adjusted by a 3% rate of inflation.

2. Natural Gas Prices

   The MISO data is based on the PowerBase 2007 value with a 4% escalation. The OES proposes to use the MISO data. For comparison, the attached tables also show the natural gas prices used in the Big Stone II proceeding and the natural gas prices from the 2008 EIA Annual Energy Outlook (AEO). In Big Stone II, the Applicants used EIA data with an adder of $0.73/MBTU and a 2.5% escalation. The $0.73/MBTU is taken from a recent study by Ernest Orlando Lawrence Berkeley National Laboratory which identified a levelized understatement of the EIA forecast price of $0.73/MBTU. Each source includes an estimate for transportation costs. The OES also proposes to run contingencies of ± 20%.

3. Coal Prices

   The MISO data contains coal prices that were provided by a consultant to MISO for each generating unit and have a 2% annual escalation. For expansion units, MISO relies on the coal prices for the Fair Station plant in Iowa. Given the recent increases in coal prices, the OES proposes to rely on data from the more recent 2008 EIA AEO. Both the MISO data and the 2008 EIA AEO data are provided in the attached tables. The OES proposes to run contingencies of ± 20%.

4. Capital Costs

   The capital cost values from MISO are based on 2006 EIA data, but have been modified through MTEP stakeholder input to reflect the increased costs which occurred at the end of 2007. The EIA value for coal, CC, CT, and nuclear was escalated by approximately 40%, then adjusted to 2008 dollars. This resulted in $/kW values of 1,835, 859, 605, and 2,493. Wind was given a 2006 price of $1,800/kW price and was escalated to the 2008 value of $1,910/kW. For IGCC, the 2008 value was set 15% higher than coal and 30% higher when sequestration is included. This resulted in a value of $2,748 per kW for IGCC with sequestration. Also, included in the attached tables, are capital costs used in the Big Stone II proceeding, and a table showing capital costs using MISO's methodology, but relying on 2008 EIA data. The OES proposes to use the MISO data for the CC, CT, and Wind units. The OES proposes to use the capital cost for coal of $2,435 per kW from the Big Stone II proceeding. For nuclear, the same factors which resulted in an increased capacity cost for coal may also apply to nuclear. The OES specifically requests stakeholder feedback on an appropriate capital cost for a nuclear unit. The OES proposes to run contingencies of ± 20%.

5. Effluent Costs

The MISO data uses PowerBase values for NOx, SO2, and Hg. The NOx and SO2 values are based on the Clean Air Interstate Rule (CAIR). The OES proposes to use the MISO data.

6. Retirement of Units

The OES proposes to run scenarios in which Monticello is retired in 2030 and Prairie Island unit 1 is retired in 2033 and unit 2 is retired in 2034.

7. Summary of Scenarios

<table>
<tr><th>Future</th><th>Scenario</th><th>CO2</th><th>NG Price</th><th>Coal Price</th><th>Capital Cost</th><th>Effluent Costs</th><th>Nuclear Retirement</th></tr>
<tr><td rowspan="3">Renewable</td><td>0 MW Wind</td><td rowspan="9">Commission Values

$4, $17, $30</td><td rowspan="9">MISO/ Powerbase

± 20%.</td><td rowspan="9">2008 EIA AEO

± 20%.</td><td rowspan="9">MISO/ Big Stone II

± 20%</td><td rowspan="9">MISO Data</td><td rowspan="9">2030, 2033, 2034</td></tr>
<tr><td>Off-Ramp Wind</td></tr>
<tr><td>RES Compliance</td></tr>
<tr><td rowspan="3">Base Load</td><td>0 MW Wind</td></tr>
<tr><td>Off-Ramp Wind</td></tr>
<tr><td>RES Compliance</td></tr>
<tr><td rowspan="3">Natural Gas Reliant</td><td>0 MW Wind</td></tr>
<tr><td>Off-Ramp Wind</td></tr>
<tr><td>RES Compliance</td></tr>
</table>

The OES welcomes stakeholder suggestions regarding any futures, scenarios, or assumptions.

Initial Proposed Resource Assessment Assumptions

Preliminary CO_2

		$/Ton	
Year	Low	Mid	High
2008	$4.00	$17.00	$30.00
2009	$4.12	$17.51	$30.90
2010	$4.24	$18.04	$31.83
2011	$4.37	$18.58	$32.78
2012	$4.50	$19.13	$33.77
2013	$4.64	$19.71	$34.78
2014	$4.78	$20.30	$35.82
2015	$4.92	$20.91	$36.90
2016	$5.07	$21.54	$38.00
2017	$5.22	$22.18	$39.14
2018	$5.38	$22.85	$40.32
2019	$5.54	$23.53	$41.53
2020	$5.70	$24.24	$42.77
2021	$5.87	$24.97	$44.06
2022	$6.05	$25.71	$45.38
2023	$6.23	$26.49	$46.74
2024	$6.42	$27.28	$48.14
2025	$6.61	$28.10	$49.59
2026	$6.81	$28.94	$51.07
2027	$7.01	$29.81	$52.61
2028	$7.22	$30.70	$54.18
2029	$7.44	$31.63	$55.81
2030	$7.66	$32.57	$57.48
2031	$7.89	$33.55	$59.21
2032	$8.13	$34.56	$60.98
2033	$8.38	$35.59	$62.81
2034	$8.63	$36.66	$64.70
2035	$8.89	$37.76	$66.64
2036	$9.15	$38.89	$68.64
2037	$9.43	$40.06	$70.70
2038	$9.71	$41.26	$72.82

Suggested Alternative Data

		$/Ton	
Year	Low	Mid	High
2008			
2009			
2010			
2011			
2012			
2013			
2014			
2015			
2016			
2017			
2018			
2019			
2020			
2021			
2022			
2023			
2024			
2025			
2026			
2027			
2028			
2029			
2030			
2031			
2032			
2033			
2034			
2035			
2036			
2037			
2038			

2039	$10.00	$42.50	$75.00
2040	$10.30	$43.78	$77.25

2039			
2040			

Preliminary Natural Gas

MISO/PowerBase

Year	$/MMBTU
2008	8.453531
2009	8.79167224
2010	9.14333913
2011	9.50907269
2012	9.8894356
2013	10.285013
2014	10.6964135
2015	11.1242701
2016	11.5692409
2017	12.0320105
2018	12.513291
2019	13.0138226
2020	13.5343755
2021	14.0757505
2022	14.6387805
2023	15.2243318
2024	15.833305
2025	16.4666372
2026	17.1253027
2027	17.8103148
2028	18.5227274
2029	19.2636365
2030	20.034182
2031	20.8355493
2032	21.6689712
2033	22.5357301
2034	23.4371593
2035	24.3746456
2036	25.3496315

Big Stone II

Year	$/MMBTU
2008	$8.75
2009	$8.38
2010	$8.25
2011	$8.01
2012	$8.06
2013	$8.04
2014	$8.31
2015	$8.49
2016	$8.85
2017	$9.37
2018	$9.53
2019	$9.72
2020	$10.13
2021	$10.35
2022	$10.83
2023	$11.31
2024	$11.83
2025	$12.14
2026	
2027	
2028	
2029	
2030	
2031	
2032	
2033	
2034	
2035	
2036	

2008 EIA AEO
(adjusted for 3% inflation)

Year	$/MMBTU
2008	$7.68
2009	$8.09
2010	$7.61
2011	$7.49
2012	$7.52
2013	$7.46
2014	$7.45
2015	$7.52
2016	$7.68
2017	$7.97
2018	$8.28
2019	$8.62
2020	$8.73
2021	$8.78
2022	$9.22
2023	$9.65
2024	$10.15
2025	$10.66
2026	$11.19
2027	$11.63
2028	$12.39
2029	$13.03
2030	$13.68
2031	
2032	
2033	
2034	
2035	
2036	

Suggested Alternative Data

Year	$/MMBTU
2008	
2009	
2010	
2011	
2012	
2013	
2014	
2015	
2016	
2017	
2018	
2019	
2020	
2021	
2022	
2023	
2024	
2025	
2026	
2027	
2028	
2029	
2030	
2031	
2032	
2033	
2034	
2035	
2036	

2037	26.3636167		2037			2037			2037	
2038	27.4181614		2038			2038			2038	
2039	28.5148879		2039			2039			2039	
2040	29.6554834		2040			2040			2040	

Contingencies:
High/Low ± 20%

Contingencies:

Preliminary Coal

Suggested Alternative Data

2008 EIA AEO

Year	$/MMBTU
2008	$1.88
2009	$1.99
2010	$2.05
2011	$2.11
2012	$2.17
2013	$2.23
2014	$2.30
2015	$2.37
2016	$2.44
2017	$2.52
2018	$2.59
2019	$2.67
2020	$2.75
2021	$2.83
2022	$2.92
2023	$3.00
2024	$3.09
2025	$3.19
2026	$3.28
2027	$3.38
2028	$3.48
2029	$3.59
2030	$3.69
2031	
2032	
2033	
2034	

MISO Data

Year	$/MMBTU
2008	$1.67
2009	$1.71
2010	$1.75
2011	$1.79
2012	$1.82
2013	$1.86
2014	$1.89
2015	$1.93
2016	$1.97
2017	$2.01
2018	$2.05
2019	$2.09
2020	$2.13
2021	$2.18
2022	$2.22
2023	$2.26
2024	$2.31
2025	$2.36
2026	$2.40
2027	$2.45
2028	$2.50
2029	$2.55
2030	$2.60
2031	$2.65
2032	$2.71
2033	$2.76
2034	$2.81

Year	$/MMBTU
2008	
2009	
2010	
2011	
2012	
2013	
2014	
2015	
2016	
2017	
2018	
2019	
2020	
2021	
2022	
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2038	
2039	
2040	

Contingencies:
High/Low ± 20%
Includes 2% Adder

2035	$2.87
2036	$2.93
2037	$2.99
2038	$3.05
2039	$3.11
2040	$3.17

2035	
2036	
2037	
2038	
2039	
2040	

Contingencies:

Preliminary Capital Costs

Proposed Data

Unit	$/kW
Coal	$2,434.77
CC	$859.00
CT	$605.00
IGCC w/ sequestration*	$3,639.98
Wind	$1,910.00
Nuclear	

*Based on MISO ratio of Coal to IGCC w/ sequestration

Big Stone Data

Unit	$/kW 2006	Adjusted to 2008
Coal	$2,295.00	$2,434.77
CC	$1,719.00	$1,823.69
CT	$1,098.00	$1,164.87
IGCC		
Wind	$1,810.00	$1,920.23
Nuclear		

MISO Data

Unit	$/kW
Coal	$1,835.00
CC	$859.00
CT	$605.00
IGCC w/ sequestration	$2,748.00
Wind	$1,910.00
Nuclear	$2,493.00

MISO Data adjusted with 2008 AEO

Unit	$/kW
Coal	$2,147.60
CC	$988.40
CT	$700.00
IGCC w/ sequestration	$3,210.66
Wind	$1,910.00
Nuclear	$3,465.00

Suggested Alternative Data

Unit	$/kW
Coal	
CC	
CT	
IGCC w/ sequestration	

Wind	
Nuclear	

Preliminary Effluent Costs

MISO/PowerBase Data

NOx	$/Ton
2008	$825.00
2009	$1,458.21
2010	$1,491.37
2011	$1,604.30
2012	$1,742.16
2013	$1,883.83
2014	$2,031.80
2015	$2,101.22
2016	$2,092.84
2017	$2,086.57
2018	$2,082.17
2019	$2,078.48
2020	$2,073.49
2021	$2,134.25
2022	$2,197.94
2023	$2,263.95
2024	$2,333.34
2025	$2,406.29
2026	$2,452.79
2027	$2,500.96
2028	$2,575.98
2029	$2,653.26
2030	$2,732.86
2031	$2,814.85
2032	$2,899.29
2033	$2,986.27
2034	$3,075.86
2035	$3,168.13
2036	$3,263.18
2037	$3,361.07
2038	$3,461.91

Hg	$/Ton
2008	
2009	
2010	$72,082,930
2011	$78,228,640
2012	$84,667,580
2013	$91,279,020
2014	$98,183,240
2015	$105,341,300
2016	$114,160,200
2017	$123,548,600
2018	$133,560,700
2019	$144,190,800
2020	$155,352,400
2021	$159,904,700
2022	$164,676,800
2023	$169,622,300
2024	$174,820,700
2025	$180,286,600
2026	$183,770,600
2027	$187,379,300
2028	$193,000,679
2029	$198,790,699
2030	$204,754,420
2031	$210,897,053
2032	$217,223,965
2033	$223,740,683
2034	$230,452,904
2035	$237,366,491
2036	$244,487,486
2037	$251,822,110
2038	$259,376,774

SO2	$/Ton
2008	$471.79
2009	$471.32
2010	$481.96
2011	$472.50
2012	$463.06
2013	$448.88
2014	$439.42
2015	$472.51
2016	$405.00
2017	$371.26
2018	$337.51
2019	$270.00
2020	$243.00
2021	$247.64
2022	$252.58
2023	$257.53
2024	$262.70
2025	$267.93
2026	$273.11
2027	$278.47
2028	$286.82
2029	$295.43
2030	$304.29
2031	$313.42
2032	$322.82
2033	$332.51
2034	$342.48
2035	$352.76
2036	$363.34
2037	$374.24
2038	$385.47

2039	$3,565.76		2039	$267,158,077		2039	$397.03
2040	$3,672.74		2040	$275,172,819		2040	$408.94

Suggested Alternative Data

2008			2008			2008	
2009			2009			2009	
2010			2010			2010	
2011			2011			2011	
2012			2012			2012	
2013			2013			2013	
2014			2014			2014	
2015			2015			2015	
2016			2016			2016	
2017			2017			2017	
2018			2018			2018	
2019			2019			2019	
2020			2020			2020	
2021			2021			2021	
2022			2022			2022	
2023			2023			2023	
2024			2024			2024	
2025			2025			2025	
2026			2026			2026	
2027			2027			2027	
2028			2028			2028	
2029			2029			2029	
2030			2030			2030	
2031			2031			2031	
2032			2032			2032	
2033			2033			2033	
2034			2034			2034	
2035			2035			2035	
2036			2036			2036	
2037			2037			2037	
2038			2038			2038	
2039			2039			2039	

2040	

2040	

2040	

Retirement of Units

Monticello	2030
Prairie Island 1	2033
Prairie Island 2	2034

MISSOURI RIVER ENERGY SERVICES®

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To: Chris Shaw

From: Raymond J. Wahle, P.E.

Date: August 13, 2008

RE: Baseload Study

In the 2008 session, the Minnesota legislature requested that a Resource Assessment/Baseload study be conducted. There are many factors that can affect the cost and reliability of a study of this nature. Just some of the things that need to be considered in a study are reliability, economics, and environmental performance. First and foremost, any plan that is put forth must have the ability to maintain the same level or reliability of the electric system in the future as the electric system provides today. Second, the cost of electricity is critically important to maintain a robust economy in Minnesota. Electric energy is a basic building block of our economy so the cost of electric energy affects all facets of life. Third, any plan put forth must meet today's environmental requirements and have the ability to adapt to possible future environmental demands.

The quality of this study is very important. This study is likely to be used by policy makers to make decisions with regard to the electric energy future in Minnesota. Policy makers cannot make reasoned decisions if the information they receive is flawed. To me, it is better to get the study right than to deliver "something" by a certain date.

Forecast Comments:

In reviewing the information provided by the Office of Energy Security (OES), it appears that certain entities were not included in the load data. For example, it is not clear if Missouri River Energy Services (MRES), Heartland Consumers Power District (HCPD), Central Minnesota Municipal Power Agency (CMMPA), or other municipal load was included in the forecasts. In order for this study to reasonably estimate the base load needs of Minnesota electric consumers, all of the load must be included in the forecast. If the OES does not have the data available to it, I suggest that they get the load data from the utilities themselves.

It appears from the discussion that significant new industrial load is also not included in the load data. Given the fact that a large taconite plant is likely to be built on the iron range, the load forecast needs to include this new load. This plant will operate 24/7 and have a large need for baseload energy. My understanding is that this plant alone will require 500 MW of baseload energy.

Given the length of the study (i.e. 2040) PHEV will be in the market place and likely use a significant amount of nighttime energy for battery charging. This needs to be taken into consideration in the forecast. Nighttime charging will increase the need for baseload facilities.

If the cars' batteries can be used to supply peak electricity during the day, then this may reduce the need for peaking capacity.

Scenario Comments:

According to the information provided for the July 30 meeting, OES is planning on three future scenarios. Given the fact that Strategist will select the lowest cost alternative based on the inputs given, why isn't the OES allowing Strategist to pick the most economic case and then forcing in units not selected in the economic case to determine the impacts of the non-optimum cases? If OES does pursue its suggested method, it is not clear how the least cost capacity expansion plan will be developed since Strategist will not be allowed to pick the lowest cost resource options.

OES is proposing to model 1,200 MW coal units and 1,200 MW combined cycle (CC) units. These units are very large compared to what utilities are actually installing. No utility in this region has constructed either a 1,200 MW coal or CC unit. Using units this large for inputs to Strategist may bias the program to not select these units. It is possible that if Strategist has the option of selecting a 1,200 MW unit to serve just a 500 MW load, it is likely to select two 320 MW combustine turbines (CT) using natural gas even though it might be more economical to install a 500 MW coal plant.

In the information provided, the OES did not state the amount of capacity that would be assigned to wind. Given the amount of wind that will need to be installed to meet the MN Renewable Energy Standard (RES), this is an important assumption. The Minnesota Wind Integration Study made an estimate of the capacity value of wind. The Midwest Independent Transmission System Operator (MISO) is proposing to use a loss of load expectation (LOLE) of one day in 10 years, which is a conservative reliability metric. Given this conservative reliability standard, it would be appropriate to use the most conservative value from the study.

The OES did not indicate the ancillary service cost for wind generation. The Minnesota Wind Integration Study determined that the cost of ancillary services for wind generation is in the range of $4 to $5/MWh. Since this study was completed prior to the run-up in fuel prices and this study assumed that about 3,500 MW of coal fired resources would be added to Minnesota, which may or may not occur, it is very likely that ancillary services for wind will be substantially higher than this. At a bare minimum, OES should estimate the cost of ancillary services for wind by increasing the $4 to $5 from the Wind Integration Study by the same percentage that the real time Locational Marginal Pricing (LMP) at the Minnesota hub has increased since the Wind Integration Study has been completed. The ancillary service costs need to be added to the cost of wind generation so that a true cost of this resource will be understood. This can easily be done using the Strategist tool.

In the Baseload Future and the Natural Gas Reliant Future, OES is proposing to force 1,200 MW plants on the system in 2015 and 2030. Having Strategist force-in units in certain years will bias the study against these particular units. A much better approach would be to limit the units that Strategist prefers so that it will then pick other units at the optimal time. For example, if Strategist prefers 320 MW CT, and OES limits the number of CT that Strategist can select it will have to pick either coal or CC units to meet the capacity requirements. This will allow Strategist to develop optimal plans with the units that it is given.

Assumptions:

It appears that OES has used different sources for the data it will put into Strategist and it appears that the data may be from different time periods. Given the recent trend in rapidly increasing fuel and construction costs, using data from different time periods will create huge problems. The old adage of garbage-in, garbage-out applies to this study in spades. Unless an internally consistent and reasonable data set can be developed, this study will be less than useless. One source of data that appears to be internally consistent is from "Increasing Costs in the Electric Markets." This was a presentation given to the Federal Energy Regulatory Commission (FERC) on June 19, 2008.

One of the most important assumptions is the forecast of natural gas prices. Recently natural gas has traded from $7/MMBtu to over $13/MMBtu. This change in price occurred within a 12-month period. In addition to this tremendous volatility, there are significant cost pressures on natural gas price. These pressures include decreasing imports of gas from Canada and the need to increase higher cost liquefied natural gas (LNG) imports and increasing use of natural gas in electric generation due to limits on coal fired power plants. Due to the high volatility and the difficulty in forecasting gas prices, a better option would be to create price bookends for gas. For example, at price X the only units that Strategist selects to add is natural gas and at price Y, the only units Strategist selects to add is coal. This method eliminates the need to predict the price of gas, which cannot really be done with any accuracy given today's volatile marketplace.

If the OES feels that it needs to start with a forecast of natural gas price, a better source would be to look at the futures market for gas prices and blend in the future prices with a long-term forecast, like the Energy Information Administration (EIA). Also, under this scenario, the OES will need to address gas volatility. Merely assuming a 20 percent price change in gas is not addressing gas volatility. Again, in a recent 12-month period, gas went from $7 to $13. This is an 85 percent increase in price!

As noted earlier, one of the drivers of the price of gas is the increased demand for gas due to electric generation. Under a carbon constrained future, the general consensus is that utilities will install increasing amounts of gas fired generation. Thus, under a carbon constrained future, gas prices will be driven upward by two pressures, the cost of carbon emissions due to the burning of gas in generators and the increasing costs due to higher demand. The OES needs to account for both causes of price increases when it runs its cases of CO_2 prices.

Capital Costs:

The capital costs for all units, except for coal, appear to be low. There appears to be a data consistency error in the capital costs. The cost for coal units was taken from a recent case, but the capital cost for the other types of units appears to be dated. This results in capital cost for all units to be low, except for coal. Given the rapid increase in construction costs, all the data needs to have the same vintage to be meaningful. Why was the capital cost of all of the units increased by 40 percent, but wind was only increased by 5 percent?

Transmission:

It appears that there are no transmission costs included in this analysis. Transmission costs have a significant impact on the delivered price of electricity. In order for the study to be meaningful, the cost of transmission must be included in the study. It is not necessary to do a transmission study to estimate the cost of transmission for generation. The recent Big Stone and CapX cases provide an estimate of the cost of transmission and an estimate of the transfer capability of the proposed projects. The cost of transmission can be estimated by taking the cost of the transmission projects and dividing it by the estimated transfer capability. The resulting cost per kW for transmission should then be added to the cost per kW of the name plate capacity of the unit being installed.

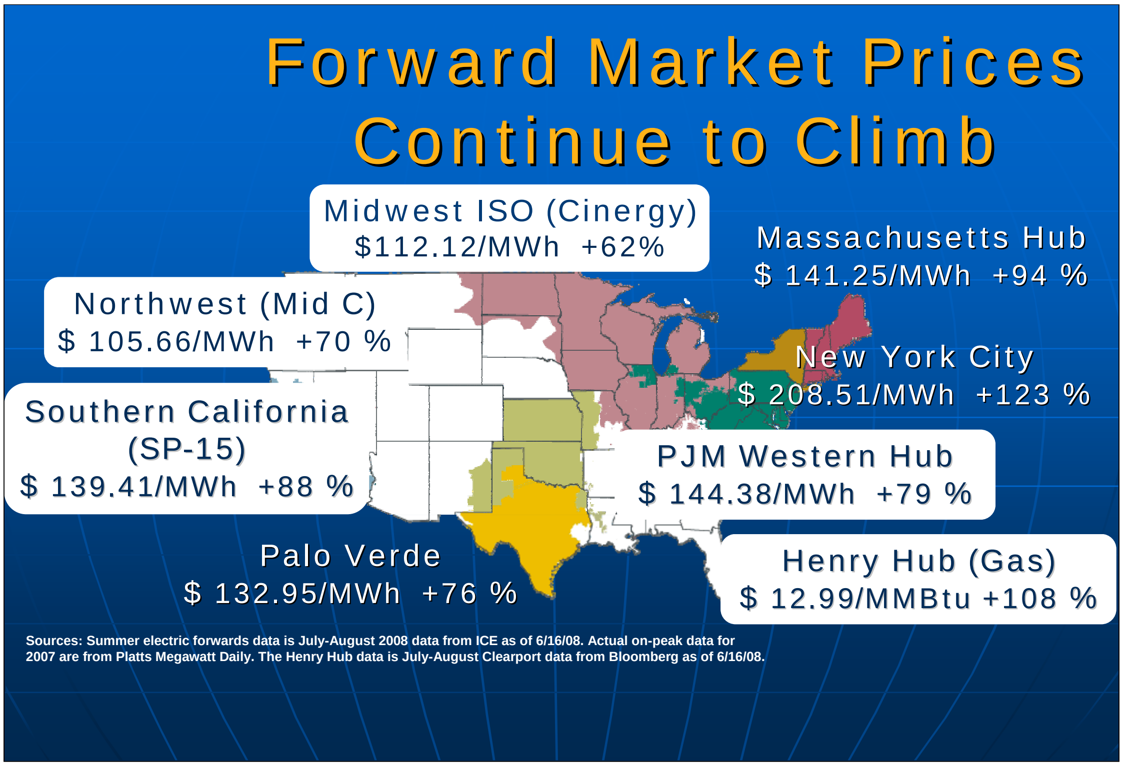
Technical Review Team

We would encourage the OES to establish a technical review team to review the data input and the Strategist runs. Should the OES establish such a technical review team, JP Schumacher would participate on that team.

Increasing Costs in Electric Markets

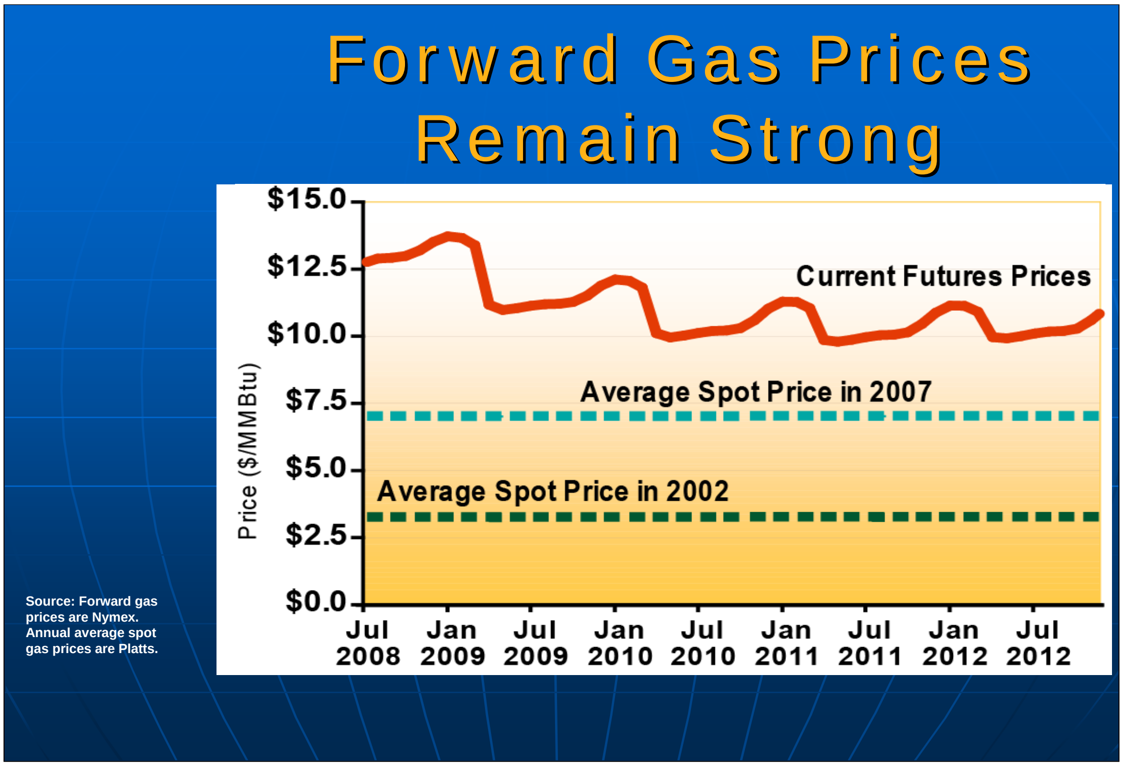
- **Item No.: A-3**
- **June 19, 2008**

Mr. Chairman and Commissioners, good morning. I am here to present the Office of Enforcement's assessment of likely electricity costs in coming years. This presentation will be posted on the Commission's Web site today.

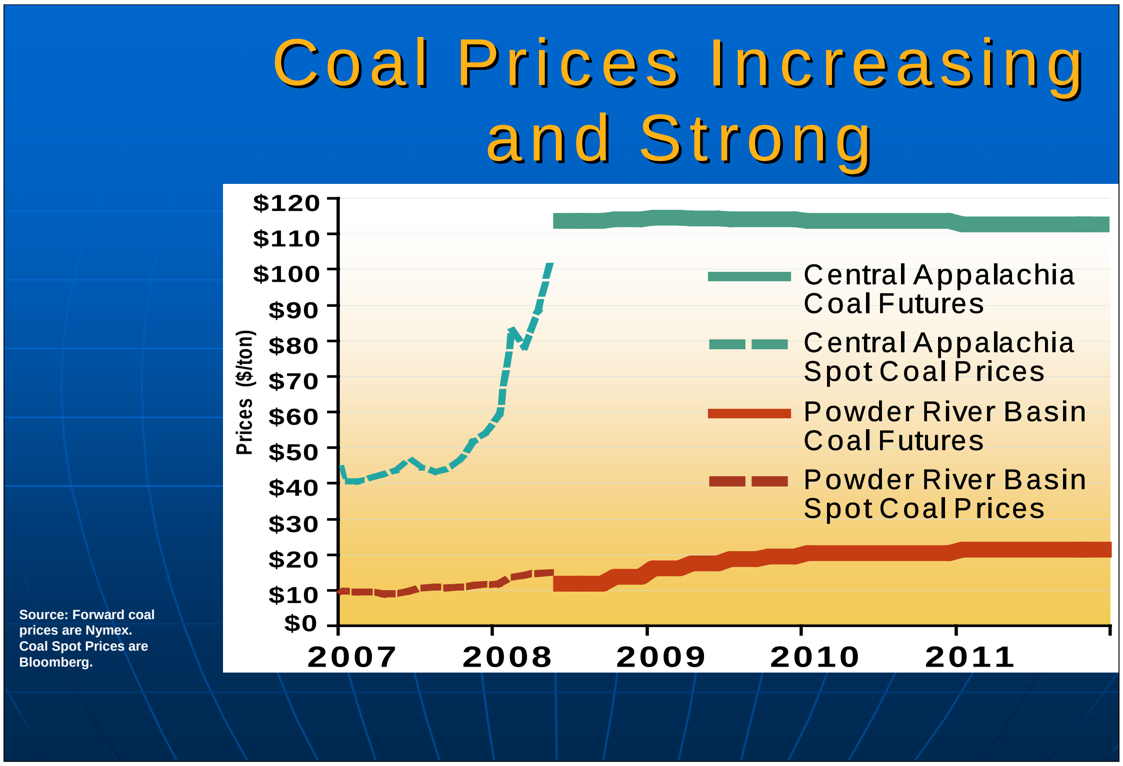


At last month's meeting, we reported that forward market prices for electric power are much higher than the prices we actually experienced last year. This trend is universal around the country. The slide shows the increases in forward prices for July and August as of this week. They have risen further during the last month as natural gas prices have continued to rise.

There is little reason to believe that this summer is unusual. Rather, it may be the beginning of significantly higher power prices that will last for years. The purpose of this presentation is to explain why that is so. The two major factors pushing the costs of electric generation higher are increased fuel costs and increased cost for new construction. These factors affect all parts of the country. That is, higher future prices are likely to affect all regions.



The primary reason for the electric power price increases this year is high fuel prices. All current market indications suggest that they will remain high. Let's look at natural gas, which often determines prices because it is so frequently on the margin. The slide shows futures prices for the next few years. The futures prices are somewhat lower for 2009 than for 2008. Even so, they are a good deal higher for all years than the prices people actually paid last year, and they are much higher than the prices many of us remember from earlier in the decade. The implication is that markets anticipate continuing high prices, even though they know that the United States has seen a significant increase in domestic natural gas production over the last year and a half. The anticipation of further high prices makes more sense when one considers the likely increase in gas demand for generation and the global nature of competition for LNG.



Natural gas is not the only important fuel in setting electric power prices. Coal still powers half of all power produced in the U.S. In some markets – the Midwest and the Southeast, for example – coal is often on the margin and plays a major role in setting average prices over time. The slide shows that the price of one key form of coal – Central Appalachian coal - has risen rapidly over the last year. Forward markets show continuing high prices for Central Appalachian coal for the next three years. This reflects, in part, the growing global market for coal and the relatively weak US dollar. Coal imports are becoming more costly and coal exports more profitable, both of which contribute to higher prices in the United States.

I should mention that other coal prices behave somewhat differently from Central Appalachian coal. For example, a majority of the overall cost for Powder River Basin coal comes from transportation rates and can be more difficult to see. Nonetheless, the implication of the prices we can see is that electric power prices are likely to increase even where coal is on the margin. This may take place somewhat differently from the way natural gas price increases flow through into power prices. Generally, companies buy coal under fairly long term contracts, so there may be a lag before the higher prices show their full effects. But the effects are coming.

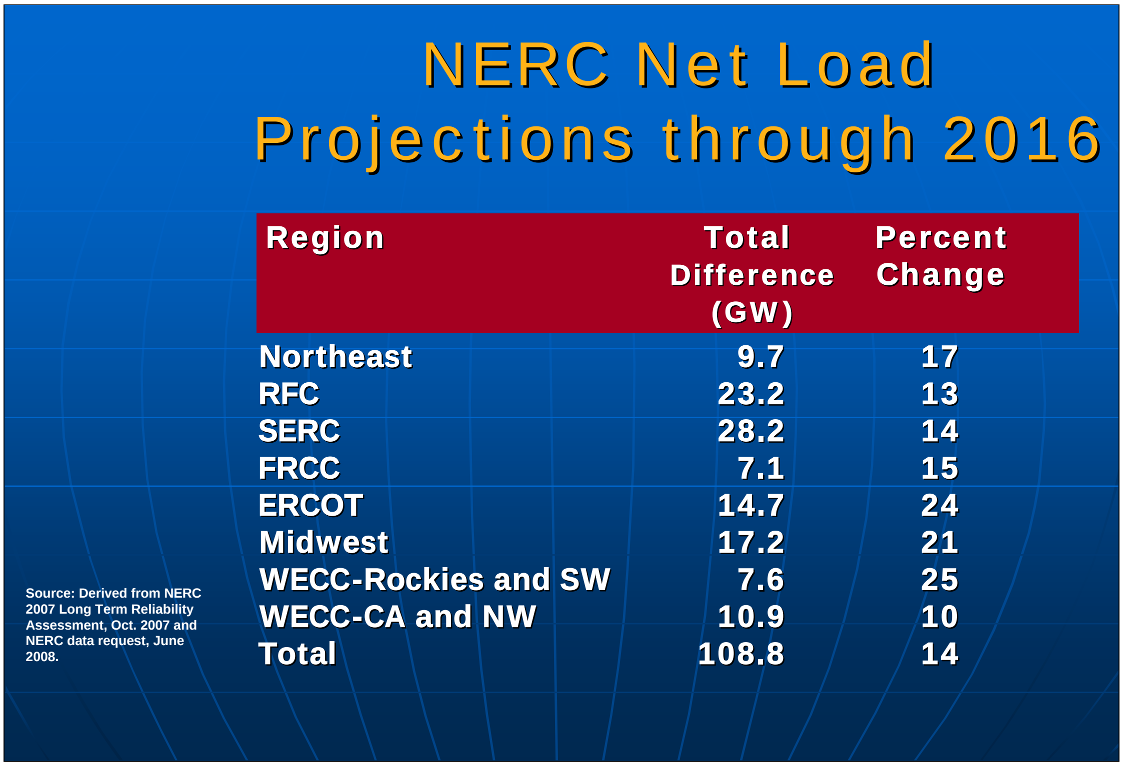
Net Natural Gas Generation by Region

(TWh)

Region	2000	2007	Difference
Northeast	66.3	103.9	37.6
RFC	41.0	64.5	23.5
SERC	86.9	150.5	63.6
FRCC	42.0	96.7	54.7
ERCOT	155.9	163.3	7.4
Midwest	44.2	62.8	18.5
WECC-Rockies and SW	28.1	77.6	49.5
WECC-CA and NW	115.4	129.7	14.4

Source: Derived from Energy Velocity (differences due to rounding).

While both natural gas and coal prices have increased rapidly, natural gas is increasingly important in every region of the country. The slide shows that even in regions where coal has historically dominated – most noticeably in SERC– natural gas usage has grown substantially since 2000, up 63.6 TWh in 2007, more than in any other region. Noticeable increases also occurred in FRCC, which has flexibility to burn either gas or oil at many facilities, and also in the Rockies and Southwest where demand continues to grow considerably.



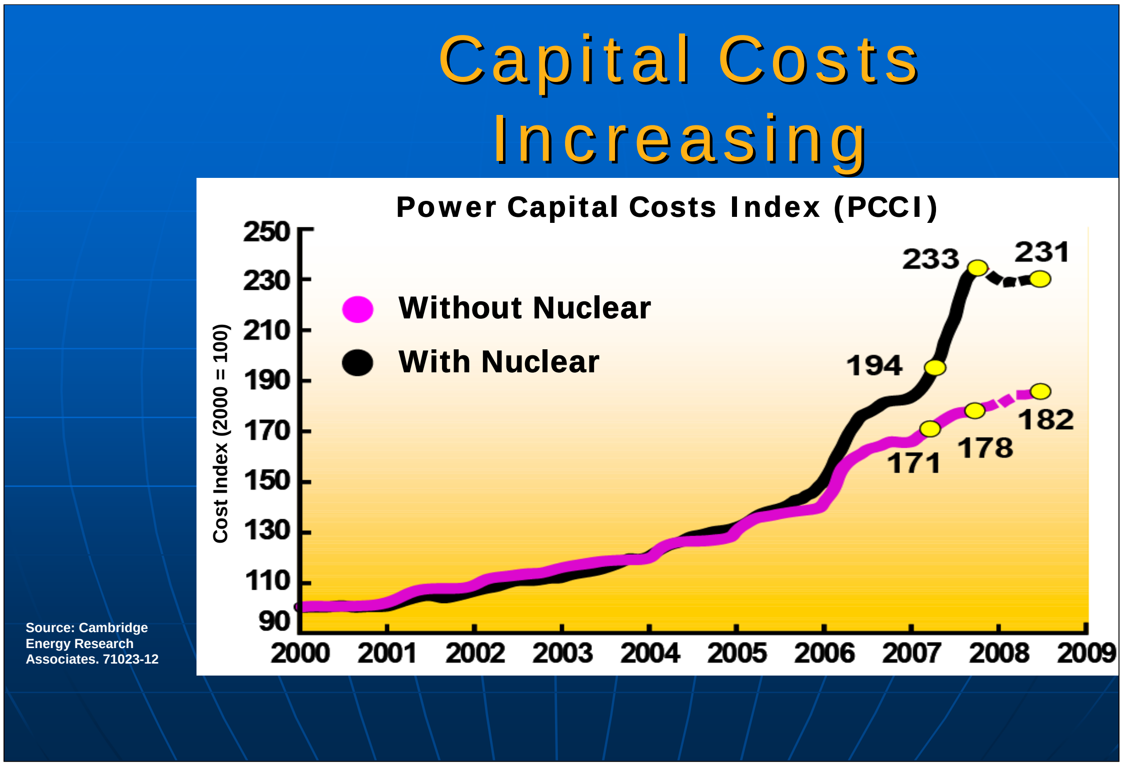
NERC Net Load Projections through 2016

Region	Total Difference (GW)	Percent Change
Northeast	9.7	17
RFC	23.2	13
SERC	28.2	14
FRCC	7.1	15
ERCOT	14.7	24
Midwest	17.2	21
WECC-Rockies and SW	7.6	25
WECC-CA and NW	10.9	10
Total	108.8	14

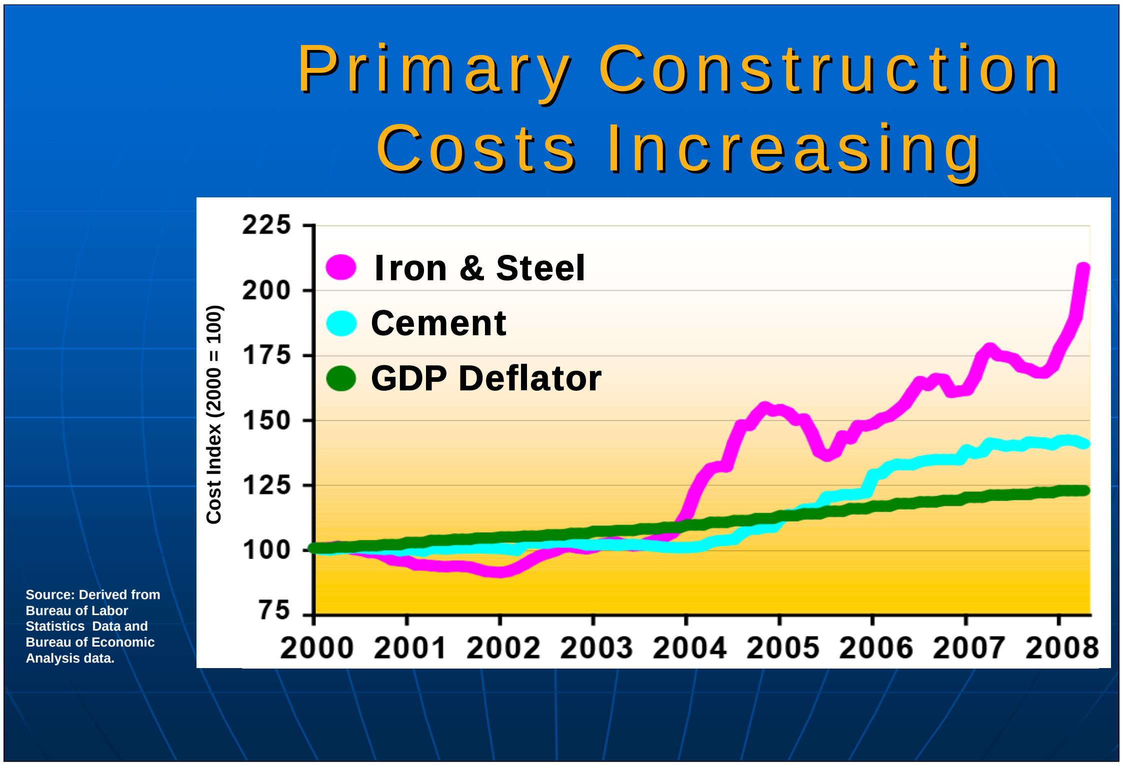
Source: Derived from NERC 2007 Long Term Reliability Assessment, Oct. 2007 and NERC data request, June 2008.

The second major factor that will put upward pressure on electric power prices is the increasing cost of new construction. This effect is particularly important because the country is entering a period when we will need to make substantial new investments, especially in generation.

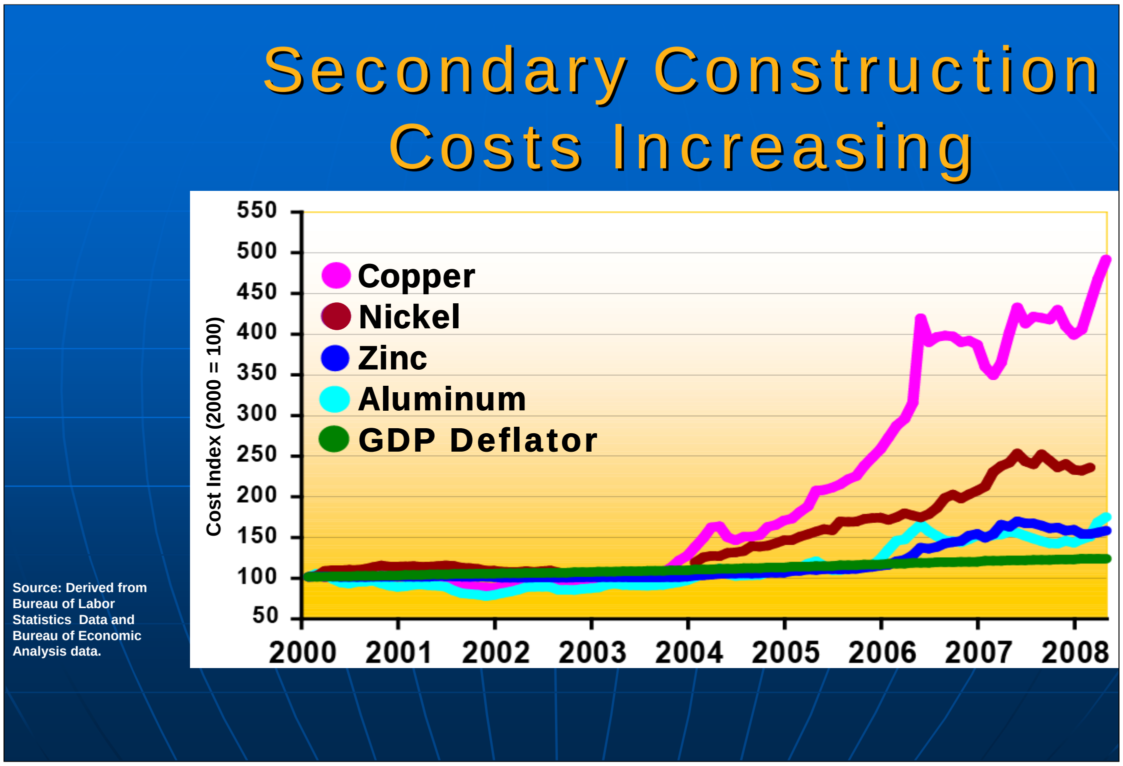
Natural gas fueled most of the last great wave of generation investment, which occurred between 1995 and 2004. In recent years, demand in most regions has gradually caught up with the capacity built around 2000. Looking forward, demand will continue to grow, and the need for new capacity will become ever more acute and ever more widespread. The slide shows NERC's expectation of peak net load growth in different regions for the next 10 years. We at the Commission are not in the business of forecasting, so I would just say this: There are legitimate reasons to be unsure about exactly how much new generation the country will need in the coming years. For one thing, higher prices will themselves discourage some power demand. Nonetheless, a significant level of demand increase seems virtually inevitable. So will be the need to build more capacity.



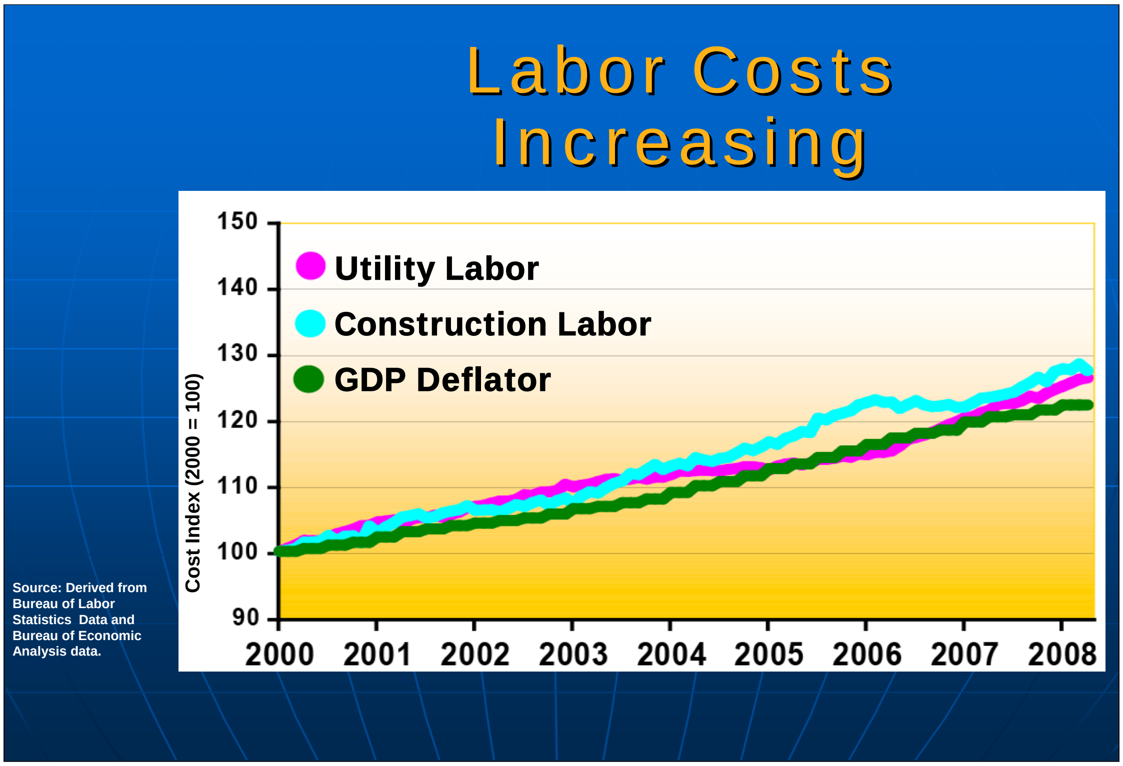
The need for new generation is important because new construction is becoming more expensive – quite aside from fuel price increases. Cambridge Energy Research Associates – CERA – produces an index of costs for the main inputs that go into building new generating plants. The slide shows how that index has almost doubled since 2003. The increase in nuclear plant inputs has risen even faster. Much of this cost increase results from rising global demand for basic materials. Part of it also comes from shortages of people to do key engineering and construction jobs. In any case, the implication is that, we will pay more, not less, for the next round of construction.



Let's look at some of the reasons that CERA's index is rising so rapidly. The slide shows two of the primary construction materials for electric generating plants – concrete is on the blue line and iron and steel on the red line. As you can see, the prices of both have been rising recently – especially steel, which is now more than twice as expensive as it was four years ago. Rising costs for iron and steel will also affect fuel prices for the power industry. For example, natural gas wells and pipelines both use substantial amounts of steel, so natural gas costs will also reflect rising iron and steel prices.

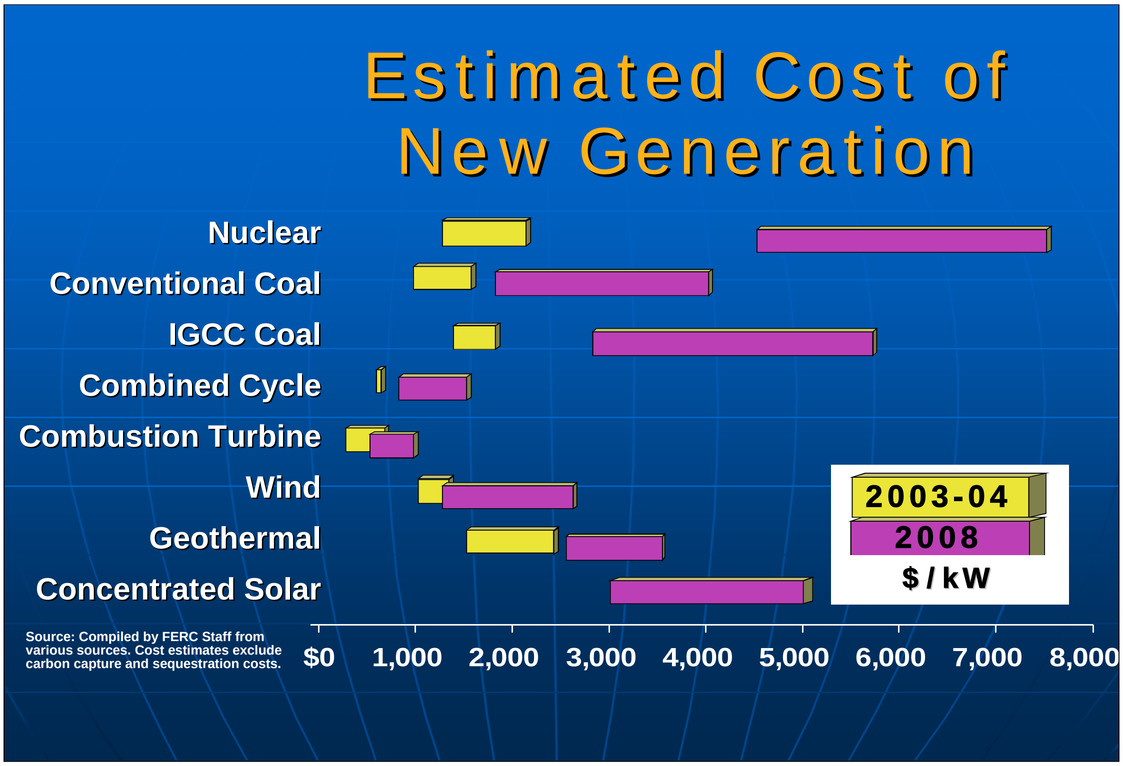


Of course, new generating plants require many other basic commodities. The slide shows the pricing for four key metals that go into generators. As you can see, all of these metals are increasing in price. The one that stands out is copper, up more than five times over the past four years. Indeed, copper is now so valuable there are reports of copper thieves cutting live cables to steal the metal.



Labor costs are also increasing. Perhaps the most frequently cited labor shortage is that for nuclear engineers. It has been a full generation since the nation built its last nuclear plant. Most of the engineers who worked on those plants are near retirement – and many have moved on to other occupations. In fact, the labor shortages are more widespread than just nuclear engineers. The slide shows that there has been about a 27% nominal change in average hourly earnings for both construction labor generally and for non-construction utility labor since 2000, outpacing inflation by over 4% for the same period.

In practice, the American labor market is quite responsive to market forces, so short-term labor shortages tend to be self-correcting over the mid-term. Still, there is no quick way to force several years of education into six months, or decades of experience into a year or two.



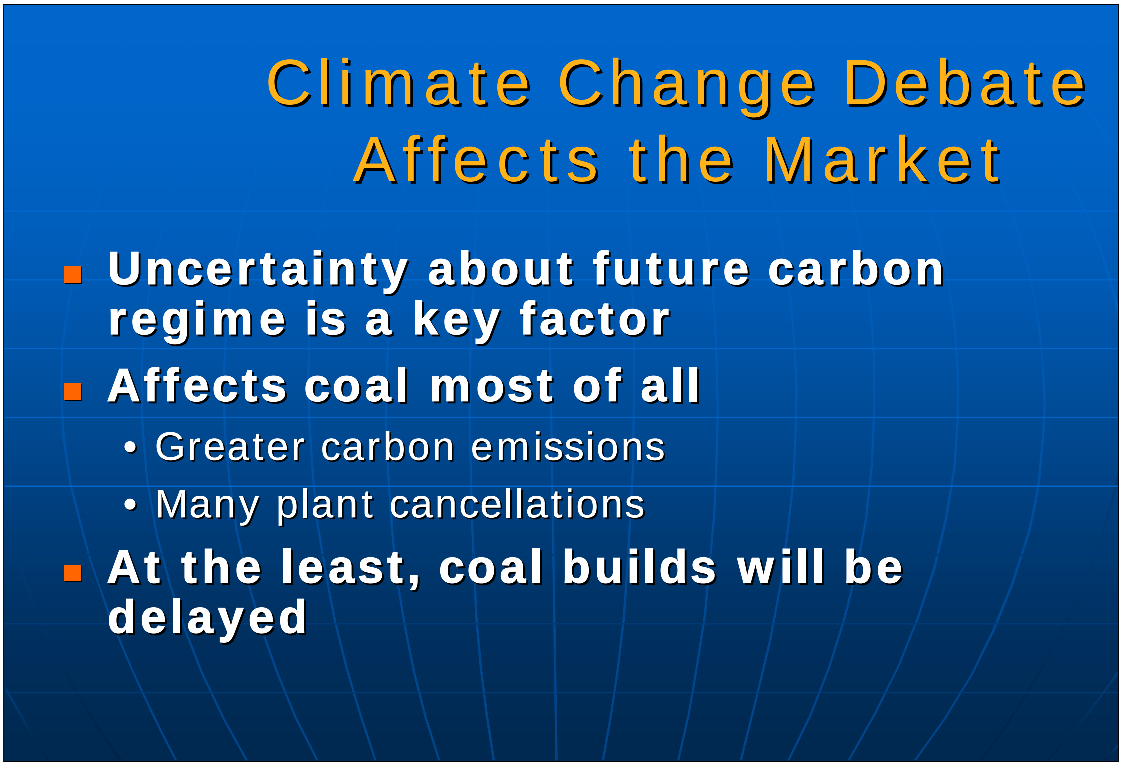
What do all these cost increases mean for the cost of building a new generating plant?

No one knows precisely. It's difficult to get consistent and trustworthy numbers about plant costs, both because they are commercially sensitive and because the assumptions behind them vary greatly. The numbers reflected on the slide come from a variety of sources and include different assumptions about, for example, location or exactly what facilities are included in the estimate. To take one example: Two recent nuclear procurements in South Carolina and Georgia produced cost estimates of $5,100 and $6,400 per kW, respectively, for the same technology. We have been told that most of the difference may be due to different uses of Allowances for Funds Used during Construction – AFUDC.

Despite the difficulties in being precise, the slide represents a good general indication of how capital costs have been changing. If anything, the cost estimates may be lower than the final costs of projects, if input costs continue to rise.

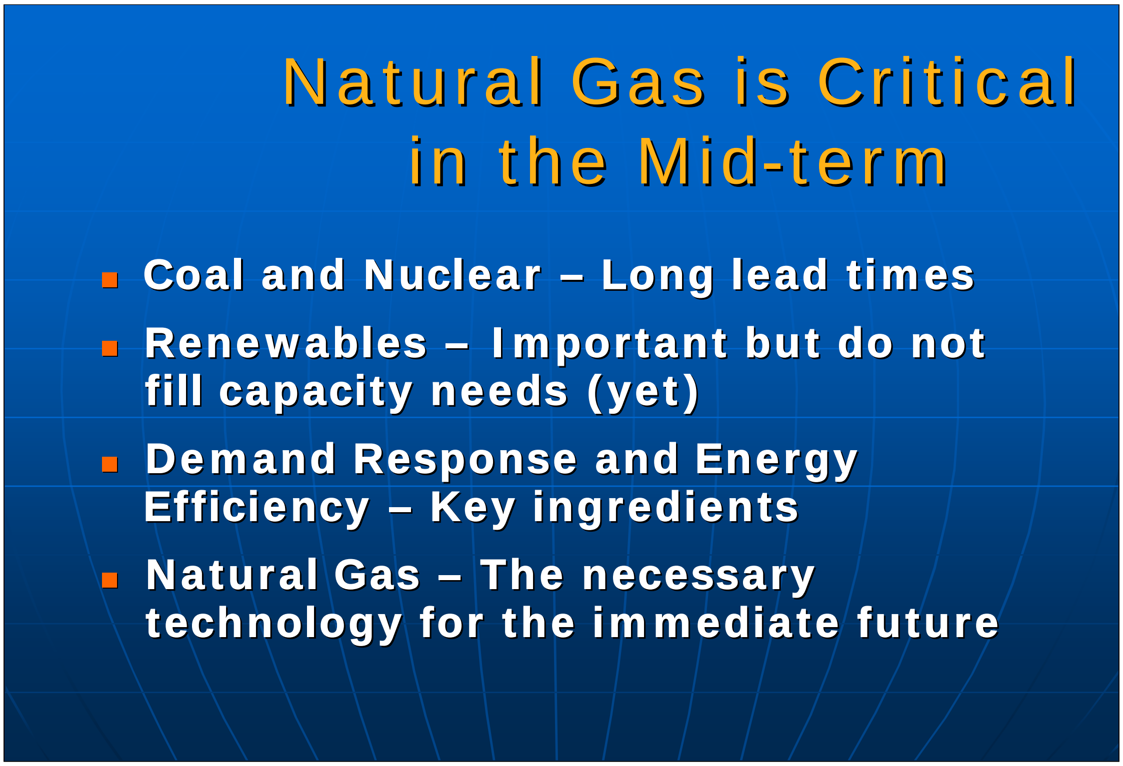
It's also important to remember that these cost estimates cover only capital costs. They do not include fuel costs, which as we've seen earlier will be a large factor for both natural gas and coal-fired plants. To the extent that plants do not have major fuel costs - they may be more competitive over their life cycles than would be suggested just looking at the capital costs. That would affect renewables and, to a degree, nuclear plants.

Similarly, these estimates generally do not include a full accounting of major risk factors, especially those affecting coal and nuclear plants. Both of these technologies have long lead times. That increases the chance that market conditions will change before they are complete and adds to the financial risk of building them. Nuclear plants also have risks associated with both decommissioning and waste fuel disposal. And coal plants have risks associated with the future treatment of greenhouse gases. Of course, relatively new technologies like wind and the new approaches to nuclear also have some risks, simply because they do not have the same track record of more mature technologies.



Climate change has become an increasingly urgent national issue. The debate over how to address carbon dioxide emissions is lively and has already affected how companies think about investments. Until recently, rising natural gas prices made coal plants attractive. However, the national uncertainty about carbon policy has made investing in coal plants more risky. Without carbon capture or sequestration, coal unit emit about four times as much carbon as natural gas combined cycle units per MWh. Since January 2007, 50 coal plants have been canceled or postponed. Only 26 remain under construction.

Whatever the eventual result of the climate change debate, costs of producing power from both coal and natural gas are likely to increase. Moreover, as long as future climate change policy is unclear, market participants will have a considerable disincentive to invest in coal plants. Even when the issues are resolved, it remains an open question how competitive coal-fired generation will be, and it would take another four to eight years to build new coal-fired capacity.



Over the long run, the nation can meet its increasing need for generation in several ways. But for the next few years, the options are more limited, and natural gas will be crucial.

The lead times for both nuclear and coal units mean that they will not supply a significant amount of new capacity for nearly a decade.

Most people expect renewables to supply an increasing proportion of the nation's power. For the next few years, wind will almost certainly account for a large share of generation investment and will account for a growing share of overall generation. Wind power has no fuel costs, and so will generally operate when available. However, wind is a variable, weather-dependent resource. As a result, it will not make up as strong a share of the Nation's capacity needs over the next few years. Other renewables are becoming more competitive. Geothermal power is already an important resource in the west, and concentrated solar is becoming economically attractive in desert areas like the Southwest. But these sources are likely to remain relatively small in the national picture over the next few years.

Both demand response and energy efficiency will be important – I'll talk more about them on the next slide – but they are unlikely to eliminate the need for new capacity.

Overall, the most likely outcome is that natural gas will continue to be the leading fuel for new capacity over the next half decade. For example, the consulting firm, Wood Mackenzie estimates that in a carbon constrained environment, gas consumption for power will increase by 69 % by 2017. That's in addition to the 55% increase we've seen since 2000.

Over the years, we have learned repeatedly that people respond to prices. In the case of electric power, this is likely to take several forms.

First, there is likely to be more demand response. In the simplest terms, high prices at peak will lead some customers – both businesses and others – to prefer to save their money rather than use power. In fact, the first round of demand response may be both the cheapest and fastest way to improve capacity margins on many systems. The best cost estimates for the first rounds of demand response suggest that it should be available for about $165/kW, far less than any generation side options. The results of ISO-NE's first Forward Capacity Market auction last year corroborates the economic importance of demand response - 7.4 % of the accepted bids were for demand response. However, there are impediments that limit the full use of demand response. For example, most customers do not have the option to respond directly to real-time prices. As a result, they are unlikely to reduce peak consumption as much as they might prefer to if they could take advantage of the price.

Second, customers are likely to be more energy efficient. While few customers see real-time prices, most get an average price over a month. As a result, high prices give them considerable incentive to reduce their overall consumption of power – though no more at peak than at other times. That is, energy efficiency is essentially a substitute for baseload capacity, while demand response is a substitute for peaking capacity. Energy efficiency is also likely to be economically important. Cost estimates show that the first round of energy efficiency may be available for about 3 cents/kWh. At

Continued on next page

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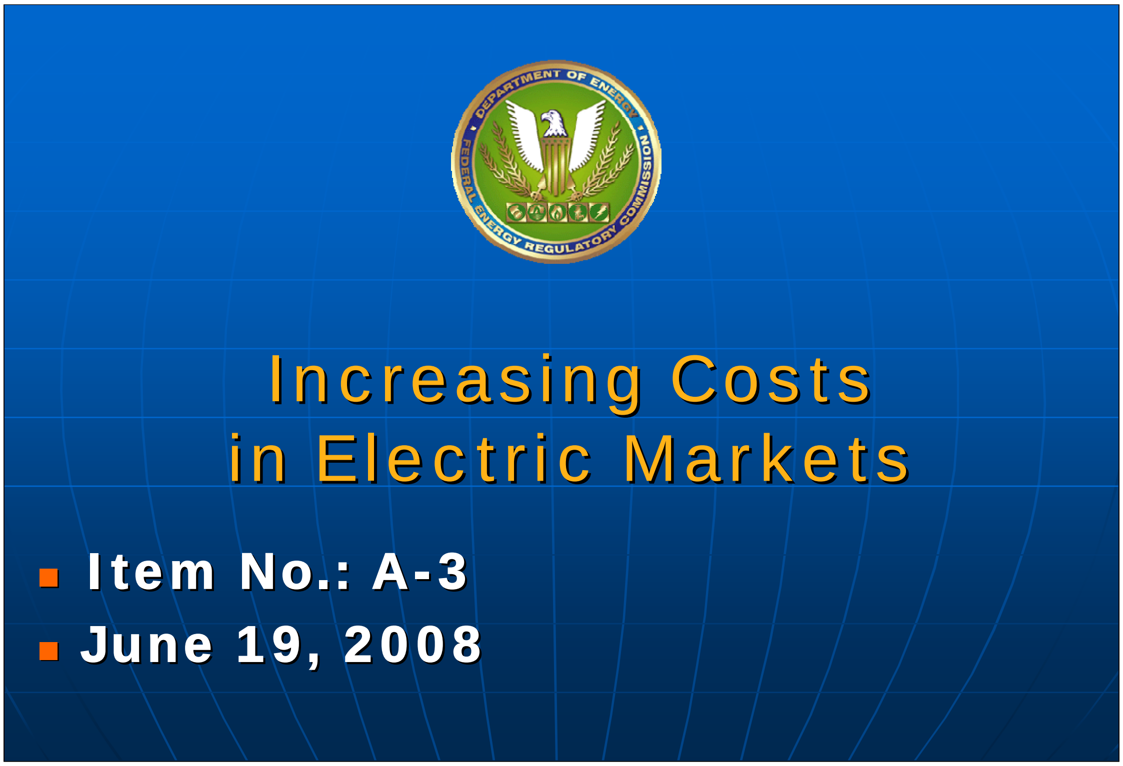
current prices, supplying that same kWh from a combined cycle gas plant would cost 9 cents just for the fuel. Adding to the likelihood of greater energy efficiency is that many states have adopted fairly strong energy efficiency standards.

Third, innovators see higher prices as an opportunity. By the nature of things, it's hard to predict what innovations will succeed. The electric industry has a number of technologies that might take off – including concentrating solar power, hydrokinetic power, and vehicle to grid technologies. In addition, distributed generation is becoming more important, and may continue to do so for both cost and emissions reasons   In other newly competitive industries, such as telecoms and natural gas, innovations have produced large changes, sometimes quickly. Given continuing high electric prices, the electric power industry may see similar results.



That concludes our presentation. We welcome comments and questions.

Minnesota Center for Environmental Advocacy

The legal and scientific voice protecting and defending Minnesota's environment

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August 14, 2008

VIA EMAIL ONLY

Chris Shaw
Office of Energy Security
85 7th Place East Suite 500
St. Paul, MN 55101

RE: Comments on Assumptions for "Minnesota Resource Assessment"

Dear Mr. Shaw:

Thank you for the opportunity to comment on the Minnesota Office of Energy Security's work plan for the Minnesota Resource Assessment, the study to be prepared for the legislature pursuant to section 16 of the Next Generation Energy Act of 2007. We appreciated the information you shared at the stakeholder meeting last month. Please accept these comments on behalf of the Izaak Walton League of America – Midwest Office, Fresh Energy, and Minnesota Center for Environmental Advocacy.

The purpose of our suggested approach for the Assessment is to ensure that it is a useful tool for the legislature. We are concerned, however, that certain analytical assumptions OES outlined at the stakeholder meeting are inconsistent with that purpose. In particular, we are concerned that the capital cost assumptions for supercritical coal-fired power plants are far too low to present a realistic assessment to the legislature. The proposed CO2 regulatory costs are also too low. We have attached to our comments suggested alternative values for these study assumptions.

We also have forecast methodology concerns and question the validity and utility of the "futures" scenarios that OES intends to develop, that is, a "Renewable Future", a "Baseload Future", and a "Natural Gas Reliant Future".

Capital Cost Assumptions for Supercritical Coal

OES proposes to use Big Stone II capital cost data that Big Stone II utilities have put forward in the CN-05-619 docket as the capital cost assumption for a new coal unit that the Strategist model may select

($2,434.77/kW). However, the capital cost assumptions from the Big Stone docket are at best the wishful thinking of the Big Stone II utilities. Other utilities are currently experiencing much higher capital costs for coal units, and these higher costs should be the basis of OES' analysis and assessment, not costs that the Big Stone utilities have failed to reconcile with the marketplace since the summer of 2006. We attach a report prepared last month by Synapse Energy Economics that shows that a more realistic capital cost assumption for new supercritical units is in the range of $3100/kW to $3800/kW. The sensitivity cases that OES intends to run should be 20 percent above and below these higher capital costs, augmented by carbon offset costs, rather than in reference to an outdated Big Stone estimate. The costs of carbon offsets are required for new coal units in Minnesota.

CO2 Regulatory Cost Assumptions

OES proposes to use the Commission's range of carbon dioxide values adopted in December 2007, $4/ton to $30/ton, with a $17/ton midpoint. These values, however, have become out-of-date, and should be replaced with the suggested alternative values found in the attached report prepared last month by Synapse Energy Economics. Figure 3 and Table 2 of the attached Synapse report updates its previous forecast of low, medium and high CO2 allowance prices, forecasts on which the Commission relied when it adopted the current $4/ton to $30/ton range. Based on the developments and reasoning set forth in the Synapse report, we recommend that OES utilize Synapse's medium range, which starts at $15/ton in 2013, and moves up to $53.40/ton in 2030.

Forecasts

OES also states that it will be using utilities' demand forecasts prepared in each utility's most recent integrated resource plan. We are concerned that Minnesota utilities' most recent IRPs are not up-to-date, however, especially regarding the changes in law enacted in 2007 that require increased DSM. Utilities have not uniformly used DSM attainment goals in their forecasts to meet the 1.5% requirement. It is unclear how the OES' assessment will address the critical issue of varying IRP DSM assumptions by utility.

We propose that the OES, in its forecast, have as a base assumption attainment by the state of the 1.5% DSM requirement. In addition, OES should prepare a scenario that assumes achievement of the Midwestern Governors' Association goal to obtain 2% per year of retail sales from energy efficiency and DSM beginning in 2015. The legislature may be asked to take meaningful action to implement the MGA goal and should be able to access relevant analysis in the OES' Assessment.

"Futures" Scenarios

OES provided an outline at the stakeholder meeting for the Resource Assessment that describes three "futures" scenarios to be developed through Strategist modeling. Because the Baseload Future and Natural Gas Future scenarios "force" the model to select coal units and natural gas units at specified sizes and intervals, despite there being no legislative mandate to put such units in service, the model is not presenting future scenarios based on least cost or actual need principles. These non-optimized scenarios seem of little use to the legislature and the public.

Thank you for the opportunity to submit these comments. Please do not hesitate to contact me if you have questions about the issues we have raised or about the alternative data that we provide from the attached reports.

Sincerely,

Elizabeth Goodpaster

Attorney for Izaak Walton League of America – Midwest Office, Fresh Energy, and Minnesota Center for Environmental Advocacy

Synapse
Energy Economics, Inc.

Coal-Fired Power Plant Construction Costs

July 2008

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Introduction

Construction cost estimates for new coal-fired power plants are very uncertain and have increased significantly in recent years. The industry is using terms like “soaring,” “skyrocketing,” and “staggering” to describe the cost increases being experienced by coal plant construction projects. In fact, the estimated costs of building new coal plants have reached $3,500 per kW, without financing costs, and are still expected to increase further. This would mean a cost of well over $2 billion for a new 600 MW coal plant when financing costs are included. These cost increases have been driven by a worldwide competition for power plant design and construction resources, commodities, equipment and manufacturing capacity. Moreover, there is little reason to expect that this worldwide competition will end anytime in the foreseeable future.

Cost Estimates for Proposed Coal-Fired Power Plants

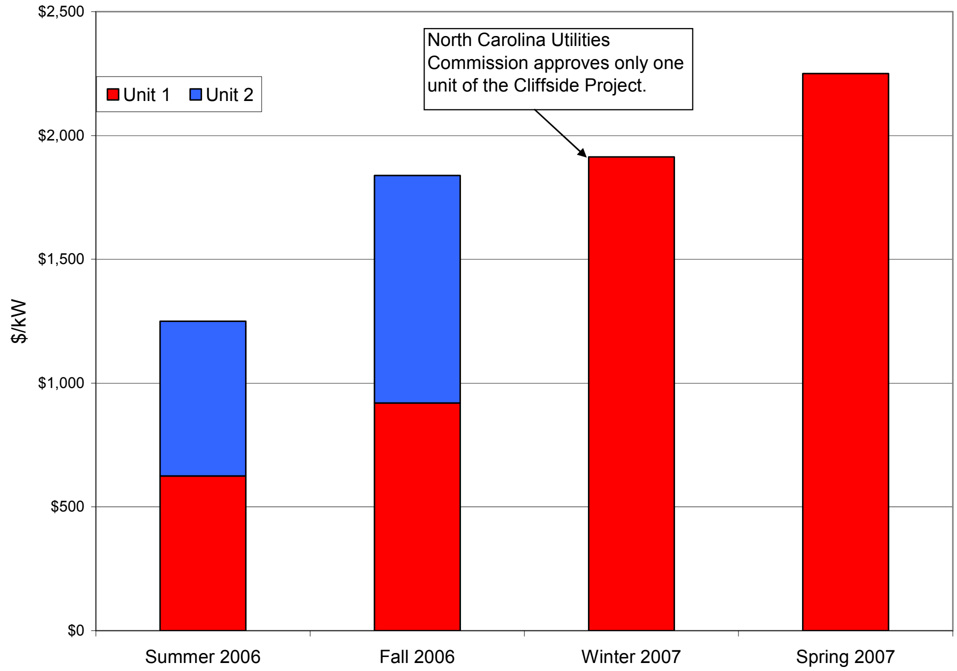
As recently as 2005, companies were saying that proposed coal-fired power plants would cost as little as $1,500/kW to $1,800/kW. However, the estimated construction costs of new coal plants have risen significantly since then.

The following examples illustrate the cost increases that proposed projects experienced in the past two or three years:

- Duke Energy Carolinas’ summer 2006 cost estimate for the two unit Cliffside Project was approximately $2 billion. In the fall of 2006, Duke announced that the cost of the project had increased by approximately 47 percent ($1 billion). After the project had been downsized because the North Carolina Utilities Commission refused to grant a permit for two units, Duke announced that the cost of the remaining single unit would be about $1.53 billion, not including financing costs. In late May 2007, Duke announced that the cost of building the single Cliffside unit had increased by yet another 20 percent. As a result, the estimate cost of the one unit that Duke is building at Cliffside is now $1.8 billion exclusive of financing costs. Thus, the single Cliffside unit is now expected to cost almost as much as Duke estimated for a two unit plant only two years ago in the summer of 2006.

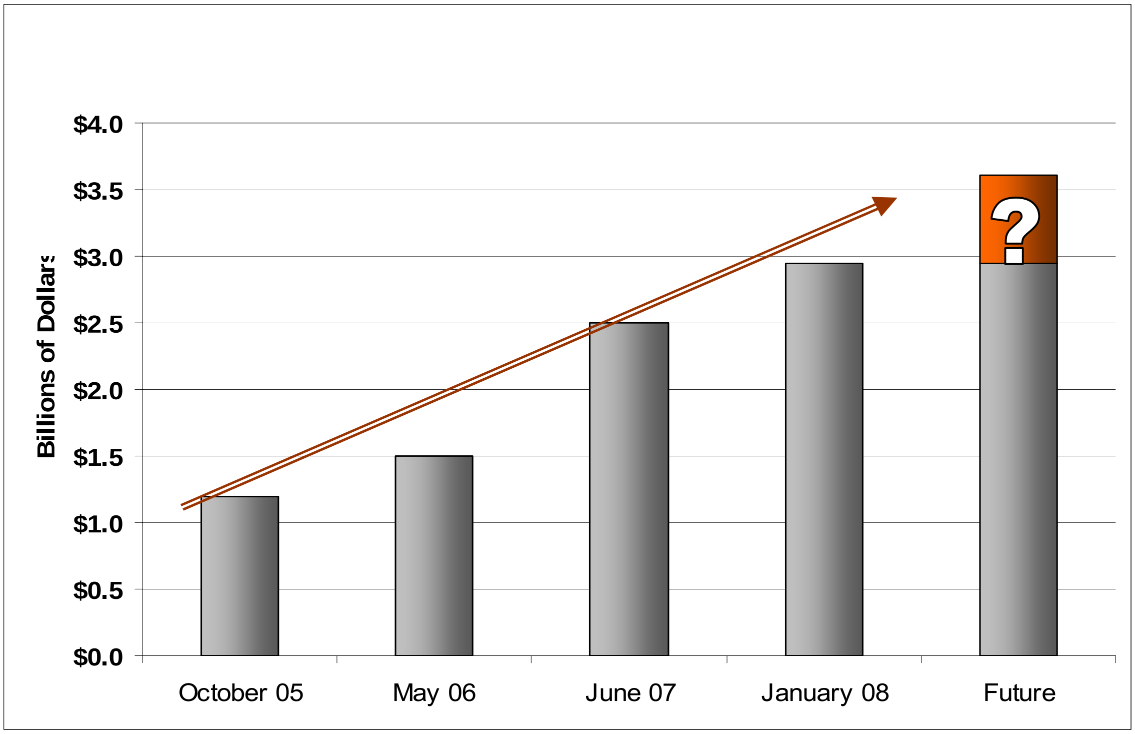
The increases in the estimated cost of the Cliffside Project are presented in Figure 1 below.

Figure 1: Duke Energy Carolinas Cliffside Project Cost Increases 2006-2007 ($/kW)



- As shown in Figure 2 below, the estimated cost of AMP-Ohio's proposed 960 MW coal-fired power plant project nearly doubled between May 2006 and January 2008. The estimated cost increased by 15 percent in just the six months between June 2007 and January 2008. The estimated cost of the 960 MW plant is currently estimated at nearly $3 billion, without any financing costs. This represents a construction cost of more than $3,100 per kW. And the available evidence suggests that plant costs will continue to rise.

Figure 2: AMP-Ohio AMPGS Cost Increases 2005-2008 ($)



- In mid-June 2008, Wisconsin Power & Light ("WPL") announced a nearly 40 percent increase in the estimated cost of its proposed 300 MW Nelson Dewey 3 coal-fired power plant. The previous estimate had been prepared in late 2006. The estimated cost for this Circulating Fluid Bed plant is above $3,500/kW, in early 2008 dollars. The company has similarly estimated that the cost of building a new supercritical coal plant also would exceed $3,500/kW. In support of its new cost estimates, WPL presented testimony that noted that "EPC [Engineering, Procurement and Construction] pricing for other non-IGCC, primarily coal-fired generating projects under construction or in the planning stages have similarly increased with many projects falling in the $2,500 to $3,800/kW range, without AFUDC or uncommon owner's costs (e.g., major railway additions.)."[1]
- In April 2008, Duke Energy Indiana announced an 18 percent increase in the estimated cost of its proposed Edwardsport coal plant just since the spring of 2007. Duke said that "the increase in the cost estimate is driven by factors outside the Company's control, including unprecedented global competition for commodities, engineered equipment and materials, and increased labor costs."[2] Duke noted in its Petition to the Indiana Utility Regulatory Commission that this

[1] Direct Testimony of Charles J. Hookham on behalf on Wisconsin Power & Light Company in Public Service Commission of Wisconsin Docket No. 6680-CE-170, June 2008, at page 21.

[2] Verified Petition in Indiana Utility Regulatory Commission Cause No. 43114 IGCC-1, filed on May 1, 2008, at pages 3-4

> projected increase in cost "is consistent with other recent power plant project cost increases across the country."[3]

Nor are coal-fired power plants that are under construction immune to further cost increases. For example, Kansas City Power & Light just announced a 15 percent price increase for the Iatan 2 power plant that has been under construction for several years and is scheduled to be completed by 2010. This shows that one cannot assume that the cost of a plant will be fixed when construction begins.

Indeed, in the past utilities were able to secure fixed-price contracts for their power plant construction projects. However, it is not possible to obtain fixed-price contracts for new power plant projects in the present environment. The reasons for this change in circumstances has been explained as follows by a witness for the Appalachian Power Company, a subsidiary of American Electric Power in testimony before the West Virginia Public Service Commission:

> Company witness Renchek discusses in his testimony the rapid escalation of key commodity prices in the [Engineering, Procurement and Construction] industry. **In such a situation, no contractor is willing to assume this risk for a multi-year project.** Even if a contractor was willing to do so, its estimated price for the project would reflect this risk and the resulting price estimate would be much higher.[4] [Emphasis added.]

A fall 2007 assessment of AMP-Ohio's proposed coal-fired power plant similarly noted that the reviewing engineers from Burns and Roe Enterprises:

> agree that the fixed price turnkey EPC contract is a reasonable approach to executing the project. However, the viability of obtaining a contract of this type is not certain. The high cost of the EPC contract, in excess of $2 billion, significantly reduces the number of potential contractors even when teaming of engineers, constructors and equipment suppliers is taken into account. Recent experience on large U.S. coal projects indicates that the major EPC Contractors are not willing to fix price the entire project cost. This is the result of volatile costs for materials (alloy pipe, steel, copper, concrete) as well as a very tight construction labor market. When asked to fix the price, several EPC Contractors have commented that they are willing to do so, but the amount of money to be added to cover potential risks of a cost overrun would make the project uneconomical.[5]

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3 Id, at page 7.

4 Ibid, at page 16, lines 16-20.

5 *Consulting Engineer's Report for the American Municipal Power Generating Station located in Meigs County, Ohio*, for the Division of Cleveland Public Power, Burns and Roe Enterprises, Inc., October 16, 2007, at page 11-1.

In fact, rising commodity prices and increasing construction cost risks have been responsible, at least in part, for the cancellation or delay of more than fifty proposed coal-fired power plants since mid-2006. The following examples are illustrative of the factors and risks which have contributed to these cancellations and delays:

- Tenaska Energy cancelled plans to build a coal-fired power plant in Oklahoma in 2007 because of rising steel and construction prices. According to the Company's general manager of business development:

  > ".. coal prices have gone up "dramatically" since Tenaska started planning the project more than a year ago.
  >
  > And coal plants are largely built with steel, so there's the cost of the unit that we would build has gone up a lot… At one point in our development, we had some of the steel and equipment at some very attractive prices and that equipment all of a sudden was not available.
  >
  > We went immediately trying to buy additional equipment and the pricing was so high, we looked at the price of the power that would be produced because of those higher prices and equipment and it just wouldn't be a prudent business decision to build it."[6]

- Westar Energy announced in December 2006 that it was deferring site selection for a new 600 MW coal-fired power plant due to significant increases in the facility's estimated capital cost of 20 to 40 percent, over just 18 months. This prompted Westar's Chief Executive to warn: "When equipment and construction cost estimates grow by $200 million to $400 million in 18 months, it's necessary to proceed with caution."[7] As a result, Westar Energy has suspended site selection for the coal-plant and is considering other options, including building a natural gas plant, to meet growing electricity demand. The company also explained that:

  > most major engineering firms and equipment manufacturers of coal-fueled power plant equipment are at full production capacity and yet are not indicating any plans to significantly increase their production capability. As a result, fewer manufacturers and suppliers are bidding on new projects and equipment prices have escalated and become unpredictable.[8]

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6 Available at www.swtimes.com/articles/2007/07/09/news/news02.prt.

7 Available at http://www.westarenergy.com/corp_com/corpcomm.nsf/F6BE1277A768F0E4862572690055581C/$file/122806%20coal%20plant%20final2.pdf.

8 Id.

The increases in construction costs being experienced by proposed coal-fired power plants are due, in large part, to a significant increase in the worldwide demand for power plant design and construction resources, commodities and equipment. This worldwide competition is driven mainly by huge demands for power plants in China and India, by a rapidly increasing demand for power plants and power plant pollution control modifications in the United States required to meet SO_2 and NO_x emissions standards, and by the competition for resources from the petroleum refining industry.

The limited capacity of EPC firms and equipment manufacturers also has contributed to rising power plant construction costs. This has meant fewer bidders for work, higher prices, earlier payment schedules and longer delivery times. The demand for and cost of both on-site construction labor and skilled manufacturing labor also have escalated significantly in recent years.

In addition, the planned construction of new nuclear power plants is expected to compete for limited power plant design and construction resources, manufacturing capacity and commodities.

It is reasonable to expect that the factors that have led to skyrocketing power plant construction costs in recent years will lead to further increases in costs and construction delays in the five or more years before the projects are scheduled to be completed. For example, a May 15, 2008 story in the Wall Street Journal noted that “escalating steel prices are halting and slowing major construction projects worldwide and limiting shipbuilding and oil and gas exploration.” The same article noted that “Steel prices are up 40 percent to 50 percent since December, and industry executives say they have not reached a peak” and “raw materials prices have surged in the past year, fueled in part because of the rapid industrialization of China, India and other developing nations.”

Indeed, there is no reason to expect that the worldwide competition for resources or the existing supply constraints and bottlenecks affecting coal-fired plant construction costs will clear anytime in the foreseeable future.

The Virginia State Corporation Commission denied the request of Appalachian Power Company to build a coal-fired power plant in West Virginia. The Commission found that the proposal was neither “reasonable” nor “prudent.” In its order denying the request to build the new coal-fired power plant, the Virginia Commission also found that the Company’s cost estimate for the project was not credible and that the Company had not updated its cost estimate since November 2006. The Commission further noted that the Company (“APCo”) will not obtain actual or firm prices for components of the project until after receiving regulatory approval.[9] The Virginia Commission Final Order included the following language concerning risk: “Indeed APCo has no fixed price contract for any appreciable portion of the total construction costs; there are no meaningful price or performance guarantees or controls for this project at this time. This represents an extraordinary risk that we cannot allow the ratepayers of Virginia in [Appalachian Power

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9 April 14, 2008 Final Order of the Virginia State Corporation Commission in Case No. PUE-2007-00068, at page 5.

Company's] service territory to assume." This is the very same "extraordinary" risk that the customers and ratepayers of investor-owned companies and publicly-owned utilities building new coal-fired power plants are being asked to assume because there are no fixed prices or contracts for the projects.

Finally, there is no currently commercially available technology for post-combustion capture of carbon dioxide from pulverized coal power plants. Moreover, it is estimated that such technology may not be commercially available until 2020 or 2030, if then. However, it is expected that the addition of carbon capture and sequestration technology will greatly increase the cost of generating power at coal-fired power. In fact, a number of independent sources agree, as illustrated in Table 1 below, that adding and operating CCS equipment will raise the cost of generating electricity at new coal-fired power plants by perhaps as much as 60% to 80%.

Table 1: Projected Increase in the Cost of Generating Power Due to Carbon Capture and Sequestration

Source	Projected Increase in Cost of Electricity from Addition of CCS
Duke Energy Indiana[10]	68%
MIT Future of Coal Report[11]	61%
Edison Electric Institute[12]	75%
National Energy Technology Laboratory[13]	81%

10 Testimony of James E. Rogers in Indiana Utility Regulatory Commission Cause No. 43114, Joint Petitioners' Exhibit No. 1, at page 13, lines 6-11.

11 *The Future of Coal*, *Options for a Carbon-Constrained World*, Massachusetts Institute of Technology, 2007, at page 19.

12 Letter to Hon. Edward J. Markey, Chairman, Select Committee on Energy Independence and Global Warming, from Thomas R. Kuhn, Edison Electric Institute, September 21, 2007, at page 4.

13 *Cost and Performance Baseline for Fossil Energy Plants*, *Revised August 2007,* DOE/NETL – 2007/1281, at page 17.

Synapse
Energy Economics, Inc.

Synapse 2008 CO_2 Price Forecasts

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1. INTRODUCTION

Synapse has prepared a 2008 CO_2 price forecast for use in Integrated Resource Planning (IRP) and other electricity resource planning analyses. The 2008 Synapse Low CO_2 Price Forecast starts at $10/ton[1] in 2013, in 2007 dollars, and increases to approximately $23/ton in 2030. This represents a $15/ton levelized price over the period 2013-2030, in 2007 dollars. The 2008 Synapse High CO_2 Price Forecast starts at $30/ton in 2013, in 2007 dollars, and rises to approximately $68/ton in 2030. This High Forecast represents a $45/ton levelized price over the period 2013-2030, also in 2007 dollars. Synapse also has prepared a Mid CO_2 Price Forecast that starts close to the low case, at $15/ton in 2013 in 2007 dollars, but then climbs to $53/ton by 2030. The levelized cost of this mid CO_2 price forecast is $30/ton in 2007 dollars.

In 2006, Synapse developed a set of CO_2 price forecasts for use in IRP and other electricity resource planning analyses.[2] Those forecasts ranged from a low of $10.23 levelized over the years 2013-2030, to a high of $37.11 levelized over the same period (all in 2007 dollars).

Significant developments in the past two years led Synapse to re-examine and revise its 2006 CO_2 price forecasts to ensure that these forecasts reflect an appropriate level of financial risk associated with greenhouse gas emissions. Most importantly, the political support for serious climate change legislation has expanded significantly in Federal and State governments, as well as in the public at large, as the scientific evidence of climate change has become more certain. Concurrently, the new greenhouse gas regulation bills under consideration in the 110th U.S. Congress contain emissions reductions that are significantly more stringent than would have been required by proposals introduced in earlier years. Moreover, an increasing number of states have adopted policies, either individually and/or as members of regional coalitions, to reduce greenhouse gas emissions. In addition, in the past two years, additional information has been developed regarding technology innovations in the areas of renewables, energy efficiency, and carbon capture and sequestration, leading to greater clarity about the cost of emissions mitigation; however, cost estimates for many of these technologies are still in the early stages. Taken together these developments lead to higher financial risks associated with future greenhouse gas emissions and justify the use of higher projected CO_2 emissions

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1 Throughout this paper, emission allowance prices are quoted in dollars per ton. This should be interpreted as dollars per short ton of CO_2. Prices in the economic literature and in international trading are often quoted in dollars per metric ton of CO_2 or dollars per metric ton of carbon, but the units we use are more typical of US carbon pricing schemes.

2 CO_2 price: Carbon dioxide (CO_2) is one of a cohort of six gases known to contribute to the atmospheric greenhouse effect which are collectively called greenhouse gases, or GHG. Most of the policies being designed at state, federal, and international levels propose to limit emissions of CO_2 as well as methane (CH_4), and nitrous oxide (N_2O), amongst others. Although these other gases are more potent greenhouse gases than CO_2, carbon dioxide is far more abundant and is the primary greenhouse gas emitted as a result of fossil fuel combustion. The “allowance price” is the price to emit one unit of CO_2, or more precisely, quantity of GHG equivalent to the 100-year global warming potential of one unit of CO_2. In shorthand and for simplicity, we refer to the “allowance price to emit one short ton of carbon dioxide equivalent greenhouse gas” as the “CO_2 price”.

allowance prices in electricity resource planning and selection for the period 2013 to 2030.

As discussed in our earlier carbon price reports, we conclude that federal regulation of greenhouse gas emissions is certain. However, the costs of any program will be affected by important details that are still uncertain, such as the timing, goals, and design of the program that will ultimately be adopted and implemented. Therefore, it is critical to consider a reasonable range of CO_2 emissions allowance prices in resource planning to achieve decisions that are robust in an uncertain future just as resource planners normally consider a range of fuel prices. For this reason, we provide high, low and mid CO_2 allowance price forecasts.

This report discusses the specific factors and developments that we have considered in re-examining and revising the Synapse forecast of CO_2 prices for use in resource planning and selection. In general, our CO_2 price forecasts are based on:

1. Our review of the current political conditions in the U.S. concerning the issue of climate change and responses thereto;
2. The results of publicly available modeling analyses of greenhouse gas regulatory proposals in the current U.S. Congress;
3. The ranges of CO_2 prices used by utility regulatory commissions and utilities in electric resource planning;
4. Our review of the estimated costs for technological solutions to electric sector carbon emissions such as energy efficiency, renewable resources, nuclear power, and carbon capture and sequestration;
5. Our work experience and professional judgment on global climate change and electric resource planning issues.

2. NEW DEVELOPMENTS SINCE THE SPRING OF 2006

The most significant new developments since Synapse released its original CO_2 price forecasts in the spring of 2006 include the following:

Increasing Evidence of Climate Change

The Intergovernmental Panel on Climate Change (IPCC) released the IPCC Fourth Assessment Report, in 2007.[3] This report, a consensus document reflecting the views of hundreds of the world's top climate scientists, concluded in far stronger language than had any previous version that the climate of the Earth has been, and will continue to be, adversely affected by human-induced climate change. The report noted that "warming of the climate system is unequivocal", and that "Observational evidence from all continents and most oceans shows that many natural systems are being affected by regional climate changes, particularly temperature increases." The report documents increases in both surface temperature and sea level, as well as reductions in snow cover, that result directly from human activities. Finally, the report notes that "Continued GHG emissions at or above current rates would cause further warming and induce many changes in the global climate system during the 21st century that would *very likely* be larger than those observed during the 20th century."

The IPCC report, and numerous related scientific studies and reports, continue to corroborate and strengthen a consistent message: while uncertainties remain in the nature and timing of certain specific *impacts* of climate change, human-caused climate change is now established beyond any credible scientific doubt. The social and economic costs of climate change will be large and detrimental to societies all over the world, although those in less-developed regions are more likely to suffer greater damages in the short term. Importantly, the expected damages and costs associated with climate change rise with increasing levels of greenhouse gases in the atmosphere, as do the risks of crossing dangerous thresholds into cataclysmic impacts, such as the loss of the largest Antarctic glaciers and the resulting inundation of coastal regions around the world. Actions taken by governments and societies today will make an enormous difference in the ultimate economic and societal costs and dislocations associated with climate change.

Increased Political Support for Serious Government Action on Climate Change

A number of developments demonstrate growing political support for, and anticipation of, serious action by federal and state governments in the U.S. to mitigate climate change. These developments include:

- Bipartisan support for climate change legislation – Senators and representatives of both major parties support the climate change legislation introduced in the

3 http://www.ipcc.ch/

current Congress, and the presumptive nominees for President from both major parties also support some form of aggressive climate change legislation.

- Carbon Principles issued by three leading financial institutions – Citi, JPMorgan Chase, and Morgan Stanley developed climate change guidelines for advisors and lenders to power companies in the United States. These Principles create an approach to evaluating and addressing carbon risks in the financing of electric power projects.[4] Several other financial institutions, such as Bank of America and Credit Suisse, have adopted the Principles.
- State and Regional Actions to reduce greenhouse gas emissions – More than 30 states have developed or are developing climate change plans. Some states, like California, Montana, Oregon and Washington, have adopted explicit performance based standards regarding long-term investments in baseload generation. The California Energy Commission requires that new investments in baseload generation comply with a standard of 1,100 lbs of CO_2 per MWh. The Northeast states are implementing a regional cap on carbon emissions. States in the upper Midwest and the West are also acting regionally to address CO_2 emissions. As of Dec. 2007, 25 states had adopted Renewable Portfolio Standards that require certain percentages of energy consumption be supplied by renewable resources.
- Judicial decisions regarding greenhouse gases– In April 2007, the U.S. Supreme Court found in Massachusetts v. EPA that CO_2 is an air pollutant under the Clean Air Act.5 For this reason the EPA has statutory authority to regulate emissions of CO_2. The court found that EPA's refusal to do so or to provide a reasonable explanation of why it could not regulate was arbitrary, capricious and otherwise not in accordance with law. The Supreme Court also found that the "harms associated with climate change are serious and well recognized."
- A state court in Georgia has subsequently ruled that an air permit cannot be issued for a new coal-fired power plant without CO_2 emission limitations based on a Best Available Control Technology ("BACT") analysis.[6]
- Increasingly stringent federal legislative proposals that would require much more substantial reductions in greenhouse gas emissions than the proposals introduced in earlier sessions of Congress (see below).
- A 2007 resolution adopted by the National Association of Regulatory Utility Commissioners (NARUC) encouraged utility requirements to "assess and incorporate carbon-related risks in their planning and decision-making processes."[7]

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4 Carbon Principles adopted February 8, 2008. For more information see: http://www.carbonprinciples.com/

5 127 S. Ct. 1438 (2007)

6 *Friends of the Chattahoochie, Inc. and Sierra Club v. Dr. Carol Couch, Direct Environmental Protection Division, Georgia Department of Natural Resources and Longleaf Energy Associates,* LLC, Final Order in the Superior Court of Fulton County, State of Georgia, Docket No. 2008CV146398, issued on June 30, 2008.

7 NARUC, *Resolution on State Regulatory Policies Toward Climate Change,* adopted November 2007.

Federal Legislative Proposals

To date, the U.S. government has not required greenhouse gas emission reductions in the private sector. However, a number of legislative initiatives for mandatory emissions reduction proposals have been introduced in Congress. These proposals establish carbon dioxide emission trajectories below the projected business-as-usual emission trajectories, and they generally rely on market-based mechanisms, such as cap and trade programs, for achieving the targets. The proposals also include various provisions to spur technology innovation, as well as various details pertaining to offsets, allowance allocation, “safety valve” maximum allowance prices and other issues. The major federal proposals that would require greenhouse gas emission reductions that had been submitted in the 110th U.S. Congress are summarized in Table 1 below.

Table 1. Summary of Mandatory Emissions Targets in Proposals Discussed in the current U.S. Congress

Proposed National Policy	Title or Description	Year Proposed	Emission Targets	Sectors Covered
Feinstein-Carper S.317	Electric Utility Cap & Trade Act	2007	▪ 2006 level by 2011 ▪ 2001 level by 2015 ▪ 1%/year reduction from 2016-2019 ▪ 1.5%/year reduction starting in 2020	Electricity sector
Kerry-Snowe S.485	Global Warming Reduction Act	2007	▪ 2010 level from 2010-2019 ▪ 1990 level from 2020-2029 ▪ 2.5%/year reductions from 2020-2029 ▪ 3.5%/year reduction from 2030-2050 ▪ 65% below 2000 level in 2050	Economy-wide
McCain-Lieberman S.280	Climate Stewardship and Innovation Act	2007	▪ 2004 level in 2012 ▪ 1990 level in 2020 ▪ 20% below 1990 level in 2030 ▪ 60% below 1990 level in 2050	Economy-wide
Sanders-Boxer S.309	Global Warming Pollution Reduction Act	2007	▪ 2%/year reduction from 2010 to 2020 ▪ 1990 level in 2020 ▪ 27% below 1990 level in 2030 ▪ 53% below 1990 level in 2040 ▪ 80% below 1990 level in 2050	Economy-wide
Olver, et al HR 620	Climate Stewardship Act	2007	▪ Cap at 2006 level by 2012 ▪ 1%/year reduction from 2013-2020 ▪ 3%/year reduction from 2021-2030 ▪ 5%/year reduction from 2031-2050 ▪ equivalent to 70% below 1990 level by 2050	US national
Bingaman–Specter S.1766	Low Carbon Economy Act	2007	▪ 2012 levels in 2012 ▪ 2006 levels in 2020 ▪ 1990 levels by 2030 ▪ President may set further goals $\geq$60% below 2006 levels by 2050 contingent upon international effort	Economy-wide
Lieberman-Warner S. 2191	America's Climate Security Act	2007	▪ 2005 level in 2012 ▪ 1990 level in 2020 ▪ 65% below 1990 level in 2050	U.S. electric power, transportation, and manufacturing sources.
Boxer-Lieberman-Warner S. 3036	Substitute for S. 2191	2008	▪ 4% below 2005 level in 2012 ▪ 19% below 2005 level in 2020 ▪ 71% below 2005 level in 2050	Economy-wide
Markey HR. 6186	The Investing in Climate Action and Protection Act	2008	▪ 2005 level in 2012 ▪ 20% below 2005 level by 2020 ▪ 80% below 2005 level by 2050	Economy-wide

The emissions levels that would be mandated by these bills that are shown in Figure 1 below, reproduced from a recent World Resources Institute analysis.[8]

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8 Version as of June 2008, available at http://pdf.wri.org/usclimatetargets_2008-06-18.pdf.

Each of the major legislative proposals that have been introduced in the 110th Congress would require far more substantial reductions in greenhouse gas emissions than would have been required by the proposals that had been introduced in Congress by the spring of 2006. For example, Figure 2 compares the emissions caps that would have been required by Senate Bill S. 2028 in the 109th Congress with the emissions levels that would be mandated under Senate Bills S. 2191 and S. 3036.

Figure 1: Comparison of Legislative Climate Change Targets in the Current 110th U.S. Congress

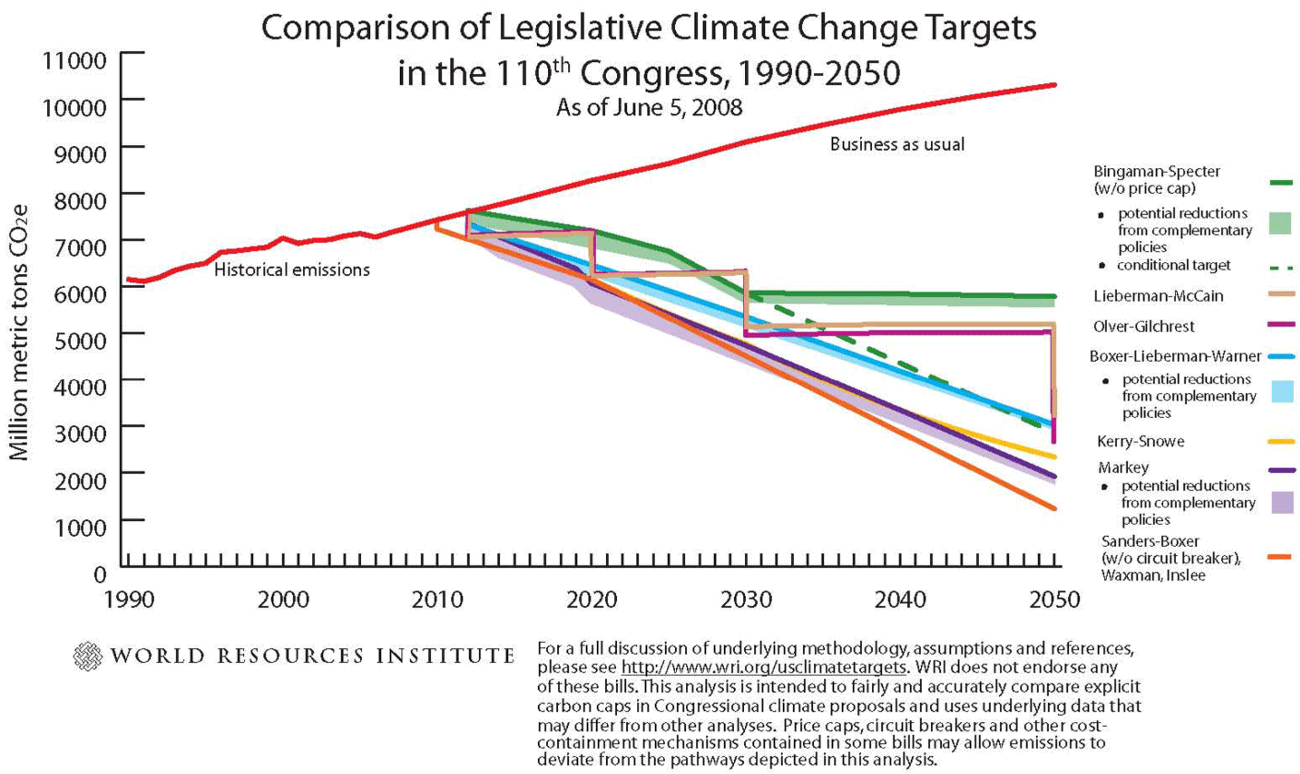
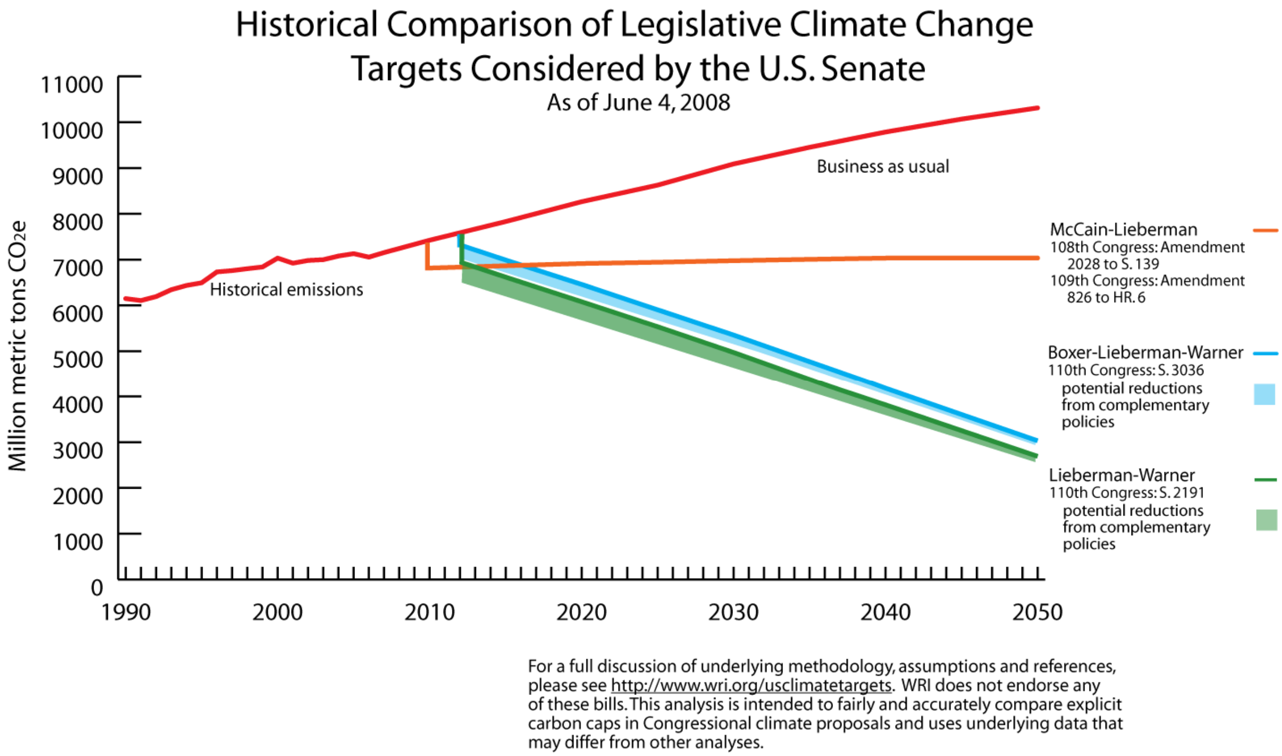


Figure 2: Historical Comparison of Legislative Climate Change Proposals in U.S. Congress



It is uncertain which, if any, of the specific climate change bills that have been introduced to date in the Congress will be adopted. The general trend is clear, however, and it would be a mistake to ignore it in long-term decisions concerning electric resources: over time the proposals in Congress are becoming more stringent as evidence of climate change accumulates and as the political support for serious governmental action grows.

3. FACTORS THAT INFLUENCE CO_2 PRICES

A large number of modeling analyses have been undertaken to evaluate the CO_2 allowance prices that would result from the major climate change bills introduced in the current Congress. It is not possible to compare the results of all of these analyses directly because the specific models and the key assumptions vary. However, the results of these analyses do provide important insights into the ranges of possible future CO_2 allowance prices under a range of potential scenarios.

These analyses included the following:

- The Energy Information Administration of the U.S. Department of Energy's ("EIA") assessment of the *Energy Market and Economic Impacts of S. 280, the Climate Stewardship and Innovation Act of 2007* (July 2007).[9]
- The October 2007 Supplement to the EIA's assessment of the *Energy Market and Economic Impacts of S. 280, the Climate Stewardship and Innovation Act of 2007*.[10]
- The EIA's assessment of the *Energy Market and Economic Impacts of S. 1766, the Low Carbon Economy Act of 2007* (January 2008).[11]
- The EIA's assessment of the *Energy Market and Economic Impacts of S. 2191, the Lieberman-Warner Climate Security Act of 2007* (April 2008).[12]
- The U.S. Environmental Protection Agency's ("EPA") *Analysis of the Climate Stewardship and Innovation Act of 2007 – S. 280 in 110th Congress* (July 2007).[13]
- The EPA's *Analysis of the Low Carbon Economy Act of 2007 – S. 1766 in 110th Congress* (January 2008).[14]
- The EPA's *Analysis of the Lieberman-Warner Climate Security Act of 2008 – S. 2191 in 110th Congress* (March 2008).[15]
- *Assessment of U.S. Cap-and-Trade Proposals* by the Joint Program at the Massachusetts Institute of Technology ("MIT") on the Science and Policy of Global Change (April 2007).[16]
- *Analysis of the Cap and Trade Features of the Lieberman-Warner Climate Security Act – S. 2191* by the Joint Program at MIT on the Science and Policy of Global Change (April 2008).[17]

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9 Available at http://www.eia.doe.gov/oiaf/servicerpt/csia/pdf/sroiaf(2007)04.pdf.
10 Available at http://www.eia.doe.gov/oiaf/servicerpt/biv/pdf/s280_1007.pdf
11 Available at http://www.eia.doe.gov/oiaf/servicerpt/lcea/pdf/sroiaf(2007)06.pdf
12 Available at http://www.eia.doe.gov/oiaf/servicerpt/s2191/pdf/sroiaf(2008)01.pdf.
13 Available at http://www.epa.gov/climatechange/economics/economicanalyses.html.
14 Available at http://www.epa.gov/climatechange/economics/economicanalyses.html.
15 Available at http://www.epa.gov/climatechange/economics/economicanalyses.html.
16 Available at http://web.mit.edu/globalchange/www/MITJPSPGC_Rpt146.pdf
17 Available at http://mit.edu/globalchange/www/MITJPSPGC_Rpt146_AppendixD.pdf.

- *The Lieberman-Warner America's Climate Security Act: A Preliminary Assessment of Potential Economic Impacts, prepared by the Nicholas Institute for Environmental Policy Solutions, Duke University and RTI International, (*October 2007)[18]
- *U.S. Technology Choices, Costs and Opportunities under the Lieberman-Warner Climate Security Act: Assessing Compliance Pathways,* prepared by the International Resources Group for the Natural Resources Defense Council, *NRDC (May 2008)*[19]
- *The Lieberman-Warner Climate Security Act – S. 2191, Modeling Results from the National Energy Modeling System – Preliminary Results,* Clean Air Task Force, (January 2008).[20]
- *Economic Analysis of the Lieberman-Warner Climate Security Act of 2007 Using CRA's MRN-NEEM Model*, CRA International, (April 2008).[21]
- *Analysis of the Lieberman-Warner Climate Security Act (S. 2191) using the National Energy Modeling System (NEMS/ACCF/NAM),* a report by the American Council for Capital Formation and the National Association of Manufacturers, NMA, (March 2008).[22]

The results of these and other analyses show that there are a number of factors that affect projections of allowance prices under federal greenhouse gas regulation. These include: the base case emissions forecast; the reduction targets in each proposal; whether complementary policies such as aggressive investments in energy efficiency and renewable energy are implemented, independent of the emissions allowance market; the policy implementation timeline; program flexibility regarding emissions offsets (perhaps international) and allowance banking; assumptions about technological progress; the presence or absence of a "safety valve" price; and emissions co-benefits.[23]

Based on our review of the more than 75 scenarios examined in the modeling analyses listed above we conclude that:

1. Other things being equal, more aggressive emissions reductions will lead to higher allowance prices than less aggressive emissions reductions.
2. Greater program flexibility decreases the expected allowance prices, while less flexibility increases prices. This flexibility can be achieved through increasing the percentage of emissions that can be offset, by allowing banking of allowances or by allowing international trading.[24]

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18 Available at http://www.nicholas.duke.edu/institute/econsummary.pdf
19 Available at http://docs.nrdc.org/globalwarming/glo_08051401A.pdf
20 Available at http://lieberman.senate.gov/documents/catflwcsa.pdf .
21 Available at http://www.nma.org/pdf/040808_crai_presentation.pdf ….
22 Available at http://www.accf.org/pdf/NAM/fullstudy031208.pdf.
23 Discussed in more detail in *Climate Change and Power: Carbon Dioxide Emissions Costs and Electricity Resource Planning* Synapse Energy Economics, May 2006
24 One drawback to programs with higher flexibility is that they are much more complex to administer, monitor, and verify. Emissions reductions must be credited only once, and offsets and trades must be associated with verifiable actions to reduce atmospheric CO_2. A generally accepted standard is the "five-point" test: "at a minimum, eligible offsets shall consist of actions that are real, surplus,

3. The rate of improvement in emissions mitigation technology is a crucial assumption in predicting future emissions costs. For CO_2, looming questions include the future feasibility and cost of carbon capture and sequestration, and cost improvements in integrating carbon-free generation technologies. Improvements in the efficiency of coal burning technologies and in the costs of nuclear power plants could also be a factor.

   In general, those scenarios in the modeling analyses with lesser availability of low-carbon alternatives have the higher CO_2 allowance prices. When low carbon technologies are widely available, CO_2 allowance prices tend to be lower.

4. Complementary energy policies, such as direct investments in energy efficiency or policies that foster renewable energy resources are a very effective way to reduce the demand for emissions allowances and thereby lower their market prices. A policy scenario which includes aggressive energy efficiency and/or renewable resource development along with carbon emissions limits will result in lower allowance prices than one in which these resources are not directly addressed.

5. Most technologies which reduce carbon emissions also reduce emissions of other criteria pollutants, such as NO_x, SO_2 and mercury. Adopting carbon reduction technology results not only in cost savings to the generators who no longer need criteria pollutant permits, but also in broader economic benefits in the form of reduced permit costs and consequently lower priced electricity. In addition, there are a number of co-benefits such as improved public health, reduced premature mortality, and cleaner air associated with overall reductions in power plant emissions which have a high economic value to society. Models which include these co-benefits will predict a lower overall cost impact from carbon regulations, as the cost of reducing carbon emissions will be offset by savings in these other areas.

6. Projected emissions under a business-as-usual scenario (in the absence of greenhouse gas emission restrictions) have a significant bearing on projected allowance costs. The higher the projected emissions, the higher the projected cost of allowance to achieve a given reduction target.

verifiable, permanent and enforceable." Still, there appears to be a benefit in terms of overall mitigation costs to aim for as much flexibility as possible, especially as it is impossible to predict with certainty what the most cost-effective mitigation strategies will be in the future. Models which assume greater program flexibility are likely to predict lower compliance costs for reaching any specified goal.

4. THE SYNAPSE 2008 CO_2 ALLOWANCE PRICE FORECASTS

The Synapse 2008 CO_2 price forecasts begin in 2013. This is a reasonable assumption since it is likely that climate change legislation will be passed by the next Congress and that the implementation of the regulatory scheme may take two years.

The Synapse Low CO_2 Price Forecast starts at $10/ton[25] in 2013, in 2007 dollars, and increases to approximately $23/ton in 2030. This represents a $15/ton levelized price over the period 2013-2030, in 2007 dollars.

This Low Forecast is consistent with the coincidence of one or more of the factors discussed above that have the effect of lowering prices. For example, this price trajectory may represent a scenario in which Congress begins regulation of greenhouse gas emissions slowly by either:

1. including a very modest or loose cap, especially in the initial years,
2. including a safety valve price similar to the Technology Accelerator Payment in the current Bingaman-Specter Legislation (S. 1766), or
3. allowing for significant offset flexibility, including the use of substantial numbers of international offsets.

The factors could also include a decision by Congress to adopt a set of aggressive complementary policies as part of a package to reduce CO_2 emissions. These complementary policies could include an aggressive federal Renewable Portfolio Standard, more stringent automobile CAFE mileage standards (in an economy-wide regulation scenario), and/or substantial energy efficiency investments. Such complementary policies would lead directly to a reduction in CO_2 emissions independent of federal cap-and-trade or carbon tax policies, and would lower the expected allowance prices associated with the achievement of any particular federally-mandated goal.

The 2008 Synapse High CO_2 Price Forecast starts at $30/ton in 2013, in 2007 dollars, and rises to approximately $68/ton in 2030. This High Forecast represents a $45/ton levelized price over the period 2013-2030, also in 2007 dollars.

This High CO_2 Price Forecast is consistent with the occurrence of one or more of the factors identified above that have the effect of raising prices. These factors include somewhat more aggressive emissions reduction targets, greater restrictions on the use of offsets, some restrictions on the availability of or the high cost of technology alternatives such as nuclear, biomass and carbon capture and sequestration, and more aggressive international actions (thereby resulting in fewer inexpensive international offsets available for purchase by U.S. emitters).

There are some CO_2 price scenarios identified in recent analyses that are significantly higher than our Synapse High Price Forecast. These scenarios represent situations with

[25] Throughout this paper, emission allowance prices are quoted in dollars per ton. This should be interpreted as dollars per short ton of CO_2. Prices in the economic literature and in international trading are often quoted in dollars per metric ton of CO_2 or dollars per metric ton of carbon, but the units we use are more typical of US carbon pricing schemes.

limited availability of alternatives to carbon-emitting technologies and/or limited use of international and domestic offsets. We do not believe that the CO_2 prices characteristic of such scenarios are likely in the current political environment, given that there may potentially be avenues available for meeting likely emissions goals that would mitigate the costs to below these levels. This may change over time due to changes in technical, economic, and political circumstances, more stringent CO_2 emissions targets, and/or developments in scientific evidence and of the impacts of a changing climate.

Synapse also has prepared a Mid CO_2 Price Forecast that starts close to the low case, at \$15/ton in 2013 in 2007 dollars, but then climbs to \$53/ton by 2030. The levelized cost of this mid CO_2 price forecast is \$30/ton in 2007 dollars, which is the midpoint between the \$15/ton Low CO_2 Price Forecast and the \$45/ton High CO_2 Price Forecast. The Mid CO_2 price forecast represents a scenario in which CO_2 allowance prices begin rather low, perhaps reflecting the hesitance of the U.S. Congress to impose high costs in the short run, but then climb significantly over time as federal regulation of CO_2 emissions becomes progressively more stringent.

The 2008 Synapse High, Mid and Low CO_2 Price Forecasts are shown in Figure 3 and Table 2 below:

Figure 3: Synapse 2008 CO_2 Price Forecasts

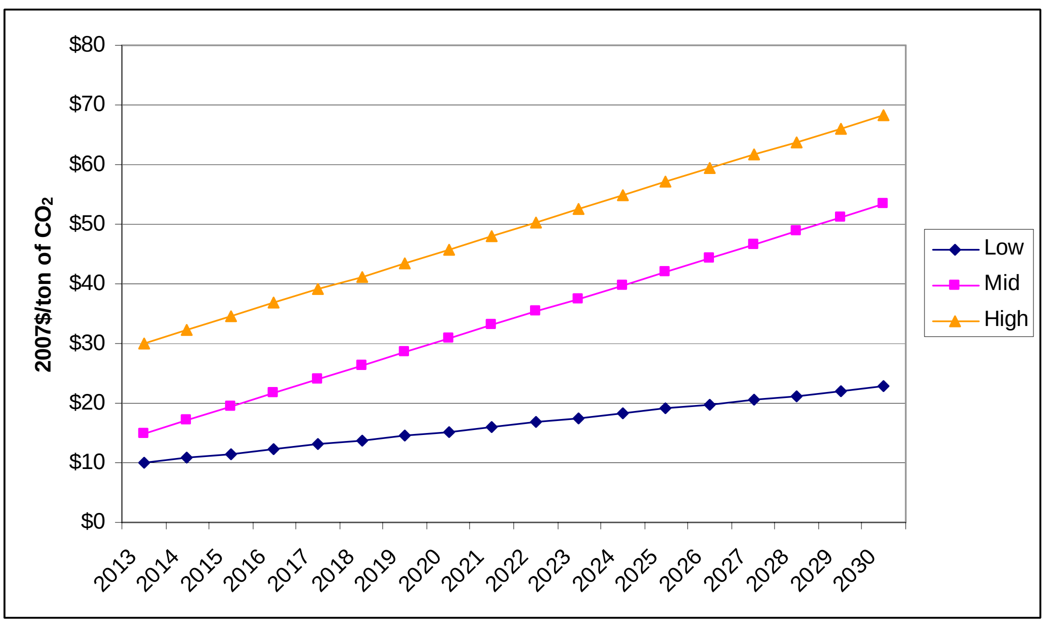

Table 2: Synapse 2008 CO_2 Price Forecasts (in 2007 dollars)

Year	Low	Mid	High
2013	$10.00	$15.00	$30.00
2014	$10.80	$17.30	$32.30
2015	$11.50	$19.50	$34.50
2016	$12.30	$21.80	$36.80
2017	$13.00	$24.00	$39.00
2018	$13.80	$26.30	$41.30
2019	$14.50	$28.50	$43.50
2020	$15.30	$30.80	$45.80
2021	$16.00	$33.10	$48.10
2022	$16.80	$35.30	$50.30
2023	$17.50	$37.60	$52.60
2024	$18.30	$39.80	$54.80
2025	$19.00	$42.10	$57.10
2026	$19.80	$44.30	$59.30
2027	$20.50	$46.60	$61.60
2028	$21.30	$48.80	$63.80
2029	$22.00	$51.10	$66.10
2030	$22.80	$53.40	$68.40

Given the significant uncertainty in the timing and design of CO_2 regulatory programs, we believe that the use of a range of CO_2 prices, such as that represented by the Synapse Low and High CO_2 Price Forecasts ($15/ton to $45/ton on a levelized basis between 2013 and 2030) is appropriate in utility resource planning.

The Synapse CO_2 price forecasts are consistent with the results of the analyses of current legislative proposals and recent forecasts by regulatory commissions and utilities. For example, Figure 4 compares the annual CO_2 prices in the Synapse Low, Mid and High Forecasts with the CO_2 prices in the scenarios examined by the EIA, EPA, MIT, and Duke University in their assessments of the proposals that have been introduced in the current U.S. Congress. The Synapse forecasts are shown in the solid red lines. A number of the analyses resulted in allowance price trajectories that were significantly higher than the Synapse forecasts. As noted earlier, however, we do not believe that the highest scenarios are realistic given the current political environment and the options available for mitigating high price impacts from carbon regulation.

Figure 4: **Synapse 2008 CO_2 Price Forecasts vs. Results of Modeling Analyses Major Bills in Current U.S. Congress – Annual CO_2 Prices (in 2007 dollars)**

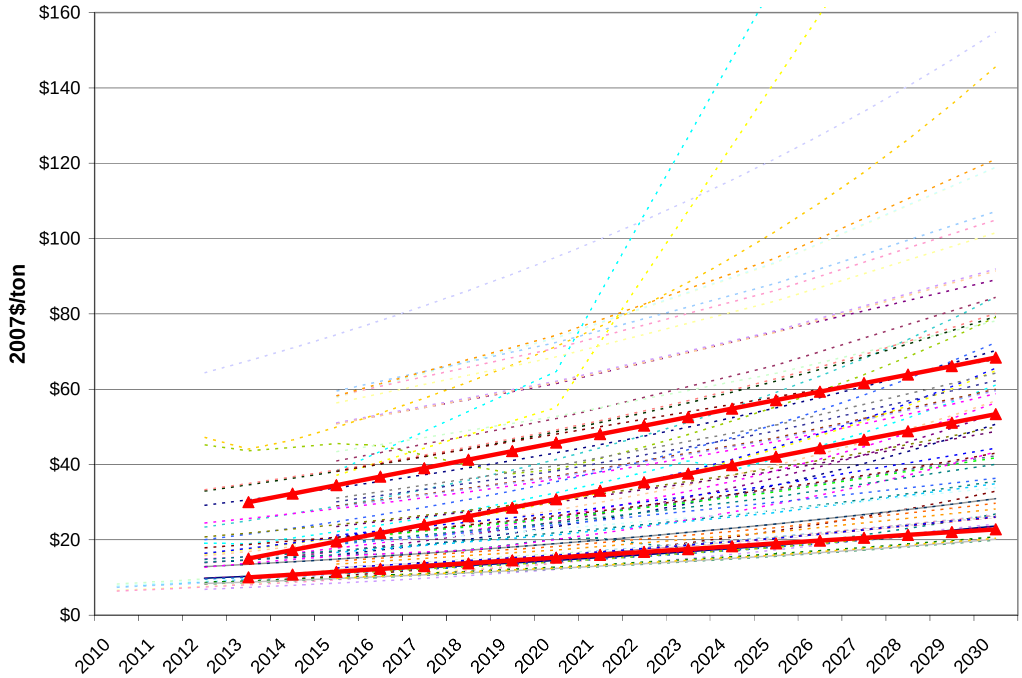

Figure 5 presents a similar comparison but in a simplified format. In Figure 5, rather than annual costs, the comparison is in terms of levelized costs for the years 2013 through 2030, also in 2007 dollars.[26] Also, in Figure 5 only the high, low, and median cases for each study are presented.

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[26] Synapse used a real discount rate of 7.32% for calculating levelized values. This is equivalent to 10% nominal and 2.5% inflation. We used the CPI to convert past year dollars to 2007 dollars. At the same time, we used a 2.5% inflation rate to convert future year dollars back to 2007 dollars.

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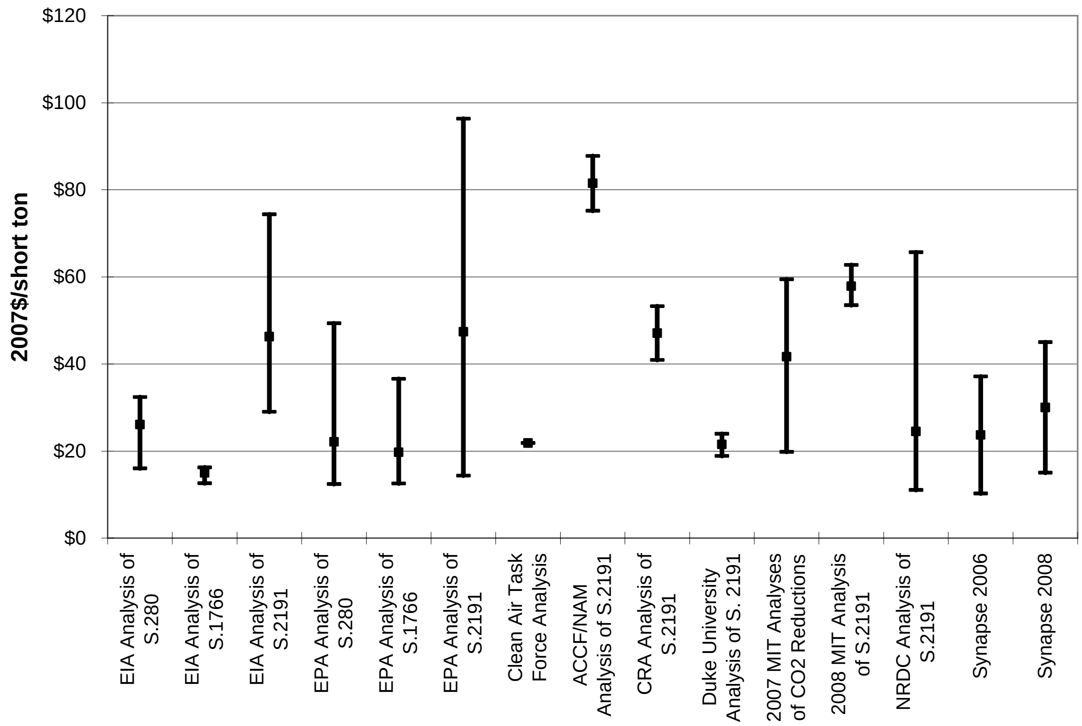
Figure 5: **Synapse 2008 CO_2 Price Forecasts vs. Results of Modeling Analyses Major Bills in Current U.S. Congress – Levelized CO_2 Prices (2013-2030, in 2007 dollars)**



As shown in Figure 6, the 2008 Synapse CO_2 Price Forecasts also are consistent with the ranges of CO_2 prices that an increasing number of regulatory commissions and utilities are using in electric resource planning analyses. [27]

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27 Synapse used a real discount rate of 7.32% for calculating levelized values. This is equivalent to 10% nominal and 2.5% inflation. We used the CPI to convert past year dollars to 2007 dollars. At the same time, we used a 2.5% inflation rate to convert future year dollars back to 2007 dollars.

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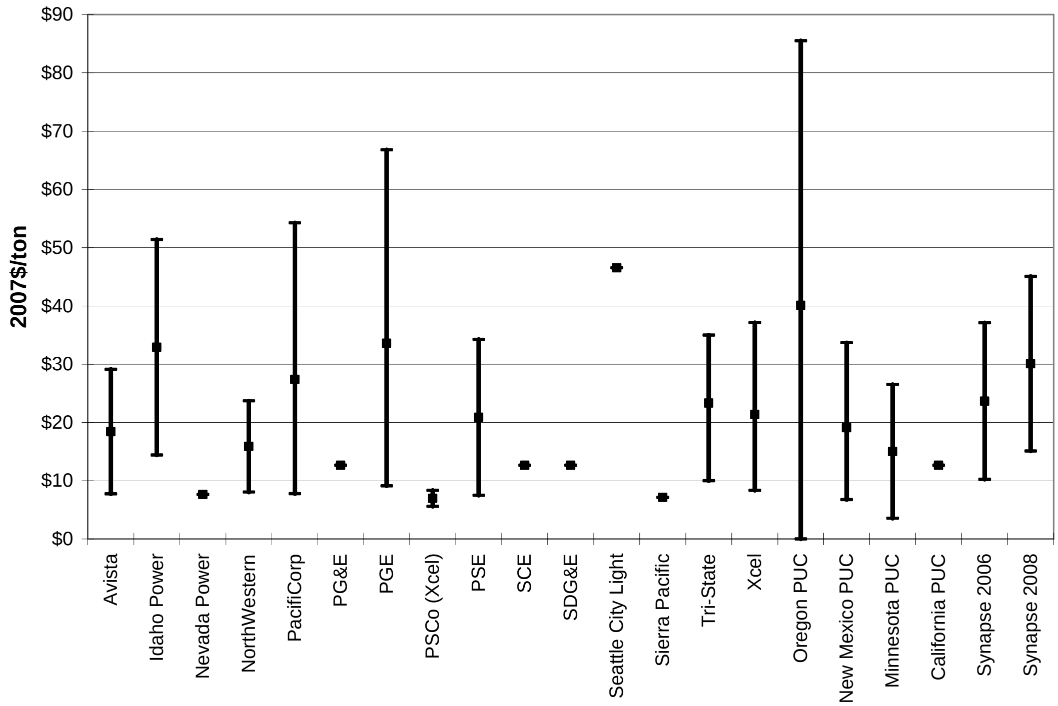
Figure 6: **Synapse 2008 CO_2 Price Forecasts vs. CO_2 Prices Used by Regulatory Commissions and Utilities in Resource Planning Analyses (2013-2030, in 2007 dollars)**



5. CONCLUSION

In 2006, Synapse developed an initial forecast of CO_2 allowance prices for use in electricity resource planning. In the past two years, we have seen a number of developments that have caused us to refine our expectations for the likely emission allowance costs under federal greenhouse gas regulation. More recent legislative proposals reveal a greater understanding, in Congress and among the pubic, of climate change and the emissions reductions that will be necessary to avoid dangerous climate change. As a result, long-term emission reduction targets contained in current federal proposals are more stringent than those from prior sessions, approaching the reduction levels identified by the scientific community as necessary to avoid dangerous climate change. This trend leads us to conclude that allowance prices will be higher than we projected back in 2006.

Simultaneously, today's legislative proposals reveal a more sophisticated understanding of the advantages and value of a comprehensive approach to achieving emission reductions. These proposals incorporate complementary energy policies, such as incentives for technology innovation, funds targeted to energy efficiency, restrictions on non-CCS new coal, and/or emissions performance standards, which are likely to mitigate the cost of achieving aggressive emissions goals. Further, provisions for program flexibility and trends in technological innovation hold promise to limit the price impact in the long term. Based on all of these factors, we believe our allowance price projections for the period 2013 to 2030 represent an appropriate range of values to facilitate robust decision-making for an uncertain future, in which carbon emissions will be regulated by some as-yet undefined federal regime.

Resource Assessment Assumptions - Xcel Energy Preferred Inputs

Preliminary CO2

Year	Low ($/Ton)	Mid ($/Ton)	High ($/Ton)
2008	$4.00	$17.00	$30.00
2009	$4.12	$17.51	$30.90
2010	$4.24	$18.04	$31.83
2011	$4.37	$18.58	$32.78
2012	$4.50	$19.13	$33.77
2013	$4.64	$19.71	$34.78
2014	$4.78	$20.30	$35.82
2015	$4.92	$20.91	$36.90
2016	$5.07	$21.54	$38.00
2017	$5.22	$22.18	$39.14
2018	$5.38	$22.85	$40.32
2019	$5.54	$23.53	$41.53
2020	$5.70	$24.24	$42.77
2021	$5.87	$24.97	$44.06
2022	$6.05	$25.71	$45.38
2023	$6.23	$26.49	$46.74
2024	$6.42	$27.28	$48.14
2025	$6.61	$28.10	$49.59
2026	$6.81	$28.94	$51.07
2027	$7.01	$29.81	$52.61
2028	$7.22	$30.70	$54.18
2029	$7.44	$31.63	$55.81
2030	$7.66	$32.57	$57.48
2031	$7.89	$33.55	$59.21
2032	$8.13	$34.56	$60.98
2033	$8.38	$35.59	$62.81
2034	$8.63	$36.66	$64.70
2035	$8.89	$37.76	$66.64
2036	$9.15	$38.89	$68.64
2037	$9.43	$40.06	$70.70
2038	$9.71	$41.26	$72.82
2039	$10.00	$42.50	$75.00
2040	$10.30	$43.78	$77.25

Suggested Alternative Data

Year	Low ($/Ton)	Mid ($/Ton)	High ($/Ton)
2008	0	0	0
2009	0	0	0
2010	$10.00	$20.00	$40.00
2011	$10.25	$20.50	$41.00
2012	$10.51	$21.01	$42.03
2013	$10.77	$21.54	$43.08
2014	$11.04	$22.08	$44.15
2015	$11.31	$22.63	$45.26
2016	$11.60	$23.19	$46.39
2017	$11.89	$23.77	$47.55
2018	$12.18	$24.37	$48.74
2019	$12.49	$24.98	$49.95
2020	$12.80	$25.60	$51.20
2021	$13.12	$26.24	$52.48
2022	$13.45	$26.90	$53.80
2023	$13.79	$27.57	$55.14
2024	$14.13	$28.26	$56.52
2025	$14.48	$28.97	$57.93
2026	$14.85	$29.69	$59.38
2027	$15.22	$30.43	$60.86
2028	$15.60	$31.19	$62.39
2029	$15.99	$31.97	$63.95
2030	$16.39	$32.77	$65.54
2031	$16.80	$33.59	$67.18
2032	$17.22	$34.43	$68.86
2033	$17.65	$35.29	$70.58
2034	$18.09	$36.17	$72.35
2035	$18.54	$37.08	$74.16
2036	$19.00	$38.01	$76.01
2037	$19.48	$38.96	$77.91
2038	$19.96	$39.93	$79.86
2039	$20.46	$40.93	$81.86
2040	$20.98	$41.95	$83.90

Nice round values.

EPA forecasted very high CO2 prices in their national carbon model, maybe do a scenario at $75 for an extreem carbon scenario?

based on recent NYMEX

Preliminary Natural Gas

MISO/PowerBase

Year	$/MMBTU
2008	8.453531
2009	8.79167224
2010	9.14333913
2011	9.50907269
2012	9.8894356
2013	10.285013
2014	10.6964135
2015	11.1242701
2016	11.5692409
2017	12.0320105
2018	12.513291
2019	13.0138226
2020	13.5343755
2021	14.0757505
2022	14.6387805
2023	15.2243318
2024	15.833305
2025	16.4666372
2026	17.1253027
2027	17.8103148
2028	18.5227274
2029	19.2636365
2030	20.034182
2031	20.8355493
2032	21.6689712
2033	22.5357301
2034	23.4371593
2035	24.3746456
2036	25.3496315
2037	26.3636167
2038	27.4181614
2039	28.5148879
2040	29.6554834

Contingencies:
High/Low ± 20%

Big Stone II

Year	$/MMBTU
2008	$8.75
2009	$8.38
2010	$8.25
2011	$8.01
2012	$8.06
2013	$8.04
2014	$8.31
2015	$8.49
2016	$8.85
2017	$9.37
2018	$9.53
2019	$9.72
2020	$10.13
2021	$10.35
2022	$10.83
2023	$11.31
2024	$11.83
2025	$12.14
2026	
2027	
2028	
2029	
2030	
2031	
2032	
2033	
2034	
2035	
2036	
2037	
2038	
2039	
2040	

2008 EIA AEO
(adjusted for 3% inflation)

Year	$/MMBTU
2008	$7.68
2009	$8.09
2010	$7.61
2011	$7.49
2012	$7.52
2013	$7.46
2014	$7.45
2015	$7.52
2016	$7.68
2017	$7.97
2018	$8.28
2019	$8.62
2020	$8.73
2021	$8.78
2022	$9.22
2023	$9.65
2024	$10.15
2025	$10.66
2026	$11.19
2027	$11.63
2028	$12.39
2029	$13.03
2030	$13.68
2031	
2032	
2033	
2034	
2035	
2036	
2037	
2038	
2039	
2040	

Suggested Alternative Data

Year	$/MMBTU
2008	$9.05
2009	$9.13
2010	$9.22
2011	$8.95
2012	$8.73
2013	$8.60
2014	$8.00
2015	$7.71
2016	$7.91
2017	$8.17
2018	$8.46
2019	$8.84
2020	$9.05
2021	$9.13
2022	$9.43
2023	$9.76
2024	$10.11
2025	$10.34
2026	$10.65
2027	$10.98
2028	$11.31
2029	$11.65
2030	$11.98
2031	$12.25
2032	$12.54
2033	$12.83
2034	$13.12
2035	$13.42
2036	$13.69
2037	$13.97
2038	$14.24
2039	$14.53
2040	$14.82

Contingencies:

Preliminary Coal

2008 EIA AEO			MISO Data			Suggested Alternative Data		
Year	$/MMBTU		Year	$/MMBTU		Year	$/MMBTU	
2008	$1.88		2008	$1.67		2008	$1.93	
2009	$1.99	5.73%	2009	$1.71	2.00%	2009	$2.12	9.77%
2010	$2.05	3.00%	2010	$1.75	2.50%	2010	$2.28	7.56%
2011	$2.11	3.00%	2011	$1.79	2.00%	2011	$2.44	6.81%
2012	$2.17	3.00%	2012	$1.82	2.00%	2012	$2.50	2.49%
2013	$2.23	3.00%	2013	$1.86	2.00%	2013	$2.53	1.26%
2014	$2.30	3.00%	2014	$1.89	2.00%	2014	$2.58	2.00%
2015	$2.37	3.00%	2015	$1.93	2.00%	2015	$2.63	2.00%
2016	$2.44	3.00%	2016	$1.97	2.00%	2016	$2.69	2.00%
2017	$2.52	3.00%	2017	$2.01	2.00%	2017	$2.74	2.00%
2018	$2.59	3.00%	2018	$2.05	2.00%	2018	$2.79	2.00%
2019	$2.67	3.00%	2019	$2.09	2.00%	2019	$2.85	2.00%
2020	$2.75	3.00%	2020	$2.13	2.00%	2020	$2.91	2.00%
2021	$2.83	3.00%	2021	$2.18	2.00%	2021	$2.96	2.00%
2022	$2.92	3.00%	2022	$2.22	2.00%	2022	$3.02	2.00%
2023	$3.00	3.00%	2023	$2.26	2.00%	2023	$3.08	2.00%
2024	$3.09	3.00%	2024	$2.31	2.00%	2024	$3.15	2.00%
2025	$3.19	3.00%	2025	$2.36	2.00%	2025	$3.21	2.00%
2026	$3.28	3.00%	2026	$2.40	2.00%	2026	$3.27	2.00%
2027	$3.38	3.00%	2027	$2.45	2.00%	2027	$3.34	2.00%
2028	$3.48	3.00%	2028	$2.50	2.00%	2028	$3.41	2.00%
2029	$3.59	3.00%	2029	$2.55	2.00%	2029	$3.47	2.00%
2030	$3.69	3.00%	2030	$2.60	2.00%	2030	$3.54	2.00%
2031			2031	$2.65	2.00%	2031	$3.61	2.00%
2032			2032	$2.71	2.00%	2032	$3.69	2.00%
2033			2033	$2.76	2.00%	2033	$3.76	2.00%
2034			2034	$2.81	2.00%	2034	$3.83	2.00%
2035			2035	$2.87	2.00%	2035	$3.91	2.00%
2036			2036	$2.93	2.00%	2036	$3.99	2.00%
2037			2037	$2.99	2.00%	2037	$4.07	2.00%
2038			2038	$3.05	2.00%	2038	$4.15	2.00%
2039			2039	$3.11	2.00%	2039	$4.23	2.00%
2040			2040	$3.17	2.00%	2040	$4.32	2.00%

Contingencies:
High/Low ± 20%
Includes 2% Adder

Contingencies:

about half the cost of coal is transportation, closely tied to the cost of diesel. Recent run up in delivery cost when we renegotiated rail contracts.

Preliminary Capital Costs

Proposed Data

Unit	$/kW
Coal	$2,434.77
CC	$859.00
CT	$605.00
IGCC w/ sequestration*	$3,639.98
Wind	$1,910.00
Nuclear	

*Based a MISO ratio of Coal to IGCC w/ sequestration

Big Stone Data

Unit	$/kW 2006	Adjusted to 2008
Coal	$2,295.00	$2,434.77
CC	$1,719.00	$1,823.69
CT	$1,098.00	$1,164.87
IGCC		
Wind	$1,810.00	$1,920.23
Nuclear		

MISO Data

Unit	$/kW
Coal	$1,835.00
CC	$859.00
CT	$605.00
IGCC w/ sequestration	$2,748.00
Wind	$1,910.00
Nuclear	$2,493.00

MISO Data adjusted with 2008 AEO

Unit	$/kW
Coal	$2,147.60
CC	$988.40
CT	$700.00
IGCC w/ sequestration	$3,210.66
Wind	$1,910.00
Nuclear	$3,465.00

Suggested Alternative Data

Unit	$/kW	
Coal	$3,000	
CC	$1,000	- This is a recent estimate for a 700MW 2x1 with duct firing.
CT	$750	
IGCC w/ sequestration	$4,000	- There should also be a performance penalty for sequestration (25% higher heat rate?)
Wind	$2,500	- The turbine market is very tight.
Nuclear	$5,500	

Preliminary Effluent Costs

MISO/PowerBase Data

NOx	$/Ton	Hg	$/Ton	SO2	$/Ton
2008	$825.00	2008		2008	$471.79
2009	$1,458.21	2009		2009	$471.32
2010	$1,491.37	2010	$72,082,930	2010	$481.96
2011	$1,604.30	2011	$78,228,640	2011	$472.50
2012	$1,742.16	2012	$84,667,580	2012	$463.06
2013	$1,883.83	2013	$91,279,020	2013	$448.88
2014	$2,031.80	2014	$98,183,240	2014	$439.42
2015	$2,101.22	2015	$105,341,300	2015	$472.51
2016	$2,092.84	2016	$114,160,200	2016	$405.00
2017	$2,086.57	2017	$123,548,600	2017	$371.26
2018	$2,082.17	2018	$133,560,700	2018	$337.51
2019	$2,078.48	2019	$144,190,800	2019	$270.00
2020	$2,073.49	2020	$155,352,400	2020	$243.00
2021	$2,134.25	2021	$159,904,700	2021	$247.64
2022	$2,197.94	2022	$164,676,800	2022	$252.58
2023	$2,263.95	2023	$169,622,300	2023	$257.53
2024	$2,333.34	2024	$174,820,700	2024	$262.70
2025	$2,406.29	2025	$180,286,600	2025	$267.93
2026	$2,452.79	2026	$183,770,600	2026	$273.11
2027	$2,500.96	2027	$187,379,300	2027	$278.47
2028	$2,575.98	2028	$193,000,679	2028	$286.82
2029	$2,653.26	2029	$198,790,699	2029	$295.43
2030	$2,732.86	2030	$204,754,420	2030	$304.29
2031	$2,814.85	2031	$210,897,053	2031	$313.42
2032	$2,899.29	2032	$217,223,965	2032	$322.82
2033	$2,986.27	2033	$223,740,683	2033	$332.51
2034	$3,075.86	2034	$230,452,904	2034	$342.48
2035	$3,168.13	2035	$237,366,491	2035	$352.76
2036	$3,263.18	2036	$244,487,486	2036	$363.34
2037	$3,361.07	2037	$251,822,110	2037	$374.24
2038	$3,461.91	2038	$259,376,774	2038	$385.47
2039	$3,565.76	2039	$267,158,077	2039	$397.03
2040	$3,672.74	2040	$275,172,819	2040	$408.94

Suggested Alternative Data

No CAMR

2008	$200.00	2008	$0.00	2008	$850.00
2009	$204.00	2009	$0.00	2009	$867.00
2010	$208.00	2010	$0.00	2010	$884.00
2011	$212.00	2011	$0.00	2011	$902.00
2012	$216.00	2012	$0.00	2012	$920.00
2013	$221.00	2013	$0.00	2013	$938.00
2014	$225.00	2014	$0.00	2014	$957.00
2015	$230.00	2015	$0.00	2015	$976.00
2016	$234.00	2016	$0.00	2016	$996.00
2017	$239.00	2017	$0.00	2017	$1,016.00
2018	$244.00	2018	$0.00	2018	$1,036.00
2019	$249.00	2019	$0.00	2019	$1,057.00
2020	$254.00	2020	$0.00	2020	$1,078.00
2021	$259.00	2021	$0.00	2021	$1,100.00
2022	$264.00	2022	$0.00	2022	$1,122.00
2023	$269.00	2023	$0.00	2023	$1,144.00
2024	$275.00	2024	$0.00	2024	$1,167.00
2025	$280.00	2025	$0.00	2025	$1,190.00
2026	$286.00	2026	$0.00	2026	$1,214.00
2027	$291.00	2027	$0.00	2027	$1,238.00
2028	$297.00	2028	$0.00	2028	$1,263.00
2029	$303.00	2029	$0.00	2029	$1,288.00
2030	$309.00	2030	$0.00	2030	$1,314.00
2031	$315.00	2031	$0.00	2031	$1,340.00
2032	$322.00	2032	$0.00	2032	$1,367.00
2033	$328.00	2033	$0.00	2033	$1,395.00
2034	$335.00	2034	$0.00	2034	$1,422.00
2035	$341.00	2035	$0.00	2035	$1,451.00
2036	$348.00	2036	$0.00	2036	$1,480.00
2037	$355.00	2037	$0.00	2037	$1,509.00
2038	$362.00	2038	$0.00	2038	$1,540.00
2039	$370.00	2039	$0.00	2039	$1,570.00
2040	$377.00	2040	$0.00	2040	$1,602.00

There's been a dramatic drop in SOx and NOx permit prices since CAIR was abandoned.

Retirement of Units

Monticello	2030
Prairie Island 1	2033
Prairie Island 2	2034

Interstate Power and Light Company (IPL) appreciates the opportunity to submit comments regarding the assumptions contemplated for the Minnesota Resource Assessment.

IPL is very supportive of the concept of long term resource assessments. Resource planning must consider a wide variety of analytical, market and policy issues and present a plan to continue to meet customer needs in a low-cost, reliable and environmentally sound manner.

IPL offers the following comments:

I. Data Source

IPL has comments related to the use of IPL data which can be found under the forecast section of this document.

II. Proposed Scenarios

A. Forecast

IPL conducts Integrated Resource Planning on a system-wide basis for the entire IPL service territory. Currently approximately 94% of IPL load is located in Iowa with the remaining 6% located in Minnesota. IPL is concerned about including IPL-Iowa load in a resource assessment for the Minnesota Legislature. A couple of IPL's concerns are as follows:

- Inclusion of IPL-Iowa load may provide a distorted picture to the Legislature of the resources required to satisfy Minnesota requirements, and
- Such an assessment may lead to public policy decisions and actions in Minnesota that may have unintended consequences in other states, such as IPL's Iowa customers.

Instead, IPL proposes to include only the IPL-Minnesota load and the appropriate 6% of all generation resources that are allocated to IPL-Minnesota customers.

B. Price Estimates

IPL believes that it is crucial that a consistent set of cost estimates from a single source are utilized and benchmarked with recent experience. Selecting a cost estimate for base load coal from one source and a cost estimate for combined cycle gas from another source may result in analysis that has no meaning. It is imperative that each cost estimate have relativity to each other and were developed consistently and in the same time period.

C. Scenarios

While IPL recognizes the desire to conduct a high level assessment, IPL believes that more appropriate size for a pulverized coal unit is in the 650 MW range, a 2x1 arrangement that would have a net summer capacity of approximately 550 MW for combined cycle, and 150 MW for simple cycle combustion turbine technology. IPL believes that these sizes more closely align with present day technology and adequately capture economies of scale. IPL also recommends an IGCC unit size comparable to a combined cycle unit. Disproportionate sizes can adversely influence technology selection.

1. Renewable Future

Because wind is primarily an energy resource, IPL is concerned about the lack of capacity to satisfy reserve requirements under either an RES compliance or off-ramp scenario. IPL would recommend that under these two scenarios, the OES/Commission allow other resources to be selected to satisfy reserve capacity obligations.

2. Base Load Future

No additional comments.

3. Natural Gas Reliant Future

IPL believes that if significant amounts of coal capacity currently planned is delayed or cancelled, natural gas will become the fuel of choice. As a result, because of increased demand, price increases will occur over and above those prices contained in a base load future scenario. IPL would recommend an addition to the base natural gas forecast of at least 10% to reflect increased natural gas demand under this scenario.

D. Assumptions

1. CO_2

IPL believes that a base case needs to be developed assuming no CO_2 tax. While IPL understands the importance of comparison of a range of potential CO_2 taxes, IPL believes that it is equally important to understand the implications of a CO_2 tax relative to the status quo so that an informed decision can be made on public policy with a full understanding of rate impacts to customers. Absent a base case with no CO_2 tax, an informed decision as to the implications of such a tax cannot be made. Additionally, IPL recommends that modeling of a potential cap-and-trade system be included, such as Senate Bill 2191: Lieberman-Warner Climate Security Act of 2007.

2. Natural Gas Prices

Please see IPL's comments under the Natural Gas Reliant Future. Once again, IPL would reiterate that ALL costs, capital and fuel, are developed in a consistent manner and benchmarked with recent experience. For example, in the Energy Information Administration's (EIA) Annual Energy Outlook (AEO) for 2008, natural gas price projections appear to be lower than what IPL is currently experiencing and EIA's AEO 2008 coal projections appear to be on the high side based upon what IPL is currently experiencing. IPL supports an analysis of price contingencies, but as noted in IPL's Natural Gas Reliant Future comments above, those price contingencies should be conducted on a +10% base natural gas price to reflect the increased demand of natural gas in a non base load future.

3. Coal Prices

No comments.

4. Capital Costs

The proposed use of MISO prices for certain generating technologies and the use of Big Stone II estimates for other technologies is of concern to IPL. By picking and choosing certain capital cost information from one source and picking and choosing certain capital cost information from another source is not an apples-to-apples basis to the extent that the results are not meaningful or accurate. IPL recommends that the OES select one source for ALL capital cost data and use it throughout the study with additions, as necessary, to reflect certain conditions. IPL believes the implications of not using an apples-to-apples comparison may undermine Minnesota's overall resource planning. IPL recommends the use of the Big Stone II and comparative alternative cost data consistently throughout the study.

IPL at this time has no basis to suggest capital costs associated with a nuclear unit.

CENTRAL MINNESOTA MUNICIPAL POWER AGENCY
459 South Grove Street Blue Earth, Minnesota 56013 507-526-2193

August 13, 2008

Ms. Marya White
Office of the Reliability Administrator
Minnesota Department of Commerce
85-7th Place East
St. Paul, MN 55101

RE: Outline and Assumptions for Minnesota Resource Assessment

Dear Marya:

Thank you for the invitation to review and comment on input assumptions for the Office of Energy Security's (OES) Resource Assessment, to be performed to fulfill requirements of the 2007 Next Generation Energy Act.

First of all, Central Minnesota Municipal Power Agency (CMMPA) appreciates your challenge in accomplishing this study. As Assistant Commissioner Edward Garvey stated at the stakeholders meeting, such a broad, statewide study by definition and level of detail cannot hope to determine the resource needs of individual utilities. Nevertheless, we offer the attached suggestions in the hope they will be helpful to you in providing useful information to the Legislature.

Sincerely,

Bob Schulte

Robert Schulte
Chief Executive Officer

Attachment

CMMPA Review Comments on
Minnesota Resource Assessment
Outline and Assumptions
August 13, 2008

The following CMMPA comments follow the same order as the Outline provided by the OES on July 21, 2008.

I. Data Sources

It appears the load data to be used does not include the loads of CMMPA members or Willmar, who is participating with CMMPA in the Big Stone II project. Further, it appears that it does not include load data for other municipal utilities that are not aligned with a municipal power agency.

From the list of load data to be used, it appears that the result of the study will be a Minnesota "island" in what is actually a regional power pool. We understand this is the perspective defined by the legislation. However, this approach has the potential for study results that Balkanize Minnesota from the rest of the regional pool; thereby denying the economies of scale and shared resources that are the reasons for a regional approach in the first place. When the study results are evaluated, this should be taken into account.

II. Proposed Scenarios

A. Forecast

Again, it appears the demand forecasts of CMMPA and non-aligned municipal utilities are not included in the load forecast for the study, because CMMPA and such other utilities doe not submit Integrated Resource Plans. To include CMMPA, you could use the CMMPA forecast included in the Big Stone II certificate of need application. You would need to secure forecasts from the other municipal utilities directly.

Also, as discussed at the Stakeholder's meeting, the study should include one or more sensitivity scenarios that illustrate the outcomes if the 1.5% CIP goal is not achieved. While CMMPA and other utilities are making good-faith efforts to achieve this aggressive goal, from a state planning perspective such sensitivities should be included in the study. We note that OES included a range of 1.0 % to 1.5% in its testimony in the CAPX proceeding.

B. Price Estimates

The draft assumptions state that the OES intends to run contingencies for each major price assumption. We submit that the contingency on capital costs should apply the planned plus or minus 20% variation on ***all*** alternatives.

C. Scenarios

We note that the current plan for the "Baseload Future" scenario intends to use single, 1,200 MW coal units with their in-service dates specified in 2015 and 2030.

While this approach may provide some useful, global information between the various scenarios, it is a good example of Ed Garvey's comment at the Stakeholders meeting that the study as defined cannot determine the appropriate resource mixes for individual utilities. This is true because a 1,200 MW coal unit in a specified year may be too large for the actual baseload need in that year. What if the actual baseload need in that year is significant (say, 250 MW or 750 MW), but smaller than 1,200 MW? Also, multiple generation units whose total output equals 1,200 MW would have reliability and cost advantages over a single 1,200 MW unit. If the model is only offered baseload additions in 1,200 MW increments, the study will likely miss the right answer.

Again, this may be a simplifying assumption that is necessary. However, the study results need to acknowledge this very clearly. At a minimum, we suggest that the unit sizes of the coal, IGCC and nuclear units all be the same MW size, to avoid biases between those alternatives that could arise merely from the simplifying MW size assumption.

1. Renewable Future

   Although it is not mentioned in the draft assumptions, we assume that the Renewable Future scenarios will include consideration of transmission costs necessary to support the wind alternatives.

2. Base Load Future

   Our previous comments above regarding baseload assumptions apply here as well.

3. Natural-Gas-Reliant Future

   Given the recent high volatility in natural gas prices we have seen (up to $13/MMBtu), this scenario should be subjected to price sensitivity analyses that represent the potential for continued volatility and high prices.

D. Assumptions

CMMPA's comments regarding assumptions are provided below. We understand MRES will also be providing comments, and for the sake of brevity we recommend you use specific planning values provided by MRES.

1. CO2

   No comments.

2. Natural Gas Prices

   As noted above, the 2007 data is not representative of the future possibilities of natural gas prices. The natural gas price scenario should consider the possible return of futures like we have seen recently ($13+ gas). This should be a prime concern for the Reliability Administrator.

3. Coal Prices

   Although it is appropriate to do price sensitivities on coal, the relative sensitivities (in $/MMBtu) used on natural gas prices should be wider (and higher) than for coal.

4. Capital Costs

   The initial assumptions list appears to inappropriately mix and match capital costs of various vintages. If the study plans to use the capital cost of Big Stone II as a base assumption for coal units, then the corresponding capital costs for the other alternatives should be consistent with that.

   In particular, it appears the EIA values for combustion turbines and combined cycle units are far too low.

5. Effluent Costs

   No comments.

6. Retirement of Units

   No comments.

7. Summary of Scenarios

   It appears that the scenarios list needs an important additional scenario. In particular, the analysis should include a scenario where a large industrial baseload need is added to the forecast. This could represent the Minnesota Steel Project at Nashwauk. Construction of this project could break ground yet this fall, and could represent a baseload need of 500 MW by 2014 -- a load that is not included in anyone's IRP forecast to-date.

We believe it is important that the Reliability Administrator represent the possibility of such needs in the Resource Assessment.

Thank you for the opportunity to comment!

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EXCELSIOR ENERGY INC. COMMENTS ON THE MINNESOTA STATEWIDE ELECTRICITY RESOURCE ASSESSMENT

AUGUST 15, 2008

I. INTRODUCTION

Excelsior Energy Inc. appreciates the opportunity to provide comments on the Office of Energy Security's ("OES") Minnesota Resource Assessment ("Assessment"), which is being prepared on behalf of the Reliability Administrator as required under the Next Generation Energy Act of 2007. This Assessment is an important part of the Reliability Administrator's duties as "a source of independent expertise and a technical advisor to the commissioner [of commerce], the [public utilities] commission and the public on issues related to the reliability of the electric system."[1] The public has a particularly important interest in a reliable statewide electric system with ample capacity under a variety of foreseeable load-growth scenarios, and the Assessment provides the first opportunity ever to assess statewide electric needs taking into account all utilities serving customers in Minnesota (i.e., including municipal utilities and not just large investor-owned and cooperative utilities) as well as different assumptions about future growth rates in the state. For these reasons, it is imperative that the Assessment include robust load-growth scenario analyses for all utilities in the state combined with consistent and reasonable modeling assumptions to allow for accurate and useful conclusions that can provide some level of assurance to the people of Minnesota that reliable and cost-effective electric service will be available to meet foreseeable electric energy demand growth.

II. MODELING ASSUMPTIONS

A. Energy Demand Forecasting

Because the Assessment allows for an examination, on an integrated statewide basis, of whether electric generation resources will be sufficient in the future to continue providing reliable service, the most important assumption in the Assessment is the forecast of energy demand growth in the state. Based on the "Outline and Assumptions for Minnesota Resource Assessment" document provided by the OES for the July 30, 2008 Stakeholder Meeting, it appears that the OES will not be including any load served by municipal utilities other than Hutchinson and Southern Minnesota Municipal Power Agency in its load growth data set.[2] Given that in 2005 municipal utilities served 350,762 customers in Minnesota consuming 9,408 gigawatt hours of electricity,[3] any

[1] Minn. Stat. § 216C.052, subd. 1(a).

[2] Office of Energy Security, Outline and Assumptions for Minnesota Resource Assessment, page 1 ("[T]he data that will be relied upon for the Resource Assessment will be MISO data for the following utilities, Alliant West, Great River Energy, Hutchinson, Minnesota Power, Northern States Power, Otter Tail Power, and Southern Minnesota Municipal Power Agency.").

[3] Minnesota Department of Commerce, *The Minnesota Utility Data Book: 1965–2005*, Tables 1C, 2C. To illustrate how much electric capacity is required to generate 9,408 gigawatt hours of electricity, 1,342 megawatts of installed capacity operating at an 80 percent capacity factor would yield approximately 9,405

meaningful assessment of statewide need must include data for the municipal utilities in the state. To account for municipal load growth in the Assessment, OES could extrapolate from actual historical data for all municipal utilities. In addition, the Assessment needs to account for new industrial loads, such as the 400-megawatt Minnesota Steel load,[4] and the potential expansion of plug-in hybrid electric vehicles. The Assessment will not provide useful results if it disregards major electric loads in Minnesota.

The Assessment should also include different scenarios to acknowledge that not all Minnesota utilities will achieve the aspirational 1.5-percent conservation goal set forth in Minnesota Statutes Section 216B.241. The Assessment certainly should run a scenario where all utilities do meet the conservation goal of Minnesota Statutes Section 216B.241, but since the Reliability Administrator's primary concern should be ensuring the reliability of the state's electric system under all foreseeable load-growth scenarios, the Assessment should also include scenarios where statewide growth meets or exceeds historical growth levels of 2.24 percent per year from 1990 to 2005.[5] Otter Tail Power and Xcel Energy have proposed conservation plans that include energy savings of 1.1 percent or less, while Great River Energy has expressed uncertainty over whether it will achieve the 1.5-percent goal it has recently proposed.[6] Since two of the largest utilities in the state will apparently not be meeting the 1.5-percent conservation goal in the near future, assuming 1.5-percent conservation across all utilities in the state is unrealistic and will paint a misleading picture about future growth that will undermine the usefulness of the Assessment as a tool for regulators, stakeholders and the public to use in planning to meet future needs.

To ensure the Assessment covers a range of foreseeable load-growth outcomes and to account for uncertainty with achievable conservation levels and potentially significant industrial load growth, the forecast of energy need should include projected need for all

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gigawatt hours of electricity. Assuming the historical growth rate of 2.97% that municipal utilities experienced between 1990 and 2005 (based on data in Table 1C of the *Utility Data Book*) were to continue, municipal utilities would need to provide 12,603,946 megawatt hours of electricity by 2015, which is equivalent to approximately an additional 457 megawatts of installed capacity operating at an 80-percent capacity factor, beyond what the municipal utilities needed in 2005. Furthermore, this 457-megawatt increase in needed capacity does not include any major new industrial loads.

[4] *See, e.g.*, Correspondence from Nashwauk Public Utilities to Administrative Law Judges Mihalchick and Neilson, Jan. 15, 2008, filed in MPUC Docket No. CN-05-619 on Feb. 8, 2008 (noting a need for up to 400 MW of baseload need to serve large industrial loads such as the new Minnesota Steel plant).

[5] *See* Minnesota Department of Commerce, The Minnesota Utility Data Book: 1965–2005, Table 1.

[6] Otter Tail has proposed 1.08 percent conservation. Otter Tail Power Company, 2009–2010 Biennial Conservation Improvement Plan Filing, MPUC Docket No. E017/CIP-08-640, Executive Summary, page 4. In its most recent resource plan, Xcel Energy stated that it would "request the Commissioner allow an adjustment down from a 1.5% savings level for direct conservation improvement programs to a 1.1% savings level." Xcel Energy, 2007 Resource Plan, MPUC Docket No. E002/RP-07-1572, page 9-4. Great River Energy has assumed that it will meet the 1.5-percent goal in its 2008 resource plan, but noted the uncertainties involved: "[W]e acknowledge that there are practical challenges in developing [demand side programs] and unique risks in relying upon them. The results achieved through demand side programs depend upon consumer actions that are inherently more difficult to predict, monitor, measure, and control than supply side resources." Great River Energy, 2008 Resource Plan, MPUC Docket No. ET2/RP-08-784, page 47.

utilities in the state (including all municipal utility loads), and should include the following load-growth scenarios: (1) Base Case = historical load growth of 2.24 percent/year for all utilities in the state from 1990 to 2005 continues; (2) Low Case = aspirational 1.5 percent/year conservation goal is achieved by all utilities reducing Base Case load growth rate to 0.74 percent/year; and (3) High Case = historical load growth plus 0.5 percent/year, reflecting increased population and/or economic growth due to expanding industrial development or stronger than historic growth in the state's gross domestic product.

B. Cost Assumptions

1. Capital Costs

The cost assumptions used in the Assessment should be consistent and reflect recent experience with commodity prices. The U.S. Department of Energy, Energy Information Administration ("EIA") cost data is a reasonable starting point. The basis for all the technology capital costs must be consistent, so it is inappropriate to escalate conventional coal, combined cycle, combustion turbine and nuclear costs by 40 percent and wind costs by only 6 percent.[7] Given the higher percentage of steel in a wind project compared to the other listed resources, increasing commodity costs for steel, if anything, would have a larger impact on wind project cost escalation than for other resources.[8] Nonetheless, for purposes of the Assessment the same 40-percent escalation factor should be applied to wind if it is applied to the other resources. The capital cost for integrated gasification combined cycle ("IGCC") plants should also be taken from the same 2006 EIA cost data that OES proposes to use and escalated 40 percent, just like the other generation resources. There is no rational basis to extrapolate IGCC costs from conventional coal if EIA data is to be used as the basis for comparative cost data.

To maintain the integrity and consistency of the data set, OES should not use plant-specific data, such as speculative Big Stone II costs, for the coal plant costs while using generic EIA data for other resources. Generic and plant-specific cost data are created using different methodologies and assumptions, yielding materially misleading cost comparison results that would seriously undermine the integrity and usefulness of the Assessment for the public and energy policy makers in the state. EIA data should be used as the source data for capital costs of all resources considered.

Finally, with respect to carbon capture and sequestration costs, there is no rational basis for attributing capture and sequestration costs to only one resource, IGCC, and none of the other resources, such as conventional coal, combined cycle and combustion turbine resources. If carbon capture costs were to be attributed to one fossil resource then they must be attributed to all. Otherwise, attempting to factor in carbon capture costs only for IGCC plants (and not any other fossil fuel plants) will not provide a reasonable or

[7] *See* Office of Energy Security, Outline and Assumptions for Minnesota Resource Assessment, page 3.
[8] In its recent resource plan, Basin Electric Power Cooperative has reported that wind energy projects have increased in price by 220 percent in the past five years. Basin Electric Power Cooperative, 2008 Resource Plan, MPUC Docket No. ET6125/RP-08-846, page 79.

meaningful cost comparison. Furthermore, carbon costs in the $4–$30/ton range will not justify the capital and operating expenses required to actually capture carbon from any fossil resource (natural gas, conventional coal, or IGCC), providing another reason that it would be inappropriate to attempt to attribute carbon capture costs just to IGCC and not to other fossil resources (since even at $30/ton it is more economical to simply pay the $30/ton for a natural gas, conventional coal, or IGCC plant than to install and operate capture equipment for any of those resources). Therefore, capital costs for carbon capture should not be applied to any fossil resource in the Assessment's modeling.

2. Fuel Prices

Just as capital costs should reflect recent escalation, natural gas price scenarios should also reflect recent experience. A range of ± 20 percent on natural gas prices ignores recent price increases in the 50-percent or greater range. Therefore, natural gas price scenarios that provide a range of at least ± 50 percent (even though fundamental market analysis suggests that the contingency of negative 50 percent is highly unlikely) should be used if the Assessment is going to provide insight into the effects of the likely and completely foreseeable increasing volatility of natural gas prices on power generation in Minnesota.

Given the recent dramatic increases in natural gas use for power generation that are set to increase even more in the coming years, natural gas price volatility is one of the most important factors for the Assessment to realistically consider. In 1997, Minnesota consumed approximately 6.1 billion cubic feet ("BCF") of natural gas for electric generation, which has increased to 34.0 BCF (a 457% increase) by 2007.[9] As a percentage of overall statewide natural gas consumption for all purposes (home heating and cooking, industrial and power generation), in 1997 power generation accounted for approximately 1.7% of all gas used in Minnesota, while in 2006 (the most recent year for which data is available) the percentage of statewide natural gas consumption attributable to power generation increased to 7.1%.[10] Natural gas consumed for electric generation will increase dramatically from current levels beginning in 2008 when Xcel brings its new 515-megawatt ("MW") High Bridge and (in 2009) 439-MW Riverside natural gas plants on line (the result of Xcel's voluntary, $1-billion-plus Metropolitan Emission Reduction Project, or MERP). Xcel has estimated that the new High Bridge and Riverside plants alone would annually consume between 30 BCF and 43 BCF of natural gas.[11] Therefore, these two plants alone will use about the same amount of natural gas

[9] U.S. Department of Energy, Energy Information Administration, Minnesota Natural Gas Deliveries to Electric Power Consumers, *available at* http://tonto.eia.doe.gov/dnav/ng/hist/n3045mn2A.htm.

[10] Total natural gas consumption in Minnesota was 354.0 BCF in 1997 and 352.6 BCF in 2006. U.S. Department of Energy, Energy Information Administration, Minnesota Natural Gas Total Consumption, *available at* http://tonto.eia.doe.gov/dnav/ng/hist/na1490_smn_2a.htm. Minnesota utilities consumed a total of 6.1 BCF of natural gas for electric generation in 1997 and 24.9 BCF in 2006. U.S. Department of Energy, Energy Information Administration, Minnesota Natural Gas Deliveries to Electric Power Consumers, *available at* http://tonto.eia.doe.gov/dnav/ng/hist/n3045mn2a.htm.

[11] Xcel Energy Response to Minnesota Department of Commerce Information Request 25, Oct. 2, 2002, Table 25.2, Proposed Plan Average Yearly Gas Burn in BCF (2010–2020), Docket No. E002/M-02-633.

consumed for power generation by all utilities throughout the entire state in 2007 (34.0 BCF).

C. Scenarios

The goal of the Reliability Administrator in any assessment of future statewide electric power system reliability must be to ensure that adequate electric capacity is in place to meet foreseeable future growth. Historically excess capacity has served the state well, and recent history from other regions of the country demonstrates that capacity shortfalls can have extreme reliability and cost consequences. Therefore once the statewide load growth scenarios described in section II.A. above have been constructed, presumably all of the existing installed and currently approved new generation in the state would be added to the statewide model in order to allow the model to demonstrate when current installed and approved capacity will be insufficient to meet statewide need. Then the Assessment should run a "least-cost" expansion scenario that allows the model to identify the least-cost new resources that would be required in each load growth scenario (Base Case, Low Case and High Case) to meet future statewide need. Once the least cost scenario has been established for each load growth scenario, then the three "Future Scenarios" described in Section II.C. of the OES *Outline and Assumptions for Minnesota Resource Asssessment* can be run, in light of the comments below, to see what the variation from the least-cost scenario would be.

1. Renewable Future

Just as the 1.5-percent conservation goal will likely not be achieved across all utilities in Minnesota, the Renewable Energy Standard ("RES") has significant challenges to full implementation as well. In an update to the Minnesota Senate Energy, Utilities, Technology and Communications Committee, Clair Moeller of the Midwest Independent Transmission System Operator, Inc. ("MISO") stated that the transmission system will need to be upgraded in ways that have not yet been identified in order to meet the 2016 and beyond RES milestones.[12] Former Reliability Administrator Edward Garvey made a similar point, observing that transmission is the Achilles heel of energy policy and needs to be upgraded.[13]

Transmission constraints will limit the addition of all new generation resources, whether they are renewable or not. In order to accurately reflect the physical realities facing Minnesota and thereby ensure that electric service reliability is maintained, the Assessment cannot simply assume the addition of any new resource that transmission system experts confirm cannot be interconnected to the grid at the times assumed in the Assessment. To honestly present the known limitations of the transmission grid and the delays imposed by the MISO interconnection queue, the Assessment should present scenarios where resource additions are limited to those for which realistic and timely interconnection to the grid are possible. It does not serve the purposes of the Reliability

[12] Minnesota Senate Energy, Utilities, Technology and Communications Committee, Update, April 10, 2008, http://www.senate.leg.state.mn.us/committees/2007-2008/energy/update.htm.
[13] *Id.*

Administrator to present scenarios including resource additions that cannot physically be interconnected to the grid in the timeframes proposed. The future reliability of the electric energy system in Minnesota necessarily depends on a candid presentation of known transmission limitations in the Assessment's assumptions for all resource additions, including renewable resources.

2. Baseload/Natural Gas Futures

The scenarios proposed by the OES should reflect the realities involved in permitting new facilities. As with the transmission assumptions discussed above, simply assuming the addition of large new baseload plants that cannot possibly be developed and permitted in the timeframes presented in the OES "Base Load Future," for instance, presents a materially misleading picture of Minnesota's energy future. The Reliability Administrator should be primarily concerned with "stressing" the electric system in foreseeable and realistic ways in order to ensure that the system will remain reliable in a variety of circumstances. It is not realistic to simply add large blocks of baseload resources without coordinating the timing of those resources with the forecasted energy needs and permitting timetables. This approach would likely result in artificially high costs for any generation additions. As described above, the Reliability Administrator should develop the energy demand forecasts described in section II.A. above and then meet the resulting generation deficits in each demand forecast scenario with resources selected by the model if it is reasonable to believe those resources can be permitted and interconnected to the grid in time to meet the identified need.

3. Retirements and Carbon Dioxide Reduction Goals

If the legislature's aggressive mid-century greenhouse gas reduction goals in the Next Generation Energy Act of 2007 are to be met during the 40-year period covered by the Assessment, it is improper to assume that only nuclear resources will be retired in the planning period. The Sherburne County Generating Plant, which is one of the ten largest emitters of carbon dioxide in the nation,[14] will have to be retired for the state to be able to achieve 80-percent carbon dioxide reductions by 2050 and the nuclear plants will likely have to be extended. Therefore, the Assessment should account for identified and likely plant retirements that will be necessary to achieve the state's carbon dioxide emission reduction goals.

III. CONCLUSION

Excelsior appreciates this opportunity to participate in the preparation of the Assessment and looks forward to working with the Reliability Administrator and the OES as they prepare this important study.

[14] U.S. Environmental Protection Agency, Emissions and Generation Resource Integrated Database, eGRID2006 Version 2.1 Plant File (Year 2004 Data), *available at* http://www.epa.gov/cleanenergy/energy-resources/egrid/index.html.

COMMENTS OF A GROUP OF MINNESOTA RATEPAYERS
August 15, 2008

On behalf of a group of Minnesota ratepayers, we provide the following comments on the Outline and Assumptions for Minnesota Resource Assessment presented at the July 30, 2008 Stakeholder Meeting of the Office of the Reliability Administrator. At that meeting, Marya White, the acting Reliability Administrator, noted that interested persons wishing to comment should review the statute mandating the Resource Assessment/Baseload Legislative Study ("Assessment").

Section 16 of that statute, the Next Generation Energy Act of 2007 ("NGE Act"), provides:

> The reliability administrator shall conduct an engineering assessment of Minnesota's electricity resource needs through 2025, with a focus on baseload resources. The reliability administrator may contract with an independent entity to conduct all or part of the study. The assessment must consider additional generation and transmission resources necessary to meet the state's renewable energy standard under Laws 2007, chapter 3, section 1, subdivision 2a, and projected energy savings resulting from the implementation of article 2. The assessment, among other activities, must review and evaluate the most recent Minnesota utility demand forecasts, integrated resource plans filed under section 216B.2422, and transmission projects reports filed under section 216B.2425, including the assumptions underlying them, and **provide independent projections of demand and baseload and nonbaseload generation and transmission resources available to meet projected demand in 2010, 2015, 2020, and 2025.** The reliability administrator shall manage the assessment process and shall appoint a technical review committee to review the assessment's proposed methods, assumptions, and preliminary data and results. The reliability administrator must submit a report on the assessment to the chairs and ranking minority members of the senate and house of representatives committees with primary jurisdiction over energy policy. The cost of the assessment is recoverable under section 216C.052, subdivision 2.

(emphasis added)

This Assessment is an important part of the Reliability Administrator's duties as "a source of independent expertise and a technical advisor" to the Public Utilities Commission and the Commissioner of Commerce and its obligation to "present independent, factual, expert, and technical information" on reliability issues.[1] Given the Legislature's requirements for the Reliability Administrator, it is critically important that the Assessment reflect unbiased, factual, expert, and independent assumptions in order to satisfy the NGE's requirement that the Reliability Administrator "**provide independent projections of demand and baseload and nonbaseload generation and transmission resources available to meet projected demand in 2010, 2015, 2020, and 2025."**

[1] Minn. Stat. § 216C.052, subd. 1(a).

The Legislative mandate in the NGE Act is telling. Notably, the NGE Act did not require the Reliability Administrator to only look at projected energy savings resulting from the implementation of article 2 of the NGE Act, entitled Energy Efficiency and Conservation. Rather, the Legislature requires independent projections of demand and generation and transmission resources. As a result, the Assessment must include at least the following:

<u>1. Historical trends for demand.</u>

Historically demand for electricity has grown each year in Minnesota. Indeed, such load growth led to the statutory energy-savings “goal equivalent to1.5 percent of gross annual retail sales” for electric utilities and associations set forth in Minn. Stat. § 216B.241, subd. 1(c). As a result, in order to satisfy the Legislature’s requirement of independence, the Reliability Administrator must include a scenario using historical demand for electricity among its scenarios for the Assessment.

<u>2. Actual impediments to developing generation resources.</u>

The Assessment must address meeting projected demand for the years 2010, 2015, 2020 and 2025. In addition, the Reliability Administrator must present factual information on reliability issues. As a result, the current backlog for interconnection studies for new generation projects at the Midwest Independent System Operator (“MISO”), estimated by a MISO representative on July 30, 2008 to be over 7 years for projects already in the interconnection queue, requires that the Reliability Administrator exclude from the Assessment for meeting projected demand for at least the years 2010 and 2015, any generation resources that do not have signed interconnection agreement with the MISO. Moreover, any future projects must reflect similar delays in the interconnection process until the backlog is eliminated.

Another actual impediment to developing generation resources is the lack of transmission capacity in the region. As evidenced by the CapEx 2020 process, new transmission lines take years to be permitted. The Assessment must reflect the factual realities of the long lead time for new transmission lines for all generation projects but, most particularly, new wind farms west of Minnesota and new hydro projects north of Minnesota.

<u>3. Fuel Assumptions.</u>

The factual realities of recent fuel prices must be reflected in the range of fuel projections to be used in the Assessment. In particular, recent increases in natural gas prices since 2003, along with the increased reliance on natural gas for producing electricity, require that the Assessment assumptions include a +50 percent scenario for each of its natural gas price projections.

We appreciate the opportunity to comment on the assumptions for the Assessment and look forward to a final report that is independent, expert, and factual so that the Legislature obtains what the NGE Act requires.

Respectfully submitted,

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Outline and Assumptions for Minnesota Resource Assessment

Otter Tail submits the following comments regarding the assumptions under consideration for the Minnesota Resource Assessment.

I. Data Source

II. Proposed Scenarios

A. Forecast

Although a 1.5% conservation goal is planned in MN, Otter Tail recommends that the resource assessment take into account the possibility of a high growth scenario for planning purposes. Due to the potential advancement of energy demanding technologies and increase in large industrial loads within the state, a high growth scenario may have a greater likelihood of becoming a reality. Otter Tail supports assessing the resource needs for load located inside Minnesota's borders and excluding load outside of Minnesota's borders.

Otter Tail would like to know the source of the "typical week" shapes that will be used for load and conservation in the modeling effort. Also, load control should be clarified if it is pre-managed to the forecast. If load control is not pre-managed, application of the demand response should be defined.

B. Price Estimates

Otter Tail recommends that the OES utilize a clearly defined interconnected set of LMP, emission, and fuel price estimates that are developed in a consistent manner from one source. For example, if the OES wishes to evaluate a high natural gas scenario, then the LMP forecast must be adjusted respectively to maintain the relationship implied in the initial set of price estimates. The source for the LMP forecast is currently not defined in the OES assumptions set. All escalators should be clearly defined for fuel prices, capital costs, O&M, emissions costs, etc., and where possible, consistency should be enforced.

C. Scenarios

1. Renewable Future

2. Base Load Future

3. Natural-Gas-Reliant Future

D. Assumptions

1. CO_2

   Otter Tail believes that "Cap and Trade" is the most likely mechanism to apply a cost to CO_2 emissions and should be modeled rather than attributing a cost to every ton of CO_2 produced. Additionally, Otter Tail recommends a $0 CO_2 scenario to weigh the costs incurred by CO_2 regulation and to show the rate impacts to customers.

2. Natural Gas Prices

   Otter Tail is concerned that natural gas prices may increase greatly as coal capacity is delayed or cancelled and demand for natural gas increases to offset the capacity deficit. Without investment in natural gas supply infrastructure, supply deficiency may also drive prices higher.

3. Coal Prices

4. Capital Costs

   Otter Tail proposes using the Big Stone 2 capital costs for the resource assessment analysis since it is the most recent regional study provided by a single source and aids in maintaining consistency across resource alternatives. Escalation values for the various options should be defined. Otter Tail can provide no nuclear cost data.

5. Effluent Costs

6. Retirement of Units

7. Summary of Scenarios

Future	Scenario	CO2	NG Price	Coal Price	Capital Cost	Effluent Costs	Nuclear Retirement
Renewable	**0 MW Wind**	Commission Values $4, $17, $30	MISO/ Powerbase ± 20%.	2008 EIA AEO ± 20%.	MISO/ Big Stone II ± 20%	MISO Data	2030, 2033, 2034
	Off-Ramp Wind						
	RES Compliance						
Base Load	**0 MW Wind**						
	Off-Ramp Wind						
	RES Compliance						
Natural Gas Reliant	**0 MW Wind**						
	Off-Ramp Wind						
	RES Compliance						

The OES welcomes stakeholder suggestions regarding any futures, scenarios, or assumptions.

Engineering work on the mine, concentrating facilities, Direct Reduction Iron plant and Electric Arc Furnace steel mill to be built by Minnesota Steel is currently underway, so there is something of an evolution going on with respect to their anticipated needs. The City of Nashwauk and its Public Utilities Commission, is providing you with the latest estimates of power needs, but please be aware that these estimates may, and probably will change as we move forward of these large and complex facilities. We will undertake to update you as to any significant changes as they become known. The current estimates are as follows:

Month-Year	**Peak Demand in MW**	**Expected Energy Use in mwh/Annual**	**Portion of Plant in Operation**
July 2010			Pellet Plant and Concentrator ramp up begins
Sept 2010	110 start	90% PF 720,000mwh	Pellet Plant and Concentrator in full operation
July 2012			Ramp up of DRI Plant begins
Sept 2012	140 added	90% PF 907,000mwh	DRI Plant in full operation
July 2014	130 added		Ramp up of EAF steel mill begins
Sept 2014	270	75% PF 1,580,000mwh	Steel mill and DRI in full operation
Total Loading 2014 for site	110+270=380	2,000,000mwh	

In addition, Minnesota Steel anticipates building a second DRI Plant and Steel Mill on the site that will require approximately another 180 MW of power. However, the timing for construction of this second phase of the project has not yet been determined. Moreover, Minnesota Steel is also considering the possible enlargement of the proposed concentrating facilities on the site from a 4 million ton per year operation to a 6 million ton per year operation. However, no decision has yet been made about this project alternative, and, if and when a decision is made in favor of this approach, it would be necessary to apply for and obtain environmental permitting for such an enlargement of the project. Until such time as permit applications are actually filed and appropriate discussions with the regulators occur, it is not possible to predict the timing of this possible addition. If this addition does go forward, however, it would add approximately 30-35 MW to the total project demand. The total plant site could approach 590MW, best guess before 2020. Essar Steel, a subsidiary of Essar Global, has currently expanded their other steel plants around the globe to operate up to four lines of production. If you are planning loads to the year 2040, it would not be "out of line" to project expansion of two more 180MW EAF lines to the project. Site totals could approach 950MW