

Chapter 1. Executive Summary

Introduction

Northern States Power Company, a Minnesota corporation (“Xcel Energy” or the “Company”), submits to the Minnesota Public Utilities Commission (“MPUC” or “Commission”) our 2010 Resource Plan covering the period from 2011 to 2025 for consideration and approval. This Plan identifies how we propose to meet our customers’ needs for electrical energy during the planning period.

As we enter this decade, we are in the midst of a significant program of investment that has been designed to expand and renew our generation fleet and meet state and federal policy goals. With our current and expected investments in 350 megawatts of wind power, 283 megawatts of nuclear and coal power uprates, nuclear life extensions, completion of the Manitoba Hydro agreement, and our pursuit of the Commission-approved Demand Side Management goals, Xcel Energy is well-positioned to provide reliable and economic service into the future. While this Resource Plan presents some additional work we need to do to continue along that path of providing cost effective and environmentally responsible resources, our system is in good shape to meet both our foreseeable customer needs and many of the environmental challenges we expect to face in the future.

As we submit this Resource Plan, we recognize that there are issues in our economy and in our industry that make it important that we maintain flexibility and balance in our Resource Plan. Although we are well positioned for the future, we highlight in the following paragraphs issues that have emerged or evolved since our last filing in 2007.

Forecasts

Forecasts are always uncertain but the economic and policy circumstances surrounding this Resource Plan appear to amplify that uncertainty. Our economy appears to be slowly recovering from a deep recession. In this plan, forecasts of electricity use are higher than those prepared last fall but remain lower than those

presented in the last Resource Plan cycle. As in previous plans our forecasts are based on statistical regression analysis that attempts to predict electricity use based on historic trends, forecasts of economic activity, and forecasts of population growth. The analysis suggests that a new relationship between energy consumption and peak demand may be developing. Our forecasts predict higher growth in peak demand but lower energy consumption than would have been the case in the past. These are driven by refinements to our peak demand forecast that better track recent changes in our system peak. However, during this period of economic transition it is difficult to know if these changes will be sustained over time. It will take additional data and a number of forecasts over the next few years to better understand whether a new trend is emerging.

Our peak demand forecast is also affected by our efforts to nearly double the energy consumption savings achieved through DSM programs. Our analysis indicates that it is likely that the relationship between energy savings and peak demand reductions will change. More energy savings will occur at off peak times than in the past and, therefore, smaller production capacity reductions for each unit of energy savings appear to be emerging. Since we are just beginning to significantly grow DSM savings, it is again difficult to predict how the relationship between energy and peak demand will change.

These forecast adjustments change the load factor of our system and show higher peak demand even with low growth in energy consumption. If the economic recovery accelerates or if we do not see the DSM impacts on peak demand that have been projected, the generating requirements on our system could be higher. On the other hand, the changes made to the forecast models are new and may not match 2010 and 2011 results as well as previous estimates. Peak demand and energy use, both, may remain low. We also do not project significant breakthroughs in our plan associated with smart technologies (although our DSM goals do anticipate continued advancement in efficiency technology). In light of these developments, our forecast of peak demand will need to be continuously

reviewed. Our currently approved upgrades and additions put us in good position to respond appropriately to changes in customer demand. This plan assures a more flexible approach to the timing of new resource additions than previous plans. Also, the additions needed to meet projected growing demand dovetail well with our ongoing efforts to modernize and improve environmental performance. In addition, we have the option to add peaking resources if needed or rely on shorter term purchases if economical.

Natural Gas Forecasts

The industry has seen changes in forecasts of natural gas prices that may affect future size, type, and timing of resource decisions. Our previous two Resource Plans were impacted by natural gas production rates in the U.S. that were declining to levels that had not be encountered since the late 1980's or early 1990's. In 2005 natural gas production rates bottomed out near 50 BCF/day. By 2007 those production rates had begun to creep upwards, but low production rates were continuing to impact natural gas prices and the near and longer term outlook for natural gas costs was substantially higher than what we now believe to be the case. With the development of large shale plays in Texas, Arkansas and Pennsylvania, the natural gas industry has finally been able to reverse a declining production trend. In 2009, production exceeded 57 BCF/day or nearly a 14% increase in just four years. Coupled with a slowing economy, natural gas prices are significantly lower than just two years ago and are expected to stay at a lower level for a number of years to come.

A long-term lower price for natural gas will produce benefits to our customers as it will reduce the production cost of both current and new resources. In addition to lowering the cost of energy from our natural gas fired facilities, the lower cost of energy from natural gas is expected to put downward pressure on wind prices, which are a close competitor. At the same time, lower gas prices reduce the integration costs of wind on our system, as our ability to follow the wind with flexible gas generation becomes less expensive.

Through our early adoption of significant amounts of wind power we are well positioned to meet the compliance requirements for renewables of the states we serve. We have the flexibility to adjust our schedule for new increments of wind power as new market information becomes available.

Federal Environmental Policy

In our last Resource Plan, there was an expectation that greenhouse gas regulation was on the horizon, and that long-term decisions related to resources need to include estimates of potential carbon pricing to assure that our resource selections would keep our system costs reasonable over time. While we continue to believe there will eventually be a direct cost associated with the emission of carbon, the delay in legislation and the onset of Environmental Protection Agency (“EPA”) regulation adds to the uncertainty of both the timing and level of carbon costs that should be used in resource selection. We have developed sensitivity analyses to address the potential for a range of scenarios.

In addition to uncertainty surrounding greenhouse gas regulation, the EPA is poised to introduce several new regulations that will impact the operation of our plants. EPA’s recent release of the Transport Rule is expected to be followed by regulations affecting emissions of sulfur dioxide (“SO₂”), nitrous oxides (“NO_x”), mercury, water use and solid waste disposal. We have mitigated some of the impact on our system with our efforts to modernize and improve environmental performance to date. Even so our preliminary estimates indicate that the costs of complying with these regulations may be significant, and may be required prior to receiving any certainty on carbon regulation. Our plan continues our efforts to improve environmental performance by converting the last, less efficient coal units in the metropolitan area to natural gas.

Five-Year Action Plan

Our five-year action plan has been tailored to address the uncertainty and change that is occurring. The additions required to ensure system reliability are limited and

dovetail well with our continuing strategy to modernize and improve environmental performance. Our analysis indicates we have time to determine how we can achieve higher DSM goals without adversely affecting resource acquisition plans. We have flexibility to adjust renewable generation acquisitions earlier or later to respond to market conditions. Because of the substantial investment program already underway, there are only a limited number of steps in our five-year action plan needed to maintain reliable service:

- *DSM. Work with stakeholders to grow DSM energy savings to 1.5%. This Plan presents our assessment of economic potential on our system and explores expanding our 1.3% savings goal further. The 1.5% savings goal appears to represent a cost effective way to reduce the overall energy needed to serve our customers. While we have become more confident in our ability to achieve 1.3% of savings from traditional DSM projects, to move to the state goal of 1.5%, we will likely need to refine how we measure savings. Items like behavioral change, efficiencies on the utility system and measurement of the impact of code and standard changes are all anticipated by the Next Generation Energy Act of 2007, 2007 Minn. Laws Ch. 136, (“2007 Act”) Act and should be implemented to help move to a long run assumption of 1.5%.*

The level of DSM savings does not appear to have an impact on the need for new resources until late in the planning period. This provides time for these actions to be addressed and for us to advance conservation efforts to the 1.5% goal.

- *Renewables. Issue an RFP for up to 250 MW of wind power to be developed by the end of 2012 if benefits are demonstrated. Use the results to help guide the timing and size of the next addition of renewables to our system. We are committed to meeting the renewable policy goals of the states we serve. Wind power has proven to be a cost effective resource addition to our system to date. Because the Federal*

Production Tax Credit (“PTC”) is scheduled to expire at the end of 2012, we believe we should continue to explore acquisition of wind power to capture PTC savings for our customers. However, we do not need to add wind power to comply with RES/REO milestones in the next five years. Requesting proposals for additional wind generation prior to the expiration of the PTC provides us with an opportunity to achieve pricing that remains cost-effective for customers under a variety of future scenarios. If the results of our bidding program do not provide adequate benefits we have the option to defer acquisitions and still stay on track with compliance. We will engage our stakeholders to obtain appropriate input on our plans once we have the best available market information.

- *Existing Generation. Replace the 270 MW of generating capacity at Black Dog 3&4 with a 680 MW natural gas, combined cycle unit in 2016.* We have examined the feasibility and economics of eliminating the last coal-fired units at the Black Dog plant site and conclude a new natural gas, combined cycle unit can provide multiple benefits to our system. We can increase the production capacity at an existing plant site to cost effectively help meet the growing demand for power with no new land use impacts. And we can further reduce criteria pollutant and greenhouse gas emissions from the production of electricity. Repowering Black Dog is our least cost option for anticipated needed capacity additions in 2016. We are preparing to file the necessary applications by mid-year 2011.
- *Existing Generation. Develop a plan to update or replace Sherco 1&2.* Sherco Units 1 & 2 are approaching the end of their economic life near the end of the planning period (2023). There are a number of new environmental regulations on the horizon that will require further investment in backend controls. We will continue to evaluate the best strategy for these units in the years to come. We expect to have sufficient time to file this information in our next Resource Plan, prior to committing to major investments at these

units. However, we do not anticipate that we will have clarity on a number of the key assumptions by that time and, accordingly, we will need to remain flexible in our response to new and changing regulations.

- *Peaking Resources. Evaluate all options to meet peaking requirements that may materialize between 2015 and 2020. Maintain a contingency plan that preserves the ability to install additional peaking or intermediate resources if necessary.* Our forecasts indicate there may be a deficit in generating capacity on our system by 2015 even after extending the Manitoba Hydro purchases and fully implementing capacity upgrades in our nuclear fleet. However our plans to repower Black Dog in 2016, bring our load and resources back in balance. Thus we would expect to meet a 2015 need with a short term capacity purchase. However because of some of the forecast uncertainty, we propose to closely monitor our forecast and the underlying economic conditions. If required, we will issue an RFP for peaking resources so that we can meet that growing demand as it materializes. If we conclude an RFP is necessary, we will file our forecast updates and other supporting information with the Commission. We also plan to begin engineering and development work at one or more sites to be prepared to install additional peaking or intermediate resources as a contingency plan.
- *Transmission. Continue to support efforts to ensure that sufficient transmission resources are available to move needed generation to load centers and maintain system reliability.* While federal regulatory requirements separate generation from transmission, both are needed to serve customers. Our experience with bidding demonstrates the influence transmission access and availability has on our resource selection. Given the need for transmission capacity projected for the planning period, it is important that adequate transmission is developed in a timely fashion. We have undertaken that effort by obtaining approval of Certificates of Need for our CapX 2020 projects which reflect a commitment to invest nearly \$1 billion to support reliability

and to move renewable energy to market. We plan to continue our advocacy before state and federal regulatory bodies and the Midwest Independent System Operator (“MISO”) to encourage effective transmission planning and appropriate levels of transmission investment.

Impacts on Customer Prices and Company Health

While we are proposing a plan that will provide low cost power and energy to our customers and achieve public policy goals, there are substantial capital investments associated with these decisions. Our costs of providing service have been and will continue to be, to a large extent determined, driven by the choices made and approved in our resource and transmission plans. Up to now, our Resource Plans have not emphasized the price impacts of these decisions on our customers, focusing more on the long-run economic benefits of various alternatives. We think that the trajectory of our cost growth (and consequently the growth in the price of our product) should be better understood by both our regulators and other stakeholders in our plans. Between 2010 and 2016 we will add over \$4 billion in investment to our system for all generating resources; \$2.5 billion of that is for new generation or major refurbishments. In addition, we are forecasting nearly \$2 billion in transmission investment and another \$1 billion in our distribution system. Our capital program has grown to roughly \$1 billion each year, the total of the three Metropolitan Emissions Reduction Project (“MERP”) projects for which capital was expended over a six year period. Customer prices in this same period are projected to rise by an average of approximately 5% each year including our estimates of reductions in fuel costs, as some of our resources, such as wind and nuclear are offset by zero or very low fuel costs.

While less expensive than alternative plans, implementation of the proposed plan will nonetheless require rate increases to our customers. The pace of our investment and the fact that much of it is not supported by load growth makes the method of determining rates a more critical issue. Ratemaking tools currently in

use may no longer be adequate to address our extensive investment program. To achieve federal and state policy goals and sustain the related multi-billion dollar investment, we believe it is time to examine alternative cost recovery/rate making approaches that are fair to both our customers and allow our investors a reasonable opportunity to earn our authorized return.

We are not asking the Commission to take specific action in this proceeding concerning rate impacts. We have begun the process of examining rate making options in preparation for future rate proceedings. We raise the issue here to emphasize the importance of a comprehensive well integrated strategy that meets customer needs at reasonable cost, reaches consensus on the pace of future investment and maintains utility financial health. We will continue to work with stakeholders to ensure that our resource acquisition plans and resulting costs are well understood and can be implemented effectively.

Chapter Summaries

To assist in understanding the key components of our proposed Resource Plan, we provide the following summaries of each chapter of this filing.

Chapter 2 Landscape

This chapter provides an overview of the economic and policy landscape that provides context for this Resource Plan. As we file our 2011-2025 Resource Plan, we are experiencing continuous change in our industry and the world around us. Since our last plan was filed in late 2007, the world has experienced the most significant recession in decades and is only now showing signs of recovery. Between 2007 and 2009, our peak demand forecast for 2020 fell by 1,280 MW – the equivalent of two large generating units. In the past year we have seen our forecasted demand growth increase slightly, due in part due to refinements to our peak demand forecast model and the fact that our DSM programs are not likely to reduce our system peak as much as we had previously estimated. Uncertainty

surrounding the pace and extent of economic recovery has compelled us to build a new level of flexibility into our plans.

We are experiencing dynamic movement within the energy industry as well. Recent developments in drilling and fracturing technologies have created a larger natural gas reserve that can be economically extracted from shale formations. These technologies promise an abundant supply and lower, more stable cost for natural gas over the next thirty to fifty years. New technologies, including smart grid technologies, may mature and pave the way for significant efficiency gains over our planning horizon. Although we have been working to renew our generation fleet, some of our older facilities will require attention in this period. Furthermore, the federal government is moving to implement significant environmental regulations for coal-fired generating facilities as early as 2014. These regulations impact both traditional pollutants such as SO₂ and NO₂ and we will likely have federal rules that for the first time regulate emissions of greenhouse gases.

In this Resource Plan, we have developed a comprehensive portfolio of supply-side, demand-side and contingency resources to address the needs of our customers in this uncertain environment.

Chapter 3 Forecast & Resource Needs

A Resource Plan begins with a projection of customer demand for capacity and energy over the planning horizon. This chapter outlines our forecasting methods and results. Our spring 2010 forecast projects annual energy growth of approximately 0.9 percent based on the median forecast for the planning period and annual demand growth rate of approximately 1.1 percent at a median forecast level, assuming we sustain a level of DSM savings of 1.15% of retail sales each year. See Figure 1.1.

Figure 1.1
Median Net Energy (MWh) NSP Total System with 1.15% of Retail Sales DSM Adjustment

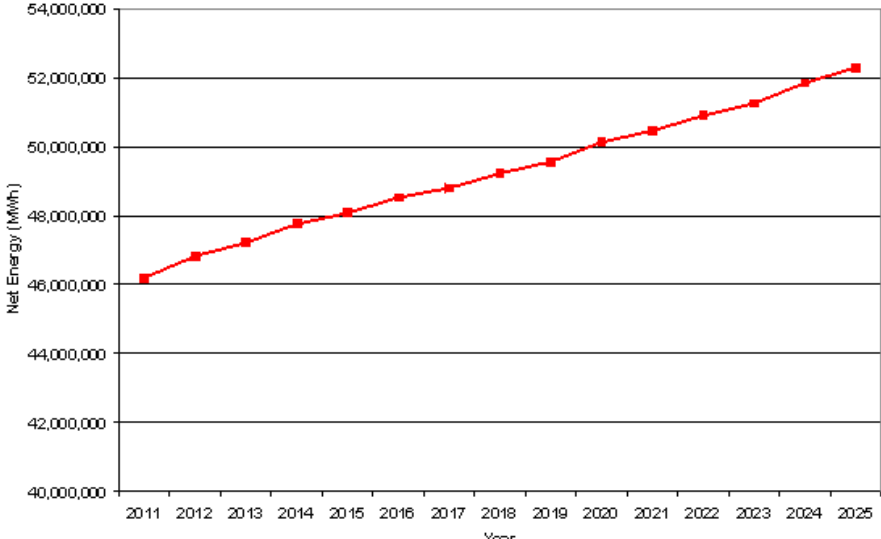
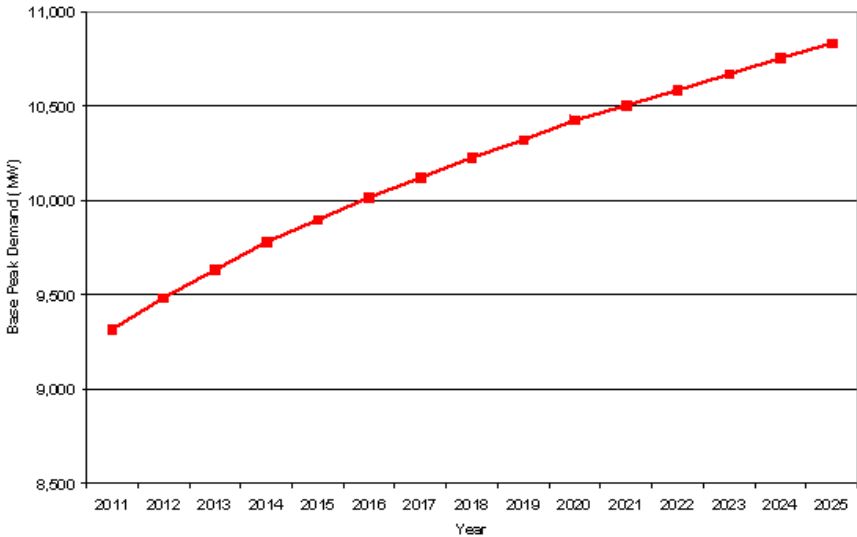


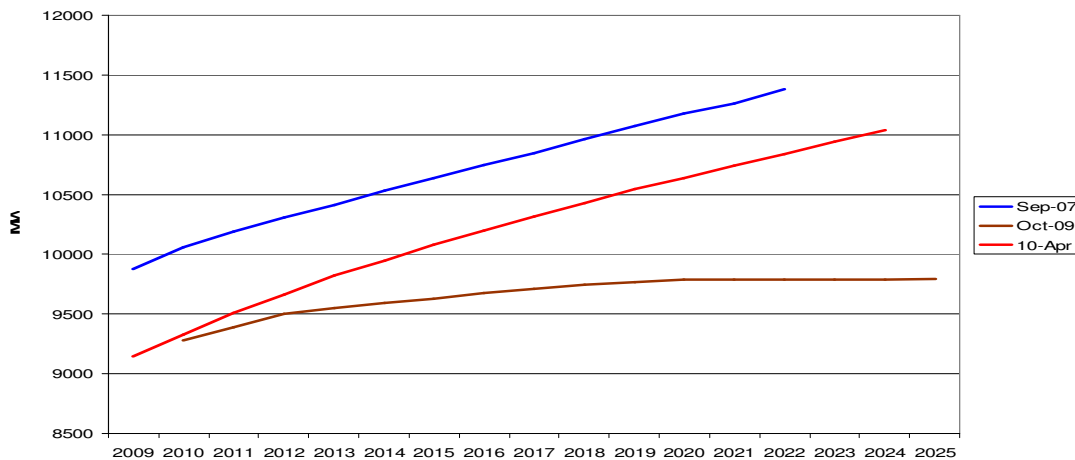
Figure 1.2
Median Base Summer Peak Demand (MW) NSP Total System with 1.15% of Retail Sales DSM Adjustment



Our forecasts are driven by a combination of demographic variables and indicators of the performance of the economy in the upper Midwest. As a result, the impacts of the deep economic recession and slow recovery that is developing are reflected in our forecasts. Figure 1.3 below compares forecasts from our 2007 Resource Plan prepared before the recession, last fall’s forecasts and this new spring 2010 forecast, which reflects some up-tick in the economy. In this period of transition, it is difficult to predict the pace and trajectory of the economic recovery and the resulting impacts on our energy and demand forecasts.

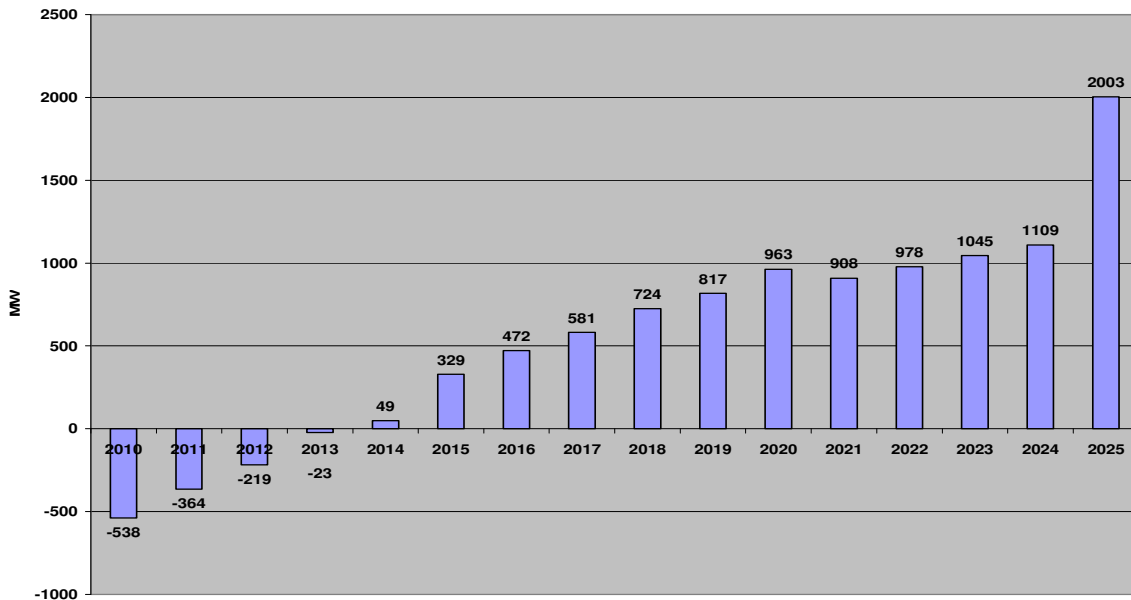
Our demand forecast has increased from last fall’s forecast due to a refinement in our peak demand forecast variables and a change in our estimate of demand savings available from our energy efficiency programs. As we strive to nearly double energy savings, our new programs do not provide the same levels of reductions in peak demand as in the past. Projected demand savings were also adjusted slightly to account for demand savings due to the recent commercial cooling code changes. This adjustment reflects savings that we believe are going to occur but are not counted in our achievements because they are due to a prior change in federal efficiency standards.

**Figure 1.3
Demand Forecast Over Time**



We also reduce the demand forecast by over 1,000 MW to reflect the load control programs we have in place to reduce peak demand. We then add the planning reserves necessary to account for the generation that must be available, above that needed to meet peak demand, to ensure reliable system operation in the event of equipment failure. Figure 1.4 presents the resulting estimate of total generating requirements and superimposes available resources.

**Figure 1.4
Resource Requirements**



When our forecasts of resource requirements are compared to our existing resources, we foresee the potential for a shortfall in generating capacity starting in 2015. The resource needs figure assumes life extension and capacity increases at our nuclear plants are fully implemented and purchases from Manitoba Hydro are extended to 2025.

Chapter 4 Modeling and Plan Description

As in previous plans, we have used the Strategist Resource Planning and simulation model to explore how best to meet the generation deficits identified in our forecast.

In this chapter we present our proposed plan to meet our customers’ energy requirements over the next 15 years. We also present our analysis that explores the impact of numerous assumptions and scenarios on the resource selections. This modeling information provides a foundation to assess how different acquisition and customer growth scenarios will affect our resource needs. Although our Sherco Units 1 and 2 reach the end of their economic life in this planning period (2023), we have assumed that they will continue to operate through 2025.

Based on our analysis, experience and judgment, we propose the following Expansion Plan in Table 1.1:

**Table 1.1
2010 Proposed plan**

Year	Planned Additions	Combined Cycle	Combustion Turbine	Wind
2011	Merricourt Wind 150 MW Sherco 3 13 MW			
2012	Monticello 71 MW			250 MW
2013				100 MW
2014	PI Unit 1 82 MW			100 MW
2015	MH 725 MW extension PI Unit 2 EPU 82 MW			100 MW
2016	Black Dog 680 MW CC Retire BD units 3&4 270 MW			100 MW
2017				100 MW
2018				100 MW
2019				100 MW
2020			390 MW	200 MW
2021	MH 125 MW			
2022			195 MW	200 MW
2023				
2024			195 MW	200 MW
2025		730 MW	585 MW	200 MW

Our proposed plan includes developing up to 1,150 MW of wind power by 2020 to meet the combined renewable policies of the states we serve. After extending the term of our purchases from Manitoba Hydro and increasing production at our

nuclear plants, our plan calls for replacing the 270 MW of the remaining coal-fired generation at the Black Dog power plant, Units 3 and 4, with a 680 MW natural gas, combined cycle unit in 2016. Our plan also shows a potential need for a small amount of peaking capacity in 2015, which may be covered by short term capacity purchases or longer term resources, depending on the level of need predicted in our next few forecasts and market conditions.

To test the robustness of our plan we conducted several sensitivity analyses regarding key variables. These analyses included both higher and lower demand and energy forecasts, two levels of DSM performance, higher and lower natural gas commodity cost forecasts, varying levels of environmental externalities, and varying levels of potential greenhouse gas regulation cost implications.

We also examined the implications of using different public policy approaches to renewables and DSM that have been discussed by regulators.

It should not be surprising that the resource additions needed to meet our customers' energy requirements and the cost effectiveness of our plan are most sensitive to our forecast assumptions. If the economy recovers more quickly than we have forecasted, or assumed DSM program demand savings don't materialize, several additional generating resources will be needed. If recovery is prolonged, or new technologies act to further reduce the pace of sales growth, resources may be deferred.

Our plan is also sensitive to natural gas forecast assumptions. If natural gas prices remain low as currently forecasted and wind power prices continue to climb as they have in recent years, further additions of wind power are no longer a cost effective addition compared to the alternatives. This is especially true if the PTC is no longer available. However, we have not tested the market recently and have seen lower prices in other jurisdictions. We are hopeful that we will see more competitive responses in our RFP.

Our action plan related to this analysis is discussed in Chapters 5, 6 and 7 below. Given the uncertainty in future requirements we believe that flexibility along with a solid contingency plan is an appropriate means of developing responsive action to changing conditions. This same flexibility should apply to our efforts to add renewables to our system given the sensitivity of cost effectiveness tests to commodity prices.

Chapter 5 Renewable Energy

This chapter discusses our plan to acquire renewable energy to comply with the policies of the states we serve. We also describe the role renewable energy from the Manitoba Hydro system plays in our resource mix and our proposal to extend our purchases through the planning period.

Currently 14% of the energy we provide our customers comes from over 1800 MW of RES/REO eligible generating resources. Based on the additional generation we have under contract, we expect renewable energy production to grow to 19% of sales by 2012.

We estimate that approximately 1,150 MW of nameplate wind power, in addition to the amount of renewable energy we have operational on our system or under contract, will be needed by 2020 to continue to meet the state's renewables policies.

Since our program began in the mid '90s we have been able to add over 1,200 MW of wind power to our system in a way that has been cost effective compared to the alternatives at the time. Early adoption has kept the overall cost of wind powered electricity low.

Our modeling suggests that may no longer be the case. Two forces appear to be in play. Wind power prices have increased in recent years as natural gas prices rose. Now, forecasts of the cost of energy from the alternative, natural gas fueled

combustion turbines and combined cycle units, are declining. Thus, this is a good time to assess current market prices of wind energy through an RFP.

The Minnesota and Wisconsin Commissions allow renewable energy credits to be used to demonstrate compliance up to four years after the energy is produced. As the result of our early investments in wind power, we have a significant inventory of renewable energy credits that allow us to comply for several years and provide considerable flexibility in the size and timing of new wind power additions to our system.

In light of uncertain market conditions and our compliance flexibility, we propose to take a measured approach to the additions of wind power in our plan. We plan to issue an RFP for up to 250 MW of wind powered generation to be in service by the end of 2012. The PTC is scheduled to expire by the end of that year and this RFP is designed to capture the benefits it provides. We will encourage all types of ownership structures and development strategies: community based power purchases, larger developer power purchases, and any other more creative combinations of projects. In doing so, we hope to develop good information about the relative cost differences of the alternatives and encourage the most cost effective proposals possible.

We will assess the outcome of the 250 MW RFP process along with additional information on state and federal policies and incentives to help us determine the next steps in our wind acquisition program. If the results are favorable we will design additional acquisitions to fulfill the schedule in our proposed plan. At the other end of the spectrum, if wind appears to be too expensive compared to alternatives, we may need to engage the Commission and other stakeholders to explore whether the goals or timing of our renewables program should be adjusted as provided by statute.

This chapter also serves as an update to our Renewable Energy Plan the Commission approved in Docket No. E002/M- 07-1558. The basic elements of our plan have not changed. However, based on the feedback of the OES and the Commission in recent PPA approval cases, we have adjusted our ownership structure goals slightly. Over the long term, the current plan calls for roughly a third of our resources to be owned by the Company, a third through community-based ownership structures and a third through traditional independent developer ownership structures. Dedicated community-based acquisition programs have been challenging to successfully implement. Our desire to give community-based projects the opportunity to develop and provide benefits to the local economy has not diminished. However, we do not believe it is productive to debate how much of our wind power purchases should be from community-based or traditional developer projects. We expect the results of future bidding programs to help guide the division of power purchases. We propose to soften the distinction in our long term goals by simply identifying an objective to own roughly a third of our wind portfolio, and acquire two-thirds through power purchases.

There is a second component to the Company's renewable energy program. Xcel Energy has a series of contracts with Manitoba Hydro that provide up to 850 MW of generating capacity, the vast majority of which comes from Manitoba Hydro's hydroelectric resources. Purchases from Manitoba Hydro provide approximately 5% of the energy our customers use. While most of the purchases are not RES eligible, they do represent a significant contribution to our system from larger scale renewable generation.

We are pleased to report that we have reached agreement with Manitoba Hydro to extend our purchases another ten years, to 2025. On June 9, 2010, we filed a petition with the Commission seeking approval of the new agreements (MPUC Docket No. E002/M-10-633). Our analysis of the agreements indicates the purchases will continue to be economical for our customers and will help meet our environmental performance goals. In this Resource Plan we have not duplicated

the analysis of the alternatives we provide in the 633 docket. We encourage interested parties to review our analysis there. Our proposal to extend purchases from Manitoba Hydro is subject to the Commission's alternative acquisition process, which provides independent power suppliers the opportunity to sponsor a competing proposal if they believe they can offer a better alternative.

Chapter 6 Thermal Generation

Xcel Energy's thermal generating system comprised of nuclear, coal, natural gas, and fuel oil resources provides in excess of 70% of the electrical energy our customers consume. During the planning period, these resources will continue to play an essential role in providing power reliably.

We have made a number of improvements to the fleet in recent years. Last year we brought an extensive program of updates and environmental improvements to our three largest power plants in the metro area to a successful conclusion. With investments totaling \$1 billion, we were able to extend the economic life of King, High Bridge and Riverside, increase their output to meet growing demand, and reduce air emissions in a large metropolitan area. We are extending the life of our nuclear power plants and increasing their production capacity by 230 MW with approximately \$1.5 billion in investments. We have added generating capacity and improved production efficiency with improvements to Sherco 3's turbine. We repowered Black Dog Units 1&2 by retiring coal fired boilers and reusing generating equipment as part of a natural gas fired combined cycle unit.

In this Resource Plan we propose to continue modernizing our fleet to extend their life and improve production and environmental performance. In particular, we have evaluated options for the remaining coal-fired units at our Black Dog plant. We propose to retire the remaining 270 MW of coal fired capacity at the plant and replace it with 680 MW of natural gas combined cycle production. The repowering project compares favorably to the alternative of continuing to operate Black Dog 3&4 with upgraded pollution control equipment and adding generation elsewhere

to meet growing demand. We plan to file applications with the Commission for the necessary approvals by mid 2011.

Toward the end of the planning period, Sherco Units 1&2 will reach the end of their current economic life. Furthermore, we expect multiple changes in air emission and pollution control requirements in federal rules over the next five years. Over the next few years we plan to conduct studies to better define the investment strategy necessary to extend the lives of Sherco 1&2, although we will likely have to do so with uncertainty on the timing and scope of some environmental requirements.

Our proposed plan calls for the addition of a limited number of peaking and intermediate resources over the planning period. Our forecast indicates a potential need for a new peaking resource as early as 2015.

Because there is considerable uncertainty in the expected demand in the 2015 to 2020 timeframe, we believe it is essential to establish a contingency plan that will preserve our ability to add units quickly if necessary. We propose to take some of the preliminary development steps such as siting and preliminary engineering, and perhaps some permitting to shorten the development cycle of combustion turbine or combined cycle additions so that we can monitor demand and respond. We also expect that we would be prepared to issue an RFP, if needed, after review of our 2011 system peak. If we believe such action is warranted, we will file all supporting forecast information with the Commission and parties.

Our plan does not call for any new coal-fired generation or other new base load additions for the foreseeable future. Our analysis at this time indicates such resources are not cost-effective. This cost difference becomes particularly acute if the cost of carbon capture and sequestration or carbon regulation is included. The thermal fleet improvements we have made and plan, allow us to monitor the

development of carbon policy over the next several years before committing to additional base load resources.

Chapter 7 Demand Side Management (DSM)

This chapter presents our analysis of the levels of conservation that can be incorporated into our Resource Plan to reduce energy and demand requirements on the system. In our 2007 Resource Plan, the Commission established goals that provide a transition to the aggressive savings of the 2007 Next Generation Energy Act. Last year we established the first triennial CIP plan with the OES to implement the significantly higher savings targets. We are pleased to report that we will exceed the 2010 goal of saving 1.15% of gross retail sales through conservation measures and we are more confident in moving to the Commission ordered goal of 1.3% of energy saved annually by 2012.

In this Chapter we discuss our efforts to continue to implement programs to save 1.3% of gross retail sales over the long term planning horizon, and plans to work with stakeholders to increase our savings to 1.5%. In our analysis we found both the 1.3 and 1.5 percent savings targets to be cost effective based on the assumptions that were incorporated. However, after we exhaust foreseeable technology over the next several years, we begin entering uncharted territory and cannot yet assess the validity of many of the assumptions we have made regarding the costs and results of an expanded DSM program. In fact, the most recent statewide achievability study, directed by the OES, indicates long run savings levels above 1.0 % may be difficult to sustain.

Our analysis also indicates that there is only modest differences in resource acquisition schedules between the two levels of DSM savings. Peaking requirements in the out years of the plan change by only a year or two. This analysis also indicates that we are in a good position to complete the transition to a 1.3% savings target, and in the meantime we can work through how we can continue progress towards meeting higher goals. We are committed to working

with stakeholders to explore how we might overcome impediments to meeting higher goals over the long-run going forward.

Chapter 8 Emerging Technologies

Minnesota Statutes, section 216B.2426 requires a discussion of distributed generation in utility Resource Plans. In addition, many stakeholders have shown interest in our activities and plans for energy storage, smart grid technologies and electric vehicles. We see these emerging technologies as interrelated, in that there are important synergies between them that reinforce their potential impact, both positive and negative. Over the course of the planning period of this Resource Plan, one or more of these technologies has the potential to have an impact on the shape of the electric industry, and the provision of electric service to our customers. At this point, however, it is difficult to say with any certainty which of these will evolve to the point when large scale adoption will be economic and reliable – or when that evolution might occur. It will be critical for us to keep a close eye on the costs and benefits of the technologies we implement on our system, to ensure that our customers receive net benefits overall from these technologies.

Chapter 9 Environment

This chapter outlines new federal environmental requirements that are in development and that we expect will be implemented over the next several years. These new air, water, and solid waste rules will affect the investments necessary to continue to operate our fossil resources. As part of our planning processes, the Company has made substantial investments in our plants over an extended period of time that will serve us well as these new rules are promulgated. However substantial additional investments may be needed to units like Sherco 1 and 2 in order to continue their operation. We plan to begin the analysis needed to determine the future for Sherco 1 and 2 and the rest of our fossil fleet and report back to the Commission in our next Resource Plan.

Because of the diversity of our system, as well as our proactive approach to environmental risk mitigation, we are able to present a Resource Plan that will manage and reduce our carbon emissions. Our plan results in a reduction in system CO₂ emissions of over 20% from 2005 levels by 2015 and nearly 25% by 2020.

Chapter 10 Transmission

Transmission planning now takes place in the Minnesota Transmission Planning Process. In conjunction with other transmission-owning utilities in the state, we submitted a Biennial Transmission Plan to the Commission on November 1, 2009. The Commission issued its Order accepting the plan report E999/M-09-602. This chapter outlines how the addition of transmission and our renewable energy goals coincide and the study work underway to maintain reliability and facilitate generation additions. Minnesota utilities have nearly completed the permitting process and will soon begin a \$1.7 billion CapX2020 construction program to meet growing system reliability needs and to integrate more renewables into our systems. We believe transmission infrastructure is on track, but critical work and evaluation will be necessary for future renewable energy milestones. The CapX 2020 initiative and subsequent transmission studies will help provide critical information to allow us to continue to develop our transmission infrastructure to serve anticipate reliability and renewable energy needs. Due to the long time horizon for adding transmission, it may well be appropriate to begin development of resources needed to meet higher levels of renewable penetration in this Resource Planning horizon, while we learn more about the viability from both a cost and reliability perspective of bringing these resources to market.

Conclusion

Xcel Energy looks forward to the engagement of interested parties in this Resource Plan. We believe we have developed a strategy that will meet the electric energy requirements of our customers and continues our modernization program, yet provides the flexibility to adjust in this time of change. We are committed to

working closely with our regulators to better integrate Resource Planning, its impact on our customer's bills and how it impacts the current ratemaking tools to effectively address the unprecedented investment program before us.

We welcome consideration of our Plan, and look forward to dialogue with stakeholders.