Chapter 2. Landscape

Xcel Energy has worked throughout the years to develop a diverse and responsible resource portfolio that provides our customers with reliable service at a reasonable price. Over the past 20 years, we have accomplished this goal while demonstrating our leadership in making substantial environmental performance improvements. Our extensive implementation of demand-side management programs, our expanding renewable energy portfolio and the environmental upgrades to our existing generating plants have positioned us well to meet the challenges of the coming decade.

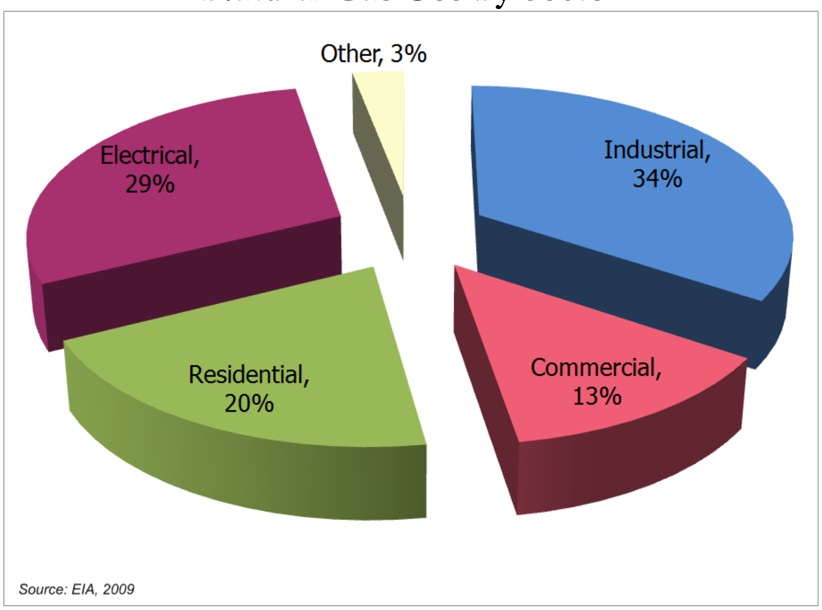
As noted in our Executive Summary, we are currently experiencing significant changes in evolving regulations and greater uncertainty in our economy and business. Since our last plan was filed in late 2007, the economy has been in a significant recession and is only now showing signs of recovery. Between 2007 and 2009, as a direct result of economic downturn, our peak demand forecast for 2020 fell by 1,280 MW – the equivalent of two large generating units. Our current position will provide greater flexibility to gather more experience before addressing the potential for a change in the pace and extent of the economic recovery as well as changes to some of the key assumptions in both our peak demand forecast and the degree of coincidence of DSM initiatives on our peak loads.

In this chapter, we explore several issues that will evolve over the planning period and could have significant impacts on our load and operations, as well as on our cost of service and resulting customer prices. Included in this discussion is a look at natural gas supply issues, upcoming MISO policies and the potential for behind the meter advances, developing federal environmental regulations, the future price impacts of resource planning decisions and the impact of this significant investment plan and rate of sales growth on our current ratemaking tools.

Changes in the Natural Gas Market

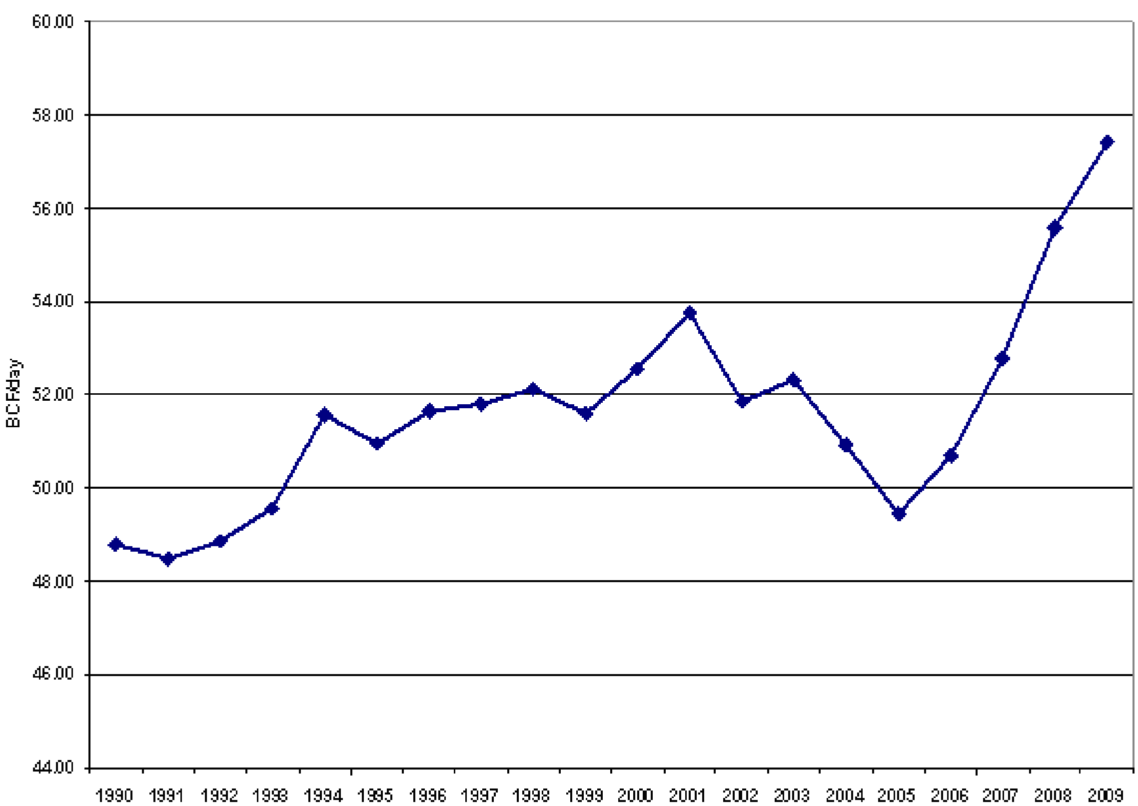
Natural gas is an important fuel for our economy. It plays a major role in industrial production and residential and commercial heating applications. In the past two decades, natural gas has played an increasingly important role in the production of electricity. It is a relatively clean fuel and facilities that convert natural gas to electricity are less expensive to construct per kW than coal-fired facilities. In 2009, electricity production accounted for roughly 29% of domestic natural gas use. Figure 2.1 illustrates natural gas use by sector.

Figure 2.1
Natural Gas Use by Sector



Our regulators have long been concerned about the long term supply of natural gas, the availability of natural gas for home heating and the impact of gas price volatility on customers. In 2007 natural gas production in the U.S. started to increase again after hitting a low of 49.45 BCF/day in 2005. U.S. gas production in the 2005 had dropped to its lowest level since the early 1990's, prompting the call for increased imports from abroad. The decline in U.S. production increased the potential that disruption in production or an increase in demand due to a cold winter resulted in increased gas prices and increased gas price volatility. The gas industry's "just in time" inventory practice led the markets to believe that domestic natural gas reserves were waning and the future of natural gas supplies in the U.S. was dependent on foreign liquid natural gas ("LNG") development and was subject to worldwide influence on pricing. Figure 2.2 is the history of Dry Gas Production in the U.S. over the last 20 years.

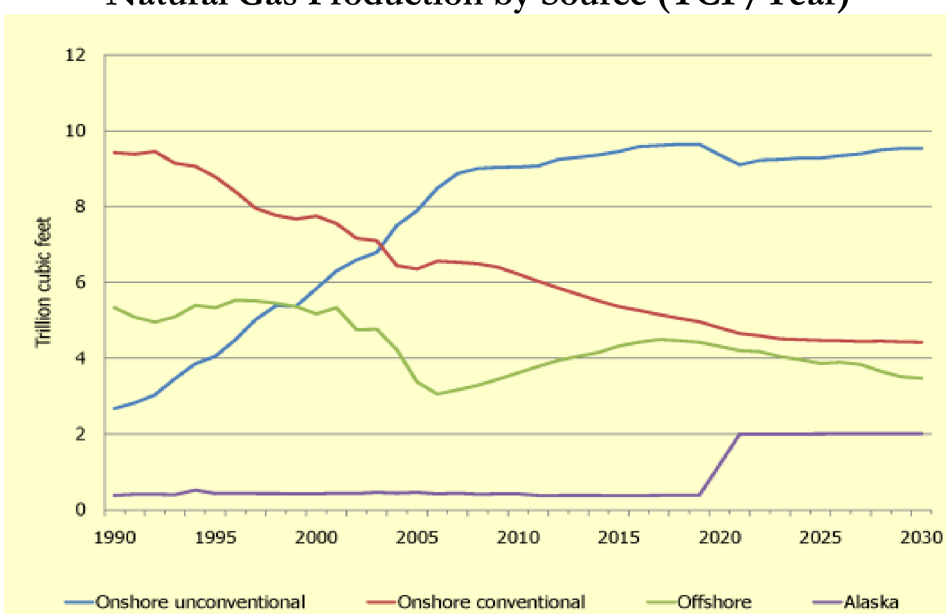
Figure 2.2
US Dry Natural Gas Production



Due to the concerns regarding future supplies of natural gas in the U.S. large investments were beginning to be made based on the need to develop and ship LNG to the U.S. including a new fleet of LNG tankers. In 2007, LNG imports were expected to rise to 4 BCF/day in 2010 and to exceed 12 BCF/day in 2020. With the increased production in the U.S. LNG imports have been limited to the 1.5 to 2 BCF/day range and are expected to stay around that level for some time to come. The decreased reliance on LNG imports in the near-term future has allowed the natural gas pricing in the U.S. to become somewhat disconnected from the worldwide markets and have allowed the pricing mechanisms to return to the traditional production life-cycle approach. This market separation has had the impact of lowering expectations for prices in the U.S. and has provided a market pricing outlook that is focused on the incremental cost of producing natural gas largely from new and emerging sources as described below.

Between 1990 and 2009, annual domestic natural gas production from conventional sources declined more than 30%, from over 9 trillion cubic feet ("TCF") to 6 TCF. However, the extraction of unconventional natural gas resources increased from 2 TCF to nearly 9 TCF. This is illustrated in Figure 2.3.

Figure 2.3
Natural Gas Production by Source (TCF/Year)



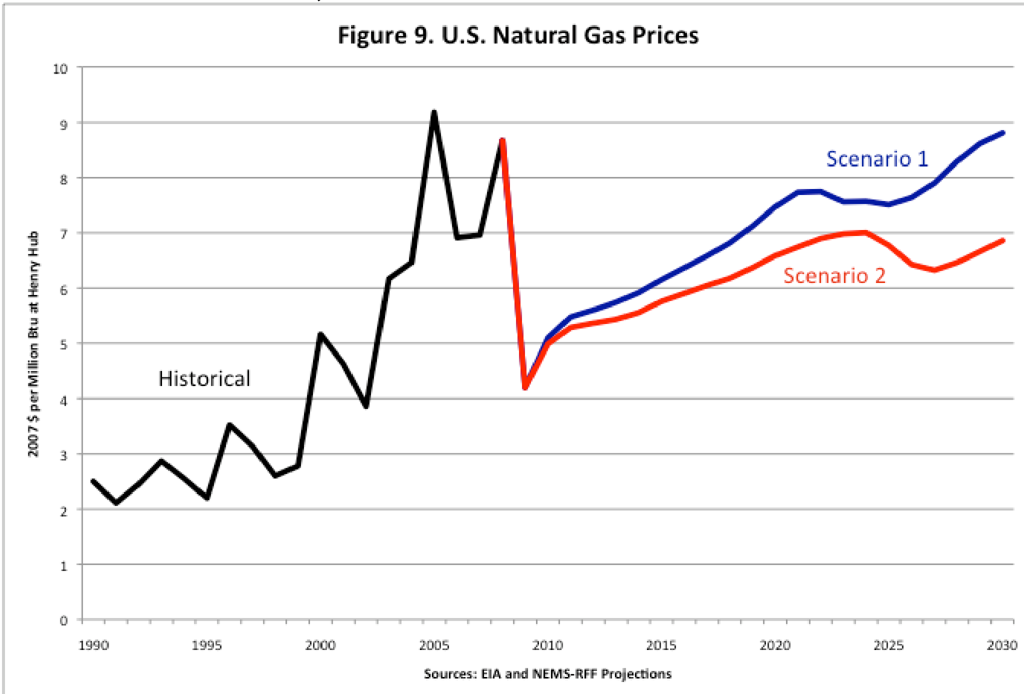
Unconventional gas resources include "tight" gas (gas in low-porosity sandstone and carbonate reservoirs), coal bed methane (gas in coal seams) and shale gas (gas held in low-porosity shale formations). While these natural gas sources have long been considered in estimating the total domestic natural gas resource, recent improvements in horizontal drilling and hydraulic fracturing along with historic higher natural gas prices have greatly expanded economically recoverable reserves of unconventional gas.

Economically recoverable shale gas has been a major contributor to increasing reserves and declining natural gas prices. Analysts estimate that by next year, more than half of the new proven reserves will come from shale gas. Estimates of recoverable shale gas have been increasing. According to the Energy Information Administration, in 2007 shale gas reserves were estimated at 269.3 TCF. In 2009, the Potential Gas Committee released an estimate of 615.9 TCF. . Natural gas production in 2009 from the major U.S. shale formations equaled less than 10 BCF/day or approximately 20% of the U.S. overall production. Recent forecasts suggest that production from major shale plays in the U.S. will rise to nearly 35 BCF/day by 2020 or nearly 60%.

The expectation of this expansion of the domestic natural gas supply is that a more abundant supply will lead to lower natural gas prices long-term. In April 2010, Resources for the Future published an analysis of the impact of shale gas supply on natural gas prices. It considered two scenarios, one with the more conservative 2007 estimate of reserves, and one with the higher estimate from the PGC. In the first scenario, the price of natural gas at Henry Hub in 2030 was estimated to be $8.81/MMBtu. Under the second scenario, with higher shale gas supplies, the 2030 price was estimated at $6.86/MMBtu. These scenarios are depicted in Figure 2.4.

Figure 2.4

Projected US Natural Gas Prices



As shale gas drilling has become more prevalent, there have been increasing concerns about the environmental effects of hydraulic fracturing to extract the gas. Hydraulic fracturing requires significant amounts of water (4.5 million gallons per average well), and grit and chemicals are mixed into the water to help fracture the shale. Shale gas drilling discharges both fracturing water and natural water, which needs to be retreated and either re-used or returned to the aquifer. The Federal Safe Water Drinking Act regulates water that is reinjected into the ground; however, states are also able to adopt stricter standards. As the use of shale gas continues to expand, there is likely to be increasing environmental regulation that could modify the amount of cost-effective shale gas available for extraction.

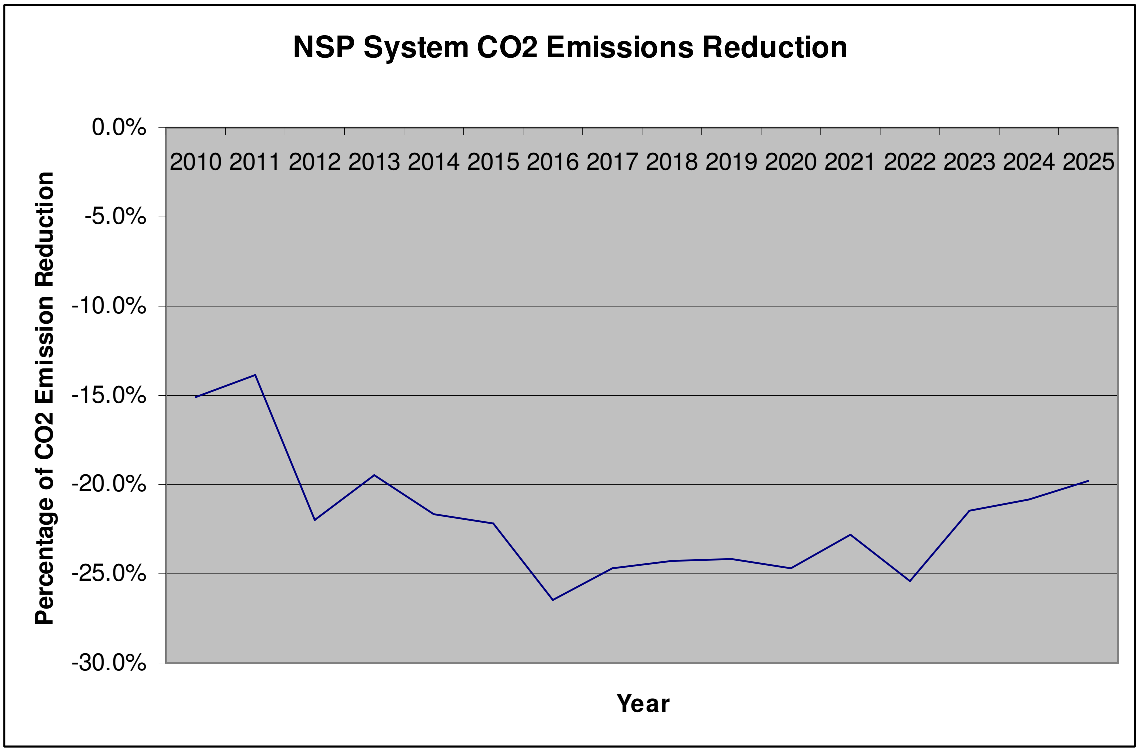
A long-term lower price for natural gas will produce significant benefits to our customers. It will reduce the production cost at both current and new resources. In addition to lowering the cost of energy from our natural-gas fired facilities, the lower cost of energy from natural gas is expected to put downward pressure on wind prices, which are a close competitor. Lower natural gas production costs also reduce the integration costs of wind on our system since our ability to follow the wind with flexible gas generation becomes less expensive. Today's natural gas forecasts also predict reduced price volatility.

The Commission has expressed concern in the past that more extensive use of natural gas for electric generation would hamper the supply and increase the cost of natural gas for residential heating customers. The substantial increase in supply due to the ability to economically recover shale gas may result in the ability to expand natural gas-fired generation while reducing the cost to all users of natural gas. Still, natural gas is a commodity that comes with some price volatility and the impacts of federal regulations on shale extraction will be a key factor in whether the same level of volatility that we have seen in the past decade returns.

Federal Environmental Regulation

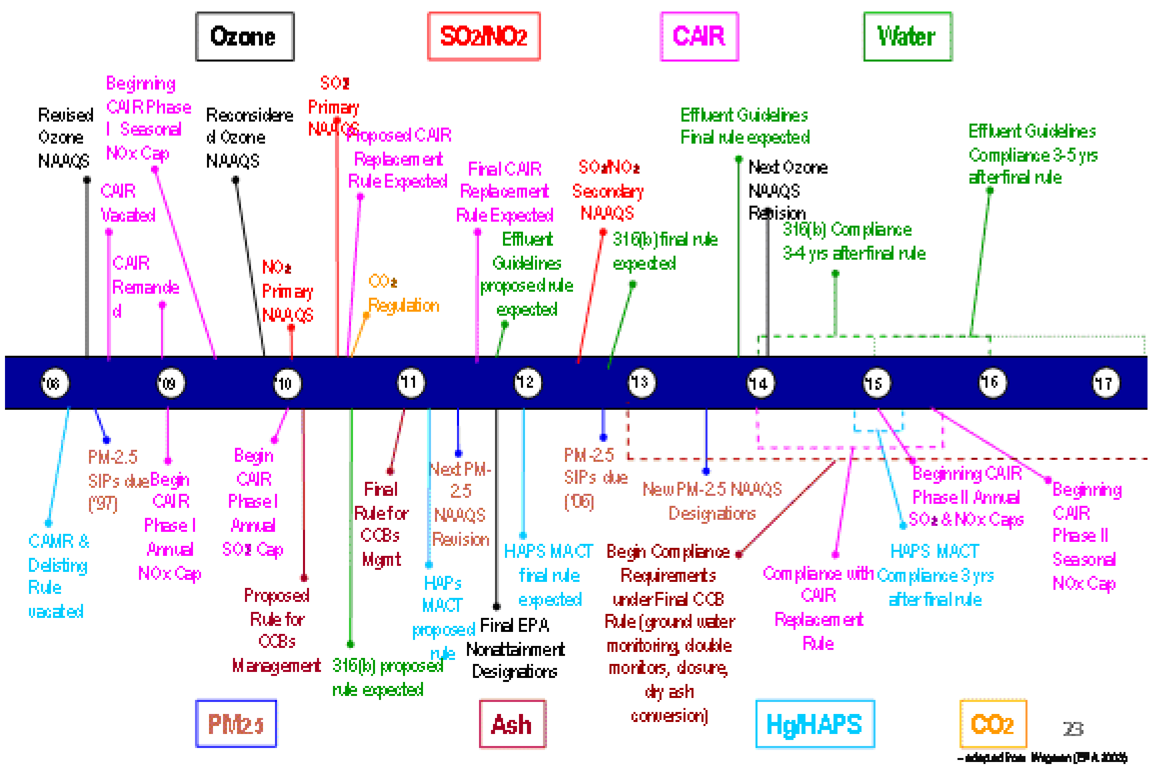
As discussed more fully in Chapter 9, Xcel Energy has historically led other utilities in demand-side management, renewable energy and environmental performance. Our MERP conversions at High Bridge and Riverside allowed us to increase the capacity of our system while significantly reducing air emissions associated with older coal units. We have acquired a significant amount of wind at a relatively low price, resulting in a renewables portfolio that is substantially less expensive than the market price for energy. While we have seen increases in the price of wind more recently, we are hopeful that the more recent drop in natural gas prices will help to moderate wind pricing. Our proposed nuclear upgrades and the recently signed contract for an additional 10 years of capacity and energy from Manitoba Hydro (if approved) continue our strategy of implementing lower cost, environmentally sound resources. As described below, the likely changes in environmental regulation will heighten the value of these past decisions. In this plan, we propose another major project to improve our environmental performance by repowering our Black Dog facility with natural gas.

Figure 2.5
NSP System CO2 Reduction



We anticipate significant changes in environmental requirements over the planning period. The Environmental Protection Agency ("EPA") has proposed new, more stringent regulations for air emissions, water quality and solid waste disposal. The following chart (Figure 2.6) was developed in an attempt to place all of the likely upcoming environmental regulations on a single timeline. While we may not be subject to all of these requirements, and the timing may change, it is clear, that our generation will need to respond to new standards for air quality after a lengthy period of dormancy under the Clean Air Act.

Figure 2.6
Environmental Regulatory Timeline



Some of the regulations that we expect will have near term impacts include the EPA Transport Rule (a replacement for the Clean Air Interstate Rule), National Ambient Air Quality Standards ("NAAQS), the National Emissions Standard for Hazardous Air Pollutants ("NESHAP") (regulating mercury and other emissions) and regulations dictating monitoring of coal ash ponds and future disposal of coal ash.

The Transport Rule, proposed by EPA in July of this year, now includes Minnesota as an affected state. It will require reductions in SO_2 and NO_x as early as 2012 if the final rule maintains the proposed compliance schedule.

This rule, combined with NAAQS and other actions, is expected to reduce SO_2 emissions by 71% and NO_x emissions by 52% over 2005 emissions by 2015.

We may be able to meet emerging hazardous air pollutant requirements through controls at our Sherco and King plants, but older plants like Black Dog and Bay Front may require extensive retrofits. These older plants are not cost-effective to bring into compliance unless we also make significant investments in extending the lives of the units. In Chapter 6, we will demonstrate that repowering Black Dog with natural gas is a lower cost option then extending the life of the coal units and acquiring our other needs elsewhere.

Under coal ash regulations, some of the coal residuals that are currently regulated as non-hazardous waste could be reclassified as hazardous waste. We may also need to move to a dry disposal system for Sherco 1&2 in lieu of our current ponds.

While each of these regulations are significant in their own right, the development of back-end controls to manage all of the requirements at once will be complicated. The result of certain requirements (dry ash handling at Sherco, for example) could dictate the types of controls that will be more effective to meet other standards (such as the current use of wet scrubbers for SO_2 control). We are committed to developing the most cost-effective and efficient strategy for meeting the combined regulations, but nonetheless we expect our investment in this area to be significant.

In addition to the rules discussed above, methods of carbon regulation are still being debated. While cap and trade proposals are currently stalled in Congress, the EPA has expressed its willingness to regulate carbon under the Clean Air Act and has already taken steps to confirm its ability to do so. In Chapter 9 we discuss possible regulations that EPA could adopt with respect to carbon.

While many of our early actions will ease meeting the emerging requirements, complying with these and other new regulations will require investment in our plants and like all environmental improvements, these costs are not supported by sales growth. As we develop our compliance plans we will evaluate all options to ensure that we are providing the best options for our customers. In particular, in this plan, we propose to undertake a thorough evaluation of the economic value of extending the lives of Sherco Units 1 and 2. These units' economic lives end in 2023 and we may need to make decisions as early as our next resource plan. It is likely that we will need to make planning decisions that reflect uncertainty with respect to the timing and scope of greenhouse gas regulation and without knowing the costs associated with meeting potential future environmental regulations.

Potential for Significant changes in our customer's usage

In each of our recent resource plans, we have increased our DSM goals and expanded our programs to achieve high levels of energy savings. In our 2007 plan, the Commission approved a goal to achieve a 1.3% savings goal by 2012. Currently our experience to date shows that we should be able to meet or perhaps exceed that goal in the near term As a result, we are now considering the types of programs and measures that could allow us to achieve the Minnesota statewide goal of 1.5% energy savings per year.

Yet there are many who believe that much deeper efficiency gains are possible and will be achieved relatively quickly through emerging "smart" technologies. Appliances may be programmed with chips to respond to real-time price signals. Customers almost certainly will be able to control their home energy usage remotely as firms such as Google and Microsoft enter the behind the meter market for potential savings. As discussed below, market changes, being advanced by the FERC may also affect our demands. In addition, behind-the-meter generation can play a significant role in utility system energy savings. Customers that install solar generation, for example, directly reduce their purchases from Xcel Energy, particularly on-peak. Distributed solar power is improving in efficiency and fuel cell technologies are also under development. For example, the International Energy Agency predicts that solar efficiencies will more than double by 2030, and that solar could be on competitive parity with the power grid by 2020. In February 2010 Bloom Energy announced that it had developed a fuel cell powered by natural gas that could generate electricity in the price range of 8 to 10 cents/kWh.

Finally, one widely discussed new technology, the electric vehicle, will actually cause loads to increase if widely adopted. A typical battery charging at night will consume as much energy as the average household, effectively doubling that customer's usage. Technology advances either in efficiency or the electrification of transportation, as well as advances in distributed generation could have a profound impact on our need for future resources. How widely these tools are adapted, and their impact on our sales is difficult to assess. Based on the current pace of development it is likely that their impact will not occur until the latter part of the planning horizon.

While we are more optimistic than in the past about our ability to deliver high levels of savings in a cost-effective manner, there are potential obstacles. Our updated potential study shows an achievable savings rate of approximately 1 percent of energy sales. The Company has been outperforming the potential studies and therefore are basing our recommendations**,** more on experience than estimates of customer behavior. It may be that our success is ephemeral, but we are fortunate that this approach does not have a material impact on load needs in the near term, such that if we are wrong, we should have ample time to expand our system.

Evolving MISO Policies

MISO also plays a significant role in maintaining our reliability. The value of MISO has evolved since the time of our last plan. As a major user of wind energy, the MISO market assists in managing variability issues of a smaller utility system. In addition, the MISO ancillary services market has produced customer savings in its first year of operation. MISO's markets have matured, and while MISO is a complex market, it is delivering on its promise of efficiency through coordinated regional dispatch.

However, MISO continues to consider adoption of policies that could have significant impacts on our operations. For example, MISO is working on a proposal for utilities to bid all of their interruptible load and other DSM programs into the market as resources. This change puts the control decision farther away from the customer and, depending on how such market rules are implemented, may effectively increase the demand we will need to plan for, raising both our need for resources and our reserves. Such a change would also impact our rate design, changing the way interruptible customers are compensated for their ability to control.

In another proceeding, MISO is experimenting with a voluntary capacity market and considering whether the market should be mandatory to ensure long-term reliability of the system. Xcel Energy and other utilities that are subject to state resource planning requirements are skeptical that a mandatory capacity market will provide the same level of consideration for cost, reliability and environmental stewardship as current state regulation has provided.

We are actively working within MISO to shape policies on issues such as these as well as reserve margins, ancillary services, wind integration costs and transmission cost allocation to ensure that our customers continue to have cost-effective and reliable service.

Potentially Divergent Jurisdictional Policies

NSP-MN and NSP-WI have always planned and operated their systems in an integrated manner, where all of the resources on both systems are used to serve the entire load. Costs have traditionally been allocated according to the percentage of our system utilized by each operating company and jurisdiction. This method of planning has served all of our jurisdictions well as we have been able to leverage the size and diversity of our service territory to serve our customers at a lower cost then if we were to satisfy each state's requirement individually.

In the past few years, the interests and requirements of our jurisdictions have started to diverge, particularly with respect to environmental policy. As discussed in Chapter 5, each of our jurisdictions has its own RES or renewable objective, with different rules on which resources are eligible to be counted.[1] In addition, each state has different approaches to demand-side management programs and carbon dioxide costs and reduction goals.

Because we develop a single Resource Plan applicable to our entire system, it is challenging to create plans that will satisfy individual and divergent requirements in all jurisdictions. In Chapter 4, we explore the differences among the states in which we operate and provide scenarios in which we meet specific scenarios. For example, because North Dakota law prohibits the use of environmental costs (including carbon dioxide costs) in resource decisions, we have for the first time developed a scenario that examines which resources would be added to our system if we excluded all carbon costs by ignoring the potential for greenhouse gas regulation. While these scenarios are unlikely to change the resources we are proposing in our action plan, it will advise our various jurisdictions on the costs and risks of particular resource choices. We expect this information to assist our regulators in making informed decisions

[1] For example, Minnesota permits municipal solid waste to be eligible for the RES, and North Dakota permits counting energy from waste heat (recycled energy). Our Bayfront plant can be counted as a renewable in Wisconsin but not in Minnesota.

about specific resources. We are hopeful that all jurisdictions will conclude that a diverse portfolio of resources is needed to respond effectively to a variety of potential future scenarios and that our current plan is a cost-effective, diversified means of meeting future resource needs in a manner that recognizes the uncertainty of different planning assumptions and attempts to select resources that perform well under a variety of different conditions.

Customer Prices

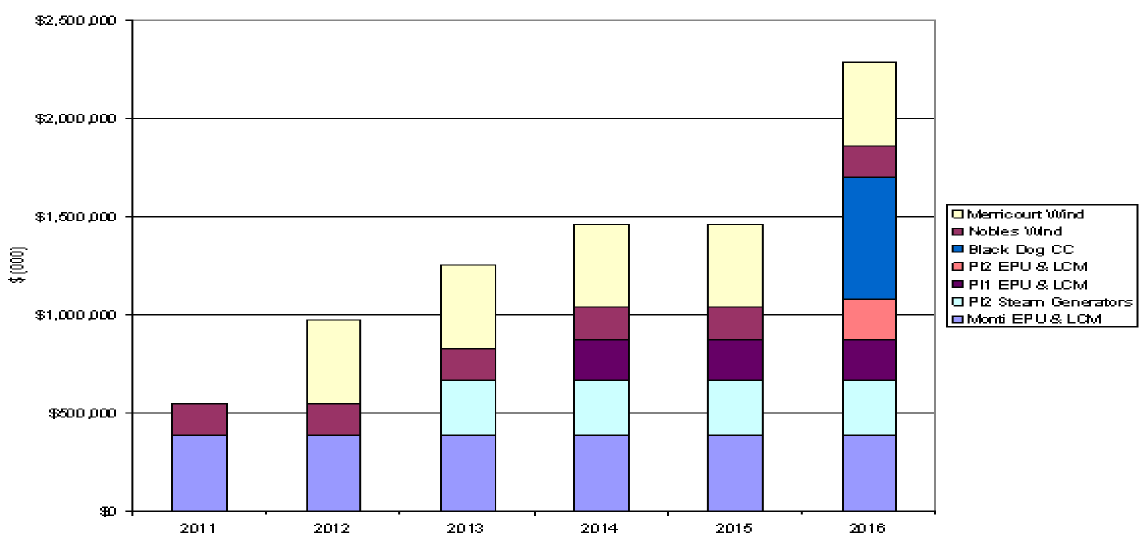
All of the initiatives undertaken by the Company consistent with recent plans along with the initiatives proposed in this Resource Plan necessarily have an impact on the prices our customers pay for electricity. While rates are not formally set in resource plan dockets, the decisions made by the Commission in this proceeding will ultimately determine not only the technologies used to provide energy but fundamentally, the price that our customers pay for this energy. These decisions will form the cost trajectory that our customers will see implemented in future rider and general ratemaking proceedings as the Company implements the plan approved in the instant proceeding as well as decisions made in other recent plans.

Initially, resource plans were designed to provide stakeholders and the Commission a view of alternatives for meeting growing demand. This growing demand was met primarily with the addition of traditional base load and peaking energy resources. While it was well understood that large plant additions would lead to rate increases, these increases were relatively infrequent and were offset somewhat by increased fixed cost contribution through increased energy consumption. Finally, transmission planning was not explicitly incorporated into these plans, as the existing backbone system was already in place to deliver the increased power needs.

Our more recent plans have seen a shift in emphasis. We are now in the process of modernizing our generation fleet to provide cost effective power, to achieve important environmental policy objectives and to address emerging environmental compliance requirements. This has entailed significant investment in renewable resources, life extensions and expansion of our nuclear fleet, and repowering and upgrading of some of our older fossil generation. Figure 2.7 provides a summary of our planned major generation investments over the next six years.[2]

We will invest nearly $1.5 billion to expand our nuclear fleet, another $900 million for our Nobles and Merricourt wind generation and potentially $600 million to repower the Black Dog generating facility with a 2x1 combined cycle gas facility. The investment in just these additions will lead to major capital investments approaching $3.0 billion during this period. This amount does not include the costs that may be associated with further environmental upgrades at our Sherco plant. In addition, as demonstrated in Figure 2.7, these resources are being placed in service at a pace of nearly one per year, necessitating more frequent rate cases to assure recovery.

Figure 2.7 Planned Generation Investments- Cumulative



As discussed in Chapter 10, we have also incorporated in this Resource Plan the significant transmission expansion that is necessary to support future generation needs and state energy policies encouraging wind generation. This transmission investment is an integral part of our efforts to ensure the availability of energy to our customers during the plan period.

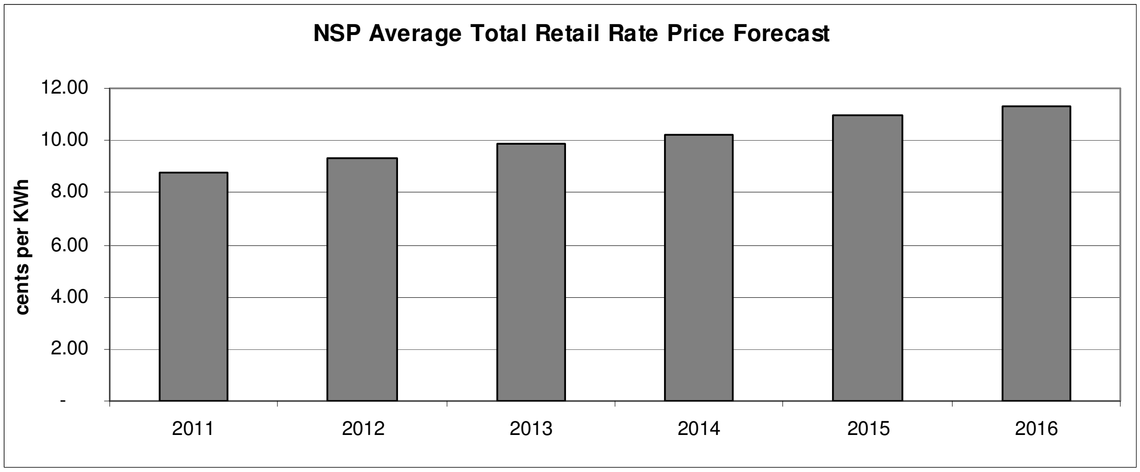
All of these initiatives are consistent with implementing a least cost plan that cost effectively addresses the direction we have received from policy makers regarding the future provision of energy services. As described throughout this Resource Plan, we have taken numerous steps to ensure that our plan is a least cost method of achieving the dramatic transformation of our system discussed above. Further, our plan, with its significant capital investments in wind and nuclear energy resources and significant expenditures for demand side resources, minimizes the increases in our overall fuel costs.

Finally, as described in Chapter 8, we have also incorporated dramatic increases in our efforts to reduce the growth in energy demand through aggressive marketing and implementation of demand side management programs throughout our service territory and across all customer classes. Current legislative policy direction in this area will continue to drive down energy demand growth at the same time that we modernize our generation fleet.

Our combined efforts to implement our approved plans and initiatives to reduce demand increases, along with events in the larger economy, have reduced our ability to mitigate the need for rate increases to our customers through sales growth. We expect that impact of these efforts will raise the price of electricity to our customers at a fairly consistent pace over the next several years.

When all of our costs, including our distribution plant investment and operating costs which have high rates of growth in chemicals, pension expense and health care, are taken into account, we expect the system average price per kWh to move from about 8 cents today to 11 cents in 2016. Figure 2.8 below provides a near term look at the both the fuel and base rate increases that will be needed to implement prior and current resource decisions. Our system is growing at an average compound growth rate of about 5% during this period.

Figure 2.8
Near Term Rate Increases



Note: Rates include fuel costs & riders and represent the average total retail rates for MN, ND, SD, WI, and MI

As can be seen from this chart, implementation of our approved and planned initiatives will require additional revenue and increased rates. With the fairly consistent rise in costs over the next few years, we anticipate the need for more frequent rate cases to meet all of the obligations of this plan and our previous Resource Plans.

The rate increases needed from 2011 through 2016 cannot be easily avoided in order to continue to provide safe and adequate electric service while complying with State and Federal energy policies. For example, because our nuclear facilities have limited lives established by operating permits from the NRC we need to make the investments in life extension now in order to preserve the fuel savings and other benefits they provide. The need to retire Black Dog comes with the alternative of spending significant capital to retrofit the least efficient coal units on our system. And our wind investments will have a zero fuel cost, offsetting a major portion of their fixed cost recovery. The

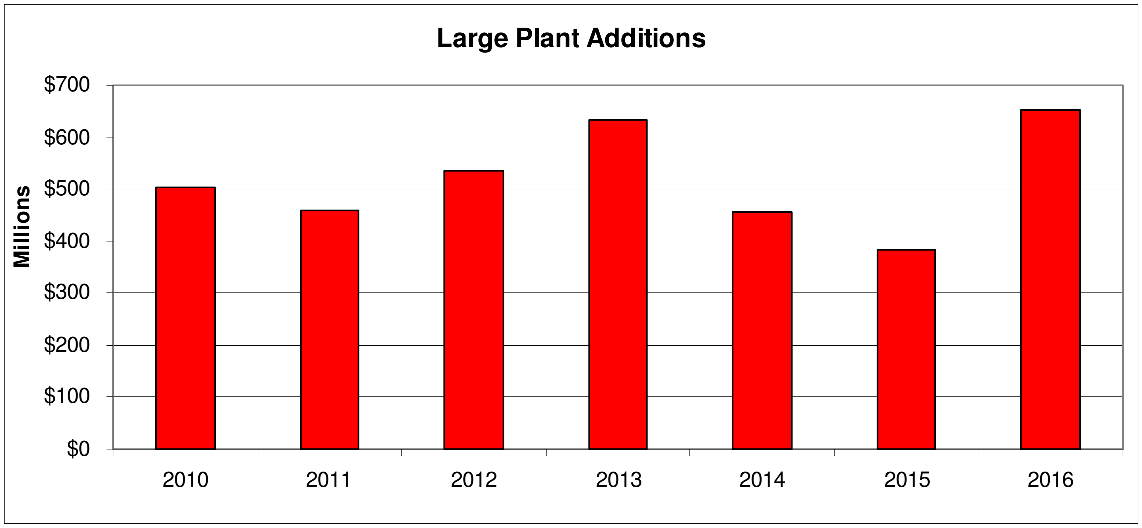
Commission has recognized the long-run benefits of many of these investments and it will be important to recognize that these initiatives come at a cost to ratepayers. Further, it should be recognized that the near term rate of increase shown above could potentially be steeper and with considerably less certainty, if we were to pursue alternative investments needed to meet load and price volatility resulting from movements in coal, natural gas and regional electricity market prices.

In short, we believe that our plan and resulting cost trajectory strikes an appropriate balance for our customers and that under any scenario, the price of electricity will increase at about the pace shown in Figure 2.8 during this period. Comparatively, however, as other utilities face similar challenges, we fully expect to maintain an average retail price that is well below the national average.

Utility Financial Health

We believe it is important at this point in our investment plan to ensure that stakeholders see clearly the linkage of our resource decisions and the rate impacts of these decisions, which are the means by which we are able to access the financial resources to implement these decisions. The continued investment needs envisioned in our current plan as well as the continued rise in key elements of operations such as chemicals, pension and active health care expense, requires significant capital Our investment in major projects from 2003 to 2009 totaled about $1.5 billion (for MERP, Buffalo Ridge transmission and Grand Meadows wind). In the 2010 to 2016 period, this major project investment will rise to roughly $4 billion (for nuclear investments, wind generation and CAP-X 2020 transmission). (See Figure 2.9) This is on top of our base cost of production, transmission and distribution and does not assume widespread deployment of "smart" technology on our distribution network.

Figure 2.9



These types of costs and the costs that will be incurred in upcoming years to implement our plans create a need for consideration of new ratemaking policies to implement this plan and prior resource plans. New ratemaking policies that reflect the increasing expenditures necessary to implement our resource plans will be important to allow us to be able to raise capital on reasonable terms in order to finance this growth in our investment program.

In the past, the Commission has used a combination of traditional and non traditional ratemaking tools to implement the policy direction provided in its resource plans. We have been able to supplement periodic rate cases with capital rider recovery to implement a substantial and needed capital investment program. This ratemaking approach has accomplished its goal by permitting the Company to continue its accelerated capital expansion while maintaining an opportunity to earn reasonable returns and maintain financial strength. However, this approach has also created new complexities and challenges for both utilities and our regulators. In fact, our investment plans over the next several years combined with lower levels of sales growth than we have experienced in the past will render this ratemaking paradigm less effective, as multiple rate cases will be required within a short period of time, creating challenges for utilities, regulators and other stakeholders.

The continued investment needs envisioned in our current plan as well as the continued rise in key elements of operations cause the need for consideration of new ratemaking policies to meet the circumstances presented here. New ratemaking policies that reflect (i) major energy policy developments, (ii) increasing expenditures, and (iii) downward pressure on demand increases will allow us to be able to raise capital on reasonable terms in order to finance this growth in our investment program.

While not seeking to address rate change in this proceeding, we raise this issue now recognizing the importance of these ratemaking issues will be critical to the execution of our plan. It will be difficult to deliver the promise and benefits of these investments without the ability to recover our costs of providing service in a timely manner. We are hopeful that our stakeholders will recognize the need to facilitate plan implementation through a supportive regulatory framework.

The Commission's Utilities Rates Study, (see Laws of Minnesota, Chapter 110(S.F. No. 550)) discussed several alternatives to the current structure that relies on a combination of traditional ratemaking and rider recovery to implement its policy direction. We expect to continue to work with stakeholders to explore these alternative ratemaking strategies and develop tools that best fit our future cost structure, while at the same time continuing to provide the appropriate incentive for us to achieve continued efficiency of operations. We believe that the move to a ratemaking framework that allows for annual base rate changes and fewer riders is necessary to meet the goals and objectives laid out in this Resource Plan.