Chapter 3. Forecast and Resource Needs

Forecasting is a key component of any Resource Plan. The demand and energy forecasts provide the basis for determining the type and amount of resources that will be needed over the 15-year planning period.[1] In this chapter, we present our forecast results, discuss key assumptions and compliance issues, and identify overall resource needs for the 2011 – 2025 planning period.

The peak and energy forecasts are first produced with a 50% probability that the energy or demand will be less than the forecast and a 50% probability it could be higher. These initial forecasts are referred to as the median forecasts.

Forecast Adjustments

Our demand and energy forecasts are developed using a number of key forecast variables as described in the next section of this chapter. One important adjustment to the forecasts is to take into account our conservation programs.

The impacts from all conservation program installations prior to 2010 are embedded in the historical demand and energy data. However, to accurately predict future supply needs, the energy and demand forecasts must be reduced by an estimate of future conservation savings. For the base forecast, we adjust the demand and energy forecast by 1.15%, which is our 2010 goal as approved in the 2007 Resource Plan and our 2009 Triennial CIP filing. The base forecast represents our expected peak demand and energy needs if 2010 levels of DSM are maintained.

After determining the base forecast, we develop net forecasts that include other adjustments, including incremental DSM over the 1.15% goal and the effects of our load management programs. In this plan, we evaluated future DSM at two levels: 1.3%, which is our 2012 phased-in goal from our 2007 Resource Plan, and 1.5%. The monthly conservation impacts are calculated by customer class, and then subtracted

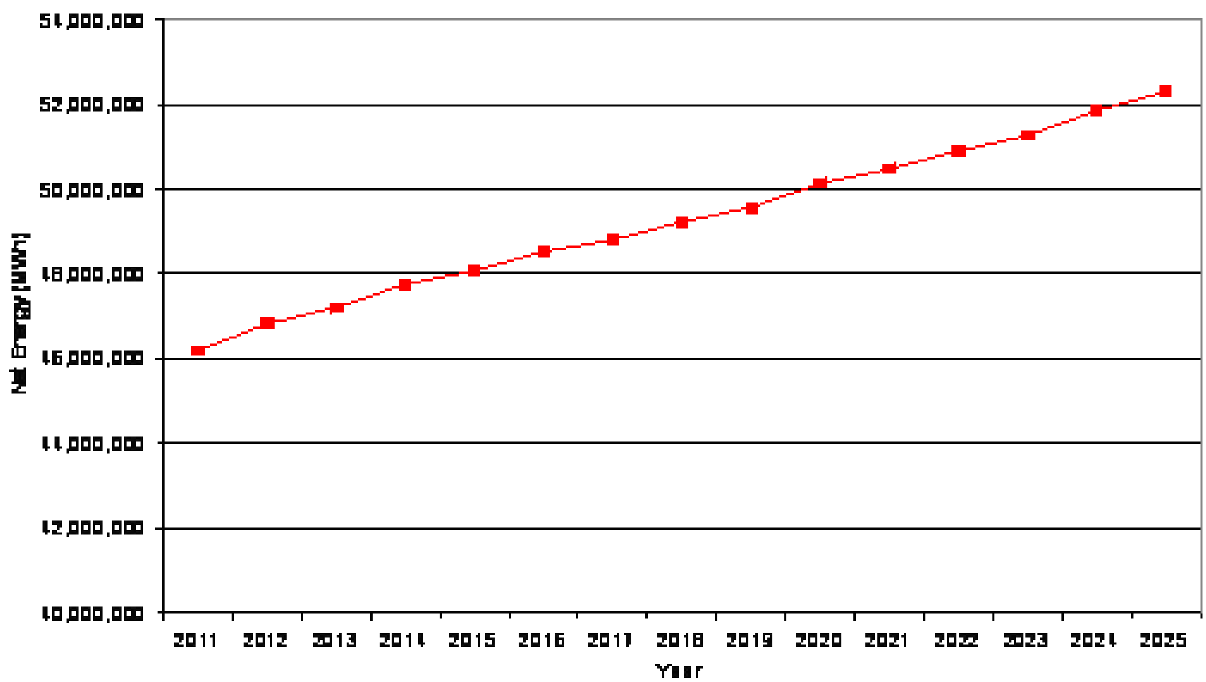
[1] The 15-year forecast includes Xcel Energy's service territories in North Dakota, South Dakota, Minnesota, Wisconsin and Michigan.

from the customer class sales forecasts that result from the regression modeling process.

Energy Forecast

The base energy forecast increases at an average annual growth rate of 0.9% over the 2011 – 2025 forecast period. Electric energy requirements are expected to increase at an annual average of 444 GWhs a year, starting with 46,191 GWhs in 2011 to 52,303 GWhs in 2025. See Figure 3.1 below.

Figure 3.1
Median Net Energy (MWh) NSP Total System with 1.15% Retail Sales DSM Adjustment

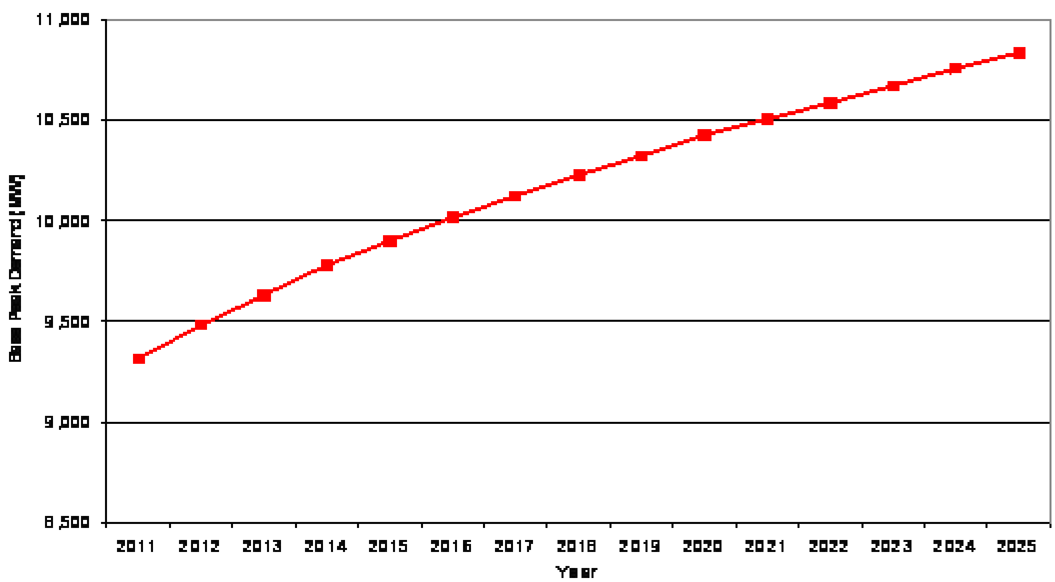


System Peak Demand Forecast

As a summer peaking utility, our system peak demand is the greatest load placed on our system during the hour of highest use in the summer season. The peak normally occurs during periods of very hot and humid weather. We meet this peak demand through a combination of Company owned generation, purchases and load management programs.

Like the energy forecast, the base peak demand forecast has been reduced to account for conservation efforts at 2010 levels but not the Company's load management programs. During the 2011 – 2025 planning period, the median base peak increases at an average annual growth rate of 1.1%. As demonstrated in Figure 3.2, annual peak demand increases at an average of 113 MWs each year, starting with 9,315 MWs in 2011 to 10,834 MWs in 2025.

Figure 3.2
Median Base Summer Peak Demand (MW) - NSP System with 1.15% Retail Sales DSM Adjustment



Additional Demand Forecast Adjustment

As a general rule, external adjustments are not made to the Company's econometric forecast. However, in this forecast period we did find it necessary to make an adjustment to our demand forecast due to a recent code modification in air conditioning standards for businesses. The adjustment was made to avoid overstating our demand forecast by failing to count savings that are not adequately captured in our data.

In 2007, the commercial air conditioning standard was modified to increase minimum efficiency levels. While this change in required efficiency will likely result in higher demand savings on our system, we are only able to include the difference between the more efficient model's SEER and the minimum SEER as demand savings we achieved through our programs. However, customers that replace their cooling systems are likely to have systems that are far less efficient than the new minimum SEER. As those units are replaced, there is more demand savings occurring on our system than we account for in our DSM achievements.

Normally, the impacts of these code changes are captured in our forecast in historical data. Because this code change was recent and significant, and we are concerned that its effect is not adequately represented. To account for this, we estimated the level of savings that are occurring, but not accounted for in our historical data or our savings goals, and subtracted that amount from our demand forecast. We believe this adjustment results in a more accurate estimate of peak demand, and allows us to avoid acquiring excess peak resources. The net effect of this change is a reduction in the IRP demand forecast of 53 MW in 2015 and 120 MW in 2020.

Key Demand and Energy Forecast Variables

Below we discuss some of the key variables that are included in the 2010 Resource Plan forecasts.

Demographics

Population projections are essential to the development of the long-range forecasts. The consumption of electricity is closely correlated with population statistics. The number of residential customers and weather data are key variables in the residential energy sales forecast. Over 99% of the variability in historical electric consumption by residential customers in our service territory can be explained through an econometric model that contains the number of residential customers and weather as key drivers. Forecasts for residential customers are derived from population and household projections provided by Global Insight, Inc. We forecast an average annual growth rate for residential customers on our system of 0.9%, with the addition of 14,903 residential customers per year from 2011 through 2025.

Economic Indicators

Xcel Energy uses estimates of key economic indicators to develop electric sales forecasts. Theses variables include gross state product, employment, real personal income and productivity. Most of the variables used are specific to the jurisdiction and are statistically significant in the sales models for the commercial and industrial customer classes. Growth in electric energy consumption in the commercial and industrial sectors closely follows trends in economic activity. Global Insight, Inc. provided the economic forecasts used in our regression models.

Weather

The peak demand for electric power is heavily influenced by hot and humid weather. As the temperature and humidity rise, the demand for cooling rises steeply. Our approach to forecasting peak demand includes using a weather variable that consists of the mean of an index of heat and humidity referred to as the temperature humidity index ("THI"). Simply stated, the THI is an accurate measure of how hot it really feels when the effects of humidity are added to the high temperature. We have tracked the THI at the time of the system peak demand over the past 20 years. Because of the 20 years of smoothing, the weather variable does not drastically affect our median forecasts; however, it becomes a key factor in assessing the potential peak demand if and when hot and humid weather extremes are encountered. Since Xcel Energy must have adequate generating resources available during hotter than normal circumstances, planning for the extreme is important.

Forecast Methodology

Xcel Energy serves customers in five jurisdictions in the upper Midwest: Minnesota, North Dakota, South Dakota, Wisconsin and Michigan. We develop a forecast for each major customer class and jurisdiction using a variety of statistical techniques.

We first develop our system sales forecasts by using a set of econometric models at the jurisdictional level for the residential, small commercial and industrial and large commercial and industrial sectors. These models relate our historical electric sales to demographic, economic and weather variables as detailed in the prior section of this document. For the remaining customer classes, Public Street and Highway Lighting, Other Sales to Public Authorities, Interdepartmental and Firm Wholesale sales, we use trend analysis and customer specific data. We compile our system sales by summing the individual forecasts for each sector in each jurisdiction.

Since some energy is lost, mostly in the form of heat created in transmission and distribution conductors, we use loss factors to convert the sales forecasts into energy production requirements at the generator. The forecasted loss factors are developed using actual historical loss factors and are held constant over the forecast period.

We have developed an econometric model to relate Xcel Energy's historical uninterrupted monthly peak demand to native energy requirements and weather at the time of the peak in the winter and summer seasons. The median energy requirements forecast (50/50 forecast) and normal peak-producing weather are used in the model to create the peak demand forecast. (Appendix A – Forecast Methodology at pages 6-7 contains a comprehensive summary of the econometric modeling process utilized to develop the energy and demand forecasts.)

Forecast Variability

As with any forecast, our forecasts of energy requirements and peak demand depend on other forecasts of key variables. Changes in these variables will affect our forecasts. For instance, if the number of households in our service territory is lower than Global Insight, Inc. has predicted, electric consumption in the residential sector will be lower. The peak demand for electric power each year is very sensitive to weather conditions and can vary considerably as the result of abnormal weather conditions. We supplement the median forecasts with forecasts developed using statistical techniques to reflect the potential variability in energy requirements and peak demand. Tables 3.1, 3.2, and 3.3, and Figures 3.4, 3.5, and 3.6 show the higher and lower variations of the 2011 to 2025 long-range forecasts of energy requirements and net summer peak demand. Note these Tables are adjusted for our current year's approved DSM goal of 1.15% of retail sales. Figure 3.8 shows the forecast adjusted for our proposed goals of 1.3% and 1.5%.

To assess the potential variability embedded in our forecasts, we developed probability distributions for the peak demand and energy requirements. The probability distributions were developed using a Monte Carlo stochastic simulation of peak demand (MW) and a simulation of energy (MWh). For example, the peak demand simulation involved taking 10,000 random draws from the weather probability distributions as well as 10,000 random draws from the 12-month sum of the energy probability distribution. The random draws produce 10,000 forecasts of peak demand and thus generate a probability distribution around the mean peak demand.

The probability distributions developed for this forecast yielded the following result for the net energy forecast. There is a 90% probability that the net energy will be less than 58,271,318 MWh in 2025 or alternatively, there is a 10% probability that the net energy will be less than 46,329,695 MWh.

A more detailed description of the probability distribution methodology is included in Appendix A. A summary is provided in Table 3.1 below.

Table 3.1
Annual Net Energy
With 1.15% of Retail Sales DSM Adjustment

	Annual Net Energy (MWh)		
	90% Probability	Median	10% Probability
2011	48,531,169	46,191,286	43,880,489
2012	49,568,017	46,823,815	44,078,400
2013	50,313,148	47,213,690	44,120,445
2014	51,164,358	47,756,996	44,326,662
2015	51,799,768	48,076,670	44,367,861
2016	52,486,314	48,530,467	44,564,263
2017	53,009,267	48,803,217	44,597,142
2018	53,687,459	49,230,611	44,755,927
2019	54,267,927	49,568,829	44,884,163
2020	55,051,752	50,137,716	45,217,998
2021	55,611,110	50,472,966	45,336,786
2022	56,257,171	50,903,335	45,550,391
2023	56,816,366	51,260,184	45,705,611
2024	57,619,973	51,853,309	46,076,167
2025	58,271,318	52,303,296	46,329,695
Average Annual Growth 2011 - 2025	**1.3%**	**0.9%**	**0.4%**

Table 3.2
Annual Base Summer Peak Demand (MW)
With 1.15% of Retail Sales DSM Adjustment

	Annual Base Summer Peak Demand (MW)		
	90% Probability	Median	10% Probability
2011	9,957	9,315	8,684
2012	10,225	9,483	8,781
2013	10,451	9,631	8,859
2014	10,645	9,779	8,922
2015	10,824	9,897	8,972
2016	10,990	10,016	9,035
2017	11,177	10,122	9,072
2018	11,331	10,228	9,130
2019	11,505	10,321	9,170
2020	11,647	10,425	9,217
2021	11,788	10,504	9,243
2022	11,911	10,586	9,240
2023	12,061	10,670	9,296
2024	12,196	10,757	9,337
2025	12,322	10,834	9,351
Average Annual Growth 2011 - 2025	**1.5%**	**1.1%**	**0.5%**

Table 3.3
Annual Net Peak Demand (MW)
With 1.15% of Retail Sales DSM Adjustment

	Annual Net Summer Peak Demand (MW)		
	90% Probability	Median	10% Probability
2011	8,932	8,290	7,659
2012	9,185	8,443	7,741
2013	9,399	8,578	7,806
2014	9,586	8,720	7,863
2015	9,761	8,834	7,908
2016	9,923	8,949	7,968
2017	10,110	9,054	8,004
2018	10,264	9,160	8,063
2019	10,438	9,254	8,103
2020	10,580	9,358	8,150
2021	10,721	9,437	8,176
2022	10,845	9,519	8,173
2023	10,995	9,603	8,229
2024	11,129	9,690	8,270
2025	11,255	9,768	8,285
Average Annual Growth 2011 - 2025	**1.7%**	**1.2%**	**0.6%**

Figure 3.3
Net Energy (MWh) NSP Total System with 1.15% of Retail Sales DSM Embedded

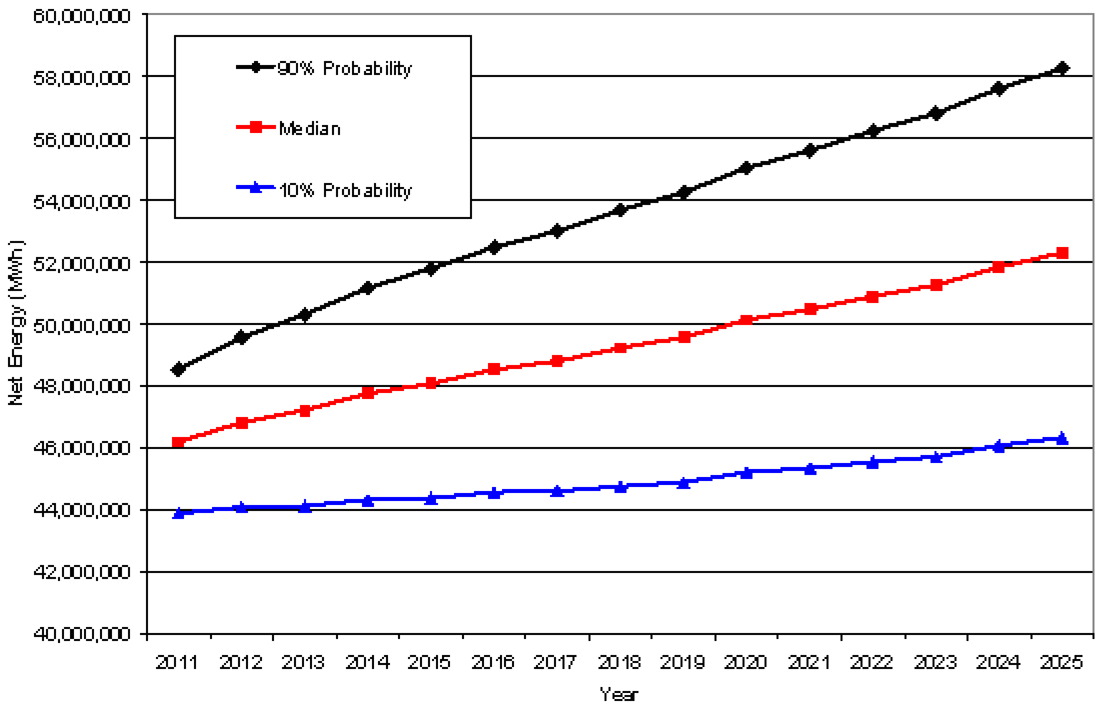


Figure 3.4
Base Summer Peak Demand (MW) NSP Total System with 1.15% of Retail Sales DSM Embedded

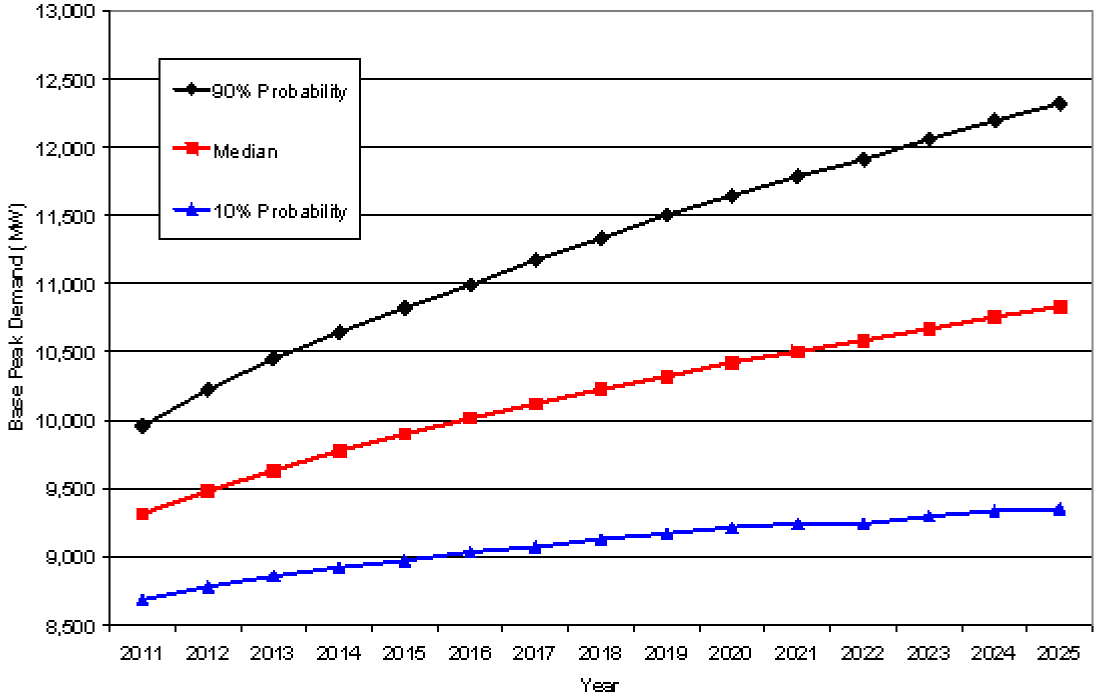
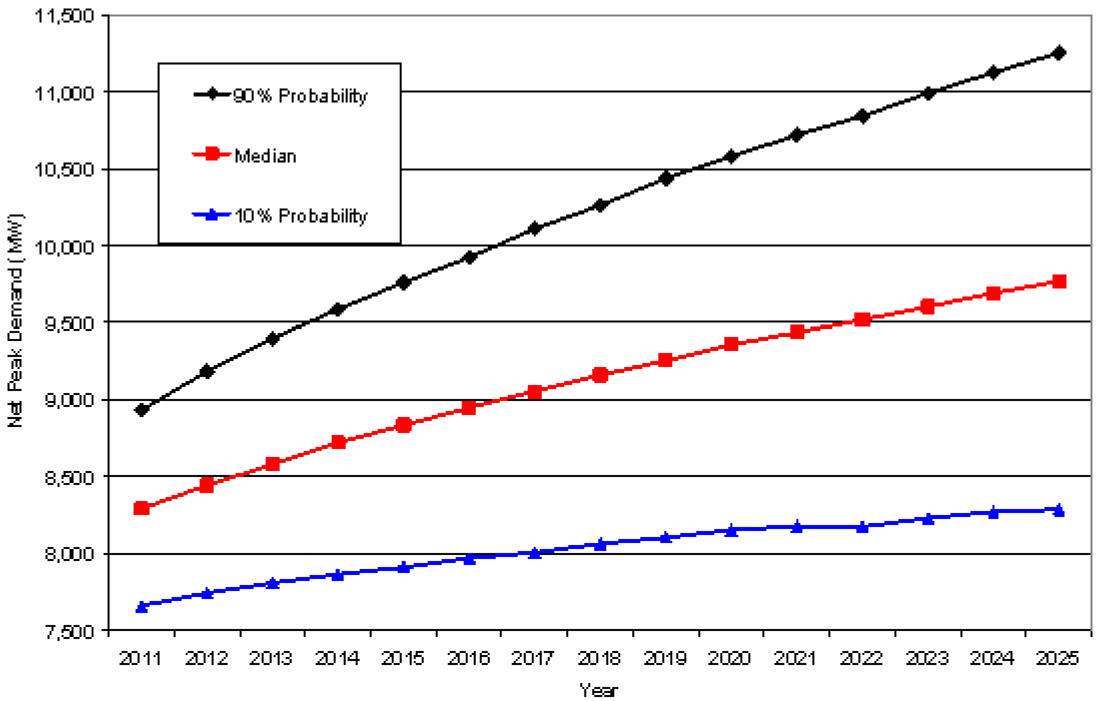


Figure 3.5
Net Summer Peak Demand (MW) NSP Total System with 1.15% DSM Embedded



Forecast Vintage Comparison

As described above, projections of energy and demand are fundamental to identifying the need for generation resources. Thus, these forecasts are an important component in determining the size, type and timing of new generation resources. As a result, ensuring robust forecasts with fully analyzed assumptions and variables is a key component to analyzing a Resource Plan or Certificate of Need.

Forecast Vintage and Comparison

The review process for a Resource Plan or a Certificate of Need typically takes a significant amount of time and effort to complete. During this time, forecasts can change as economic variables change. The graphs below compare the peak demand and energy of the Company's current forecast with the forecasts filed in the 2007 Resource Plan and the Electric Utility Annual Report filed in mid 2010.

Figure 3.6 indicates that the energy forecast is the same as the forecast reported in our 2010 Annual Electric Utility Report, but lower than the forecast approved in our 2007 Resource Plan. This is due to a reduction in historical volumes and slower growth in some economic indicators since the 2007 Resource Plan forecast was produced.

Figure 3.6
Net Energy Requirements (MWh)
Median (50th Percentile) Forecast
Comparison of Current and Previous Energy Forecasts

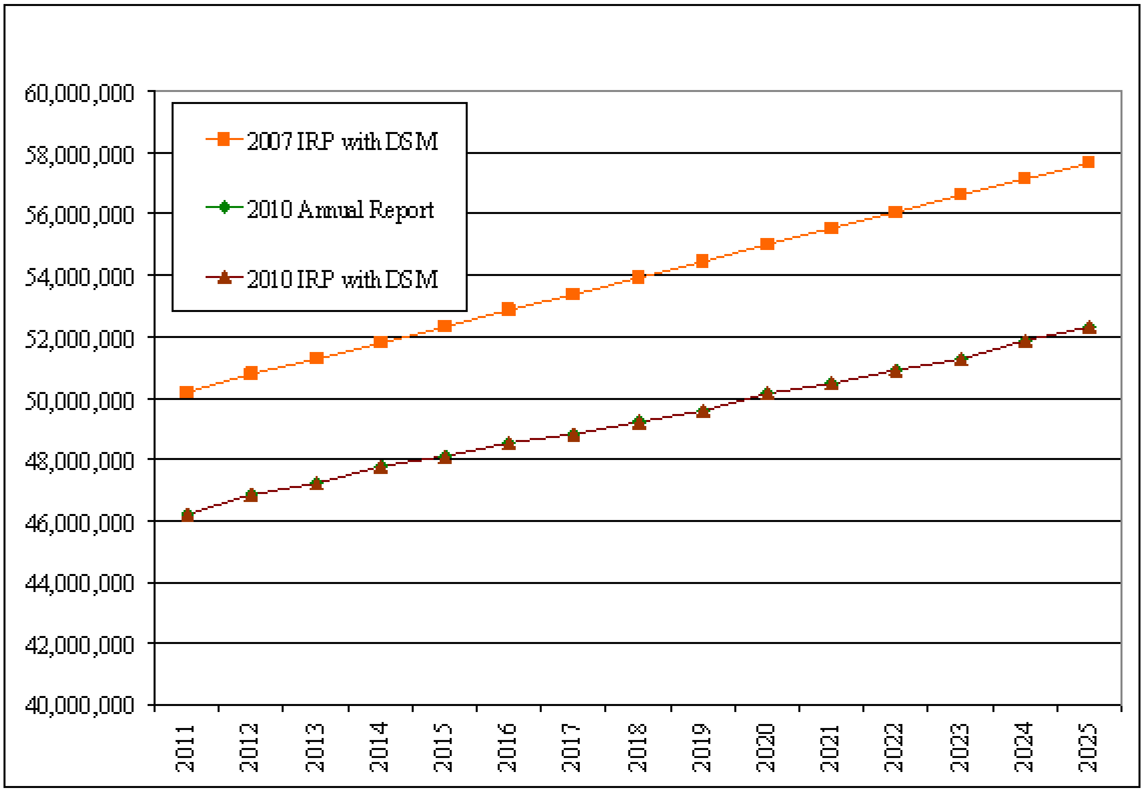
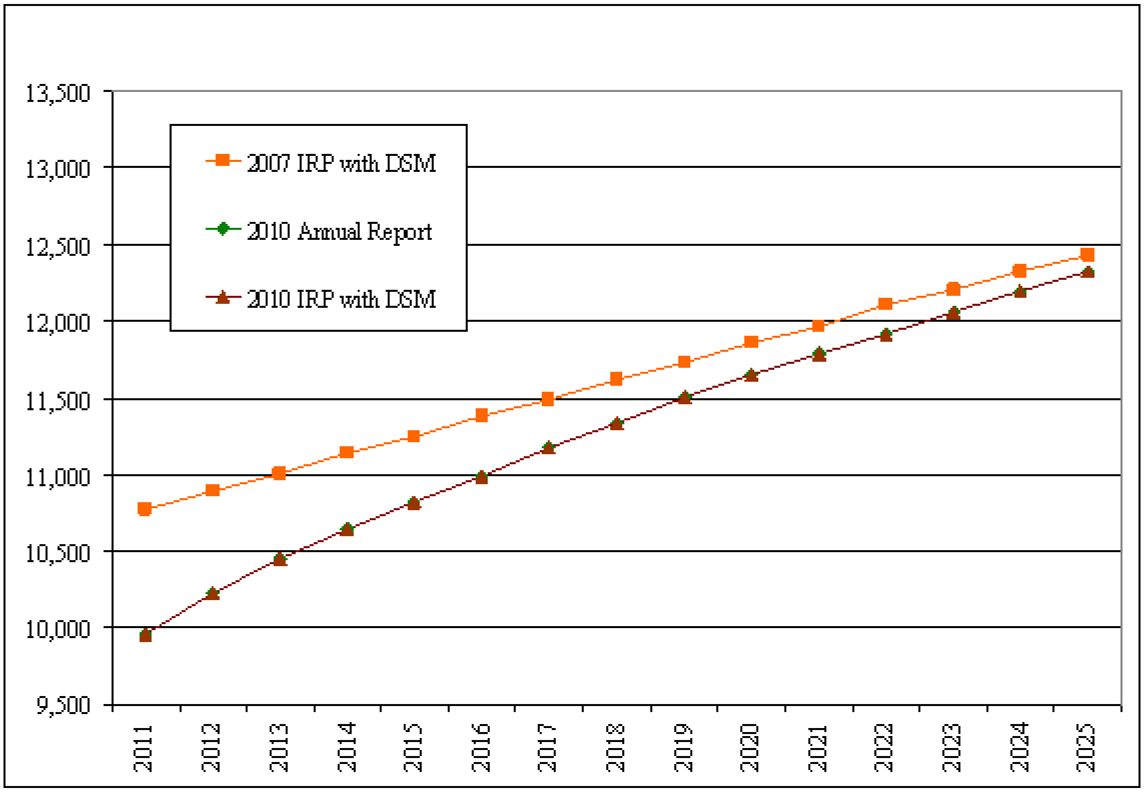


Figure 3.7 shows a comparison of the 90% peak demand forecasts between 2007 and 2010. While we used a 90% demand forecast in our last Resource Plan, we now use a 50% forecast pursuant to our requirements in the MISO Planning Reserve Sharing Group. However, a comparison of the 90% forecasts is supplied here to provide a visual context for the differences in the two forecasts. Similar to the energy forecast, the 2010 Demand Forecast starts from a much lower level than in 2007. However, the growth rate in 2010 is slightly higher, which is a product of the lower peak demand savings we expect to get from our DSM programs.

Figure 3.7
Base Peak Demand (MW)
90th Percentile Forecast
Comparison of Current and Previous Demand Forecasts



Resource Needs

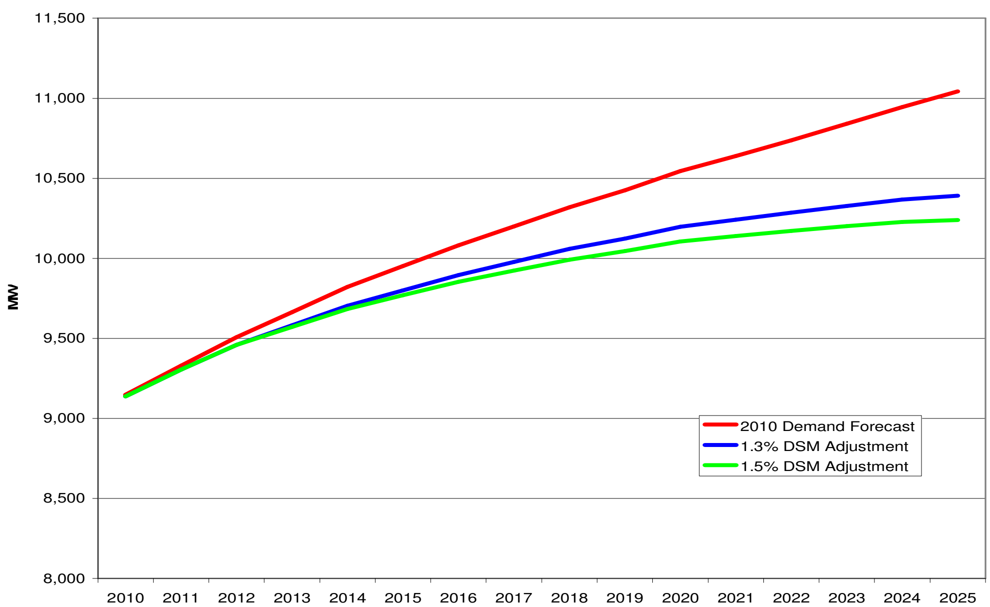
Xcel Energy is required by Minn. Stat. §216B.04 to supply safe, adequate and reasonable electric service to all customers in our exclusive service territory. It is extremely important that we have adequate generation capacity in place to meet those requirements and we strive to closely match need and supply over the forecast horizon. However, we believe the consequences of having too much capacity are preferable to having too little. Consequently, we need to plan to a fairly high level of certainty that the generation capacity in our portfolio will meet the projected demand for the coming season.

Total Load Obligation

Once the forecast is completed, we take three additional steps to arrive at our total load obligation. First, we adjust the demand and energy forecast to account for our proposed DSM goals in this Resource Plan. Next, we reduce the demand forecast by the amount of direct load management that we have on the system. Finally, we add a planning reserve margin to the net result.

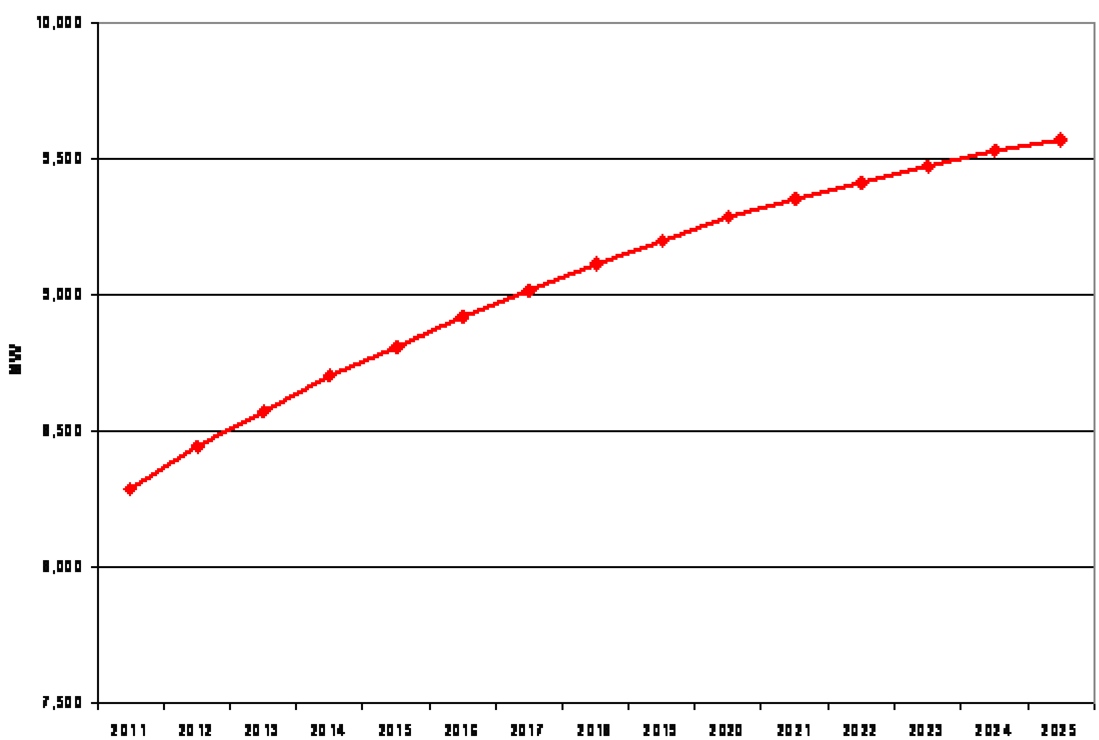
For this Resource Plan, we modeled energy savings of 1.3% and 1.5% of retail sales from our DSM programs. This is done by subtracting the incremental savings between 1.3% or 1.5% and 1.15% from the demand and energy forecasts. Figures 3.8 and 3.9 show this adjustment.

Figure 3.8
NSP Median Base Summer Peak Forecast
Adjusted for 1.3% and 1.5% Energy Savings



The net peak forecast is the forecast after we adjust the base peak forecast for the demand reductions due to our very successful load management programs. The programs interrupt participating customers' electric supply during peak periods that usually occur during hot summer weather. The net peak demand forecast is the demand the Company must meet through generation and purchases. The median net peak demand forecast increases at an average annual rate of 1.2% over the 2011 – 2025 planning period. Additionally, the net peak demand forecast increases at an average of 112 MW annually, starting with 8,290 MW in 2011 to 9,768 MW in 2025. See Figure 3.9 below.

Figure 3.9
Medium Net Summer Peak Demand with 1.3% DSM Adjustment



Our planning reserve margin is determined by the Midwest ISO pursuant to study and recommendations of the MISO Planning Reserve Sharing Group ("PSRG"). The reserve margin is designed to result, statistically, in an interruption of electric service of no more than one day in ten years. For 2010, MISO utilities must carry a planning reserve of 11.94%. This is based on a reserve margin of 15% of the MISO peak demand, adjusted for the diversity of load across the system (such that the MISO peak in aggregate is lower than the sum of all members' peaks).

For the past two years, MISO's reserve margin has been changed annually and applied only to the current summer season. That is, for 2010 we are required to show that we have adequate resources to cover our 50% load forecast plus an 11.94% reserve margin. Because these are not long-term reserve margins, we must make assumptions in our Resource Plan on what the reserve margins will be for the next 15 years. For purposes of this Resource Plan, we have assumed that the reserve margin will remain at 12% through the planning period.

Supply Resources

On the supply side, we own approximately 5,760 MW of existing non-nuclear accredited production capacity and approximately 1,604 MW from Prairie Island and Monticello nuclear plants. Existing long-term power purchases amount to approximately 2,000 MW in 2011, but this amount will change over time as purchase agreements expire and additional contracts are acquired for new wind generation. We have included the addition of 300-450 MW of short-term purchases from various parties. Lastly, in determining our future available resources, we have made the assumption that Prairie Island is successfully relicensed, the uprates at both of our nuclear facilities are installed and our pending contract with Manitoba Hydro for 2015-2025 is approved. Based on our forecasted demand and expected available resources discussed above, we anticipate the need for new production capacity starting in 2015.

Generation Requirements

Once estimates of our total load obligation is established through our forecasting process, we conduct an examination of the generating resources available to meet those requirements. Figure 3.10 presents a comparison of Xcel Energy's forecast of production capacity requirements compared to existing generation resources and pending generation acquisitions.

Figure 3.10
Requirements and Resources 2011-2024

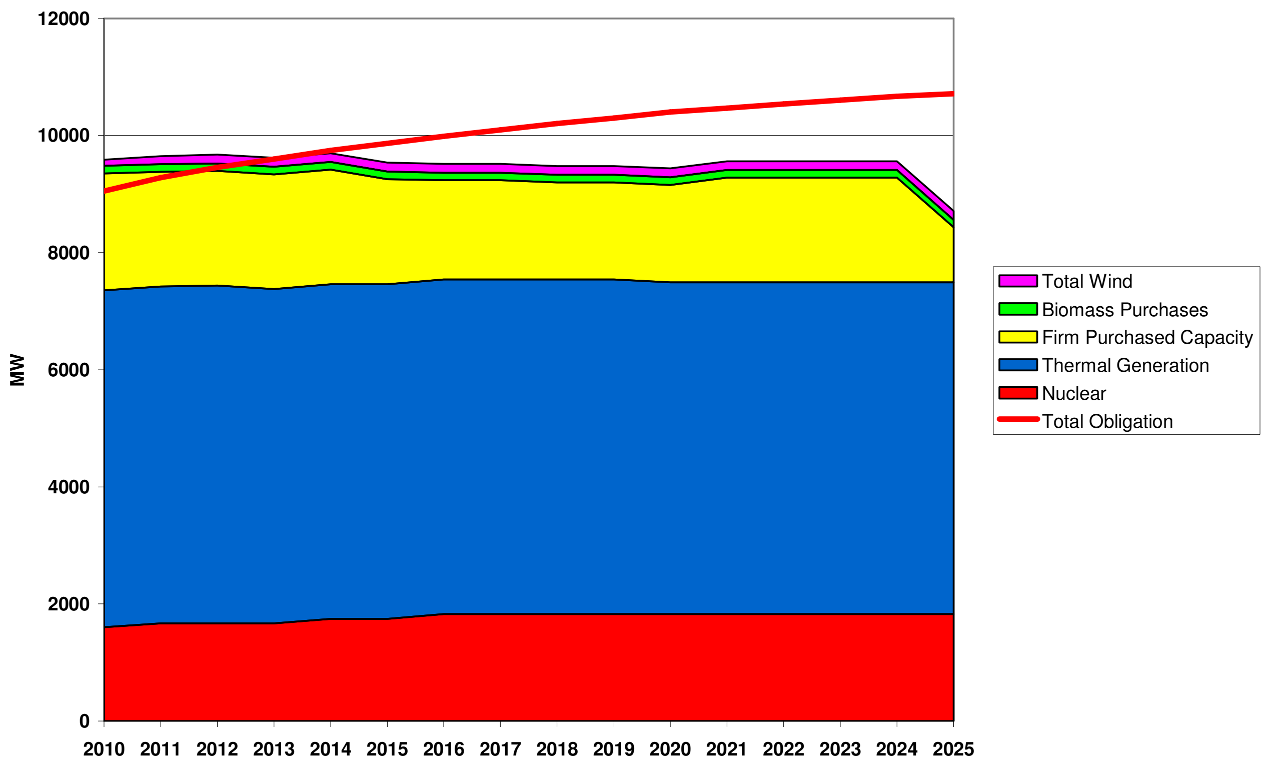
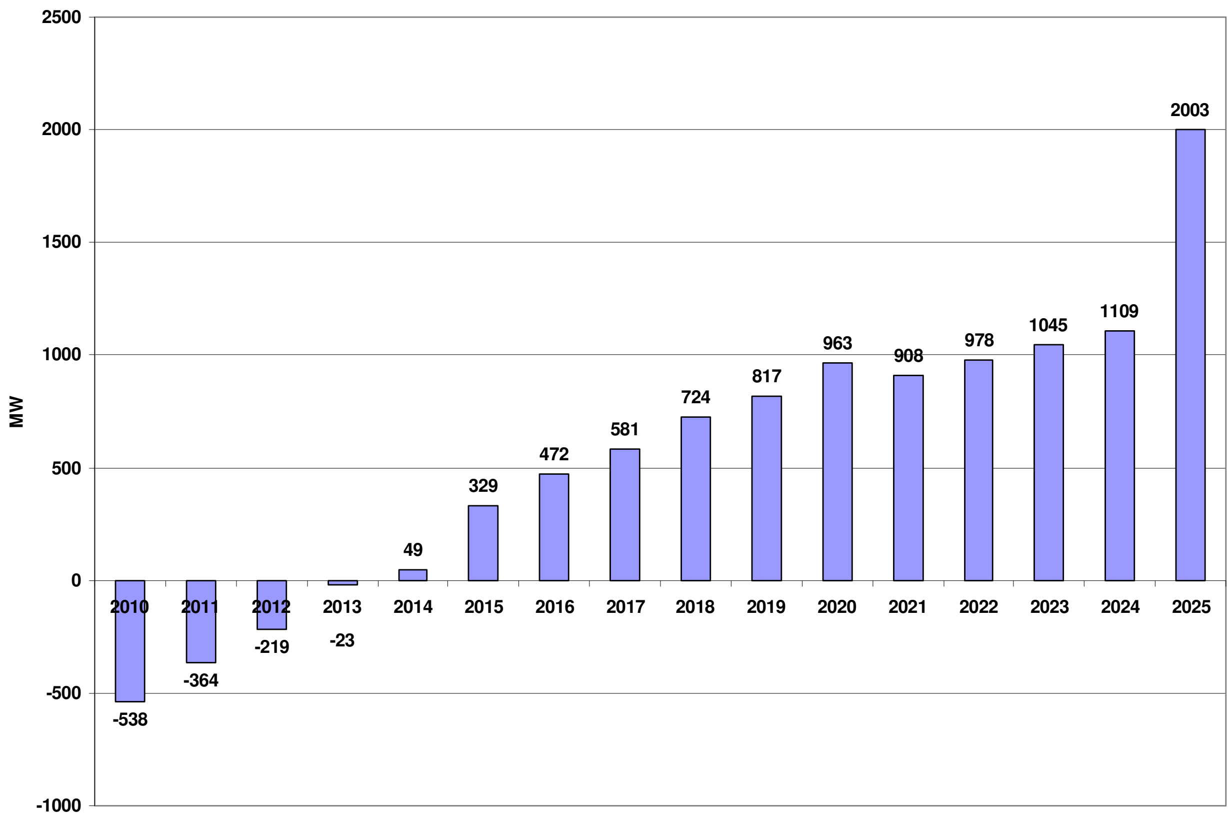


Figure 3-11 shows our projected resource needs for the planning period.

Figure 3.11
Resource Needs by Year



This figure indicates that in 2011 we expect to have a surplus of approximately 360 MW. In 2015, however, we show a resource need of just over 300 MW, growing to about 2,000 MW in 2024. A significant portion of the increase in resource need between 2024 and 2025 reflects the end of our extended agreement with Manitoba Hydro, which will eliminate 850 MW of summer capacity from our system on April 30, 2025.

If any of our current generation initiatives – or the assumed DSM savings - fail to materialize as planned, additional resources will be required. In addition, the pace of economic recovery is uncertain, and our forecast may also be subject to significant change over the next several years. Thus, reaching consensus on an action plan to hedge this risk will be important to ensuring our ability to reliably and cost-effectively meet our customers' needs.

Conclusion

Our forecasts predict continued growth in demand of 1.1 % per year and energy of 0.9% per year over the 15-year planning period. The predicted growth rates assume we maintain DSM savings at 1.15% of retail sales. Growth will be lower as we move to higher goals of 1.3% and 1.5%. Comparing our projections to our available resources, we anticipate a need for additional generating resources starting in 2015, with up to 2,003 MW of additional capacity needed by 2025. The remainder of this Plan outlines our assessment of this resource needs and plans for meeting it.