Chapter 5. Renewable Energy

As part of our Resource Plan, we are pleased to submit this update to our Renewable Energy Plan, in compliance with Minn. Stat. § 216B.1691, subd. 10, and the Commission's June 19, 2009 order approving our previous Renewable Energy Plan,[1] outlining how we intend to secure the renewable energy resources needed to comply with the Minnesota renewable energy standard (RES) and the renewables policies of the other states we serve in the Upper Midwest. We submit this update to our Renewable Energy Plan both as a stand-alone report, and as a chapter embedded in our Resource Plan.

Overview

In this chapter, we review Xcel Energy's current renewable resources – wind, hydroelectric power, biomass and solar – and our plans for compliance with the renewable energy targets in the states in the Upper Midwest in which we operate. Situated within some of the best wind resources in the world, with access to cost-effective, reliable Canadian hydro resources directly to our north, our renewable energy portfolio provides multiple benefits to our rate payers, as an intrinsic part of our diverse and robust generation portfolio.

We currently have over 2,370 MW of installed renewable capacity (owned and contracted) serving the NSP system:

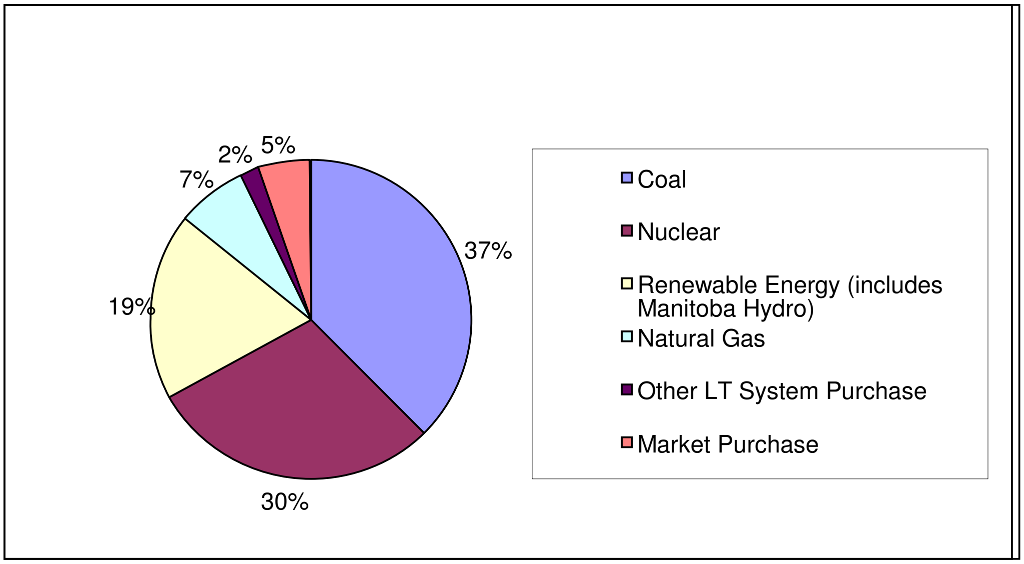
- 1,270 MW of wind generation
- 812.5 MW of hydro-electric power, including our supply arrangement with Manitoba Hydro
- 290 MW of biomass generation

In addition, we have just over 1 MW of solar energy on our system. When all of the energy from these resources is tallied, renewable energy accounts for 19% of the

[1] In the Matter of Northern States Power Company d/b/a Xcel Energy's Application for Approval of its Renewable Energy Plan, MPUC Docket No. E-002/M-07-1558.

energy provided to our customers across all of the NSP system (NSP-MN and NSP-WI) service territories in 2010, as shown in Figure 5.1.

Figure 5.1
Energy Mix for NSP System – 2010



State Renewable Energy Targets

Each of the five states in which we provide service in the Upper Midwest establishes a renewable energy target for Xcel Energy. Each of these targets is expressed as a specified percentage of the electricity sold in that state at retail to come from qualifying resources by a date certain:

- North Dakota and South Dakota each has a voluntary Renewable and Recycled Energy Objective which establishes a goal for each retail provider of electricity to have 10 percent renewable or recycled energy by 2015.[2]

[2] N.D. Cent. Code § 49-02-28 (2010) and S.D. Codified Laws § 49-34A-101 (2010). As defined in N.D. Cent. Code § 49-02-25, recycled energy means "systems producing electricity from currently unused waste heat resulting from combustion or other processes into electricity and which do not use an additional combustion process. The term does not include any system whose primary purpose is the generation of electricity unless the generation system consumes wellhead gas that would otherwise be flared, vented, or wasted." S.D. Codified Laws § 49-34A-94 (2010) contains a similar definition.

- Michigan has a RES that requires Xcel Energy to have 10 percent renewable energy by 2015.
- Wisconsin has a Renewable Portfolio Standard (RPS) that requires Xcel Energy to have approximately 12.9 percent renewable energy by 2015.
- Minnesota has a RES that requires Xcel Energy to have 30 percent by 2020, including interim targets of:
    - 15 percent by 2010
    - 18 percent by 2012
    - 25 percent by 2016.

In addition, Minnesota's RES requires Xcel Energy to have 25 percent of the electricity it provides at retail come from wind energy by 2020.[3]

We are currently generating sufficient renewable energy credits (RECs) [4] on an annual basis to ensure that approximately 14% of the energy we provide our customers comes from RES/REO eligible renewable resources.[5] This amount climbs to at least 19% by the end of 2012, assuming all of the projects we have under contract come on line as planned. Together with the REC bank we have accumulated due to our early actions to add renewable generation to our portfolio, we are well ahead of all of our renewable energy targets.

Our early actions to add renewable resources to our system provides for reduced environmental regulatory risk and a hedge against volatility in fuel markets. Perhaps most importantly to our ratepayers, we added these generation resources at a time when renewable generation, wind energy in particular, was a low cost resource relative to other alternatives.

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[3] This requirement is included in the total 30% RES, and we are authorized to count a limited amount of solar energy towards this 25 percent. Minn. Stat. § 216B.1691, subd. 2a(b) (2010).

[4] RECs are the renewable energy attributes associated with each kilowatt-hour of renewable energy generation, and are the currency for compliance with state renewable targets. We retire RECs as necessary to comply with those renewable targets, and are allowed to "bank" RECs that are not yet needed for compliance for up to four years from the year in which the REC is generated.

[5] Under state law in Minnesota and Wisconsin, renewable energy from large hydroelectric facilities is not considered eligible to be counted toward the renewable energy requirements of those states. See Minn. Stat., section 216B.1691, and Wisc. Stat, section 196.378.

Current Renewable Resources

Wind

Xcel Energy began contracting for wind resources in 1993, pursuant to our 1991 Resource Plan requirement to develop at least 50 MW of wind energy by 1997. Since then, in response to various mandates, state programs and all-source bid selections, we now have 1,270 MW of wind operational on the NSP.[6]

Our first Company-owned wind project, the 100 MW Grand Meadows Wind Project in Mower County, Minnesota, became operational at the end of 2008. The other 1,170 MW of wind have been acquired through power purchase agreements (PPAs), in which the project is owned by an entity other than Xcel Energy, and we contract to purchase the energy generated by the project. These PPA projects range from projects that are smaller than 2 MW to the 205 MW Fenton project in Nobles and Murray Counties, Minnesota.

About 142.5 MW of these PPAs are with very small locally-owned projects that were developed under the Minnesota Renewable Energy Production Incentive (REPI) program. The Minnesota REPI program pays locally owned projects of 2 MW or less a production incentive of between 1 and 1.5 cents per for each kilowatt-hour produced for the first 10 years of operation. Payments are made from the Xcel Energy Renewable Development Fund. The program was entirely subscribed as of 2005.

Another 85.25 MW of these projects are Community-Based Energy Development (C-BED) wind projects. C-BED is the Minnesota program designed to replace the now-closed REPI program. Like REPI, the mission of C-BED is to promote local economic benefit from development of wind generation. We have issued three C-BED wind requests for proposals since 2007, in which we looked at hundreds of

[6] Of this 1,270 MW, approximately 1,218 MW is dedicated to complying with our renewable energy targets. The balance is allocated to our Windsource program, our voluntary green pricing program discussed further below.

projects and thousands of MWs of wind capacity. Of these many proposals, we selected 40 C-BED projects (about 860 MW), with which to negotiate PPAs. Ultimately, we signed PPAs with 26 C-BED projects (470 MW), and offered PPAs to another nine projects (292 MW). These nine projects, along with eight of the projects with which we had a signed PPA, did not go forward due to turbine availability, financing, or transmission interconnection issues. Seven projects have become operational, with 10 projects (about 240 MW) pending construction.

Table 5.1 on the following page provides an update of the status of these pending C-BED projects.

Table 5.1
Pending C-BED Wind Projects

Project	MW	Date PPA Executed	Date of MPUC Approval	Expected Commercial Operation Date
Grant	20	August 12, 2009	August 27, 2009	Late summer 2010
Winona	1.5	October 15, 2009	Dec 1, 2009	October 1, 2010
Community Wind North	30	May 28, 2010	Filed w/ MPUC June 30, 2010	March 31, 2012
Valley View	10	Sept 26, 2008	March 9, 2009	Dec 30, 2010
Ridgewind	25.3	Nov 3, 2008	January 2, 3009	October 31, 2010
Goodhue Wind South	39	October 20, 2009	April 28, 2010	Dec 31, 2011
Goodhue Wind North	39	October 20, 2009	April 28, 2010	Dec 31, 2011
Danielson	19.8	October 27, 2009	Dec 24, 2009	Dec 30, 2010
Adams	19.8	October 27, 2009	Dec 24, 2009	Dec 30, 2010
Big Blue	36	June 1, 2010	Filed w/ MPUC June 30, 2010	July 1, 2011

The balance of our wind generation portfolio, about 940 MW, consists of projects owned by Independent Power Producers (IPPs) who develop, own and operate generation facilities and sell the output to electric utilities.

In addition to these operational wind projects, we have about 590 MW of projects that we expect to add to our system by the end of 2011 or 2012. These projects include 351 MW of Xcel Energy owned wind projects:

- The 201 MW Nobles Wind Project in Nobles County, Minnesota, which will be operational by the end of 2010; and
- The 150 MW Merricourt Wind Project in McIntosh and Dickey Counties in North Dakota, is planned for completion by the end of 2011. Development work for the project is on-going. The project developer, enXco, is working to acquire major permits and approvals and working through environmental issues. It is anticipated that construction will start in May 2011.

If these projects and all of the aforementioned CBED projects that are under contract are completed, we will have acquired or contracted for about 1,860 MW of wind projects on the NSP system by the end of 2012. See Table 5.2 below.

Table 5.2
Wind Projects on the NSP System by 2012

Project Type	Known Wind Projects (end of 2012)	Percentage of Total
C-BED	327	18%
REPI	142.5	8%
Xcel	450	24%
IPP	940.5	50%
Total	1860	100%

Hydro

The Company owns 253 MW of hydroelectric generation in Minnesota and Wisconsin. In addition, Xcel Energy purchases 24 MW of small hydro from other parties, and significant generation from Manitoba Hydro that is sourced primarily from its fleet of hydroelectric facilities.

In June of 2010, we filed a petition for approval of a series of agreements with Manitoba Hydro for up to 850 MW (summer) system resources from its almost exclusively hydroelectric system. If approved, these agreements would become effective in 2015, when the first of the existing set of agreements with Manitoba Hydro is set to expire. This set of agreements will be more fully discussed later in this chapter.

Biomass

Our biomass generation resources include a wide variety of biomass resources. We receive landfill gas-fired generation from the Burnsville, Flying Cloud and Pine Bend landfills. Xcel Energy also contracts with St. Paul Cogen, Fibrominn, and Laurentian Energy Authority for biomass energy:

- St. Paul Cogen's waste wood-fired generator, which began operating in early 2003, produces 25 MW.
- Fibrominn, LLC produces 50 MW of biomass generation using poultry litter and went into commercial service in August 2007.
- The Laurentian Energy Authority, an LLC jointly owned by the cities of Hibbing and Virginia, produce 35 MW of energy in two plant facilities that attained commercial biomass operation on December 31, 2006.

Our biomass resources also include the existing wood-fired generation at two of the three units at our Bay Front plant, and refuse derived fuel (RDF)-fired generation from the Red Wing, Wilmarth and French Island plants. Each of these facilities is discussed below.

Bayfront. As noted above, we currently use biomass at two of the three units at this generation facility. We are exploring expanding our use of biomass at Bay Front through the reconfiguration of the third unit at that facility. Initially, the goal of the project was to install a biomass gasifier, and convert the plant's remaining coal-fired unit to a technology that will allow it to use 100 percent biomass. When the gasification project application was initially filed with our regulators in February 2009, the cost was estimated to be $58-$70 million based on the first phase of engineering studies. Following approval of the project by the Public Service Commission of Wisconsin in December 2009, we completed a more detailed engineering and design phase for the project. Those studies show that additional enhancements will be needed in order to maintain stable combustion using synthetic gas, and the cost is likely to be much higher than expected. As a result of the increased project scope, we have decided to review other alternatives for the Bay Front Unit #5 over the next six months.

*Red Wing and Wilmarth***.** Both of these RDF plants are located south of the Twin Cities area. The Red Wing plant is located in Red Wing, Minnesota and the Wilmarth plant in Mankato, Minnesota. Both plants are 20 MW generating facilities.

These plants were built in the 1940s as coal-fired generating facilities. They were both converted in the late 1980's to burn RDF. The processed municipal solid waste provides a low-cost fuel alternative to generate electricity and reduces the amount of material going to landfills. Both plants employ scrubbers with fabric filter baghouses to meet their respective emissions permits. The scrubbers treat flue gas with water and hydrated lime, while the baghouses trap particulate by forcing flue gas streams through large filter bags. These systems are considered to be best available control technology ("BACT"), which allows energy production from Red Wing and Wilmarth to be counted toward the RES.

The RDF for both plants is produced at a resource recovery facility in Newport, Minnesota. The structure of the current RDF supply contract requires that we make a decision about the continued operation of these plants prior to June 30, 2011. In the previous Resource Plan, we assumed that we would discontinue operation of the plants in 2012, but initiated a life extension study to assist in the determination of whether to continue to operate these plants beyond that date. That study did not identify any major issues for either of the facilities that would require major additional capital investment for operation through 2017. We are now assuming continued operation of these plants, pending successful resolution of RDF fuel supply contract discussions.

French Island Generating Plant. The French Island Generating Plant is located in La Crosse, Wisconsin, on the Mississippi and Black rivers. Units 1 and 2 were retrofitted with fluidized bed boilers, and use wood waste, railroad ties and RDF as primary fuels. Units 1 and 2 combined produce 21 MW. The current fuel supply contract for French Island Units 1 and 2 runs through 2023, which is also the end of book life for these units.

Solar

Although the solar resource in the NSP-MN/NSP-WI service territories is not nearly as good as in our Colorado, New Mexico, and Texas operations,[7] we have added just over a megawatt of solar electricity production to our NSP system in the past three years. Under our current programs, we expect this amount to grow over the next decade to approximately 20 MW of solar photovoltaics ("PV").

Absent large gains in PV productivity and additional reductions in the cost of PV systems, solar PV will likely not be a cost effective generation resource in the Upper Midwest for some time. However, our current strategic additions of solar energy will help us gain experience with the operation of solar technologies in this northern climate, explore various project sizes, ownership configurations and technologies and help build the solar industry in this region. This experience will stand our customers

[7] Capacity factors for solar PV in the southwestern US can be about 20% In Minnesota, capacity factors for solar PV are more likely to be in the 12% to 15% range. See, e.g. the Minnesota Solar Electric Rebate Program Report 2002-2008 which found that solar energy production among projects in the state's solar rebate program had an average capacity factor of 13.4%. Minnesota Office of Energy Security, April 8, 2009, at page 4. Capacity factor is the expected energy production of a generation facility divided by its total potential production.

in good stead if and when the cost and production efficiency of solar technologies evolves to the point where solar can be a cost effective resource in this region.

Solar generation is being added to our system currently through three programs:

- *Solar*Rewards.* Solar*Rewards is an energy conservation program that is available to Xcel Energy residential and commercial customers beginning March 2010. The program's goal is to increase the installation of solar photovoltaic (PV) systems and help Xcel Energy business and residential customers capture energy savings from their systems. At the current level of funding, the program could result in up to 6 MW of solar PV by 2012. The program was included in the Company's 2010-2012 Conservation Improvement Program ("CIP") Triennial Plan approved through the Office of Energy Security (OES) in Docket No. E,G002/CIP-09-198. Under Solar*Rewards, Xcel Energy is providing an incentive payment not to exceed $2.25 per watt to help offset solar PV system installation costs. The amount may change as solar project economics change or as other funds become available. The program is limited to one qualifying solar PV system no larger than 40 kW per business or residential customer building location. The average size of a residential system is expected to be approximately 4.5 kW. [8]
- *Solar grants and rebates through the Xcel Energy Renewable Development Fund.* In the past grant cycle, the Renewable Development Fund awarded over $8 million to support the development of solar projects totaling about 3.5 MW on the NSP system. In addition, state rebates funded through the RDF supported the development of nearly 800 kW in Minnesota in 2010. In the 2010 legislative session, the Renewable Development Fund was directed to allocate $21 million over the next five years to support Solar*Reward installations on the NSP system that use solar equipment manufactured in Minnesota.[9]

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[8] The projected increase in solar PV through 2020 would primarily be through continued implementation of the Solar*Rewards program, and thus is contingent on continued approval of our regulators of that program and future customer enrollment.

[9] See Laws of Minnesota 2010, chapter 361, article 5, section 3.

- *Solar in Windsource.* The Commission has authorized us to add one-half to one MW of solar resources to the generation portfolio of the Windsource program (described below) in each of the next three years.[10] By including solar, customers will be able to expand their support of environmentally friendly electric generation to non-wind resources. We believe making this change to Windsource will increase the attractiveness of this successful voluntary program, already the largest voluntary renewable energy program in the country.

Windsource

We offer our customers an opportunity to purchase additional wind energy under a green pricing program to meet their electric needs. Xcel Energy began offering the Windsource program in March 2003. During the first year we sold almost 8,000 MWH of wind energy under this program to just over 5,500 customers. In 2009, we supplied almost 147,400 MWh to 23,500 customers. The Company has about 52 MW of wind generation dedicated to the program, and has certified a total of 89 MW so that as our Windsource needs grow, we have identified the resources necessary to meet customer expectations. As noted above, the Commission has approved the addition of one-half to 1 MW of solar energy starting in 2011 to our Windsource portfolio. These resources (both wind and solar) do not count toward meeting the RES.

Going Forward

The environment for renewable energy development, and wind energy in particular, over the next few years is decidedly less certain than when we filed our 2007 Resource Plan. The economy has made it difficult especially for smaller projects to obtain financing. In addition, wind generation costs seem to be increasing; natural gas costs appear likely to remain relatively low; federal production tax credits once again expire in 2012; federal legislation to establish carbon markets and/or a federal renewable requirement appears to be stalled; integration costs may be higher than we originally

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[10] In the Matter of Xcel Energy's Request for Approval of Revisions to its Voluntary Renewable and High Efficiency Purchase Rider, MPUC Docket No. E002/M-09-1177.

anticipated; and transmission capacity continues to be scarce, although that is likely to ease somewhat in the next few years as the CapX2020 projects are constructed and become operational.

This combination of factors creates an environment in which we need to act more cautiously in our renewable acquisition strategy, to ensure that our generation portfolio continues to provide our customers with reliable, affordable and clean electric service.

One benefit to our early actions to add cost-effective renewable generation to our portfolio is that we are well ahead of our compliance schedule for the state renewable targets in the jurisdictions in which we operate. This has allowed us to bank a significant number of RECs that we can draw upon for compliance as needed.

Based on our assessment of our current renewable portfolio, forecasted future generation and REC banking and retirements, we would be able to comply with the 2012 and 2016 milestones of the Minnesota RES without adding any new renewable resources. However, we continue to believe that a measured approach to installing cost-effective renewable resources provides greater stability in the market and avoids scenarios where Xcel Energy would need to acquire large amounts of wind over a relatively short time period. In addition, with the federal PTC expiring in 2012, it may be prudent to secure another increment of wind generation before the tax credit expires. As a result, we are proposing a flexible approach to expanding our renewable portfolio.

Our REC bank allows us to manage the type, size and timing of renewable energy additions on our system to ensure that we identify and acquire the renewable generation resources that provide our customers with the greatest value at the lowest cost. To do that we will continue to:

- Rely predominantly on the most productive and cost-effective renewable resources and technologies available to us;

- Invest to the extent practicable in renewable generation resources that we will own;
- Compare proposed resources against the cost and productivity of other resources, renewable and non-renewable, available to us in the marketplace; and
- Time the acquisition of new resources to allow advantageous tax and other incentive treatment when feasible.

Table 5.3 demonstrates our compliance with the renewable targets for the states NSP operates in, in the aggregate, for years 2010, 2012, 2016 and 2020, assuming that we add all of the wind capacity shown in our proposed plan.

Table 5.3
Compliance with Renewable Targets
with Planned Wind[11]

	2010	2012	2016	2020
1. NSP Retail Sales	41,643,581	42,783,901	44,377,881	45,870,669
2. Banked RECs at Beginning of Year	9,216,299	11,813,364	23,960,864	27,941,381
3. RECs Generated During Year	5,849,380	8,835,721	10,649,851	11,634,954
4. RECs Generated During Year as a % of NSP Retail Sales	14.0%	20.6%	24.0%	25.4%
5. RECs Needed for Compliance (all jurisdictions)	5,231,014	6,314,257	9,558,751	11,564,050
6. Banked RECs After Full Compliance (2+3-5)	9,834,665	14,334,828	25,051,964	28,012,285

[11] These figures include the RECs associated with our PPAs that are silent on the treatment of the environmental attributes associated with the renewable energy we are purchasing. See MPUC Docket No. E002/M-08-440. These so-called "silent RECs" are RECs from PPAs signed prior to the establishment of renewable tracking. It is the Company's position that the RECs are an integral part of the purchase and belong to Xcel Energy as part and parcel of its purchase of renewable energy and therefore should be available to be used for our compliance purposes. This issue has been presented to the Commission for consideration and the Company has been working to try to negotiate settlements. A number of these contracts have been successfully resolved. The sellers under other agreements do not agree and have maintained that these "silent" RECs belong to them.

Similarly, Table 5.4 demonstrates our compliance with the renewable targets for the states NSP operates in, in the aggregate, for years 2010, 2012, 2016 and 2020, assuming that we add no additional wind capacity beyond the projects we currently have under contract.

Table 5.4
Compliance with Renewable Targets, without Planned Wind

	2010	2012	2016	2020
1. NSP Retail Sales	41,643,581	42,783,901	44,377,881	45,870,669
2. Banked RECs at Beginning of Year	9,216,299	11,813,364	18,689,492	12,649,390
3. RECs Generated During Year	5,849,380	8,099,878	8,439,160	7,634,761
4. RECs Generated During Year as a % of NSP Retail Sales	14.0%	18.9%	19.0%	16.6%
5. RECs Needed for Compliance (all jurisdictions)	5,231,014	6,314,257	9,558,751	11,564,050
6. Banked RECs After Full Compliance (2+3-5)	9,834,665	13,598,985	17,569,901	8,720,101

As can be seen in Table 5.4, we would generate sufficient amount of RECs in 2012, and very nearly so in 2016, to satisfy our renewable obligations in those years without adding any wind capacity beyond the projects we currently have under contract. In addition, utilizing our banked RECs, we would be able to comply with all of the various renewable targets of the states in which we operate through 2020, without any additional wind beyond those contracted projects.

While the above table demonstrates our favorable position with respect to compliance with the RES, we have also considered construction scenarios and public policy goals in creating our Wind Expansion Plan. If we were to decide not to add wind to our portfolio until 2020, we would immediately need to add about 1,100 MW of wind in order to continue to comply in 2021. In addition, because many of our states also have economic development goals related to the construction of renewable projects, we would like to ensure that development happens in a way that fosters a robust renewable industry. Although we do not plan to defer construction of new wind resources until our bank is depleted, we do intend to take advantage of the flexibility our early actions to add renewable to our system provides us, to ensure the best possible value for our ratepayers. Using this flexibility will help ensure cost effective compliance with renewable targets.

Wind Expansion Plan

We estimate that we would need approximately 1,150 MW of wind generation, in addition to those renewable projects that are operational, under contract, or under construction, to meet our 2020 RES requirement primarily from annual generation. As noted above, we would also be able to install a lesser amount of new wind generation and use a larger portion of our banked RECs to comply.

As a general rule, we believe that the market for renewable resources will develop in a more efficient manner if we spread our additions out more evenly over the compliance window. This approach will allow for orderly development of wind projects and provide for stability in the marketplace that will encourage the establishment of sustainable manufacturing and labor pools. Given that the federal Production Tax Credit for wind may expire at the end of 2012, we also believe it is important to maintain the flexibility to pursue economic projects even in advance of the milestones anticipated by the various state renewable statutes. We further think that competition for wind resources will continue to be strong as regional utilities seek to comply with state requirements, and that early acquisition of quality resources may be prudent.

To benefit from these considerations, Xcel Energy plans to issue a Request for Proposals (RFP) in August of 2010 to seek up to 250 MW of wind power by the end of 2012.

Price will be an important factor in determining how much wind we will acquire through the RFP. As demonstrated in our modeling discussion below, recent wind pricing proposals that we have received carry a premium over a natural gas alternative under today's forecasts. There are signs, however, that wind pricing has been coming down in other parts of the country. We expect that the proposals submitted in the RFP will reveal substantial improvement in the economics of wind as compared to past experience. If that is not the case, we will look closely at the the risks and benefits and could take advantage of our flexibility and opt not to add wind resources at this time.

Depending on the results of this RFP, the continued availability of the PTC or other incentives, and our ongoing evaluation of the cost impacts wind has on our system, our Wind Expansion Plan (WEP) would add another 400 MW between 2013 and 2016, and 500 MW between 2017 and 2020 to achieve RES compliance primarily with annual generation. For purposes of Strategist modeling we have suggested that these resources may be added at a rate of 100 MW per year, but we intend to retain the flexibility to install the wind earlier or later in this period, as necessary to ensure the best value to our ratepayers. Beyond 2020, we would only need to add wind as necessary to replace expiring contracts and keep up with retail sales growth. It is our intention to use the results o fthe 250 MW Wind RFP to help inform the pace of our Wind Expansison Program. We will bring the results back to the Commission if we see significant impediments to our expansion schedule and we will continue to evaluate this issue in future resource plans.

Wind Expansion Plan Cost Evaluation

To examine the cost impacts of our wind expansion plan, we have evaluated the addition of 1,150 MW of new wind by 2020, assuming wind costs similar to what we have seen recently in this region. The cost effectiveness of this level of wind resource depends highly on the continuation of the PTC, the operational and market experience associated with higher wind penetration levels, technological advancements and the cost of additional transmission resources, as well as the cost of alternative generating resources.

In the proposed plan, projected energy production from all Xcel Energy owned or purchased renewable resources were included in the assessment, and wind generation was added according to the WEP described above.

We evaluated the Wind Expansion Plan with a base assumption that the PTC will be extended once more through 2014. Rather than attempting to forecast uncertain future wind prices, we also assumed that future wind project costs would be similar to the cost of projects we have seen recently. We also looked at the impact of wind on our plan if the PTC expired at the current date of 2012, and if it were extended to 2020. Not surprisingly, our analysis shows that wind with PTC pricing is more economic than non-PTC pricing, assuming that the entire lost value of the PTC is made up in the PPA through increased prices. While this result is intuitive, the magnitude of the difference indicates how much of wind energy economics is driven by the availability of the federal subsidy.

Finally, as discussed in Chapter 4, we compared our wind expansion plan with a scenario in which no new wind is added beyond the projects we currently have under contract, all of which is to be installed by the end of 2012. The purpose of this scenario is twofold. First, as discussed by the Chamber of Commerce in their October 2, 2009 comments in MPUC Docket E-999/CI-03-869, we are using this scenario to establish a baseline with which the costs of wind additions can be compared in order to determine the rate impact of meeting the Minnesota RES. As the Chamber noted, this information is important for evaluating whether any party wishes to petition the Commission for a reduction of the RES under Minn. Stat. 216B.1691, subd. 2a.

Second, the "no new wind" scenario illustrates the differences in costs and expansion plans were we to have a lower RES system-wide. Several of our jurisdictions with lower RES requirements or objectives are interested in evaluating the cost and impact of the Minnesota RES on customer cost allocations and rates in their states. This scenario provides them with information that can help them review those costs and decisions. See Table 5.5 below.

Table 5.5
Wind Cost Evaluation ($000s)

	PVRR	$ Difference from Base
WEP with 2014 PTC Expiration (Base Assumption)	$90,702,859	
WEP with 2012 PTC Expiration	$90,863,004	$160,145
WEP with 2020 PTC Expiration	$90,256,401	-$446,458
No New Wind after 2012	$89,302,895	-$1,399,964

There are three key takeaways from this analysis. Assuming wind generation costs are roughly similar to the costs we have seen in this region recently:

- If the PTC expires in 2012, implementing our 1,150 MW wind expansion plan will have a PVRR impact of $160 million more than doing so if the PTC is extended until 2014.
- If the PTC is extended until 2020, implementing our WEP will reduce total PVRR by almost $450 million, relative to our base assumption.
- Under recent price levels, acquiring additional wind generation on the schedule and in the amounts we have described in our Wind Expansion Plan results in a PVRR of $1.4 billion more than a plan where no wind is acquired beyond our current commitments.

That last point is important – given wind costs similar to what we have seen in this region recently, we estimate that our total system costs would be over $1 billion more than if we used natural gas generation to provide the energy that the wind generation would supply. Looked at another way, to the extent that we can drive down the costs of wind generation to be closer to what we estimate natural gas generation would cost our ratepayers, we can reduce this PVRR difference.

To that end, we have also estimated a wind price at which we would be indifferent between wind energy and a natural gas alternative ("the breakeven price"). Using our base gas price forecast and a mid-range cost for carbon, we estimated that the breakeven cost for wind including PTCs is in the mid-$50's/MWh. This price range is substantially lower than the wind prices we have seen in this region recently.

Wind Expansion Plan cost analysis summary

Table 5-5 shows that under current pricing, the implementation of our full wind expansion plan would have a higher cost than an alternative portfolio that does not include this level of wind. However, we believe there may be an opportunity for reduced wind costs in the future. Xcel Energy is actively acquiring wind for all of our operating companies. In recent bidding processes we have seen substantially lower wind pricing in our Colorado and Texas utilities. We are hopeful that our 250 MW wind RFP will result in wind costs that are significantly lower than prices we have seen in the recent past. However, if we do not see the level of pricing we expect from this RFP, we may need to adjust our plans for wind expansion. In that event we will engage the Commission and stakeholders to work toward appropriate refinements.

Our assessment indicates that the overall cost and reliability impacts of implementation of the wind expansion plan needs to be monitored on an on-going basis as the market evolves and issues such as the life of the PTC are determined. Meanwhile, we intend to manage this situation as effectively as we can in the near term, and plan to seek up to 250 MW of PTC-qualifying wind between now and our next Resource Plan. We will bring the issue of the cost effectiveness of wind back to the Commission if we do not see the wind prices that we expect, or if the PTC is not extended.

Related Renewable Energy Issues

Off-Ramps and Natural Gas Prices

The Minnesota RES provides the Minnesota Commission with the authority to modify or delay implementation of the RES under certain conditions, including when necessary to avoid a significant rate impact to a utility's ratepayers. This authority has come to be known as the "RES off-ramps." This potential also helps ensure that we will comply with our renewable obligations in Minnesota Statutes, section 216B.1691, subdivision 2b:

> Subd. 2b.Modification or delay of standard.
>
> (a) The commission shall modify or delay the implementation of a standard obligation, in whole or in part, if the commission determines it is in the public interest to do so. The commission, when requested to modify or delay implementation of a standard, must consider:
>
> (1) the impact of implementing the standard on its customers' utility costs, including the economic and competitive pressure on the utility's customers;
>
> (2) the effects of implementing the standard on the reliability of the electric system;
>
> (3) technical advances or technical concerns;
>
> (4) delays in acquiring sites or routes due to rejection or delays of necessary siting or other permitting approvals;
>
> (5) delays, cancellations, or nondelivery of necessary equipment for construction or commercial operation of an eligible energy technology facility;
>
> (6) transmission constraints preventing delivery of service; and
>
> (7) other statutory obligations imposed on the commission or a utility.

This authority has never been used, due in part to the fact that the statute is still relatively new. But another reason is that most utilities have relied heavily on wind generation for RES compliance, and wind generation has been a cost-effective resource over the past several years. With the potential for low, stable natural gas costs, the cost-effectiveness of wind generation may be changing. To better track the cumulative cost impact of the Minnesota RES on our ratepayers, we have forecast cost impacts with and without RES compliance. See Table 5.6 below.

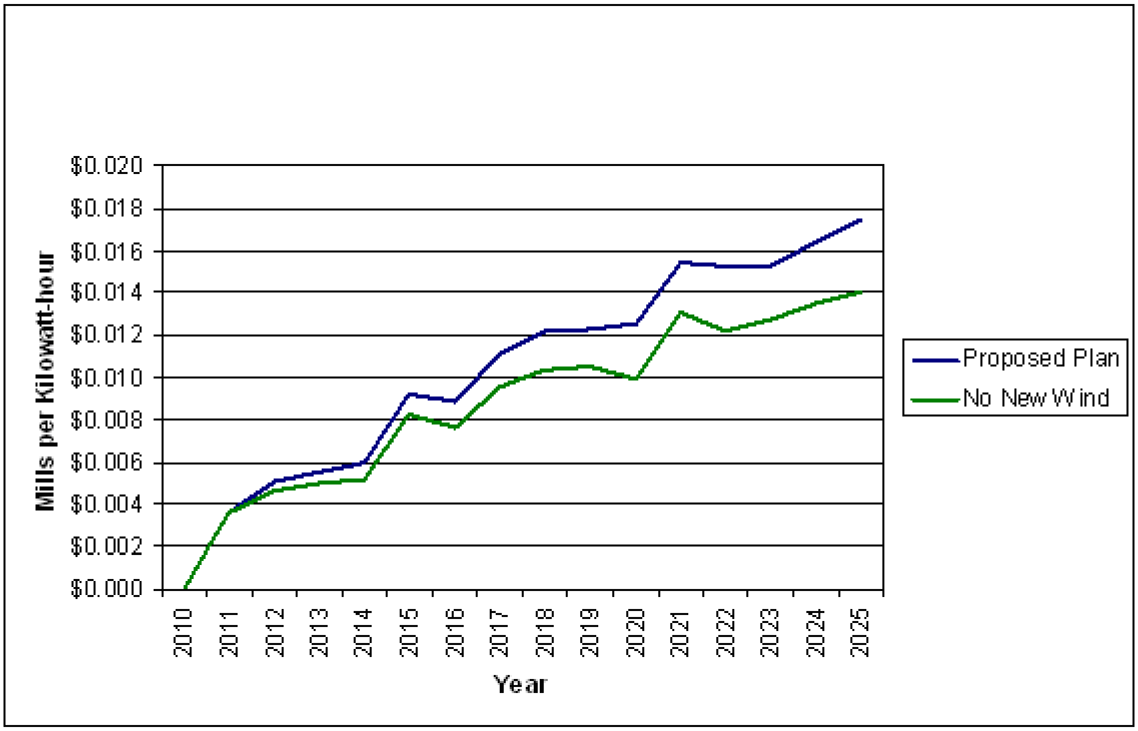
Table 5.6
Estimated Energy Cost Impacts
for Selected Years ($/kwh)

	2015 Increase over 2010	2020 Increase over 2010	2025 Increase over 2010
Proposed Plan with Wind Expansion Plan	$0.009	$0.013	$0.017
No New Wind after 2012	$0.008	$0.010	$0.014

This table shows the incremental cost per kilowatt-hour increase over a 2010 base cost per kwh. Under this analysis, our proposed plan with the WEP as described above would have a cost impact in 2020 of $0.003 per kilowatt-hour more than not adding additional wind generation beyond our current commitments.

Figure 5.2 graphs the incremental difference between these two scenarios over the full planning period.

Figure 5.2
Incremental Cost Per Kilowatt-hour Over 2010
Proposed Plan and No New Wind Scenarios



Even a small shift in our current expectations for gas prices, carbon regulation and wind cost could result in significant future cost impacts to fulfill the RES. In addition, individual wind projects may result in rate impacts that in aggregate could be significant. In order to monitor these impacts, Xcel Energy proposes to track, with each wind project approval process, both the incremental and aggregate rate impact of fulfilling RES requirements as compared to a reasonable alternative. We are not offering any specific proposals as to what might constitute a "significant rate impact," but providing this data will allow Xcel Energy and stakeholders to evaluate the impacts if an examination of adjustments to renewables policy is judged necessary.

Transmission

Transmission availability is a key factor in the cost-effective development of wind resources and is needed to ensure developments can continue to occur in prime wind areas of the state. The development of additional transmission resources is critical to the success of utilities' resource plans, both to minimize the cost of wind resources through the elimination or reduction of curtailment payments to producers, and to avoid the need for expensive contingency plans of additional resources in the event the renewable resources are not available to meet growing customer needs. The Biennial Transmission Plan, submitted to the Commission by the Minnesota utilities, provides additional information on how we plan to fulfill this important role.

With regard to transmission needed to support the Minnesota RES, the Minnesota OES found in its review of the 2009 Biennial Transmission Plan that there is or will be sufficient transmission capacity to allow the Minnesota utilities to remain on course to meet the 2010 and 2012 milestones established by the Minnesota RES. The OES also found that meeting the RES milestones of 2016 and beyond will require additional transmission capability. To ensure adequate transmission capacity to meet those milestones, the Minnesota transmission owning utilities (including Xcel Energy) listed a number of potential transmission projects at various stages of the plan-permit-build-cost recovery process. Table 5.7 shows the various projects.

Table 5.7
MTO Identified Transmission Projects

Project *** Denotes Xcel Energy Involved In.**	**Est. Additional Capacity Enabled (MW)**	**Current Status**
Blue Lake Upgrade*	600	Under construction
Brookings – Twin Cities *	700	In permitting
Fargo – Twin Cities*	700	In permitting
DC Line Purchase	355	In permitting
RIGO*	500	In permitting
Corridor*	2,000	Under review
La Crosse – Madison*	1,600	Under study
Fargo – Split Rock*	1,000	Under study

Although we have successfully acquired certificates of need for many of these lines, the construction of the Brookings line has been delayed due to the uncertainty surrounding how the costs to build the line will be allocated. More information in MISO's cost allocation proposal is presented in the Transmission chapter of this Resource Plan.

Wind Integration and Baseload Cycling

As the percentage of wind energy on our system and in the MISO region continues to increase, we remain concerned about the cost and reliability of integrating wind with our other resources. The intermittent nature of wind resources requires supportive, ancillary services to follow the generation and respond instantaneously as wind resource production rises and falls. Although the ability to integrate wind resources across MISO has kept our integration costs relatively low, we are starting to see higher impacts on the operation of our facilities as wind penetration increases. This effect will become even greater if significant amounts of wind are developed in Minnesota and the Dakotas for export to eastern states.

Adding wind resources to the level of 25 percent or more of our system energy requirements will require operational changes. It is already important to develop methods to manage both variable wind resources and dispatchable resources, including how to manage the transmission grid to accommodate the variability of wind output. As a result, our expansion plan provides for the addition of more flexible, gas-fired resources, including the 680 MW of combined cycle generation to be added at our Black Dog facility. However, even these more flexible resources can be subject to startup costs, minimum loadings and ramping requirements that do not allow us to fully follow the wind.

Wind integration costs include a number of components that have been quantified in several studies, including the 2006 Minnesota Wind Integration Study, such as regulation, load following, unit commitment, uncertainty and variability. One component of wind integration costs that has not been yet been quantified is the costs associated with increased ramping on our baseload facilities.

Baseload generating plants operate at their peak efficiency when running at full load around the clock. When the combination of nuclear and coal generation on our system is higher than our customer demand, these plants need to reduce generation to meet available load. When wind is operating, especially in low load periods, these resources may also need to ramp generation up and down to respond to the variability of the wind generation. This additional ramping results in stress on plant components and leads to higher O&M costs and reduced efficiency of generation.

The Company has been studying the effect of cycling on our base load coal generating facilities. Our studies have focused on three coal fired thermal units, one each in Minnesota (Sherco 1), Colorado, and Texas. These studies are not yet complete but preliminary results do indicate that cycling our baseload plants can result in an increase in O&M cost, a reduction in the life of key plant components, a decrease in unit reliability and an increase in fuel costs per unit of output..

Wind generation is only one reason that base load generation is ramped. Based on an evaluation of 2009 data, our generating units were backed down specifically to accommodate wind generation approximately 18% of the hours in which any plant was backed down. Variation in customer load and MISO dispatch decisions also contribute to the cycling of these plants, and some of the base load reduction due to MISO dispatch decisions may be due to wind generation. We know that increased cycling will lead increased costs associated with additional wear on the facilities and suboptimal operating conditions. However, we have not yet been able to quantify these costs or to estimate the direct effect that wind generation has on these cost increases.

As the amount of power generated from renewable energy sources like wind and solar becomes a larger part of our generation fleet, so does the impact of its variability. At the same time, new environmental controls and operating limits may reduce the ability of our coal plants to move up and down as frequently as they may now. Planning for, reacting optimally to, and quickly responding to these varying generation sources can

have a significant impact on our overall fleet which will require careful management to assure optimization.
We will be continuing this study and will update the Commission on our progress in our next Resource Plan.

Wind Forecasting
We are investigating the integration of wind resources with our real-time operations to allow for real-time dispatch of wind resources at some level. Every day, our customers' demand for electricity increases in the morning, drives toward a peak in the late afternoon to early evening, and then decreases. Often, wind patterns show increasing generation at the same time that load is dropping. This mismatch creates a load-following burden on the system. By integrating signals from the real-time operations to the wind turbine regulating system, we could ease this load-following burden at times when traditional generation has trouble keeping up with the changes in load and wind generation.

In the spring of 2009, the National Center for Atmospheric Research (NCAR) agreed to work with Xcel Energy to provide highly detailed, localized weather forecasts to enable the utility to better integrate electricity generated from wind into the power grid. The forecasts will help operators make critical decisions about powering down traditional coal- and natural gas-fired plants when sufficient winds are predicted, allowing the utility to increase reliance on alternative energy while still meeting the needs of its customers.

The U.S. Department of Energy's National Renewable Energy Laboratory (NREL) is helping to support the project by developing mathematical formulas to calculate the amount of energy that turbines generate when winds blow at various speeds.

NCAR will use a suite of tools, including cutting-edge computer models, to issue high-resolution wind forecasts for wind farm sites every three hours. If the prediction system is successful, wind forecasting companies may adopt the technology to help utilities in the United States and overseas transition away from fossil fuels.

Wind Curtailment

We have been providing monthly wind curtailment reports for more than five years, beginning with May 2004. Transmission system limitations continue to be the primary reason for curtailment of wind production. With the addition of several transmission improvements in 2009, system limitations have been significantly reduced. As a result, we do not anticipate significant curtailment events in the coming years. Over the next five years, we expect wind generation curtailment and the associated payments to vendors to decrease significantly compared to historical levels. In our 2009 curtailment report, curtailment payments were projected to be approximately $2.6 million. Compare this amount to 2004, when curtailment payments exceeded $10 million, and 2006, where such payments were in excess of $6 million. In the 2010 to 2014 time frame, curtailment payments should be minimal under current wind project plans (both transmission and generation) for the NSP area. Of course, actual curtailment experience will depend on the timing of wind development relative to the timing of ongoing system improvements to support them.

Ownership of generation

As the wind industry has evolved, several different ownership structures have emerged. One primary structure is an independent developer that owns and operates a wind facility, selling its output to a utility through a long-term PPA. Xcel Energy has also entered into small wind contracts with individuals, and community-based energy development (C-BED) projects. In 2008, we placed our first owned wind project into service, the 100 MW Grand Meadow project. We now have an additional 350 MW of owned wind under development. Maintaining all of these ownership structures in our wind portfolio allows us to capitalize on the various strengths of market participants, by working toward a robust marketplace where all market participants compete for and contribute to our renewable energy plan.

We believe utility ownership of renewable generation has proven to be of value to our customers, and should continue to be an option for some portion of the additional resources we will need to acquire for compliance by 2020. By the end of 2011, we will have 450 MW of Xcel Energy owned wind generation on our system. Going forward, utility ownership of wind resources may take different forms than this build-transfer/complete ownership model we have used thus far. Our investments in wind generation in the future may include smaller, targeted, partnerships or partial ownership of projects or some other structure. We believe this balanced portfolio offers benefits to all stakeholders.

We continue to support the objective of creating and retaining local benefits through wind development, as envisioned by the Minnesota C-BED program. Our compliance strategy reflects this commitment through continued efforts to secure C-BED resources for our system, but with a renewed focus on the cost-effectiveness of those resources.

Going forward, it will be increasingly important that C-BED projects are competitive with other projects available to us. In a recent proceeding before the Commission, our regulators expressed a growing concern that C-BED projects may require too high a premium relative to non-C-BED projects, and directed us to take steps to ensure against that possibility in the future. We understand that concern, and will take steps in the future to further ensure the competitiveness of the C-BED projects we propose to add to our supply portfolio. Legislation was enacted in the 2010 Minnesota legislative session to reform the C-BED statute. Proponents of that legislation stated that the legislation expands the variety of project structures that can qualify as C-BED, and clarifies the requirements and process for C-BED eligibility. As a result, the advocates for the legislation believe that it will help C-BED projects be more competitive with non-C-BED projects.

In the Renewable Energy Plan approved by the Commission, long term targets for different types of ownership structures, CBED, traditional developer PPA, and utility ownership, were established. Our plan called for approximately a third of each. While we have the same underlying goals in mind we do not believe it is necessary or productive to focus on long term goals at this time. The appropriate mix will be determined in the near term, in large part, as the result of our 250 MW Wind RFP. We believe utility ownership will continue to be an effective way to bring value to customers and mitigate some of the risk associated with heavy reliance on power purchases but we too must compete. We propose our statement of long term targets be adjusted slightly to reflect the importance of cost competitive proposals and suggest consolidating the targets to roughly a third utility owned and two thirds power purchases of all types, including C-BED. As we note above, it is very possible the distinctions we have used to describe ownership structures will blur considerably over time.

Renewable Resources and DSM Cases

Minn. Stat. § 216B.2422, subdivision 2 requires that a utility must, in its Resource Plan, develop scenarios for obtaining 50 and 75 percent of its new and refurbished resource capacity needs from renewable resources and demand-side management. This requirement, which preceded the Minnesota RES and the legislated increase in our Minnesota DSM goals, ensured that utilities seriously considered the role of renewable energy and DSM could play in their resource mixes, and appropriately evaluated the associated costs.

With the passage of the RES and the higher DSM requirements, it appears that this requirement has become somewhat redundant. Based on our analysis of our proposed plan, we find that 75% of our incremental energy needs in this plan are being supplied by renewable energy or demand-side management. Supplying less, as the 50% scenario contemplates, would not fulfill the RES and DSM statutes; thus, we did not perform a separate analysis of that scenario.

Renewable Contingency Plan

The Minnesota RES sets an aggressive goal that we are committed to achieving. That said, it is only prudent that we recognize the possibility that we will be unable to implement all of the wind energy needed to fulfill our RES requirements, or that the economics will change and the costs of compliance would no longer be reasonable. The RES requires that we continue to monitor the costs and progress through each Resource Plan, and provides two specific mechanisms to assist if we are unable to meet the RES through our Wind Expansion Plan. First, the legislation required the

Commission to establish a trading system for renewable energy credits ("RECs"). In Docket No. E999/CI-04-1616, the Commission established the Midwest Renewable Energy Tracking System ("MRETS") as the means for tracking RECs and set out the basis for a system that would allow for trading over a broader regional area. If Xcel Energy is unable to meet the RES through cost-effective installation or acquisition of wind resources, our first contingency will be utilize our existing REC bank for compliance. The second contingency is to attempt to purchase RECs to meet the RES. Since we have a specific wind energy requirement for RES compliance, we assume that we would need to specifically purchase wind RECs for compliance.

As discussed above, the third mechanism provided by the Minnesota RES legislation is the ability for the Commission to modify or delay a utility's RES requirement under certain circumstances.

We believe that our ongoing planning efforts, required updates to the Renewable Energy Plan, and future Resource Plans will ensure that these factors are evaluated and offer the opportunity for parties to comment on our progress toward compliance and whether any modifications are necessary or appropriate.

Manitoba Hydro

Currently, Xcel Energy and Manitoba Hydro are parties to a 500 MW System Power Sale Agreement that terminates on April 30, 2015. This contract provides Xcel Energy with 500 MW of capacity from MH's system along with intermediate-load energy, five days per week, sixteen hours per day. In addition, these utilities are parties to two diversity exchange agreements, which in aggregate call for the seasonal exchange of 350 MW of capacity along with peaking energy. These diversity exchange agreements begin expiring starting in 2015.

On May 27, 2010, Xcel Energy executed a series of 3 new power purchase agreements with Manitoba Hydro that in essence extend a series of existing agreements through mid-2025. On May 28, 2010 we issued a press release announcing our new transaction. On June 10, 2010 we filed a Petition for approval of our agreements with the Commission under Docket No. E002/M-10-633. The three agreements will work together as a single transaction, and will extend our long-standing contractual relationship with Manitoba Hydro for another ten years. If approved by the Commission and Canadian authorities, this transaction will result in the Company obtaining 725 MW of reliable capacity during summer season months when NSP needs additional capacity, along with energy from Manitoba Hydro's system. Depending on future circumstances, the transaction could increase to up to 850 MW in the summer season (450 MW in the winter season) beginning in May 2021.

Power Purchase Agreements

The Manitoba Hydro PPAs as a group consist of three (3) power purchase agreements covering generating capacity and energy being purchased and sold. Without these agreements, we would lose 850 MW of capacity and energy that is important in meeting our customers' power requirements and contributes to our environmental goals. The PPAs will provide a low-cost resource to address our capacity and energy needs, and extend, update and restructure our contractual relationship with Manitoba Hydro.

The bulk of the energy provided by the agreement is based on a fixed price and therefore protects Xcel Energy from potential volatility in the natural gas market. The transaction is also structured to fully utilize the existing transmission path between Manitoba Hydro and Xcel Energy and provide our customers access to the environmental attributes of Manitoba Hydro's system, which consists predominantly of hydro generation resources.

The three agreements are summarized as follows:

- *375/325 MW System Power Agreement:* This agreement is scheduled to last from May 1, 2015 through April 30, 2025. Xcel Energy will purchase 375 MW of capacity during the six summer season months and 325 MW of capacity during the remaining six winter season months. The capacity must be qualified by MISO as an external resource, allowing Xcel Energy to include it as reliable system capacity. This agreement also includes several energy products. Manitoba Hydro must offer energy during the four system peak hours every day as part of MISO's capacity requirements. NSP must purchase energy five days per week year-round; 16 hours per day in the summer, and 12 hours per day in the winter.

- *125 MW System Power Agreement.* This agreement will last from May 1, 2021 through April 30, 2025, if Manitoba Hydro has contracted to construct its next major hydroelectric project. Under this agreement, Xcel Energy will purchase an additional 125 MW (year-round) capacity and energy on essentially the same terms as the 375/325 MW System Power Agreement, increasing Xcel Energy's system purchase to 500 MW (Summer) and 450 MW (Winter). If by May 1, 2018, MH has not committed to proceed with a new major hydroelectric project, this contract will terminate, unless Manitoba Hydro waives this new project condition but the 375/325 MW agreement will remain in place.

- *350 MW Diversity Agreement.* Under the Diversity Agreement, the parties replace and extend their existing 350 MW of seasonal capacity exchange through April 30, 2025.

The overall transaction results in at least 725 MW (potentially up to 850 MW) of reliable capacity along with environmental attributes associated with MH's hydroelectric system. It ensures the availability of reliable generating capacity and energy, at favorable pricing, to our customers through 2025. The transaction also provides less capacity during the six winter season months, reflecting Xcel Energy's reduced need for capacity during that period. The Manitoba Hydro PPAs utilize an existing transmission path, which can support as much as 892 MW per hour of transfer. Because of the energy profile of these contracts, there will be many hours of the year when substantially less power is flowing over the transmission path. The three Manitoba Hydro PPAs collectively provide a mechanism to more efficiently utilize the path when it is not being used to serve the requirements of the contract.

Alternative Competitive Resource Acquisition

Our filing initiated the Alternative Competitive Resource Acquisition process established in Docket No. E002/RP-04-1752, established by the Commission as part of our 2004 Resource Plan. The process provides an opportunity for alternative proposals to be filed with the Commission when the Company is requesting approval for a project that was not selected in a competitive bidding process It allows regulators to ensure that the resources the Company acquires are the most reliable and cost-effective options for our customers. Prospective alternative providers must intervene in support of their own proposal in a contested case proceeding.

We have recommended that the Commission set a schedule in the MH proceeding to require any alternatives to the Company's proposal to be filed by October 1. For the sake of procedural efficiency, we ask that the evaluation of our Manitoba Hydro proposal and alternatives to that proposal be considered entirely within the Manitoba Hydro proceeding, MPUC Docket No. E002/M-10-633, and that issues and questions related to that proposal not be taken up in consideration of this Resource Plan.

Project Benefits

Our Manitoba Hydro petition demonstrates a number of benefits that will accrue to our customers should the contracts be approved. First, our analysis indicates that these contracts are lower cost than other feasible alternatives we evaluated. The fixed price energy and capacity within the transaction provide a hedge against the volatility of natural gas and other fuels, and enhances the diversity of our generation portfolio. They further utilize an existing transmission path and contractually provide us with the environmental benefits of the Manitoba Hydro system. We are confident that these contracts provide superior value to our customers and will be approved.

Conclusion

Our renewable energy resources comprise a significant portion of our system and consist of wind, biomass, solar, small hydro and purchases from Manitoba Hydro. While the Manitoba Hydro resources are not considered an "eligible energy technology" for purposes of complying with the RES, they nonetheless provide our customers with significant environmental and other benefits.

Our early installation of wind resources has allowed us to build a significant portfolio of cost-effective renewable resources in order to comply with our RES. As such, we have the flexibility to ensure that we are complying with future RES milestones in the most cost-effective manner. We recognize that we will need to continue monitoring our progress toward compliance and its impacts on reliability and costs, as transmission access, the life of the PTC, the cost of resource alternatives and other issues may significantly influence our compliance strategy. We are undertaking efforts to address these issues; however, as contemplated by the RES, on-going monitoring and continued evaluation of the cost and reliability impacts of the RES will be important.