Xcel Energy®

414 Nicollet Mall
Minneapolis, MN 55401

December 18, 2012

—Via Electronic Filing—

Burl W. Haar
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101

RE: UPDATED ANALYSIS AND COMMENTS
2011-2025 RESOURCE PLAN
DOCKET NO. E002/RP-10-825

Dear Dr. Haar:

Northern States Power Company, doing business as Xcel Energy, submits the attached Updated Analysis and Comments in Compliance with the Minnesota Public Utilities Commission's November 30, 2012 Order in the docket referenced above We have electronically filed this document with the Commission, and copies have been served on the parties on the attached service lists.

Please contact me at christoper.b.clark@xcelenergy.com or (612) 215-4593 or Jim Alders at james.r.alders@xcelenergy.com or (612) 330-6732 if you have any questions regarding this filing.

Sincerely,

/s/

CHRISTOPHER B. CLARK
REGIONAL VICE PRESIDENT
RATES AND REGULATORY AFFAIRS

Enclosures
c: Service Lists

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Beverly Jones Heydinger	Chair
David C. Boyd	Commissioner
J. Dennis O'Brien	Commissioner
Phyllis A. Reha	Commissioner
Betsy Wergin	Commissioner

IN THE MATTER OF THE APPLICATION OF NORTHERN STATES POWER COMPANY FOR APPROVAL OF OUR 2011-2025 INTEGRATED RESOURCE PLAN

DOCKET NO. E002/RP-10-825

UPDATED ANALYSIS AND COMMENTS

OVERVIEW

Northern States Power Company, doing business as Xcel Energy, submits to the Minnesota Public Utilities Commission this filing in compliance with the Commission's November 30, 2012 Order in our 2011-2025 Resource Plan proceeding. The November 30 Order directed Xcel Energy and the Department of Commerce, Division of Energy Resources, to file additional analyses to assist the Commission in establishing parameters for the size, type, and timing of the Company's next generation resource needs to inform the resource acquisition process scheduled to begin in March 2013. The Commission specifically directed that our revised analysis examine the impact of not continuing with the Prairie Island uprate project and should include other updates or revisions as appropriate. The Commission also encouraged the parties to explore whether the issues surrounding the determination of the type of resource needed could be further developed.

We are in general agreement with using the base modeling assumptions recommended by the Department in their June 12, 2012 Comments, including the Department's forecast of peak demand. We recommend the Commission's Order establishing parameters for the competitive resource acquisition process:

- Set the need at 154 MW in 2017, 319 MW in 2018, and 443 MW in 2019; and
- Not specify the resource type, but let the process select the most cost effective proposals.

We recommend the Commission's Order specify the estimated generation deficits by year to provide project developers with specific guidance regarding the size and timing of our resource needs. We believe providing developers the flexibility to offer the generating unit size of their choice to meet either all or part of the resource need will elicit as many proposals as possible and result in options that are cost effective for our customers.

We note that there has been discussion in this proceeding about additional demand response potential on our system. In this filing, we provide information on the limitations of the specific DSM potential study mentioned. We recommend the Commission take no action at this time to reduce the estimated resource need based on potential demand response benchmarking.

Regarding generation type, our updated analysis, which includes planning level cost assumptions for generic resources, does not readily distinguish between the cost effectiveness of combustion turbine and combined cycle additions in the 2017 to 2019 timeframe. Based on these results and the sensitivity of the analysis to small differences in modeling assumptions, we conclude that selection of the most cost effective alternative will depend on the detailed characteristics, including costs, of the actual proposals. As such, we request that the Commission not predetermine what mix of peaking and intermediate generation best meets the identified need. Instead, we recommend the Commission give general guidance and allow proposals consisting of either type or a combination of resources. Providing this flexibility allows the resource acquisition process to select the most cost effective generation portfolio to obtain the best outcome for our customers.

We are actively developing our proposal to meet the resource need identified here and have determined the most cost effective proposal we can put forward to meet generation needs in the 2017 to 2019 timeframe consists of three combustion turbine units. We would like the opportunity provide a flexible proposal that allows the Commission to select all or portions of our proposal in combination with other projects to meet our customers' power requirements reliably and as cost effectively as possible.

Finally, we note that we have engaged in discussions and made progress on a confidentiality agreement with Calpine. We have forwarded a draft non-disclosure agreement to Calpine and understand they would like to review these Comments before providing us their feedback on the draft agreement. We expect to resolve this issue before the Commission's hearing in this matter, and we will provide an update to the Commission in our Reply Comments due January 16, 2013.

We provide our analysis and additional discussion in the following sections:

- *Size and Timing of Resource Need,* providing our updated base modeling assumptions, presenting the results of our analysis, and discussing the demand response potential study;
- *Resource Type,* providing additional information on our analysis of cost effectiveness by generation type and presenting the results of our analysis and sensitivity testing around certain modeling assumptions; and
- *Conclusion,* summarizing our recommendations for the Commission's consideration.

A. Size and Timing of Resource Need

The size and timing of our generation resource need are informed by a relatively straightforward comparison of the forecast of peak demand plus system reserve requirements with existing resources available to meet that requirement. Our analysis identifies a 154 MW capacity deficit in 2017, growing to 319 MW in 2018 and 443 MW in 2019.

We are in general agreement with using the base modeling assumptions recommended by the Department, including the Department's forecast of peak demand. For clarity, Attachment A lists the assumptions, which are the same assumptions we propose to use in analyzing proposals in the 2013 competitive resource acquisition process.

Our resource need analysis continues to be based on the median peak demand forecast presented in our December 2011 Resource Plan Update filing with the adjustments recommended by the Department in their June 2012 Comments. We have also updated our resource need estimate to reflect a reserve generation margin based on MISO's unforced capacity (UCAP) methodology, consistent with the Department's recommendations.

On the supply side, we have updated our model to remove the 117 MW that was anticipated with the completion of the Prairie Island EPU, and we continue to reflect our plan to retire Black Dog Units 3 and 4 in 2015. We have also reexamined our assessment of three smaller peaking resources – Key City, Granite City, and French Island.

As noted in previous filings, we have several small peaking units at the Key City plant in Mankato (43 MW) and at the Granite City plant near St Cloud (54 MW). The depreciable life of current assets at these units expires at the end of 2012. However, we have no immediate plans to retire these units from operation, and we believe their age and condition is such that they can continue to operate through 2016. We have updated our model to reflect continued operation of these plants through 2016 but have not extended their life further at this time.

French Island Unit 3 developed a short circuit in the generator stator in 2009 and has been unavailable for dispatch since that time. Since the NSP system has had excess capacity since 2009, there has been no need to invest the capital necessary to repair the unit. We have examined the cost of repair and currently estimate the facility can be brought back to service with an approximate $3 million investment. We have determined that this is a cost effective way to maintain peaking generating capacity, and we are including the necessary funds in our budgets. Our updated model includes the 57 MW of production capacity at French Island Unit 3 starting in 2016 and continuing for through the planning period.

While the size and timing of our resource need recommendation is based on this analysis, we recognize there are factors that could affect resource requirements on our system. For example, MISO is revising the way reserve margins are calculated, which may affect overall resource requirements. Historically our reserve requirements were set based on the NSP system's peak demand. The new method is based on reserves on the NSP system load at the time of the MISO's peak demand. Historical data indicates that our system's power demand is typically lower at the time of MISO's system-wide peak. With this change, future reserve requirements may be lower than they are now. While the reduction in reserve requirements for the NSP system could be substantial, this concept is just now being implemented by MISO, and we do not have enough information about the impact of these changes on the long-term planning needs of the Company to recommend updating reserve requirement calculations at this time.

Additionally, in this proceeding the environmental intervenors raised the issue of demand response potential, noting that a recent Demand Side Management potential study identified an additional 300 MW of demand response that could be achieved on our system. Through existing tariffs, including our interruptible service and Savers Switch programs, the Company can currently reduce demand during peak periods by approximately 1000 MW.

We do not believe the demand response study work identified is developed sufficiently to establish additional programs to deliver a firm demand reduction. KEMA, the consulting firm that did the study work, created estimates of demand response potential using FERC's National Assessment of Demand Response[1] model

[1] *A National Assessment of Demand Response Potential*, Staff Report, Federal Energy Regulatory Commission, prepared by the Brattle Group, Freeman, Sullivan & CO., and Global Energy Partners, LLC, June 2009.

with limited inputs to represent Xcel Energy's Minnesota service territory. The study was done in conjunction with the 2011 DSM Potential Study but has not progressed to the same level as the rest of the DSM Potential Study.

Xcel Energy refers to this study as benchmarking to communicate that it is a precursor to further demand response potential analysis. While it compares our programs to other demand response portfolios across the nation, it does not take into consideration customer preferences, current program penetration levels, or cost implications, such as the cost of metering technology to support some of the anticipated pricing mechanisms. To address demand response at Xcel Energy, a comprehensive review of forecasts, economic conditions, and various other attributes outside the study parameters would also need to be conducted.

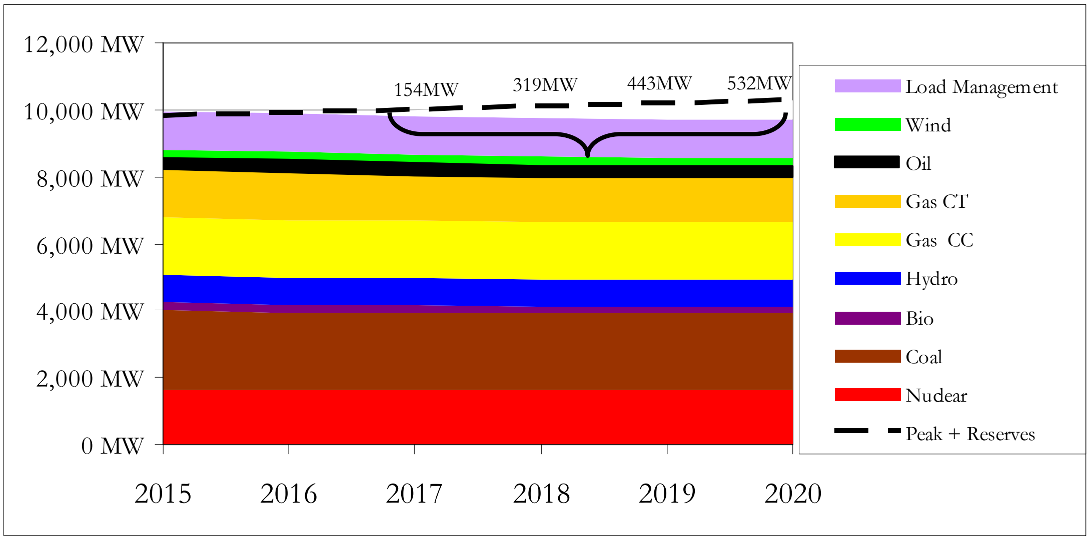
We believe we can use the report to benchmark how our programs compare on a national level and what mechanisms and customer segments may provide further sources of demand response potential. However, to reduce estimates of generation requirements at this time would require high confidence and certainty in the amount of new demand response. As such, we recommend the Commission take no action at this time to reduce the estimated generation needs in anticipation of future demand response programs.

While there are uncertainties around any future resource need estimates, we believe it is appropriate to base our resource acquisition process on our current analysis, specifying the estimated resource need by year. From a practical perspective, generation additions will not exactly match the resource need in any one year. We believe communicating that developers have the flexibility to design their proposal based on the unit size of their choice would result in the best options being available to select for our customers.

B. Resource Type

We have refreshed our analysis of the cost effectiveness of various alternative types of generation to meet the anticipated need. The type of generation selected does not affect the size or timing of the resource need. Instead, the type of generator added to the system affects the overall dispatch and operation of the fleet of generators and cost of electricity. The mix of existing generation on our system impacts the need for additional resources on our system. Figure 1 shows how our existing diverse generation mix combines to meet peak load plus reserve margin without overreliance on any specific generating technology.

Figure 1
Peak Demand, Reserve, and Resources 2015-2020



Consistent with previous analyses in this proceeding, modeling selects a combination of combustion turbines and combined cycle power plants as the most cost effective resource additions to our system over the next decade. However, using planning level cost assumptions of generic generation units, the model does not readily distinguish between the cost effectiveness of the combustion turbine and combined cycle additions to our system in the 2017 to 2019 time frame. The sequencing of peaking and intermediate generation additions to our system appears to be a close call and will depend on the detailed cost and operating characteristics of actual proposals that will be offered to the Company next year.

Under the baseline assumptions, including planning level cost estimates for generic resources, Strategist selected a resource portfolio with one intermediate unit and one peaking unit between 2017 and 2019 as the least cost plan. An alternative portfolio that included only peaking units was estimated to have an additional $16 million in present value of revenue requirements (PVRR). This PVRR difference is fairly small in comparison to the total cost of over $30 billion over the study period.

Table 1
Base Case Strategist Results

	Size & Timing	At Least 1/2 Intermediate	All Peaking
2015	157		
2016	32		
2017	(154)	Intermediate(354MW)	Peaking(189MW)
2018	(319)		Peaking(189MW)
2019	(443)	Peaking(189MW)	Peaking(189MW)
2020	(532)		
2021	(612)	Peaking(189MW)	Intermediate(354MW)
2022	(694)		
2023	(795)	Peaking(189MW)	
2024	(904)		
2025	(2077)	Peaking(189MW) & Interm x3(1062MW)	Peaking(189MW) & Interm x3(1062MW)
2026	(2120)		
PVRR $millions		**$34,462**	**$34,478**
Difference			**$16**

To test the robustness of the baseline results and the planning level cost assumptions, we conducted a number of sensitivity tests to see how the results change with different input assumptions. Table 2 presents the results of this sensitivity analysis.

Table 2
Strategist Sensitivity Results

PVRR ($millions)	At Least 1/2 Intermediate	All Peaking	Difference	*Change from Base*
Base Assumptions	$34,462	$34,478	**$16**	
Low Gas	$33,419	$33,435	**$16**	*$0*
High Gas	$35,439	$35,456	**$17**	*$1*
$0 CO2	$29,526	$29,538	**$12**	*($5)*
RES Wind	$34,798	$34,807	**$9**	*($7)*
Markets On	$33,545	$33,542	**($3)**	*($19)*
CTs -15%	$34,403	$34,408	**$4**	*($12)*
CTs + 15%	$34,520	$34,548	**$28**	*$12*
CC - 15%	$34,324	$34,354	**$30**	*$13*
CC +15%	$34,600	$34,602	**$3**	*($13)*

The sensitivity analysis shows that several factors can impact the cost effectiveness of various resource alternatives and when considered on an individual basis or in combination can reduce or reverse the cost differences between peaking and intermediate generation.

For example, the base case was designed without the addition of any new wind generation beyond what is current on the system and under contract. The base case design is not meant to express a preference for or against further wind additions on our system. It simply is meant to establish a reference point for comparisons. The RES wind scenario includes an additional 1200 MW of wind generation in 200 MW increments spread between 2014 and 2025. This scenario approximates the additions necessary to fully comply with the renewable energy standards and objectives of the five states in which we operate. Less electrical energy production is required from the remainder of the system as the result of incorporating additional wind power. With additional wind energy production other generating units operate less and an intermediate unit addition becomes less valuable. This sensitivity test does not indicate that combustions turbines are cost effective only if pared with additional wind power. As discussed in previous filings, the cost effectiveness of additional wind acquisitions will depend heavily on federal tax policy decisions regardless of peaking or intermediate generating additions.

Similarly, when Strategist model is allowed to purchase energy from the MISO market, peaking resources look more cost effective than adding a combined cycle plant in the 2017 to 2019 timeframe. The model defers a moderately sized combine cycle addition to 2021. In the market sensitivity test the model is allowed to simulate energy purchases from the MISO market during times when lower cost generation may be available. The Company agrees with the Department that market capacity purchases should not be relied upon as a long term generating resource to meet our generation capacity needs. However, we believe the MISO market will continue to provide opportunities to purchase hourly energy at prices below the cost of our own generation resources. Making energy purchases when it is advantageous reduces costs for our customers immediately as these cost savings are passed through the fuel clause adjustment. When economical market energy is available, peaking resources can be lower cost alternatives due to their lower capital requirements and lower revenue requirements in base rates.

The combined impact of only these two sensitivity test changes the results by $26 million PVRR ($7 million + $19 million) and would be sufficient to change the conclusion that the addition of an intermediate unit will be more cost effective than the combustion turbine alternative in the 2017 to 2019 timeframe. The model still predicts the need for generation with intermediate capacity factors but defers it a few years to better match energy production requirements.

These Strategist analyses are based on generic units, and the cost and performance data used represents typical units. Actual projects either proposed by the Company or offered by developers will differ in cost and performance. For example, we have identified opportunities on our system to develop combustion turbine generation at costs lower than the generics used in resource plan modeling. When we replace generic combustion turbine cost estimates with our preliminary estimates and leave all other base case assumptions unchanged the model selects only combustion turbines in the 2017 to 2019 timeframe and defers intermediate capacity factor, combined cycle additions to the next decade. Likewise, a developer proposing an intermediate resource may be able to offer a project below the cost of the generic unit modeled in Strategist.

Finally, as we have developed our proposal, we have investigated whether other utilities or market participants would be willing to offer us existing firm capacity and energy, and there has been some interest in this option. A short term capacity and energy purchase of sufficient size could help reduce customer costs by delaying inservice date of our first proposed combustion turbine from 2017 to 2018. We continue to examine the potential benefits of incorporating a firm purchase in our proposal that would meet the 2017 resource need. To recognize that there may be other opportunities to reduce customer costs while still meeting system reliability requirements, we recommend the Commission allow proposals from existing generators in the competitive acquisition process.

CONCLUSION

Based on the analysis and discussion presented in this filing, we recommend that the Commission:

- establish the size and timing of our generating resource need to be addressed in the competitive resource acquisition process at 154 MW in 2017, 319 MW in 2018, and 443 in 2019;
- provide participants in the competitive resource acquisition process the flexibility to offer peaking or intermediate resources or a combination of the two, as well as the flexibility to address all or a portion of the identified need;
- allow proposals in the competitive resource acquisition process from existing generators; and
- take no action at this time to reduce the estimated resource need based on demand response potential.

Xcel Energy is actively preparing the most cost effective proposal we can identify to meet the resource needs presented in our updated analyses. We intend to design our proposal in a modular fashion so that the Commission has flexibility to select three combustion turbines to meet the entire need identified or combine fewer units with other proposals if more cost effective. We also have flexibility to adjust the timing of our generation additions if evolving circumstances warrant. We look forward to Commission's consideration in the competitive acquisition process.

Dated: December 18, 2012

Northern States Power Company

Attachment A
Xcel Energy
Strategist Modeling Assumptions
December 18, 2012

The following details certain assumptions used in the December 18, 2012 Resource Plan analysis. These are the same modeling assumptions we plan to use in the 2013 competitive resource acquisition process.

Inflation Rate: 2.36%

Discount Rate: 7.56%

Reserve Margin: Based on MISO UCAP for planning year 2011/12: 3.8%

Externality Costs: Based on Commission established high externality values.

Carbon Costs: $21.50/ton beginning in 2017, escalating at inflation.

Load Forecast: As presented in our Dec 2011 resource plan update and modified by the Department.

	2013	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Peak	9,237 MW	9,328 MW	9,428 MW	9,524 MW	9,613 MW	9,708 MW	9,799 MW
	2020	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
	9,881 MW	9,963 MW	10,029 MW	10,082 MW	10,123 MW	10,151 MW	10,177 MW
	2013	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Energy	45,569 GWh	45,901 GWh	46,243 GWh	46,628 GWh	46,838 GWh	47,137 GWh	47,416 GWh
	2020	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
	47,720 GWh	48,020 GWh	48,236 GWh	48,466 GWh	48,747 GWh	49,060 GWh	49,404 GWh

Resources: As presented in our December 2011 Resource Plan Update and discussed in this filing, the resources that will be included in the baseline model are summarized below.

MISO UCAP Summer Capacity (MW)	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Load Management	1,122	1,134	1,145	1,153	1,157	1,153	1,149	1,145	1,141	1,137	1,133	1,128	1,124	1,120
Coal	2,663	2,663	2,423	2,331	2,331	2,331	2,331	2,331	2,331	2,331	2,331	2,320	2,320	2,320
Nuclear	1,610	1,610	1,610	1,610	1,610	1,610	1,610	1,610	1,610	1,610	1,610	1,610	1,610	1,610
Bio	211	211	211	211	211	162	151	151	151	151	127	87	87	81
Gas CC	1,716	1,716	1,716	1,716	1,716	1,716	1,716	1,716	1,716	1,716	1,716	1,716	1,716	1,716
Gas CT	1,450	1,450	1,450	1,450	1,354	1,341	1,341	1,341	1,341	1,341	1,341	1,341	1,046	1,046
Oil	310	310	310	367	367	367	367	367	253	253	253	253	253	253
Hydro	961	961	817	817	814	814	814	814	936	928	928	928	98	98
Wind & Solar	260	260	260	261	262	262	247	248	236	234	215	204	187	180
Total Resources	**10,303**	**10,315**	**9,943**	**9,917**	**9,823**	**9,757**	**9,727**	**9,724**	**9,715**	**9,701**	**9,654**	**9,587**	**8,441**	**8,425**

Fuel Prices: As presented in our December 2011 Resource Plan Update (all prices in \$/mmBtu).

Natural Gas	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Ventura Hub	\$4.86	\$5.16	\$5.50	\$5.95	\$6.22	\$6.34	\$6.60
	2020	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
	\$6.85	\$7.27	\$7.57	\$7.83	\$8.06	\$8.35	\$8.59

Coal	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Sherco	\$2.25	\$2.34	\$2.38	\$2.44	\$2.47	\$2.52	\$2.57
	2020	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
	\$2.68	\$2.73	\$2.78	\$2.84	\$2.88	\$2.94	\$3.00

Nuclear	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Prairie Island	\$0.90	\$0.89	\$0.96	\$0.97	\$1.01	\$1.04	\$1.06
	2020	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
	\$1.08	\$1.13	\$1.16	\$1.19	\$1.21	\$1.21	\$1.21

CERTIFICATE OF SERVICE

I, Ketti Lindberg, hereby certify that I have this day served copies of the foregoing document or a summary thereof on the attached lists of persons:

xx by depositing a true and correct copy or summary thereof, properly enveloped with postage paid, in the United States Mail at Minneapolis, Minnesota; or

xx via electronic filing

DOCKET NOS. E002/RP-10-825; E002/CN-12-1240

Dated this 18th day of December, 2012

/s/

____

Ketti Lindberg

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