MINNESOTA DEPARTMENT OF COMMERCE

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October 27, 2014

Burl W. Haar
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, Minnesota 55101-2147

RE: **Comments of the Minnesota Department of Commerce, Division of Energy Resources**
Docket No. ET6,ET6132/RP-14-526

Dear Dr. Haar:

Attached are the comments of the Minnesota Department of Commerce, Division of Energy Resources (Department) in the following matter:

> Minnkota Power Cooperative, Inc. and Northern Municipal Power Agency's (the Joint System) 2014 Integrated Resource Plan.

The petition was filed on June 26, 2014. The petitioner is:

> Jamie Overgaard
> Rates, Load & Planning Manager
> Minnkota Power Cooperative, Inc.
> 1822 Mill Rd
> Grand Forks, ND 58203

The Department recommends that the Minnesota Public Utilities Commission (Commission) accept the Joint System resource plan for planning purposes, subject to requiring the Joint System to include the Commission's externalities in future resource plans; the Department will provide additional recommendations in reply comments. The Department's team of Christopher Davis, Susan Peirce, and Steve Rakow are available to answer any questions the Public Utilities Commission may have.

Sincerely,

/s/ CHRISTOPHER T. DAVIS
Rates Analyst

CTD/ja
Attachment

BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

COMMENTS OF THE
MINNESOTA DEPARTMENT OF COMMERCE
DIVISION OF ENERGY RESOURCES

DOCKET NO. ET6,ET6132/RP-14-526

I. INTRODUCTION

A. BACKGROUND

Minnesota Rules parts 7843.0100 to 7843.0600 require electric utilities to file proposed integrated resource plans (IRPs) every two years. The Minnesota Public Utilities Commission (Commission) can vary those rules for good cause shown. Minnkota Power Cooperative, Inc. (Minnkota) and Northern Municipal Power Agency (NMPA) last filed a joint IRP on July 12, 2010 in Docket No. ET6,ET6132/RP-10-782.

On June 26, 2014, Minnkota and NMPA submitted their Petition for their Integrated Resource Plan (Petition) for the period 2015 to 2028.

B. JOINT SYSTEM BACKGROUND

The Minnesota Department of Commerce, Division of Energy Resources (Department), refers to the municipal (NMPA)/cooperative (Minnkota) utility as the Joint System. Minnkota is a wholesale generation and transmission cooperative with eleven member/owner distribution cooperatives. Eight of the member/owners are located in northwestern Minnesota and three are located in northeastern North Dakota.

In addition, Minnkota is associated with NMPA. NMPA consists of twelve member municipal utilities in the same region as Minnkota's distribution cooperatives. Ten of the members are located in northwestern Minnesota and two are located in northeastern North Dakota.

Together Minnkota and NMPA form a Joint System and serve a total of about 125,000 customers over a 34,500 square mile service territory. As in 2010, Minnkota and NMPA submitted their IRP as a Joint System since the electric generation resources and Western Area Power Administration (WAPA) allocations of NMPA and Minnkota are used collectively to serve the Joint System's load.[1] The Joint System is a market participant in the Midcontinent Independent System Operator's (MISO) energy market.

C. JOINT SYSTEM PLANNING

The Joint System's planning process consisted of the following steps:

- develop energy and peak demand forecasts, including high and low forecasts based on the effects of (1) harsh and (2) mild weather conditions.
- determinate the Joint System's resource needs, both energy and capacity, over the planning period.

Based on a comparison of the projected energy requirements of the Joint System and the output of its generation resources, WAPA purchases, and wind PPAs, the Joint System determined that it did not need additional generation resources in the 2014-2028 period.

D. JOINT SYSTEM'S PROPOSED PLAN

While the Joint System stated that it does not need any new resources, it plans on continuing to investigate cost-effective ways of implementing demand response, energy conservation, and renewable energy technologies.

II. DEPARTMENT ANALYSIS

A. OVERVIEW OF ANALYSIS

To review this IRP, the Department evaluated the Joint System's:

1. energy and demand forecasts,
2. demand-side resources,
3. compliance with the renewable energy objective/standard (REO/RES), and
4. environmental issues.

Each component is discussed below in detail. Overall, the Department's analysis indicates that:

1. The forecast has remained stable over time and thus the Department did not conduct an in-depth review. The Department recommends that the Commission accept the Agency's forecast for planning purposes.
2. The Joint System's lack of modeling would be inadequate in the event the utility needed to apply for a certificate of need in Minnesota; however, the information provided in this proceeding is acceptable for planning purposes.
3. The Joint System appears to have no resource needs during the planning period.

[1] The Department notes that the instant IRP was submitted to both the Minnesota Public Utilities Commission (Commission) and WAPA.

4. The Joint System met the State's 1.5 percent energy savings goal in 2011, 2012, and 2013. Further, the Deputy Commissioner of the Department found that Minnkota has a broad array of energy savings projects.
5 The Joint System has exceeded Minnesota's Renewable Energy Standard.
6. The Department will comment on the Joint System's progress towards meeting Minnesota's greenhouse gas emissions reduction plan in reply comments.

B. OVERALL PLANNING APPROACH

On page 2-1 of its filing, the Joint System states:

> The primary function of an IRP is to demonstrate how a utility plans to meet the electrical needs of its end-use consumers over the next 15 years. The resource plan includes the resource and demand side options that best fit the utility's forecasted energy requirements.

In its previous IRP, the Joint System projected that it needed new resources. The Department previously concluded that the Joint System's IRP failed to evaluate properly what resource options would lead to the least-cost plan of meeting its member customers' future energy needs. However, in the instant IRP the Joint System and Department agree that the Joint System has no resource needs during the planning period. In fact, the Department's review of the Joint System's resource needs indicates that Minnkota and NMPA will be able to sell excess capacity and energy throughout the planning period. In the event that the Joint System's member/customer needs grow sufficiently in the future or if existing generation resources need to be retired,[2] the Department recommends that the Joint System be prepared to conduct capacity expansion modeling that meets Minnesota requirements for a certificate of need, including appropriate modeling to reflect the preference for a renewable facility.[3]

C. ENERGY AND DEMAND FORECAST

The Department initially performed a limited review of the Joint System's forecast to answer three questions:

1. Is there any evidence of past errors in forecast?
2. Is there any evidence of volatility in results from forecast to forecast?
3. Is there any evidence of methodological issues observed by the Department in past reviews?

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[2] In its October 2010 publication entitled 2010 Special Reliability Scenario Assessment: Resource Adequacy Impacts of Potential U.S. Environmental Regulations, the North American Electric Reliability Corporation (NERC) projected that the implementation of four new environmental rules could result in the loss of up to 19 percent of existing fossil fuel-fired steam capacity in the United States by 2018.
[3] Specifically, Minn. Stat. §216B.2422, subd. 4 states that "[t]he Commission shall not approve a new or refurbished nonrenewable energy facility in an integrated resource plan . . . unless the utility as demonstrated that a renewable facility is not in the public interest."

The purpose of the initial review was to determine if a more detailed forecast analysis was necessary, given the time and resources available for the Joint System's IRP and the fact that the Joint System projects no need to add resources over the planning period. Below are the results of the Department's initial forecast review.

1. Forecasts vs. Actuals

a. Energy Forecasts

In the Petition's Appendix G - *Minnkota Power Cooperative's 2013 Load Forecast Study*, at Appendix E (contained within Appendix G), Minnkota provided a table with each energy forecast (Comparison with Previous Forecast Results - Total Member System Energy Requirements) from the 1995 forecast through the 2013 forecast. The Department compared the results of the past five Joint System energy forecasts (2003, 2005, 2007, 2009, and 2011) as shown in Figure 1 below.

Figure 1: Comparing Joint System Forecasts to Actual Sales

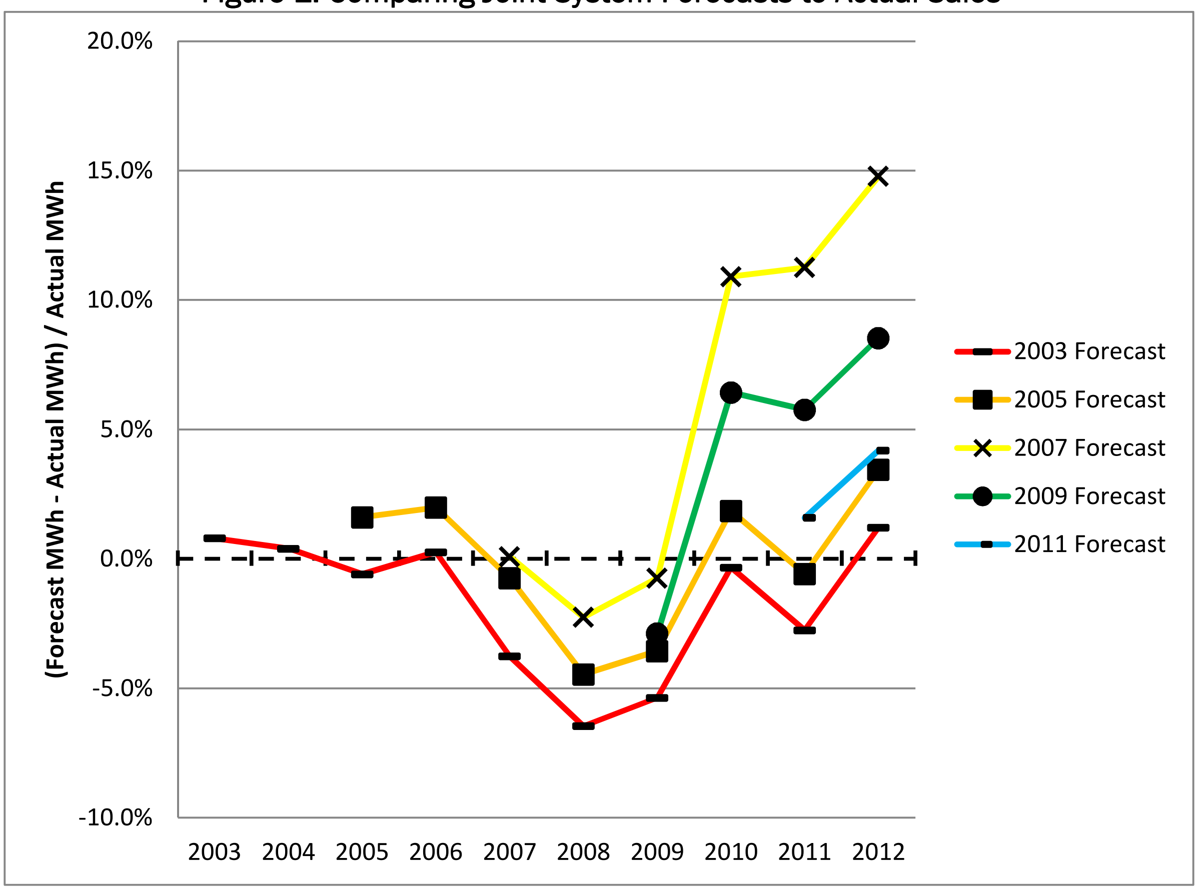


Figure 1 shows percentage differences between forecasted and actual sales; a positive percentage indicates that forecasted sales were higher than actual sales (the forecast overestimated actual sales), whereas a negative percentage indicates that the forecast underestimated actual sales. The results demonstrate that the variation between the more recent forecasts (2007 and on) and actual total system energy tend to be too high in the

2010 to 2012 time frame. Further, actual sales in 2012 were lower than any of the forecasts, although the 2003 forecast came the closest to estimating 2012 sales.

b. Demand Forecasts

The Joint System has been a winter-peaking system. However, because it is important to understand both major seasons in resource planning, the Department assesses how well the Joint System is able to forecast load in both seasons. Overall for the demand forecast comparison, the Department used the Joint System's annual filings with the Department under Minnesota Rules 7610.[4] The differences between the recent demand forecasts (2007 to 2011) and actual peak demand are shown below in Table 1 (summer season) and Table 2 (winter season).[5] Again, a positive number indicates that the forecast overestimated actual peak demand while a negative number indicates that the forecast underestimated peak demand. Because underestimations raise potential concerns about the ability to meet the needs of the Joint System, negative numbers are highlighted below.

Table 1: Demand Forecast vs. Actual—Summer Season

	Difference in MW (Forecast - Historical)				
Year	2011 Forecast	2010 Forecast	2009 Forecast	2008 Forecast	2007 Forecast
2008					(4)
2009				(8)	(8)
2010			(47)	(6)	(6)
2011		(21)	(21)	24	24
2012	(65)	(37)	(37)	10	10
	Percent Difference in MW (Forecast - Historical)/Historical				
	2011 Forecast	2010 Forecast	2009 Forecast	2008 Forecast	2007 Forecast
2008					-0.8%
2009				-1.5%	-1.5%
2010			-8.2%	-1.0%	-1.0%
2011		-3.7%	-3.7%	4.2%	4.2%
2012	-10.9%	-6.2%	-6.2%	1.7%	1.7%

Table 1 shows that the summer season difference between forecast and actual were typically negative in more recent forecasts (actual greater than forecast), with the most recent forecast being the least able to estimate actual summer sales in 2012. This result may indicate that summer load is growing in a way that the Joint System has been unaware (such as increased installations or use of air conditioning in hotter-than-expected weather)

[4] The Department used the 7610 forecasts because Minnkota's Power Requirements Study in the Petition's Appendix G did not contain data on a sufficient number of past demand forecasts.
[5] Note that the Department is comparing forecast assuming normal weather to actuals under actual weather (not weather normalized). The Department is using this test to determine if Minnkota's forecasts are sufficiently different from actual demand as experienced by Minnkota's system to cause concern.

or some other factor. The Joint System has more than sufficient resources available to meet summer load, but should improve its forecast of summer peak load.

Table 2: Demand Forecast vs. Actual—Winter Season

Year	Difference in MW (Forecast - Historical) 2011 Forecast	2010 Forecast	2009 Forecast	2008 Forecast	2007 Forecast
2008					(62)
2009				(14)	(14)
2010			79	86	86
2011		53	53	59	59
2012	36	73	73	75	75
Year	**Percent Difference in MW (Forecast - Historical)/Historical 2011 Forecast**	**2010 Forecast**	**2009 Forecast**	**2008 Forecast**	**2007 Forecast**
2008					-6.9%
2009				-1.5%	-1.5%
2010			9.2%	10.0%	10.0%
2011		5.9%	5.9%	6.6%	6.6%
2012	4.0%	8.2%	8.2%	8.4%	8.4%

Table 2 shows that the more recent forecasts have tended to be above recent actuals; however, the difference between forecast and actual for the winter season is also relatively small: the average forecast was over actual by 48 MW or 5.4 percent. There are a number of reasons that a forecast will differ from actual. Among the reasons will be weather (hotter or cooler than expected), the economy (higher or lower economic growth than expected), and an error in the forecast process. The most important question is whether the Joint System has enough resources to meet peak need under winter conditions.

While the information above indicates that the Joint System has done well in forecasting peak needs in the years shown above, it would be helpful for the Joint System to show in reply comments the comparison between forecasted and actual winter demands for 2013 and 2014.

c. Overall Summary

In summary, the Department concludes that, considering the Cooperative's forecasted capacity surplus, the forecasts have not differed from actuals in a manner that indicates a detailed forecast analysis is warranted at this time. However, the Department requests that the Joint System show in reply comments the comparison between forecasted and actual winter demands (energy sales and peak demand) for 2013 and 2014.

2. *Volatility from Forecast to Forecast*

a. *Energy Forecasts*

As suggested in Figure 1 above, the Joint System's energy forecast varied noticeably over the varying changes in economic growth in recent years. The annual differences between the current energy forecast (the 2013 forecast), which is the lowest of all of the recent forecasts, and the average of recent past forecasts are shown below in Table 3 below.

Table 3: 2013 Forecast vs. Recent Past Forecasts—Energy (MWh)

		2007-2013 Forecasts						
Year	2013 Forecast	Max	Average	Min	Range	%* Range	2013 Minus Average	% Diff.
2014	3,755,668	4,236,106	3,957,584	3,755,668	480,438	12%	-201,916	-5.1%
2015	3,828,298	4,323,620	4,029,075	3,828,298	495,322	12%	-200,777	-5.0%
2016	3,932,290	4,399,861	4,106,694	3,932,290	467,571	11%	-174,404	-4.2%
2017	3,996,395	4,491,652	4,179,737	3,996,395	495,257	12%	-183,342	-4.4%
2018	4,065,169	4,570,844	4,252,569	4,065,169	505,675	12%	-187,400	-4.4%
2019	4,131,135	4,658,073	4,329,111	4,131,135	526,938	12%	-197,976	-4.6%
2020	4,205,276	4,748,679	4,408,757	4,205,276	543,403	12%	-203,481	-4.6%
2021	4,279,406	4,852,197	4,492,953	4,279,406	572,791	13%	-213,547	-4.8%
2022	4,359,487	4,956,505	4,577,560	4,359,487	597,018	13%	-218,073	-4.8%

*Percent of average of the range.

Table 3 shows that the recent energy forecasts have a range of about 500 GWh in any one year or about 12 to 13 percent. However, the current energy forecast is lower than the average of recent past forecasts by about 4 to 5 percent. That is, the current summer demand forecast is not at an extreme (high or low) but is somewhat lower than average.

b. *Demand Forecasts*

The differences between the current demand forecast (the 2013 forecast) and recent past forecasts are shown below in Table 4 (summer season) and Table 5 (winter season).

Table 4: 2013 Forecast vs. Recent Past Forecasts—Summer Season MW

Year	2013 Forecast	2007-2013 Forecasts Max	Average	Min	Range	% Range	2013 Minus Average
2014	582	629	584	542	87	15%	(2)
2015	589	641	593	546	95	16%	(4)
2016	599	651	601	552	99	16%	(2)
2017	608	664	611	558	106	17%	(3)
2018	619	674	620	563	111	18%	(1)
2019	627	686	630	569	117	19%	(3)
2020	636	699	640	575	124	19%	(4)
2021	644	713	650	582	131	20%	(6)
2022	653	727	660	589	138	21%	(7)

Table 5: 2013 Forecast vs. Recent Past Forecasts—Winter Season MW

Year	2013 Forecast	2007-2013 Forecasts Max	Average	Min	Range	% Range	2013 Minus Average
2014	950	1,001	979	949	52	5%	(29)
2015	960	1,018	991	957	61	6%	(31)
2016	974	1,038	1,006	966	72	7%	(32)
2017	988	1,058	1,021	977	81	8%	(33)
2018	1004	1,078	1,036	987	91	9%	(32)
2019	1015	1,097	1,051	998	99	9%	(36)
2020	1028	1,118	1,066	1,009	109	10%	(38)
2021	1040	1,138	1,082	1,020	118	11%	(42)
2022	1055	1,159	1,099	1,031	128	12%	(44)

Tables 4 and 5 show that the recent summer forecasts have had a wide range of forecasts over the period considered, but the current forecast is not materially different than the average of recent past forecasts. That is, the current summer demand forecast is not at an extreme (high or low). The recent winter forecasts, which again reflect the overall peak of the Joint System, also have a wide range, but somewhat smaller than the summer forecasts. In this case the current winter forecast, while not at the extreme, is significantly lower than the average of recent past forecasts.

In summary, Tables 4 and 5 show that the current forecasts are not extreme by the standards of recent past forecasts. As noted above, it will be helpful to compare the peak forecasts with the actual peak in 2014.

c. Overall Summary

In summary, there is no evidence that the current (2013) forecast has produced a result that is extreme by the standard of recent past forecasts.

3. Methodological Issues

a. Most Recent Comments

The Department made the following forecasting recommendations in our December 29, 2010 comments in Docket No. ET6,ET6132/RP-10-782, with four main recommendations regarding The Joint System's forecast. The Department's recommendations were that the Joint System should:

- explore using econometric estimation for customers in the large commercial class on a going-forward basis;
- explore, in its next IRP filing, alternative regression analyses that will increase the number of observations used in its forecast models; and
- discuss in its next IRP how the Joint System would address a scenario of unusual population growth outside the member cooperative's service area in the county.

That is, the Department's comments in The Joint System's prior IRP did not find significant methodological issues, but suggested different ways to improve the Joint System's forecast process. That is, the Department concluded that the forecast was reasonable for planning purposes.[6] The Department's overall observation at this time is that the Joint System appears to have been trying to make its forecasts more accurate; the Department strongly encourages the Joint System to focus on this important task to help ensure that the Joint System has adequate resources to serve the needs of its members/customers in both the summer and the winter.

b. Overall Summary

The Department's most recent comments on the Joint System's forecast contained suggestions for improvement but did not identify any fatal flaws or methods that had to be changed at this time.

4. Recommendation

Given the lack of evidence of forecasted values being significantly different from actuals, a reasonable level of stability in the forecasts, and lack of evidence of methodological issues, the Department did not perform a detailed analysis of the Joint System's IRP forecast. The Department recommends that the Commission accept the Joint System's forecast for planning purposes. However, the Department also recommends that Joint System show in

[6] That is, if the Joint System were to file a certificate of need for Minnesota, the forecasts would need to be examined more thoroughly.

reply comments the comparison between forecasted and actual winter demands (energy sales and peak demand) for 2013 and 2014.

E. PLANNING

1. Introduction

Figure 2 below illustrates the Commission's energy facility planning and permitting process as it applies to a cooperative such as the Joint System. Since the Commission has no role in setting rates for such systems, there are only three steps, which are, briefly:

1. Resource Planning: jointly determine the least-cost:

    - size, type, and timing of the expansion units;
    - renewables expansion plan;
    - appropriate level of demand-side management (DSM) in the expansion plan;

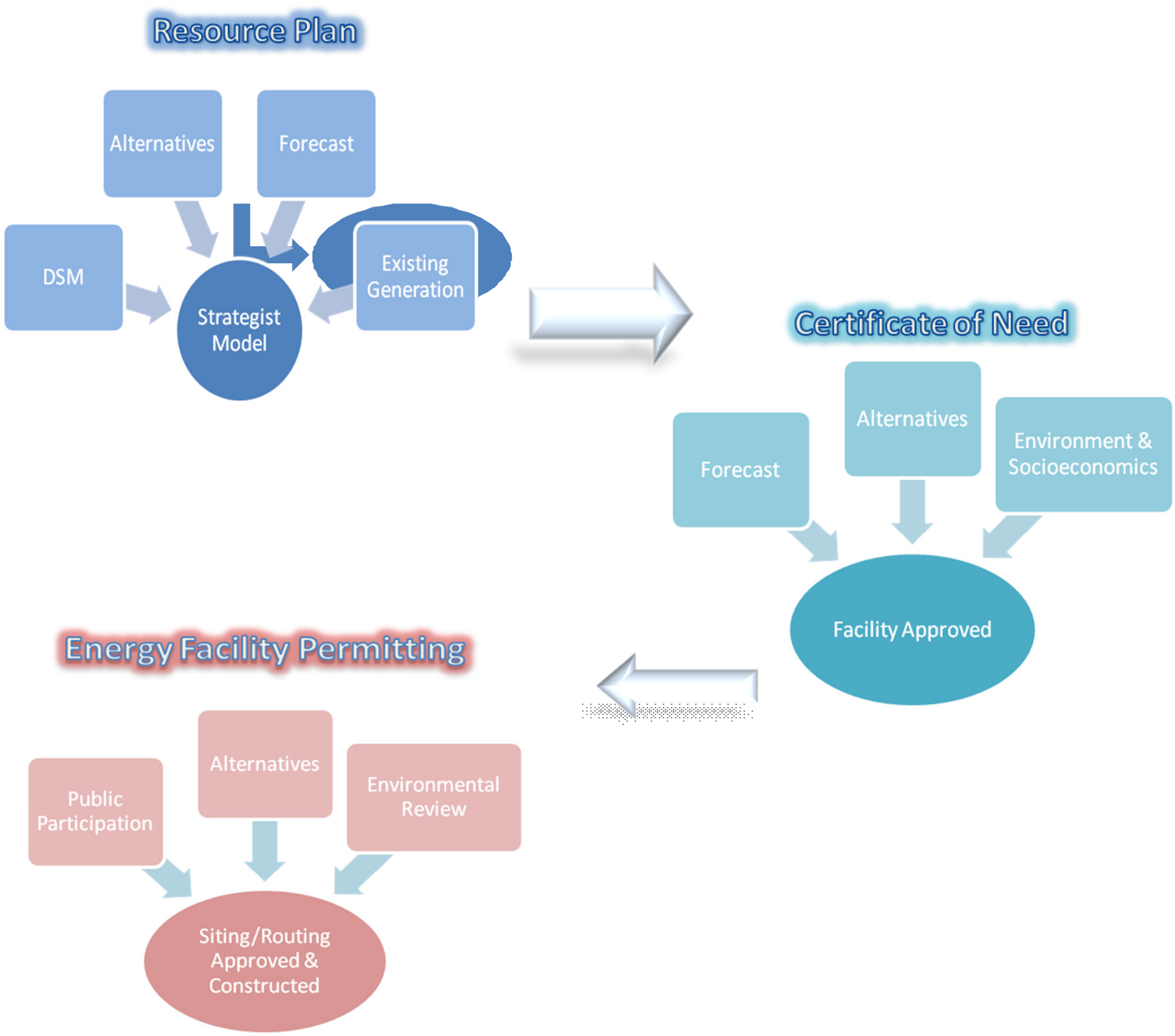
2. Certificate of Need:

    - determine least cost facility to meet the IRP-determined size, type, and timing;

3. Energy Facility Permitting:

    - determine best site/route for the CN-determined facility.

Figure 2: Commission Process for Cooperative Utility



The Joint System did not perform capacity expansion modeling of the Joint System's system. Due to the Joint System's lack of need for new generation resources in the five-year action plan window, the Department did not create its own model of Minnkota's system using the Strategist capacity expansion model. However, the Department reviewed the Joint System's analysis.

2. *Overview of the Joint System's Analysis*

When determining the best mixture of future resources the Department recommends the use of a capacity expansion model, which models the forecast, finances, existing resources and potential resources of a utility's system. The model goes through thousands of iterations to determine which mixture of resources would provide the best and most robust expansion plan. That is, the inputs to the model can be varied to determine the best expansion plan under a variety of assumptions.

In contrast, the Joint System conducted a more basic analysis to characterize the type of resources needed. First, the Joint System reviewed the Cooperative's load and capability report. The Joint System concluded that the Cooperative will have sufficient resource capacity to serve its firm load during the next 15 years.[7] Next the Joint System reviewed the Cooperative's energy situation. The Joint System calculated the expected energy production of the Cooperative's existing units, its members' energy allocations from WAPA and the energy expected to be received under PPAs with wind generation facilities. The Joint System compared that amount to its energy forecast, resulting in estimated gaps between expected production and the forecast—which would be acquired via purchases from the MISO energy market—ranging from a low of 0.2% to a high of 5.4% of its total annual energy requirements.[8]

In brief, the Joint System's analysis is that the Cooperative will have surplus capacity for the next 15 years and that any energy requirements will be minimal and easily managed via participation in MISO's energy market.

The Department notes that the Petition did not use the Commission's environmental cost values.[9] However, the Joint System did not perform any economic analysis within the Petition. Minnesota Statutes §216B.2422, subd 3 (a) states "A utility shall use the values established by the commission in conjunction with other external factors, including socioeconomic costs, *when evaluating and selecting resource options* in all proceedings before the commission, including resource plan and certificate of need proceedings" emphasis added. Since the Joint System did not evaluate resource options and given the lack of any resource needs during the planning period, the Commission may conclude that this oversight, while technically not in compliance with Minnesota Statutes §216B.2422, subd 3 (a), can be remedied in the Joint System's next IRP. That is, the Commission could put the Joint System on notice that its future IRPs must explain how the Cooperative used the Commission-approved externality values.

3. Recommendation

Given that the Joint System does not forecast the need for any new resources during the planning period, the Commission may conclude that this oversight can be remedied in the Joint System's next IRP. That is, the Commission could put the Joint System on notice that its future IRPs must explain how the Cooperative used the Commission-approved externality values. In future resource plans that require resource additions the Department recommends that the Cooperative not only use the Commission-approved externality values, but also consider using a capacity expansion model to evaluate the best resource additions.

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[7] See section 2.2 of the resource plan.
[8] See sections 2.3 and 7.2 of the resource plan.
[9] See section 16 of the resource plan for Minnkota's discussion of environmental cost values.

F. DEMAND-SIDE RESOURCES

The Joint System greatly improved its energy conservation programming and reporting of energy savings over the past three IRPs. Table 6 below shows the Joint System's energy savings for 2011-2013 as reported in Docket No. E,G999/CIP-13-1112.

Table 6: Joint System Energy Savings 2011-2013

2011 (kWh)	**2012 (kWh)**	**2013 (kWh)**
25,050,178	26,700,330	27,079,360

The Joint System met the State's 1.5 percent energy savings goal for each of these years.

The Joint System's five-year plan includes attempts to continue to develop new programs. Some new programs will be needed over time for the Joint System to maintain compliance with the State energy savings goal. Moreover, additional energy savings can enable the Joint System to reduce its energy purchases from MISO (which are already minimal compared to many Minnesota utilities.)

Table 7 below shows the Joint System's summer and winter peak demand savings.

Table 7: Joint System's Summer and Winter Peak Demand Savings

	Summer (MW)	Winter (MW)
2014	88	370
2015	90	375
2016	92	380
2017	94	385
2018	96	390
2019	98	395
2020	100	400
2021	102	405
2022	104	410
2023	106	415
2024	108	420
2025	110	425
2026	112	430
2027	114	435
2028	116	440

As noted above, the Joint System is a winter peaking entity. The Joint System is not a member of MISO and plans for its system peak rather than for MISO's summer peak. Thus it is reasonable that the Joint System's winter demand response resources are approximately four times the size of its summer demand response resources. As shown in Table 7 above, the Joint System projects that its summer MW will grow by approximately 2 MW per year and that its winter demand response resources will grow by 5 MW per year.

The Department concludes that the Joint System's demand resources are reasonable and encourages the Joint System to continue with its plan to investigate new opportunities.

F. COMPLIANCE WITH THE RENEWABLE ENERGY OBJECTIVE

1. Background

Prior to the 2007 Legislative Session, Minn. Stat. §216B.1691 required utilities to make a good faith effort to obtain 15 percent of their Minnesota retail sales from eligible energy technologies by 2015, and to obtain 0.5 percent renewable energy from biomass technologies. The 2007 Minnesota Legislature amended Minn. Stat. §216B.1691 to include a Renewable Energy Standard (RES) beginning in 2010. As amended, Minn. Stat. §216B.1691, subd. 2 sets forth the Renewable Energy Objective in place through 2010 and requires that:

> Each electric utility shall make a good faith effort to generate or procure sufficient electricity generated by an eligible energy technology to provide its retail customers or the retail customers of a distribution utility to which the electric utility provides wholesale electric service so that commencing in 2005, at least one percent of the electric utility's total retail electric sales to retail customers in Minnesota is generated by eligible energy technologies, and seven percent of the electric utility's total retail electric sales to retail customers in Minnesota by 2010 is generated by eligible energy technologies.

Minn. Stat. §216B.1691, subd 2a establishes the Renewable Energy Standard utilities must meet through 2025 and specifically requires that:

> … each electric utility shall generate or procure sufficient electricity generated by an eligible energy technology to provide its retail customers in Minnesota, or the retail customers of a distribution utility to which the electric utility provides wholesale electric service, so that at least the following standard percentages of the electric utility's total retail electric sales to retail customers in Minnesota is generated by eligible energy technologies by the end of the year indicated:

2012	12 percent
2016	17 percent
2020	20 percent
2025	25 percent

The statute no longer requires that a portion of the renewable energy generation come from biomass technologies. An eligible energy technology is defined by Minn. Stat. §216B.1691, subd. 1 as an energy technology that:

> Generates electricity from the following energy sources: (1) solar; (2) wind; (3) hydroelectric with a capacity of less than 100 megawatts; (4) hydrogen, provided that after January 1, 2010, the hydrogen must be generated from the resources listed in this clause; or (5) biomass, which includes without limitation, landfill gas, an anaerobic digester system, and an energy recovery facility used to capture the heat value of mixed municipal solid waste or refuse-derived fuel from mixed municipal solid waste as a primary fuel.

Minn. Stat. §216B.1691, subd. 2(d) directs the Commission to "issue necessary orders detailing the criteria and standards by which it will measure an electric utility's efforts to meet the renewable energy objectives of subdivision 2 to determine whether the utility is making the required good faith effort."

The Commission set forth the criteria for determining compliance with the RES Statute after taking comments from effected parties in a number of Orders.[10] Among the resources the Commission determined to be ineligible for meeting the RES are resources used for green pricing, resources that do not meet the statutory definition of eligibility, and generation assigned to compliance for other regulatory purposes such as another state's Renewable Portfolio Standard Requirements (RPS).

The 2007 amendment to Minn. Stat. §216B.1691, subd. 4 required the Commission to establish a program for tradable Renewable Energy Credits (RECs) by January 2008, and to require all electric utilities to participate in a Commission-approved REC tracking system once such a system was in operation.

The Commission subsequently adopted the use of the Midwest Renewable Energy Tracking System (M-RETS), a multi-state REC tracking system, as the REC tracking system under

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[10] *In the Matter of Detailing Criteria and Standards for Measuring an Electric Utility's Good Faith Efforts in Meeting the Renewable Energy Objectives Under Minn. Stat. §216B.1691,* Docket No. E999/CI-03-869, Initial Order Detailing Criteria and Standards for Determining Compliance with Minn. Stat. §216B.1691 and Requiring Customer Notification by Certain Cooperative, Municipal, and Investor-Owned Distribution Utilities. (June 1, 2004)
In the Matter of Detailing Criteria and Standards for Measuring an Electric Utility's Good Faith Efforts in Meeting the Renewable Energy Objectives Under Minn. Stat. §216B.1691, Docket No. E999/CI-03-869; *In the Matter of a Commission Investigation into a Multi-State Tracking and Trading System for Renewable Energy Credits,* Docket No. E999/CI-04-1616, Second Order Implementing Minn. Stat. §216B.1691, Opening Docket to Investigate Multi-State Program for Tracking and Trading Renewable Credits and Requesting Periodic Updates from Stakeholder Group; (October 19, 2004)
In the Matter of Detailing Criteria and Standards for Measuring an Electric Utility's Good Faith Efforts in Meeting the Renewable Energy Objectives Under Minn. Stat. §216B.1691, Docket No. E999/CI-03-869, Order After Reconsideration (August 13, 2004)

Minn. Stat. §216B.1691, subd. 4(d) and required Minnesota utilities to participate.[11] Specifically, the Commission required utilities to complete the online registration process and sign the Terms of Use agreement with the M-RETS system administrator APX, Inc, and receive account approval from APX by January 1, 2008. In addition, the Commission directed utilities to make a substantial and good faith effort to create a system account and sub-accounts for its organization, and to register its generation units/facilities in the M-RETS system by March 1, 2008.

In its December 18, 2007 *Order Establishing Initial Protocols for Trading Renewable Energy Credits,* the Commission adopted a four-year shelf life for all renewable energy credits to be used for compliance with the Minnesota RES. A four-year shelf life allows a REC to be retired towards MN RES compliance in the year of generation and during the four years following the year of generation.

Finally, in its December 3, 2008 *Third Order Detailing Criteria and Standards for Determining Compliance under Minn. Stat. §216B.1691 and Setting Procedures for Retiring Renewable Energy Credits*, the Commission directed utilities to begin retiring RECs equivalent to one percent of their Minnesota annual retail sales for the 2008 and 2009 compliance year by May 1st of the following year. Upon retirement, RECs are transferred into a specific Minnesota RES retirement account and, once retired, are not available to meet other state or program requirements, thus addressing the statutory prohibition against double counting the RECs and promoting the environmental benefits of renewable energy. The Commission further directed the utilities to submit a compliance filing demonstrating their compliance with the RES by June 1st.

In addition to amending the RES Statute, Minn. Stat. §216B.241, subd. 1c(b) was added to establish an energy-savings goal as part of a utility's conservation improvement plan (CIP), and states:

> Each individual utility and association shall have an annual energy-savings goal equivalent to 1.5 percent of gross annual retail energy sales unless modified by the commissioner under paragraph (d). The savings goals must be calculated based on the most recent three-year weather normalized average.

The attainment of the 1.5 percent energy savings goal will reduce a utility's forecasted retail sales, and consequently lower the amount of renewable generation required to meet RES obligations.

[11] *In the Matter of a Commission Investigation into a Multi-State Tracking and Trading System for Renewable Energy Credits,* Docket No. E999/CI-04-1616, Order Approving Midwest Renewable Energy Tracking System (M-RETS) Under Minn. Stat. §216B.1691, subd. 4(d), and Requiring Utilities to Participate in M-RETS (October 9, 2007)

2. The Joint System's Renewable Obligation

In addition to its Minnesota RES requirement the Joint System will be subject to a 10 percent REO in North Dakota beginning in 2015. Table 8, below, summarizes The Joint System's RES and REO obligations for Minnesota and North Dakota over the forecast period.

Table 8: The Joint System's Renewable Energy Objective

Year	MN Retail Sales	RES MN %	RES MN RES (MWhs)	ND Retail Sales	ND REO %	ND REO (MWhs)
2013	1,618,100	12%	194,172			
2014	1,768,230	12%	212,188	2,297,767		
2015	1,778,898	12%	213,468	2,340,904	10%	234,090
2016	1,795,008	17%	305,151	2,400,666	10%	240,067
2017	1,813,925	17%	308,367	2,452,351	10%	245,235
2018	1,835,425	17%	312,022	2,510,419	10%	251,042
2019	1,851,511	17%	314,757	2,555,271	10%	255,527
2020	1,868,499	20%	373,700	2,604,254	10%	260,425
2021	1,890,595	20%	378,119	2,643,408	10%	264,341
2022	1,918,680	20%	383,736	2,687,306	10%	268,731
2023	1,940,241	20%	388,048	2,733,758	10%	273,376
2024	1,962,259	20%	392,452	2,776,394	10%	277,639
2025	1,986,070	25%	496,518	2,814,319	10%	281,432
2026	2,001,421	25%	500,355	2,858,496	10%	285,850
2027	2,014,731	25%	503,683	2,891,098	10%	289,110
2028	2,026,812	25%	506,703	2,927,164	10%	292,716

Over the forecast period, the Joint System's Minnesota RES requirement increases from 194,172 MWhs in 2013 to an estimated 506,703 in 2028. For North Dakota, the Joint System's REO increases from 234,090 MWhs beginning in 2015 to 292,716 in 2028.

3. RES Compliance

The Joint System relies primarily on PPAs for generation from the Langdon and Ashtabula North Dakota wind projects. The Cooperative has contracted for generation from a total of 357 MW wind at these two facilities. Assuming a 40 percent capacity factor for these wind facilities, the Joint System is expected to obtain approximately 1,250,928 MWh in annual renewable generation to use towards its RES obligations in Minnesota and North Dakota. To date, the Cooperative has been selling excess RECs, and consequently does not have a significant REC balance to carry forward for future use. Nonetheless, the Joint System should have sufficient annual renewable generation to meet its RES requirements in both Minnesota and North Dakota throughout the planning period, as shown in Table 9 below.

Table 9: RES Compliance

Year	MN & ND REO/RES Requirement MWh	The Joint System Existing Renew. Generation (MWh)	Existing Generation less RES Req. Surplus/ (Deficit) MWh
2014	212,188	1,250,928	1,038,740
2015	447,558	1,250,928	803,370
2016	545,218	1,250,928	705,710
2017	553,602	1,250,928	697,326
2018	563,064	1,250,928	687,864
2019	570,284	1,250,928	680,644
2020	634,125	1,250,928	616,803
2021	642,460	1,250,928	608,468
2022	652,467	1,250,928	598,461
2023	661,424	1,250,928	589,504
2024	670,091	1,250,928	580,837
2025	777,949	1,250,928	472,979
2026	786,205	1,250,928	464,723
2027	792,793	1,250,928	458,135
2028	799,419	1,250,928	451,509

G. ENVIRONMENTAL ISSUES

1. Regional Haze

The Joint System entered into an agreement with the Environmental Protection Agency (EPA) to install various control technologies to reduce NOx and SO_2 emissions at its Milton R. Young generation facility to settle alleged violations of the New Source Review provisions of the Clean Air Act. Under the consent decree, the Cooperative agreed to install Best Available Control Technology (BACT) as determined by the State of North Dakota. Following a dispute over whether the technology installed by the Joint System and supported by the State of North Dakota in its state implementation plan to reduce regional haze was appropriate, the EPA approved North Dakota's state implementation plan for reducing regional haze in March 2012, including BACT equipment. A petition for reconsideration by the National Parks Conservation Association and the Sierra Club of North Dakota's Regional Haze state implementation plan remains pending before the EPA.

2. Mercury

The EPA issued its final Mercury and Air Toxics (MATS) rule in 2012. The Joint System states that one of the difficulties it faces in meeting mercury emissions reduction is that the North Dakota lignite used by its generation facilities contains substantial elemental mercury (as opposed to other forms) that are particularly difficult to remove. The Cooperative indicates that it is continuing to explore appropriate technologies for use at its facilities. The Department requests that the Joint System provide an update on its plans to comply with MATS in reply comments.

3. Greenhouse Gas Emissions

The Department requests that the Joint System provide an update in reply on its ability to comply with the EPA's recently issued Clean Power Plan to reduce carbon emissions from existing power plants. Specifically, the Department requests that the Cooperative address its understanding of any reductions it may be required to make as part of North Dakota's reduction plan.

4. Minnesota Greenhouse Gas Emissions Reduction Goal

In 2013, the Minnesota Legislature passed amendments to Minnesota Statutes §216B.2422, subd. 4. The newly amended legislation now states (new language underlined):

> The commission shall not approve a new or refurbished nonrenewable energy facility in an integrated resource plan or a certificate of need, pursuant to section 216B.243, nor shall the commission allow rate recovery pursuant to section 216B.16 for such a nonrenewable energy facility, unless the utility has demonstrated that a renewable energy facility is not in the public interest. <u>The public interest determination must include whether the resource plan helps the utility achieve the greenhouse gas reduction goals under section 216H.02, the renewable energy standard under section 216B.1691, or the solar energy standard under section 216B.1691, subdivision 2f</u>.

On August 5, 2013, the Commission issued in all of the most recent IRPs, including that of the Joint System, a Notice of Information in Future Resource Plan Filings (Commission's Letter). The Commission Letter states, in part:

> **PLEASE TAKE NOTICE** that the Commission expects utilities to include in their resource plans filed after August 1, 2013 an explanation [of] how the resource plan helps the utility achieve the greenhouse gas reduction goals, renewable energy standard, and solar energy standard as listed in the above-

> referenced legislation. Parties should also be prepared to discuss the matter in comments.

Minnkota did not include the explanation on how its resource plan helps the utility achieve the greenhouse gas reduction goals, so on September 15, 2014 the Department sent DOC IR No. 3. At the time the Department was finalizing these comments the Joint System was working on a response. The Department will review the utility's response and discuss the utility's progress in meeting the State's greenhouse gas reduction goal in our reply comments, due December 27, 2014.

III. DEPARTMENT RECOMMENDATIONS

The Department recommends that the Commission consider accept the Joint System resource plan for planning purposes, but put the Joint System on notice that its future IRPs must explain how the Cooperative used the Commission-approved externality values.

The Department recommends that the Joint System provide the following in reply comments:

- the comparison between forecasted and actual winter demands (energy sales and peak demand) for 2013 and 2014,
- an update on the Joint System's plans to comply with MATS, and
- any other information that the Joint System believes is important for the Commission to consider.

The Department will provide written comments on the Joint System's progress towards meeting the State's greenhouse gas emissions reduction goal in reply comments. If any material issues surface based on the information in the Joint System's reply comments, the Department may request the opportunity to provide additional comments.

/ja

CERTIFICATE OF SERVICE

I, Sharon Ferguson, hereby certify that I have this day, served copies of the following document on the attached list of persons by electronic filing, certified mail, e-mail, or by depositing a true and correct copy thereof properly enveloped with postage paid in the United States Mail at St. Paul, Minnesota.

Minnesota Department of Commerce
Comments

Docket No. **ET6,ET6132/RP-14-526**

Dated this 27th day of October 2014

/s/Sharon Ferguson

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