Minnesota Public Utilities Commission

Staff Briefing Papers

Meeting Date: October 2, 2014..**Agenda Item **#5**

Company:	Utilities subject to Minnesota Statutes §216B.1691, Minnesota's renewable energy statute
Docket No.	**E-999/CI-11-852**
	In the Matter of Utility Renewable Energy Cost Impact Reports Required by Minnesota Statutes Section 216B.1691, Subd.2e.
Issue:	What uniform reporting system should the Commission adopt for Renewable Energy Standard rate impact reports under Minn. Stat. §216B.1691, Subd. 2(e)?
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Relevant Documents

Interstate Power and Light Company, Comments. .... December 19, 2013
Wind on the Wires, Initial Comments. .... December 20, 2013
Otter Tail Power Company, Comments. .... December 20, 2013
Joint Business Intervenors, Comments .... December 20, 2013
Xcel Energy, Initial Comments... . December 20, 2013
Missouri River Energy Services, Initial Comments .... December 20, 2013
Minnesota Power, Initial Comments... December 20, 2013
Department of Commerce, Initial Comments. .... December 20, 2013
Department of Commerce, Reply Comments .... January 27, 2014
Otter Tail Power Company, Reply Comments .... January 27, 2014
Xcel Energy, Reply Comments... January 27, 2014
Southern Minnesota Municipal Power Agency, Comments .... January 28, 2014
Missouri River Energy Services, Supplemental Comments. .... May 7, 2014
Joint Business Intervenors, Supplemental Comments .... May 8, 2014
Minnesota Power, Supplemental Comments .... May 8, 2014
Xcel Energy, Supplemental Comments .... May 8, 2014
Great River Energy, Supplemental Comments. .... May 8, 2014
Otter Tail Power, Supplemental Comments. .... May 8, 2014
Wind on the Wires, Supplemental Comments. .... May 9, 2014
Department of Commerce, Supplemental Comments. .... May 20, 2014

Xcel Energy, Response to Information Request. .... June 6, 2014

The attached materials are workpapers of the Commission Staff. They are intended for use by the Public Utilities Commission and are based upon information already in the record unless noted otherwise.

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Statement of the Issue

What uniform reporting system should the Commission adopt for Renewable Energy Standard rate impact reports under Minn. Stat. §216B.1691, Subd. 2(e)?

Background

Minn. Stat. §216B.1691 (the Minnesota Renewable Energy Statute, or RES) lays out the requirements for the RES, including the eligible technologies, the percentage of retail sales that must come from renewables, and the reporting requirements that each electric utility shall undergo with regard to the statute's objectives.

There are sixteen (16) utilities subject to Minnesota's RES:

- Basin Electric Power Cooperative
- Central Minnesota Municipal Power Agency
- Dairyland Power Cooperative
- East River Electric Cooperative, Inc.
- Great River Energy
- Heartland Consumers Power District
- Interstate Power and Light
- L&O Power Cooperative
- Minnesota Municipal Power Agency
- Minnesota Power
- Minnkota Power Cooperative, Inc.
- Missouri River Energy Services
- Northwestern Wisconsin Electric Company
- Otter Tail Power Company
- Southern Minnesota Municipal Power Agency
- Xcel Energy

Additionally, Subd. 2(b) of the RES enumerates the conditions under which the Commission can modify or delay the RES. Among other conditions, the Commission can consider modifying or delaying the RES if compliance imposes a significant rate impact, requires significant measures to address reliability, or raises significant technical issues.

No utility has filed a request for Commission consideration of delay or modification for RES compliance to date (commonly referred to as an "off ramp").[1] In the event a utility did request

[1] However, some utilities have indicated obstacles to meeting the RES in future years and have stated that they may request an "off ramp" in the future. For example: "If a satisfactory solution to the unintended consequences of poor wind energy economics isn't identified and implemented, and/or if the banking of RECs is eliminated or severely limited, and/or if energy recovery facilities are declassified as eligible energy technologies, GRE may need to evaluate requesting a delay of the standard from the Commission as set forth in Minn. Stat. §216B.1691, subd. 2a." GRE Biennial RES report, Docket E999/M-10-989, November 15, 2010.

an off ramp, according to Subd. 2(b), the utility "must file a plan to comply with its standard obligation in the same proceeding that it is requesting the delay."[2]

Minn. Stat. §216B.1691 Subd. 2(e), which was added to the statute in 2011, requires electric utilities subject to the RES to file reports with the Commission estimating the "rate impact of activities…necessary to comply with this section."[3] In late October, 2011, fifteen utilities filed their required reports in Docket E999/CI-11-852.

In January 2012, the Department of Commerce, Division of Energy Resources (the Department) submitted comments on the utilities' 2011 RES cost impact reports. The Department commented on the differences among the utilities' approaches for considering RES rate impacts, and observed that "RES compliance is generally cost effective for the utilities subject to Minnesota's RES Statute."[4] Overall, the Department concluded that the rate impact of the RES is "best determined through the resource planning process rather than through a simple comparison with market prices."[5] The Department supplanted its comments with a summary of results from recent integrated resource plan (IRP) analyses, further showing the utilities having been procuring renewable energy in a reasonable and cost-effective manner.

In the 2013 legislative session, Minn. Stat. §216B.1691 Subd. 2(e) was modified to require the Commission, in consultation with the Department, to devise a uniform RES rate impact reporting system.

On November 6, 2013, the Commission issued a Notice of Comment Period that included a staff "straw proposal" for a format for a uniform reporting system. The Notice solicited comment on the appropriate baseline year, which expenditures should be included in the analysis, and what avoided costs should be used as a basis for comparison. The Notice also proposed four "general guiding principles" to assist the Commission with developing the uniform reporting system. The proposed general guiding principles were:

1) *Foster transparency*, by using publicly available (or aggregated) information;
2) *Support consistency, coordination and non-burdensome administration*, by utilizing utilities' integrated resource planning, electric transmission planning, financial statements, FERC filings, tariffs and other already produced reports, documents or models including the biennial compliance reports required under Minn. Stat. §216B.1691, Subd. 3 (a);[6] annual qualifying facilities reports (e.g., Docket 13-09).
3) *Provide realistic representation of baseline, actual (to date) and future expected costs for achieving and maintaining standard compliance*, by using clearly identified and validly supported inputs, with limitations specifically noted;
4) *Enable comparison across utilities*, by using similar methodologies with easy to understand illustrations including narrative explanations of estimated rate impact of standard compliance for wholesale and retail rates, as applicable.

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[2] Minn. Stat. §216B.1691, Subd. 2b. (c)
[3] Minnesota Laws 2011, Chapter 97, Section 15, amends Minn. Stat. §216B.1691 by adding a Subdivision 2e.
[4] Department, January 25, 2012 comments on RES cost impact reports, at page 6.
[5] Ibid.
[6] See ORDER FINDING UTILITIES IN COMPLIANCE WITH MINN. STAT. §216B.1691 AND MODIFYING BIENNIAL REPORTING PROCEDURES, issued May 28, 2013, at pages 6-8.

The Notice also invited parties to propose alternative uniform reporting templates. A party submitting an alternative proposal was asked to explain the rationale for the proposal and to explain how it would address staff's proposed guiding principles.

In response to the Notice, nine parties filed comments. Two of them—Xcel Energy (Xcel) and the Department—offered RES rate impact templates, which are attached as appendices A and B, respectively. On April 18, 2014, the Commission opened a supplemental comment period, in which parties were invited to comment on the proposals put forth by Xcel and the Department.

Statute

Staff Comment

Staff's analysis in this case is guided by its interpretation of the statutory language provided in Minn. Stat. §216B.1691, Subd, 2e. As amended, the section reads:

> Subd. 2e. Rate impact of standard compliance; report.
> Each electric utility must submit to the commission and the legislative committees with primary jurisdiction over energy policy a report containing an estimation of the rate impact of activities of the electric utility necessary to comply with this section. In consultation with the Department of Commerce, the commission shall determine a uniform reporting system to ensure that individual utility reports are consistent and comparable, and shall, by order, require each electric utility subject to this section to use that reporting system. The rate impact estimate must be for wholesale rates and, if the electric utility makes retail sales, the estimate shall also be for the impact on the electric utility's retail rates. Those activities include, without limitation, energy purchases, generation facility acquisition and construction, and transmission improvements. An initial report must be submitted within 150 days of May 28, 2011. After the initial report, a report must be updated and submitted as part of each integrated resource plan or plan modification filed by the electric utility under section 216B.2422. The reporting obligation of an electric utility under this subdivision expires December 31, 2025, for an electric utility subject to subdivision 2a, paragraph (a), and December 31, 2020, for an electric utility subject to subdivision 2a, paragraph (b).

Staff identifies four primary components of the statute that can guide Commissioners as they develop a uniform RES rate impact methodology:

- The methodology must be "uniform […] consistent and comparable" across all utilities filing the rate impact reports.
- The analysis must include, "without limitation, energy purchases, generation facility acquisition and construction, and transmission improvements."
- The "impact" is a *rate* impact, which includes both wholesale and retail rates, and ratemaking and least-cost planning are two different processes.
- Reports shall be "submitted as part of each integrated resource plan."

Overview of Briefing Papers

These briefing papers begin with a very brief summary of the two proposals, with a focus on the four main components the proposals share. This summary is followed by four sections that provide a more detailed description of the main components and the parties' positions on each. These are followed with a brief summary of two issues that require additional clarification.

The development of a uniform RES/SES rate impact methodology is a complex undertaking. While the Department's and Xcel's proposals have similar components, they have several important differences. Additionally, parties and staff offer many possible alterations to each. Staff recommends that commissioners reference the two proposals (appendices A and B) and the Decision Options as they read these briefing papers.

Parties' Proposals: Xcel Energy & the Department of Commerce

In their December 20, 2013 comments, Xcel and the Department each proposed a rate impact template for the RES and Solar Energy Standard (SES), which are attached as Appendices A and B.[7] Xcel's proposal received general support from Great River Energy (GRE), the Joint Business Intervenors (JBI), Missouri River Energy Services (MRES), and Wind on the Wires (WOW), although the parties provide various comments on, and modifications to, the proposal. The Department's proposal was supported by Minnesota Power (MP) and Otter Tail Power (OTP).

The templates have four main categories, which have been color-coded[8] by staff: rows shaded brown represent the RES/SES-related *generation*; rows shaded blue represent RES/SES-related *costs*; rows shaded purple represent *avoided costs* resulting from RES/SES generation; and rows shaded red use totals from previous sections to make *final calculations*. The basic premise of the proposals is simple: the costs that a utility has incurred in procuring renewable energy are compared to an estimate of what the utility would have otherwise paid to attain the same amount of energy and capacity. This produces an estimate of the total, net cost of the RES/SES in $/MWh or $/kWh.

While the templates are similar conceptually, they are very different in their specifics. One main difference is that Xcel's proposal is much more complex and detailed than the Department's. For example, where the Department's plan includes only one row each for RES/SES costs and avoided costs, Xcel's template divides them into components: Xcel's template separates RES/SES costs into direct, indirect, and transmission costs, and avoided costs are separated into avoided energy costs, avoided capacity costs, and avoided emissions costs. There are several other important differences between the plans, such as the timeframe for the analysis, the RES/SES costs that should be included, and the calculation of avoided costs; these will be discussed in more detail below.

[7] Appendix A is staff's rendition of the template originally proposed by Xcel. All changes were approved by the Company. In its December 20, 2013 comments, the Department described the principles of an alternative RES/SES rate impact template, which has been adapted by staff and attached as Appendix B.
[8] The color-coding system is not intended to equate corresponding rows of the two templates, but merely to aid readers in their comparison of the proposals.

<u>Staff Comment</u>

In the context of an RES/SES rate impact methodology, staff believes there is a fundamental tension between accuracy and transparency. In practice, the more accurate and precise the estimate of the rate impact of the SES or RES, the more utility-specific, trade secret information is required. This increases the administrative burden, reduces transparency, and impairs the inter-utility comparability of the rate impact estimates. Conversely, a simpler methodology using publically available inputs that are common to all utilities enhances transparency and comparability, but does so at the expense of accuracy and reliability.

In sum, the guiding principles are, to a degree, contradictory. This is not an oversight; rather, staff believes it is the direct result of the dual objectives of the task at hand: developing methodology that is both a reliable estimation of the rate impact of the RES and SES and an easily comprehensible, publically available tool that allows for comparisons between utilities. This can be thought of as a continuum, with transparency on one end and accuracy on the other:

Department's Proposal	Xcel's Proposal
← Transparency/Comparability	**Accuracy/Reliability →**

As proposed, the two templates sit on opposite sides of this continuum. Later, the briefing papers take a more detailed look at the parties' proposals. There are many potential modifications that could move each proposal in either direction along the continuum.

One way the Commission could contemplate the four main categories—generation, expenditures, avoided costs, and calculation method—is by addressing the four following questions sequentially:

1) Which facilities should be included in the methodology and over what time frame should they be evaluated?
2) What is the most appropriate way to calculate the costs of these facilities?
3) What is the most reasonable basis for comparison?
4) How should the costs and avoided costs be compared?

The next four sections address each of these questions in turn.

1. Calculating RES/SES Generation

Facilities to be Included

When calculating RES/SES generation, one must first determine which facilities should be included in the analysis. Xcel recommends that the cost of all facilities used to comply with the RES should be included in the rate impact calculation:

> [W]e have hydroelectric resources that were constructed in the early 1900s, refuse derived fuel (RDF) plants from the 1980s, and our first large-scale wind project came on line in 1992. While these resources were not acquired specifically for the purpose of RES compliance, their generation is counted towards our goal. If all renewables are not included in the calculation, the reporting template should

> provide clear and unambiguous guidance on which renewables should be included.[9]

The Department agrees with Xcel that the cost of all facilities currently being used to meet RES obligations should be included in the reporting system. However, the Department recommends that the utilities separate the costs of facilities acquired by utilities prior to 2005 from the costs of facilities acquired after 2005.[10]

Wind on the Wires (WOW) recommends including only the costs of facilities acquired since 2005 because those facilities "will capture existing renewable facilities placed in service in anticipation of the REO/RES and currently contributing to each utilities RES requirement."[11] In other words, WOW's approach would exclude the older hydroelectric facilities Xcel references in its recommendation to include all RES-included facilities.

Almost all parties recommend that the SES should be distinct from REO/RES requirements in this analysis. The only exception was MRES, which believes it would not be helpful to separate the costs of different standards and recommended costs be combined to decrease administrative burden.[12] Conversely, the Department suggests all types of renewable energy should be reported separately; thus, there would be a separate calculation for wind, hydro, solar, and biomass resources.[13]

<u>Staff Comment</u>

Staff believes that the relevant language of the statute—which calls for "an estimation of the rate impact of activities of the electric utility necessary to comply with this section"—could be read to support either position. However, staff believes that Xcel's and the Department's interpretation may produce unintended consequences. For example, MP, OTP, and Xcel each operate hydroelectric plants that were installed over a century ago. Under Xcel's template, which considers annualized costs from 2005 through the 15 years following the report, a utility would receive credit for all of the plants' generation in that year (through the avoided costs calculation), but the only costs included would be O&M. And under the Department's template, where costs are levelized over the life of the facility, the costs of these facilities would need to be levelized throughout their entire lifetime. Staff requests that the Department devote a portion of its comments at the upcoming agenda meeting to a discussion of how utilities should calculate the lifetime costs of these resources.

Timeframe

In the November 6, 2013 Staff Notice, Staff proposed a start date of 2005 out through 15 years from each utility's next filed IRP. JBI, WOW, and Xcel agree that the proposed 2005 start date and 15-year forecast period creates a reasonable time frame for the analysis.[14] Interstate Power

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[9] Xcel, December 20, 2013 comments, page 2.
[10] Department, January 27, 2014 comments, page 2.
[11] WOW, December 20, 2013 comments, page 2.
[12] MRES, December 20, 2013 comments, page 2.
[13] The Department's proposed calculation process is described in more detail on page 19 below.
[14] JBI clarifies that if the 2005 start year is used for the purpose of including costs incurred to meet the REO, as well as the RES, then JBI agrees 2005 is an appropriate start date.

& Light (IPL) also supports the proposed time frame. However, IPL notes that forecasting these impacts in future years depends on the results of IRP modeling which assume the Commission approves those revenue requirements.

The Department's template also uses a start date of 2005, but under its plan, costs and avoided costs would be compared throughout the entire *lifetime* of a renewable facility, not just its first 15 years. In addition, the Department observes that in order to begin the analysis with a 2005 start year, the Commission "may wish to obtain past information, either annually or in total, beginning with 2005."[15] Future filings, though, should include actual costs for the most recent year, along with estimates of future compliance costs.

MP states that, generally, the rate impact forecasts will be more consistent if aligned with procedures already established for resource planning purposes. As such, MP suggests the "future time period should consist of **the same five years as the IRP's short-term action plan**" (emphasis added).[16]

GRE notes that its first report under the statute in 2011 reflected 2010 costs.[17] As such, GRE interprets the statute to apply the same way in this instance, in other words, to establish a baseline for future RES cost impact reports. Thus, GRE "recommends the reports look forward **from the last reported year**" (emphasis added).[18] Under GRE's interpretation of the statute, forecasted RES cost impacts would be part of the IRP process. If a least cost resource plan does not meet the RES, the impact would be reflected in the difference between the least cost resource plan and a plan that meets the RES.

2. Calculating RES/SES Costs

Department of Commerce

Under the Department's proposal, the costs of the RES/SES are defined as the sum of all future payments under PPAs and all future revenue requirements associated with utility owned renewable energy projects. Per the three-step process described above, these costs would first be calculated individually for each type of renewable generation resource added in a given two-year period, then for all renewable resources added in that period, and finally for all renewable resources used to meet the RES/SES in that period.

The Department notes that some of these calculations may be trade secret: for example, if only one wind farm was added in a given period, the per-kWh cost will be considered trade secret. However, the Department argues that, in these cases, the per-kWh cost of all resources used to meet the RES/SES (the third calculation) would likely be public information.

[15] Department, December 20, 2013 comments, page 5.
[16] MP, December 20, 2013 comments, page 2.
[17] Staff notes that the 16 utilities' reports did not use consistent timeframes; by staff's count, 8 utilities provided data for past years, 7 provided data for future years, and 3 provided cost information for a single year.
[18] GRE, May 8, 2014 comments, page 2.

Staff Comment

Currently, the Department's proposal does not include a cost component for transmission costs. As discussed in the following section, transmission improvements are long-term investments that are made for a variety of reasons; staff believes that the allocation of a specific percentage of the cost of transmission investments to renewables will be contentious at best and specious at worst. Nevertheless, the statute clearly states that transmission investments must be included: "activities include, **without limitation**, energy purchases, generation facility acquisition and construction, and **transmission improvements**" (emphasis added). If the Commission is interested in adopting the Department's template, staff recommends it consider adding a component for transmission improvements. In addition, staff requests that the Department devote a portion of its comments at the upcoming agenda meeting to a discussion of whether and how transmission improvements could be incorporated.

Xcel Energy

Xcel's proposal considers three types of costs: direct, indirect, and transmission. Like the Department's, Xcel's template calculates direct costs as the sum of PPA payments for renewables and revenue requirements for utility-owned renewable facilities. Specifically, Xcel states that revenue requirements should include "O&M expenses, book depreciation expense, deferred taxes, current taxes, capital financing expenses, property taxes, insurance, and any tax credits or other subsidies."[19] For indirect costs, Xcel includes "[c]osts associated with integrating renewables, including but not limited to additional ancillary services and incremental costs associated with baseload cycling caused by intermittent resources ."[20] Finally, the template calls for an approximation of transmission expenses incurred in meeting the RES/SES. Xcel notes that transmission investments are made for many reasons, so the proposal asks the utility to provide documentation of the transmission projects and the percentage of the expenditure attributed to RES/SES compliance.

Several parties took issue with the proposal's treatment of indirect costs. MRES noted that the increased detail will result in increased administrative burden. GRE was generally supportive of the cost components included, but noted that many are difficult to measure; for example, GRE noted it has not identified baseload cycling or additional ancillary service costs. Accordingly, GRE recommend that "utilities be allowed some flexibility to include each cost in the template to the best of their ability, that is, that estimates be allowed, as long as they are so noted."[21] OTP argued that ancillary services and baseload cycling costs are "are incurred as a consequence of the resource mix as a whole," making it very difficult to accurately quantify the costs specifically attributable to the RES/SES.[22]

WOW and MRES also make similar arguments for the transmission cost component of Xcel's proposal. In WOW's words:

> In WOW's experience there are multiple reasons for transmission expansion including but not limited to renewable energy integration, reliability concerns, and

[19] Xcel, December 20, 2013 comments, Attachment A, page 1 of 2.
[20] Ibid., at page 4.
[21] GRE, May 8, 2014 comments, page 1.
[22] OTP, January 27, 2014 comments, pages 1-2.

> relieving congestion/economic needs. Renewable energy is but one of the drivers for additional transmission. It is therefore critical the Commission determine (or agree upon a process with stakeholders) the necessary utility documentation used to decide what portion of transmission costs is renewables related as opposed to other factors.[23]

Staff Comment

Staff agrees with WOW's statement on transmission costs. It would be possible, should the Commission so desire, to develop a formula to assign a specific percentage of a utility's transmission investments to the RES/SES. However, the proportion of a transmission investment that is attributable to renewables will be specific to that investment, varying considerably from project to project. Accordingly, staff supports Xcel's proposed approach to calculating transmission costs. If any parties have recommendations to further improve this estimate, staff encourages them to include them in their comments at the upcoming hearing.

Joint Business Intervenors

JBI argue that there are a number of important costs of renewable generation that are not considered in either template. As JBI put it: "Increasing amounts of renewable resources in a utility's generation portfolio introduces more volatility and risk, which needs to be discussed and monetized by utilities to more realistically estimate the impact of activities to meet RES."[24] Specifically, JBI raise four issues: the calculation of transmission costs and fuel price variability, the inclusion of renewable intermittency risk, and the use of non-existent carbon price costs in modeling.

JBI's first argument is that Strategist modeling assumes that there are no transmission constraints. JBI argue that transmission constraints often force the curtailment of wind. For example, JBI cite MISO curtailment data, which show that in 2010 there were 2,117 curtailments in the MISO footprint totaling an estimated 824,000 MWh curtailed. Thus, JBI argue, models that assume a constraint-free system will over-value wind projects. JBI recommend that Strategist modeling be supplemented by the PROMOD model every fifth year to analyze transmission constraints.

The second issue raised by JBI is that current modeling—and both templates—do not include a cost component for the intermittency risk of renewable output. JBI argue that "there are costs associated with cycling existing units to accommodate wind that are overlooked and wind generates electricity when there is a surplus of supply resulting in negative prices."[25] Accordingly, JBI recommend that utilities use the PROMOD model to identify the variance in wind generation, which should then be monetized and included as a cost.

JBI's third argument is that current modeling practice includes a $21.50/ton carbon price adder in future years of IRPs. JBI argue that this is an "unrealistic assumption" that "biases the results towards adding certain types of generation, when in reality such resources may not result in the

[23] WOW, May 9, 2014 comments, page 1.
[24] JBI, December 20, 2013 comments, page 4.
[25] Ibid., at pages 9-10.

least cost plan."[26] Therefore, JBI conclude that these costs should not be included in the avoided emissions benefit (Row P) section of Xcel's proposal.

The final issue raised by JBI is that fuel price variability is not accurately accounted for in current modeling. As JBI put it:

> The price of fuel such as natural gas changes on an intra-day basis. Yet, the integrated resource planning models ignore this variability. While there are sensitivity analyses conducted to ascertain the impacts of dramatic increases to fuel prices, there is no explicit recognition of the risk associated with volatile fuel prices. For example, to the extent that natural gas price assumptions are overstated, the subsequent fuel cost savings associated with wind generation will also be overstated. JBI recommends that the fuel price variability risk be monetized in order to provide a more accurate and realistic representation of RES impacts.[27]

In response, Xcel and the Department argue that JBI's criticisms are misplaced. The Department believes that these criticisms would be more appropriately raised in a certificate of need proceeding than in this docket. Similarly, Xcel noted that it welcomes discussion of modeling issues, but believes these discussions "are more appropriate in the Resource Planning process where specifics related to modeling and assumptions are thoroughly reviewed."[28] In addition, both Xcel and the Department also provided brief, substantive rebuttals to JBI's modeling critiques.[29]

<u>Staff Comment</u>

The Department addresses many of these issues in "The Role of Resource Planning," which is included as Part II.C of its January 27, 2014 reply comments. Staff agrees with the Department's summary in its entirety, and does not repeat the Department's comments here. Staff does, however, provide additional comments on each of JBI's four complaints.

In response to JBI's first argument—that Strategist should be supplemented by PROMOD every fifth year—staff notes that Strategist and PROMOD are two different production cost software models that can be used for a variety of resource planning applications in the utility industry. Several Minnesota utilities use Strategist for their resource planning analysis, whereas MISO uses PROMOD for hourly, chronological unit commitment and dispatch. PROMOD allows for more operational granularity than Strategist, including production cost simulations for unit start-up, ramp rates, and minimum run/down times. This additional layer of operational granularity appears to be the reason JBI recommends PROMOD be run every five years.

The advantages and disadvantages of Strategist versus PROMOD are, in staff's view, of limited relevance in this proceeding. Thus, in lieu of a comparison of the two software packages here, staff includes as Appendix C to this document an Information Request (IR) response from

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[26] Ibid., at page 10.
[27] JBI, December 20, 2013 comments, pages 10-11.
[28] Xcel, January 27, 2014 comments, page 3.
[29] See, e.g.: Xcel, January 27, 2014 comments, page 3; Department, January 27, 2014 comments, pages 3-4; and Department, May 20, 2014 comments page 3.

Minnesota Power, provided in their most recently approved resource plan docket.[30] As noted in MP's response to the IR, MP is licensed to use Strategist, not PROMOD, for its resource planning analysis. It is staff's understanding that neither the Department nor any utility in the state is currently licensed to use PROMOD. Moreover, not all utilities that are required to file rate impact reports have a license to use Strategist. Staff requests that JBI devote a portion of its comments at the upcoming agenda meeting to answer the following questions: who will perform the PROMOD analyses? How much time will these analyses take? Is using PROMOD or Strategist modeling appropriate for this proceeding, given the "comparable, consistent, and uniform" language of the Statute?

Overall, staff is supportive of JBI's broader interest in acquiring more information to assist the decision-making process. In this case, however, staff questions the appropriateness of assessing costs to ratepayers to either acquire PROMOD or to pay a third party to run PROMOD. Staff could only support JBI's recommendation if it would come at minimal, reasonable cost to ratepayers. This would include any rate-regulated utility paying MISO to run the analysis for this proceeding.

To JBI's second point—that intermittency risk of renewable output should be included as a cost—staff agrees with JBI's claims that the Strategist model may fail to capture certain operational details, such as wind intermittency. Moreover, staff agrees that subsequent planning proceedings should attempt to capture reliability concerns for all resources, not just wind, especially as more variable renewable resources become a major contributor to generation.

However, staff notes that these discussions should exist within a regional context, given that Minnesota's generating resources are dispatched regionally. Attempting to model Minnesota in isolation, regardless of the power flow model which is used, will lead to inaccurate results without an entire RTO scope reflecting how MISO dispatches resources and how MISO adjusts to the intermittency of renewable resources.

In response to JBI's third argument—that the $21.50/ton carbon price adder should not be included—staff notes that there are several statutes and rules pertaining to IRP that require utilities to consider emissions and externalities.[31] Irrespective of the outcome of this proceeding, IRP will continue to factor emissions and externalities into the modeling because IRP is required to do so. However, it is up to the Commission to determine how they pertain to the rate impact calculation. Xcel's proposed template includes emissions as an indirect avoided cost. The Department's template does not include any indirect avoided costs, such as emissions.

In previous resource plans, the Commission has often considered CO_2 costs as a measure of risk. According to the Commission's order in the CO_2 values docket:[32]

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[30] This IR was provided in response to an inquiry from the Large Power Intervenors in that proceeding.

[31] Minn. Stat. §216B.2422 (the IRP statute) requires the Commission to "quantify and establish a range of environmental costs associated with each method of electricity generation" (Subd. 3). In the Minnesota Resource Planning Rules (Chapter 7843), resource plans "must be evaluated on their ability to… minimize adverse socioeconomic effects and adverse effects upon the environment" (7843.0500, Subp. 3). Finally, Minn. Stat. §216H.06 (Greenhouse Gas Emissions) requires the Commission to "establish an estimate of the likely range of costs of future carbon dioxide regulation on electricity generation," and these values "must be used in all electricity generation resource acquisition proceedings."

[32] Commission Order, Docket No. 07-1199.

> The Commission recognizes, however, that the while the costs of carbon pollution are not currently regulated, they continue to be real. And, while the regulatory environment regarding CO_2 emissions continues to be uncertain, such regulation will likely eventually occur, with concomitant costs for ratepayers.

Looking retroactively at costs actually incurred and those yet to be incurred, it may be misleading and inappropriate to measure a utility's reduced exposure to risk in the rearview mirror. Utilities making investments in renewable resource have done so not only as a result of RES mandates, but also to strategically position themselves for a low carbon future. Thus, staff agrees with Xcel in concept that including avoided emissions as an indirect avoided cost is appropriate, irrespective of whether carbon penalties are presently incurred, particularly since the Commission has previously found that carbon pollution reflects a real ratepayer risk.

In response to JBI's final argument—that fuel price variability is not accurately accounted for—staff notes that measuring fuel price volatility uniformly is complicated by the fact that utilities have varying exposure to the wholesale market, varying reliance on coal-fired generation, and varying reliance on natural gas, as shown in the table below. Thus, small fluctuations in coal prices can have much greater impacts than relatively larger swings in natural gas prices, particularly for GRE, MP, and OTP. The following table shows energy production by fuel source, according to a sample of four utility resource plans: GRE, MP, OTP, and Xcel.

Energy Production by Resource Type (in percent)

	Coal	Natural Gas	Wind	Bilateral / Market	Hydro	Other
GRE (2011)	73	2	10	6	4	5
MP (2013)[33]	70	0	15	10	3	2
OTP (2012)[34]	64	1	7.5	20	7.5	0
Xcel (2012)	34	18	11	-	7	30

3. Calculating RES/SES Avoided Costs

The parties generally agree that the rate impact methodology should result in a "net rate impact," which means the expenses should be compared to some estimate of what other expenses would have been otherwise incurred to meet its resource needs. Both Xcel's and the Department's proposals employ a counterfactual analysis, in which the spending observed under the RES/SES is compared to an approximation for the costs that would have been incurred absent an RES/SES. In addition, in its May 8, 2014 comments MP suggests an alternative method. In this section, each party's proposed approximation method is presented individually.

[33] MP's energy position is a PUC staff estimate based on Figure 7, 2013 Energy Position, from MP's 2013 IRP.

[34] OTP groups together hydro and wind as one "renewables" category, so staff split the 15% renewables in half.

Before turning to the propositions, staff first notes that, just as there is considerable variation in the resource mix employed by utilities in Minnesota, there is also significant variation in their near-term capacity and energy needs. The table below shows the load and capability values from the same four utilities' resource plans: GRE, MP, OTP, and Xcel. Each utility has varying degrees of resource needs, and some are considerably long on capacity.

Net Capacity Surplus or Deficit by Utility (in MW)

Plan Year	GRE 2012 IRP[35]	MP 2013 IRP[36]	OTP Baseload Study[37]	Xcel 2011 IRP[38]
2012	550	-	62	690
2013	550	69	64	729
2014	510	31	39	656
2015	425	34	32	686
2016	410	16	23	303
2017	490	1	(81)	(1)

Thus, to the question of what would have been added in place of certain renewable projects, the answer could be very different, depending on the utility. In previous resource plans, the effect of procuring economical renewable energy facilities typically has displaced generation from higher cost existing units, avoided wholesale market purchases, or changed the economics of adding a certain "type" of generation (baseload, intermediate, or peaking).[39]

Locational Marginal Prices (Xcel)

Row L of Xcel's proposed template is an "avoided energy benefit," which aims to approximate what the Company's energy-related costs would have been absent the RES. This benefit is calculated using Locational Marginal Prices (LMPs), with past years calculated using historic LMPs published by MISO and future years based on forecasted LMPs or dispatch simulation.

In its June 6th, 2014 comments, the Company provided greater detail on the proposed calculation:

> [T]he Company proposes calculating the avoided energy benefit by multiplying the historical hourly generation by the corresponding historical hourly day ahead LMP at a representative MISO load zone, such as NSP.NSP for example. The sum of this multiplication across the full reporting period would constitute the avoided energy benefit for that particular resource.

[35] GRE 2012 Resource Plan, Docket No. 12-114, page 12. (Staff note: The numbers in the table are staff estimates, based on Figure 1-5 of GRE's IRP, which is a histogram of GRE's capacity position.)
[36] MP 2013 Resource Plan, Docket No. 13-53, page 28.
[37] OTP Company Baseload Diversification Study, Docket No. 10-623, page 8.
[38] Xcel, December 2011 Update to Resource Plan, Docket No. 10-825, page 21. (Staff note: Xcel's capacity position has been updated in Docket 12-1240, its resource acquisition docket. Since that docket is ongoing, PUC staff elected to use the most recent information from Xcel's IRP filing.)
[39] For example, in 2013, Minnesota Power received Commission approval for its 200 MW Bison 4 wind project. In its Petition for Approval, MP estimated that Bison 4 would supply approximately 835,000 MWh per year, with roughly two-thirds displacing market purchases and the remainder displacing existing thermal generation.

> For resources that do not have historical hourly generation profiles available (typically smaller resources or non-metered DG resources), an analytically-derived "typical" profile appropriate for the type of resource and scaled to the capacity of the specific resource would be used as a substitute. The expected hourly generation based on this typical profile would also be multiplied by the corresponding MISO day ahead LMP to derive the avoided energy benefit for these resources.[40]

MRES and the Department raise several issues with the use of LMPs to estimate avoided energy costs. MRES notes that its LMP forecasts are developed by a third party, and MRES is contractually prohibited from disclosing these forecasts. In addition, the Department lists three main concerns:

> First, because there is no regional entity to ensure that there will be adequate generation resources across the region to serve the demand for power at peak periods, it is not reasonable to assume that it will always be possible to buy power in the wholesale market and have it delivered to load when needed. Second, there is no long-term forecast of prices in the wholesale energy market and thus no viable price to use for comparison, particularly given that the market price changes significantly in the face of higher demand relative to the supply of power over time.[41]

In addition, the Department also argues that renewable resources influence LMPs. As an example, the Department cites last winter's "polar vortex," in which MISO set a new winter peak demand record. The Department notes that above-average wind production as the front moved through helped keep LMPs relatively low. In the Department's words, the example "indicates that comparing the market price of energy given the existence of significant renewable energy generation, and assuming the LMPs would remain the same had the renewable energy generation not existed, is unreasonable and inappropriate."[42]

Staff Comment

As mentioned above, MRES uses LMP forecasts developed by a third party. Because the terms of the agreement with the third party prevent MRES from disclosing the LMP forecasts, MRES recommends that "only the highest levels of aggregated data" be disclosed publicly when providing avoided cost information.[43] What isn't clear among the parties' comments is whether there is consensus regarding what that "highest level" data is for forecasting LMPs.

In addition, wind output affects regional LMPs by displacing generation from higher-marginal cost generators. Because LMPs are influenced by wind generation, estimating what avoided energy benefits would have been absent the RES is theoretically problematic, since low LMPs can be, in part, a result of high wind output. For example, according to a recent MISO

[40] Xcel, June 6, 2014 comments, page 1.
[41] Department, May 20, 2104 comments, pages 2-3.
[42] Department, January 27, 2014 comments, page 3.
[43] MRES, May 7, 2014 comments, pages 1-2

Independent Market Monitor report, prices at the Minnesota hub "were again much lower than other hub prices partly because of wind output, which was 3 percent higher than last June."[44]

Thus, under Xcel's proposal, wind resources would be under-credited in two ways: first, they would not receive credit for lowering the price a utility pays for market purchases. If wind resources reduce a utility's market expenditures, this is in effect a benefit to utilities that could be included as an indirect avoided cost. Second, the LMP, which is the measure of the resource's avoided cost under Xcel's proposal, would actually be *lower* than it would have been absent the wind generation additions that have been made over the past decade. In other words, without wind additions, LMPs would have been higher, which means the avoided energy benefit in Xcel's proposal would have been larger. Staff believes that in order for wind to be compared fairly to LMPs, the analysis would have to estimate what the LMP at each node would have been absent available wind energy.

Avoided Capacity and Emissions Costs (Xcel)

In addition to the energy benefit represented by LMPs, Xcel's template also includes calculations for avoided capacity and emissions costs. To calculate avoided capacity costs, Xcel's proposal includes "the revenue requirements or fixed annual PPA payments associated with the construction of a new natural gas plant that has been avoided by renewable resources."[45] In addition, Xcel notes that renewables may allow utilities to avoid environmental permitting costs and costs of future environmental regulations; accordingly, Xcel's template includes a line for avoided emissions costs. For past years, the calculation includes avoided SO_2 and NO_x permits under Title IV of the Clean Air Act, and for future years the proposal allows (but does not require) the estimation of potential cost savings from reductions in CO_2 and other emissions.

Two parties took issue with this part of Xcel's template. MRES noted that the inputs necessary to calculate the avoided capacity benefit would be non-public, thus decreasing transparency. In addition, JBI believes "unknown or immeasurable emissions costs that do not appear in ratepayers' bills" should not be included in estimates of future avoided emissions costs.[46]

Levelized Cost of Energy (the Department)

Row D of the Department's proposed template includes the expenses associated with a non-renewable generation source, which it calculates using the Energy Information Administration's (EIA) most recent Levelized Cost of Energy (LCOE) for a natural gas-fired Combined Cycle (CC) or Combustion Turbine (CT) plant. The LCOE is a rough, generalized estimate that allows for a comparison of the economic competitiveness of different types of generation resources. It is a life-cycle analysis in which three types of cost components—fixed costs, variable costs, and financing costs—are compared to the facility's expected energy production, giving a single estimate (usually in $/MWh) of how much the energy from a given technology type will cost

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[44] David B. Patton, "IMM Monthly Market Metrics Report, June 2014," July 23, 2014. Available online at https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/BOD/Markets%20Committee/2014/20140723/20140723%20Markets%20Committee%20of%20the%20BOD%20Item%2003%20IMM%20Report.pdf

[45] Xcel, December 20, 2013 comments, page 5.

[46] JBI, May 8, 2014 comments, page 3.

over the lifetime of the facility.[47] In 2014, the EIA calculated an LCOE for sixteen different generation resources.[48]

The Department argues that "no utility has indicated that the power was not needed,"[49] and, so, the costs of the renewable facilities used to comply with the RES should be compared to "whatever other new resource the utility would have added if the renewable power had not been added to its system."[50] CTs and CCs are chosen because "[t]hese types of facilities are the alternative resources most commonly selected in resource plans."[51]

Several parties opposed the Department's LCOE approach. JBI argued that the resources added absent the RES may not have been natural gas-fired. Xcel concurred, arguing that its "our simulations have shown that approximately 40 percent of the fossil fuel displaced by wind generation comes from coal plants or market purchases […] As such, the use of a natural gas plant in comparison to wind is not likely accurate."[52] In addition, MP quotes the EIA itself:

> Since projected utilization rates, the existing resource mix, and capacity values can all vary dramatically across regions where new generation capacity may be needed, the direct comparison of Levelized Cost of Energy across technologies is often problematic and can be misleading as a method to assess the economic competitiveness of various generation alternatives.[53]

<u>Staff Comment</u>

As MP noted in its May 8, 2014 comments in this docket, EIA's annual LCOE estimates are for generation resources that will come on-line in five years. For example, the estimates in the 2014 EIA report are for projects that would come on-line in 2019. This lag is intentional, intended to reflect the fact that some technologies have longer lead times than others. Thus, although the EIA has made annual LCOE estimates for many years, the report estimating the LCOE for 2005 would have been released in 2000. Even if estimates are available back through 2000, staff is concerned that there may have been methodological changes over this period, which would limit the comparability of the rate impact reports over time. Staff requests that the Department devote a portion of its oral argument at the upcoming agenda hearing to a discussion of the timing of the EIA's LCOE.

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[47] For a detailed explanation of the LCOE calculation, see the U.S. EIA's July 2013 "Levelized Cost of Electricity and Levelized Avoided Cost of Electricity Methodology Supplement," included as Attachment A to the Department's May 20, 2014 comments.

[48] See EIA's April 17, 2014 "Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2014." http://www.eia.gov/forecasts/aeo/electricity_generation.cfm

[49] Staff notes that at least one utility has indicated that not all of its renewable additions were needed: As SMMPA put it in its 2010 Biennial RES Report: "Meeting RES targets required SMMPA to acquire a greater number of megawatts of generation than SMMPA would have otherwise required at the time, so, to a degree, this new generation was redundant" (SMMPA's November 15, 2010 filing in Docket Number E-999/M-10-989).

[50] Department, December 20, 2013 comments, page 4.

[51] Ibid.

[52] Xcel, May 8, 2014 comments, page 3.

[53] MP, May 8, 2014 comments, pages 2 and 3, quoting the EIA's "Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2014."

If the Commission is interested in employing an LCOE approach, staff notes that the EIA is not the only organization that makes LCOE calculations.[54]

Another possible alternative, which would be consistent with the Department's December 20, 2013 comments, would be a combination of IRP analysis and LCOE. Under this approach, the utility would calculate the avoided cost as "whatever else the utilities would have added to their systems instead of the renewable power," as identified through their IRP processes.[55] If a utility does not participate in the Commission-approved IRP process, or if "its needs were not large enough to warrant building a new non-renewable energy facility rather than adding the renewable power (which tends to be added in smaller increments)," then it would report the LCOE estimate for a CC or CT.[56] This has the advantage of providing a more accurate estimate of the actual avoided costs. However, this approach arguably conflicts with the "uniform, consistent, and comparable" language of the statute, as it may result in utilities calculating avoided costs differently in the same year, with some using the IRP approach and others using the LCOE.

Levelized Avoided Energy Cost (MP)

In its supplemental comments, MP recommended the Department's proposal replace the LCOE with the EIA's Levelized Avoided Cost of Electricity (LACE). As its name suggests, the LACE is an estimate of the "avoided cost" of the energy and capacity that will be displaced by the new generation unit. This calculation is unique for each technology type, taking into account the times of day and year that the generation is likely to occur and uses corresponding market prices to estimate the energy and capacity payments that would have been incurred without the generation facility. Like the LCOE, this estimate is levelized over the facility's lifetime to give a single figure (in $/MWh) for each type of generation resource.[57]

MP concedes that the LACE has two limitations for use in an RES rate impact report. First, the LACE represents an average across the entire country, so it is not specifically targeted to Minnesota. Second, because the EIA calculated the LACE for the first time in 2014, the earliest this rate could be appropriately applied is 2019. MP did not offer a methodology to correct for the "misaligned time periods," but it indicated that it is "open to suggestions from the Department or other stakeholders on possible resolutions."[58]

In its May 20, 2014 comments, the Department took issue with the use of the LACE. Its reasoning was the same as for its opposition to the use of LMPs: the lack of a regional entity to ensure adequate generation resources, the lack of a long-term wholesale market forecast prices, and the influence of renewable resources on marginal prices.

[54] For example, Lazard, an independent financial advisory and asset management firm, has produced LCOE estimates annually since at least 2007.
[55] Department, December 20, 2013 comments, at page 4.
[56] Ibid.
[57] For a detailed explanation of the LACE calculation, see the U.S. EIA's July 2013 "Levelized Cost of Electricity and Levelized Avoided Cost of Electricity Methodology Supplement," included as Attachment A to the Department's May 20, 2014 comments.
[58] MP, May 8, 2014 comments, page 3.

Staff Comment

The impact of the five-year lag between EIA's report and the estimate is even more pronounced for the LACE, which the EIA estimated for the first time in 2014 (projects coming online in 2019). Per the legislation, utilities are obligated to file rate impact reports through 2020 (Xcel) or 2025 (all others); thus, Xcel would only use the LACE for one report, and the others for only three or four. This does not necessarily mean that the LACE would not be a valuable addition in those years, but staff notes that this does limit the usefulness of the LACE in this docket.

Additional Possible Avoided Costs

Staff Comment

Just as JBI pointed out that there are potential costs that are not included in either template, there are also potential avoided costs that are not included in either template. One such avoided cost option would be an estimate of renewable resources' fuel price hedge value. According to several utilities' wind acquisition petitions, recent wind additions have been pursued for both economic and strategic purposes. Fuel prices can vary dramatically over time, and an increased penetration of renewables limits utilities' exposure to these price fluctuations.

However, each utility's strategic vision is different because—as displayed in the table on page 12—each utility is characteristically different. As with incorporating a cost for fuel price variability, a uniform template that included a fuel price hedge benefit would be inherently limited, as different methodologies would inevitably have relative advantages and disadvantages.

A second possible addition is an indirect benefit for the impact renewables have had on wholesale market prices. As more low-marginal-cost renewables come on-line, they tend to replace higher-marginal-cost alternatives. As referenced above, a recent MISO Independent Market Monitor report suggests that wholesale prices in Minnesota are significantly lower as the result of wind additions. In addition, according to a recent study by the National Renewable Energy Laboratory, roughly a quarter of the states that employ RPS cost impacts include an estimate for wholesale market price reductions; according to the report, these studies have found "price suppression benefits of $2-$50/MWh of renewable energy generation."[59]

Staff raises these two issues not to either support or oppose their inclusion, but simply to aid the Commission in making an informed decision.

4. Comparing RES/SES Costs and Avoided Costs

Once costs and avoided costs have been estimated, they must then be compared to calculate a "rate impact." Xcel's and the Department's proposals have two main differences in how costs are compared and calculations are made. In addition, staff offers a possible additional step to calculate a "rate impact" rather than a comparison of net costs. This section presents each of these three issues individually.

[59] Heeter et al., "A Survey of State-Level Cost and Benefit Estimates of Renewable Portfolio Standards," May 2014, at page vii. NREL/TP-6A20-61042.

Final Calculations

Xcel's and the Department's templates approach the final calculations differently. Under Xcel's proposal, each utility would fill out two spreadsheets: one for the RES and one for the SES. Under the Department's template, on the other hand, utilities would calculate the RES/SES rate impact in three steps:

1) Compile the per-kWh costs for each type of renewable generation added in the past year. This means that there would be a separate calculation for wind, solar, hydro, and biomass renewable facilities added in the previous year.
2) Average the totals compiled in step 1, giving the average per-kWh cost of all renewable power resources added in the past year.
3) Compile the per-kWh cost of all renewable power resources on the system used to meet the year's RPS RES/SES requirements. Unlike the previous two steps, this is not limited to resources added in the last year.

The Department's broader position is to continue to evaluate renewable energy acquisitions within the utilities' resource planning processes. This way, the Commission can base its decisions on actual data, which includes trade secret data, as well as each renewable facility's fit into a specific utility's overall resource mix. Thus, according to the Department, any rate impact template, including its own, "should be considered with care to avoid reaching unsound conclusions" and "could be considered as first steps in assessing the effects of adding any generation resource to a utility's system."[60]

Levelized or Annualized Costs

A second major difference between the two proposals is that Xcel's plan uses annualized costs, while the Department's uses levelized costs. Under the Department's plan, the total lifetime costs of a utility-owned renewable facility are compared to the total lifetime production, so that the facility's average cost-per-MWh-produced is the same for each year. The Department takes this approach because it aligns most closely with the IRP process. The Department's broader position is that IRP is the best method to assess whether renewable generation will result in a least-cost mix of resources, and levelizing costs over the facility's lifetime is most consistent with least-cost planning.

Xcel's proposal, on the other hand, lists costs and benefits in the year in which they were actually incurred. Thus, a wind farm installed in 2013 will have the entire cost of the construction listed in 2013, and the annual avoided costs due to the production will be included in the projections for each of the 15 forecast years. According to Xcel, "the intent of Subd.2e is to provide stakeholders with a reliable estimate of actual cost incurred for renewable energy. The use of levelized cost could potentially obscure the actual rate impacts."[61]

<u>Staff Comment</u>

The advantage of Xcel's approach (annualizing) is that it shows cost variations over time, which is a more accurate reflection of the "lumpy" nature of investments. The weakness of this approach, in this context, is that it will undervalue renewable generation facilities: relative to non-renewable forms of generation, renewables require larger up-front investments but tend to

[60] Department, January 27, 2014 comments, page 4.
[61] Xcel, December 20, 2013 comments, page 3.

have lower O&M costs and have no fuel costs. Thus, for example, under Xcel's approach, a utility-owned renewable resource that was constructed in 2013 would have almost all of its costs included in the 2014 rate impact report, but only 15 years of its benefits would be calculated.

MP recommends the Commission consider a similar approach for the calculating RES costs and rate impact as used by the Company in its 2013 IRP.[62] There, MP presented its RES cost impact analysis in both annualized and levelized terms, and thus, consistent with both Xcel's and the Department's recommendation in this case. MP also included both the cost and rate impact of investments made to comply with the RES.

As shown in the figure below—from the MP resource plan's Appendix G: Rate Impact for RES Compliance—MP calculated the aggregated revenue requirements of all RES investments. Figure 3 shows costs on both an annualized (blue line) and levelized (green line) basis, and these costs were compared to a projected regional market energy forecast (red line).

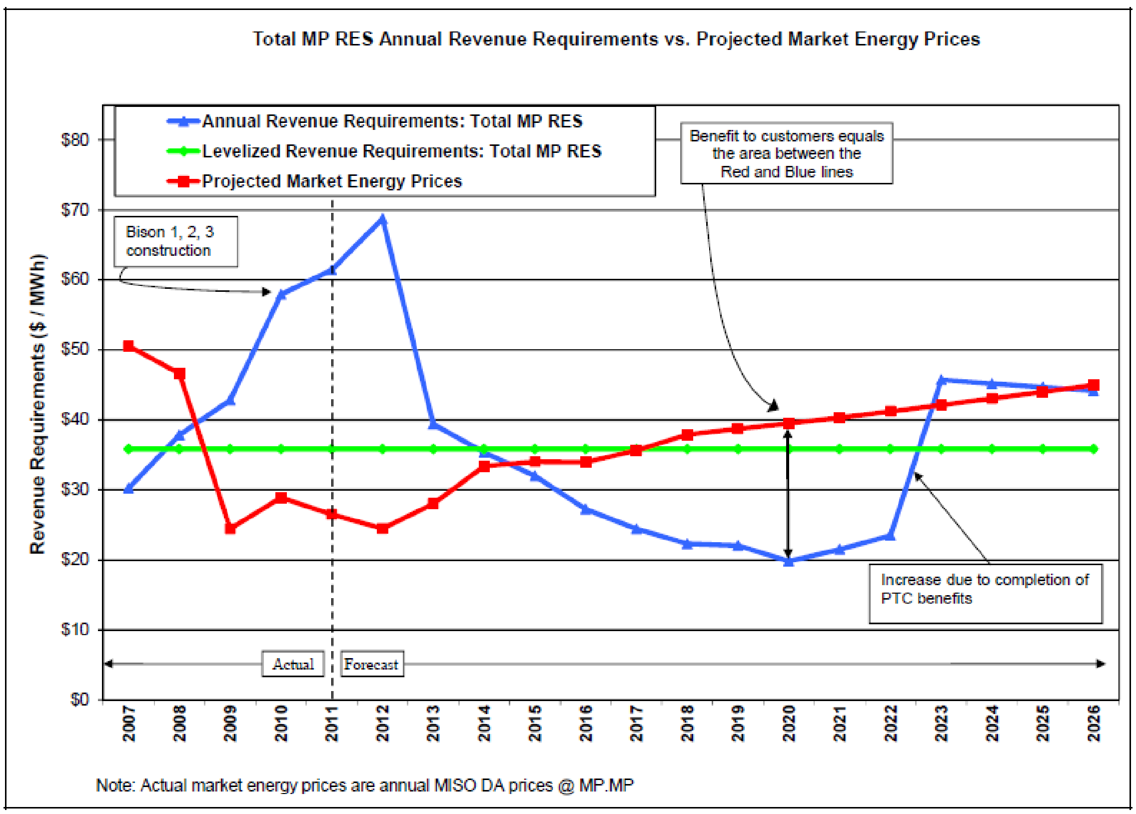

Figure 3 - Minnesota Power Renewable Project Cost Outlook

The combined levelized revenue requirement of MP's RES investments was estimated to be approximately $36 per MWh. On an annualized basis, the revenue requirements are higher in the initial years as capital investment takes place, then decline sharply due to the benefits attributable to the wind Production Tax Credit (PTC) and MP's accelerated tax depreciation treatment.[63]

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[62] Docket No. 13-53

[63] MP, 2013 Integrated Resource Plan, Appendix G, page 12.

Thus, while Xcel prefers an annualized approach and the Department prefers a levelized approach, Staff notes that at least one utility, Minnesota Power, already incorporates both annualized and levelized RES costs in IRP. However, the annualized cost approach could be complicated by accounting issues, such as treatment of tax credits and depreciation. Staff requests that parties devote a portion of their comments at the upcoming agenda hearing to address the feasibility of reporting both annualized and levelized rate impacts.

Calculating the Retail Rate Impact

In its May 8, 2014 comments, GRE argued that the Department's proposal does not determine "an ultimate rate impact, but rather calculates the difference in the cost of renewable energy and a hypothetical generation alternative"; and, as GRE notes, "[a] difference between the costs of two resources is not the same as a rate impact."[64]

Staff Comment

GRE's criticism highlights a notable omission in both the Department's and Xcel's proposals. The RES rate impact statue states: "The rate impact estimate must be for wholesale rates and, if the electric utility makes retail sales, the estimate shall also be for the impact on the electric utility's retail rates." The totals calculated in Row U of Xcel's proposal and Row G of the Department's proposal are comparisons of costs, but not estimates of the wholesale or retail rate impacts. Rather, staff believes a comparison of a renewable project's costs to its avoided costs gives an estimate of the "renewable premium" (if costs outweigh avoided costs) or the "renewable discount" (if avoided costs outweigh costs).

Looking only at this cost difference, however, will make the impact on rates appear larger than it actually was. As of 2012, the RES required utilities to procure at least 12 percent (or 18 percent, in the case of Xcel) of their electric sales from renewable resources. Thus, because renewable energy comprises only a fraction of a utility's total energy costs, the retail or wholesale rate impact will only be a fraction of the renewable premium/discount, as the majority of the utility's energy costs will be the same as they would have been absent an RES/SES.

This concern could be addressed through the addition of a "rate impact" component to the final rate impact template. In Xcel's proposal, a final line would be added in which the per-kWh "renewable premium/discount" (Row U) would be multiplied by the percentage of the utility's sales that came from renewable generation (Row Y). For example, if an RPS-compliant utility's 2012 calculation showed that, on average, renewable projects' costs were larger than their avoided costs by $0.01/kWh, the "rate impact" would be $0.0012/kWh ($0.01 x 12%). Similarly, the Department's template would first calculate the percentage of the utility's sales that comes from renewable generation and then multiply this by the per-kWh "renewable premium/discount" (row G).[65] This option is included as Decision Option 3)A below.

[64] Page 2.

[65] Under the Department's proposed template, this calculation would be slightly different in step 3 than in steps 1 and 2: steps 1 and 2 would multiply the wholesale rate impact by the energy generated by facilities *added in that period* as a percentage of total sales, while step three would multiply the wholesale rate impact by all renewable generation as a percentage of total sales.

The calculation outlined above is only one possible option. Parties may wish to comment on this option at the agenda meeting. If, after hearing these comments, the Commission believes the record is not sufficiently developed on this issue, it could take additional written comments from interested stakeholders on this issue prior to finalizing the details of the rate impact calculation. Decision option 3)B below offers a process for an additional comment period on this topic. This option solicits comments solely on the rate impact calculation, so that the Commission could make decisions on the other issues presented in this docket and implement a methodology that could be used for reports due before the final rate impact calculation is determined.

Additional Clarifications Required

Trade Secret Data

In broad terms, any rate impact methodology would require some comparison of costs to generation. Thus, irrespective of the methodology for calculating RES/SES costs and avoided costs, several parties believe that it is important to acknowledge the confidentiality of expenses and generation. In its January 27th comments, Xcel addresses the publicly available data issue:

> [The methodology] must protect against the disclosure of prices associated with newly acquired projects… While none of the proposed reporting templates suggest that the price of individual projects be publicly disclosed, it is possible to infer project prices if the wrong type of data is provided or if only a small number of projects are involved in a calculation.
>
> Of equal concern is the public disclosure of avoided cost estimates. Parties generally agree that the cost of renewable energy must be compared to the cost of generation from conventional fossil fuels, and we agree. When reported on a per-kWh basis, these avoided costs essentially show what a utility's breakeven price is for a particular renewable energy resource… Should a utility publicly disclose its estimate of the avoided cost of wind … we believe there could be negative impacts the next time the utility attempts to acquire new wind resources. If a company has announced its breakeven price, bidders are likely to only offer prices in that range.
>
> Given the contractual confidentiality issues associated with new projects and the potential harm to customers through disclosure of avoided cost information, we recommend that only the highest levels of aggregated data be disclosed publicly.[66]

As the Commission considers the proposed templates, Staff notes that, whether the basis for comparison is fossil-based generation, the regional energy market, or something else, many parties note the trade secret nature of fuel price and market energy price forecasts. These are, in many cases, acquired from third parties and not available for public consumption.

The Role of Rate Impact Reports in Resource Plans

Staff Comment

The RES rate impact statute requires utilities to file reports that "must be updated and submitted as part of each integrated resource plan."[67] It is not yet clear what it means to be "a part of each

[66] Xcel, January 27, 2014 comments, pages 1-2.

integrated resource plan." Staff identifies two possibilities: the report would either be filed as an appendix within the utility's Petition for Approval, or it would be merged with the IRP decision-making process. Under the first option, a report's primary purpose would be *descriptive*, providing an estimate of the rate impact of a utility's collective IRP decisions. Under the second option, a report would be *prescriptive*, integrated into the IRP process as a decision-making tool.

Staff assumes that as with many other new filings, the Commission will determine the role of the report as it and stakeholders gain experience reviewing these filings. Another group interested in these filings may be the general public. Staff has consulted with the Commission's Consumer Affairs Office (CAO), who has received calls from the general public asking for information on the rate impact of the state's renewable standard.

Because IRPs are long and complex documents, the Commission may wish to direct utilities to file these as appendices to their IRPs and have them clearly listed in an IRP table of contents. This would allow the CAO to easily access the rate impact report in the case of calls from the public.

In addition, as the Commission considers all of the decision options before it, it may wish to consider what format and information would be most easily understandable by the public, as one of several considerations.

Utilities that Do Not File Resource Plans

Staff Comment

Staff notes that the statute requires these rate impact reports be filed in IRPs; however, the following utilities, which are subject to the renewable standard, are not required to file IRPs:

- Central Minnesota Municipal Power Agency
- East River Electric Cooperative, Inc.
- Heartland Consumers Power District
- L&O Power Cooperative
- Northwestern Wisconsin Electric Company

In addition, two cooperatives— Basin Electric Cooperative and Dairyland Power Cooperative— file streamlined O-IRPs yearly, rather than on the two year schedule for traditional IRPs.

The legislation in question is silent on how a utility that does not file a resource plan should file its report. Further, the purpose of an O-IRP was to streamline the filing of resource information; it may be counterproductive to require Basin and Dairyland to file their rate impact reports each year rather than every two years.

One possible solution, assuming the Commission wants to clarify the filing schedule for these seven (7) utilities, is to require each of these utilities to file its rate impact reports as a part of its biennial RES compliance dockets.

[67] Minn. Stat. §216B.1691, Subd, 2e.

Decision Options

Facilities Included and Timeframe for Reports filed under Minn. Stat. §216B.1691, subd. 2e

1) Find that the following facilities should be included in the RES/SES calculations:

   A) Renewable facilities added since 2005 (WOW). Or,

   B) All facilities used to comply with the RES/SES, regardless of when they were constructed. (Department, Xcel). Or,

   C) Only new renewable facilities that are being considered in the relevant Integrated Resource Plan (IRP).

2) Find that the timeframe for the analysis should be:

   A) A start date of 2005 out through the 15 years covered in the relevant IRP (IPL, JBI, WOW, Xcel). Or,

   B) A start date of 2005 out through the lifetime of the facilities added in the relevant IRP (Department). Or,

   C) A start date of 2005 out through the 5 years of the IRP's short-term action plan (MP). Or,

   D) Starting with the year following the last reported year out through the 15 years covered in the relevant IRP (GRE).

Definition of Rate Impact

3) Make the following determination on the "rate impact":

   A) Find that the RES/SES rate impact report template should include additional rate impact calculation as outlined on page 21 of the briefing papers. Or,

   B) Find that the RES/SES rate impact report template should include additional rate impact information. Delegate to the Executive Secretary the authority to issue notices for comments on how to implement this decision. Until the Commission issues a further order on the specific form and information to be provided, utilities may, but are not required to, provide such information in their reports. Or,

   C) Interpret "rate impact" as a comparison of the cost of renewable facilities to the cost of alternative generation investments. Or,

   D) Take no action at this time.

The Role of the Rate Impact Report in Resource Planning

4) Direct all utilities filing rate impact reports in IRPs to:

    A) File the report as an appendix in the utility's IRP and clearly identified in the table of contents. Or,

    B) Take some other action.

5) Direct all utilities that are subject to Minn. Stat. §216B.1691 but are: 1) not required to file IRPs under Minn. Stat. §216B.2422; or 2) eligible to make filings under Minn. Stat. §216B.2422. subd. 2b, to:

    A) File their rate impact reports as part of their biennial RES compliance dockets. Or,

    B) Take some other action.

Template Design

(Staff note: the Commission could choose to adopt either the template proposed by Xcel (Appendix A) or the template proposed by the Department of Commerce (Appendix B), in which no action would be needed on Decision Option #8. If the Commission wishes to develop its own template based on various parties' recommended modifications, those options are categorized below as Decision Option #8.)

6) Adopt the template proposed by Xcel (Appendix A). Or,

7) Adopt the template proposed by the Department (Appendix B). Or,

8) Develop a new template consisting of the following components:

Per-kWh costs

8.1) Direct costs, to include:

    A) Payments under PPAs and revenue requirements associated with utility-owned renewable energy projects. (Xcel, Department)

    B) Strategist modeling as augmented by JBI in their December 20, 2013 comments, supplemented with the PROMOD model. (JBI)

8.2) Indirect costs, to include:

A) Ancillary services costs and baseload cycling costs that may have been incurred as a result of adding renewable resources to the utility's generation system. (Xcel)

B) Ancillary services costs and baseload cycling costs. Allow utilities to use estimates of these costs, so long as they are so noted. (GRE)

C) Ancillary service costs, baseload cycling costs, and an estimate of the intermittency cost of renewables calculated using the PROMOD model as described by JBI in their December 20, 2013 comments. (JBI)

D) None of the above. (Department)

8.3) Transmission costs, to be calculated by:

A) Requiring utilities to provide documentation of any transmission investments and to estimate the percentage of the expenditure that was attributable to RES/SES compliance. (Xcel)

B) Some other calculation.

Per-kWh avoided costs

8.4) Direct avoided costs, to include:

A) Historical or forecasted Locational Marginal Prices (LMPs). (Xcel, JBI)

B) Avoided capacity costs, calculated based on the cost of a CT as described in Xcel's December 20, 2013 comments. (Xcel)

C) The appropriate Levelized Cost of Energy (LCOE) estimated by the EIA for a combined cycle (CC) or combustion turbine (CT) natural gas plant. (Department).

D) The appropriate LCOE estimated for a CC or CT by Lazard or another reputable source.

E) The cost of whatever facilities the utility would have added to its system instead of the renewable power, as identified through their IRP processes. If a utility does not participate in the Commission-approved IRP process, or if its needs were not large enough to warrant building a new non-renewable energy facility, then it would report the appropriate EIA LCOE estimate for a CC or CT.

F) The EIA's most recent Levelized Avoided Cost of Energy beginning in 2019 and some other number before that. (MP)

8.5) Indirect avoided costs, to include:

A) Avoided emissions costs, defined as the costs of avoided SO_2 and NO_x permits and forecasts of savings expected from the avoidance of future emissions costs. (Xcel)

B) Avoided emissions costs, defined as avoided SO2 and NOx permits only. (JBI)

C) Fuel price hedge benefit.

D) Wholesale market price reduction benefit.

E) None of the above. (Department)

Additional clarification

8.6) Calculations by generation type

A) Calculate rate impacts in three steps: first, calculate the rate impact for each type of renewable generation added in the previous year; second, combine these totals to give the average rate impacts of the RES for that year; third, calculate the rate impacts of all renewable resources used to fulfill that year's RES requirement (Department), or

B) Calculate one set of rate impacts for the RES and a second for the SES. (Xcel)

8.7) Levelized or annualized costs

A) Calculate annualized costs and avoided costs, including historic costs from 2005 to the year of the IRP and forecasts for the next 15 years out from the IRP. (Xcel)

B) Levelize costs and avoided costs over the expected lifetime of the generation source. (Department)

C) Calculate both annualized and levelized costs and avoided costs, including historic costs from 2005 to the year of the IRP and forecasts for the lifetime of the facilities.

	Minn Stat 216B.1691 Subd.2e	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
A	Capacity associated With RES, MW	Total capacity of resources that are used for compliance with the RES.																								
B	Accredited capacity associated with RES, MW	Total accredited capacity of resources that are used for compliance with the RES as determined by MISO.																								
C	Generation associated with RES, GWh	Generation total should correspond to generation listed in FERC Form 1. Deviations from generation listed in FF1 should be notes (e.g. projects from which only a portion of output qualifies for RES compliance) listed in FERC Form 1. Deviations from generation listed in FF1 should be notes (e.g. projects from which only a portion of output qualifies for RES compliance).									Forecast of total renewable resources should be based on recent resource plans and reflect compliance with the Renewable Energy Standard (RES) including the utilization of banked credits.															
D	Direct expenses associated with RES, $millions	Direct expenses include payments under PPAs and revenue requirements associated with utility owned renewable energy projects. Historic payments for PPA contracts should correspond to expenses reported in FERC Form 1. Revenue requirements for owned projects should include O&M expenses, book depreciation expense, deferred taxes, current taxes, capital financing expenses, property taxes, insurance, and any tax credits or other subsidies.									Forecasts of total direct expenses should be based on recent IRPs. Assumptions regarding the cost of future renewable resources should be clearly documented including assumption regarding the availability of tax credits or other cost subsidies.															
E	Average direct expenses, $/MWh = D / C	Average costs expressed in $/MWh																								
F	Indirect expenses associated with RES, $millions	Indirect expenses include additional ancillary services costs and baseload cycling costs that may have been incurred as a result of adding renewable resources to the utilities generation system.									Forecasts of indirect costs should be consistent with assumptions used in recent resource plan and reflect costs such as additional ancillary services and baseload cycling costs.															
G	Average indirect expenses, $/MWh = F / C	Average costs expressed in $/MWh																								
H	Transmission expenses associated with RES, $millions	Transmission expenses include approximation of transmission associated with addition renewable energy to the utilities system. Recognizing that transmission investments can be made for multiple reasons including renewable energy, utilities are asked to provide documentation related to specific transmission project and the proportion of costs deemed attributable to adding renewable energy resources.																								
I	Average transmission expenses, $/MWh = H / C	Average costs expressed in $/MWh																								
J	Total expenses associated with RES, $millions = D + F + H	Total expenses associated with complying with RES																								
K	Average total expenses, $/MWh = J / C	Average costs expressed in $/MWh																								

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<table>
<tr><th></th><th>Minn Stat 216B.1691 Subd.2e</th><th>2005</th><th>2006</th><th>2007</th><th>2008</th><th>2009</th><th>2010</th><th>2011</th><th>2012</th><th>2013</th><th>2014</th><th>2015</th><th>2016</th><th>2017</th><th>2018</th><th>2019</th><th>2020</th><th>2021</th><th>2022</th><th>2023</th><th>2024</th><th>2025</th><th>2026</th><th>2027</th><th>2028</th><th>2029</th></tr>
<tr><td>L</td><td>Avoided energy benefit, $millions</td><td colspan="9">Historic avoided energy benefit should be based on historic locational marginal prices (LMPs) as published by MISO.</td><td colspan="16">Forecasted avoided costs should be based on forecasted LMPs or dispatch simulation.</td></tr>
<tr><td>M</td><td>Average energy benefit,
$/MWh = L / C</td><td colspan="25">Average benefits expressed in $/MWh</td></tr>
<tr><td>N</td><td>Avoided capacity benefit, $millions</td><td colspan="9">Historic avoided capacity benefit should be based on the cost of a natural gas combustion turbine.</td><td colspan="16">Forecasted avoided capacity cost benefit should reflect the forecasted cost of natural gas combustion turbine consistent with recent resource plan or resource acquisition processes. Capacity credit for new resources should reflect the first year that the utility expected to need new thermal generation.</td></tr>
<tr><td>O</td><td>Average capacity benefit,
$/kW-mo = N / B / 12</td><td colspan="25">Average benefits expressed in $/MWh</td></tr>
<tr><td>P</td><td>Avoided emissions benefit, $millions</td><td colspan="9">Historic avoided emissions costs may reflect the costs of avoided SO2 and NOx permits under Title IV of the Clean Air Act Amendment.</td><td colspan="16">Forecasts emission benefits may reflect the savings expected from future emission regulation but inclusion of future emission costs are not required. Assumptions regarding future emission costs should be clearly documented.</td></tr>
<tr><td>Q</td><td>Average emission benefits
$/MWh = P / C</td><td colspan="25">Average benefits expressed in $/MWh</td></tr>
<tr><td>R</td><td>Total avoided cost benefits associated with RES, $millions =L+N+P</td><td colspan="25">Total avoided costs benefits associated with complying with the renewable energy standard</td></tr>
<tr><td>S</td><td>Average total avoided cost benefits
$/MWh = R / C</td><td colspan="25">Average benefits expressed in $/MWh</td></tr>
</table>

<table>
<tr><td>T</td><td>Total net costs of RES, $millions = J - R</td><td colspan="25">Net cost of RES related activities</td></tr>
<tr><td>U</td><td>Average total net costs of RES,
$/MWh = K - S</td><td colspan="25">Average net cost of RES related activities expressed in $/MWh</td></tr>
<tr><td>V</td><td>Total utility revenues, $millions</td><td colspan="9">Total historic sales can be taken from information reported in FERC Form 1.</td><td colspan="16">Forecasted total revenues can be based on detailed revenue requirement forecast but may also utilize more general assumptions regarding growth in sales and changes in average rates.</td></tr>
<tr><td>W</td><td>Percentage rate impact associated with RES, % = T/(V-T)</td><td colspan="25">Net cost of RES related activities in percentage terms</td></tr>
<tr><td>X</td><td>Total utility sales, GWh</td><td colspan="9">Total historic sales can be taken from information reported in FERC Form 1.</td><td colspan="16">Forecasted total sales should reflect the sales forecast used in recent resource plans or other regulatory filings.</td></tr>
<tr><td>Y</td><td>Energy associated with RES as a percentage of total sales
% = C / (X - C)</td><td colspan="25">Percentage of sales represented by renewable energy generation</td></tr>
</table>

Appendix B

Minn Stat 216B.1691 Subd.2e

A	Generation associated with RES, GWh	Total expected generation throughout the lifetime of the facilities.
B	Expenses associated with RES facilities, $millions	Source: the sum of all future payments under PPAs and all future revenue requirements associated with utility owned renewable energy projects.
C	Total per-kWh cost for renewable facilities, $/kWh = B / A	Average costs expressed in $/kWh
D	Expenses associated with gas-fired generation source (CT or CC), MWh	Source: the Energy Information Administration's most recent estimate of levelized, per-kWh costs of either a gas-fired combustion turbine (CT) or a gas-fired combined cycle (CC) unit that would produce generation equivalent to row A.
E	Additional note (no cost estimate needed)	If the utility is aware that any addition of these types of resources would require further costs (such as the addition of a natural gas pipeline), the utility should note that fact.
F	Total per-kWh cost for gas-fired generation source, $/kWh = D / 1000	Average avoided costs expressed in $/kWh
G	Net rate impact of RES, $/kWh = C - F	Net rate impact expressed in $/kWh

Three steps*:

1) Compile the lifetime per-kWh costs (row G) for all renewable power *of a given type added in the past year* .

2) Average the totals compiled in step 1, giving the average per-kWh cost of *all renewable power resources added in the past year* .

3) Compile the lifetime per-kWh cost (row G) of all renewable power resources on the system *used to meet the year's RPS requirements* .

*See DOC-DER's December 20, 2013 comments at "Section B: Department-Proposed Reporting System" (pp. 3-4).

LARGE POWER INTERVENORS

Utility Information Request

Docket Number: E015/RP-13-53 | Date of Request: March 14, 2013

Requested From: Minnesota Power | Response Due: March 26, 2013

By: Large Power Intervenors (Andrew P. Moratzka, Chad T. Marriott)

LPI 203

Please explain how Minnesota Power's model/analysis is different from, or similar to, the MISO model used to assess the reliability impact (i.e., transmission considerations) of retiring a unit.

Response:

Minnesota Power uses the Ventyx Strategist software for the resource planning analysis, where MISO would use the Ventyx PROMOD model to assess the reliability impact of retiring a unit. Below is a summary of the differences between the Strategist and PROMOD software products written together with the engineering firm Burns & McDonnell who has experience using both the Strategist and PROMOD products.

Summary of differences between Strategist and PROMOD

Strategist and PROMOD are mature, widely accepted production cost model software tools that can be used for a variety of resource planning applications in the utility industry. Both software programs are developed and maintained by Ventyx, an ABB company.[1] Below is a summary of capabilities and study applications for each respective software program.

Strategist
Strategist is comprised of several different analysis modules that allow for dynamic optimization of integrated resources (supply and demand-side) in a side-by-side long range planning study. Strategist uses reserve margin logic to evaluate expansion plans over a defined period of time, returning plans in a ranked order according to a defined objective function. Typically, the objective function is minimized utility cost. Strategist uses simplified operational details to

[1] Information about ABB is available at http://www.abb.com/.

Response by:	Julie Pierce	List Sources of Information:
Title:	Manager, Resource Planning	
Department:	Strategy & Planning	
Telephone:	218-355-3829	

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achieve quicker scenario analysis and evaluation than a full hourly dispatch model. Some of the simplified assumptions include:

1. Hourly typical week vs. full hourly dispatch consideration
2. Unit start-up costs
3. Unit ramp rates
4. Unit minimum run/down times

This approach sacrifices some operational detail, but allows for quicker evaluation of resource expansion plans that consider a variety of timeframes and constraints. Due to the simplifications, Strategist results are typically best interpreted as screening level rather than budgetary level. Strategist is suited for use in long range planning that involves multiple economic decision variables and can be solved against a defined constraint. Model constraints can include reserve margin, emission limit, renewable energy target, or other economic target. Other analytical applications of Strategist include evaluating transmission interface projects and unit conversion or retirement.

PROMOD

PROMOD is an hourly chronological unit commitment and dispatch production cost model software program capable of simulation under two different levels of engine granularity. These levels are typically referred to as Zonal and Nodal. Zonal simulations require transmission constraints be identified, Nodal simulations include transmission topology for commitment and dispatch including transmission congestion. Licensing of the software is accompanied by a database that includes relevant information for the North American market. PROMOD includes more detailed operational granularity than Strategist, including consideration for unit start-up, ramp rates, and minimum run/down times. However, due to the analysis granularity, an iterative approach would be required to arrive at the multiple expansion plans that Strategist returns on a ranked NPV (net present value) basis in one Proview run. PROMOD is suited for use in long range planning that involves single or defined economic decisions and where resources include significant hourly considerations. PROMOD can also be used for other applications such as LMP (locational marginal pricing) forecasting, economic transmission analysis, renewable energy curtailment, and other complex studies involving both generation and transmission considerations.

Both programs have useful aspects and can be considered in a variety of resource planning applications. The desired application should be taken into account when choosing which program might be more beneficial for the analysis. Typically, PROMOD produces results more closely aligned with budgetary assumptions; however, both programs still only provide results as good as the input that is entered for the analysis. Level of effort for the application use is generally the same for Strategist and PROMOD Zonal; PROMOD Nodal generally requires an even greater level of effort.

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