division of energy resources
Minnesota Department of Commerce

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November 12, 2013 **PUBLIC DOCUMENT**

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

RE: **PUBLIC Comments of the Minnesota Department of Commerce, Division of Energy Resources**
Docket No. E015/M-13-907

Dear Dr. Haar,

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

> Petition of Minnesota Power for Approval of Investments and Expenditures in the Bison 4 Wind Project for Recovery through Minnesota Power's Renewable Resources Rider under Minn. Stat. §216B.1645.

The Petition was filed on September 27, 2013 by:

> David R. Moeller
> Senior Attorney
> Minnesota Power
> 30 West Superior Street
> Duluth, MN 55802

The Department expects to recommend approval of Minnesota Power's petition, pending receipt of additional information, and is available to answer any questions the Commission may have.

Sincerely

/s/ CRAIG ADDONIZIO
Financial Analyst

PUBLIC DOCUMENT

BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

PUBLIC COMMENTS OF THE
MINNESOTA DEPARTMENT OF COMMERCE
DIVISION OF ENERGY RESOURCES

DOCKET NO. E015/M-13-907

I. BACKGROUND

On September 27, 2013, Minnesota Power (MP or the Company) filed a petition with the Minnesota Public Utilities Commission (Commission) to request approval of investments and expenditures related to the development of the Bison 4 Wind Project (Bison 4 or the Project). The Company filed this petition pursuant to Minn. Stat. §216B.1645 (Power Purchase Contract or Investment).

Bison 4 is a 204.8 MW wind generation facility located in the New Salem, North Dakota area, adjacent to the Company's Bison 1, 2, and 3 Wind Projects. The Project's scheduled commercial operation date is December, 2014.

I. DEPARTMENT ANALYSIS

A. GENERAL FRAMEWORK

The Department's analysis is organized as follows:

First, the Department examines whether or not Bison 4 meets the requirements of Minn. Stat. §216B.1691 (Renewable Energy Objective). This test is required by Minn. Stat. §216B.1645, the statute controlling MP's filing. Second, the Department analyzes MP's need for wind resources as part of the Company's optimal expansion plan. Third, the Department analyzes the cost recovery process as required by Minn. Stat. §216B.1645. Fourth, the Department analyzes whether Bison 4 is reasonable and prudent, based on its cost. Finally, the Department provides its conclusions and recommendations.

B. THRESHOLD REQUIREMENTS FOR COMMISSION APPROVAL

MP requests Commission approval of its investments and expenditures in Bison 4 under Minn. Stat. §216B.1645 (Power Purchase Contract or Investment). Minn. Stat. §216B.1645, subd. 1 states:

> **216B.1645 POWER PURCHASE CONTRACT OR INVESTMENT.**
>
> Subdivision 1. **Commission authority.** Upon the petition of a public utility, the Public Utilities Commission shall approve or disapprove power purchase contracts, investments, or expenditures entered into or made by the utility to satisfy the wind and biomass mandates contained in sections 216B.169, 216B.2423, and 216B.2424, and to satisfy the renewable energy objectives and standards set forth in section 216B.1691, including reasonable investments and expenditures made to:
>
> (1) transmit the electricity generated from sources developed under those sections that is ultimately used to provide service to the utility's retail customers, including studies necessary to identify new transmission facilities needed to transmit electricity to Minnesota retail customers from generating facilities constructed to satisfy the renewable energy objectives and standards, provided that the costs of the studies have not been recovered previously under existing tariffs and the utility has filed an application for a certificate of need or for certification as a priority project under section 216B.2425 for the new transmission facilities identified in the studies;
>
> (2) provide storage facilities for renewable energy generation facilities that contribute to the reliability, efficiency, or cost-effectiveness of the renewable facilities; or
>
> (3) develop renewable energy sources from the account required in section 116C.779.

Therefore, given the facts in this proceeding, based on Minn. Stat. §216B.1645, subd. 1, the Commission may approve MP's petition only if it meets the requirements in Minn. Stat. §216B.1691.

Minn. Stat. §216B.1691, subd. 1 defines "eligible energy technology." Under this definition, a wind facility is an eligible energy technology. Also, Minn. Stat. §216B.1691, subd. 2a sets the following eligible energy technology standard for utilities not owning nuclear generating facilities:

> **216B.1691 RENEWABLE ENERGY OBJECTIVES.**
> Subd. 2a. **Eligible energy technology standard.** (a) Except as provided in paragraph (b), each electric utility shall generate or procure sufficient electricity generated by an eligible energy technology to provide its retail customers in Minnesota, or the retail customers of a distribution utility to which the electric utility provides wholesale electric service, so that at least the following standard percentages of the electric utility's total retail electric sales to retail customers in Minnesota are generated by eligible energy technologies by the end of the year indicated:
>
> (1) 2012 12 percent
> (2) 2016 17 percent
> (3) 2020 20 percent
> (4) 2025 25 percent.

Figure 7 of MP's petition shows that the Company's current renewable resources produce enough energy to meet 17.8 percent of its projected 2025 sales, and that the addition of Bison 4 would raise that percentage to 24.8 by the end of 2015. Thus, Bison 4 would greatly assist MP in its effort to meet its renewable energy requirements in 2020 and 2025. However, because MP needs no additional renewable energy to meet the requirements set forth in Minn. Stat. §216B.1691, subd. 2a, until 2020, it is also necessary to show that the addition of Bison 4 represents a reasonable resource addition to allow MP to optimally meet its future resource needs.

C. RESOURCE NEED

MP's most recent resource plan (Docket No. E015/RP-13-53) analyzed MP's future resource needs in detail. In its resource plan, MP determined that its least cost optimal expansion plan includes the addition of up to 200 MW of competitive wind in the next two to three years.[1] After reviewing MP's resource plan and conducting its own analysis, the Department recommended that the Commission require MP to add 100 to 200 MW of wind capacity in the 2014-2016 time frame as long as the resource is reasonably priced.[2] On September 25, 2013, the Commission approved MP's resource plan by motion.[3] Based on this analysis and the Commission's motion, the Department concludes that the proposed Bison 4 Wind Project would allow MP to meet its

[1] See MP's March 1, 2013 Integrated Resource Plan, page 77, in Docket No. E015/RP-13-53.
[2] See the Department's June 3, 2013 Comments, page 51, in Docket No. E015/RP-13-53.
[3] The Commission has not yet issued a written order in Docket No. E015/RP-13-53.

optimal resource expansion plan, thus minimizing the net present value of MP's future revenue requirements.

D. COST RECOVERY

Minn. Stat. §216B.1645, subd. 2 and subd. 2a identify the cost recovery process. They state:

> Subd. 2. **Cost recovery.** The expenses incurred by the utility over the duration of the approved contract or useful life of the investment and expenditures made pursuant to section 116C.779 shall be recoverable from the ratepayers of the utility, to the extent they are not offset by utility revenues attributable to the contracts, investments, or expenditures. Upon petition by a public utility, the commission shall approve or approve as modified a rate schedule providing for the automatic adjustment of charges to recover the expenses or costs approved by the commission under subdivision 1, which, in the case of transmission expenditures, are limited to the portion of actual transmission costs that are directly allocable to the need to transmit power from the renewable sources of energy. The commission may not approve recovery of the costs for that portion of the power generated from sources governed by this section that the utility sells into the wholesale market.
>
> Subd. 2a. **Cost recovery for utility's renewable facilities.**
> (a) A utility may petition the commission to approve a rate schedule that provides for the automatic adjustment of charges to recover prudently incurred investments, expenses, or costs associated with facilities constructed, owned, or operated by a utility to satisfy the requirements of section 216B.1691, provided those facilities were previously approved by the commission under section 216B.2422 or 216B.243, or were determined by the commission to be reasonable and prudent under section 216B.243, subdivision 9. For facilities not subject to review by the commission under section 216B.2422 or 216B.243, a utility shall petition the commission for eligibility for cost recovery under this section prior to requesting cost recovery for the facility. The commission may approve, or approve as modified, a rate schedule that:
> (1) allows a utility to recover directly from customers on a timely basis the costs of qualifying renewable energy projects, including:

> (i) return on investment;
> (ii) depreciation;
> (iii) ongoing operation and maintenance costs;
> (iv) taxes; and
> (v) costs of transmission and other ancillary expenses directly allocable to transmitting electricity generated from a project meeting the specifications of this paragraph;
>
> (2) provides a current return on construction work in progress, provided that recovery of these costs from Minnesota ratepayers is not sought through any other mechanism;
>
> (3) allows recovery of other expenses incurred that are directly related to a renewable energy project, including expenses for energy storage, provided that the utility demonstrates to the commission's satisfaction that the expenses improve project economics, ensure project implementation, advance research and understanding of how storage devices may improve renewable energy projects, or facilitate coordination with the development of transmission necessary to transport energy produced by the project to market;
>
> (4) allocates recoverable costs appropriately between wholesale and retail customers;
>
> (5) terminates recovery when costs have been fully recovered or have otherwise been reflected in a utility's rates.
>
> (b) A petition filed under this subdivision must include:
>
> (1) a description of the facilities for which costs are to be recovered;
>
> (2) an implementation schedule for the facilities;
>
> (3) the utility's costs for the facilities;
>
> (4) a description of the utility's efforts to ensure that costs of the facilities are reasonable and were prudently incurred; and
>
> (5) a description of the benefits of the project in promoting the development of renewable energy in a manner consistent with this chapter.

The Department notes that Minn. Stat. §216B.1645 contains two provisions related to Commission approval:

1. Subd. 1 requires the Commission to approve or disapprove the investment and expenditures associated with the renewable energy facilities, and

2. Subd. 2 states that upon petition of the public utility the Commission shall approve or or approve as modified a rate schedule providing for the automatic adjustment of charges to recover the expenses or costs approved by the Commission under subdivision 1. Moreover, subdivision 2a more specifically itemizes the cost components that may be recovered by a utility that constructs, owns, or operates the renewable energy facility.

The Department further notes that the second cost recovery provision is closely related to the first provision. In particular, subdivision 2 of Minn. Stat. §216B.1645 allows for automatic adjustment of charges to recover the expenses or costs approved by the Commission under subdivision 2 for service to retail customers.

Therefore, based on Minn. Stat. §216B.1645 and the discussion above, the Department concludes that Commission approval of the investment and expenditures for Bison 4, under subdivision 1, requires MP to include in its petition for automatic adjustment of charges only the investment and expenditures approved by the Commission under subdivision 1 for service to retail customers. If MP's petition is approved, then upon MP's eventual filing for automatic adjustments to charges, the Department expects these cost adjustments to include only costs that were approved by the Commission under subdivision 1.

II. IS THE PROPOSED BISON 4 WIND PROJECT REASONABLE AND PRUDENT?

Given the Department's discussion and analysis in Sections I and II of these comments, the Department concludes that Bison 4 is reasonable if its costs are reasonable. Below is the Department's analysis of Bison 4's costs.

A. COST COMPARISONS

Below, the Department compares the estimated cost of Bison 4 to projects which were available to MP as alternatives to Bison 4, and to the costs of other wind projects which were recently approved by the Commission.

1. RFP Process

Bison 4 will be built and owned by the Company, but was selected among competing proposals via a competitive bidding process. When a wind facility is secured via a competitive bidding process, the cost of the facility is likely to be competitive and reasonable. MP issued a request for proposals (RFP) in March, 2013 for a wind project of up to 225 MW to be installed in the next two to three years. MP submitted its own proposal into the RFP and an independent evaluation was completed. The opinion of the independent evaluator is included as Exhibit 1 to MP's petition.

MP's RFP generated responses representing over 32 distinct projects, some of which had more than one associated proposal. Table A-1 of Exhibit 1 to MP's contains a summary of the bids received and the independent evaluator's initial estimate of each project's levelized cost.[4] As shown in the table, the levelized costs of the proposals received ranges from **[TRADE SECRET DATA HAS BEEN EXCISED]**.[5] MP and the independent evaluator conducted further analysis on the top ten bids and ultimately selected seven proposals, including MP's Bison 4 proposal, for a final evaluation. Table A-3 of Exhibit 1 contains the final ranking of the top seven projects.

The Department notes that Bison 4 appears twice in Table A-3, with two different estimates of the levelized cost of energy from the project. The difference between the two relates to MP's ability to utilize the federal wind production tax credit and tax benefits associated with accelerated depreciation. The less expensive of the two projects assumes that MP will be able to utilize all tax benefits generated by Bison 4 as those tax benefits are created. The more expensive of the two projects, referred to in the table as "Minnesota Power – Bison 4 (tax delay)" assumes that the Company will not be able to fully utilize all of the tax benefits as they are generated. MP explains on page 23 of its petition that it is anticipating a net tax operating loss in 2015, which will force it to defer some of the anticipated tax benefits into the future. To do so, MP will create deferred tax assets (DTAs) that will be included in rate base, increasing total allowed return and the levelized cost of Bison 4. On page 24 of its petition, MP states that the total levelized cost of Bison 4 is about $30/MWh when all tax impacts are considered, thus, the Department considers the "tax delay" scenario to be representative of MP's Bison 4 bid.[6]

Table A-3 demonstrates that, per the independent evaluator's analysis, the Bison 4 – Tax Delay project is the lowest cost option.[7] The Department notes that final levelized cost estimates of each proposal, shown in Table A-3 in the column titled "Total Project Cost" are comprised of three separate components: the bid price, debt equivalence adjustment, and a transmission adjustment. The bid price represents the levelized cost per MWh of each project. For Bison 4, the bid price shown is a levelized revenue requirement. All of the other projects shown in table A-3 are PPA proposals, and the bid prices represent the levelized contract price per MWh over the life of each PPA.

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[4] For projects which had multiple, distinct proposals, Table A-1 presents the levelized cost of the proposal with the lowest levelized cost.

[5] The Department notes that the initial levelized cost of Bison 4 was later revised upwards, as discussed below.

[6] Additionally, a representative of the Company confirmed during a telephone call that the Company considers the "tax delay" scenario to be the most likely scenario.

[7] The Department notes that the independent evaluator calculated two separate metrics to rank the projects: a total project cost (i.e. the levelized cost of energy per MWh) and a project market value which incorporates forecasts of energy and capacity costs. The Department's analysis focuses on the former.

The transmission adjustment is an adjustment made to reflect differentials between locational marginal prices (LMPs) at the injection node of each project and LMPs at MP's load node. For each of the PPA proposals, MP would purchase the energy at the wind facility and inject the energy into the transmission system near the wind facility, and withdraw the energy at its load node. The structure of this transaction is such that the Midcontinent Independent System Operator will effectively buy the energy from the facility from MP at the prevailing LMP per MWh at the injection node, and then sell energy back to MP at the prevailing LMP at the withdrawal node. While the LMPs at injection and withdrawal nodes are generally roughly equal, differences can arise due to transmission congestion and line losses, and MP's ratepayers would be responsible for those differences. The transmission adjustment represents a historical average of the differences between the LMPs at the relevant nodes for each proposal.

The debt equivalence adjustment is an adjustment made to reflect the impact of each project on MP's overall cost of capital. In its response to Department Information Request No. 11, MP explained that credit ratings agencies view PPAs as having debt-like qualities, and thus after executing a PPA, a utility must issue equity to preserve its capital structure and maintain its credit rating.[8] The debt equivalence adjustment reflects the costs associated with that additional equity. As part of the same response, MP provided a document from Standard & Poor's (S&P) titled "Standard & Poor's Methodology For Imputing Debt for U.S. Utilities' Power Purchase Agreements." The first paragraph of that document states:

> For many years, Standard & Poor's Ratings Services has viewed power supply agreements (PPA) in the U.S. utility sector as creating fixed, debt-like, financial obligations that represent substitutes for debt-financed capital investments in in generation capacity. In a sense, a utility that has entered into a PPA has contracted with a supplier to make the financial investment on its behalf. Consequently, **PPA fixed obligations, in the form of capacity payments,** merit inclusion in a utility's financial metrics as though they are part of the utility's permanent capital structure and are incorporated in our assessment of a utility's creditworthiness **[emphasis added].**

Based on this language, as well as the remainder of the document, the Department concludes that the debt equivalence adjustment is appropriate only if the PPA includes a fixed capacity payment.

In response to Department Information Request No. 10, MP provided the Microsoft Excel spreadsheet used to calculate the levelized bid price and debt equivalence adjustment for each proposal. Based on the Department's review of that spreadsheet, it appears that the PPA

[8] MP's response to Department Information Request No. 11 is included with these Comments as Attachment 1.

proposals are for energy-delivery only, and do not require fixed capacity credits. Thus, the Department concludes that the debt equivalence adjustment is inappropriate. The Department requests that MP indicate in reply comments whether the PPA proposals shown in Table A-3 include fixed capacity payments.

Additionally, the Department notes that MP's estimated levelized cost for the Bison 4 – Tax Delay scenario differs slightly from the independent evaluator's estimated levelized cost. As noted above, on page 24 of its petition, MP states that, when the total impact of the net operating loss (NOL) and production tax credit (PTC) DTAs are included, the total levelized cost of Bison 4 is about $30/MWh (excluding the transmission adjustment).[9] Column [e] in Table 1 below presents the total costs of each project excluding the debt equivalence adjustment. Table 1 also presents MP's estimate of the levelized cost of Bison 4 – Tax Delay, in addition to the independent consultant's estimate.

Table 1
Total Project Cost
Excluding Debt Equivalence Adjustment

Project	Capacity (MW)	Term (Yrs.)	As Presented in Petition, Table A-3 Bid Price ($/MWh)	Debt Equivalence Adjustment ($/MWh)	Final Transmission Adjustment ($/MWh)	Total Project Cost ($/MWh)	Total Cost Excluding Debt Equivalence Adjustment ($/MWh)
			[a]	[b]	[c]	[d]=[a]+[b]+[c]	[e]=[a]+[c]
Bison 4 - Tax Delay	208	35					
Bison 4 - Tax Delay MP ESTIMATE	208	35					
National Wind - High Country	150	25	**TRADE SECRET DATA HAS BEEN EXCISED**				
National Wind - Lake Country	40	25					
Geronimo - Odell	200	20					
RES Americas - Pleasant Valley	200	25					
Duke - Thunder Spirit	150	25					
RES Americas - Border Winds	150	20					

Source: Petition, Exhibit 1, Table A-3. Bison 4 - Tax Delay MP ESTIMATE Bid price from page 24 of MP's petition.

As shown, when debt equivalence adjustments are removed from the levelized cost estimates, the Bison 4 project is no longer the lowest cost option, although the levelized costs of the top proposals are tightly clustered, and the differences between the projects are small. Additionally, the Department notes that of the four projects which have lower levelized costs than Bison 4, one (National Wind – Lake Country) is only 40 MW, two (Geronimo – Odell and RES Americas – Pleasant Valley) recently executed agreements with Xcel Energy and are presumably no longer

[9] The Company provided the Department the revenue requirements used to calculate the $30/MWh levelized cost reflecting the impacts of the DTAs. A summary of those revenue requirements is included in Attachment 2.

available to MP.[10] Additionally, National Wind recently announced that it has terminated the High Country project.[11]

The Department has one additional concern related to MP's estimate of Bison 4's levelized cost. In its analysis, MP assumes a capacity factor of 46.5 percent.[12] The Department notes that the assumed capacity factors for Bison 1, 2, and 3 were 45.12 percent, 41.31 percent, and 39.68 percent.[13] Thus, while Bison 4's assumed capacity factor is not clearly unreasonably high, it is slightly higher than the average capacity factor for the other three, geographically similar, Bison projects. The Department requests that MP provide additional support for its assumed capacity factor in reply comments and explain the differences between Bison 4 and the other three Bison projects.

2. Recent Wind Projects

Table 2 below compares the levelized cost of Bison 4 to the levelized costs of MP's three other Bison projects and five projects approved recently by the Commission.

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[10] See Docket No. E002/M-13-603.

[11] A copy of a news article regarding National Wind's announcement is included in these comments as Attachment 3.

[12] On page 11 of its petition, MP states that Bison 4's estimated annual average energy production will be 835,000 MWh, which, on a 204.8 MW facility translates to a 46.5 percent capacity factor (835,000 MWh / (204.8 MW x 8760 hours per year)).

[13] See MP's petitions in Docket Nos. E015/M-09-285, E015/M-11-234, and E015/M-11-626. The capacity factors were calculated in the manner demonstrated in footnote 12.

Table 2
Levelized Cost Comparison

Project	Docket No.	Levelized Cost ($/MWh)
MP		
Bison 1	E015/M-09-285	
Bison 2	E015/M-11-234	
Bison 3	E015/M-11-626	
Xcel Energy		
Odell	E002/M-13-603	**TRADE SECRET DATA HAS BEEN EXCISED**
Courtenay	E002/M-13-603	
Pleasant Valley	E002/M-13-603	
Border Winds	E002/M-13-716	
Otter Tail Power		
Ashtabula Wind III	E017/M-13-386	
Average of Xcel and Otter Tail Projects		
Bison 4 (Proposed)		30.10

As shown, the levelized cost of Bison 4 is slightly higher than the average levelized cost of the five recently approved projects shown.

3. Conclusion Regarding the Cost of the Bison 4 Wind Project

Bison 4 is slightly more expensive than other recently approved projects, however its cost is generally competitive with those projects and the other options available to MP. Therefore, the Department concludes that the cost of Bison 4 is reasonable.

B. TRANSMISSION AND CURTAILMENT

In its petition, MP states that it will use its DC line and available non-firm AC transmission to transmit the output of Bison 4 from North Dakota to the Company's service territory. The DC line is a 500 MW transmission line owned by MP and shared with Minnkota Power. By the time Bison 4 is placed into service in late 2014, the Company expects to have completed an upgrade to its DC line which will increase the line's capacity from 500 MW to 550 MW, and Minnkota Power will have discontinued using the DC line, giving MP full access to the line. The upgraded

DC line by itself, however, will not meet the full transmission needs of the Company, and MP will have to rely on available non-firm transmission on the AC system.

To assess the availability of non-firm capacity on the AC transmission system, MP included in its petition an analysis of the export limit around North Dakota's north, south, and east borders, referred to as NDEX. On page 16 of its petition, MP states that although the total current firm transfer capability of the NDEX is reserved under long-term contracts, **[TRADE SECRET DATA HAS BEEN EXCISED].**

Additionally, in its response to Department Information Request No. 7,[14] the Company explained that it has approval from the Midcontinent Independent System Operator (MISO) for Network Resource Integration Service (NRIS) interconnection status for Bison 4. To be awarded NRIS status, a project must be demonstrated to be capable of delivering into the transmission system while maintaining all reliability standards under a variety of stressed conditions.

Based on this analysis, the Department concludes that the risk of curtailment for Bison 4 is low. However, as it has with MP's other Bison wind projects, the Department recommends that the Commission require MP to report the dates and amount of any curtailment of Bison 4 output resulting from use of the AC system.

III. CONCLUSION AND RECOMMENDATIONS

Based on the analysis above, the Department expects to recommend approval of MP's petition, but requests that MP provide in reply comments further support for its assumed capacity factor for Bison 4. The Department will make a final recommendation to the Commission after it reviews MP's reply comments.

/ja

[14] MP's response to Department Information Request No. 7 is included with the Comments as Attachment 3.

State of Minnesota
DEPARTMENT OF COMMERCE
DIVISION OF ENERGY RESOURCES

Utility Information Request

Docket Number: E015/M-13-907 Date of Request: October 18, 2013

Requested From: Lori Hoyum, Minnesota Power Response Due: October 30, 2013

Analyst Requesting Information: Craig Addonizio

Type of Inquiry:			
	[ ].....Financial	[ ].....Rate of Return	[ ].....Rate Design
	[ ].....Engineering	[ ].....Forecasting	[ ].....Conservation
	[ ].....Cost of Service	[ ].....CIP	[X]...Other:

If you feel your responses are trade secret or privileged, please indicate this on your response.

Request No.

11. Reference: Debt Equivalence Adjustment

a. Please provide a fuller explanation of the debt equivalence adjustment and why it is included in this analysis.

b. Please provide support for the assertion that credit ratings agencies view PPAs as being partially equivalent to debt obligations made in Exhibit 1, page 4, footnote 2.

c. Does the bid price for the Bison 4 project reflect MP's allowed return? If not, please explain why there is no Debt Equivalence Adjustment included for the Bison 4 Project.

d. Are all of the proposals shown in Table A-2 (except for Bison 4) PPA proposals?

e. Are Debt Equivalence Adjustments required only for PPA proposals (and are not require for build-own-transfer proposals)?

Response by: Kevin Lindstrom List sources of information:

Title: Energy Supply Planning Manager

Department: Energy Supply Asset Optimization

Telephone: (218) 355-3986

Response:

a. Debt equivalence adjustments are typically included in utility power procurement analyses to reflect the impact that executing a long-term power purchase agreement ("PPA") can have on a utility's credit rating. Specifically, credit rating agencies (e.g., S&P, Moody's, Fitch) view PPAs as having debt-like qualities. Thus, at some point after executing a PPA, a utility must issue additional equity to rebalance its balance sheet and preserve its debt/equity ratio so that its original credit rating is maintained. The debt equivalence costs that Sedway Consulting calculated for each PPA proposal in Minnesota Power's 2013 Wind Resource Request reflected the expected incremental costs of such additional equity issuances. The methodology for the debt equivalence adjustment that Sedway Consulting calculated was identical to the methodology that it and utilities have used for many years around the country in other power supply solicitations and is based on guidance from S&P. The details of the calculations are reflected in the "DE" worksheet in Sedway Consulting's Renewable Bid Evaluation Model that was provided in response to DOC IR 010, item b (see DOC IR 010.2 Attachment TS).

b. Please see the attached S&P material titled "MP Bison 4 - DOC IR 011 - S&P Imputed Debt.pdf" (see DOC IR 011.1 Attachment) that describes the rating agency's approach to debt equivalence/imputed debt.

c. Yes.

d. Yes.

e. Yes.

Response by:	Kevin Lindstrom	List sources of information:
Title:	Energy Supply Planning Manager	
Department:	Energy Supply Asset Optimization	
Telephone:	(218) 355-3986	

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Department Attachment 1
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STANDARD
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May 7, 2007

Criteria | Corporates | Utilities:

Standard & Poor's Methodology For Imputing Debt For U.S. Utilities' Power Purchase Agreements

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Criteria | Corporates | Utilities:

Standard & Poor's Methodology For Imputing Debt For U.S. Utilities' Power Purchase Agreements

For many years, Standard & Poor's Ratings Services has viewed power supply agreements (PPA) in the U.S. utility sector as creating fixed, debt-like, financial obligations that represent substitutes for debt-financed capital investments in generation capacity. In a sense, a utility that has entered into a PPA has contracted with a supplier to make the financial investment on its behalf. Consequently, PPA fixed obligations, in the form of capacity payments, merit inclusion in a utility's financial metrics as though they are part of a utility's permanent capital structure and are incorporated in our assessment of a utility's creditworthiness.

We adjust utilities' financial metrics, incorporating PPA fixed obligations, so that we can compare companies that finance and build generation capacity and those that purchase capacity to satisfy customer needs. The analytical goal of our financial adjustments for PPAs is to reflect fixed obligations in a way that depicts the credit exposure that is added by PPAs. That said, PPAs also benefit utilities that enter into contracts with suppliers because PPAs will typically shift various risks to the suppliers, such as construction risk and most of the operating risk. PPAs can also provide utilities with asset diversity that might not have been achievable through self-build. The principal risk borne by a utility that relies on PPAs is the recovery of the financial obligation in rates.

The Mechanics Of PPA Debt Imputation

A starting point for calculating the debt to be imputed for PPA-related fixed obligations can be found among the "commitments and contingencies" in the notes to a utility's financial statements. We calculate a net present value (NPV) of the stream of the outstanding contracts' capacity payments reported in the financial statements as the foundation of our financial adjustments.

The notes to the financial statements enumerate capacity payments for the five years succeeding the annual report and a "thereafter" period. While we have access to proprietary forecasts that show the detail underlying the costs that are amalgamated beyond the five-year horizon, others, for purposes of calculating an NPV, can divide the amount reported as "thereafter" by the average of the capacity payments in the preceding five years to derive an approximate tenor of the amounts combined as the sum of the obligations beyond the fifth year.

In calculating debt equivalents, we also include new contracts that will commence during the forecast period. Such contracts aren't reflected in the notes to the financial statements, but relevant information regarding these contracts are provided to us on a confidential basis. If a contract has been executed but the energy will not flow until some later period, we won't impute debt for that contract until the year that energy deliveries begin under the contract if the contract represents incremental capacity. However, to the extent that the contract will simply replace an expiring contract, we will impute debt as though the future contract is a continuation of the existing contract.

We calculate the NPV of capacity payments using a discount rate equivalent to the company's average cost of debt, net of securitization debt. Once we arrive at the NPV, we apply a risk factor, as is discussed below, to reflect the benefits of regulatory or legislative cost recovery mechanisms.

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Balance sheet debt is increased by the risk-factor-adjusted NPV of the stream of capacity payments. We derive an adjusted debt-to-capitalization ratio by adding the adjusted NPV to both the numerator and the denominator of that ratio.

We calculate an implied interest expense for the imputed debt by multiplying the same utility average cost of debt used as the discount rate in the NPV calculation by the amount of imputed debt. The adjusted FFO-to-interest expense ratio is calculated by adding the implied interest expense to both the numerator and denominator of the equation. We also add implied depreciation to the equation's numerator. We calculate the adjusted FFO-to-total-debt ratio by adding imputed debt to the equation's denominator and an implied depreciation expense to its numerator.

Our adjusted cash flow credit metrics include a depreciation expense adjustment to FFO. This adjustment represents a vehicle for capturing the ownership-like attributes of the contracted asset and tempers the effects of imputation on the cash flow ratios. We derive the depreciation expense adjustment by multiplying the relevant year's capacity payment obligation by the risk factor and then subtracting the implied PPA-related interest expense for that year from the product of the risk factor times the scheduled capacity payment.

Risk Factors

The NPVs that Standard & Poor's calculates to adjust reported financial metrics to capture PPA capacity payments are multiplied by risk factors. These risk factors typically range between 0% to 50%, but can be as high as 100%. Risk factors are inversely related to the strength and availability of regulatory or legislative vehicles for the recovery of the capacity costs associated with power supply arrangements. The strongest recovery mechanisms translate into the smallest risk factors. A 100% risk factor would signify that all risk related to contractual obligations rests on the company with no mitigating regulatory or legislative support.

For example, an unregulated energy company that has entered into a tolling arrangement with a third-party supplier would be assigned a 100% risk factor. Conversely, a 0% risk factor indicates that the burden of the contractual payments rests solely with ratepayers. This type of arrangement is frequently found among regulated utilities that act as conduits for the delivery of a third party's electricity and essentially deliver power, collect charges, and remit revenues to the suppliers. These utilities have typically been directed to sell all their generation assets, are barred from developing new generation assets, and the power supplied to their customers is sourced through a state auction or third parties, leaving the utilities to act as intermediaries between retail customers and the electricity suppliers.

Intermediate degrees of recovery risk are presented by a number of regulatory and legislative mechanisms. For example, some regulators use a utility's rate case to establish base rates that provide for the recovery of the fixed costs created by PPAs. Although we see this type of mechanism as generally supportive of credit quality, the fact remains that the utility will need to litigate the right to recover costs and the prudence of PPA capacity payments in successive rate cases to ensure ongoing recovery of its fixed costs. For such a PPA, we employ a 50% risk factor. In cases where a regulator has established a power cost adjustment mechanism that recovers all prudent PPA costs, we employ a risk factor of 25% because the recovery hurdle is lower than it is for a utility that must litigate time and again its right to recover costs.

We recognize that there are certain jurisdictions that have true-up mechanisms that are more favorable and frequent than the review of base rates, but still don't amount to pure pass-through mechanisms. Some of these mechanisms

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are triggered when certain financial thresholds are met or after prescribed periods of time have passed. In these instances, in calculating adjusted ratios, we will employ a risk factor between the revised 25% risk factors for utilities with power cost adjustment mechanisms and 50%.

Finally, we view legislatively created cost recovery mechanisms as longer lasting and more resilient to change than regulatory cost recovery vehicles. Consequently, such mechanisms lead to risk factors between 0% and 15%, depending on the legislative provisions for cost recovery and the supply function borne by the utility. Legislative guarantees of complete and timely recovery of costs are particularly important to achieving the lowest risk factors.

Illustration Of The PPA Adjustment Methodology

The calculations of the debt equivalents, implied interest expense, depreciation expense, and adjusted financial metrics, using risk factors, are illustrated in the following example:

Example Of Power-Purchase Agreement Adjustment

($000s)	**Assumption**	**Year 1**	**Year 2**	**Year 3**	**Year 4**	**Year 5**	**Thereafter**
Cash from operations	2,000,000						
Funds from operations	1,500,000						
Interest expense	444,000						
Directly issued debt							
Short-term debt	600,000						
Long-term due within one year	300,000						
Long-term debt	6,500,000						
Shareholder's Equity	6,000,000						
Fixed capacity commitments	600,000	600,000	600,000	600,000	600,000	600,000	4,200,000*
NPV of fixed capacity commitments							
Using a 6.0% discount rate	5,030,306						
Application of an assumed 25% risk factor	1,257,577						
Implied interest expense¶	75,455						
Implied depreciation expense	74,545						
Unadjusted ratios							
FFO to interest (x)	4.4						
FFO to total Debt (%)	20.0						
Debt to capitalization (%)	55.0						
Ratios adjusted for debt imputation							
FFO to interest (x)§	4.0						
FFO to total debt (%)**	18.0						
Debt to capitalization (%)¶¶	59.0						

*Thereafter approximate years: 7. ¶The current year's implied interest is subtracted from the product of the risk factor multiplied by the current year's capacity payment. §Adds implied interest to the numerator and denominator and adds implied depreciation to FFO. **Adds implied depreciation expense to FFO and implied debt to reported debt. ¶¶Adds implied debt to both the numerator and the denominator. FFO--Funds from operations. NPV--Net present value.

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Short-Term Contracts

Standard & Poor's has abandoned its historical practice of not imputing debt for contracts with terms of three years or less. However, we understand that there are some utilities that use short-term PPAs of approximately one year or less as gap fillers pending the construction of new capacity. To the extent that such short-term supply arrangements represent a nominal percentage of demand and serve the purposes described above, we will neither impute debt for such contracts nor provide evergreen treatment to such contracts.

Evergreen Treatment

The NPV of the fixed obligations associated with a portfolio of short-term or intermediate-term contracts can lead to distortions in a utility's financial profile relative to the NPV of the fixed obligations of a utility with a portfolio of PPAs that is made up of longer-term commitments. Where there is the potential for such distortions, rating committees will consider evergreen treatment of existing PPA obligations as a scenario for inclusion in the rating analysis. Evergreen treatment extends the tenor of short- and intermediate-term contracts to reflect the long-term obligation of electric utilities to meet their customers' demand for electricity.

While we have concluded that there is a limited pool of utilities whose portfolios of existing and projected PPAs don't meaningfully correspond to long-term load serving obligations, we will nevertheless apply evergreen treatment in those cases where the portfolio of existing and projected PPAs is inconsistent with long-term load-serving obligations. A blanket application of evergreen treatment is not warranted.

To provide evergreen treatment, Standard & Poor's starts by looking at the tenor of outstanding PPAs. Others can look to the "commitments and contingencies" in the notes to a utility's financial statements to derive an approximate tenor of the contracts. If we conclude that the duration of PPAs is short relative to our targeted tenor, we would then add capacity payments until the targeted tenor is achieved. Based on our analysis of several companies, we have determined that the evergreen extension of the tenor of existing contracts and anticipated contracts should extend contracts to a common length of about 12 years.

The price for the capacity that we add will be derived from new peaker entry economics. We use empirical data to establish the cost of developing new peaking capacity and reflect regional differences in our analysis. The cost of new capacity is translated into a dollars per kilowatt-year (kW-year) figure using a weighted average cost of capital for the utility and a proxy capital recovery period.

Analytical Treatment Of Contracts With All-In Energy Prices

The pricing for some PPA contracts is stated as a single, all-in energy price. Standard & Poor's considers an implied capacity price that funds the recovery of the supplier's capital investment to be subsumed within the all-in energy price. Consequently, we use a proxy capacity charge, stated in $/kW, to calculate an implied capacity payment associated with the PPA. The $/kW figure is multiplied by the number of kilowatts under contract. In cases of resources such as wind power that exhibit very low capacity factors, we will adjust the kilowatts under contract to reflect the anticipated capacity factor that the resource is expected to achieve.

We derive the proxy cost of capacity using empirical data evidencing the cost of developing new peaking capacity.

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We will reflect regional differences in our analysis. The cost of new capacity is translated into a $/kW figure using a weighted average cost of capital and a proxy capital recovery period. This number will be updated from time to time to reflect prevailing costs for the development and financing of the marginal unit, a combustion turbine.

Transmission Arrangements

In recent years, some utilities have entered into long-term transmission contracts in lieu of building generation. In some cases, these contracts provide access to specific power plants, while other transmission arrangements provide access to competitive wholesale electricity markets. We have concluded that these types of transmission arrangements represent extensions of the power plants to which they are connected or the markets that they serve. Irrespective of whether these transmission lines are integral to the delivery of power from a specific plant or are conduits to wholesale markets, we view these arrangements as exhibiting very strong parallels to PPAs as a substitute for investment in power plants. Consequently, we will impute debt for the fixed costs associated with long-term transmission contracts.

PPAs Treated As Leases

Several utilities have reported that their accountants dictate that certain PPAs need to be treated as leases for accounting purposes due to the tenor of the PPA or the residual value of the asset upon the PPA's expiration. We have consistently taken the position that companies should identify those capacity charges that are subject to operating lease treatment in the financial statements so that we can accord PPA treatment to those obligations, in lieu of lease treatment. That is, PPAs that receive operating lease treatment for accounting purposes won't be subject to a 100% risk factor for analytical purposes as though they were leases. Rather, the NPV of the stream of capacity payments associated with these PPAs will be reduced by the risk factor that is applied to the utility's other PPA commitments. PPAs that are treated as capital leases for accounting purposes will not receive PPA treatment because capital lease treatment indicates that the plant under contract economically "belongs" to the utility.

Evaluating The Effect Of PPAs

Though history is on the side of full cost recovery, PPAs nevertheless add financial obligations that heighten financial risk. Yet, we apply risk factors that reduce debt imputation to recognize that utilities that rely on PPAs transfer significant risks to ratepayers and suppliers.

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Bison 4 Wind Project
Summary of Revenue Requirements and Levelized Cost

	Revenue Requirement by Project Component							
Year	Bison 4 Wind	Bison 4 Substation	Tri-County Substation	230 kV Line Ext	Center-Hesket Line Upgrade	On-Going Capital Expenditures	Total Revenue Requirement	Annual Generation (MWh)
2014	24,966,731	187,922	431,271	701,410	155,970	-	26,443,303	-
2015	19,171,993	464,058	744,363	926,825	203,900	1,666	21,512,805	835,000
2016	18,820,583	443,030	711,394	885,811	199,297	4,795	21,064,911	835,000
2017	13,894,156	423,484	680,706	847,760	195,049	40,245	16,081,399	835,000
2018	10,639,511	405,268	652,068	812,374	191,123	79,702	12,780,046	835,000
2019	9,575,661	388,250	625,275	779,370	185,122	115,991	11,669,669	835,000
2020	10,886,704	372,256	600,058	746,792	179,194	150,274	12,935,278	835,000
2021	11,598,718	356,719	575,545	714,628	173,264	183,010	13,601,885	835,000
2022	13,787,805	341,182	551,032	682,462	167,334	214,526	15,744,340	835,000
2023	13,141,756	325,637	526,506	650,297	161,404	245,466	15,051,067	835,000
2024	9,309,558	310,092	501,981	618,133	155,474	276,152	11,171,390	835,000
2025	44,961,737	294,547	477,456	585,969	149,543	306,567	46,775,820	835,000
2026	37,843,946	279,002	452,931	553,805	143,613	336,697	39,609,994	835,000
2027	32,112,427	263,457	428,405	521,641	137,683	366,525	33,830,140	835,000
2028	29,673,343	247,912	403,880	489,477	132,399	396,036	31,343,048	835,000
2029	29,143,002	232,950	380,253	463,420	128,411	425,211	30,773,247	835,000
2030	28,615,356	222,636	363,783	447,144	125,069	454,034	30,228,022	835,000
2031	28,090,464	216,395	353,584	434,525	121,727	482,487	29,699,182	835,000
2032	27,568,389	210,154	343,386	421,906	118,385	510,550	29,172,770	835,000
2033	27,049,190	203,912	333,188	409,288	115,043	538,204	28,648,825	835,000
2034	26,532,933	197,671	322,989	396,669	111,701	565,430	28,127,393	835,000
2035	26,019,681	191,429	312,791	384,051	108,359	7,683,491	34,699,802	835,000
2036	25,509,500	185,188	302,593	371,432	105,017	9,166,758	35,640,488	835,000
2037	25,002,459	178,947	292,395	358,813	101,675	10,498,659	36,432,948	835,000
2038	24,498,626	172,705	282,196	346,195	98,333	11,733,032	37,131,088	835,000
2039	23,998,071	166,464	271,998	333,576	94,991	12,888,928	37,754,028	835,000
2040	23,500,868	160,223	261,800	320,957	91,649	4,349,866	28,685,364	835,000
2041	23,007,089	153,981	251,602	308,339	88,307	3,871,000	27,680,319	835,000
2042	22,516,810	147,740	241,403	295,720	84,966	3,543,607	26,830,246	835,000
2043	22,030,108	141,498	231,205	283,102	81,624	3,306,807	26,074,344	835,000
2044	21,547,063	135,257	221,007	270,483	78,282	3,138,506	25,390,596	835,000
2045	21,067,753	129,016	210,808	257,864	74,940	3,022,140	24,762,520	835,000
2046	20,592,261	122,774	200,610	245,246	71,598	2,922,725	24,155,214	835,000
2047	20,120,672	116,533	190,412	232,627	68,256	2,590,393	23,318,892	835,000
2048	19,653,070	110,291	180,214	220,008	64,914	2,340,197	22,568,694	835,000
2049	18,808,806	104,050	170,015	207,390	61,572	2,136,731	21,488,564	835,000
Net Present Value (at 8.18%)							265,933,104	8,833,899
Levelized Cost								30.10

SE Minnesota wind project terminated

Posted: Friday, October 25, 2013 7:27 am

Another wind power project has been terminated in southeastern Minnesota.

Developers have pulled the plug on the $500 million High Country Energy project after years of planning and preliminary development. The project was being developed by National Wind, a subsidiary of Trishe Renewable Energy Solutions, of India.

In a letter to investors and landowners, National Wind President Vivek Mittal says the company has not been able to acquire enough contiguous acres for the project or win broad community support. The Post-Bulletin (http://bit.ly/19DEfdG) says when the project was initially proposed in 2007, it was to cover 50 square miles in Olmsted, Dodge and Mower counties.

Earlier this month, the Minnesota Public Utilities Commission revoked a site permit for the New Era wind farm in Goodhue County, ending a five-year permitting battle.

Information from: Post-Bulletin, http://www.postbulletin.com

State of Minnesota
DEPARTMENT OF COMMERCE
DIVISION OF ENERGY RESOURCES

Utility Information Request

Docket Number: E015/M-13-907 Date of Request: October 18, 2013

Requested From: Lori Hoyum, Minnesota Power Response Due: October 30, 2013

Analyst Requesting Information: Craig Addonizio

Type of Inquiry:			
	[ ]....Financial	[ ]....Rate of Return	[ ]....Rate Design
	[ ]....Engineering	[ ]....Forecasting	[ ]....Conservation
	[ ]....Cost of Service	[ ]....CIP	[X]...Other:

If you feel your responses are trade secret or privileged, please indicate this on your response.

Request No.

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7. Reference: Interconnection Status

Please explain what type of interconnection status MP expects the Bison 4 Project to receive from MISO (e.g. NRIS, ERIS with firm transmission service).

Response:

Minnesota Power has approval for Network Resource Integration Service ("NRIS") for its Bison projects. An interconnection study for NRIS ensures that the generating facility will qualify as a network resource for any entity serving network load under the Midcontinent Independent System Operator's ("MISO") Tariff, without need for additional study representing the highest level of interconnection service.

The NRIS designation for the Bison wind farms provides Minnesota Power with the assurance that its generation was studied at a superior standard to ERIS *[placeholder for acronym explanation]*. In a situation where transmission limitations may occur, based on a region-wide economic dispatch, the market will limit other generation within the footprint as much as reliably and economically possible before curtailing wind generation that has NRIS status. Even if the wind generation is curtailed, the network load (Minnesota Power's customers) is still served by MISO aggregate generation.

Response by:	Cindy Hammarlund	List sources of information:
Title:	Transmission Marketing Manager	
Department:	Strategy & Planning	
Telephone:	(218) 723-3970	

Minnesota Power has approval for NRIS for its Bison projects with the Minnkota Center to Grand Forks 345 kV transmission line in service, which minimizes the probability of reliability impacts on the transmission system that would require curtailment. Generally, for both NRIS and ERIS, the facility's interconnection request is studied with the transmission system at both off-peak and peak loads. In addition, for NRIS, the facility's interconnection is studied at peak-load scenario under a variety of severely stressed conditions, to determine whether, with the generating facility at full output, the aggregate of generation in the local area can be delivered to the aggregate of load on the transmission system or distribution system, while maintaining all applicable reliability standards. Ultimately, this means that the resource can be claimed by a Market Participant as a capacity resource without need for acquiring additional firm transmission service.

Response by: Cindy Hammarlund

Title: Transmission Marketing Manager

Department: Strategy & Planning

Telephone: (218) 723-3970

List sources of information:

CERTIFICATE OF SERVICE

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

Minnesota Department of Commerce
Comments

Docket No. E015/M-13-907

Dated this **12th** day of **November, 2013**

/s/Sharon Ferguson

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