MONTANA-DAKOTA UTILITIES CO.
A Division of MDU Resources Group, Inc.

Before the Public Service Commission of North Dakota

Case No. PU-11-395 and PU-11-396

Rebuttal Testimony
of
Darcy J. Neigum

Q. Please state your name and business address.

A. My name is Darcy J. Neigum and my business address is 400 North Fourth Street, Bismarck, North Dakota 58501.

Q. What is your position with Montana-Dakota Utilities Co.?

A. I am the System Operations and Planning Manager of Montana-Dakota Utilities Co. (Montana-Dakota), a Division of MDU Resources Group, Inc.

Q. Are you the same Darcy J. Neigum that submitted Direct Testimony in this proceeding?

A. Yes, I am.

Q. What is the purpose of this rebuttal testimony?

A. The purposes of my rebuttal testimony is to respond to the Initial Testimony of Mr. Richard Hahn filed on behalf of the North Dakota Public Service Commission Advocacy Staff on December 12, 2011 in this proceeding. I will address why the Company's request for an Advance Determination of Prudence (ADP) and a Certificate of Public Convenience and Necessity (CPCN) for an 88 MW simple cycle combustion turbine near the R.M. Heskett Station in Mandan, North Dakota (CT Project) is in the best interest of Montana-Dakota's customers. I will demonstrate that the need for additional resources identified by the Company and accepted by Mr. Hahn are best met with the addition of an on-system resource. I will address Mr. Hahn's comments relative to resource alternatives modeled by the Company and the results of Mr. Hahn's Alternative Analysis.

Q. Would you please summarize why the Commission should not adopt Mr. Hahn's recommendation and instead approve the Company's request for an ADP and a CPCN for the CT Project as a needed and prudent resource for meeting the generation capacity requirements of its customers?

A. Yes. As explained in more detail below, Mr. Hahn's Alternative Analysis indicating that a power purchase agreement from an Illinois combustion turbine resource (IL Proposal) is significantly less costly than the Company's 88 MW Combustion Turbine Project substantially overstates any cost advantage of the IL Proposal and does not address the benefits associated with addition of a generating resource within the Company's integrated system. Mr. Hahn's allegation that the Company's modeling unduly biased the 88 MW Combustion Turbine Project is not correct as I will discuss in detail below and the risks associated with the purchase power agreement located outside Montana-Dakota's service area have not been adequately addressed by Mr. Hahn.

Finally, the use of capacity credits from the IL Proposal is only a paper transaction that does not provide the ability to physically deliver the energy from the project to Montana-Dakota's service area and is not a prudent long-term resource for Montana-Dakota's customers.

NEED FOR THE RESOURCE

Q. Does Mr. Hahn dispute Montana-Dakota's need for capacity resources in the future?

A. No, as Mr. Hahn indicates on Page 17 of his Initial Testimony, "The load forecast combined with the expiration of existing contracts in the 2011 to 2015 time period demonstrate a need for some new capacity."

Q. What is causing Montana-Dakota's need for capacity resources in 2015?

A. Montana-Dakota's need for capacity resources is driven by customer growth and the expiration of the We Energies capacity purchase agreement in May of 2015 at which point the Company is forecasted to be deficit 149 MWs or 149 MISO planning resource credits (PRCs) representing 25.3 percent of the total required PRCs.

Q. What were the Company's growth projections in the 2011 Integrated Resource Plan (2011 IRP)?

A. The five year growth levels included in the 2011 IRP were 5.2 percent for energy requirements and 2.3 percent for demand requirements, which is reduced by the forecasted impact of new demand response programs.

Q. What are the actual growth levels that the Company has seen in 2011?

A. Even with an unseasonably cool summer, retail sales through November 2011 are 1.5 percent above those for the same period in the 2011 IRP. The Company also set an all-time summer peak of 535 MW in August which is 10 MWs over the previous all-time summer peak. As a note, 537 MW is the forecasted peak demand for 2013 in the 2011 IRP.

Q. Why do the Company's 2011 IRP load growth rate projections decline after 2016?

A. Due to territorial limitations in many of the communities that Montana-Dakota serves, it is forecast that saturation of Montana-Dakota's market space will slow growth rates to historical growth levels after 2016. However, with the continued growth of oil field activity in the Bakken area and the potential for significant commercial load growth within Montana-Dakota's service areas in response to the oil activity, the potential exists to see growth levels similar to the EGEAS High Customer Growth Scenario for several years.

Q. What is the current view of excess capacity available in the MISO market?

A. As Mr. Hahn indicates on Page 10 of his Initial Testimony, MISO's 2010 Long Term Resource Assessment states: "The projected Midwest ISO reserve margin ranges from 25.4 percent in 2010 to 16.1% in 2019. This margin never drops below the Midwest ISO system Planning Reserve Margin of 15.4 percent established for the 2010-2011 planning year."

However, in MISO's recently completed "EPA Impact Analysis-Impacts from the EPA Regulations on MISO" dated October 2011 and provided as Exhibit No.___(DJN-1), MISO's current capacity margins and potential capacity margins with potential retirements due to EPA regulations places the MISO System reserve margins between 10.9 percent and 23.3 percent in 2015 when Montana-Dakota's capacity purchase agreement with We Energies expires and dropping to a low of 6.6 percent in 2021. As reflected in MISO's analysis, the impact of potential EPA regulations are causing uncertainty about the future of existing generation resources, particularly coal, which could have a significant impact on reserve margins.

Q. What is the potential impact of proposed EPA regulations on the MISO market?

A. In the MISO Study provided in Exhibit No.___(DJN-1), MISO looked at the potential effects of EPA's proposed regulations for:

a. Cooling Water Intake Structures,

b. Coal Combustion Residuals,

c. Clean Air Transport Rule, and

d. Mercury and Air Toxics Standards.

Combined, MISO estimated these proposed regulations could cause the retirement of 2.9 GW to 12.6 GW of coal-fired generation. Retirements of this level of coal-fired generation will significantly reduce the MISO capacity reserve margins and lead to the construction of new natural gas-fired generation. The net effect is that the cost of purchased capacity will increase sharply and the cost for new natural gas-fired plants will rise faster than inflation due to increased demand.

Q. **Has the uncertainty from pending EPA regulations affected Montana-Dakota's ability to purchase capacity from its previous capacity suppliers?**

A. Yes, one of Montana-Dakota's historical capacity suppliers will not bid anything longer than a one year term because of concerns with what the EPA or other governmental entities could impose regarding environmental regulation in the future. This supplier has not submitted responses to either of Montana-Dakota's last two requests for proposals.

The other recent capacity supplier was only able to offer its wholesale tariff rate in response to the 2010 RFP due to environmental uncertainty.

In short, we believe these uncertainties regarding EPA and other government regulations are limiting the availability of long-term contracts for capacity resources.

THE 2009 AND 2011 IRPs

Q. **What were the results of Montana-Dakota's modeling in the 2009 Integrated Resource Plan (2009 IRP)?**

A. The EGEAS modeling in the 2009 IRP showed the need for the Big Stone II resource and a 75 MW combustion turbine in 2015. The 75 MW combustion turbine was further studied after the 2009 IRP and the size of the resource was increased to 88 MW.

Q. What were the results of the EGEAS modeling used in the 2011 IRP?

A. Montana-Dakota's study activities for the 2011 IRP showed that the construction of an 88 MW combustion turbine near Heskett Station in 2015 was prudent along with investment in the Big Stone AQCS project and the execution of a 25 MW commercial and industrial demand response program.

Q. Did the modeling activities in the 2011 IRP also show the need for a second combustion turbine to be constructed in 2015?

A. In all cases, the modeling activities showed the need for multiple combustion turbines in 2015. The Company's plan is to issue another request for proposal in 2012 for its remaining customer demand requirements in 2015. With the addition of the 88 MW combustion turbine, the investment in the Big Stone AQCS project, and the execution of a 25 MW commercial and industrial demand response program; the current projected capacity deficit in 2015 is 36 MWs (6.1 percent of all capacity requirements) as compared to the original 149 MWs of additional capacity requirements in 2015.

OTHER SUPPLY OPTIONS

a. A 43 MW Aero-Derivative Combustion Turbine

Q. On page 22 of his Initial Testimony, Mr. Hahn questioned the Company's modeling of the equivalent forced outage rate (EFOR) for the 43 MW Aero-Derivative Combustion Turbine (43 MW CT). Why

did the Company model a 22.31 percent EFOR for the 43 MW CT and did it affect the outcome of the modeling?

A. The 22.31 percent EFOR[1] for the 43 MW CT represents a published MISO average forced outage rate for turbines of that size and class. This was a conservative approach that was applied in the same manner as a similar MISO average forced outage factor for the 88 MW CT.

In response to a request by La Capra, the Company produced a model with the EFOR for the 43 MW CT reduced to 6.45 percent. This change in the EFOR did not cause the model to select the 43 MW CT over the 88 MW CT in 2015, as shown in Summary of Additional EGEAS cases provided in Exhibit No.__(DJN-2).

Q. Why does the Company's EGEAS model select such a high number of 43 MW CTs in the sensitivity analysis as noted by Mr. Hahn on Page 38 of his Initial Testimony?

A. The EGEAS model selects an economic balance of low-cost capacity and high efficiency generation resources that complement Montana-Dakota's system, which relies heavily on low-cost coal-fired generation units. The 43 MW CT provides the best solution, after the 88 MW CT in 2015, for meeting both the energy and capacity requirements as compared to a higher cost combined cycle generating unit or a lower cost and less efficient frame type generating resource. Small coal or

[1] MISO 2011-2012 Pooled EFORd Class Average, https://www.midwestiso.org/Library/Repository/Report/Resource%20Adequacy/2011%20-%202012%20Pooled%20Class%20EFORd%20Table.pdf.

integrated gasification combined cycle units are too expensive as compared to natural gas generation to warrant consideration.

Q. Is the ADP and CPCN application requesting approval to build all of the future combustion turbines identified in the Company's resource plan?

A. No, at this time the Company is only seeking to construct one 88 MW CT in 2015 which is selected by all of Montana-Dakota's modeling runs. As indicated previously, the Company's plan is to issue another request for proposal in 2012 for its remaining 36 MWs (6.1 percent of all capacity requirements) of customer demand requirements as compared to the original 149 MWs of capacity requirements in 2015.

b. A Wind Resource

Q. How did Montana-Dakota model wind resource alternatives in the EGEAS runs for the 2011 IRP?

A. The Company modeled wind resource alternatives in the 2011 IRP as either a power purchase agreement or a self-build resource. The pricing for the power purchase agreement alternative came from a proposal received in the 2010 RFP. The proposal was for a wind generation project that is already constructed and connected to the Company's transmission system. Accordingly, the Company viewed this is an accurate reflection of pricing for such a power purchase agreement.

The pricing for the self-build wind option was based on the Company's experience with its Diamond Willow and Cedar Hills wind projects.

Q. What is the effect of the inclusion of the fixed O&M component for the purchased wind energy proposal as Mr. Hahn described on Page 23 of his Initial Testimony?

A. The Company originally modeled the purchased wind proposal as a capacity and energy resource as bid in the 2010 RFP. A capacity credit was modeled with a number of available PRCs (MISO capacity credits) from the proposal along with a fixed O&M cost to represent the cost of this purchased capacity. The EGEAS modeling did not pick this configuration as a least cost resource. The Company then modeled this wind proposal as an energy only project by removing the available PRCs and making the energy available in either 2015 or 2020, however, the fixed O&M cost was not removed as should have been done to model this resource as an energy only resource.

Removal of the fixed O&M cost associated with the wind proposal in a follow-up EGEAS run requested by La Capra did not cause the purchased wind proposal to be selected as an energy resource, as shown in Exhibit No.____(DJN-2).

Q. What is the effect on the EGEAS model if the cost of self-built wind is reduced to $1,750 per kW?

A. Reducing the installed cost of wind generation to $1,750 per kW, coupled with the extension of the Federal PTC, will cause the EGEAS similar projects included in the 2010 RFP screening runs, including the previously described fully constructed and on-line wind project which was included for modeling.

If Montana-Dakota were the off-taker for the ND Proposal, the Company would have to take out a transmission service request with WAPA as the Company does not have sufficient transmission capacity in the Hettinger area to move all of the energy to Montana-Dakota's customer load. This would also increase the cost of the ND Proposal by as much as $4.80 per MWh (in 2011 dollars).

Q. **On Page 27 of his Initial Testimony, Mr. Hahn states that the Company should have considered the lower network upgrade costs in the January 13, 2011 report for the Company's analysis of the ND Proposal. How was this information considered?**

A. On January 13, 2011, MISO released its "Montana and North Dakota DPP Cycle 5 Definitive Planning Phase" report that reduced the level of required transmission system network upgrades for the ND Proposal to $22.9 million. Even after this release in January 2011, Montana-Dakota still had concerns with the costs associated with the network upgrades for the ND Proposal and its dependence on flows on the WAPA transmission system. WAPA has taken a firm position with MISO utilities in the area that if a sufficient MISO transmission path cannot be shown for a wind generator that resource must take transmission service from the WAPA IS Tariff.

The Company believed that the purchased wind energy proposal in the EGEAS model for the 2011 IRP was an accurate and better representation of the current market price for a wind resource because that resource was already constructed, online, and had sufficient MISO transmission available for its use. Montana-Dakota's concerns with the ND Proposal made it riskier and more expensive than the purchased wind energy proposal in the 2011 IRP which was not selected as a least cost resource.

Q. Would the inclusion of the ND Proposal have affected the EGEAS model selection of the 88 MW CT as a least cost resource?

A. No, the ND Proposal is an energy only resource and does not support the Company's capacity needs. In fact, the selection of the ND Proposal in the EGEAS model as an energy resource would bias the model to select the 88 MW CT, because of its lower capacity cost, over the 43 MW CT and the 140 MW CCCT.

Q. What would be the effect if Montana-Dakota would add 150 MW of purchased wind into its resource supply mix?

A. Adding 150 MW of purchased wind generation would quadruple the amount of Montana-Dakota's wind generation and likely cause the Company to consider shutting down its smaller coal plants during the spring and fall months when customer loads would frequently be less than on-line generation (wind generation plus coal-fired generation at minimum load). Other utilities in the area have had to resort to this strategy in recent years. Moreover, wind generation is predominately an energy resource and selection of a wind resource does not change the need for capacity by the Company. The EGEAS model will continue to select combustion turbines like the 88 MW Heskett CT to meet the Company's capacity requirements with or without the addition of a wind resource.

Q. How did the Company model the expiration or extension of the Federal Production Tax Credit (PTC) for wind generation beyond 2012?

A. Montana-Dakota modeled the PTC to expire at the end of 2012 without extension for the self build wind generation resource. With current federal budget constraints it seems likely that if the PTC is extended, it will likely be at a reduced funding level.

The modeled wind purchased resource, however, is already online and its pricing includes the benefits of the existing PTC.

c. A Combined Cycle Combustion Turbine Resource

Q. What is the effect of the discrepancy in the modeled cost of the 140 MW combined cycle combustion turbine (CCCT) that Mr. Hahn discussed on Pages 24 and 25 of his Initial Testimony?

A. As Mr. Hahn indicated in his Initial Testimony, the Company improperly modeled the incremental cost of the 140 MW CCCT in the EGEAS runs developed for the 2011 IRP and used a value developed as part of the 2009 IRP. Montana-Dakota adjusted the incremental cost for the 140 MW CCCT in a follow-up EGEAS run to the 2011 IRP and there was no change in the model results.

Q. Does the incremental method used to model the combined cycle resource bias the model towards the 88 MW CT as Mr. Hahn suggests on Page 25 of his Initial Testimony?

A. No, if properly priced the decision to add or not add the combined cycle addition is based purely on economics. The model can add both the 88 MW and the incremental 140 MW CCCT resource in the same year. The net effect would be the addition of a 140 CCCT MW resource at $1,150 per kW (or $1,300 per kW as modeled in the 2011 IRP). Montana-Dakota believes that this modeling strategy for the CCCT provides economic options and does not create a selection bias towards the 88 MW CT. The model is not picking the CCCT option at this time because the incremental cost is adding an energy resource while the Company's primary need at this time is for capacity. The selection of the 88 MW CT at this time makes the availability of the CCCT in combination with the CT more economical as a future energy resource.

Q. Why did the Company allow the selection of only one 140 MW CCCT unit in the EGEAS modeling used in the 2011 IRP?

A. The EGEAS model did not select one 140 MW CCCT unit, therefore there is no need to make more than one 140 MW CCCT available. If more than one 140 MW CCCT option was available, it would increase the solution time as the model has more options to consider. If the model did select one 140 MW CCCT, then the Company would increase the number of 140 MW CCCT resources available in the model to determine if a second CCCT resource would be selected.

working with stakeholders through several issues on a new capacity market (resource adequacy) construct initiative. Changes to the capacity market and system reserve requirements discussed by stakeholders included the development of a mandatory annual capacity auction and the development of local resource zones (LRZs) for studying capacity deliverability within the MISO footprint. Concerns with the long-term ability to deliver capacity and energy from the IL Proposal to Montana-Dakota's customers caused the Company to not include the IL Proposal in the initial EGEAS screening runs for the 2010 RFP.

Q. Did the Company include the IL Proposal into subsequent EGEAS modeling runs for the 2010 RFP?

A. Yes, the proposal was included, as bid, in a post screening EGEAS run to see if it would be selected as a least cost resource. As bid, the proposal was selected as a least cost resource. No adjustments were made in the EGEAS modeling assumptions for the IL Proposal related to the deliverability issues that the Company had with this resource.

Q. What is your response to the characterizations that Mr. Hahn makes in his Initial Testimony regarding the ability of Montana-Dakota to utilize the IL Proposal as part of MISO's new resource adequacy construct?

A. Mr. Hahn, on Page 30 of his Initial Testimony, implies that the self-scheduling option in MISO's Resource Adequacy Construct would fully hedge any pricing differences between local resource zones (LRZs) if Montana-Dakota would try to use the capacity from an IL resource in LRZ

#4 to meet the Company's load obligations in LRZ #1 (See Figure 1). This is incorrect as the "self-scheduling" and "opt-out" options only work for generation and load located in the same LRZ or which has dedicated transmission between LRZs.

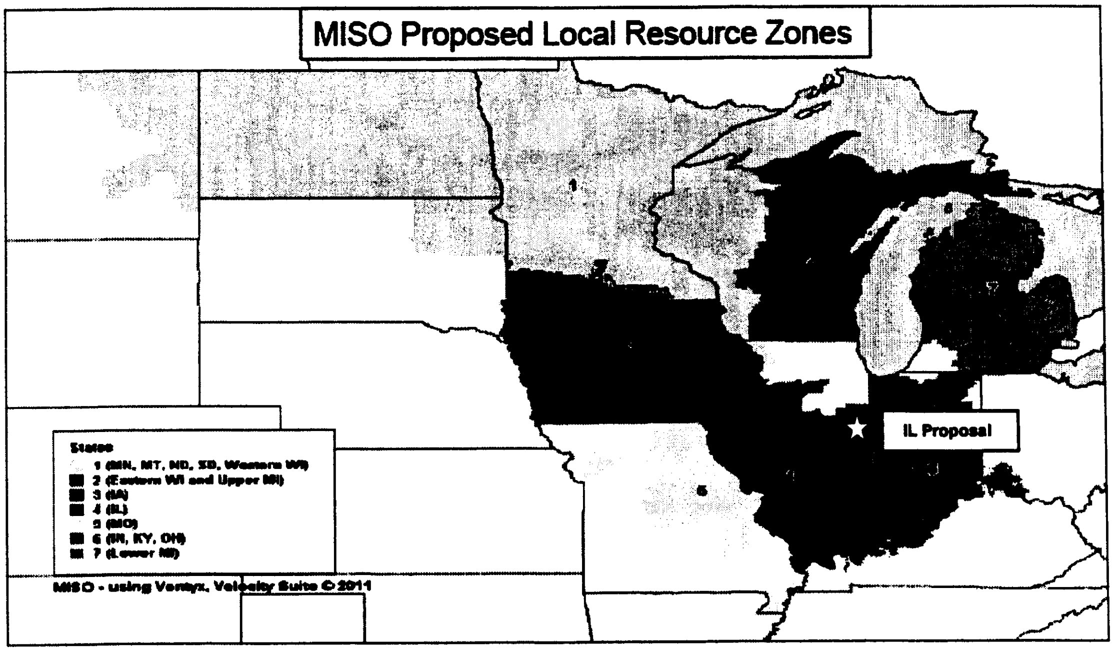

Figure 1

Q. What are the hedging mechanisms in MISO's new resource adequacy construct?

A. Load-serving entities (LSE) like Montana-Dakota, can "opt-out" of the annual capacity auction if they have dedicated transmission between LRZs and/or "self-schedule" if their load and capacity resources are located within the same LRZ. Excess capacity or load deficiencies would be subjected to the annual auction.

Q. Would "self-scheduling" and "opt-out" apply to the IL Proposal?

A. No. Montana-Dakota's load is located within LRZ #1 and the IL Proposal is located within LRZ #4. Montana-Dakota does not have a transmission path between the IL Proposal and its pricing zone.

Q. What happens when excess capacity in an LRZ goes to zero?

A. If sufficient capacity is not available within an LRZ, the LSE would be subjected to the cost of new entry (CONE) penalty which is currently $95,000 per MW-year.

Q. What is the financial risk if Montana-Dakota tried to use capacity (PRCs) from LRZ #4 to meet load obligations in LRZ #1?

A. Under MISO's new resource adequacy construct, MISO will annually study the amount of load requirements needed and capacity resources available in each LRZ. Next, MISO will determine the transfer capability of PRCs between neighboring LRZs.

The IL Proposal is not located in a neighboring LRZ but is located two LRZs away from Montana-Dakota's LRZ. If sufficient transfer capability does not exist between LRZ #1 and LRZ #3, and between LRZ #3 and LRZ #4, then Montana-Dakota may not be able to fully utilize the PRCs from the IL Proposal that it purchased.

Q. What could be the dollar spread between PRCs in IL and PRCs in ND as part of MISO's annual energy auction?

A. A worst case scenario would be where a) LRZ #1 is deficient capacity resources and the MISO Auction prices of PRCs in LRZ #1 would be the cost of new entry (CONE) and b) LRZ #4 would have excess PRCs and the auction price for PRCs in LRZ#4 would be zero. In this situation the PRCs from the IL Proposal would have no value to Montana-Dakota's customers and Montana-Dakota would be required to purchase additional PRCs from the MISO Auction at CONE.

Q. **Do you see this as a probable scenario?**

A. I believe that this is not a highly probable scenario but the situation does exist given the economic development occurring in LRZ#1. With the twenty year term of the IL Proposal, it is impossible to presume that things will work smoothly over the entire term of the agreement.

Q. **How does MISO's recently approved 2011 Candidate Multi-Value Projects (2011 MVP) affect the ability to move capacity from Illinois to North Dakota?**

A. The 2011 MVPs are not forecasted to be completed until at least 2019, which is five years into the term of the IL Proposal. The 2011 MVPs only bring transmission to the eastern edge of Montana-Dakota's service territory at Ellendale, North Dakota (see Figure 2).

MISO 2011 Candidate Multi-Value Projects

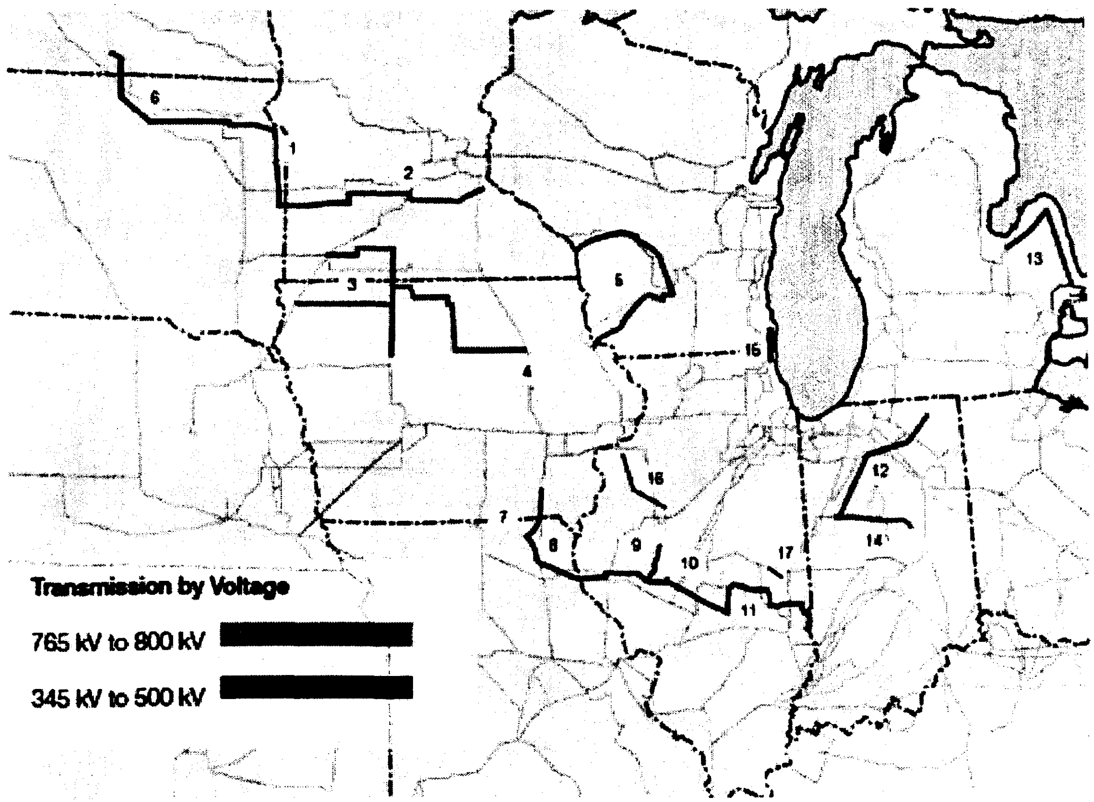

Figure 2

The 2011 MVPs in the central and eastern regions of MISO are designed to address congestion in the on-peak case while the MVPs in the western region of MISO address off-peak constraints.

Congestion exists throughout the MISO footprint, as seen in Figure 3 which is a chart from MISO's 2011 Top Congested Flowgate Study.

Top Congested Flowgates in PROMOD Run

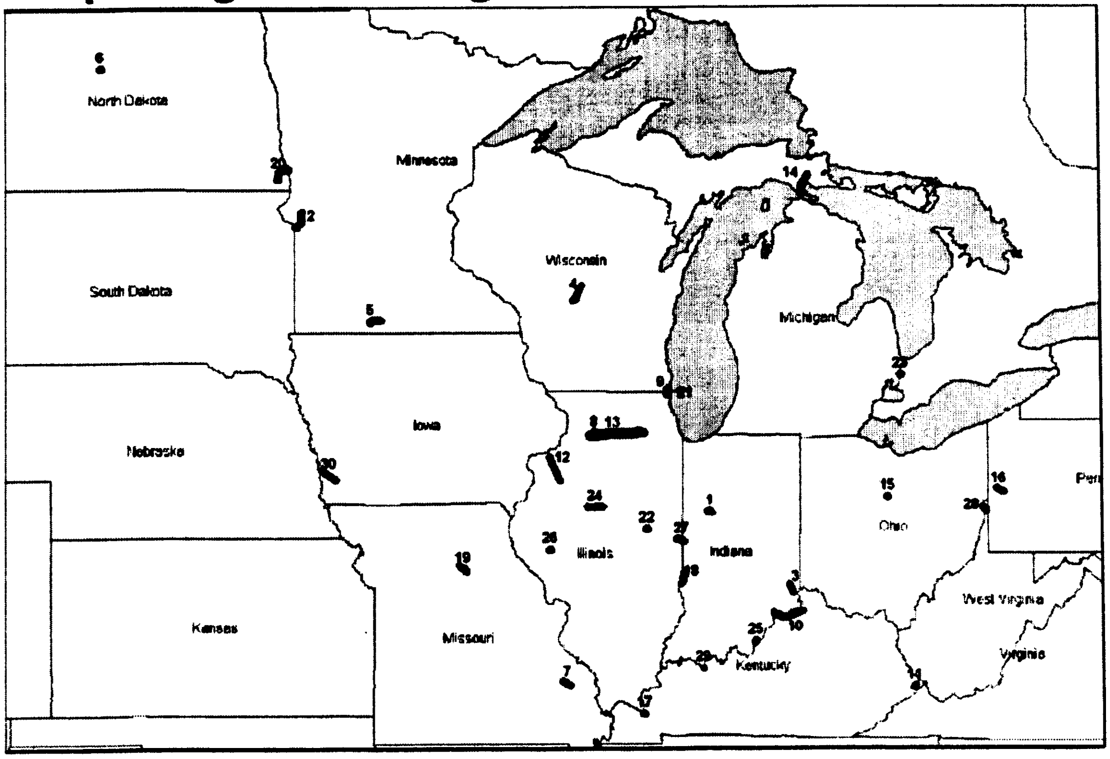

Figure 3

It is overly simplistic to assume that the 2011 MVPs will alleviate all congestion between Illinois and North Dakota and that Montana-Dakota should not be concerned with the ability to utilize PRCs from the IL Proposal to meet its load serving requirements in Montana, North Dakota, and South Dakota. Furthermore, while the MVP Portfolio was recently adopted by the MISO Board, the cost allocation treatment for the MVPs is currently in front of the Seventh Circuit Court of Appeals and the 2011 MVP portfolio is likely to be challenged by several states and stakeholders in the federal court system as well.

Q. What other factors could affect the ability to use a capacity resource from Illinois?

A. Changes in MISO membership, whether that is Montana-Dakota or others, could impact the ability to utilize capacity from Illinois. For example, Montana-Dakota's only connection to MISO is contingent upon Otter Tail Power Company's (Otter Tail) continuation as a MISO member. If either Montana-Dakota or Otter Tail were to withdraw from MISO, Montana-Dakota would be required to secure a transmission service request, if available and if economic, to show deliverability of the capacity resource from Illinois to North Dakota to utilize capacity from an Illinois resource.

Just a year ago, any network resource in MISO was fully deliverable across the footprint for capacity obligation purposes. MISO's new resource adequacy construct recognizes that capacity is not universally deliverable and congestion and transfer capabilities across the MISO footprint must be considered. There is no guarantee that the MISO tariff will not change again within the next twenty years which could adversely affect the ability of Montana-Dakota to use capacity from the IL Proposal.

Q. Is the IL Proposal deliverable to Montana-Dakota's local balancing authority?

A. No, the use of the capacity credits from the IL Proposal is a paper transaction without the ability to physically deliver the energy to Montana-Dakota. Therefore, the contract will provide no reliability benefits to Montana-Dakota's system.

Q. Does Montana-Dakota currently have any power purchase agreements from third parties outside of its local resource zone (LRZ)?

A. Yes, the We Energies purchased power agreement is outside of LRZ #1.

Q. What concerns does Montana-Dakota have with this power purchase agreement?

A. This agreement was entered into with We Energies in 2009 and was intended to replace the NSP purchased power agreement which ends in 2011. This agreement will be used to meet Montana-Dakota's capacity resource requirements. Prior to entering into the agreement, Montana-Dakota was concerned with the ability to use this resource for capacity obligations without a transmission service request. After reviews of the MISO tariff and conversations with MISO, Montana-Dakota was comfortable that it could use the capacity without a transmission service request although the ability to move the energy back to Montana-Dakota's pricing zone would incur congestion costs. Because this agreement was entered into prior to 2011, the capacity credits will be exempt from the annual LRZ transportability restrictions.

Q. How do system constraints affect movement of energy from the western regions of MISO to the east?

A. Congestion exists throughout the MISO footprint, see Figure 3, and is not strictly a problem between Illinois and Iowa as Mr. Hahn indicates on Page 29 of his Initial Testimony. For example, constraints to the east of the Big Stone Plant frequently affect the pricing for the Big Stone pricing node. The construction of MISO 2011 Candidate MVPs will likely move current congestion on the system to new points of constraints.

Q. Please describe the results from the additional EGEAS modeling runs that the Company performed that are included in Exhibit RSH-6 of Mr. Hahn's Initial Testimony and Confidential Exhibit No. ___(DJN-3) of your Rebuttal Testimony.

A. In La Capra Data Request Set 3, the Company was requested to perform additional EGEAS modeling runs using the Base Case from the 2011 IRP to account for various discrepancies and requests that Mr. Hahn described in his Initial Testimony on Page 40. The following is a summary of those changes made to the 2011 IRP Base Case model.

- Included two additional responses from the 2010 RFP to be considered as resource alternatives:
  - 150 MW North Dakota wind proposal (ND Proposal)
  - 176 MW Illinois combustion turbine proposal (IL Proposal)
- Lowered the forced outage rate for the 43 MW Combustion Turbine from 22.31 percent to 6.45 percent
- Lowered the capital cost for the self-built wind options from $2,400/kW to $1,750/kW
- Assumed the federal production credit was extended through 2020 as compared to 2012
- Set the fixed O&M for the purchased wind energy option to $0 from $12/kW-yr

- Lowered the variable O&M for the self-built combined cycle option to $3.00/MWh from $6.00/MWh

Mr. Hahn also requested the Company remove the Keystone XL pipeline load from the demand and energy forecast used in the EGEAS model. The Company indicated in a response to La Capra Data Request 3-3 that the Keystone XL Pipeline load was not removed from the additional EGEAS models. This would have required a large amount of work and the removal of the Keystone XL Pipeline load falls within the Low Growth scenario. Also, the Company's load forecast for 2012-2031 will likely contain enough additional new growth to make-up for any loss or delay of the Keystone XL Pipeline.

The results of the La Capra Modified Base (Additional Case 1) provided in Exhibit No.__(DJN-2) page 2 showed that the IL Proposal, as originally bid, was selected to meet the Company's demand requirement in 2015 and the ND Proposal was selected to meet the Company's future energy requirements in 2015. Removal of the IL Proposal and ND Proposal from the La Capra Modified Base (Additional Case 2) showed that the resource selections in 2015 delayed the installation of one 43 MW CT by two years and continued to select the 88 MW Heskett CT as a least cost resource.

Q. Do you agree with Mr. Hahn's usage of the additional EGEAS modeling runs to quantify the dollar value difference between the IL

Proposal and the Company's 88 MW CT proposal on Page 41 of his Initial Testimony?

A. No. The EGEAS model is not a good measure of the relative dollar value difference between the IL Proposal and the 88 MW Heskett CT in this situation. The model does not account for the reliability benefits of locating an 88 MW CT at Heskett Station or any potential difference in zonal capacity prices between LRZ #1 and LRZ #4. The EGEAS model chooses future resource additions over a 20 year study period and then extends those costs out for an additional 30 years. This is done so that if a large capital resource is selected in year 20, the model will depreciate its costs and spread its benefits over the next 30 years and not bias the model into delaying high capital cost resources beyond the 20 year study period.

In the EGEAS model, the IL Proposal was modeled as a 20 year power purchase power agreement. The expiration of the 20 year power purchase agreement occurs after the 20 year study period and the model assumes that a similar sized and priced resource will be available through the 50 year modeled timeframe. This is not the case as it would effectively mean that the IL Proposal is a 45 year agreement (selected in Year 5) with flat (no escalation) Capacity and Fixed O&M pricing.

Q. Have you had a chance to review to review the side-by-side comparison that Mr. Hahn developed in his Confidential Exhibit RSH-7 and described on Page 42 of his Initial Testimony?

A. Yes, I have and I would say that the cost differential is over stated by Mr. Hahn for several reasons. First, the Company is only requesting to construct one 88 MW CT while Mr. Hahn's analysis assumes that the Company is constructing two 88 MW CTs. Second, the energy from the IL Proposal is not deliverable without incurring congestion costs and should be considered a capacity only resource. This would remove the Variable O&M and Fuel Costs from the analysis. Third, the proposed term of the IL Proposal is 20 years and not 16 years as Mr. Hahn uses in his analysis. Lastly, with the expiration of the Western Area Power Administration (WAPA) Transmission Service Agreement on December 31, 2015, Montana-Dakota will be required to take additional network transmission service from the WAPA Integrated Transmission System (IS) for loads that the Company is unable to service without support from the IS. A generating resource at Heskett Station would help ensure that the Company has sufficient transmission and generating resource available to serve all customer load and deliverability requirements east of Beulah, North Dakota. The reliability and monetary benefit of having an 88 MW combustion turbine at Heskett Station is the potential avoidance of annually paying $3.12 million (in 2011 dollars) to the WAPA IS.

As shown in Confidential Exhibit No.__(DJN-3) with the above described changes, the 88 MW CT, including AFUDC, is less expensive than the IL Proposal on a total expenditures basis and only **[TRADE SECRET DATA BEGINS** $4 million dollars **TRADE SECRET DATA ENDS]** more expensive on a net present value basis.

On a side-by-side comparison basis, the 88 MW CT should be considered a prudent resource addition for the technical and economic reasons described here and in Andrea Stomberg's Rebuttal Testimony.

OTHER CONCERNS

Q. How does the Company account for AFUDC in its EGEAS modeling?

A. The installed cost for self-built supply side resources is assumed to contain AFUDC. Otherwise the EGEAS model would have to account for cash flow, construction schedules, and financing.

The detailed cost build-up for the 88 MW Heskett CT in the 2011 IRP did not contain AFUDC. Further refinements for the estimate of the 88 MW CT included adding AFUDC, removing the SCR requirement, and increasing the natural gas pipeline costs. These refinements were included in the application for the ADP and CPCN in this proceeding. The updated cost of the 88 MW Heskett CT in the ADP and CPCN filing fell within the modeling costs, assumptions, and scenarios used in the 2011 IRP.

Q. Have you reviewed Mr. Hahn's Initial Testimony on Page 38 where he states "the modeling may have been biased toward building new peaking capacity and not units that produce significant amounts of energy" and how would you respond?

A. I do not think that the modeling is biased, but it responds to a situation where the Company has few options to economically meet both the demand and energy growth requirements that are forecasted for the

Company. In 2009, the Company's IRP model picked capacity and energy from a large coal-fired generating project as least cost. That alternative is not available today and with the uncertainty surrounding coal-fired generation there are few options besides simple cycle generation resources. Combined cycle projects are too expensive today as compared to efficient combustion turbine technology in this r region. The forecasted low runtime on a combined cycle generating plant does not justify the additional cost.

Q. On Page 39 of his Initial Testimony, Mr. Hahn states the Company did not consider two important scenarios in its sensitivity analysis (1) high coal retirements in MISO and (2) renewal of wind PTCs. How would the model respond to these two scenarios?

A. A high coal retirement scenario will cause market energy prices to rise as natural-fired generation will set the marginal energy price a higher percentage of the time. A high coal retirement scenario will also cause a reduction in the excess capacity market in MISO and the cost of purchased capacity will approach the cost of a new simple cycle unit. The EGEAS model will probably look more favorably at the installation of some level of combined cycle generation to replace the retired coal generation, which requires the 88 MW CT addition.

If the Federal PTC incentive for renewable generation is extended, the MISO energy prices will remain low during off-peak periods which will bias the market towards simple cycle combustion turbines. In this scenario, a future baseload resource would look like the combination of wind turbines and simple cycle generating units which also supports the installation of the 88 MW CT.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.