**PUBLIC DOCUMENT**
**TRADE SECRET DATA EXCISED**

Direct Testimony and Schedules
Julie I. Pierce

Before the Minnesota Public Utilities Commission

State of Minnesota

In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Utility Service in Minnesota

Docket No. E015/GR-19-442

Exhibit ________

# POWER SUPPLY STRATEGY AND WHOLESALE SALE MARGINS

November 1, 2019

## TABLE OF CONTENTS

**Page**

## I. INTRODUCTION AND QUALIFICATIONS

**Q. Please state your name and business address.**

A. My name is Julie I. Pierce and my business address is 30 West Superior Street, Duluth, Minnesota 55802.

**Q. By whom are you employed and in what position?**

A. I am employed by ALLETE, Inc., doing business as Minnesota Power ("Minnesota Power" or the "Company"). My current position is Vice President of Strategy and Planning.

**Q. Please summarize your qualifications and experience.**

A. I have 20 years of experience in the electric industry that includes transmission reliability, energy markets, and utility planning. I have been with Minnesota Power for twelve years and am currently responsible for customer electric sales forecasting and load research, resource planning, fuel strategy, project development, Midcontinent Independent System Operator ("MISO") market operations, and Regional Transmission Organization ("RTO") coordination. I graduated from North Dakota State University with a Bachelor of Science in Electrical Engineering. Prior to joining Minnesota Power, I was an engineering manager for MISO. I worked for eight years at MISO, holding various management roles in the organization during that time. I am originally from Northern Minnesota and have enjoyed almost 13 years with Minnesota Power in Duluth, Minnesota and being part of the energy transformation the Company has gone through with its Energy*Forward* strategy.

**Q. What is the purpose of your testimony?**

A. I provide information on Minnesota Power's current power supply strategy and discuss the impact that this strategy has on the asset-based wholesale sales that the Company has identified for the 2020 test year.

**Q. Are you sponsoring any exhibits in this proceeding?**

A. Yes. I am sponsoring the following exhibits:

- MP Exhibit ___ (Pierce), Direct Schedule 1 – Asset-based wholesale sales from 2010 to 2018, 2019 projected year, and 2020 test year.
- MP Exhibit ___ (Pierce), Direct Schedule 2 – Large Market Contract.
- MP Exhibit ___ (Pierce), Direct Schedule 3 – Large Market Contract budget adjustment.

## II. MINNESOTA POWER'S CHANGING POWER SUPPLY

### A. <u>Energy*Forward* Power Supply Strategy</u>

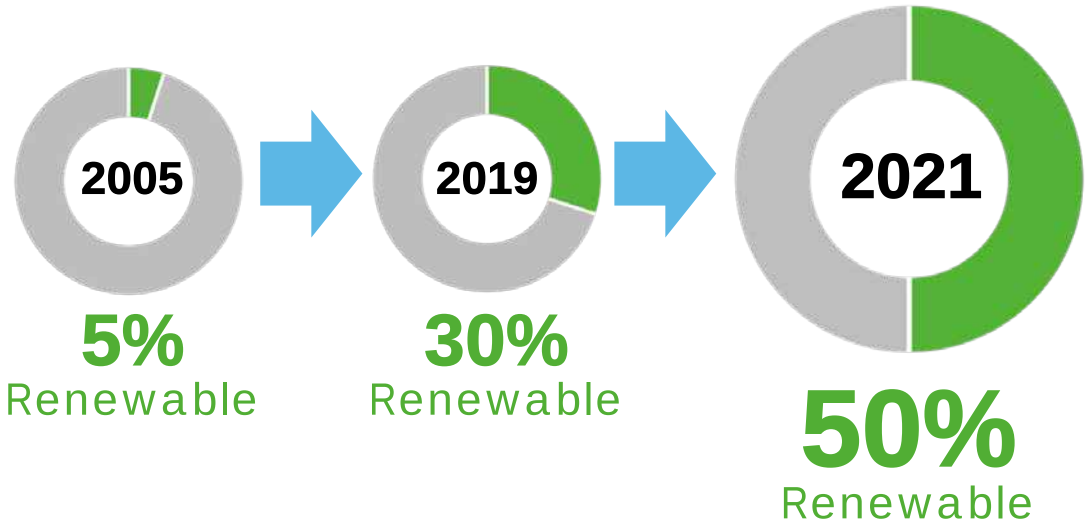
**Q. What is the purpose of this section of your testimony?**

A. In this section of my testimony, I will discuss how Minnesota Power's power supply portfolio has changed as part of our Energy*Forward* strategy and how this transition to more renewable generation resources and reduction in coal generation has impacted the total output and dispatchability of our power supply.

**Q. What is Minnesota Power's current power supply strategy?**

A. Minnesota Power has been advancing a transformation of its power supply to a cleaner energy future through its Energy*Forward* strategy. As shown in Figure 1, the Company has increased the renewable energy portion of its power supply from five percent in 2005 to 30 percent in 2019. As part of this transition, Minnesota Power has either retired or refueled seven of its nine coal-fired generating units. This transformation has also reduced carbon emissions from Minnesota Power's power supply by 30 percent as compared to 2005 levels.

**Figure 1.**




Minnesota Power is continuing to further its Energy*Forward* strategy with approved resource additions that will create a power supply to provide customers with 50 percent renewable energy and reduce carbon emissions by 50 percent by 2021 (from 2005 levels). This transformation has made Minnesota Power a state and regional leader in clean energy, while at the same time providing affordable and reliable electric service for customers.

**Q. What steps has the Company taken to achieve this increase in renewable generation and lower carbon emissions?**

A. The transformation is the result of both retiring existing thermal generation and adding or purchasing more renewable generation. Since 2010, the Company has retired, idled, or converted 600 MW of its coal-based thermal generation portfolio. Specifically, as described by Company witness Mr. Joshua J. Skelton, the Laskin Energy Center ("LEC") was converted from coal-fired to natural gas-fired generation in June 2015. Taconite Harbor Energy Center ("THEC") Unit 3 ceased coal-fired generation in May 2015, and Units 1 and 2 were idled in the fall of 2016 and will cease all coal-fired operations by 2020.[1] In addition, two of the four coal-fired units

[1] Alternatives for the THEC site will be considered in the Company's 2020 Integrated Resource Plan.

of the Boswell Energy Center ("BEC"), Unit 1 and Unit 2, were retired in December 2018. The coal reductions include LEC,[2] THEC,[3] Young 2,[4] and BEC Units 1&2.[5]

**Q. Describe the renewable generation recently added to Minnesota Power's system.**

A. Since 2005, the Company has added over 600 MW of wind generation and 11 MW of solar generation to its portfolio. Minnesota Power has been keeping pace with Minnesota's Solar Energy Standard and has added its Community Solar Garden (1 MW) and Camp Ripley (10 MW) solar arrays, and has approval to add a 10 MW solar project to its portfolio in 2020. Finally, the Company has received Commission approval for significant renewable power purchase agreements ("PPA"): (1) 250 MW capacity and energy and 133 MW energy only purchase from Manitoba Hydro expected to start June 1, 2020, and (2) 250 MW of additional wind generation from the Nobles 2 wind facility expected to start October 2020.[6] I discuss these PPAs in further detail below. These new power supply resources provide energy and capacity to help offset the capacity and energy lost from the conversion and retirement of coal-fired facilities. Minnesota Power will be submitting its next Integrated Resource Plan and Baseload Retirement Study to the Commission in October 2020.

**Q. What are the key aspects of the Manitoba Hydro 250 MW PPA?**

A. The Manitoba Hydro 250 MW PPA is a 15-year agreement to purchase 250 MW of hydroelectric energy and capacity from Manitoba Hydro that will run from June 2020 through May 2035 and provide energy and capacity 7 days a week and 16 hours a day. The 250 MW PPA is aligned with the construction of the Great Northern Transmission

---

[2] LEC was repowered to run on natural gas in June 2015 (110 MW).

[3] THEC3 was retired in May 2015. Subsequently, THEC1&2 were idled in 2016, with coal-fired operation of these units scheduled to cease by the end of 2020 (225 MW).

[4] Reductions to Minnesota Power's Young 2 capacity from 227.5 MW to 100 MW occurred since August 2014 with a phase out of Young 2 by 2026 per agreement with Minnkota Power Cooperative.

[5] BEC Units 1 & 2 were retired in December 2018 (135 MW).

[6] *In the Matter of Minnesota Power's Request for Approval of a Power Purchase Agreement with Manitoba Hydro Company*, Docket No. E015/M-11-938, ORDER (Feb. 1, 2012); *In the Matter of Minnesota Power's Petition for Approval of a 250 MW Nobles 2 Wind Power Purchase Agreement*, Docket No. E015/M-18-545, ORDER APPROVING POWER PURCHASE AGREEMENT WITH REVISIONS, REQUIRING REPORTING, AND REQUIRING COMPLIANCE FILING (Jan. 23, 2019).

Line Project ("GNTL"), a new 500 kV high-voltage transmission line from the Canadian border to Grand Rapids, Minnesota. Manitoba Hydro is also constructing a new transmission line from Winnipeg, Manitoba, in Canada to the United States border to connect with the GNTL. This line, the Minnesota Manitoba Transmission Project ("MMTP"), has started construction and is planned to be in service by June 2020.[7] Together, these two 500 kV lines will create the reliable transmission delivery needed to transfer this renewable energy and capacity to Minnesota Power customers over the long term.

**Q. What are the key aspects of the 250 MW Nobles 2 Wind PPA?**

A. The 250 MW Nobles 2 PPA is a 20-year agreement to purchase 250 MW of wind-generated capacity, energy, and renewable attributes from the Nobles 2 wind-generation facility located in Nobles County in southwestern Minnesota, to serve Minnesota Power's customers. The contract term is expected to commence in October 2020. The Nobles 2 wind project is expected to have approximately a 45 percent capacity factor and provide valuable renewable wind energy for Minnesota Power customers.

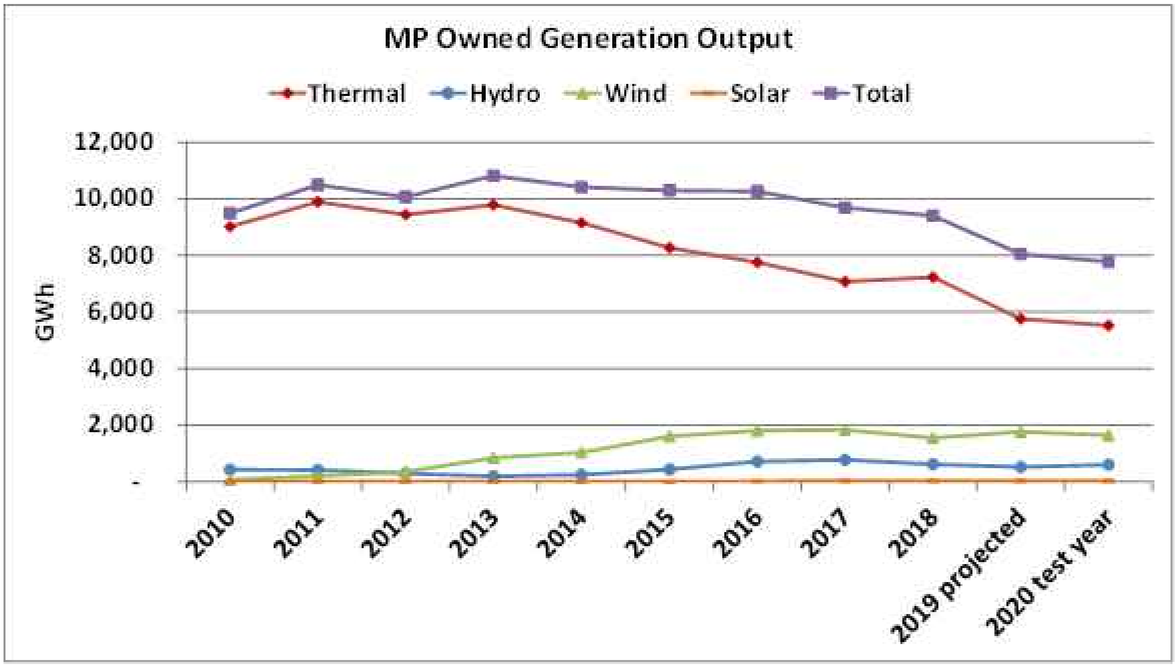
**Q. How will Minnesota Power's energy supply transformation impact the generation output from Company-owned generation resources in the 2020 test year?**

A. As shown in Figure 2, since Minnesota Power initiated its Energy*Forward* strategy in 2010, the generation transformation has removed approximately four million MWh of thermal generation output from the Company's power supply portfolio but, at the same time, only approximately two million MWh of Company-owned renewable generation (Bison 1 – 4) has been added. Minnesota Power needed to procure additional power supply resources to replace what was retired.

---

[7] Minnesota Power provided an update in its recent Transmission Cost Recovery Rider filing. *In the Matter of Minnesota Power's Petition for Approval of a Transmission Cost Recovery Rider*, Docket No. E015/M-19-440, PETITION (July 9, 2019).

**Figure 2.**

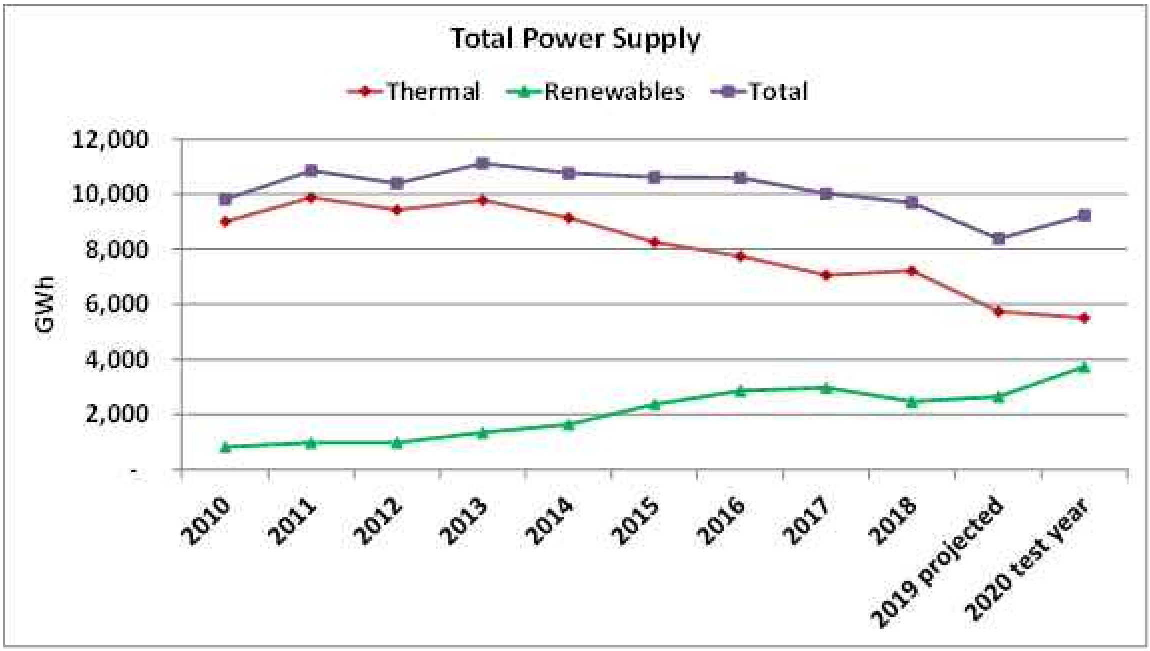



**Q. What is the make-up of Minnesota Power's total power supply (both owned and purchased resources) and how has the energy transformation impacted the Company's 2020 test year?**

A. As shown in Figure 3, Minnesota Power's thermal generation (diamond line) has been decreasing due to retirements since 2013, while the Company has been adding predominantly renewables (triangle line) to augment the power supply. Minnesota Power has more than doubled its renewable energy since 2014. The Company has added two significant renewable power purchases since 2010, Manitoba Hydro and Nobles 2 wind farm. However, even with the addition of new renewable generation from the PPAs, Minnesota Power's total power supply output (purchases and Company-owned generation assets) will be slightly lower[8] in 2020 than in 2010. This power supply transformation will provide 50 percent renewable generation for Minnesota Power customers by 2021 and has created a new profile of power supply to support customer needs.

[8] 2010 equals 9.8 million MWh and 2020 equals 9.2 million MWh.

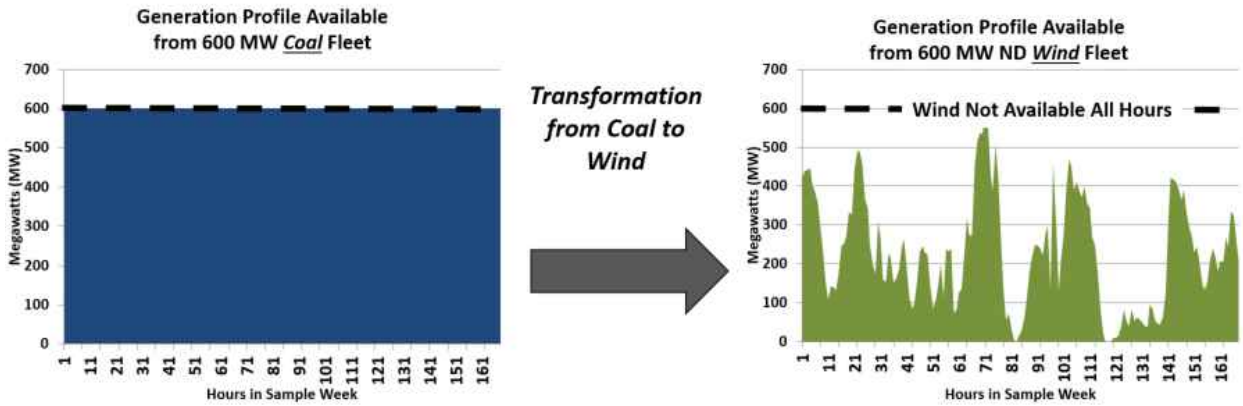
**Figure 3.**




**Q. How has Minnesota Power's energy transformation impacted the dispatchability of the Company's overall power supply portfolio?**

A. While these changes have greatly reduced Minnesota Power's carbon emissions, the addition of renewable generation has created a new profile for Minnesota Power's supply portfolio that is less dispatchable and more intermittent in nature as compared to the Company's previous baseload operations. This is because the new renewable generation that has been added does not provide energy 7 days a week, 24 hours a day on command like the dispatchable thermal generation Minnesota Power previously held as shown in Figure 4. The result is a generation output profile that is much more variable than in the past.

**Figure 4.**




**Q. How does the variability impact the Company's overall power supply?**

A. As generation availability changes due to power supply transition, and more intermittent generation is added, additional factors like wind availability increase the uncertainty of the total generation energy production available hourly, daily, or annually. The Company's hourly surplus/deficit can currently vary significantly during high-wind and low-wind conditions each day just due to the North Dakota wind in the portfolio. Figure 4 above includes a sample week of wind variability at our North Dakota wind generation facilities that demonstrates this variation of wind resource.

**Q. What does Minnesota Power do when there is surplus energy on the system?**

A. After all forecasted customer retail energy requirements have been met and Minnesota Power has additional power supply available, Minnesota Power makes wholesale energy transactions. As a general rule, the amount of energy available to sell at wholesale will be reduced as the energy requirements for any retail revenue class increases. Likewise, if the energy requirements for any retail revenue class are reduced, there will be an increase in the amount of energy that is available to sell at wholesale. These wholesale sales benefit all of the Minnesota Power's customers by providing additional revenue.

**Q. How are Minnesota Power's generation resources matched to its customers' energy requirements for the 2020 test year?**

A. Overall, there will be less surplus energy on Minnesota Power's system during the 2020 test year as compared to Minnesota Power's last rate case (Docket No. E015/GR-16-664) ("2016 Rate Case"). This is because Minnesota Power has less baseload energy in its power supply and the profile of surplus energy is much more variable due to the growth in renewable resources. This reduction in surplus generation also takes into account that Minnesota Power's current retail and resale customer load is lower since the 2017 test year due to a large industrial customer that has idled facilities, loss of municipal load, and minimal residential and commercial load growth, as described in the Direct Testimony of Company witness Mr. Benjamin S. Levine.

## III. ASSET-BASED WHOLESALE SALE MARGINS

**Q. What are asset-based wholesale sale margins?**

A. Asset-based wholesale sale margins are, in the simplest terms, the difference between the amount of energy that the generation portfolio is creating or expected to create and the customer load at any point in time.

Asset-based wholesale sale margins are created when energy or capacity is sold to the MISO market or a specific counterparty through a bilateral contract and that energy or capacity is supported by (sourced from) generation assets that are paid for by customers in their base rates. The margins from these sales are credited back to Minnesota Power customers through their base rates as a margin credit and thus lower base rates. In each rate case, the Company forecasts its expected asset-based wholesale sale margins and adjusts this credit to an expected level given the current generation supply and customer load. As described above, Minnesota Power's supply portfolio plays a key role in the ability to make wholesale sale transactions. In

Minnesota Power's 2016 Rate Case, this credit value was set at $43 million Total Company ($35.8 million MN Jurisdictional[9]).

**Q. What are the different types of asset-based wholesale sales?**

A. Minnesota Power's asset-based wholesale sales can be described as two types. First, shorter-term asset-based sales can be generated in the MISO market on a near-term daily basis when generation output exceeds customer load. Market sales and revenue for these types of sales are harder to predict due to daily changes in load levels, generation availability (particularly with intermittent wind generation), and market prices.

Second, we have longer-term (typically one or more years) bilateral sales under specific contract terms and prices. Bilateral contracts are company-to-company commitments for the sale or purchase of power products. Bilateral contracts are used to transact energy and/or capacity for longer durations than MISO can accommodate with its Day-Ahead or Real-Time markets. The bilateral contracts define term, product, and pricing between two entities. Bilateral sale revenue is defined by the contract and is more predictable than the day-to-day MISO market sales. However, the available market price for a new bilateral contract can fluctuate annually with industry and market conditions.

MP Exhibit ___ (Pierce), Direct Schedule 1 provides a summary of asset-based wholesale sales margins for 2010 to 2018 actuals, 2019 projected year, 2020 budget, and 2020 test year for the types of sales described above.

[9] A summary of allocation factors used across the Company for purposes of calculating the Minnesota Jurisdictional totals is provided with the Direct Testimony of Company witness Mr. Stewart J. Shimmin at MP Exhibit ___ (Shimmin), Direct Schedule 1—Guide to Minnesota Power's CCOSS, at Table 4.

**Q. How does the generation output of Minnesota Power's supply portfolio impact Minnesota Power's asset-based wholesale sales?**

A. When the wind is blowing and wind turbines are producing, Minnesota Power will typically have more than enough resources to serve its load requirements, making wholesale sales possible. Conversely, when the wind output is low, Minnesota Power currently needs to make MISO market purchases to meet customer requirements. As part of the annual planning process, Minnesota Power establishes the level of wholesale energy sales the Company can expect given the retail energy requirements forecasted and the system resources available to meet that forecast. The transactions can be executed in the near-term within the Day-Ahead and Real-Time MISO markets or set for longer durations using a company-to-company bilateral contract.

**Q. What forecast for retail load was used to determine Minnesota Power's forecast for asset-based wholesale transactions for the 2020 test year?**

A. The 2020 test year customer sales forecast identifies the Company's expected retail energy requirements for 2020. Company witness Mr. Levine explains the derivation of the 2020 test year retail sales forecast in his testimony.

**Q. What amount of asset-based wholesale sales margin does Minnesota Power anticipate for the 2020 test year?**

A. Asset-based wholesale sale margins for the 2020 test year are estimated to be $11.5 million Total Company ($10 million MN Jurisdictional).

**Q. How does the amount of asset-based wholesale sales and associated margin for the 2020 test year compare to the 2017 test year?**

A. The 2020 margin level represents a significant decrease in the base rate credit or margin threshold from previous years (most recently set in the 2016 Rate Case at $43 million Total Company or $35.8 million MN Jurisdictional). In alignment with the margin reduction, the amount of asset-based sales are also significantly lower than previous years. In 2017, Minnesota Power had 2.2 million MWh of asset-based energy sales; for the 2020 test year we have identified 984,000 MWh of asset-based wholesale energy sales. This is a reduction of 1.2 million MWh in available sales and leads to a large reduction in the sale margin that can be achieved.

These reductions are largely due to the expiration of a long-term sales contract with Basin Electric Power Cooperative ("Large Market Contract" or "LMC"), reduced surplus energy available to sell due to the changing power supply profile described above, and lower sale prices and margins when Minnesota Power has surplus. I discuss each of the items contributing to the reduction in asset-based wholesale sales in further detail in my testimony below.

## A. <u>MISO Market Wholesale Sales and Prices</u>

**Q. What is the purpose of this section of your testimony?**

A. In this section of my testimony, I will discuss the impact that Minnesota Power's changing power supply portfolio has had on the Company's asset-based wholesale energy sales in the MISO market. I will discuss the new profile of MISO market sales that are made, along with the price trends that are expected for the 2020 test year. MISO market wholesale sales can include both energy (hourly) and capacity (annual).

**Q. What is the benefit to the Company's customers as a result of Minnesota Power's continued participation in MISO?**

A. Minnesota Power's generation is dispatched according to MISO market price signals, which has allowed the Company to optimize the value of its various generation resources. The MISO market, including the Day-Ahead, Real-Time, and Ancillary Services, has allowed Minnesota Power to make economic use of the wholesale power market. Additional benefits include increased purchase and sale opportunities, more transparent pricing, a reserve sharing pool, and the ability to purchase the energy needed based on customer demand. Overall, the benefits of participation in MISO have more than offset the costs incurred with participation.

1. MISO Wholesale Energy Sales

**Q. What is MISO's role in facilitating wholesale energy sales?**

A. MISO's Day 2 energy market began on April 1, 2005, and MISO's tariff re-characterized the way utilities provide electricity to serve native load customers, including retail customers. Traditionally the utilities generated most of the electricity needed to serve their customers, and bought or sold any deficit or surplus from or to neighboring utilities. In contrast, under MISO's tariff, utilities sell all power from their electric generation and other resources into the wholesale market, and purchase power back from the market to provide electric service for their ratepayers. Net accounting ensures that each company's generation assets are allocated to its retail and municipal customers, and only the excess is sold to the market at the Locational Margin Price ("LMP") of the generating unit.

**Q. How does the MISO market operate and facilitate sales?**

A. Under the MISO Day 2 tariffs, in the Day-Ahead Market, all market participants that own or operate generation are required to submit offers for their generation resources (either owned generation or purchases) that are network resources of the market participant. At the same time, each MISO Load-Serving Entity ("LSE") must bid their load requirements into the market. The following day, MISO, with the Real-Time Market, implements its plans, adjusted to accommodate changes arising from, for example, unanticipated hot weather that impacts load or a mechanical failure at a power plant. Generation that clears the MISO Day-Ahead and/or Real-Time markets that is not needed to serve native load becomes a "wholesale sale" into the MISO market.

**Q. How do MISO sales help utilities manage generation and load fluctuations?**

A. Utilities utilize the MISO market to manage the day-to-day fluctuations between their customers' energy needs and their generation supply on an hourly basis. Utilities also have an additional tool to balance their generation to load through bilateral contracts.

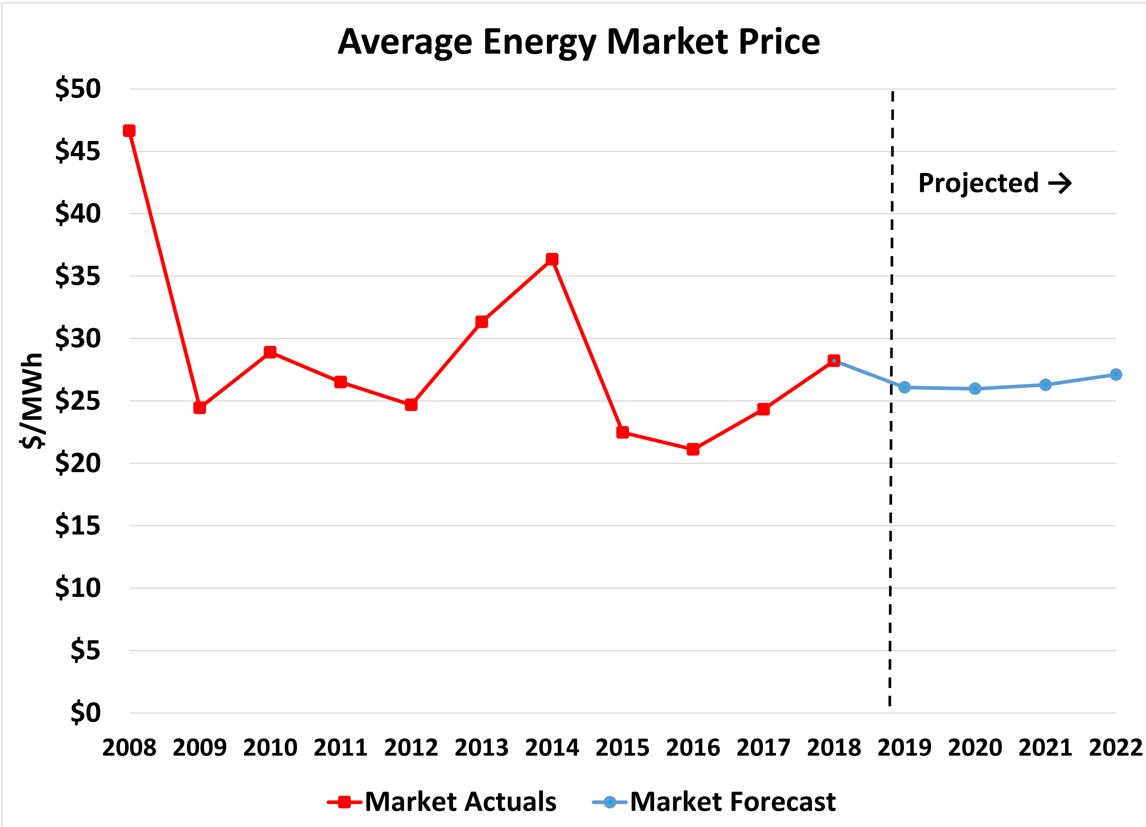
The MISO market will balance the requirements remaining after all bilateral contracts (purchases and sales) are taken into consideration.

**Q. At what average price can a utility expect to sell and purchase energy in the MISO market?**

A. The MISO market is very specific for each utility – it is dependent on their geographical and electric grid location in the large MISO footprint and the characteristics of the surrounding load and generation. The average annual energy market price and current projections to 2022 for Minnesota Power are provided in Figure 5 below. The average annual energy price does not show the variability that a utility can see on an hourly basis or for different times of the day, both of which can vary greatly. It does, however, show that the energy market price is expected to remain steady on an annual basis in the near-term outlook. With the exception of 2014, the MISO energy price has been relatively stable since 2009, which helps support Minnesota Power's MISO price projection for 2019 through 2022 time period.[10]

[10] The energy price projection is provided by a third-party forecast from IHS Global Insight.

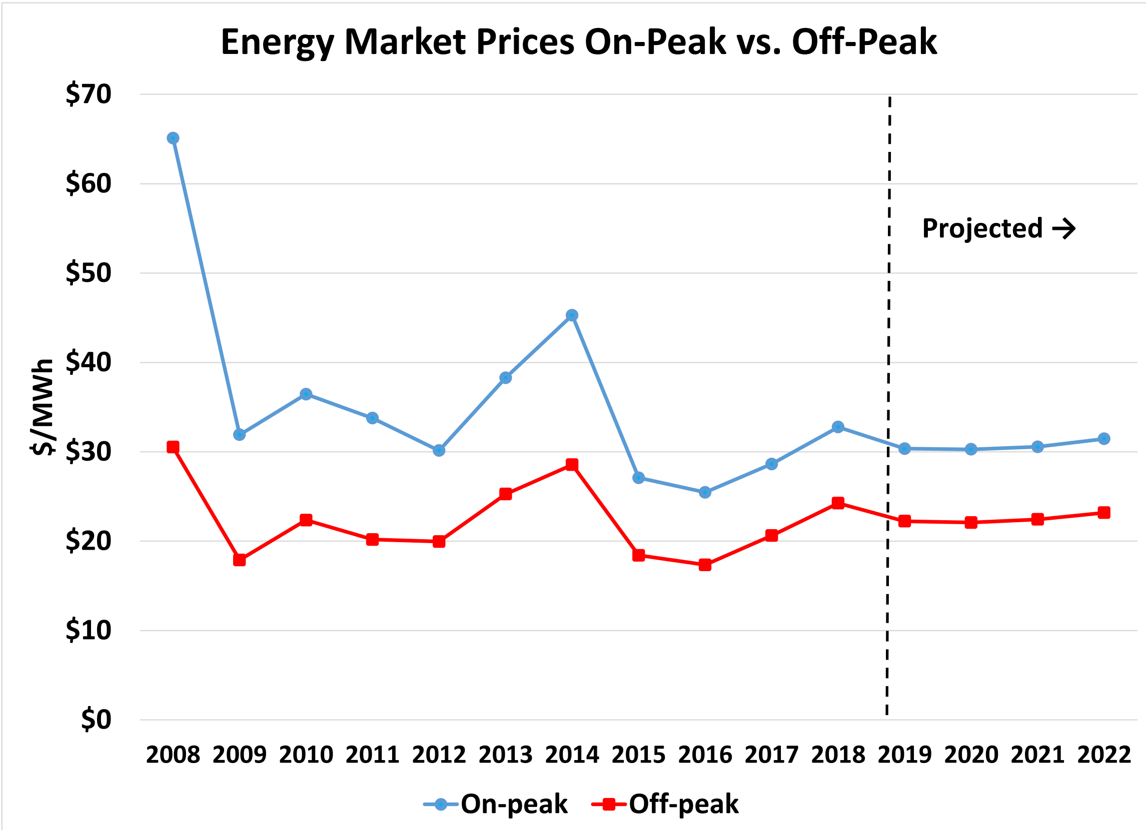
**Figure 5.**




**Q. Do MISO prices vary depending on whether power is being bought or sold during on-peak or off-peak periods of each day?**

A. Yes. As shown in Figure 6, the on-peak and off-peak time periods have a different pricing profile creating a significant price difference. The price differential between the on-peak and off-peak time periods from 2015 to 2018 has been approximately 40 percent. Thus, if Minnesota Power needs additional power or has surplus to sell with the MISO market, the price can vary significantly depending on when the energy is needed or available.

**Figure 6.**




**Q. How has Minnesota Power's changing power supply impacted its MISO purchases and sales?**

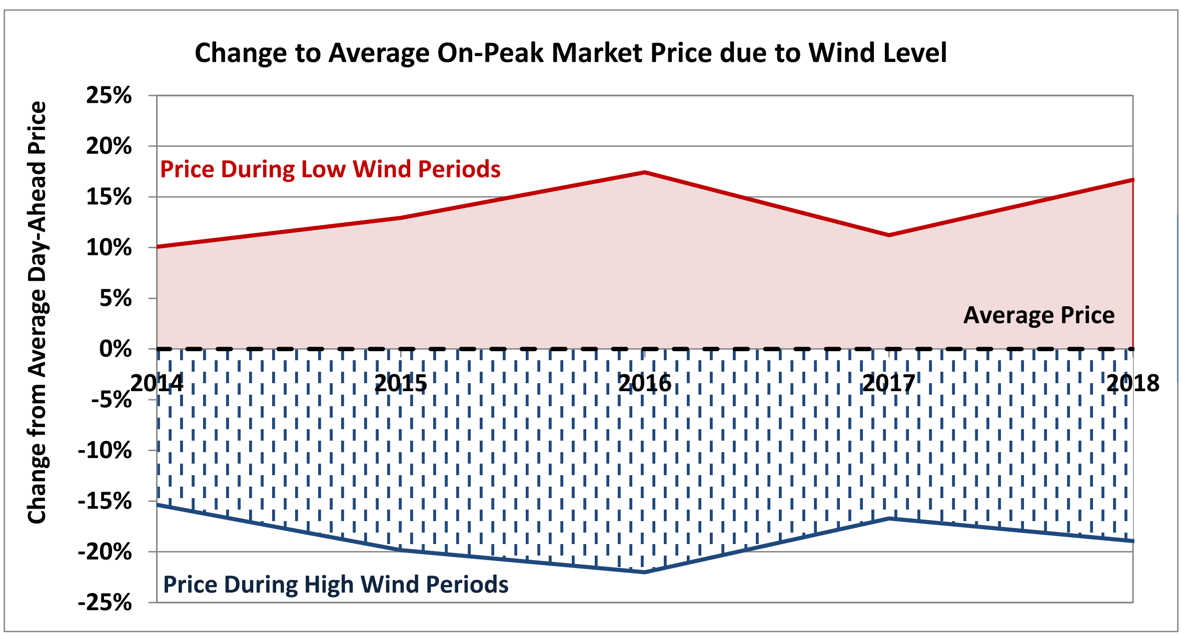
A. Minnesota Power's surplus and deficit profile for MISO purchases and sales has been changing, and with the addition of wind generation, now follows the variable wind generation patterns. When the wind energy availability is higher, Minnesota Power typically has a surplus and is selling energy. When the wind is low, there is typically a deficit and Minnesota Power is purchasing energy. The Company's surplus/deficit will vary by up to 850 MW in high wind to low wind conditions on a daily basis. For the 2020 test year, we have added more wind generation in the power supply portfolio; the impact of wind generation on our sale and purchase profile is greater than in previous years.

**Q. How does the availability of wind generation impact MISO market prices?**

A. The amount of wind generation in the MISO footprint is now significant enough that wind availability impacts the regional energy supply and demand balance, and resulting energy market prices. The market prices during high and low wind periods can vary greatly. Market prices are often lower when the Company's and regional wind generation is at its highest level and market prices are higher when wind generation is at its lowest level. Thus, when generation output is available for surplus sales, the market prices are lower. When generation is not available and purchases are needed, the market prices are higher.

Figure 7 below demonstrates the impact wind variability has had on the actual MISO market price since 2014. For example, as demonstrated in the chart below, in 2018 on-peak market prices were 17 percent higher than the average in low wind periods and 19 percent lower than average in the high wind periods.

**Figure 7.**



**Q. When does Minnesota Power typically have excess energy to sell into the MISO market and how does that impact the sale price?**

A. As Minnesota Power market sales tend to occur during high wind levels, Minnesota Power receives lower than average market prices for these sales. The price will impact the amount of sales revenue that Minnesota Power can expect to receive when it sells energy.

2. MISO Capacity Sales

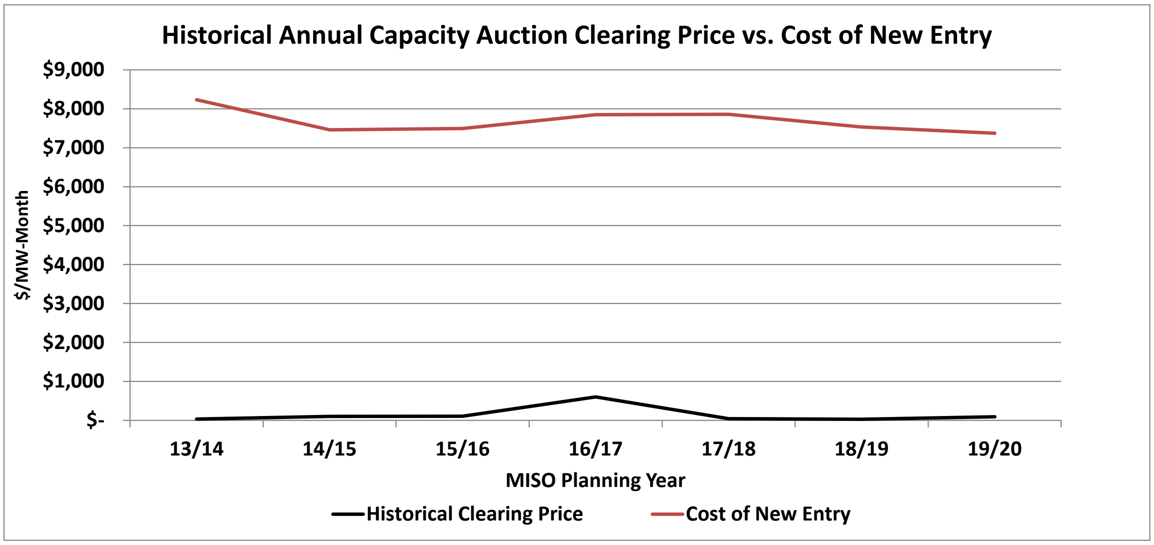
**Q. Does Minnesota Power make capacity sales to the MISO market?**

A. Yes. Each year Minnesota Power enters any excess capacity that remains after all load, bilateral contract and reserve requirements have been met into the MISO capacity auction. The capacity auction is a surplus capacity auction and does not represent the price or cost of the resources that are being used to serve customer load. There is not a Real-Time or Day-Ahead market for capacity in MISO. Rather, capacity transactions are conducted only on an annual basis through an auction process.

**Q. At what price can a utility expect to sell and purchase capacity at in the MISO market?**

A. Any capacity that is not needed by a utility to meet the load requirements for its customers can be offered into the MISO annual auction. The capacity is sold if the offer price is lower than or equal to the auction clearing price. Figure 8 below identifies the capacity auction price from MISO since 2014 along with the cost of new entry (CONE) which sets the upper bound for the MISO auction process.

**Figure 8.**




This auction price for MISO Zone 1 (where Minnesota Power's resources are located) has been very low since its inception and provides minimal revenue to Minnesota Power as demonstrated in MP Exhibit ___ (Pierce), Direct Schedule 1. Even during the 2016/2017 planning year, the highest pricing in recent years,[11] the auction clearing price only hit $600/MW-month, which is $7,200 a year per MW of capacity. The volume the Company sells into the MISO capacity auction varies each year based on the annual customer load, available capacity resources, and annual reserve margin requirement that is set by MISO's Resource Adequacy Program (Module E).

**B. <u>Bilateral Contracts</u>**

**Q. What are bilateral contracts?**

A. Bilateral contracts are company-to-company commitments for the sale or purchase of power products. A bilateral contract is a contract that is typically longer term (one or more years) and has defined term, product, and pricing contract terms between two entities. Bilateral contracts are used to transact energy and/or capacity for durations

[11] The MISO capacity auction hit a spike in the 2016/2017 planning year due to a zonal constraint that was triggered for one year.

longer than short-term markets like MISO can accommodate with its Day-Ahead or Real-Time markets.

**Q. What asset-based bilateral sales contracts are included in Minnesota Power's 2020 test year?**

A. Minnesota Power has three bilateral sales included in the 2020 test year: (1) a **[TRADE SECRET BEGINS TRADE SECRET ENDS]** contract with Oconto Electric Cooperative; (2) a **[TRADE SECRET BEGINS TRADE SECRET ENDS]** contract with AEP Energy Partners, Inc.; and (3) a **[TRADE SECRET BEGINS TRADE SECRET ENDS]** contract with NextEra Energy Marketing, LLC. These bilateral contracts provide 86 percent of the $11.5 million Total Company ($10 million MN Jurisdictional) test year margin credit for 2020.

**Q. Can you explain the difference in the terms of these three contracts?**

A. The bilateral contracts with AEP Energy Partners, Inc. and NextEra Energy Marketing, LLC are both **[TRADE SECRET BEGINS TRADE SECRET ENDS]** sales rather than **[TRADE SECRET BEGINS TRADE SECRET ENDS]** sales. Off-peak market prices are low (see Figure 6 in the MISO section above) and are not always high enough to support a forward bilateral **[TRADE SECRET BEGINS TRADE SECRET ENDS]** sale. Therefore, only a **[TRADE SECRET BEGINS TRADE SECRET ENDS]** sale was made for these transactions. Minnesota Power monitors the off-peak time period to determine if the market pricing is high enough to make additional forward bilateral sales.

However, included in the MISO market sale portion of the asset-based wholesale sale margins is the assumption that when prices are expected to exceed the generation fuel cost, excess energy will be sold as a shorter-term bilateral contract or directly to the MISO market. Minnesota Power continues to pursue transactions to balance our power supply with system requirements and optimize overall costs for customers.

**Q. Could Minnesota Power make more asset-based wholesale sale margins if it enters into bilateral sale contracts for all hours?**

A. No, not at this time. It is more beneficial for customers if the Company sells available energy when the market supports the sale hourly and purchases energy when lower priced energy is available. Currently, a **[TRADE SECRET BEGINS TRADE SECRET ENDS]** energy sale typically provides the greatest value for customers.

**Q. Are there any significant long-term bilateral sale contracts expiring during the 2020 test year?**

A. Yes. Minnesota Power has one Large Market Contract that is ending in 2020. The contract term is from May 2010 through April 2020 and it does not have an extension. The Company entered into the long-term contract in 2009 due to the economic downturn at that time which caused industrial loads that Minnesota Power had expected to develop to be delayed.

The LMC, with its unique attributes, has reduced Minnesota Power retail customer revenue requirements over the sale term and offered significant annual benefits through margin contributions. The 100 MW block of energy is sold **[TRADE SECRET BEGINS TRADE SECRET ENDS]** and has an energy and capacity sale price that cannot be replicated in today's market. Due to the contract pricing terms for energy and capacity, the LMC provided a Total Company margin benefit between **[TRADE SECRET BEGINS**

**TRADE SECRET ENDS]** each year. The LMC revenue was included in Minnesota Power's 2009 and 2016 rate cases as revenue credits. The presence of the LMC has reduced the Company's retail revenue requirements significantly, along with customer rates, since 2010.

**Q. What makes the LMC unable to be replicated today?**

A. The LMC was executed in 2009 when there was still higher market prices available for forward bilateral contracts. Today's forward power market does not contain the same premium outlook for bilateral sale contracts, making the LMC unique in current markets such that it cannot be replicated today.

Also, as described above, there have been significant changes made to Minnesota Power's supply portfolio that have made our generation portfolio much more variable than it was in the past such that a **[TRADE SECRET BEGINS TRADE SECRET ENDS]** sale of this magnitude cannot be replicated with existing resources. MP Exhibit ___ (Pierce), Direct Schedule 2 is a copy of the LMC.

**Q. How does Minnesota Power propose to treat the termination of the LMC in the 2020 test year?**

A. As the LMC is now ending, it is important that the transition out of the contract is treated in the same and consistent manner as when the transaction was brought into the sale portfolio for customers during Minnesota Power's 2009 rate case.

In Minnesota Power's 2009 rate case with a 2010 test year, Minnesota Power requested that the LMC be included in the test year at the start of the contract term or May 1, 2010. During the course of the rate case, it was determined that an adjustment would be made to the MN Jurisdictional asset-based wholesale margins to reflect the new LMC for the entire 2010 test year even though the contract did not start until May 1, 2010.[12]

---

[12] *In the Matter of Application of Minn. Power for Auth. To Increase Elec. Serv. Rates in Minn.*, Docket No. E015/GR-09-1151, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER at 6 (Nov. 2, 2010); *In the Matter of Application of Minn. Power for Auth. To Increase Elec. Serv. Rates in Minn*., Docket No. E015/GR-09-1151, DIRECT TESTIMONY OF NANCY A. CAMPBELL at 45 (March 31, 2010); *In the Matter of Application of Minn. Power for Auth. To Increase Elec. Serv. Rates in Minn*., Docket No. E015/GR-09-1151, DIRECT TESTIMONY OF PETER J. SEELING at 4 (Apr. 29, 2010).

By adding the four months of LMC sales credit to customers for the 2010 test year (even though the transaction did not start until mid-year), customers received approximately **[TRADE SECRET BEGINS TRADE SECRET ENDS]** in additional base rate credit in 2010. The reasoning identified by the Commission for this change in the treatment for the LMC was that it was a known and measureable change for the 2010 test year that was going to perpetuate into future years. As the LMC will expire on April 30, 2020, Minnesota Power is requesting similar treatment in this rate case as the transaction ends.

**Q. Why is it appropriate for the LMC to be removed for the full 2020 test year?**

A. There are two primary reasons why it is appropriate for the LMC to be removed for a full year. First, this is a known and measureable change that will perpetuate into future years. Such treatment is consistent with the treatment granted by the Commission when the LMC commenced in May 2010 and yet the margin and MWh were included for the entire 2010 test year. It would be inconsistent not to follow the same practice at the end of the contract and would overstate the revenues from this contract. Second, as I explain in more detail later, the asset-based margins would be greatly overstated if the LMC sale margins were included in the 2020 test year because it is not presently possible to duplicate margin levels consistent with the LMC given the unique nature of this contract and available market pricing. Thus, Minnesota Power proposes to remove both the margin and MWh for the LMC from the 2020 test year and replace them with margin and MWh quantities that reflect current sales projections for 2020. This is reflected in MP Exhibit ___ (Pierce), Direct Schedule 3.

**Q. Describe how the expiration of the LMC has impacted the 2020 test year asset-based sale margins?**

A. The expiration of the LMC is the single most significant driver of the reduction in the asset-based margin credit in the 2020 test year as compared to prior years. For the 2020 test year, the LMC was replaced with bilateral and MISO market sales with associated margins to the extent possible with Minnesota Power's current power supply portfolio and expected load requirements. MP Exhibit ___ (Pierce), Direct Schedule 1 provides the details of these margins for the 2020 test year.

**Q. Why is it difficult to replace the terms of the LMC?**

A. The LMC has provided a sale with a significant **[TRADE SECRET BEGINS TRADE SECRET ENDS]** over its contract term. Figure 9 below demonstrates the historical trend of the LMC and market prices.[13] The Company negotiated the LMC in the 2009 time period when MISO market pricing was at levels much higher than today. Looking forward, the market price outlook does not support additional sales at the same price as the LMC. For example, in 2019, the LMC provided a combined energy and capacity sale price of approximately **[TRADE SECRET BEGINS TRADE SECRET ENDS]**. Had this energy and capacity been sold into the MISO market, the combined selling price would have been $26 per MWh.[14] The sales price achieved through the LMC simply cannot be replicated in today's market place as shown in Figure 5, and wholesale sale asset-based margin expectations therefore need to be reduced.

---

[13] The market prices in Figure 5 represent the 7x24 annual average price for each year.

[14] Energy/Capacity price based on Day-Ahead price of $26.09/MWh from Figure 5 and an annual capacity value of $2.16/MW Day (January-May $1.00 MW Day and June-December $2.99/MW Day) from Figure 8.

**[TRADE SECRET BEGINS**

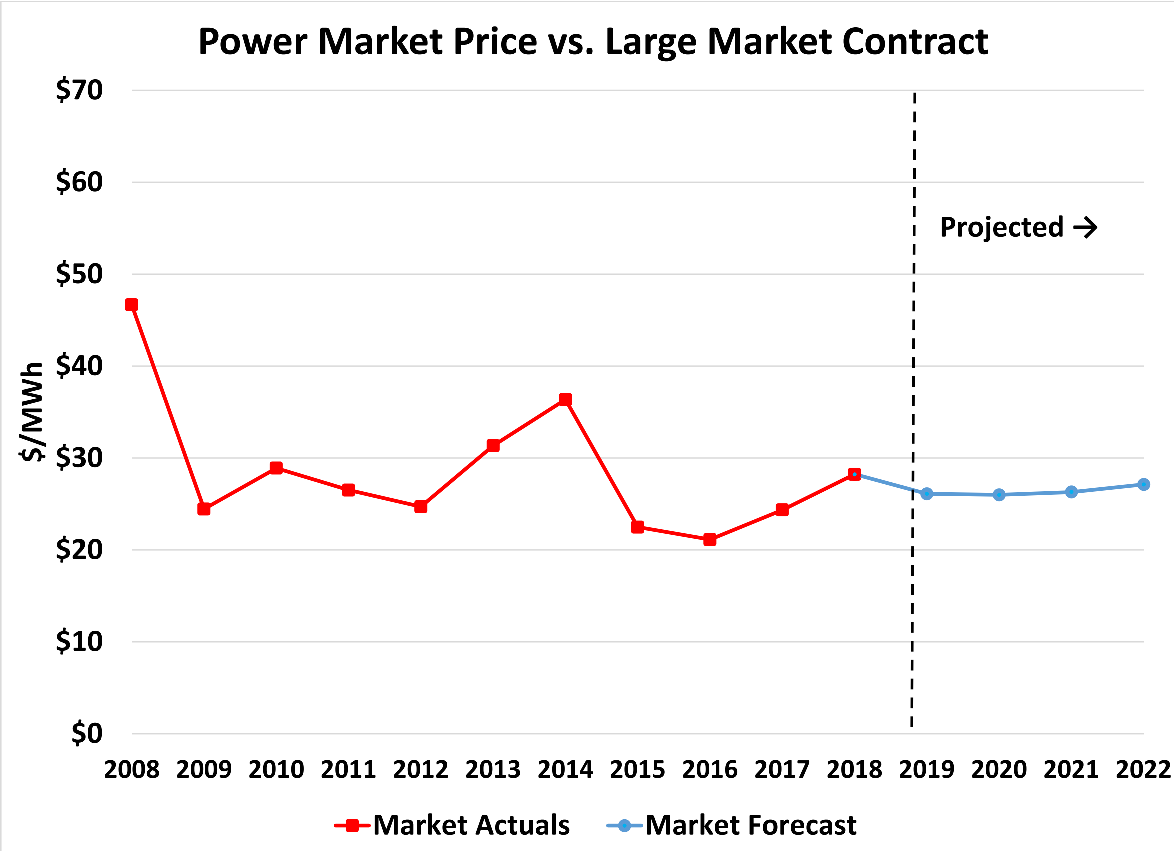
**Figure 9.**

**(Trade Secret Version)**

**TRADE SECRET ENDS]**

**Figure 9.**

**(Public Version)**




**Q. How does the LMC price compare to the Company's other bilateral contracts?**

A. There are three bilateral contracts included in the 2020 test year. They each have **[TRADE SECRET BEGINS TRADE SECRET ENDS]** selling prices of approximately **[TRADE SECRET BEGINS TRADE SECRET ENDS]**. This price **[TRADE SECRET BEGINS TRADE SECRET ENDS]**. Consequently, the expected margin threshold is greatly reduced without the LMC and the corresponding credit to base rates must be reduced to a more reasonable level given the end of the LMC system conditions, and the market outlook.

## IV. TEST YEAR ASSET-BASED WHOLESALE SALE MARGINS

**Q. What factors impact Minnesota Power's asset-based energy sales margin each year?**

A. The level of the asset-based wholesale sale margin in a given year is driven by two main factors: (1) energy volume that is sold, and (2) market price received for those sales.

The first, energy volume that is available to be sold, is driven by customer load and the generation profile available. As described above, Minnesota Power has been transforming its generation portfolio to more intermittent and variable generation sources, and its customer load has declined. Each of these impact the energy volume that is able to be sold.

The second, the margin received for the energy sold, is driven by the market price and the fuel price to produce the sale. If the market price available is higher and there is energy available to sell, the asset-based wholesale margins typically increase as long as the cost of the fuel to produce the energy does not also increase.

**Q. How did Minnesota Power forecast the volume of asset-based wholesale energy sales for the 2020 test year?**

A. Minnesota Power used an RTSim production cost model to evaluate the amount of energy that was sold through bilateral contracts and determine remaining energy available to sell into the MISO market and ultimately the asset-based wholesale margins associated with these sales.

First, all energy sources that serve native load (i.e., including Minnesota Power's retail customers and municipal resale customers) and all committed wholesale bilateral sales were modeled on an hourly basis. The RTSim estimate for the 2020 test year sales includes the generation changes and new market pricing. The Company then determined how much energy it would have available on its system to sell into the wholesale market after meeting its projected retail and full-requirements municipal resale sales and its committed bilateral wholesale sales (described above and included in MP Exhibit ___ (Pierce), Direct Schedule 1). Minnesota Power's load forecasting process and projected retail sales for the test year that were modeled are outlined in the Direct Testimony of Company witness Mr. Levine.

**Q. What was the volume of asset-based wholesale energy transactions Minnesota Power identified for the 2020 test year?**

A. The planning process for the 2020 test year identified that, due to the expiration of the LMC, lower thermal base load generation, and additional intermittent generation in the power supply, there will be a significant decrease in MWh sales available in 2020 as compared to earlier years. In 2017, Minnesota Power had 2.2 million MWh of energy sales; for the 2020 test year we have identified 984,000 MWh of asset-based wholesale energy sales. This is a reduction of 1.2 million MWh and leads to a large reduction in the sale margin that can be achieved.

**Q. How did Minnesota Power determine the MISO market price for the 2020 test year asset-based sales?**

A. Minnesota Power utilized an independent third-party to determine the monthly MISO market sale price for the 2020 test year.

Market prices in 2020 are expected to average $26 per MWh. We expect market prices to stay lower than historical prices and the LMC price into the future (see Figure 9 above). This is largely due to natural gas pricing trends and additional renewable generation in the region that drive MISO market pricing levels. Lower market prices reduce the Company's asset-based wholesale margins from historical levels.

As discussed earlier in my testimony, MISO market prices also correlate with the Company's wind output. Market prices are often lower than the average price when the Company wind generation is at its highest level and higher when wind generation is at its lowest level. Market price variations due to wind profiles were incorporated into the RTSim estimate for the 2020 test year.

**Q. How did Minnesota Power determine the test year margins for these asset-based wholesale sales?**

A. Minnesota Power determined the test year margins for its asset-based wholesale sales by multiplying the energy projected to be sold into the MISO market (MWh) by the hourly market price projections for 2020 to yield the total test year wholesale revenue from MISO market sales. The MISO wholesale market sales revenue for the test year was then added to the test year revenue from the bilateral wholesale contracts to arrive at the total test year wholesale revenue. The fuel costs associated with the production of the energy sold at wholesale were then subtracted from the test year wholesale revenue to arrive at the test year asset-based wholesale margins.

**Q. What are Minnesota Power's projected 2020 test year asset-based wholesale sale margins?**

A. Asset-based wholesale sale margins for the 2020 test year are estimated to be $11.5 million Total Company ($10 million MN Jurisdictional). This margin level represents a significant decrease in the base rate credit or margin threshold from previous years (most recently set in the 2016 Rate Case at $43 million Total Company or $35.8 million MN Jurisdictional).

MP Exhibit ___ (Pierce), Direct Schedule 1 and Figure 10 below provide the base rate credit benefit approved by the Commission that retail customers have received (Commission Approved Margin Threshold) vs. the actual asset-based margins the Company was able to generate each year from 2010 through 2018 and projected for 2019 (LMC plus Other Sale Margins).

**[TRADE SECRET BEGINS**

**Figure 10.**

**(Trade Secret Version)**

**TRADE SECRET ENDS]**

**Figure 10.**

**(Public Version)**

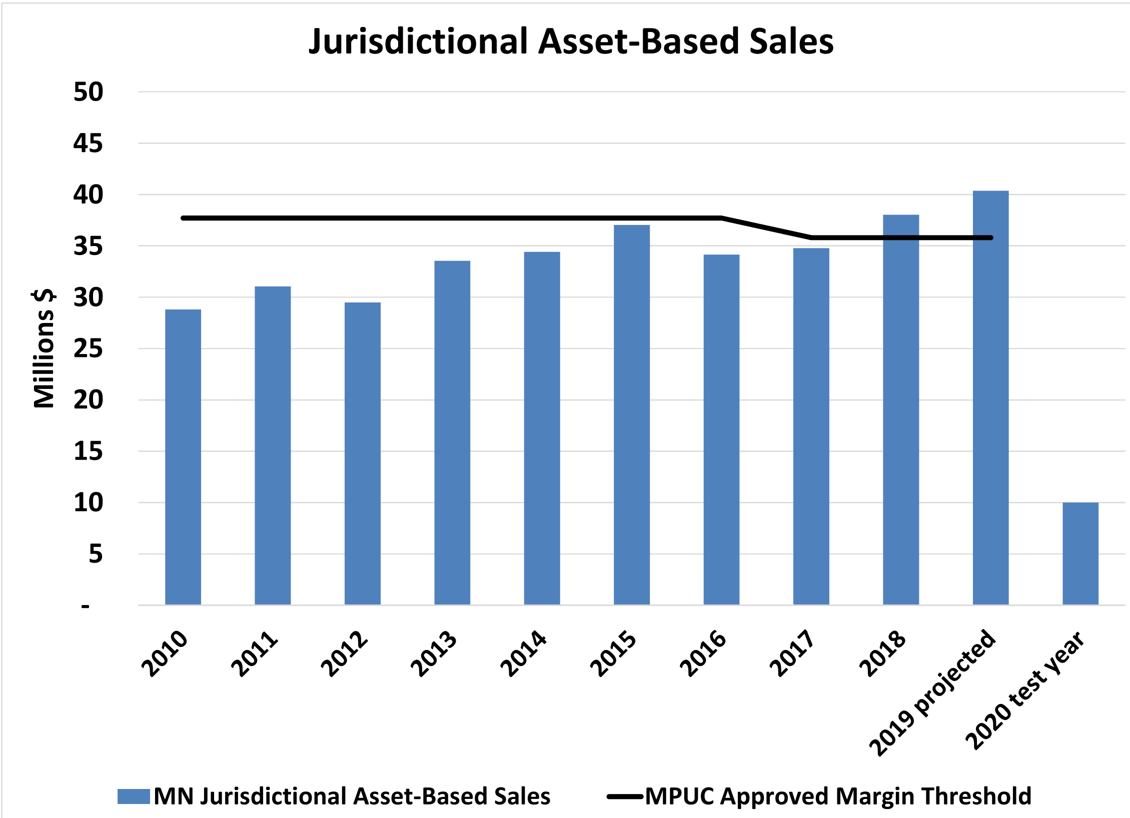



Figure 10 illustrates several important items. First, **[TRADE SECRET BEGINS TRADE SECRET ENDS]**[15] have been provided from the LMC. Second, the LMC expiration is very impactful to the margin level available. As the LMC ends, the level of asset-based wholesale sale margins will be much lower and the current market does not allow replication of the sale margin that was created with this sale.

**Q. Why have Minnesota Power's asset-based sale margins exceeded the Commission approved base rate credit for these margins in 2018 and projected 2019?**

A. The margin level exceeded the base rate credit threshold in these two years due to the terms of the LMC. The LMC is a long-term sale that was entered into before a

[15] LMC margin divided by total asset-based wholesale sale margin for 2010 from Figure 10.

significant downward shift in the power market occurred, and it has an escalator that increased its sale price and corresponding margin. As indicated in Figure 10 (Trade Secret Version) above, the LMC sale margin became a larger share of total margins in those years. For the years from 2010 through 2017, the sales margin was below the base rate credit amount; in these years customers received the full credit in base rates even though Minnesota Power was not able to make transactions that achieved these margins.

**Q. Describe the reduction in the base rate credit due to asset-based wholesale sale margins from the 2016 Rate Case to this rate case.**

A. The asset-based wholesale sales are made up of bilateral sales and MISO market sales as described earlier in my testimony. For bilateral contracts, the LMC is not included in the 2020 test year, and three bilateral sales were added. The expected bilateral contract sale margin for 2020 is $9.9 million Total Company ($8.6 million MN Jurisdictional). To determine the MISO market sales, the RTSim evaluation was conducted for the MP system and identified that the expected asset-based sales to the MISO market would be 451,000 MWh for the year. The total sale margin for the MISO markets sales are $1.6 million Total Company ($1.4 million MN Jurisdictional).[16]

The market sales margin ($1.4 million) is combined with the expected bilateral contract sale margin ($8.6 million) to create the total projected $10 million MN Jurisdictional sale margin threshold (MP Exhibit ___ (Pierce), Direct Schedule 1). The previous base rate credit due to asset-based wholesale sale margins was $43.0 million Total Company ($35.8 million MN Jurisdictional). For 2020, due to the end of the LMC and system and power market changes, the projected asset-based wholesale margin is reduced to $11.5 Total Company ($10 million MN Jurisdictional).

[16] The margin values identify the MN Jurisdictional value for the market sale and bilateral categories.

**Q. Would it be appropriate to use a three- or five-year average of previous asset-based sale margins to determine the 2020 test year amount?**

A. No. As noted above, there have been significant changes in the 2020 test year and future expectations such that the use of historic averages is not appropriate to determine the test year asset-based sale margins amount. Specifically, the LMC will expire in 2020 and Minnesota Power has had generation power supply changes in recent years that impact the volume and price of its asset-based sales.

**Q. Are the asset-based sale margins included in the 2020 test year a reasonable estimate of the margins expected in 2020 and beyond?**

A. Yes. Minnesota Power has provided a robust estimate of the expected load for the 2020 test year as outlined in the testimony of Company witness Mr. Levine. All available generation in the Company's portfolio has been included. Bilateral sale contracts that are expected to continue have been included along with the expectation for near-term MISO market sales. These comprise the best available information for 2020, making the 2020 test year level of $11.5 million Total Company ($10 million MN Jurisdictional) a reasonable estimate for asset-based wholesale sale margins.

## V. REVENUE MITIGATION DURING CUSTOMER LOSS

**Q. What is the impact to wholesale sale margins when Minnesota Power loses a significant customer?**

A. Minnesota Power's customer mix is comprised largely of industrial customers, and the business cycles that can occur in each of the industries we serve can create large fluctuations in system load on an annual basis. When a large customer comes off the system or reduces load significantly, the Company makes additional energy sales to the market. The amount of energy that is sold is equivalent to the amount of energy not consumed by these customers. The sales margin due to customer load loss sales are utilized to mitigate the lost retail and municipal revenue.

**Q. Why is revenue mitigation important to the Company?**

A. Base rates are set with an agreed load forecast with expected demand and energy revenue based on this load. Of course, if load falls off significantly or a large customer shuts down, it will have a significant impact on the Company's revenue. The Company's risk profile is explained in the testimony of Company witnesses Mr. Patrick L. Cutshall and Ms. Ann E. Bulkley. Presently, the Company can offset a portion of this revenue loss by selling an equivalent amount of energy to the market to reduce the impacts of the load loss.

**Q. Does the Company recover all of its revenue losses due to a customer downturn?**

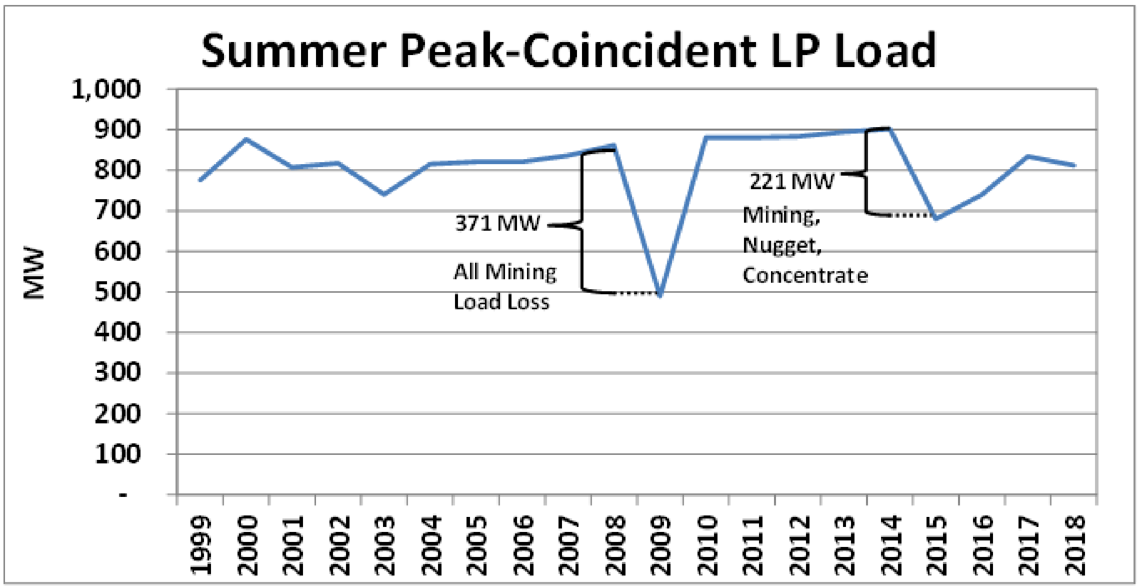
A. No. In the current low-priced market, the lost revenue due to the load reduction cannot be made up in the wholesale market. Although this mitigation strategy was fairly effective in 2009, it has become more difficult to recover revenue losses due to a customer downturn as markets have been declining and electric costs have been increasing.

In 2009, when several large industrial customers were idled, Minnesota Power was able to offset 79 percent of the load reduction by making sales in the market. In 2015, Minnesota Power had over 200 MW of large customer load that unexpectedly came off its system and made bilateral sales in an attempt to recover the lost revenue from the customer downturn. These sales were made in a market lower than historical levels and as such the Company was able to recover only 57 percent of the lost retail margin.[17] In present market conditions and with current industrial rates, the Company can expect to recover only 4 percent of the lost retail margin. This demonstrates the fluctuation in Company revenue that can occur when there is a loss of customer load. The inability to recover 100 percent of the lost revenue creates a difficult cost recovery equation for Minnesota Power in meeting its ongoing fixed-cost requirement.

[17] Lost retail margin equals large power demand and energy revenue less fuel cost.

History and current operations has shown that our large customers can experience significant downturns and load reductions with short notification periods[18] that put Minnesota Power in a position where it is not able to recover its cost of service. Figure 11 below demonstrates how retail load for large power customers has fluctuated from 1999 to 2018.

**Figure 11.**




**Q. Do wholesale sale transactions entered into as a result of the customer loss of load impact asset-based wholesale sale margins?**

A. No. Asset-based wholesale sale margins are wholesale transactions sourced from Minnesota Power's generating unit energy – that is, energy from generation facilities included in rate base and hence paid for by ratepayers. Transactions that are made as a result of a customer loss of load are priced using the average cost of fuel, the "source" of these transactions includes both rate based generating unit energy and energy market purchases. Therefore, the wholesale transactions do not represent a purely

[18] As referenced in the Large Power Customer Outlook Direct Testimony of Mr. Frank L. Frederickson and the Direct Testimony of Mr. Levine, in late 2019 there was a reduction in United States Steel production that was announced with short notice.

asset-based margin but rather a combination of an asset-based margin with a purchased energy margin.

**Q. Does the Company expect to make any sales in 2020 due to customer losses?**

A. No. The Company has adjusted customer loads in the 2020 test year to reflect the expected customer loads at this time; consequently, no sales related to customer loss of load are expected for 2020.

**Q. Does Minnesota Power have other established mechanisms to recover revenue due to a loss of load?**

A. The ability to make wholesale sale transactions are a critical component of recovering revenue due to a loss of load. The only other mechanism is to file a rate case and adjust all remaining customer rates.

## VI. CONCLUSION

**Q. Does this complete your testimony?**

A. Yes.

**PUBLIC DOCUMENT**
**TRADE SECRET DATA EXCISED**



## Asset-Based Wholesale Sales
## 2010 Actual

| LINE No. | | Executed due to Industrial Load Loss | MWH | FUEL COST | MN JURISDICTION FUEL COST | SALES PRICE | MN JURISDICTION SALES PRICE | NET ENERGY MARGIN | MN JURISDICTION MARGIN | CAPACITY REVENUE | MN JURISDICTION CAPACITY REVENUE |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | TRADE SECRET DATA BEGINS | | | | | | | | |
| 1 | MISO Market Sales | | | | | | | | | | |
| 2 | Cargill | | | | | | | | | | |
| 3 | Cargill | yes | | | | | | | | | |
| 4 | Basin | | | | | | | | | | |
| 5 | GRE Block A | | | | | | | | | | |
| 6 | GRE Block B | | | | | | | | | | |
| 7 | Ottertail | | | | | | | | | | |
| 8 | NextEra | | | | | | | | | | |
| 9 | AEP | | | | | | | | | | |
| 10 | Detroit Edison | | | | | | | | | | |
| 11 | Integrys | | | | | | | | | | |
| 12 | AEPSC | yes | | | | | | | | | |
| 13 | GSE | yes | | | | | | | | | |
| 14 | MISO Market Sales | yes | | | | | | | | | |
| 15 | SMPM | yes | | | | | | | | | |
| 16 | MISO Costs | | | | | | | | | | |
| | | | | | | | | | | TRADE SECRET DATA ENDS | |
| | Total Wholesale Energy Sales | | 1,677,954 | $ 30,287,710.86 | $ 25,402,908.85 | $ 57,618,791.86 | $ 48,326,033.11 | $ 27,331,081.00 | $ 22,923,124.26 | $ 13,424,600.00 | $ 11,010,454.18 |

| | |
|---|---|
| Total Margin | $ 40,755,681.00 |
| MN Jurisdictional Margin | $ 33,933,578.44 |

| | | |
|---|---|---|
| Note: | MN Jurisdictional (2010 Cost of Service Study) | |
| | Energy | 0.83872 |
| | Demand | 0.82017 |

**PUBLIC DOCUMENT**
**TRADE SECRET DATA EXCISED**



## Asset-Based Wholesale Sales
## 2011 Actual

| LINE No. | | Executed due to Industrial Load Loss | MWH | FUEL COST | MN JURISDICTION FUEL COST | SALES PRICE | MN JURISDICTION SALES PRICE | NET ENERGY MARGIN | MN JURISDICTION MARGIN | CAPACITY REVENUE | MN JURISDICTION CAPACITY REVENUE |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | TRADE SECRET DATA BEGINS | | | | | | | | |
| 1 | MISO Market Sales | | | | | | | | | | |
| 2 | Cargill | | | | | | | | | | |
| 3 | Basin | | | | | | | | | | |
| 4 | Alliant | | | | | | | | | | |
| 5 | Ottertail | | | | | | | | | | |
| 6 | SMPM | | | | | | | | | | |
| 7 | MISO Costs | | | | | | | | | | |
| | | | | | | | | | | TRADE SECRET DATA ENDS | |
| | Total Wholesale Energy Sales | | 1,817,983 | $ 31,757,948.00 | $ 26,636,026.15 | $ 66,217,765.00 | $ 55,538,163.86 | $ 34,459,817.00 | $ 28,902,137.71 | $ 2,632,000.00 | $ 2,158,687.44 |

| | |
|---|---|
| Total Margin | $ 37,091,817.00 |
| MN Jurisdictional Margin | $ 31,060,825.15 |

Note: MN Jurisdictional (2010 Cost of Service Study)

| | |
|---|---|
| Energy | 0.83872 |
| Demand | 0.82017 |

**PUBLIC DOCUMENT**
**TRADE SECRET DATA EXCISED**



## Asset-Based Wholesale Sales
## 2012 Actual

TRADE SECRET DATA BEGINS

| LINE No. | | Executed due to Industrial Load Loss | MWH | FUEL COST | MN JURISDICTION FUEL COST | SALES PRICE | MN JURISDICTION SALES PRICE | NET ENERGY MARGIN | MN JURISDICTION MARGIN | CAPACITY REVENUE | MN JURISDICTION CAPACITY REVENUE |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | MISO Market Sales | | | | | | | | | | |
| 2 | Cargill | | | | | | | | | | |
| 3 | Basin | | | | | | | | | | |
| 4 | EDF | | | | | | | | | | |
| 5 | Ameren | | | | | | | | | | |
| 6 | MISO Market Sales | yes | | | | | | | | | |
| 7 | AEP | | | | | | | | | | |
| 8 | SMPM | | | | | | | | | | |
| 9 | Alliant | | | | | | | | | | |
| 10 | Exelon | | | | | | | | | | |
| 11 | EDF | | | | | | | | | | |
| 12 | MISO Costs | | | | | | | | | | |
| | **Total Wholesale Energy Sales** | | 1,635,980 | $ 29,328,470.00 | $ 24,598,374.36 | $ 62,048,943.00 | $ 52,041,689.47 | $ 32,720,473.00 | $ 27,443,315.11 | $ 2,503,888.00 | $ 2,053,613.82 |

TRADE SECRET DATA ENDS

| | |
|---|---|
| Total Margin | $ 35,224,361.00 |
| MN Jurisdictional Margin | $ 29,496,928.93 |

Note: MN Jurisdictional (2010 Cost of Service Study)

| | |
|---|---|
| Energy | 0.83872 |
| Demand | 0.82017 |

**PUBLIC DOCUMENT**
**TRADE SECRET DATA EXCISED**



**Asset-Based Wholesale Sales**
**2013 Actual**

| LINE No. | | Executed due to Industrial Load Loss | MWH | FUEL COST | MN JURISDICTION FUEL COST | SALES PRICE | MN JURISDICTION SALES PRICE | NET ENERGY MARGIN | MN JURISDICTION MARGIN | CAPACITY REVENUE | MN JURISDICTION CAPACITY REVENUE |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | TRADE SECRET DATA BEGINS | | | | | | | | |
| 1 | MISO Market Sales | | | | | | | | | | |
| 2 | Cargill | | | | | | | | | | |
| 3 | Basin | | | | | | | | | | |
| 4 | MPC | | | | | | | | | | |
| 5 | MISO Market Sales | yes | | | | | | | | | |
| 6 | MISO Costs | | | | | | | | | | |
| 7 | | | | | | | | | | | |
| | | | | | | | | | | TRADE SECRET DATA ENDS | |
| | Total Wholesale Energy Sales | | 1,806,599 | $ 35,714,126.00 | $ 29,954,151.76 | $ 63,751,624.00 | $ 53,469,762.08 | $ 28,037,498.00 | $ 23,515,610.32 | $ 12,248,254.00 | $ 10,045,650.48 |

| | |
|---|---|
| Total Margin | $ 40,285,752.00 |
| MN Jurisdictional Margin | $ 33,561,260.80 |

Note: MN Jurisdictional (2010 Cost of Service Study)

| | |
|---|---|
| Energy | 0.83872 |
| Demand | 0.82017 |

**PUBLIC DOCUMENT**
**TRADE SECRET DATA EXCISED**

## Asset-Based Wholesale Sales
## 2014 Actual

| LINE No. | | Executed due to Industrial Load Loss | MWH | FUEL COST | MN JURISDICTION FUEL COST | SALES PRICE | MN JURISDICTION SALES PRICE | NET ENERGY MARGIN | MN JURISDICTION MARGIN | CAPACITY REVENUE | MN JURISDICTION CAPACITY REVENUE |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | TRADE SECRET DATA BEGINS | | | | | | | | |
| 1 | MISO Market Sales | | | | | | | | | | |
| 2 | Cargill | | | | | | | | | | |
| 3 | Basin | | | | | | | | | | |
| 4 | NSP | | | | | | | | | | |
| 5 | MISO Market Sales | yes | | | | | | | | | |
| 6 | EDF | | | | | | | | | | |
| 7 | MISO Costs | | | | | | | | | | |
| | | | | | | | | | | TRADE SECRET DATA ENDS | |
| | Total Wholesale Energy Sales | | 1,918,151 | $ 33,878,508.00 | $ 28,414,582.23 | $ 72,762,899.00 | $ 61,027,698.65 | $ 38,884,391.00 | $ 32,613,116.42 | $ 2,581,567.00 | $ 2,117,323.81 |

| | |
|---|---|
| Total Margin | $ 41,465,958.00 |
| MN Jurisdictional Margin | $ 34,730,440.23 |

Note: MN Jurisdictional (2010 Cost of Service Study)

| | |
|---|---|
| Energy | 0.83872 |
| Demand | 0.82017 |

**PUBLIC DOCUMENT**
**TRADE SECRET DATA EXCISED**



## Asset-Based Wholesale Sales
## 2015 Actual

| LINE No. | | Executed due to Industrial Load Loss | MWH | FUEL COST | MN JURISDICTION FUEL COST | SALES PRICE | MN JURISDICTION SALES PRICE | NET ENERGY MARGIN | MN JURISDICTION MARGIN | CAPACITY REVENUE | MN JURISDICTION CAPACITY REVENUE |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | TRADE SECRET DATA BEGINS | | | | | | | | |
| 1 | MISO Market Sales | | | | | | | | | | |
| 2 | AEP | | | | | | | | | | |
| 3 | Basin | | | | | | | | | | |
| 4 | NextEra | | | | | | | | | | |
| 5 | MISO Market Sales | yes | | | | | | | | | |
| 6 | Cargill | yes | | | | | | | | | |
| 7 | MISO Costs | | | | | | | | | | |
| | | | | | | | | | | TRADE SECRET DATA ENDS | |
| | Total Wholesale Energy Sales | | 2,391,914 | $ 40,543,607.61 | $ 34,027,844.43 | $ 82,100,133.87 | $ 68,905,821.36 | $ 41,556,526.26 | $ 34,877,976.93 | $ 6,065,948.00 | $ 5,098,671.93 |

| | |
|---|---|
| Total Margin | $ 47,622,474.26 |
| MN Jurisdictional Margin | $ 39,976,648.86 |

| | | |
|---|---|---|
| Note: | MN Jurisdictional (2015 Actual Cost of Service Study) | |
| | Energy | 0.83929 |
| | Demand | 0.84054 |

## Asset-Based Wholesale Sales
## 2016 Actual

| LINE No. | | Executed due to Industrial Load Loss | MWH | FUEL COST | MN JURISDICTION FUEL COST | SALES PRICE | MN JURISDICTION SALES PRICE | NET ENERGY MARGIN | MN JURISDICTION MARGIN | CAPACITY REVENUE | MN JURISDICTION CAPACITY REVENUE |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | TRADE SECRET DATA BEGINS | | | | | | | | |
| 1 | MISO Market Sales | | | | | | | | | | |
| 2 | AEP | | | | | | | | | | |
| 3 | Basin | | | | | | | | | | |
| 4 | Alliant | | | | | | | | | | |
| 5 | MDU | | | | | | | | | | |
| 6 | MISO Resource Adequacy | | | | | | | | | | |
| 7 | MISO Market Sales | yes | | | | | | | | | |
| 8 | Alliant | yes | | | | | | | | | |
| 9 | Shell | yes | | | | | | | | | |
| 10 | MISO Costs | | | | | | | | | | |
| | | | | | | | | | | TRADE SECRET DATA ENDS | |
| | Total Wholesale Energy Sales | | 2,827,857 | $ 54,068,826.40 | $ 44,907,945.14 | $ 100,991,091.33 | $ 83,880,170.73 | $ 46,922,264.93 | $ 38,972,225.58 | $ 9,858,922.38 | $ 8,192,370.14 |

| | |
|---|---|
| Total Margin | $ 56,781,187.31 |
| MN Jurisdictional Margin | $ 47,164,595.72 |

Note: MN Jurisdictional (2016 Projected Year Cost of Service Study)

| | |
|---|---|
| Energy | 0.83057 |
| Demand | 0.83096 |

**PUBLIC DOCUMENT**
**TRADE SECRET DATA EXCISED**



## Asset-Based Wholesale Sales
## 2017 Actual

TRADE SECRET DATA BEGINS

| LINE No. | | Executed due to Industrial Load Loss | MWH | FUEL COST | MN JURISDICTION FUEL COST | SALES PRICE | MN JURISDICTION SALES PRICE | NET ENERGY MARGIN | MN JURISDICTION MARGIN | CAPACITY REVENUE | MN JURISDICTION CAPACITY REVENUE |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | MISO Market Sales | | | | | | | | | | |
| 2 | AEP | | | | | | | | | | |
| 3 | Basin 100 MW | | | | | | | | | | |
| 4 | Basin | | | | | | | | | | |
| 5 | NextEra | | | | | | | | | | |
| 6 | MDU | | | | | | | | | | |
| 7 | MISO Resource Adequacy | | | | | | | | | | |
| 7 | MMPA | | | | | | | | | | |
| 8 | OTA | | | | | | | | | | |
| 9 | MISO Costs | | | | | | | | | | |
| | Total Wholesale Energy Sales | | 2,244,242 | $ 51,514,972.57 | $ 43,430,727.92 | $ 79,367,618.35 | $ 66,912,458.00 | $ 27,852,645.78 | $ 23,481,730.08 | $ 13,375,272.21 | $ 11,283,379.64 |

TRADE SECRET DATA ENDS

| | |
|---|---|
| Total Margin | $ 41,227,917.99 |
| MN Jurisdictional Margin | $ 34,765,109.72 |

Note: MN Jurisdictional (2017 Cost of Service Study)

| | |
|---|---|
| Energy | 0.84307 |
| Demand | 0.84360 |

**PUBLIC DOCUMENT**
**TRADE SECRET DATA EXCISED**



## Asset-Based Wholesale Sales
## 2018 Actual

| LINE No. | | Executed due to Industrial Load Loss | MWH | FUEL COST | MN JURISDICTION FUEL COST | SALES PRICE | MN JURISDICTION SALES PRICE | NET ENERGY MARGIN | MN JURISDICTION MARGIN | CAPACITY REVENUE | MN JURISDICTION CAPACITY REVENUE |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | TRADE SECRET DATA BEGINS | | | | | | | | |
| 1 | MISO Market Sales | | | | | | | | | | |
| 2 | Shell | | | | | | | | | | |
| 3 | Basin 100 MW | | | | | | | | | | |
| 4 | Basin | | | | | | | | | | |
| 5 | NextEra | | | | | | | | | | |
| 6 | MMPA | | | | | | | | | | |
| 7 | OTP | | | | | | | | | | |
| 8 | TEA | | | | | | | | | | |
| 9 | MISO Resource Adequacy | | | | | | | | | | |
| 10 | MISO Market Sales | yes | | | | | | | | | |
| 11 | NextEra | yes | | | | | | | | | |
| 12 | Shell | yes | | | | | | | | | |
| 13 | MISO Costs | | | | | | | | | | |
| | | | | | | | | | | TRADE SECRET DATA ENDS | |
| | Total Wholesale Energy Sales | | 2,147,649 | $ 49,315,295.42 | $ 41,636,410.77 | $ 83,077,353.56 | $ 70,141,378.84 | $ 33,762,058.14 | $ 28,504,968.07 | $ 13,382,303.55 | $ 11,320,492.04 |

| | |
|---|---|
| Total Margin | $ 47,144,361.69 |
| MN Jurisdictional Margin | $ 39,825,460.11 |

| | | |
|---|---|---|
| Note: | MN Jurisdictional (2018 Cost of Service Study) | |
| | Energy | 0.84429 |
| | Demand | 0.84593 |

**PUBLIC DOCUMENT**
**TRADE SECRET DATA EXCISED**



## Asset-Based Wholesale Sales
## 2019 Projected Year

| LINE No. | | Executed due to Industrial Load Loss | MWH | FUEL COST | MN JURISDICTION FUEL COST | SALES PRICE | MN JURISDICTION SALES PRICE | NET ENERGY MARGIN | MN JURISDICTION MARGIN | CAPACITY REVENUE | MN JURISDICTION CAPACITY REVENUE |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | TRADE SECRET DATA BEGINS | | | | | | | | |
| 1 | MISO Market Sales | | | | | | | | | | |
| 2 | TransAlta | | | | | | | | | | |
| 3 | Basin 100 MW | | | | | | | | | | |
| 4 | Basin | | | | | | | | | | |
| 5 | Oconto | | | | | | | | | | |
| 6 | NextEra | | | | | | | | | | |
| 7 | NextEra | yes | | | | | | | | | |
| 8 | Unidentified capacity sale | | | | | | | | | | |
| 9 | MISO Costs | | | | | | | | | | |
| | | | | | | | | | | TRADE SECRET DATA ENDS | |
| | Total Wholesale Energy Sales | | 1,720,755 | $ 37,280,628.00 | $ 32,187,721.41 | $ 73,797,466.00 | $ 63,715,994.17 | $ 36,516,838.00 | $ 31,528,272.76 | $ 13,669,136.00 | $ 11,812,183.87 |

| | |
|---|---|
| Total Margin | $ 50,185,974.00 |
| MN Jurisdictional Margin | $ 43,340,456.64 |

Note: MN Jurisdictional (2019 Cost of Service Study)

| | |
|---|---|
| Energy | 0.86339 |
| Demand | 0.86415 |

**PUBLIC DOCUMENT**
**TRADE SECRET DATA EXCISED**

### Asset-Based Wholesale Sales
### 2020 Test Year

| LINE No. | | Executed due to Industrial Load Loss | MWH | FUEL COST | MN JURISDICTION FUEL COST | SALES PRICE | MN JURISDICTION SALES PRICE | NET ENERGY MARGIN | MN JURISDICTION MARGIN | CAPACITY REVENUE | MN JURISDICTION CAPACITY REVENUE |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | TRADE SECRET DATA BEGINS | | | | | | | | |
| 1 | MISO Market Sales | | | | | | | | | | |
| 2 | AEP | | | | | | | | | | |
| 3 | Oconto | | | | | | | | | | |
| 4 | NextEra | | | | | | | | | | |
| 5 | NextEra | | | | | | | | | | |
| 6 | MISO Resource Adequacy | | | | | | | | | | |
| 7 | Unidentified capacity sale | | | | | | | | | | |
| 8 | MISO Costs | | | | | | | | | | |
| | | | | | | | | | | TRADE SECRET DATA ENDS | |
| | Total Wholesale Energy Sales | | 984,098 | $ 22,363,632.00 | $ 19,341,187.14 | $ 30,336,674.00 | $ 26,236,672.51 | $ 7,973,042.00 | $ 6,895,485.37 | $ 3,573,864.00 | $ 3,095,573.78 |

| | |
|---|---|
| Total Margin | $ 11,546,906.00 |
| MN Jurisdictional Margin | $ 9,991,059.15 |

Note: MN Jurisdictional (2020 Cost of Service Study)

| | |
|---|---|
| Energy | 0.86485 |
| Demand | 0.86617 |

# MEMA SCHEDULE Q, MAPP PRODUCT A: UNIT PARTICIPATION POWER INTERCHANGE AGREEMENT

between

**ALLETE, Inc. dba Minnesota Power**
and
**Basin Electric Power Cooperative**

This Unit Participation Power Interchange Agreement ("Agreement") shall confirm the agreement reached on October __, 2009, by and between ALLETE, Inc. dba Minnesota Power ("Minnesota Power"), and Basin Electric Power Cooperative ("Basin Electric"). Basin Electric and Minnesota Power shall collectively be referred to as "Parties" and individually as "Party".

**WHEREAS**, the Parties are members of Mid-Continent Energy Marketers Association (MEMA); and

**WHEREAS**, the Parties herein desire to enter into a MEMA Capacity and Energy Tariff, Schedule Q, MAPP Product A: Unit Participation Power Interchange Service Agreement;

**NOW, THEREFORE**, the Parties agree as follows:

1. ***Governing Agreement:*** Mid-Continent Energy Marketers Association ("MEMA") Power and Energy Market Rate Tariff, effective November 1, 2006 ("MEMA Tariff"). Unless otherwise specified in this Agreement, all definitions and references to and use of terms and their abbreviations shall have meanings as set out in the Governing Agreement.

   When appropriate, references to the Midwest Independent Transmission System Operator ("MISO") Open Access Transmission, Energy, and Operating Reserve Markets Tariff ("TEMT"), effective January 6, 2009, are used herein. If a conflict in terms occurs between the MEMA Tariff and the TEMT, the MEMA Tariff shall govern.

2. ***Seller:*** Minnesota Power

3. ***Buyer:*** Basin Electric Power Cooperative [TRADE SECRET DATA EXCISED]

4. ***Contract Term:*** [redacted]

5. ***Contract Extension:*** The parties may extend the Contract Term of this transaction; provided the Parties have mutually agreed to pricing, delivery, and other terms and conditions, including but not limited to, environmental upgrade costs, for any such extension on or before the close of business on [redacted] [TRADE SECRET DATA EXCISED]

6. ***Commodity:*** MEMA Schedule Q, Product A – Unit Participation Power Interchange Service. [TRADE SECRET DATA EXCISED]

7. ***Contract Quantity:*** [redacted]

[TRADE SECRET DATA EXCISED]

8. ***Capacity Sources:*** [redacted]

9. ***Delivery Point:*** [redacted]

10. ***Sink Point:*** [redacted]

11. ***Capacity Price:***

[TRADE SECRET DATA EXCISED]

| Contract Term | Capacity Price (US dollars) |
|---|---|
| [redacted] | [redacted] |
| [redacted] | [redacted] |

12. ***Energy Price:***

a. The following table notes the Energy Price from May 1, 2010 through April 30, 2011.

[TRADE SECRET DATA EXCISED]

| Contract Term | Energy Price (US dollars) |
|---|---|
| [redacted] | [redacted] |
| [redacted] | [redacted] |
| [redacted] | [redacted] |

b. [redacted]

[TRADE SECRET DATA EXCISED]

c. [redacted]

13. ***Energy Scheduling:*** [redacted]

a. [redacted]

b. [redacted]

14. ***Repricing:***

a. [redacted]

b. [redacted]

c. [redacted]

15. ***Transmission Congestion and Losses:***

a. Basin Electric shall arrange and pay for all transmission service beyond the Delivery Point. Basin Electric is responsible for congestion and losses from the Delivery Point to the Sink Point;

b. Minnesota Power will facilitate supplying Basin Electric with access to existing Financial Transmission Rights ("FTRs") if available and accessible during the Contract Term from the Delivery Point to the MISO commercial pricing node of GRE.GRE.

PUBLIC DOCUMENT
TRADE SECRET DATA EXCISED



[TRADE SECRET DATA EXCISED]

16. ***Costs Related to Emissions:***
    a. [redacted]
        i. [redacted]
        ii. [redacted]
        iii. [redacted]
        iv. [redacted]
    b. [redacted]
        i. [redacted]
        ii. [redacted]
    c. [redacted]
        *i.* [redacted]

[TRADE SECRET DATA EXCISED]

[redacted]

*ii.* [redacted]

d. [redacted]

e. [redacted]

f. [redacted]

17. ***Invoice and Payment:*** Unless otherwise agreed, the power costs invoiced under this Agreement by Minnesota Power shall be rendered to Basin Electric by the tenth working day of each month for capacity and energy provided during the previous calendar month. Basin Electric's payment to MP in immediately available funds shall be due to MP no later than 15 days following the date of receipt of such invoice. Wire transfer or automated clearing house (ACH) payments shall accomplish payment within the fifteen (15) day period. Payment received subsequent to this due date shall be subject to a prorated annual interest charge equal to the JP Morgan Chase Bank, or its successor's prime rate plus two (2) percent, applied to late payments on a daily basis, on a three hundred and sixty-five (365) day year. If the due date falls on a weekend or a recognized holiday, the due date shall be the next business day.

18. ***Audit Rights:*** Minnesota Power shall, during normal working hours, make available at its principal office, all such records and supporting documents to authorized representatives of Basin Electric. The records shall also be made available upon 30

days written request by Basin Electric to internal or independent external auditors and representatives of any regulatory body or taxing authority having jurisdiction for inspection, copying, audit and other proper business requirements. Upon request by Basin Electric, Minnesota Power shall furnish copies of any such supporting documents and shall be reimbursed for the expense of preparing such copies by the requesting party.

All relevant books and records shall be made available by Minnesota Power for a period of twenty-four (24) months per incident during the term of the Agreement and for a period of two years after the termination of the Agreement.

19. ***Adequate Assurance and Creditworthiness:*** In the event that either Party does not have an issuer rating of investment grade or above from a nationally recognized rating agency, or if either Parties' issuer rating as rated by a nationally recognized rating agency falls below investment grade during the term of this Agreement, an unconditional and irrevocable letter of credit equal to the Aggregate Exposure will be required in order to provide adequate assurance to the other Party. Such irrevocable letter of credit must be issued in a format and by a bank reasonably acceptable to the requesting Party. Other alternative forms of eligible security may be used by mutual agreement of both Parties.

    Aggregate Exposure shall be defined as the dollar value of power provided under this Agreement for which payment has not yet been made. This Agreement may also be terminated immediately by either Party in the event that either Parties' issuer rating falls below investment grade during the term of the Agreement; however, such termination shall not relieve the other Party of its obligation to pay for power delivered under this Agreement.

20. ***Assignment:*** The rights and obligations created by an Agreement associated with this proposal shall inure to the benefit of, and be binding on the successors and assigns of the respective Parties hereto, provided, however that neither Party shall be permitted to assign its rights and obligations under this Agreement without the prior written consent of the other Party.

21. ***Contacts:***

| Basin Electric | Minnesota Power |
|---|---|
| Dave Raatz | Kevin Lindstrom |
| Manager of Marketing&Power Supply Planning | Energy Supply Planning Manager |
| 1717 East Interstate Ave. | 30 W Superior St |
| Bismarck, ND 58503 | Duluth MN 55802 |
| Phone: (701) 223-0441 | Phone: (218) 723-3986 |

22. ***Operating Committee:*** The Parties will form an Operating Committee consisting of the Manager of Marketing and Power Supply Planning or delegate from Basin Electric and Director of Energy Supply and Asset Optimization or delegate from Minnesota Power. Basin Electric and Minnesota Power shall each have one vote, and all decisions of the Operating Committee must be unanimous to be effective. The Operating Committee shall meet at the request of either of its members within two weeks of receipt of such request. Written minutes shall be kept of all meetings and copies of such minutes shall be distributed to the Operating Committee members and the Parties within five working

days after each meeting. The Operating Committee shall maintain written minutes of all meetings and the Operating Committee's decisions. The Operating Committee may:

a. make and implement decisions regarding the creation and revision, from time to time, of accounting and billing procedures necessary to implement the terms and conditions of this Agreement;

b. make recommendations to the Parties concerning amendment and revision of this Agreement;

c. perform any other obligations expressly provided in this Agreement, and any other matters as they may agree from time to time; and

d. settle any controversy, claim or dispute prior to referring such matters to the Senior Vice President of Generation at Basin Electric and/or the Senior Vice President of Strategy and Planning at Minnesota Power.

23. ***Confidentiality:*** Neither Party shall disclose the terms and provisions of this Agreement, except to its representatives who have a need to know; provided, that if a Party is required by law or necessary for a regulatory body to make such a disclosure, it shall first notify the other Party, and shall use commercially reasonable efforts to attempt, at its own expense, to restrict or prevent such disclosure, and shall allow the other Party to participate in such attempt, should it choose to do so.

24. ***Governing Terms:*** Capitalized terms used but not defined herein shall have the meanings ascribed to them in the Governing Agreement. To the extent the provisions of this Agreement are in conflict with the Governing Agreement, the provisions of this Agreement shall control.

| | |
|---|---|
| **Accepted and Agreed to:** | **Accepted and Agreed to:** |
| **Basin Electric Power Cooperative** | **ALLETE, Inc. dba Minnesota Power** |
| By:______________ Acting CEO & GM | By: Eric Norberg |
| FOR Ronald R. Harper | Eric Norberg |
| CEO & General Manager | Senior Vice-President Strategy & Planning |
| Date: 10-28-09 | Date: 10/29/09 |

# Attachment A
# Emission Formulas Examples

Incremental cost for SO2 Monthly Billing

**[TRADE SECRET DATA BEGINS**

[redacted]

**TRADE SECRET DATA ENDS]**

Incremental cost for NOx Monthly Billing

**[TRADE SECRET DATA BEGINS**

[redacted]

**TRADE SECRET DATA ENDS]**

*Current SO2 and NOx Index Price shall equal the average of each daily close of the respective SO2 and NOx price index for the month as published in the ARGUS Air Daily. In the event the Argus Air Daily no longer publishes the SO2 and/or NOx index, the Parties shall mutually agree to alternative SO2 and/or NOx pricing index.

**PUBLIC DOCUMENT**
**TRADE SECRET DATA EXCISED**



## Asset-Based Wholesale Sales
## 2020 Budget

| LINE No. | | Executed due to Industrial Load Loss | MWH | FUEL COST | MN JURISDICTION FUEL COST | SALES PRICE | MN JURISDICTION SALES PRICE | NET ENERGY MARGIN | MN JURISDICTION MARGIN | CAPACITY REVENUE | MN JURISDICTION CAPACITY REVENUE |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | TRADE SECRET DATA BEGINS | | | | | | | | |
| 1 | MISO Market Sales | | | | | | | | | | |
| 2 | AEP | | | | | | | | | | |
| 3 | Basin 100 MW | | | | | | | | | | |
| 4 | Oconto | | | | | | | | | | |
| 5 | NextEra | | | | | | | | | | |
| 6 | NextEra | | | | | | | | | | |
| 7 | MISO Resource Adequacy | | | | | | | | | | |
| 8 | Unidentified capacity sale | | | | | | | | | | |
| 9 | MISO Costs | | | | | | | | | | |
| | | | | | | | | | | TRADE SECRET DATA ENDS | |
| | Total Wholesale Energy Sales | | 1,242,266 | $ 27,918,107.00 | $ 24,144,974.84 | $ 44,927,347.00 | $ 38,855,416.05 | $ 17,009,240.00 | $ 14,710,441.21 | $ 6,352,188.00 | $ 5,502,074.68 |

| | |
|---|---|
| Total Margin | $ 23,361,428.00 |
| MN Jurisdictional Margin | $ 20,212,515.89 |

| | | |
|---|---|---|
| Note: | MN Jurisdictional (2020 Cost of Service Study) | |
| | Energy | 0.86485 |
| | Demand | 0.86617 |

Minnesota Power
Docket No. E015/GR-19-442

**PUBLIC DOCUMENT**
**TRADE SECRET DATA EXCISED**

MP Exhibit ___ (Pierce)
Pierce Direct Schedule 3


## Asset-Based Wholesale Sales
### 2020 Test Year

| LINE No. | | Executed due to Industrial Load Loss | MWH | FUEL COST | MN JURISDICTION FUEL COST | SALES PRICE | MN JURISDICTION SALES PRICE | NET ENERGY MARGIN | MN JURISDICTION MARGIN | CAPACITY REVENUE | MN JURISDICTION CAPACITY REVENUE |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | TRADE SECRET DATA BEGINS | | | | | | | | |
| 1 | MISO Market Sales | | | | | | | | | | |
| 2 | AEP | | | | | | | | | | |
| 3 | Oconto | | | | | | | | | | |
| 4 | NextEra | | | | | | | | | | |
| 5 | NextEra | | | | | | | | | | |
| 6 | MISO Resource Adequacy | | | | | | | | | | |
| 7 | Unidentified capacity sale | | | | | | | | | | |
| 8 | MISO Costs | | | | | | | | | | |
| | | | | | | | | | | TRADE SECRET DATA ENDS | |
| | Total Wholesale Energy Sales | | 984,098 | $ 22,363,632.00 | $ 19,341,187.14 | $ 30,336,674.00 | $ 26,236,672.51 | $ 7,973,042.00 | $ 6,895,485.37 | $ 3,573,864.00 | $ 3,095,573.78 |

| | |
|---|---|
| Total Margin | $ 11,546,906.00 |
| MN Jurisdictional Margin | $ 9,991,059.15 |

Note: MN Jurisdictional (2020 Cost of Service Study)

| | |
|---|---|
| Energy | 0.86485 |
| Demand | 0.86617 |