Before the South Dakota Public Utilities Commission
State of South Dakota

In the Matter of the Application of
Otter Tail Power Company
For Authority to Increase Rates for Electric Utility
Service in South Dakota

EXHIBIT _____

Docket No. EL10-011

REBUTTAL TESTIMONY AND SCHEDULES OF

ROBERT A. PATRYLAK

March 28, 2011

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ATTACHED SCHEDULES

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND EMPLOYMENT.

A. My name is Robert A. Patrylak. My address is 3321 Keenland Road, Marietta GA 30062. I am a Managing Director in the Enterprise Management Solutions division of Black & Veatch. Black & Veatch Corporation (Black & Veatch) is a leading global engineering, consulting and construction company. Founded in 1915, Black & Veatch specializes in infrastructure development in energy, water, telecommunications, federal management consulting, and environmental markets. Black & Veatch is an employee-owned company that has more than 100 offices worldwide. Black & Veatch is ranked on the Forbes "500 Largest Private Companies in the United States" listing.

Q. PLEASE DESCRIBE YOUR EDUCATION, PROFESSIONAL QUALIFICATIONS AND EXPERIENCE.

A. I am a graduate of Pennsylvania State University with a Bachelor of Science degree in Mechanical Engineering. I am also a graduate of Saint Joseph's University with a Master's degree in Business Administration. My professional qualifications and experience spans over 22 years in the energy industry. At Black & Veatch I am responsible for the Strategic Resource Planning service line which includes Integrated Resource Planning consulting services.

Prior to Black & Veatch, I led and directed R. W. Beck's Energy Market's Practice which consisted of approximately 35 professionals, providing advisory services related to integrated resource planning, market assessment and asset valuation, transmission planning and fuel strategy. Prior to R. W. Beck, I was responsible to lead the consulting organization at New Energy Associates/Ventyx. This team consisted of approximately 50 professionals. Ventyx is a leading software developer in providing planning software to electric and gas utilities. The consulting services that were provided by the consulting organization leveraged this software to provide advisory services related to integrated resource planning, transmission planning, as well as market assessment and asset valuation.

Prior to R.W. Beck, I was employed by The Energy Authority, Navigant Consulting and PECO Energy. While at Navigant Consulting, I supported both resource planning and transmission planning efforts. During my approximately four years at Navigant Consulting, my primary focus was supporting integrated resource planning efforts for a northeastern utility. This involved analyzing and evaluating future resources which included generation and transmission as well as DSM and Energy efficiency resources to meet load and reserve requirements. The generation and transmission resources were used for both capacity and energy needs required by the utility. It also involved development and issuance of Power Supply Requests for Proposals (RFPs), evaluation of proposals in response to those RFPs and then negotiation of those contracts. I was involved in the above efforts for numerous generation and transmission resources. Further detail on my background and experience is included in Exhibit ___ (RAP-1), Schedule 1, to this testimony.

Q. HAVE YOU EVER BEEN REQUESTED TO PRESENT TO THE INDUSTRY ON RESOURCE PLANNING?

A. Yes, most recently at the Energy Utility Consultants, Inc. (EUCI) 6th Annual Conference on Resource and Supply Planning in Arlington, VA on March 23-24, 2010. At this forum, I gave two presentations--one for the general meeting and one for the workshop. The general meeting presentation discussed assessing greenhouse gas (GHG) Concerns in your integrated resource planning efforts. The workshop was entitled "Simulating Energy Policy and its Effects on Resource Planning."

Q. HAVE YOU SPOKEN AT OTHER CONFERENCES ON TOPICS RELATED TO THIS CASE?

A. I had presented at the RMEL 2009 Spring Electric Energy Conference on "How are Utilities firming-up Renewables". I also presented in August of 2008 at the 2008 EUCI Western Resource Planning Conference at the workshop entitled Economic Transmission

Analysis and Wind Integration. My presentation was entitled "Wind Feasibility and Transmission Studies". Additionally, I presented at the EUCI Resource and Supply Planning Conference on January 28, 2008 in San Antonio Texas "Designing and Implementing an RFP for Power Supply Needs."

Q. HAVE YOU TESTIFIED IN PAST BEFORE THE SOUTH DAKOTA PUBLIC UTILITIES COMMISSION (THE COMMISSION) OR OTHER STATE COMMISSIONS?

A. No.

Q. HAVE YOU OR BLACK & VEATCH BEEN INVOLVED IN INTEGRATED RESOURCE PLANNING FOR OTTER TAIL POWER COMPANY (OTP)?

A. No.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony is intended to: (i) provide the Commission some additional perspective based on the experience and practices of other utilities with respect to integrated resource planning; and (ii) provide information relating to OTP's planning and processes in connection with its 2006-2020 Integrated Resource Plan (2006-2020 IRP) and relating to the Luverne 49.5 MW wind generating facility (Luverne).

II. SUMMARY OF TESTIMONY

Q. PLEASE SUMMARIZE YOUR TESTIMONY IN THIS PROCEEDING.

A. My testimony:

- Provides a brief perspective on the importance of substantial ratepayer benefits in relation to cost recovery;
- Provides a basic overview of integrated resource planning;
- Shows that Luverne was a good resource choice in 2006;
- Shows that the "IRP-Manager" model used by OTP is a reliable and sophisticated model;

- Shows that OTP's modeling of wind, including its approach to wind integration cost, was reasonable;
- Provides other evidence that the Luverne project was a good resource choice in 2006;
- Shows that Luverne would be a good resource choice today; and
- Concludes that the Luverne wind project should be included in OTP's ratebase in South Dakota.

III. COST RECOVERY FOR INVESTMENTS PROVIDING SUBSTANTIAL RATEPAYER BENEFITS

Q. WHEN WAS THE DECISION MADE TO CONSTRUCT LUVERNE?

A. The decision to construct Luverne was made shortly after the completion of OTP's 2006-2020 IRP.

Q. WHEN DID THE LUVERNE WIND PROJECT ACHIEVE COMMERCIAL OPERATION?

A. The Luverne wind project achieved commercial operation on September 1, 2009.

Q. IS THIS THE FIRST TIME THAT OTP HAS ASKED TO HAVE THE LUVERNE WIND PROJECT INCLUDED IN RATES IN SOUTH DAKOTA?

A. Yes.

Q. DOES THE LUVERNE WIND PROJECT PROVIDE SUBSTANTIAL BENEFITS TO SOUTH DAKOTA RATEPAYERS?

A. Yes. In his Rebuttal Testimony, Mr. Bryan Morlock shows that, over its useful life, Luverne will be a very good resource for South Dakota ratepayers and will provide substantial benefits to South Dakota ratepayers. In addition, as I discuss later in my testimony, Luverne is a good resource when compared to Black & Veatch recent forecast of power costs in South Dakota, and it compares very favorably to the typical costs of wind resources that can be built today.

Q. ARE THESE FACTS SIGNIFICANT TO THE ISSUE OF COST RECOVERY FOR LUVERNE?

A. I believe that they are. From the ratepayers' perspective, it seems logical that the first question is whether a resource, in fact, provides substantial benefits to ratepayers at a reasonable cost. If the resource does provide substantial benefits at a reasonable cost, then cost recovery seems appropriate without further review of the decision making behind the resource. If the resource does not provide substantial benefits at a reasonable cost, then the circumstances of the decision making are reviewed to determine whether cost recovery is appropriate.

Q. HAS MR. EVANS ATTEMPTED TO DETERMINE IF LUVERNE IS A BENEFICIAL RESOURCE FOR SOUTH DAKOTA RATEPAYERS TODAY?

A. No. It is my understanding that Mr. Evans has not attempted to determine if Luverne is a beneficial resource for South Dakota ratepayers. Rather, it is my understanding that Mr. Evans' review was focused on the OTP 2006-2020 IRP to determine if it provided a good basis for the decision to build Luverne. My testimony responds to his review and conclusions even though the threshold question for cost recovery seems to have been answered affirmatively by Mr. Morlock.

IV. OVERVIEW OF INTEGRATED RESOURCE PLANNING

Q. WHEN DID THE CONCEPT OF INTEGRATED RESOURCE PLANNING COME INTO PRACTICE?

A. Integrated resource planning originated in the decade of the 1980s. In part, it was in response to canceled nuclear plants across the country. Regulators believed that many utilities were doing resource planning without obtaining appropriate stakeholder input, and that without the benefit of stakeholder input, the utilities were making resource choices that were too risky or otherwise not optimal. Regulators were not satisfied with not getting stakeholder input until significantly after construction decisions had been made and significant money spent as a result of those construction decisions. Regulators wanted to review plans in advance in order to avoid having to make prudency rulings related to resource decisions during rate cases several years after decisions were made.

Q. WERE THERE OTHER REASONS THAT INTEGRATED RESOURCE PLANNING WAS FORMALIZED BY REGULATORS?

A. Yes. One such reason was the growing desire to have utilities look not only at new resources that could be used to meet objectives in the future, but also to have the utilities look at demand side adjustments to load that may assist in meeting objectives in the future. The idea was to consider both demand and supply side options for meeting objectives in the same analysis.

Q. DOES EVERY STATE REQUIRE UTILITIES TO DEVELOP IRPS?

A. No. Between the 1980s and late 1990s, most, but not all, states required utilities to perform integrated resource planning. In the late 1990s, competitive wholesale markets, merchant generation, and restructuring initiatives led many state regulators to allow utilities to abandon integrated resource planning. After concerns about power supply shortfalls arose in the early 2000s, a large number of states have resumed the requirement that utilities file Integrated Resource Plans (IRPs).

Q. ARE ALL IRPS PERFORMED IN THE SAME MANNER?

A. Not entirely. Some high level aspects appear to be the same in all IRPs. Beyond the commonality in higher level objectives, IRPs can vary significantly by utility and state depending on a number of factors.

Q. WHAT ASPECTS APPEAR TO BE THE SAME IN ALL IRPS?

A. The Tellus Institute has published a Best Practices Guide for Integrated Resource Planning which provides a fairly good statement of aspects of IRPs that are common and states:

> *Integrated Resource Planning, or IRP, can be thought of as a process of planning to meet users needs for electricity services in a way that satisfies multiple objectives for resource use.*

Q. WHAT ARE SOME OF THE OBJECTIVES FOR RESOURCE USE THAT TELLUS LISTS?

A. The Tellus indicates that broad IRP objectives can include:

- Conform to national, regional, and local development objectives.
- Ensure that all households and businesses have access to electricity services.
- Maintain reliability of supply.
- Minimize the short term or long term economic cost of delivering electricity services or their equivalent.
- Minimize the environmental impacts of electricity supply and use.
- Enhance energy security by minimizing the use of external resources.
- Provide local economic benefits.
- Minimize foreign exchange costs.

Tellus goes on to state:

> *Each country, or other planning region, establishes its own objectives to guide planning for electricity services. Objectives such as those listed above are often among those selected to guide IRP[integrated resource planning]. Such objectives as the above conflict with one another to varying degrees. Therefore, preparing, deciding upon, and implementing a preferred resource plan requires both a series of objective analyses and the use of processes by which the values and judgements of stakeholders are applied in developing plans.*

Q. BASED YOUR EXPERIENCE AND THAT OF YOUR COLLEAGUES AT BLACK & VEATCH, WHAT CAN YOU SAY IS GENERALLY IDENTIFIED AS OBJECTIVES OF IRPS?

A. In general, an IRP reflects a utility’s objectives of providing: (a) competitive rates to its customers; (b) delivering reliable power; and (c) a commitment to environmental stewardship.

Q. DID OTP REFLECT SUCH OBJECTIVES IN THE OTP 2006-2020 IRP?

A. Yes. In the Preface to the OTP 2006-2020 IRP, OTP stated as follows:

> *This resource plan filing is intended to identify the Company's likely courses of action that are designed to … allow the Company to continue providing reliable, low-cost electricity to meet the service requirements and the desires of customers, while minimizing potential adverse environmental and socioeconomic impacts in an increasingly competitive industry.*

Q. HAS OTP CONTINUED TO REFLECT THESE OBJECTIVES IN ITS INTEGRATED RESOURCE PLANNING?

A. Yes. OTP has continued to reflect these objectives in its 2011-2025 Integrated Resource Plan (OTP 2011-2025 IRP).

Q. BEYOND HIGHER LEVEL OBJECTIVES, WHAT DIFFERENCES HAVE YOU OR BLACK & VEATCH SEEN IN IRPS?

A. Each utility is in a somewhat different position in its current need for new supplies or energy efficiency to reliably serve load. Different states and utilities also have different measures of what constitutes a reliable power supply. In assuring that the power supply is reliable, it is necessary to define what is meant by reliable. In the case of OTP, the reliability criteria are defined by the North American Electric Reliability Council (NERC) and the Midwest Reliability Organization (MRO). The reliability criteria are implemented by the Midwest Independent Transmission System Operator (MISO) and the utilities. Because a reliability problem on one utility’s system can migrate to another utility system, it is common for interconnected utilities (and their stakeholders) to define the agreed upon reliability criteria. At the time of the 2006-2020 IRP, OTP Power was still part of Mid America Power Pool (MAPP) and had a net reserve requirement of 15 percent. Currently, MISO’s average net reserve requirement is 11.94 percent.

Q. BESIDES DIFFERENT NEEDS FOR RELIABILITY AND NEW RESOURCES, WHAT OTHER DIFFERENCES HAVE YOU AND BLACK & VEATCH OBSERVED IN THE DIFFERENT IRPS WITH WHICH YOU HAVE BEEN INVOLVED?

A. There are many differences. There are differences in the "look forward" period that is used in an IRP. IRPs are generally intended to be updated every few years, so the action plan from any IRP is one that guides actions in the next few years until a new IRP or an IRP update is performed. The longer term look is intended to provide a forward view of what might happen if different near term actions are taken. Different utilities choose to include different look forward periods.

Q. ARE THERE OTHER DIFFERENCES?

A. Yes. Differences exist in:

- Models that are used. There is no single accepted best model for doing IRP analysis. The perfect model would be one that exactly mimics utility real time operations over the IRP forecast period. Technology does not allow us to run a perfect day-ahead model for every day of the forecast period. Approximation approaches need to be reflected in the modeling. Different models approach these approximations differently. Without doing any extensive research, I am aware of 8 commercially available models that have been used to assist utilities in performing their IRPs. Each model requires a slightly different approach to accomplish the effort. I am also aware that that there are several other consultant developed and utility developed models that are not available for license that are used for IRPs.
- Treatment of energy efficiency/demand side management. While the theoretical idea is to evaluate demand side and supply side options together in an IRP, the fact is that it is difficult to do so comprehensively. As such, utilities take different approaches. Some simply perform a separate study of demand side management plans for the future and include the results in their IRP as input data. Some utilities separately study demand side management plans and develop two or three different levels of subsidies they could choose to implement. Then those two or three different levels are included in the IRP process and the analysis will indicate what the preferred level is.

- Availability of candidate options for meeting future needs. Different utilities have different ability to accomplish demand side management in their systems. Different utilities have access to different candidate supply side options. These differences will impact what candidate scenarios are ultimately tested in the IRP modeling process.
- Use of Scenarios. Many utilities have a single base case scenario for their IRP process. Some utilities look at scenarios that involve different load growth, different federal energy policies that might evolve, different natural gas prices, different technological improvements in supply over time, etc. The use of scenarios can rapidly grow to an unmanageable number. As a result, if different scenarios are to be used, there needs to be rigor in limiting the number. Further, if different scenarios are to be used, there also needs to be a method to weight the probability of each scenario. This is not an exact science. It is because of the many complexities that arise when performing multiple scenarios that many jurisdictions have chosen to spend available time and effort on better studying a single most likely scenario than spending the time and effort studying more scenarios.
- Use of stochastics in IRPs. Stochastic variables are ones that vary outside the influence of any stakeholder. For example, weather variations can impact the level of load that might need to be served from day to day and hour to hour. For example, natural gas prices may vary widely depending on the occurrence of hurricanes in supply regions or temperature effects on demand for natural gas in non-electric sectors of the economy. Because of the complexity of performing stochastic analysis in the IRP, most IRPs do not perform stochastic analysis.
- Transmission analysis in the IRP. Theoretically there may be different impacts on the transmission grid under different candidate portfolios. Typically it is beyond the scope of the IRP to perform detailed transmission analysis in the IRP. Typically the IRP simply adds some estimated transmission costs to certain of the candidate supply resources.

Q. HAVE YOU REVIEWED THE OTP IRPS TO DETERMINE IF THE APPROACHES USED BY OTP ARE CONSISTENT WITH IRP PRACTICES OF OTHER UTILITIES?

A. Yes. I have reviewed the OTP 2006-2020 IRP and the OTP 2011-2025 IRP and believe the OTP IRPs are consistent with standard utility practice.

V. LUVERNE FROM THE STANDPOINT OF OTP'S DEMONSTRATED NEED AND THE ALTERNATIVE RESOURCES AVAILABLE IN 2006

Q. IN YOUR VIEW, WAS IT REASONABLE FOR OTP TO PURSUE WIND PROJECTS, INCLUDING LUVERNE, WHEN VIEWED FROM THE 2006 TIMEFRAME?

A. Yes. In the 2006-2020 IRP, OTP identified a reasonable need for the generation, and its analysis demonstrated that wind generation was the most reasonable means of meeting that need. Not only did the OTP 2006-2020 IRP analysis conclude that Luverne would be a good resource, but there is other evidence that it would be a good resource choice in 2006, which I will discuss later in my Rebuttal Testimony.

Q. MR. EVANS CRITICIZED OTP FOR PURSUING LUVERNE, STATING OTP DID NOT HAVE A CAPACITY NEED WHEN IT COMPLETED ITS 2006-2020 IRP. DO YOU AGREE WITH MR. EVANS ON THIS POINT?

A. No, I disagree with Mr. Evans for two reasons.

First, as reflected in Mr. Morlock's Rebuttal Testimony, OTP did need additional capacity when it conducted the OTP 2006-2020 IRP. OTP receives some capacity accreditation from the wind generation that helps it to satisfy this capacity need. OTP included 15 percent of the nameplate capacity of the Luverne wind project toward its summer capacity needs in the OTP 2006-2020 IRP. OTP actually receives accreditation for 25 percent of the nameplate under current MISO rules due to the high capacity factors being realized by Luverne. While this contribution to meeting OTP's capacity need was not the primary driver for the addition, and adding capacity is not a threshold requirement for justifying the addition of Luverne. However, even if it was a threshold, Luverne would meet such a requirement.

Second, I disagree that it would have been reasonable for OTP to add this resource only if OTP had a capacity need. Wind plants are typically considered energy resources. As I explain later in my testimony, the fuel cost of operating an efficient gas fired resource would have been assumed to range from $49/MWh to $70/MWh in the 2006-2007 time periods. A wind project such as Luverne, with an all in energy cost of $41/MWh, would have been a good choice to enable displacing the fuel cost of gas fired generation even if the wind project provided no capacity value.

Q. DOES MR. EVANS ACKNOWLEDGE THAT IT CAN MAKE SENSE FOR A UTILITY TO CHOOSE A RESOURCE TO REDUCE ENERGY COST EVEN IF THAT RESOURCE DOES NOT PROVIDE A CAPACITY BENEFIT?

A. Yes. Mr. Evans acknowledges that in his response to SD-OTP-02 (attached as Exhibit ___ (RAP-2), Schedule 2).

VI. "IRP-MANAGER" IS A RELIABLE AND SOPHISTICATED MODEL

Q. MR. EVANS TESTIFIES THAT THE IRP COMPUTER MODEL USED BY OTP (IRP-MANAGER) IS UNRELIABLE AND NOT SOPHISTICATED ENOUGH TO PROPERLY CONSIDER WIND FACILITIES. DO YOU AGREE?

A. No. I have reviewed the documentation for IRP-Manager. It is extensive. IRP-Manager is an hourly chronological unit commitment and dispatch model of the very type that many utilities use in their IRP modeling. Many utilities have used this model. IRP Manager was no longer supported by its vendor in the late 1990s early 2000s when utilities generally stopped doing IRPs. As a result, when IRPs became generally conducted again in the decade of 2000, other models have been selected, although those decisions are not based on the quality of IRP-Manager.

IRP-Manager was and remains a very good model. In some aspects, it is a better model than the Strategist model that Mr. Evans prefers. For example, Strategist does not perform an hourly chronological unit commitment and dispatch analysis, but IRP-Manager does.

Mr. Evans criticizes IRP-Manager for not replicating daily and hourly utility power system operations, but that is not a reasonable criticism. No computer model, including Strategist, can perform the kind of detailed analysis that is needed to replicate daily and hourly utility power system operations. Such a detailed model cannot be designed and run for 20 years into the future because it would require more computing power than can be made available. No one is doing that. As a result, IRP models necessarily need to make approximations. This is generally not considered a problem, because input assumptions for the next 20 years are fairly uncertain.

Q. DOES STRATEGIST HAVE A BETTER ABILITY TO MODEL WIND THAN IRP-MANAGER HAS?

A. No. In fact, both IRP-Manager and Strategist appear to model wind in the same manner, as do other models used in IRP analysis. Both Strategist and IRP-Manager have the analyst input how much of the wind can be counted toward Resource Adequacy (i.e. the amount they can be counted on to meet the peak load). Both Strategist and IRP-Manager are designed to have expected hourly output of the wind plant provided as input data. Both Strategist and IRP-Manager match up the expected hourly wind output with expected hourly loads, and both Strategist and IRP-Manager are designed so that wind generation is modeled as a "must run" resource, and not "dispatchable." In summation, there is no legitimate basis for Mr. Evans to claim that IRP-Manager is any less effective than Strategist in its ability to model wind.

Q. MR. EVANS TESTIFIES THAT HE HAS PERFORMED "BENCHMARKING" OF THE IRP-MANAGER MODEL AND CONCLUDES THAT IRP-MANAGER RESULTS ARE NOT REPRESENTATIVE OF OTP'S ACTUAL OPERATIONS. DO YOU AGREE?

A. No. I do not agree that Mr. Evans has performed a legitimate "benchmarking" of IRP-Manager. A legitimate "benchmarking" analysis is a very complicated process, and Mr. Evans has not performed one.

Q. DID MR. EVANS RUN IRP-MANAGER FOR THE YEARS 2003, 2004 AND 2005 TO TEST ITS ABILITY TO REPLICATE ACTUAL RESULTS IN THOSE YEARS?

A. No. Mr. Evans did not run IRP-Manager himself, Exhibit ___ (RAP-3), Schedule 3. Instead, he looked at a run of IRP-Manager that was made by OTP. However, that model run did not attempt to provide model input data that was based on actual data for 2003, 2004, or 2005. As a result, it would not be possible to use that model run to test if IRP-Manager was closely approximating actual operations because IRP-Manager was not input with the actual loads, etc., that occurred in those years.

Q. WHAT IS NECESSARY TO PERFORM A LEGITIMATE BENCHMARKING OF A MODEL OF A POWER SYSTEM?

A. Testing the ability of a model to reasonably approximate operations of a power system will often involve determining if the model can provide results that are very similar to actual operations in a historical period. For example, one might want to test if the model can reasonably replicate operations in the historical year 2005. To see if the model can reasonably replicate 2005 actual results, the model needs to be provided key input data that actually occurred in 2005. For example, the model needs to be input with actual 2005 loads. The model is not attempting to *estimate* 2005 loads. The model is designed so that load levels *are input data*.

Similarly, the model would need to be provided the actual natural gas prices that occurred in 2005. A large number of model input data needs to be provided so that the model's logic can be tested to see if plant operations and costs it provides reasonably approximate the actual accounting record for plant operations and costs. If the model is provided bad input data, its output will not reasonably approximate actual plant operations and costs.

Mr. Evans simply did not perform the kind of benchmarking test that would allow any conclusion about the ability of IRP-Manager to give results that are representative of OTP actual operations.

Q. WOULD YOU BE SURPRISED IF A LEGITIMATE BENCHMARKING TEST DID NOT GIVE RESULTS THAT ARE REPRESENTATIVE OF A UTILITY'S ACTUAL OPERATIONS?

A. Yes. My review of the extensive documentation for IRP-Manager leads me to believe that IRP-Manager would give results that are representative of a utility's actual operations. Further, IRP-Manager was widely used. The entities using IRP Manager had confidence in the model, which would not have been the case if IRP-Manager had not been reliable.

VII. OTP'S MODELING OF WIND WAS REASONABLE, INCLUDING ITS APPROACH TO WIND INTEGRATION COST

Q. MR. EVANS HAS STATED THAT OTP MAKES THE ERRONEOUS ASSUMPTION THAT WIND GENERATION IS COMPLETELY PREDICTABLE AND RELIABLE. DID OTP MODEL WIND GENERATION AS COMPLETELY PREDICTABLE?

A. No. OTP modeled the unpredictability of wind through the hourly wind generation profile input to IRP-Manager. To represent wind generation alternatives, OTP modeled hourly wind generation based on the hourly pattern of a nearby wind project. This hourly profile captures the volatile and unpredictable behavior of wind ranging from 0 percent output in some hours to 100 percent output in other hours, and resulting in an overall average annual capacity factor corresponding to historical wind performance.

Historical wind performance data has proven that wind generation in the northern plains will have long-term average annual capacity factors depending on geographical location. Although it is impossible to predict when the wind will be blowing in future hours and future years with certainty, it is acceptable practice to predict that the wind will blow. The hourly wind generation profile not only captures the volatility of wind, but the general patterns of typical wind generation as well, including, including that wind is: (i) more likely to blow off-peak than on-peak; (ii) more likely to blow in the winter than in the summer; and (iii) more likely to blow in the shoulder months than in the winter and summer months. OTP captured this variability using historical data and, although it is not a precise forecast of future wind generation in any specific hour, it is a valuable representation of likely unpredictable performance. Just as OTP uses IPR-Manager to model typical performance of other generation resources, so too does it model typical performance of wind generation resources.

Q. WHAT WOULD BE THE EFFECT OF EXCLUDING WIND BECAUSE OF UNPREDICTABILITY?

A. To preclude this legitimate generation alternative because of its unpredictability would be an oversight of an economic resource for meeting customer needs.

Q. DID OTP MODEL WIND GENERATION AS COMPLETELY RELIABLE?

A. No. To model completely reliable wind generation would imply that 100 percent of the resource's maximum capacity would be accredited for meeting the Resource Adequacy requirements. OTP accredits wind generation alternatives as defined and required by the regional governing entity, whether MAPP or MISO, based on system-wide reliability studies evaluating loss-of-load impacts. For the OTP 2006-2020 IRP, , this accreditation was at 15 percent for summer accreditation. The loss-of-load studies ensure that the required reserve margins and corresponding accreditation ratings of resources meet a loss-of-load probability of 1 hour in 10,000 hours or 1 day in 10 years. The variability of wind generation was accounted for in the regional governing entity's ratings for wind generation accreditation.

Q. MR. EVANS TESTIFIES THAT OTP'S "FIRM" MODELING OF WIND WAS NOT REASONABLE. DO YOU AGREE?

A. No. Mr. Evans seems to have misunderstood how IRP-Manager uses the term "Firm." IRP-Manager uses the term "Firm" to indicate that the resource is non-dispatchable (i.e. it is a must-take resource). As discussed above, IRP models in general, including IRP-Manager, model wind as "non-dispatchable." That simply recognizes that wind generation must be taken if it is available. This makes sense from both a real operations strategy (the wind has zero variable cost) and makes sense from a modeling standpoint. Mr. Evans agrees that wind should be designated as non-dispatchable in his IR Response SD-OTP-04, Exhibit ___ (RAP-4), Schedule 4, consistent with IRP Manager.

Mr. Evans is interpreting the use of the term "Firm" to mean "dependable and reliable" per SD-OTP-05, Exhibit ___ (RAP-5), Schedule 5, but, as described above, that is not how the term is used in IRP-Manager. IRP-Manager does not count 100 percent of the nameplate capacity of the wind toward meeting annual peak load just because it is called Firm (aka non-dispatchable). There are other input parameters in IRP-Manager that allow the modeler to specify how much of the nameplate capacity of the wind can count toward peak needs. OTP used those other input parameters to tell IRP-Manager how much to count toward annual peak needs.

Q. MR. EVANS TESTIFIES THAT OTP FAILED TO INCLUDE THE COST OF WIND INTEGRATION. DO YOU AGREE?

A. No. As explained in the Rebuttal Testimony of Bryan Morlock, OTP estimated that their $41/MWh cost of wind included the cost of wind integration. That was a reasonable way to take into consideration the potential for wind integration costs.

Q. MR. EVANS TESTIFIED TO WIND INTEGRATION COST STUDIES DONE BY OTHERS. HAVE YOU REVIEWED THOSE STUDIES?

A. Yes. I have reviewed those studies

Q. WHAT ARE YOUR OBSERVATIONS ABOUT THE RELEVANCE OF THOSE STUDIES TO THIS PROCEEDING?

A. First, the Commission should be aware that balancing the load and resources is the responsibility of the applicable balancing authority for the region (e.g. MISO) and not the responsibility of a utility. The studies provided by Mr. Evans are all studies done by entities that are balancing authority operators, not utilities that do not operate balancing authorities. OTP does not operate a balancing authority. Mr. Evans has agreed that it is primarily the balancing authority's obligation to maintain load and resource balance in his response to SD-OTP-13, Exhibit ___ (RAP-6), Schedule 6. The subject of wind integration is still being discussed in the industry and the industry thinking continues to evolve. For example, Black Hills has taken one approach that some in the industry believe is right. Others suggest a small wind integration charge should be reflected. In the case of Otter Tail, Mr. Morlock's testimony explains that OTP did in fact include a wind integration cost.

Q. WHICH BALANCING AUTHORITY IS PROVIDING THE WIND INTEGRATION SERVICES FOR THE LUVERNE WIND PROJECT?

A. The MISO is providing the wind integration services for the Luverne wind project. Mr. Evans acknowledges this fact in his response to SD-OTP- 14, Exhibit ___ (RAP-7), Schedule 7.

Q. HAVE UTILITIES TAKEN THE POSITION THAT THEY DO NOT NEED TO INCLUDE WIND INTEGRATION COSTS IN THEIR IRPS WHEN THEY EVALUATE WIND OPTIONS?

A. Yes. For example, in response to SD-OTP-06, Exhibit ___ (RAP-8), Schedule 8, Mr. Evans refers to a statement in the Black Hills Power 2007 IRP which reads as follows:

> *Although wind energy resources often present regulating challenges to utility operators, BHC [Black Hills Corporation] will rely on WAPA [Western Area Power Authority] to regulate new wind generation, therefore, no regulating constraints were captured or modeled in the course of conducting the IRP*.

In other words, Black Hills Corporation concluded that the wind integration costs would be sufficiently small to its customers that those costs did not need to be included in its analysis because of how WAPA collects for these costs. OTP is in a comparable position because it will rely on MISO to integrate its new wind generation, including Luverne.

Q. WHAT OTHER OBSERVATIONS DO YOU HAVE ON THE WIND INTEGRATION COST STUDIES PROVIDED BY MR. EVANS?

A. I note that two of the three wind integration cost studies discussed by Mr. Evans are for balancing authorities in other areas of the Country and that wind integration costs will be different for different balancing authorities. Mr. Evans agrees with this fact in his response to SD-OTP-11, Exhibit ___ (RAP-9), Schedule 9.

Exhibit GWE-14 to the Evans testimony is a March 2004 document developed by the Bonneville Power Administration (BPA). BPA operates a balancing authority. BPA has had considerable difficulty integrating wind into its system in some light load hours in the spring when snow-melt caused hydro inflows to its reservoirs are very high. In these conditions, BPA already wants to generate more power from its hydro generators than it needs. BPA has displaced essentially all thermal generation in the Northwest, and still has excess hydro flows that it needs to spill over its dam spillways even though it has unused hydro capacity that it could have used to generate power. If wind plants connect to the BPA system, that exacerbates BPA's problem and causes it to spill more hydro. As a result, BPA wants to charge generators for it loss of economic value when it spills more hydro. This is not the case for wind that OTP brings onto the MISO system.

Exhibit GWE-13 refers to wind integration issues presented to the Idaho PUC for Idaho Power (another utility outside this region). Idaho Power operates a balancing authority. In reading Exhibit GWE-13, the Idaho commission states as follows:

> *One of the wind developers in the case, Exergy Development Group of Idaho, argued against an integration discount saying the science is in its "infancy," and that enough variables and uncertainties exist to make it impossible to determine a fair rate.*

The Idaho PUC went on to state that the integration rates they have set were based in part on forecasted value and estimates and that in order to avoid integration costs that are inequitable, the commission is requiring all three utilities to participate in workshops that will continually update integration analysis and to regularly report to the commission.

Exhibit GWE-12 provides a single summary page from a National Renewable Energy Laboratory (NREL) report. That summary provides results from several older wind studies done for different balancing authorities. As discussed above, wind integration cost will be different for different balancing authorities, making that summary inapplicable.

Q. YOU HAVE STATED THAT MISO IS PROVIDING THE WIND INTEGRATION SERVICES FOR THE LUVERNE WIND PROJECT. HAS MR. EVANS PROVIDED ANY INFORMATION ON WIND INTEGRATION COST FOR MISO?

A. Yes. Exhibit GWE-15 provides some information on wind integration costs that MISO might incur. However, that study is of the year 2020 and not the years prior to 2020. The study indicated that wind integration cost in the order of $2/MWh to $4/MWh might be incurred when the costs were divided by the amount of wind being integrated. This is in the range of wind integration cost that OTP assumed in the OTP 2006-2020 IRP, corroborating its results.

Q. IS THERE ANYTHING ELSE THE COMMISSION SHOULD BE AWARE OF REGARDING WIND INTEGRATION COSTS INCURRED BY MISO?

A. Yes. The Commission should be aware that MISO incurs the costs (i.e. acquired the needed ancillary services) to integrate wind that is connected to its system and used to meet retail load in its geographic footprint. However, MISO does not charge the owners of the wind projects for these costs. Instead, MISO first determines its total need for ancillary services in each of 7 large zones. OTP is in what was formally the MAPP zone of MISO. Then MISO spreads the cost of these ancillary services (which includes the cost of integrating wind) to all load in this zone, based on the ratio of retail load of all users in the zone. (One of the reasons that MISO does it this way is that it is very difficult to determine which of the MISO acquired ancillary services were needed to balance the varying load, the varying wind, and other unanticipated events that cause load and resources to get out of balance.) As a result, a $2-4/MWh wind integration cost will be spread to all MISO load in the zone, substantially reducing the impact on OTP.

Q. WHAT IS YOUR CONCLUSION ABOUT THE COST OF INTEGRATING WIND AS IT RELATES TO THE LUVERNE WIND PROJECT?

A. I believe that it would be a mistake to conclude that Luverne wind is not a desirable resource because of the cost that South Dakota ratepayers will be charged to integrate the wind.

VIII. OTHER EVIDENCE THAT THE LUVERNE PROJECT WAS A GOOD RESOURCE CHOICE IN 2006

Q. HAS MR. EVANS PROVIDED DATA THAT SUPPORTS THE CONCLUSION THAT LUVERNE WOULD HAVE BEEN A GOOD RESOURCE IN WHEN VIEWED FROM THE STANDPOINT OF 2006-2007?

A. Yes. Recall that OTP had estimated for the OTP 2006-202 IRP that the cost of wind/Luverne would be approximately $41/MWh. In his response to SD-OTP-10, Exhibit ___ (RAP-10), Schedule 10, Mr. Evans provided evidence of the cost of coal and gas fired generation reflected in the IRPs of Idaho Power, Avista, and PacifiCorp that were developed in that timeframe, as follows:

Utility	Coal Cost	CT cost
Idaho Power	$61/MWh	$110/MWh
Avista	$70/MWh	$60/MWh
PacifiCorp	$51/MWh	$82/MWh

Clearly, a $41/MWh wind plant would have looked favorable in comparison to the gas and coal fired generation from the IRPs of these three utilities. While this comparison alone does not justify Luverne, it provides an additional useful point of comparison. Additionally, as I have previously explained, the OTP 2006-2020 IRP was a state of the art analysis that legitimately chose the wind project. I am providing this additional information as further evidence that OTP's analysis was consistent with what others were concluding in the 2006-2007 timeframe.

Q. IN ADDITION TO THE RESULTS OF THE OTP 2006-2020 IRP, WAS THERE OTHER EVIDENCE IN 2006 THAT LUVERNE COULD DISPLACE NATURAL GAS FUEL COSTS TO SERVE LOAD?

A. Yes. The energy produced by Luverne could be used to displace natural gas fuel costs to serve load In 2006, gas prices were expected to be quite high (20-year levelized prices in the $7/MBTU to $10/MBTU range), which makes the cost of generation electricity from natural gas fired generation quite high. The most efficient natural gas plants have a full load heat rate of 7000 BTU/kWh. So in 2006, it would have been assumed the fuel alone needed to generate electricity in a gas plant would have cost between $49/MWh and $70/MWh on a levelized basis over 20 years. It was expected that OTP could acquire some wind generation for a price of approximately $41/MWh. This price made wind a very attractive alternative in comparison to the fuel cost that might otherwise be incurred to get energy from gas fired generation.

IX. LUVERNE WIND FROM THE STANDPOINT OF WHAT IS KNOWN TODAY

Q. DO YOU BELIEVE THAT IT WOULD MAKE SENSE TO ACQUIRE A $37-41/MWH WIND RESOURCE IF THE DECISION WERE TO BE MADE TODAY?

A. Yes. There are several reasons that support that conclusion. First, most new wind plants that might be built in the future are likely to cost considerably more than $37/MWh. For example, NorthWestern Energy has established a wind avoided cost of $68.42/MWh for wind plants in Montana, based on responses to its RFP for new renewable power. Further new wind plants that can be built and owned by OTP in the future are likely to cost at least $56/MWh, and that price can only be achieved if the North Dakota tax credits for wind are available to that new OTP owned wind project. If those North Dakota tax credits are not available, then the new future wind will cost at least $62/MWh. Third, the Luverne wind plant energy cost is considerably lower than that spot market price forecast over the life of Luverne. As a result, the $37/MWh Luverne wind resource remains particularly attractive today.

X. SUMMARY

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. The Luverne wind project was reasonably analyzed in the OTP 2006-2020 IRP. That analysis reasonably concluded that the wind project would be a desirable resource for ratepayers. When looked at from today’s perspective, this conclusion continues to be the same. Luverne should be included in OTP’s ratebase in South Dakota. If it is not, it will be forever lost to South Dakota customers.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.