OTP Exhibit 117

CASE NOS. PU-06-481 & PU-06-482

BEFORE THE NORTH DAKOTA PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION BY OTTER TAIL CORPORATION D/B/A

OTTER TAIL POWER COMPANY

AND

MONTANA-DAKOTA UTILITIES CO., A DIVISION OF MDU RESOURCES GROUP, INC.

FOR AN ADVANCED DETERMINATION OF PRUDENCE

FOR THE BIG STONE II GENERATING PLANT

SUPPLEMENTAL PREFILED DIRECT TESTIMONY

OF

BRYAN MORLOCK

Manager of Resource Planning

Otter Tail Power Company

MARCH 10, 2008

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SUPPLEMENTAL PREFILED DIRECT TESTIMONY OF BRYAN MORLOCK

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I. INTRODUCTION

Q: Please state your name and business address.

A: Bryan Morlock, 215 South Cascade Street, Fergus Falls, Minnesota 56538-0496.

Q: Did you previously submit testimony in this proceeding?

A: Yes. I submitted both Direct Testimony (OTP Exhibit 103) and Rebuttal Testimony (OTP Exhibit 111) and I also introduced OTP Exhibits 103-111.

Q: Assuming Big Stone Unit II is constructed and placed in commercial operation, what portion of Otter Tail's share of Big Stone Unit II will be used to serve North Dakota customers?

A: Approximately 40% of Otter Tail's customer load is in North Dakota. Accordingly, the same percentage of our Big Stone Unit II share will serve North Dakota.

II. PURPOSE AND SUMMARY OF TESTIMONY

Q: What is the purpose of your supplemental testimony?

A: The purpose of my supplemental testimony is to describe the results of additional capacity expansion modeling and other analyses undertaken to evaluate the extent to which recent project ownership, project timing and cost, and other changes have an effect on Otter Tail's preferred resource plan. These changes include analysis of recent legislation in Minnesota that requires aggressive conservation and renewable energy goals.

Q: Please summarize your testimony with respect to your revised modeling.

A: Several recent changes have occurred that had the potential of changing or otherwise affecting the Big Stone Unit II project, including the withdrawal of two participants, potential

changes in project size and associated costs, and recent Minnesota legislation regarding renewable energy and conservation. Taking these factors into account, and relying on updated assumptions for a number of factors, our analysis continues to show the Big Stone Unit II project remains an essential component of Otter Tail's overall plan. The latest round of computer modeling demonstrates that Otter Tail has a need for 170 MW of Big Stone Unit II.

III. UPDATED PLANNING ASSUMPTIONS

Q: Have any of your planning assumptions changed since your prior testimonies in this proceeding?

A: There are a number of model inputs that have been updated or modified. These inputs include:

- an updated load forecast,
- updated Big Stone II plant and transmission costs,
- a change in the Big Stone II commercial operating date to 2013,
- an increase in conservation to comply with the MN 1.5% kWh savings goal and increased conservation efforts in North and South Dakota,
- an increase in the Minnesota renewable energy standard as well as the incorporation of a North Dakota renewable energy objective,
- an updated natural gas price forecast, and
- an updated Big Stone II coal price forecast.

Q: How does the new load forecast compare to the load forecast used in your prior modeling described in your 2007 testimony?

A: The new load forecast was developed for use in the Company's next resource plan filing in Minnesota. That forecast shows a slight increase in energy requirements compared to the previous forecast. The new load forecast has increased energy requirements approximately

0.93% by 2020 over the previous forecast. The forecasted demand in 2020 has increased by about 5.7% from the previous forecast.

Since the 2007 forecast was developed, Otter Tail was selected to provide service to a new ethanol plant located in North Dakota. This new ethanol plant is the Tharaldson Ethanol project to be located west of Casselton. Otter Tail was originally informed that the plant would have a peak demand of approximately 14 MW and 102,000 MWh annual energy use, and these figures were used in estimating future load forecasts. Since the analysis was completed, the estimate has been raised to a demand of approximately 22 MW because the facility has higher electricity usage than normal for an ethanol plant this size because it will be using technologies to reduce other forms of energy use. As a result, our forecasts are likely on the low side if anything.

Q: How does the new Big Stone II project timing compare to the timing used in your prior modeling described in your 2007 testimony?

A: Previously Big Stone II was modeled as being available in 2011. With the recent project delays, the new modeling was completed assuming a 2013 commercial operating date.

Q: How do the new Big Stone II project costs compare to the costs used in your prior modeling described in your 2007 testimony?

A: Previously, Big Stone II was modeled as a 630 MW unit. The new modeling was completed assuming costs based on a plant size of 500 MW. As a result of the assumed smaller plant size, the costs per kW of capacity increased as some economies of scale would be lost. We used a cost of $1.272 billion ($2,545/kw) for a 500 MW unit. This figure was supplied to me by Project Manager Mark Rolfes, who is also testifying in this supplemental hearing.

Otter Tail had originally intended to also conduct modeling based on a 580 MW plant size, but the results of the "worst-case" scenario at 500 MW made such additional modeling unnecessary. I use the term worst-case scenario because the higher per-unit costs of a 500 MW plant size would tend to yield a lower Otter Tail share size for Big Stone Unit II. Although such additional modeling for a 580 MW plant size would likely have suggested an even larger Big Stone Unit II share size for Otter Tail than for a 500 MW plant size, Otter Tail decided to adopt the worse-case modeling result based on the 500 MW plant size as reasonable for the 580 MW plant size option as well.

Q: Were any changes made to the costs associated with other resources?

A: Yes, several changes were made. In previous analysis, Otter Tail had used transmission costs of approximately $200/kW for most resources. Due to increases in the cost of building transmission, this was increased to $250/kW, except for wind and the IGCC option.

For wind, we revised our transmission costs as I will describe later. For the IGCC option, it was previously assumed that such an option would possibly be constructed at the Hoot Lake Plant site with the retirement of the two remaining coal units there, and that it would be able to use the existing transmission infrastructure. However, we have subsequently determined that it is impractical to assume that a new baseload generating facility could be constructed and tied to existing, older substation equipment. So we included $100/kW for substation and transmission upgrades with the IGCC option for this Hoot Lake, site-specific option. The cost of the IGCC option was also increased to be compatible with the construction cost increases being observed in all resource technologies. The IGCC option was made available to the model in 2013, compared to 2015 in previous analyses.

Finally, the costs of natural gas-fired technologies were not changed from the base cost, but the cost escalation rate over time was increased to 4.5%.

Construction costs continue to escalate at rates faster than inflation. The basic equipment cost of a combustion turbine, without the auxiliaries, had not changed much over the past few years, so price increases were basically in the construction materials and labor area. Predictions are now being made that a carbon-constrained environment will materially increase the demand and prices for combustion turbines will rise dramatically as a result.

Q: What changes were made to incorporate new conservation goals?

A: The level of conservation in the model was a significant change. We took into account conservation goals in all three states where Otter Tail has retail customers – North Dakota, South Dakota, and Minnesota. Otter Tail is expecting to implement more North Dakota conservation programs in the future, has filed a conservation plan in South Dakota, and has a new statutory directive to reduce the growth of retail sales in Minnesota. Otter Tail attempted to account for all these reductions in energy consumption in its modeling.

Otter Tail did not allow the model to evaluate and select conservation technologies based on cost effectiveness. Left to its own evaluation of cost-effectiveness, the model would not otherwise select enough conservation to comply with the new Minnesota legislation, so the required amount of conservation was manually forced into the model. The modeling did not include any cost assumptions or evaluate the technical feasibility of actually achieving the required level of conservation. Otter Tail simply assumed in the model that the new conservation requirements would be met.

With regard to North Dakota and South Dakota, Otter Tail incorporated kWh savings equal to about 0.5% of annual retail sales in those two states. With regard to Minnesota sales,

the model was scaled up to realize conservation savings of 1.5% of Minnesota retail sales averaged over the previous three years as specified by the new Minnesota law. Historically, Otter Tail has obtained conservation savings of approximately 0.6 – 0.7% of annual Minnesota kWh sales, so this assumption was quite conservative.

Q: What changes were made to incorporate new renewable energy requirements ?

A: The incorporation of a 10% renewable energy objective in North Dakota and the increase in the Minnesota renewable energy standard to 25% by 2025 represented a minimal change to the modeling. Otter Tail has already identified enough qualifying renewable resources in its resource planning to achieve more than 16% renewable energy across the entire system based on 2006 system-wide retail kWh sales prior to the Big Stone Unit II commercial operation date. Because we were already planning levels of renewable energy that approached the North Dakota and Minnesota renewable energy goals, these new goals did not really impact the results of our analysis.

Q: How much additional renewable energy did you add to previous plans in your revised analyses?

A: To ensure compliance with all applicable state goals for renewables, an additional 20 MW of wind generation were forced into the model in 2018, and 40 MW more in 2024. In addition, we incorporated the 160 MW of new wind already approved into the model within the first few years. Otter Tail's 60 MW share of the Langdon Wind Energy Center, which recently commenced commercial operation, is part of that 160 MW.

Q: Were there other changes made to your modeling of renewable resources?

A: Yes there were. First, it was assumed that the Federal Production Tax Credit (PTC) would be renewed for five years through 2013, but then not be available after that point.

Additional wind resources beyond the RES levels were made available to the model, either with or without the PTC, depending on the time frame. Another 100 MW were made available through 2013 with the PTC included, and 100 MW of additional wind generation without the PTC were made available beginning in 2014.

Q: Did you revise your approach to wind energy with regard to transmission import or cost considerations?

A: Yes. In previous analysis Otter Tail had restricted the amount of wind available to the model because of concerns with energy import capability to the region to back up the wind generation when the wind isn't blowing. Those concerns still have not been addressed by the Midwest Independent Transmission System Operator (MISO) and others, but they are being discussed by transmission planners. Otter Tail is working with MISO and transmission planners to determine an appropriate modeling limit on import capability to the Otter Tail system and into the western MISO area in general.

Otter Tail had not previously included any transmission cost associated with wind resources but had restricted the amount of wind generation available. In our latest modeling this restriction was removed and replaced by estimated transmission costs of approximately $200/kW. $200/kW is still less than the estimated transmission cost for other resources. This reduced cost level was chosen because Otter Tail believes that some small developments may occur without the need for significant transmission upgrades.

Q: Were changes made to your assumed pricing of renewable resources?

A: No changes to wind pricing prior to the expiration of the PTC were made other than to incorporate a $4.50/MWh wind integration cost, which was developed as part of the Minnesota Wind Integration Study. The pricing used is consistent with the costs of Company ownership of

wind resources, but possibly $4 - $5 /MWh below current PPA prices being discussed with developers. And, of course, the wind prices of the additional wind generation made available after expiration of the PTC are much higher than with the PTC included.

Q: What updated natural gas price forecast did you use?

A: The price used in the modeling was based on an adjusted Energy Information Administration (EIA) forecast contained in the 2007 Annual Energy Outlook.

Q: What adjustments were made to the EIA natural gas forecast?

A: The EIA forecast data was at Henry Hub, so the first adjustment was for basis difference, i.e., the price differential between a Minnesota location and the EIA forecast location. The second adjustment made was because of an inherent underestimation bias contained within the EIA model. A number of studies have documented this bias. One of the most recent was a study by Ernest Orlando Lawrence Berkeley National Laboratory which identified a levelized understatement of the EIA forecast price of $0.73/MBTU. This amount was added to the EIA forecast. Finally, a 2.5% escalator was used to convert the EIA forecast from 2005 dollars to nominal dollars.

IV. OTHER FACTORS

Q: What is the status of the 50 MW Manitoba Hydro alternative that was considered in your earlier analysis?

A: Manitoba Hydro has informed Otter Tail that it no longer has capacity and energy available to provide Otter Tail. The Manitoba Hydro purchase is no longer within the options under consideration.

Q: Did you incorporate costs based on the potential for future carbon dioxide regulation?

A: Yes, we did for our Minnesota analysis and testimony, because that is a major point of interest in Minnesota. In Minnesota, we assumed a simple carbon dioxide tax effective as of 2013. However, based on the North Dakota statute prohibiting inclusion of such costs here, new analysis and modeling were completed for North Dakota planning purposes without the inclusion of any costs for future CO_2 regulation.

V. REVISED RESOURCE PLANNING ANALYSES

Q: With regard to your revised capacity expansion planning analyses including the latest costs and assumptions for Big Stone Unit II and other resource alternatives, did you use the same analytical approach described in your previous testimony in North Dakota?

A: Yes, I did.

Q: Did your development of your optimized resource expansion plans include wholesale transactions?

A: No. Wholesale sales are made from all OTP resources, not just from a single unit such as Big Stone II. OTP has certain obligations to sell available generating capacity and energy into the MISO market, and does so as and when excess generation is available. However, to ensure that the resource planning process did not add facilities to make wholesale sales, the wholesale sales option was turned off.

Q: Is computer-based capacity expansion modeling the sole determinant of what your utility's resource plans should be?

A: No. As I previously discussed, the modeling runs were completed assuming compliance with the renewable energy and conservation goals. There was no consideration as to whether such compliance is cost-effective or technically feasible, so these results are not fully optimized by the computer modeling.

Beyond that, computer modeling is only one input to our resource planning process. It is a useful tool; but only a tool. It is not a substitute for expert management experience and judgment.

Q: Does forcing the model to accept a given level of a resource increase costs?

A: Possibly. If the model would not have picked such a resource as an economic alternative or as a least-cost alternative to meet load and reserve requirements, the answer is yes. If such a resource would have been selected anyway, then there isn't an increase in costs.

Q: Please summarize the results of the revised capacity expansion modeling you performed, compared to the results reported in your previous testimonies?

A: In general, through 2020 the amount of total baseload capacity decreased by approximately 80 MW, peaking capacity increased approximately 85 MW, demand-side management (DSM) impacts increased by about 35 MW, and nameplate wind capacity increased approximately 60 MW.

In the prior analysis, baseload generation consisted of 50 MW of Canadian hydro and 201 MW of coal, comprised of 120 MW of Big Stone II and 81 MW of IGCC. In the new analysis, all 170 MW of baseload in 2013 is in Big Stone II, and the 81 MW of IGCC in 2018 is eliminated. And, as previously mentioned, the Canadian hydro alternative is no longer available.

The conservation impacts increased because we forced Minnesota energy conservation goals into the updated model. The updated model also selected more wind, as long as the PTC is available. The selection of additional wind and an increase in peaking capacity worked to eliminate the need for the IGCC alternative.

Q: Please elaborate on the drivers behind these differences.

A: The increase in energy conservation reduced the need for baseload capacity, which is typically energy-driven. The change in ownership participation made more of Big Stone II available to Otter Tail and Manitoba Hydro withdrew their capacity and energy proposal, which eliminated a potential resource. Finally, increased wind generation, assuming the PTC is available, combined with natural gas peaking eliminated the need for the IGCC unit.

Q: Did new renewable and conservation goals have an impact on your revised resource planning results?

A: Yes, to some extent. The renewable energy goals had little impact on the results, as Otter Tail's previous plans for renewables already went most of the way toward meeting those goals. The increased conservation goals clearly had an impact, reducing baseload capacity needs by 81 MWs.

Q: Did you conduct a sensitivity analysis of the new modeling?

A: Yes I did. A sensitivity analysis was completed using a 10% higher capital cost for the Big Stone II project. The model continued to pick the full 170 MW amount of the project that was allowed.

Q: Did you conduct a fuel cost sensitivity?

A: We did not conduct a specific fuel cost sensitivity analysis. We did look at the capital cost sensitivity analysis to see what that would translate to as an equivalent fuel cost sensitivity. The result of that analysis was that the capital cost sensitivity was equivalent to conducting a fuel cost sensitivity of approximately 30%.

VI. CONCLUSIONS

Q: What do you conclude from your revised capacity expansion analyses with regard to Otter Tail's need for Big Stone Unit II in this proceeding?

A: The modeling has clearly shown that Otter Tail's proposed participation of up to 170 MW in Big Stone II is the most economic baseload alternative available to it, whether Big Stone II is constructed at a nominal 500 MW or a nominal 530 MW.

Q: Can you summarize the baseload capacity needs of the five Big Stone owners?

A: Yes, I can. The revised modeling results conducted by all five Applicants show that the five Big Stone owners have a total need for Big Stone II starting in 2013 ranging from 516 MW to 556 MW, regardless of whether Big Stone II is constructed at 500 MW or 580 MW. I have summarized the data in a table identified as OTP Exhibit 118. Previously, in the Minnesota proceeding I testified that the range was from 531 to 556 MW; the reduction is due to a drop of 15 MW of MDU's needs on the low side as determined by the analysis conducted by witness James Heidell.

Q: Does this conclude your supplemental testimony?

A: Yes.