OTP/MDU Exhibit 324

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

MARK ROLFES

PROJECT MANAGER

OTTER TAIL POWER COMPANY

MARCH 10, 2008

BIG STONE II

PARTNERS IN GENERATION

SUPPLEMENTAL PREFILED DIRECT TESTIMONY OF MARK ROLFES

TABLE OF CONTENTS

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I. INTRODUCTION

Q: Please state your name and business address.

A: Mark Rolfes, 48450 144th Street, Big Stone City, SD 57216

Q: Did you previously submit testimony in this proceeding?

A: Yes. I submitted testimony as OTP/MDU Exhibits 301 and 302.

II. PURPOSE AND SUMMARY OF TESTIMONY

Q: What is the purpose of your testimony?

A: The purpose of my testimony is to address the current schedule for the Big Stone II Project given the withdrawal by Great River Energy (GRE) and Southern Minnesota Municipal Power Agency (SMMPA). My testimony also covers the downsized plant size options being used by the Applicants in their revised planning because of the recent changes of ownership, the cost projections for these different unit sizes, and the basis for these cost projections.

Q: Please summarize your testimony?

A: The planned Commercial Operation Date (COD) for the Big Stone II project is now summer 2013. The Applicants chose to examine two plant sizes as part of their updated analyis – a nominal 500 MW facility and a nominal 580 MW facility.

Costs for these plant size alternatives were developed based on project data gathered to-date, commonly-used industry methods, and other factors including expert judgment. A 500 MW plant is estimated to cost $1.272 billion. A 580 MW plant is estimated to cost $1.411 billion. The plant efficiency and emissions rates for this range of plant sizes will not be appreciably different from the 630 MW plant size contemplated earlier.

III. BIG STONE II PROJECT SCHEDULE

Q: Please describe the current schedule for construction of Big Stone II.

A: Given the delays to the project, the schedule we are currently operating under for commercial operation of a second unit at Big Stone is summer 2013. This schedule is approximately thirteen months later than I testified to at the hearings in June of 2007. Tim Rogelstad will provide testimony on the schedule for the proposed transmission facilities.

When I last testified, the Big Stone II owners anticipated a decision on all public service commission regulatory approvals (North Dakota Public Service Commission, South Dakota Public Utilities Commission, and Minnesota Public Utilities Commission) no later than mid-year 2007. Because of the delay primarily in the Minnesota Certificate of Need matter, and the decision by the owners not to enter into large procurement contracts until the permitting is completed, the owners have been required to readjust the schedule. Given that we now expect a decision in this case at the end of May 2008, the most likely in-service date for the unit is the summer of 2013, or roughly 62 months from the time the final permits are obtained. Any additional delays in governmental authorizations will result in a commensurate delay in commercial operation.

IV. PROJECT COST ESTIMATES

Q: What size plant did the Applicants use in their updated analysis?

A: The Applicants examined two different project sizes: a 580 MW supercritical pulverized coal plant and a 500 MW supercritical pulverized coal plant. The original plant was a planned nominal 630 MW supercritical pulverized coal unit.

Q: Why were these sizes selected?

A: With the withdrawal by GRE and SMMPA from the project, and in light of the practical inability to expedite the process of admitting new participants to the project without drastically protracting the regulatory review process, the remaining five utilities understood they had to downsize the plant to optimally fit their anticipated resource needs and take advantage of the economies of scale.

A 500 MW unit is representative of a number of units that have been constructed recently, or are in the planning stage, so there is current, relevant information available on plants of this size. An example is the Weston 4 project in Wisconsin, a 500 MW supercritical pulverized coal plant being constructed by Wisconsin Public Service. Another reason for selecting 500 MW is that this size is consistent with the South Dakota tax legislation that placed a cap on property evaluation for units 500 MW and larger. Also, 500 MW is essentially the anticipated aggregate basic needs of the partners.

580 MW was chosen as the upper limit for a couple of reasons. First, it provides some economies of scale that a 500 MW plant does not present, so it offers a different cost analysis. Second, it affords more room for the owners to obtain additional generating capacity, and more likely, some capacity to accommodate the needs of additional partners if that should develop. Finally, construction of a 580 MW plant was considered to be a realistic option for the five owners so it was important to examine a plant in that size range.

Q: What are the cost estimates for these two different size plants?

A: The cost estimate used for a 500 MW nominal unit is **$1.272 billion** dollars (or $2,545/kW). The cost estimate being used by the companies in their analysis for a 580 MW nominal unit entering into service in June of 2013 is **$1.411 billion** dollars (or $2,434/kW). These cost estimates are for the plant only and do not include costs for transmission. These are in actual dollars, and represent what the owners would need to expend in the aggregate between the beginning of construction through summer of 2013. These numbers could be discounted back to present (2007) value using an assumed discount rate. We did not do so in order to avoid introducing inapt cost figures that could contribute to confusion in the record.

These costs do not include Interest During Construction (IDC) or Allowances for Funds Used During Construction (AFUDC).

Q: How did you determine these estimates?

A: The process to determine these estimates was based on the cost estimates that were provided last year with some adjustments as explained below. Using the work conducted by Black & Veatch for a 630 MW facility to be in-service in May 2011, we used information from the Electric Power Research Institute (EPRI) for scaling plant costs from a known size to a different size unit, either larger or smaller. We then used escalation factors to estimate the cost based on an in-service date two years later.

Q: Is using the EPRI formula something that can be relied on with any certainty?

A: Absolutely. Using the EPRI formula is a standard way to adjust the costs for differences in size. The formula came from a report that EPRI issued in March 2007 and it is based on current data. It is common practice in the industry to use a formula like this when one size of plant is known and an estimated cost is needed for a slightly different size unit. The sizes that we are considering are well within the accuracy range of this formula.

Q: How did you account for the delay in bringing Big Stone II into commercial operation?

A: Delay is by far the biggest component in the price change. In our previous testimony, we testified that the project is using an approximate 6% per year escalation factor. This escalation is also based on the original Black & Veatch analysis.

Q: Are you confident that a 6% escalation rate is reasonable?

A: Yes. While it is difficult to find exact information given the competitive nature of comparable projects, our research of public record literature and periodicals on published cost expectations indicates that our price estimates are well within the range of what other projects are experiencing and what others are using in their projects.

We have also examined published indices with respect to commodities such as steel, pipe, wire, etc. The majority of these indices have been at or below the escalation rate that we have been using for commodity pricing in our project. Thus, we feel that the cost estimate for delay is very reasonable. Again, it must be emphasized that delay is by far a bigger contributor to the cost exposure of a project than the change in plant size for the project within the range of sizes we are considering.

Q: Did the Applicants perform any sensitivity analysis around its estimates?

A: Yes. The Applicants are highly sensitized to the possibility of increased costs. As discussed above, that is why, in part, the Applicants elected not to reduce cost estimates for key commodity inputs, despite a moderation in the prices of those commodities over the past year. The project has employed other methods that factor in the possibility of increased costs, without referring to them as sensitivity analyses. One example is the work that the Applicants' resource planners performed, as described in the testimonies of Bryan Morlock and James Heidell.

The Applicants' consideration of two different plant sizes is also a form of sensitivity analysis. The cost of a 500 MW unit is slightly under 5% more than for a 580 MW unit on a cost per MW basis. Even with the 5% higher cost, the Applicants still have the same level of need. In addition, within our price estimate we have included a contingency of approximately 13.5%. During more predictable times, this contingency level would be lower. This is another way that we have built sensitivity to higher costs into the analysis. We have also used a number of conservative estimates on design and labor costs to try to build-in some cushion for possible upward price deviations.

Q: Can you provide any other information regarding the reasonableness of your cost estimates for Big Stone II?

A: Yes. In the Minnesota CON proceeding, intervenors pointed to Duke Energy's recently approved 800 MW Cliffside project as an example of how much a super-critical baseload plant is likely to cost. As we pointed out in Minnesota, if you take the Duke cost number and adjust it for economies of scale (because the proposed Duke facility is a larger project than Big Stone II), you would find that the Big Stone II cost estimate and the Duke cost estimate are almost exactly the same number on a per kW basis. The percentages of increase are immaterial. The final cost is the more important number. A comparison of Big Stone II with the Duke Cliffside plant actually lends credence to the fact that our estimate is in line with what the rest of the industry is seeing.

Q: Why did you decide not to engage Black & Veatch to prepare an update of the costs estimates for you?

A: We did not think that a second in-depth cost estimate was necessary because we had a very good base case to work from and we had standard industry practices to adjust for different size plants and the cost due to escalation. These are standard engineering practices. We did check with Black & Veatch to make sure our methodology was proper and followed acceptable practices. They confirmed that what we were doing was normal practice. It must be remembered that the biggest variable in the cost for the new unit is delay. This is more of a factor than the engineering work and that is the factor in the calculation that we have the least amount of control over. That's why it did not make sense to expend significant resources and time to come up with a cost number that is no more accurate than the one we have today.

The accuracy of our cost estimates cannot be sharpened until we achieve greater permitting certainty. Repeated delays have created the risk of the project being viewed by key vendors as the proverbial "boy who cried wolf." We would face the potential of not being taken seriously if we were to continually ask our prospective vendors for updated price bids. We know that the vendors will not go through the time consuming, expensive process of developing bids based on detailed cost estimates until there is greater permitting certainty than exists now.

It is simply unrealistic to assume vendors will spend a great deal of time and effort to "sharpen their pencils" until they have a more definitive timeframe and more assurances on the permitting side. If they know specific timeframes based on permitting certainty, they can prepare "firm" bids. We could spend large sums of money to have Black & Veatch or another engineering firm provide a new estimate, but without any more permit certainty this would be a waste of time and resources.

Q: Will costs increase for other kinds of technology also?

A: Yes, certainly. Most of the cost increase is due to ongoing escalation for construction labor and materials. These same cost escalation factors affect all other resource options as well.

Q: Some people have indicated that though all power generation projects use the same commodities, a coal-fired project is more adversely affected by cost increases than a natural gas project. Do you agree with this statement?

A: Depending upon what happens, a natural gas project could be more adversely affected by future developments than coal-fired projects. As coal-fired projects are being cancelled, many of them are now turning to natural gas projects. In the past we have seen huge run-ups in the cost of gas turbines in response to an increase in demand for them.

The manufacturing capability for gas turbines is quite limited, and the manufacturers have increased their prices greatly in the past when demand has increased. In addition, this is a time when other uses of gas turbines, principally for airplane propulsion, is also at a peak. The two largest manufacturers, Boeing and Airbus, are having record sales, with a huge backlog. The likely run-up in cost for gas turbines could far exceed the cost increases for other components. In addition, if there is a softening in the labor markets, a coal-fired plant could have a relative advantage, as the amount of labor needed to construct a coal-fired plant is a much larger percentage of the overall cost than it is for a natural gas fired unit.

The bottom line is that a utility must plan prudently. All power projects are going to see cost increases going forward, assuming the predicted demand for these resources continues to increase. A blanket statement that a coal-fired plant is going to fare worse than other types of resources is simplistic and is readily subject to dispute.

V. OTHER FACTORS

Q: Are there other cost considerations that should be kept in mind when looking at the cost to build Big Stone II and other resources?

A: Yes. By the nature of our business, the process that leads to the addition of supply-side resources tends to drive up the prices of power and generation equipment. Due to the industry philosophy under which we operate, utilities do not build plants when it is most economical. Because we as an industry all routinely share and trade resources to equalize generation surpluses and deficits, we all tend to go deficit together around the same time. This is what is happening in our region right now. In effect, utilities must consider their needs and only build new plants as a last resort. Utilities are not allowed to build plants when they are, in effect, "relatively cheap."

We must have overwhelming proof of a material need for a plant before we can construct one. Because we operate in a market where utilities share resources, this tends to require all utilities to build at the same time. Thus, the industry tends to cause, by the very nature of its business, construction peaks and valleys.

When any utility sets about solving the problem of acquiring needed resources, there has to be an underlying assumption that competition will exist for the material and labor required to build those generation resources. This is a fundamental aspect of our industry. We will see increases in costs for new electric generation as we defer construction until the point where neither the utilities nor their customers can afford to wait any longer, a situation the Applicants and their customers are fast approaching. This is a fundamēntal condition within which we must operate.

Q: With the change in plant size to 500 MW or 580 MW, will there be a decrease in the plant's overall efficiency?

A: No. The overall plant efficiency, or heat rate as it is referred to, will not be adversely affected in either a 500 MW or 580 MW plant as compared to the 630 MW unit. The final heat rate is dependent upon the particular equipment manufacturers and models of their equipment selected, and that is independent of size. In the size range of alternatives we are considering, size does not have an effect on unit efficiency.

Q: Does the change in size have any effect on the carbon dioxide or other emissions information previously provided?

A: Because the overall plant efficiency, or heat rate, does not change for a 500 MW or 580 MW unit, the rate of carbon dioxide and regulated emissions does not change on a per MWh basis. Of course, the smaller unit will have fewer total emissions because it produces fewer total MWh; but on a per MWh emissions rate basis there will be no change.

There will be a slight change in the cost of these controls because of the loss of economies of scale. For instance, it takes approximately the same number of people to operate the pollution control equipment on a 500 MW unit as it does on a 580 MW unit. Thus, there is some increase in the operating and maintenance cost per MWh given the smaller size. These costs were considered, however, by the companies' resource planning experts. The other costs associated with control for allowances and capital costs will be unaffected.

Q: What is the current status of the permitting for the Big Stone plant?

A: Prior to the hearings in June last year, the project had in place a Solid Waste permit, a Surface Water Appropriations permit, and a Energy Conversion Facility Permit, each from the state of South Dakota. Since then, the project has obtained a South Dakota Transmission Routing permit and a Groundwater Appropriations permit. Two other South Dakota Air permits remain in process - the Prevention of Significant Deterioration and Title V permits - and the Federal Environmental Impact Statement (EIS) (which is not really a permit, *per se*) has not been finalized. We expect to receive the PSD permit in the second quarter of 2008. The supplemental draft EIS was published on October 26, 2007 and we expect the final report/record of decision will be published in the third quarter 2008. We anticipate a decision by the Minnesota Public

Utilities Commission on the Certificate of Need and Route Permits for the transmission lines in April or May this year.

Q: Does this conclude your testimony?

A: Yes