

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



SUPPLEMENTAL PREFILED DIRECT TESTIMONY OF MARK ROLFES

TABLE OF CONTENTS

I. INTRODUCTION 1

II. PURPOSE AND SUMMARY OF TESTIMONY 1

III. BIG STONE II PROJECT SCHEDULE 2

IV. PROJECT COST ESTIMATES 2

V. OTHER FACTORS 8

1 **BEFORE THE NORTH DAKOTA PUBLIC SERVICE COMMISSION**

2 **SUPPLEMENTAL PREFILED DIRECT TESTIMONY OF MARK ROLFES**

3 **I. INTRODUCTION**

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

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

6 **Q: Did you previously submit testimony in this proceeding?**

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

8 **II. PURPOSE AND SUMMARY OF TESTIMONY**

9 **Q: What is the purpose of your testimony?**

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

15 **Q: Please summarize your testimony?**

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

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

1 **III. BIG STONE II PROJECT SCHEDULE**

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

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

7 When I last testified, the Big Stone II owners anticipated a decision on all public service
8 commission regulatory approvals (North Dakota Public Service Commission, South Dakota
9 Public Utilities Commission, and Minnesota Public Utilities Commission) no later than mid-year
10 2007. Because of the delay primarily in the Minnesota Certificate of Need matter, and the
11 decision by the owners not to enter into large procurement contracts until the permitting is
12 completed, the owners have been required to readjust the schedule. Given that we now expect a
13 decision in this case at the end of May 2008, the most likely in-service date for the unit is the
14 summer of 2013, or roughly 62 months from the time the final permits are obtained. Any
15 additional delays in governmental authorizations will result in a commensurate delay in
16 commercial operation.

17 **IV. PROJECT COST ESTIMATES**

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

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

22 **Q: Why were these sizes selected?**

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

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

13 580 MW was chosen as the upper limit for a couple of reasons. First, it provides some
14 economies of scale that a 500 MW plant does not present, so it offers a different cost analysis.
15 Second, it affords more room for the owners to obtain additional generating capacity, and more
16 likely, some capacity to accommodate the needs of additional partners if that should develop.
17 Finally, construction of a 580 MW plant was considered to be a realistic option for the five
18 owners so it was important to examine a plant in that size range.

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

20 A: The cost estimate used for a 500 MW nominal unit is **\$1.272 billion** dollars (or
21 \$2,545/kW). The cost estimate being used by the companies in their analysis for a 580 MW
22 nominal unit entering into service in June of 2013 is **\$1.411 billion** dollars (or \$2,434/kW).
23 These cost estimates are for the plant only and do not include costs for transmission. These are

1 in actual dollars, and represent what the owners would need to expend in the aggregate between
2 the beginning of construction through summer of 2013. These numbers could be discounted
3 back to present (2007) value using an assumed discount rate. We did not do so in order to avoid
4 introducing inapt cost figures that could contribute to confusion in the record.

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

7 **Q: How did you determine these estimates?**

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

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

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

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

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

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

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

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

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

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

22 The Applicants' consideration of two different plant sizes is also a form of sensitivity
23 analysis. The cost of a 500 MW unit is slightly under 5% more than for a 580 MW unit on a cost

1 per MW basis. Even with the 5% higher cost, the Applicants still have the same level of need.
2 In addition, within our price estimate we have included a contingency of approximately 13.5%.
3 During more predictable times, this contingency level would be lower. This is another way that
4 we have built sensitivity to higher costs into the analysis. We have also used a number of
5 conservative estimates on design and labor costs to try to build-in some cushion for possible
6 upward price deviations.

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

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

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

20 A: We did not think that a second in-depth cost estimate was necessary because we had a
21 very good base case to work from and we had standard industry practices to adjust for different
22 size plants and the cost due to escalation. These are standard engineering practices. We did
23 check with Black & Veatch to make sure our methodology was proper and followed acceptable

1 practices. They confirmed that what we were doing was normal practice. It must be
2 remembered that the biggest variable in the cost for the new unit is delay. This is more of a
3 factor than the engineering work and that is the factor in the calculation that we have the least
4 amount of control over. That's why it did not make sense to expend significant resources and
5 time to come up with a cost number that is no more accurate than the one we have today.

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

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

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

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

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

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

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

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

17 **V. OTHER FACTORS**

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

20 A: Yes. By the nature of our business, the process that leads to the addition of supply-side
21 resources tends to drive up the prices of power and generation equipment. Due to the industry
22 philosophy under which we operate, utilities do not build plants when it is most economical.
23 Because we as an industry all routinely share and trade resources to equalize generation

1 surpluses and deficits, we all tend to go deficit together around the same time. This is what is
2 happening in our region right now. In effect, utilities must consider their needs and only build
3 new plants as a last resort. Utilities are not allowed to build plants when they are, in effect,
4 “relatively cheap.”

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

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

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

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

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

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

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

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

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

1 Utilities Commission on the Certificate of Need and Route Permits for the transmission lines in

2 April or May this year.

3 **Q: Does this conclude your testimony?**

4 **A: Yes**