Volume 2A

Testimony and Schedules of Witnesses:

Kyle Sem

Rate Base

Before the South Dakota Public Utilities Commission
State of South Dakota

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

EL08-____

Exhibit___

RATE BASE

Direct Testimony and Exhibit of

KYLE SEM

October 31, 2008

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I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Kyle A. Sem, and my address is 215 South Cascade Street, Fergus Falls, Minnesota 56537.

Q. BY WHOM ARE YOU EMPLOYED AND WHAT IS YOUR POSITION?

A. I am employed by Otter Tail Power Company ("OTP" or the "Utility") as Rates Analyst, Regulatory Services.

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS, DUTIES, AND RESPONSIBILITIES.

A. I graduated magna cum laude from Mankato State University, now Minnesota State University, Mankato, Minnesota, in 1998 with a B.S. degree in Accounting. I am a Certified Public Accountant in Minnesota as well as a member of the Minnesota Society of Certified Public Accountants and the American Institute of Certified Public Accountants. I have been employed by OTP since 2006 as Rates Analyst. My primary responsibilities in this position are preparing the annual cost of service studies for the three jurisdictions where OTP provides service (South Dakota, North Dakota and Minnesota), preparing the Lead Lag Study and providing other regulatory and financial analyses.

Q. FOR WHOM ARE YOU TESTIFYING?

A. I am testifying on behalf of OTP.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I will explain the development of the rate base proposed for use in setting rates in this proceeding. Mr. Peter Beithon uses the results of my testimony in preparing the overall financial schedules for the rate case.

Q. WERE YOUR SCHEDULES PREPARED EITHER BY YOU OR UNDER YOUR SUPERVISION?

A. Yes.

II. RATE BASE COMPONENTS AND OVERVIEW

Q. HOW WILL YOU PRESENT YOUR TESTIMONY ON RATE BASE?

A. I will discuss each component of rate base. For each component, I will provide any needed background information and explain the information included in the unadjusted Actual Year 2007 data. I will then identify and explain any adjustments that are made to the 2007 Actual Year to arrive at the 2007 Test Year.

Q. WHAT RATE BASE ACCOUNTING STATEMENTS, SCHEDULES AND EXHIBITS ARE YOU SPONSORING?

A. I am sponsoring Statement D, and Schedules D-1 through D-9, as required by ARSD § § 20:10:13:54 to 20:10:13:63, Statement E and Schedules E-1 through E-3 as required by ARSD § § 20:10:13:64 to 20:10:13:67 and Statement F and Schedules F-1 through F-3 as required by ARSD § § 20:10:13:68 to 20:10:13:71. These Statements and Schedules are located in Volume 1, Tab – Required Statements. I am also sponsoring the following Exhibits, which are attached to my testimony:

1) Exhibit ___ (KAS-1), Schedule 1 – Rate Base Summary;

2) Exhibit ___ (KAS-1), Schedule 2 – Rate Base Components;

3) Exhibit ___ (KAS-1), Schedule 3 – Cash Working Capital;

4) Exhibit ___ (KAS-1), Schedule 4 – Rate Base Adjustments;

5) Exhibit ___ (KAS-1), Schedule 5 – Rate Base Comparison

6) Exhibit ___ (KAS-1), Schedule 6 -- Total Company and South Dakota Jurisdictional Adjustments by Project.

Q. WHAT TIME PERIODS ARE SHOWN ON YOUR SCHEDULES?

A. Statement D shows in summary form the accounts of electric utility plant classified by account as of the beginning of January 1, 2007 and the end of December 31, 2007. Schedule D-1, provides this information by detail plant accounts with subtotals by functional classification, as required by ARSD § § 20:10:13:55. Schedule D-2 shows major plant additions and retirements for the test period, as required by ARSD § § 20:10:13:56. Schedule D-3 are work papers that show the 12 month book balances during the 12 months in the test period by detailed plant account, each subtotal of functional classifications and total plant, as required by ARSD § § 20:10:13:57. Schedules D-4, D-5, D-6 and D-8 provide the information required by ARSD § § 20:10:13:58 through ARSD § § 20:10:13:60 and ARSD § § 20:10:13:62, for the five year period of 2003 through 2007. Schedule D-7 contains workpapers on plant in service carried on the Company's books which was not being used in rendering service, as required by ARSD § § 20:10:13:61. Statement E shows the beginning monthly balances of accumulated depreciation and amortization by function for January 1, 2007 through December 1, 2007 and the ending balance for December 31, 2007 as required by ARSD § § 20:10:13:64. Schedule E-1 shows the annual Test Year activity for accumulated depreciation and amortization as required by ARSD § § 20:10:13:65. Together, the information contained within Statements and Schedules D and E are combined to produce the net plant in service for OTP for the 2007 Test Year. Finally, Statement F and Schedule F-3 show the 2007 Test Year cash working capital calculation as required by ARSD § § 20:10:13:68 and ARSD § § 20:10:13:71 . Schedule F-1 shows the monthly Test Year balances for materials and supplies, fuel stocks and prepayments while Schedule F-2 shows the same monthly information for the two years preceding the 2007 Test Year as required by § § 20:10:13:69 and ARSD § § 20:10:13:70.

Q. WHAT IS THE SOURCE OF THE 2007 ACTUAL YEAR INFORMATION?

A. The 2007 Actual Year information is taken from OTP's South Dakota jurisdictional cost of service study ("JCOSS"), which was prepared by Mr. Beithon and myself and is included in Volume 4A as part of the Work Papers. The JCOSS is based on the Utility's financial information. This same financial information is used to prepare FERC Form No. 1 and the Utility section of Otter Tail Corporation's annual report to shareholders.

Q. PLEASE EXPLAIN WHAT RATE BASE REPRESENTS.

A. Rate base consists primarily of the capital expenditures made by a utility to secure plant, equipment, materials, supplies and other assets necessary for the provision of utility service, reduced by amounts recovered from depreciation rates and non-investor sources of capital (e.g. accumulated deferred income tax).

Q. PLEASE IDENTIFY THE MAJOR COMPONENTS OF THE TEST YEAR RATE BASE.

A. The test year rate base is generally comprised of the following major items which will be described in further detail later in my testimony:

- Net utility plant
- Construction work in progress
- Cash working capital items
- Accumulated deferred income taxes

Q. PLEASE BEGIN BY EXPLAINING EXHIBIT ___(KAS-1), Statement D?

A. Exhibit ___(KAS-1), Statement D, Cost of Plant, summarizes the South Dakota electric utility plant balances as of the end of December 31, 2006, the book additions and reductions to rate base during 2007, together with the book balances as of the end of December 31, 2007. Adjustments made to the 2007 Actual Year book balances and the total cost of plant are shown in Columns (H) and (I). I will separately discuss each of those adjustments later in my testimony. A full discussion of the jurisdictional allocation methodology is contained in the testimony of Mr. Beithon.

Q. HAVE YOU COMPARED THE TEST YEAR RATE BASE TO THE RATE BASE APPROVED IN THE MOST RECENT SOUTH DAKOTA ELECTRIC RATE CASE ORDER?

A. Yes. Exhibit__(KAS-1), Schedule 5, included with my testimony provides a comparison of the rate base approved in the most recent rate case with a Test Year ending December 31, 1986 ("1987 Test Year") to the 2007 Test Year rate base. As I discuss the rate base components, I will, as appropriate, review significant changes from the last rate case.

A. NET UTILITY PLANT

Q. WHAT DOES NET UTILITY PLANT REPRESENT?

A. Net utility plant represents OTP's investment in plant and equipment that is used and useful in providing retail electric service to its customers, net of accumulated depreciation.

Q. PLEASE EXPLAIN THE METHOD USED TO CALCULATE NET UTILITY PLANT INVESTMENT IN THIS CASE.

A. The net utility plant is included in rate base at depreciated original cost, reflecting the simple average of balances at the beginning and end of the test year. OTP's most recent South Dakota electric rate case also used a simple average for net electric plant in service.

Q. WHAT DO THE LINE ITEMS ON STATEMENT D AND SCHEDULE D-1 DESCRIBE?

A. These are the components of OTP's utility plant in service. Statement D lists the functional plant balances as of December 31, 2006, the 2007 Test Year activity and ends with the 2007 Test Year plant balances by FERC account. Schedule D-1 provides the same information by FERC account as well as by plant account. The electric plant in service is based upon the original cost of property from the books and records of OTP as allocated to the South Dakota jurisdiction.

Q. PLEASE EXPLAIN EXHIBIT__(KAS-1), STATEMENT E AND SCHEDULE E-1.

A. As I mentioned previously, Statement E shows the beginning monthly balances of accumulated depreciation and amortization by function for January 1, 2007 through December 1, 2007 and the ending balances for December 31, 2007, and ends with the 2007 Test Year. Schedule E-1 shows the annual Test Year activity for accumulated depreciation and amortization including: beginning balances, annual depreciation or amortization expense, retirements, salvage, ending book balances, Test Year adjustment amounts, and the ending 2007 Test Year balances by function. Schedule E-2 states that there has been no change in depreciation methods or procedures since the period covered by the last annual report on FERC Form 1 for 2007. Schedule E-3 states that each FERC account is assigned to only the functional group resulting in no allocation of overall accounts.

Q. PLEASE EXPLAIN EXHIBIT__(KAS-1), STATEMENT F AND SCHEDULES F-1 THROUGH F-3.

A. As mentioned previously, Statement F and Schedule F-3 show the 2007 Test Year cash working capital calculation. Schedule F-1 shows the monthly Test Year balances for materials and supplies, fuel stocks and prepayments while Schedule

F-2 shows the same monthly information for the two years preceding the Test Year. Both F-1 and F-2 show simple average calculations for the rate base items listed above. The simple average is the method used in this filing and is consistent with what was approved in OTP's previous rate case.

Q. PLEASE DESCRIBE THE MORE SIGNIFICANT CHANGES IN ELECTRIC PLANT SINCE OTP'S LAST GENERAL RATE CASE.

A. There have been thousands of units of property added and retired since our last general rate case in 1987. I will discuss six significant items from that time period. They are:

1) Generation:

a) addition of a combustion turbine peaking plant at Solway, Minnesota;

b) addition of a diesel generator at OTP's system operations center in Fergus Falls; and the

c) retirement of Unit #1 of OTP's Hoot Lake generating plant at Fergus Falls

2) Transmission:

a) Alexandria to Henning 115 kV line;

b) Oslo to Thief River Falls 115 kV line; and the;

c) Harvey, North Dakota, to the US-Canadian border north of Rolette, North Dakota 230 kV line.

I will discuss each of these changes in greater detail later in my testimony.

Q. WHAT ARE OTP'S OBJECTIVES WITH REGARD TO CAPITAL SPENDING?

A. OTP has four primary objectives when determining its capital spending

1) Increase the capability of the system (Plants, IT, T&D, etc.) to accommodate growth;

2) Replace aging facilities through an orderly plan to maintain reliability and customer satisfaction;

3) Invest in new technology to reduce or eliminate future expenses; and

4) Improve Key Performance Indicators (KPIs). KPIs are internal targets set by management for customer satisfaction, service reliability, generation plant availability, safety and financial performance, as Mr. Brause explains in his testimony.

Q. HOW DOES OTP ALLOCATE ITS CAPITAL BUDGET BETWEEN COMPETING ELIGIBLE PROJECTS?

A. The accountability for allocating capital spending resides in the Asset Management area of the Utility, and specifically in Delivery Planning. In carrying out this function, a Capital Allocation Review Team assists in the development of the allocation of capital. This team is made up of a representative from each functional area of the company. Functional areas include Asset Management, Supply, Customer Service, IT, Administration, and Business Planning.

Q. HOW DOES THE CAPITAL ALLOCATION PROCESS WORK?

A. Capital allocation and prioritization is an on-going process. The formal process starts in April of each year with the request for capital projects and the submittal of project applications. The deadline for submitting project applications is typically the middle of June. The projects are then reviewed and prioritized by the Capital Allocation Review Team. During this step, projects are approved, partially funded or denied. The budget is then submitted to the Utility Executive Team for review and approval in early September. The final approval of the capital budget is made by the Board of Directors in December.

Q. WHAT HAPPENS AS UNEXPECTED REQUESTS FOR CAPITAL PROJECTS OCCUR OUTSIDE OF THE NORMAL PROCESS?

A. If a request for capital funds comes outside of the normal timeline for capital allocation, the project is reviewed by the Capital Allocation Review Team similar to the regular process. However, the request is compared to other projects that have already been approved. If the new request is of a higher priority, then a lower priority project is delayed to fit the new project into the capital spending plan for the year.

Q. DO ALL PROJECT APPLICATIONS FOR CAPITAL GET APPROVED?

A. No. During any given year, requests for capital spending exceed the target levels. As a result, prioritization of capital projects is used.

Q. WHAT IS PRIORITIZATION?

A. In simple terms, it is the ranking of capital projects in order of importance from highest to lowest.

Q. HOW DOES OTP PRIORITIZE ITS CAPITAL SPENDING?

A. The first step in prioritization is categorizing the projects. Each year there are many “must do” projects. These include the projects required for connecting new customers, or projects that are necessary to meet compliance requirements, which might, for example, include installing new emission control systems on power plants. Upon providing sufficient justification, these projects are moved to “approved” status in the budget process. We then take the remaining projects and prioritize them

Q. WHAT IS OTP’S REPLACEMENT PLAN FOR ITS AGING FACILITIES?

A. One of the key components that we use in prioritizing capital spending is replacement plans. Over the past five years, OTP has developed replacement plans for various assets. For example, we have a significant amount of underground distribution cable that is over 30 years old. Each year, we set aside a certain dollar amount for replacing such cable. The replacement projects that get funded are prioritized based on their performance characteristics (e.g. number of times the cable has failed), age, etc. Another example of a replacement plan is the computers that are used by employees. The IT department has developed criteria for when a PC is replaced. This is a predictable pattern, and rather than replace all of the PC’s in one year, we spread replacement over five years. That way, we are continually replacing the PC’s, rather than replacing all in one year. The purpose of the replacement plans is to “levelize” the capital spending required so that we do not end up with large expenditures occurring in single years. Not only does this levelize the capital dollars, but it also utilizes our workforce in an efficient manner.

Q. NOW LET'S DISCUSS THE SPECIFIC PROJECTS REFERRED TO EARLIER. PLEASE DESCRIBE THE SOLWAY COMBUSTION TURBINE.

A. The Solway combustion turbine (CT) is a dual-fueled General Electric LM6000 simple cycle combustion turbine. It went into operation in May 2003. It is normally operated on interruptible natural gas, but can switch over to fuel oil operation if the gas supply is curtailed. The unit has a nameplate rating of 44,500 kW, but the monthly ratings vary from approximately 41,900 kW in the peak summer month to 48,800 kW in the peak winter month. The LM6000 engine is the same engine as on a Boeing 747 aircraft, and is one of the most efficient simple-cycle CT's available. The site is equipped with a 1,250 kW diesel generator to provide black start capability (i.e., in the event of a wide area outage, the diesel unit can be started to provide power to start the Solway CT). The unit can then pick up load in the surrounding area, including most of the load in Bemidji. The diesel is capable of synchronizing with the electric grid and serving retail customers, and is accredited by Mid-Continent Area Power Pool (MAPP).

Q. WHY DID OTP INSTALL THE SOLWAY CT?

A. The need for additional peaking capacity was identified in OTP's 1999 Integrated Resource Plan ("IRP"), a copy of which was filed with the South Dakota Commission for informational purposes, where OTP proposed adding a gas-fired CT, to begin operation after May 1, 2002, with 44,000 kW name plate winter peaking capacity. The Minnesota Public Utilities Commission approved OTP's

IRP in its ORDER ACCEPTING 1999 INTEGRATED RESOURCE PLAN, VARYING THE NEXT RESOURCE PLAN FILING DATE, ORDERING CONTINUING DISCUSSIONS AND A STUDY OF A GREEN PRICING PROGRAM BY JULY 1, 2001, Docket No. E017/RP-99-909, dated March 14, 2000. After receiving that authorization, OTP executed on its approved IRP and built the Solway CT.

OTP decided to construct a peaking facility rather than purchase power because wholesale capacity prices at the time were escalating rapidly. The Company had made a conscious decision in the late 1980's and early 1990's to purchase wholesale capacity in lieu of building generating resources, as long as those purchases could be made at an economic cost. In fact, OTP went from 1981, when Coyote Station came on-line, until 2003 without building a generating facility, other than the Fergus Falls Control Center diesel generator that I previously mentioned, and discuss in greater detail later. The resource plan filing also indicated that the Company planned to issue an RFP for peaking capacity in the later part of 1999 and would continue to pursue economic purchases of peaking capacity. However, if such capacity was unavailable or uneconomic, OTP would need to construct a combustion turbine no earlier than May 1, 2002.

Q. WHAT WERE THE SPECIFIC RESULTS OF THE PEAKING CAPACITY RFP?

A. OTP received ten proposals of which two were for year-round capacity and eight were for seasonal capacity. The two for year-round capacity would have required us to pay for capacity that OTP did not need. Four of the proposals were from inside of MAPP and the others were from areas outside of MAPP. Those located outside of the MAPP service area would have had higher delivery costs. The capacity prices ranged from $5/kW-month up to $10/kW-month. The $5/kW-month cost was close to the estimated revenue requirements of constructing a simple cycle combustion turbine at the time. Consequently, the higher priced offers were not cost justified. Most of the proposals had energy priced at the daily wholesale market price (subjecting us to the variability of the market, with the only benefit being an assured supply), and had other requirements such as a 16-hour minimum scheduling requirement (completely unacceptable for a peaking facility, which needs to be dispatchable on 45 minutes notice) or a minimum monthly capacity factor, which would have increased energy costs.

Q. WERE THERE OTHER SPECIFIC CONSIDERATIONS IN EVALUATING THE RESULTS OF THE PEAKING CAPACITY RFP?

A. Yes, then existing transmission limitations played a key role in deciding that OTP could not rely on the wholesale market to meet its needs. In particular, we had consummated a three-year purchase power agreement (PPA) with Minnesota Power for the 2000 – 2002 summer seasons. However, we were unable to get direct firm transmission service from Minnesota Power for the 2000 summer season. Consequently, OTP was only able to receive accreditation of the transaction from MAPP by offsetting another agreement that OTP had in place with Northern States Power (NSP) at the time. In essence, the Minnesota Power capacity was delivered to NSP to satisfy an equivalent OTP obligation to NSP. OTP was able to then keep the capacity it had planned to supply to NSP. A similar situation developed in the 2001 summer season. Firm transmission service was unavailable. Minnesota Power was finally able to rearrange its resources to deliver part of the capacity from a facility in North Dakota and part of the capacity from a facility located in Wisconsin, rather than from its own facilities. What caused great concern at OTP was the fact that almost all of the proposals received by OTP in response to the RFP would have been impacted by the same transmission constraint.

Minnesota Power is located fairly close to OTP and yet we were being impacted by a transmission constraint located some distance away. And because the constraint was on facilities owned by others some distance from the OTP system, OTP could not take measures to mitigate the constraint. The constraint created the potential for OTP to be restricted in its ability to purchase capacity from the wholesale marketplace and created the potential for OTP to be subject to the pricing practices of just a couple of suppliers, from whom OTP could find access to purchase capacity. The transmission constraint, combined with the increasing wholesale capacity cost, provided the impetus for moving ahead with construction of a combustion turbine.

Q. BESIDES MEETING PEAK CAPACITY AND ENERGY NEEDS ARE THERE OTHER BENEFITS ASSOCIATED WITH THE CONSTRUCTION OF THE SOLWAY CT?

A. Yes. The construction of the Solway CT allowed OTP to delay transmission investments. In selecting the site for the unit, the availability of local transmission facilities was taken into consideration. The Solway site near Bemidji, Minnesota, had existing adequate transmission and a high-pressure natural gas pipeline. In addition, at the time, OTP was facing transmission issues in the Bemidji area under certain transmission contingency situations. Under heavy loading conditions, the Bemidji area could suffer voltage problems if certain transmission facilities experienced an outage. By adding generation in that area, the existing transmission was adequate to serve that load, allowing transmission upgrades to be delayed for several years, so this was an important additional benefit to the facility.

Q. WHAT WAS THE DOLLAR AMOUNT ADDED TO ELECTRIC PLANT IN SERVICE FOR THE SOLWAY CT GENERATOR?

A. The Solway CT generator represented a net addition of $27.5 million, of which approximately $2.6 million is allocated to South Dakota.

Q. TURNING TO THE NEXT ITEM YOU LISTED – ADDITION OF THE DIESEL GENERATOR AT OTP'S SYSTEM OPERATIONS CONTROL CENTER IN FERGUS FALLS – PLEASE DESCRIBE THIS UNIT AND ITS PURPOSE.

A. This unit is a 2,000 kW nameplate rated diesel fuel powered generator located in Fergus Falls, Minnesota. The primary purpose of the unit is to provide emergency backup service to the OTP System Operations control center, but the generator is also capable of synchronizing with the electric grid and can be used to provide energy to serve retail load. It is accredited in the MAPP and counts toward OTP's MAPP Reserve Capacity obligation.

Q. WHY DID OTP INSTALL THE FERGUS FALLS CONTROL CENTER DIESEL GENERATOR?

A. In 1995 OTP developed a new System Operations control center, which is staffed around the clock to manage all generation and transmission facilities within the control area. The National Electric Reliability Council (NERC) standards required a backup power supply to ensure that the control center would always have electric service to maintain operation of computers, communications systems, and system control.

Q. WHAT IS THE DOLLAR AMOUNT ADDED TO ELECTRIC PLANT IN SERVICE FOR THIS DIESEL GENERATOR?

A. This diesel generator represented a net addition of $600,000, of which approximately $56,000 is allocated to South Dakota.

Q. PLEASE DISCUSS THE NEXT SIGNIFICANT CHANGE IN GENERATION, THE RETIREMENT OF UNIT #1 OF THE HOOT LAKE GENERATING PLANT.

A. The Hoot Lake generating plant, consisting of remaining Units #2 and #3, and a small hydroelectric plant, is located on the Otter Tail River at Fergus Falls. Hoot Lake #1 was a 1948 vintage coal-fired steam unit with a nameplate rating of about 7,500 kW that was retired December 31, 2005. The retirement came about because of a number of operational, efficiency, and environmental issues that were going to have to be addressed. Consequently, the Company proposed retirement of Hoot Lake #1 in its 2003 IRP, a copy of which was sent to the South Dakota PUC for informational purposes. The Minnesota Commission approved the Company's 2003 IRP in its ORDER ACCEPTING 2003 INTEGRATED RESOURCE PLAN, VARYING THE NEXT RESOURCE PLAN FILING DATE, AND REQUIRING INTERIM FILING, Docket No. E-017/RP-02-1168, dated May 29, 2003.

Q. WHAT WERE THE OPERATIONAL ISSUES?

A. Probably the most significant operational issue was the water requirements for cooling the unit to condense the steam back into water. The Hoot Lake Plant contained three steam units with a rather unique operational situation for cooling. In the early 1900's, OTP diverted part of the Otter Tail River to create a new lake that was named Hoot Lake. A channel was dredged to allow water to flow from

Hoot Lake into a slough area that then became Wright Lake. Wright Lake is at an elevation located above the steam units, so water could be gravity fed into the steam units for cooling, avoiding the expense and reduced net output caused by having to pump cooling water. Hoot Lake units #2 and #3 were also equipped with cooling towers, which were only needed when insufficient water was available from Wright Lake or when downstream river temperatures reached the limit allowed under the plant's permits. OTP also has several hydroelectric facilities located on the Otter Tail River. During the late 1980's, OTP was ordered to obtain licenses for these facilities from the Federal Energy Regulatory Commission (FERC). These units had existed prior to FERC and had never been licensed. As a result of the licensing process, which took several years, the terms of the license require OTP to divert less water from the Otter Tail River. This reduced the amount of water available to the steam plant. During most of the 1990's this was not a concern as most of the time the Hoot Lake units were not heavily loaded. But as wholesale market prices increased, the Hoot Lake units were called on more and more. This resulted in units # 2 and # 3 being put on cooling towers more frequently, and the consequent parasitic losses of running the cooling towers reduced the output from Hoot Lake #1. At peak times, the 7,500 kW output of the unit was reduced by the 2,000-3,000 kW required for the additional cooling needed for the other two units.

Q. WHAT WERE THE EFFICIENCY ISSUES THAT CONTRIBUTED TO THE DECISION TO RETIRE HOOT LAKE #1?

A. Over time, the seals on the steam turbine had degraded and the efficiency of the steam turbine was approximately 50 percent worse than its original design performance. Too much steam was bypassing the turbine blades and not doing productive work. The steam turbine was in need of an overhaul. It would have been possible to continue operation without overhauling the steam turbine, but this raised the cost and increased emissions per MWh of output. Also, the operating permit for the unit restricted the maximum amount of steam flow that was allowed. Without a turbine overhaul, the net output of the unit would decline as less and less of the steam was being productively used.

Q. WHAT WERE THE ENVIRONMENTAL ISSUES?

A. The Hoot Lake #1 unit was equipped with a fabric filter for particulate control. The condition of the fabric filter system had deteriorated over time, partially due to the limited operation that the unit was experiencing. If it had not been retired, the facility would have required additional significant investment to maintain ongoing compliance with operating permit emission requirements.

Q. PLEASE SUMMARIZE THE BASIS FOR THE DECISION TO RETIRE THE HOOT LAKE #1 UNIT?

A: In combination, these various issues made it uneconomic to continue operating the unit. The costs to repair and/or maintain some of the existing equipment and the negative impact to the Hoot Lake #2 and #3 units due to the water issues I described, and the limited operation of this unit, made it more cost-effective to retire the unit.

Q. IN YOUR EARLIER SUMMARY, YOU LISTED THREE TRANSMISSION LINES. WOULD YOU PLEASE RECAP THOSE FOR US?

A. Yes. Since the last rate case in 1987, OTP has constructed three major transmission lines. (1) The Alexandria to Henning 115 kV transmission line was constructed in the mid-1990's and was a joint project with Great River Energy and Missouri River Energy Services. (2) OTP constructed approximately 50 miles of 115 kV transmission line between Oslo, Minnesota, and Thief River Falls. This project was completed in 1999. (3) The construction of a 100-mile 230 kV transmission line from Harvey, North Dakota, to Glenboro, Manitoba, of which OTP owns 40 miles.

Q. WHAT WAS THE SINGLE LARGEST TRANSMISSION RATE BASE ADDITION SINCE THE LAST RATE CASE?

A. OTP's largest transmission rate base addition was the third project identified above -- the Harvey – Glenboro project. This project was jointly sponsored by OTP, Xcel Energy and Manitoba Hydro. It was a 160-mile 230 kV transmission line that originated in central North Dakota and terminated in southwestern Manitoba, with major substation additions or expansions at Harvey, Balta, Rugby, North Dakota, and Glenboro, Manitoba. This project was placed into service in the fall of 2002. This project was approved by the North Dakota Public Service Commission in Case No. PU-401-99-586.

Q. WHAT WAS OTP'S INVESTMENT IN THE HARVEY-GLENBORO TRANSMISSION PROJECT?

A. OTP invested $9.7 million in this project. We own the transmission line between Harvey-Balta and Rugby as well as the substation at Rugby. Of this amount, approximately $870,000 was allocated to the South Dakota jurisdiction.

Q. WHY DID OTP MAKE THE HARVEY-GLENBORO ADDITION?

A. As part of a regional transmission planning process, the Harvey-Glenboro project was identified as a transmission project that provided multiple benefits. From OTP's perspective, the benefits were related to improved reliability in north-central North Dakota and the reduction of generation curtailments during multiple outages of transmission facilities.

Q. HOW DOES THIS TRANSMISSION LINE BENEFIT OTP'S CUSTOMERS?

A. Transmission is regional. This transmission line is located in North Dakota and supports the transmission grid in this region. A few examples include:

a.) When transmission lines are out of service, it is not uncommon to have to reduce generation to ensure safe loading limits on the remaining transmission system. The addition of the Harvey-Glenboro line reduced the amount of generation that would need to be reduced to ensure safe loading limits. Some of this generation is used to serve South Dakota customers.

b.) This line increased the amount of power that can be transferred from Manitoba to the United States. This additional power transfer can be used to serve South Dakota customers.

Q. WAS THE HARVEY-GLENBORO PROJECT ENDORSED BY REGIONAL RELIABILITY ENTITIES?

A: Yes, it was. The project was endorsed by the Mid-Continent Area Power Pool as well as the Red River Valley Sub-regional planning group.

Q. WHAT GENERAL OBSERVATION DO YOU HAVE AS YOU COMPARE NET PLANT IN SERVICE IN 1987 WITH 2007?

A. OTP's South Dakota net electric plant in service grew by approximately $33 million, or about 96 percent, during these 20 years. (See my Exhibit__(KAS-1), Schedule 5.) In 1987, our two largest baseload steam plants were much newer, and one might expect that because of depreciation, net production plant in service could be smaller today than it was in 1987. However, net production plant in service is larger today by $17.3 million, largely due to wind project additions, which I will discuss later in my testimony. OTP has also made significant transmission and distribution investments to meet customer needs and enhance our reliability. All of the above mentioned investments have contributed to the significant increase in net electric plant in service since our last rate case in 1987.

Q. ARE YOU PROPOSING ANY KNOWN AND MEASURABLE ADJUSTMENTS TO PLANT IN SERVICE TO DEVELOP THE TEST YEAR?

A. Yes. I made several adjustments related to projects that either went into service during 2007 or will go into service by December 31, 2009. I will describe these adjustments in segments as plant adjustments that went into service during 2007 are adjusted differently than those that will go into service after 2007. The detailed calculations for the adjustments to plant in service can be found on work paper series TY-01, in Volume 4A, Tab - 2007 Test Year Work Papers. First, I made adjustments for four capital projects that went into service before the end of 2007 that were included in Long-Term Construction Work in Progress ("CWIP") on December 31, 2006, and four projects that were both started and completed during 2007. The projects in Long-Term CWIP on December 31, 2006, included (i) the final installations of the new load management ("LM") system; (ii) a Power Network Analysis Applications software package; (iii) a production-related project at the Big Stone Plant, and (iv) a production-related project at the Hoot

Lake Plant. The four projects that were started and completed during 2007 were all production-related projects with the largest investment being a $65 million addition related to the Langdon Wind Energy Center ("LWEC"), a wind farm near Langdon, ND. The other three projects were all located at the Big Stone Plant. Because rate base for plant in service is based on a simple average of the beginning and ending balances during the Test Year, this adjustment annualizes these projects so that the entire amount is included in rate base rather than only half, which would be the result if the simple average is used. It is appropriate to include a full year of investment in rate base for these projects because they occurred during the historical 2007 Test Year, and rates will not be affected as a result of this proceeding until January 2009, long after these projects became fully operational. My total adjustment to annualize the eight additions that were placed in service during 2007 is $41,819,534 (See Exhibit__(KAS-1), Schedule 6). South Dakota's share of this adjustment is approximately $3,885,921 (See Exhibit__(KAS-1), Schedule 6).

Q. PLEASE TELL US MORE ABOUT EACH OF THE ADJUSTMENTS TO PLANT IN SERVICE YOU LISTED, BEGINNING WITH THE NEW LOAD MANAGEMENT EQUIPMENT.

A. OTP first began LM with use of time clocks on water heaters in the 1940's in order to reduce our load during the morning peak hours and then again in the evening peak hours as customers returned home from work. This was in response to large load growth after the war. Then in the late 1970's a pilot radio LM system was installed in two small towns in our service territory. This resulted in the installation of the Regency Radio Load Management system in the early 1980's. At first, we replaced time clock meters on the water heaters and then moved to installing LM radios to control dual fuel electric heating systems. Since then, we have added more controlled service tariffs to give our customers more choices to respond to available technology.

Over the years, we expanded the system with additional towers to improve the radio signal to towns on the edge of our coverage and found additional suppliers for radio receivers.

Q. WHY DID OTP MAKE THE INVESTMENT IN LM IN 2007?

A. The old LM system was 22 years old and a typical system has a life of 15 years. We had done all that was practical to extend the life of that system, but ran out of options. Finding replacement components and parts was becoming very difficult. The old system was becoming less reliable as time went on. Improved technology in newer systems allows more flexibility for controlling electric load. For example, each radio receiver in our new system is individually addressable. We can reprogram many functions over the airwaves and can initiate control for a specific radio if required. We have found this to be a great help in trouble shooting at customers' premises. Another feature we needed was the ability to cycle summer cooling load. While OTP is a winter peaking utility, our summer load is approaching the winter peak, so summer load control is becoming more important to us. Overall we identified a need for a more flexible and dependable system to manage a robust portfolio of controlled service rates, and this new system meets those needs.

Q. WHAT IS THE POWER NETWORK ANALYSIS APPLICATIONS SOFTWARE?

A. The Power Network Analysis Applications (PNAA) software provides real-time power flow, state estimator and contingency analysis capabilities. The software enhances the Power System Operator's (PSO) and transmission operations engineer's ability to reliably operate the transmission system in real-time. Additionally, the PNAA tools provide "what if" analysis capabilities that allow the engineers and PSO's to complete off-line studies to enhance the short-term and long-term operation of the transmission system.

Q. WHAT ARE THE PRODUCTION RELATED PROJECTS AT BIG STONE PLANT?

A. The four production-related projects are: (i) a brine concentrator lined sludge pond expansion; (ii) a condenser retube; (iii) an Advanced Hybrid Particulate Controller (AHPC) replacement and (iv) a generator rewind.

Q. PLEASE TELL US MORE ABOUT EACH OF THE BIG STONE PROJECTS, BEGINNING WITH THE BRINE CONCENTRATOR LINED SLUDGE POND EXPANSION.

A. The original brine concentrator sludge pond was a clay lined pond designed to hold the concentrated waste stream from the plant's brine concentrator (water distillery). In the early 1990's we partitioned an area approximately 1.5 acres and lined that area with a high density polyethylene (HDPE) liner to prevent leakage from the pond. This storage area worked well for a time, but as the plant's overall water balance continued to degrade, the brine concentrator needed to operate nearly the entire year, producing more waste water than could be stored in the small pond. In 2007, an additional 8 acres of pond was lined with HDPE to store additional waste from the brine concentrator.

Q. PLEASE DESCRIBE THE CONDENSER RETUBE PROJECT.

A. The original condenser tubes were primarily admiralty brass material, with certain areas tubed with stainless steel. Admiralty brass, when clean, has a better heat transfer rate than stainless steel. In 1998, the condenser was retubed with original style material due to failing brass tubes. The failure mechanism appeared to be a manufacturing flaw that eventually resulted in tube leaks. In the last nine years, the cooling pond water chemistry became more aggressive toward the brass tubes, causing corrosion and erosion. The tubes were also becoming fouled but could not be cleaned because of concerns about causing additional leaks. However, the stainless steel tubes were remaining clean and were not leaking. We retubed the entire condenser with stainless steel tubes during 2007. The tubes will now remain clean thereby increasing plant efficiency. The retube also allowed us to rebuild the circulating water pumps in 2007, restoring full circulating water flow, also improving unit efficiency. The condenser is the largest heat exchanger in the plant, and any improvements are important.

Q. WILL YOU PLEASE DESCRIBE THE AHPC REPLACEMENT PROJECT THAT WAS COMPLETED?

A. Yes. Big Stone Plant installed the experimental AHPC in 2002 to replace our failing electrostatic precipitator (ESP). The AHPC was designed to have the benefits of both an ESP and a bag house, greatly reducing emissions of fine particulate (dust). The project was partially funded by the National Energy Technology Lab's Power Plant Improvement Initiative. However, we realized the AHPC was not meeting design expectations almost immediately. Problems included premature bag failures (expensive and time consuming to replace), and due to very high pressure drops, plant output was limited to some degree almost continually. At times, these derates were 75 MW or more. In 2005, efforts were made to add additional bags using more AHPC technology, but again, this effort failed. In 2007, the AHPC was replaced with a standard pulse-jet baghouse. The baghouse uses no ESP components, and greatly increased the number of bags, thus reducing pressure drop. Results in 2008 have been very good, with minimal operating limitations, and no failing bags.

Q. PLEASE DESCRIBE THE FOURTH AND FINAL BIG STONE PLANT PROJECT ADDED IN 2007, THE GENERATOR REWIND.

A. In 2005, the Big Stone Plant failed a transposition test, an electrical test (pass/fail) that gives an indication of the condition of the electrical insulation of the non-rotating coils of the generator. At that time, our insurance carrier recommended a full stator rewind, typical for a generator the age of Big Stone’s (30 years of age). We continued to monitor and inspect the generator until we could budget for a rewind during a future outage (scheduled for 2010). In 2006, an inspection revealed a burned strand in an end-winding of the generator. This was repaired to allow operation, but we immediately made plans to rewind the generator in the fall of 2007. The benefits of this project are improved reliability and availability. We contracted with Alstom to rewind the generator, but Alstom fell significantly behind schedule. We terminated their contract in September 2007 and hired Siemens to rewind the generator and that was completed in the late fall 2007.

Q. PLEASE DESCRIBE THE PROJECT AT HOOT LAKE PLANT THAT WAS ADDED IN 2007.

A. The capital project costs added during 2007 at the Hoot Lake Plant were related to Voluntary Investigation and Clean-up (VIC) work on several old ash landfill sites. Hoot Lake has four ash landfill sites located on the property that were built and placed in service before the Minnesota Pollution Control Agency (MPCA) had regulations and required permits regarding ash dumping in landfill areas. Over time the MPCA and OTP have identified environmental concerns with respect to these ash landfill sites. The approach that OTP employs to address the environmental concerns is VIC. VIC allows OTP to work together with the MPCA to research and find measures that can be used to clean-up and control the environmental issues at these sites.

Q. YOU LISTED THE ADDITION OF A WIND FARM NEAR LANGDON, ND, AS THE LARGEST INVESTMENT RELATED TO PROJECTS THAT WENT IN SERVICE BY THE END OF 2007. COULD YOU GIVE US MORE INFORMATION ON THIS PROJECT?

A. Yes. I will be specifically discussing wind projects later in my testimony.

Q. HAVE YOU MADE OTHER ADJUSTMENTS RELATED TO THE PLANT ADDITIONS THAT WERE PLACED IN SERVICE DURING 2007?

A. Yes. Because of the adjustment I made to include a full year of investment in rate base for the 2007 plant additions, I also made an adjustment to annualize accumulated depreciation as well as an adjustment to the operating statement to include a full year's depreciation expense on all of the 2007 plant additions. The total adjustment to accumulated depreciation related to projects that were placed into service during 2007 is an increase of $3,267,795 (See Exhibit__(KAS-1), Schedule 6) . The South Dakota share of this adjustment is $303,254 (See Exhibit__(KAS-1), Schedule 6). As I mentioned, an operating statement adjustment is also needed to normalize the amount of depreciation expense that was taken during 2007 to reflect a full or normal year. The adjustment amount totaled $3,239,513 with the South Dakota share being approximately $300,000.

Since the additions are treated as if they had been made at the start of the year, matching also justifies including a year of accumulated depreciation offset.

Q. YOU MENTIONED SEVERAL ADJUSTMENTS RELATED TO PLANT IN SERVICE THAT YOU WERE GOING TO DESCRIBE. PLEASE DISCUSS THE REMAINING ADJUSTMENTS.

A. I have two other adjustments related to plant in service that I need to discuss. The next adjustment is related to projects that were started during 2007 and are scheduled to be completed by December 31, 2009 (within 24 months of the end of the test year). This adjustment is similar to the adjustment I just described for projects that were completed in 2007. Any current capital outlay for the projects resided in Long-term CWIP at the end of 2007. There are seven projects included in this adjustment: a General Office building addition, two production-related projects at Hoot Lake Plant, a production project at Coyote Plant, the final investment in the LWEC, and two transmission projects. The adjustment needed to annualize plant in service is to add the full budgeted costs of each project. Each of the adjustments qualify as known and measurable adjustments, justifying removing them from the status of incomplete projects in 2007 and treating them as completed projects. The adjustment amount to increase plant in service is $26,305,337 (See Exhibit__(KAS-1), Schedule 6). The South Dakota share of this adjustment is $2,421,543 (See Exhibit__(KAS-1), Schedule 6).

Q. WHAT GENERAL OFFICE BUILDING ADDITION WAS STARTED IN 2007 THAT WILL BE COMPLETED BY THE END OF 2009?

A. During 2007, construction began on an addition to the Hi-Tech Building, part of OTP's General Office complex. This addition will be used to house the Print and

Mail Services department which is currently located in the lower-level of the General Office. The addition will allow for more equipment and shelving space for Print and Mail Services as well as more office space in the General Office building. The addition will be completed during 2008.

Q. WHAT PROJECTS AT THE HOOT LAKE PLANT WERE STARTED DURING 2007 AND ARE EXPECTED TO BE COMPLETED BY THE END OF 2009?

A. The two production-related capital projects at Hoot Lake that were started during 2007 were the upgrade of the burner on Unit #2 as well as the replacement of superheater tubes on Unit #2.

The burner upgrade on Unit #2 was the result of Environmental Protection Agency regulations that required our Nitrogen Oxide ("NOx") emission levels to be lowered to 0.15 pounds per million Btu by 2009. Current NOx emissions at Hoot Lake Unit #2 were averaging 0.430 pounds per million Btu at the time of the environmental regulation change and upgrades were needed in order to lower the NOx to the required level. Another contributing factor for the burner upgrade was the fact that the existing burners were past their estimated life span and were in need of replacement. The burner modifications and replacement satisfied both issues of lower NOx levels and the need to replace equipment beyond its life expectancy.

The replacement of superheater tubes on Unit #2 was due to the failure of the existing low temperature superheater tubes over the last three years which caused unplanned outages on the unit. The old tubes were well past their life expectancy and Hoot Lake mechanics had made several weld repairs to these tubes. As a result, metal thickness and metal fatigue were becoming an issue.

Based on potential generation losses and plant safety, the decision was made to replace them.

Q. PLEASE DESCRIBE THE PRODUCTION-RELATED ADDITION AT THE COYOTE PLANT.

A. The addition at the Coyote Plant was the purchase of a spare Generator Step-Up Transformer (GSU). The GSU is a large transformer that takes the 22,000 volt electricity coming off the generator and steps it up to 345,000 volts before it is sent down the transmission lines to customers. The purchase of a spare was initiated due to the long lead-time in procuring a replacement GSU, up to two years, and the fact that the existing unit was over 25 years old. The age of the existing unit led to reliability concerns and the risk of not having a spare was too great should the existing unit fail. If a failure had occurred, and a spare was not available, the unit would not be able to generate electricity and would likely have been off-line for a year or more while we waited for a replacement unit to arrive.

Q. PLEASE BRIEFLY DESCRIBE THE TWO TRANSMISSION RELATED PROJECTS THAT WERE STARTED BUT NOT COMPLETED BY THE END OF 2007.

A. The first transmission project is related to additions at the substation in Hensel, North Dakota. Prior to the addition of the LWEC customers in northeastern North Dakota were served by long radial transmission lines. Customers in the Langdon area were served by a 115 kV radial line from Devils Lake and customers in the Hensel area were served by a 115 kV radial line from Drayton. Load growth in northeastern North Dakota was indicating that a new transmission source would be needed in the future to continue serving customers in this area reliably. One transmission solution that was contemplated was a new 115 kV line from the Langdon Substation to the Hensel Substation to "loop" the Langdon and Hensel substations together via a large 115 kV loop from Drayton to Devils Lake.

When the interconnection studies for the LWEC were performed for the 159 MW wind-generating facility, a new 115 kV line from Langdon to Hensel was studied to determine if this line (along with the existing 115 kV line from Langdon to Devils Lake) provided adequate transmission outlet for the new wind farm. Interconnection studies did indeed indicate that a new 35-mile 115 kV line was necessary for sufficient transmission capacity for the LWEC. Therefore, the new Langdon - Hensel 115 kV line was accelerated for the Langdon Wind Energy Center project and energized as part of the project in December of 2007. Thus, this new line served the dual purpose of providing an adequate outlet for the LWEC, and it also improved transmission reliability in the Landgon area.

As part of the Langdon - Hensel 115 kV line addition, substation modifications were necessary at the Hensel substation to integrate the new 115 kV line into the bulk transmission system. The substation additions involved adding new 115 kV circuit breakers as well as protective relaying additions. In addition, coordinated planning efforts between Minnkota Power Cooperative and OTP indicated that a new 115/69/41.6 kV transformer at the Hensel substation is needed as a result of load growth in the Hensel area causing loading concerns on the existing transformer. The transformer addition at the Hensel substation is expected to take place during the winter of 2008-2009.

Q. WILL YOU NOW BRIEFLY DESCRIBE THE OTHER TRANSMISSION RELATED PROJECT THAT WAS STARTED BUT NOT COMPLETED BY THE END OF 2007?

A. Yes. Load growth in the area between Appleton and Canby has caused electrical facilities in this area to exceed allowable capacity. During peak load times, the transformer at the Canby substation becomes overloaded during critical contingency situations. The only practical alternative that was identified by OTP was to upgrade the existing 41.6 kV line between Appleton and Canby to 115 kV. For ease of construction, improved reliability, and lower overall cost it was determined that the entire 42 miles of upgraded line would occur in a single timeframe. Upgrading the line will result in a positive economic impact in the form of reduced system losses. OTP submitted a Certificate of Need ("CON") application and a Route Permit application to the Minnesota Public Utilities Commission on September 7, 2006. The CON and Route Permit were approved on April 18, 2007. Construction of the upgrade began in late April 2007 and the line is expected to be energized at 115 kV by May 2009.

Q. IS THERE A RELATED ADJUSTMENT TO ACCUMULATED DEPRECIATION AND DEPRECIATION EXPENSE FOR THE GROUP OF PROJECTS JUST DESCRIBED?

A. Yes. An adjustment is needed to both accumulated depreciation and depreciation expense. Because the projects added to plant are not scheduled to go into service until after 2007, there is no current year depreciation expense or accumulated depreciation included in the 2007 Actual Year. Therefore, an adjustment is needed to normalize a full year's worth of projected depreciation expense as well as an off-setting amount to annualize accumulated depreciation. As I explained earlier, these adjustments are appropriate to match depreciation and the accumulated depreciation offset to the annualized rate base addition. The adjustment amount to increase accumulated depreciation and depreciation expense is $874,433 (See Exhibit__(KAS-1), Schedule 6). The South Dakota share of this adjustment is $80,695 (See Exhibit__(KAS-1), Schedule 6).

Q. DO YOU HAVE ANY OTHER PLANT IN SERVICE ADDITIONS TO DISCUSS?

A. Yes. I have one final adjustment for projects that are scheduled to be started after December 31, 2007 and completed by December 31, 2009. There are three projects included in this adjustment; i) a Production project at Hoot Lake Plant; ii) the Ashtabula Wind Center ("AWC"), a wind farm near Ashtabula, ND; and iii) a Transmission project related to the new Casselton Ethanol Plant. The total rate base adjustment for these projects is an increase of $125,044,381 (See Exhibit__(KAS-1), Schedule 6). The South Dakota share of this adjustment is $11,584,073 (See Exhibit__(KAS-1), Schedule 6). As with the other plant additions, there are matching adjustments needed to annualize accumulated depreciation and normalize depreciation expense to reflect a full or normal year of rate base treatment. There is no current year depreciation expense or accumulated depreciation amounts included in the 2007 Actual Year. Therefore, the adjustment needed will be the same for depreciation expense and accumulated depreciation. (See Exhibit__(PJB-1), Schedule 8, Column G). The total adjustment being made is $4,827,644 (See Exhibit__(KAS-1), Schedule 6). The South Dakota share is $447,557 (See Exhibit__(KAS-1), Schedule 6).

Q. PLEASE BRIEFLY DESCRIBE THE PRODUCTION PROJECT AT HOOT LAKE.

A. The production project at Hoot Lake Plant is the replacement of superheater tubes on Unit #3. The low temperature and high temperature superheat tubes on Unit #3 are well past their life expectancy. As with the old tubes on Unit #2 that I discussed earlier, Unit #3 has seen several forced and unplanned outages due to tube leaks. Over the last few years, Hoot Lake mechanics have made a number of weld repairs in these boiler sections related to the leaks and the threat of generation losses and tube failures was becoming too great to ignore. As a result, the decision was made to replace the old tubes.

Q. PLEASE TELL US MORE ABOUT THE TRANSMISSION PROJECT RELATED TO THE NEW CASSELTON ETHANOL PLANT.

A. A new ethanol plant near Casselton, North Dakota, will be served by OTP and is expected to be in-service in October 2008. The ethanol plant has informed OTP that they have plans to double their electrical demand within 2 to 3 years after initial start-up. In order to provide reliable service to the ethanol plant, Otter Tail is constructing a new 115 kV line from Mapleton to Casselton. The new 115 kV line will be double circuited with an existing 41.6 kV line to minimize the impacts. In 2009, the new 115 kV line to Casselton will be extended further west to the Buffalo substation to complete a 115 kV loop between the Sheyenne Substation and the Buffalo Substation. As part of this project, substation modifications will occur at Buffalo, Mapleton, and Casselton.

Q. PLEASE DISCUSS OTP'S REQUEST FOR COST RECOVERY RELATED TO ANY INVESTMENTS IN WIND GENERATION IN THIS CASE?

A. OTP is the owner of a portion of a large wind farm near Langdon, North Dakota, the LWEC, that went into commercial operation in late 2007 and early 2008 as well as a portion of another large wind farm near Ashtabula, North Dakota, AWC. The cost recovery for these wind investments is being requested through base rates in this rate case. All costs have been accumulated along with any associated projected tax credits and have been incorporated into the 2007 test year rate base calculation through the adjustments described above as well as separate current and deferred tax adjustments related to the projected tax credits.

Q. PLEASE DISCUSS IN MORE DETAIL OTP'S INVESTMENT IN THE LANGDON WIND ENERGY CENTER.

A. The LWEC is a wind farm located near Langdon in Cavalier County, North Dakota. The wind farm is capable of generating enough electricity to power nearly 40,000 homes. OTP owns 27 of the 106 existing wind turbines, or 40.5 megawatts. FPL Energy, LLC, a subsidiary of FPL Group (NYSE:FPL) owns the remainder of the turbines and operates the entire wind farm. FPL Energy is the world's leader in wind energy, with wind facilities in operation in 16 states. Initial operation of the 106 wind turbines at LWEC began in December 2007. The entire wind farm became commercially operational in January 2008. OTP's total investment in the LWEC is $77,826,262. The South Dakota share of this investment is approximately $7,225,000. The total investment in this project is included in rate base for the 2007 test year to reflect the capital outlay that was placed into service in the 2007 actual year with the remaining balance picked up through the test year adjustments mentioned previously in my testimony. Also, as an incentive to generate investment in wind projects such as the LWEC, North Dakota offers an Investment Tax Credit and the Federal government offers a Production Tax Credit, both of which can be used to offset the costs of investing in and operating the wind projects. OTP is proposing a test year adjustment for these tax credits which is included in Mr. Beithon's Direct Testimony.

Q. WILL YOU ALSO PLEASE DISCUSS IN MORE DETAIL THE INVESTMENT IN AWC AS WELL?

A. Yes. The AWC is a wind farm being constructed near Ashtabula in Barnes County, North Dakota. OTP will own 48 megawatts of wind energy generation at the 200 megawatt AWC. FPL Energy owns the remainder of the megawatts and operates the entire wind farm. The AWC is scheduled to be commercially operational by the end of 2008 and once built, this project will increase the amount of wind-generated electricity owned or purchased by the company to 130 megawatts, enough to power more than 38,000 homes. OTP's total investment in the AWC is $116,343,081. The South Dakota share of this investment is approximately $10,800,000. The total investment in this project is included in rate base for the 2007 test year through the adjustments mentioned previously in my testimony. Also, as an incentive to generate investment in wind projects such as the AWC, North Dakota offers an Investment Tax Credit and the Federal government offers a Production Tax Credit, both of which can be used to offset the costs of investing in and operating the wind projects. OTP is proposing a test year adjustment for these tax credits which is included in Mr. Beithon's Direct Testimony.

Q. PLEASE SUMMARIZE THE TOTAL ADJUSTMENTS TO PLANT-IN-SERVICE RELATED TO NEW PROJECT ADDITIONS.

A. The total adjustments to gross plant related to new projects being added in the Test Year is $193,169,252. The South Dakota share of this amount is $17,891,537. The total of all adjustments to accumulated depreciation related to new projects is $8,969,874. The South Dakota share is $831,505. These adjustments result in a net increase to Total Company and South Dakota plant-in-service of $184,199,379 and $17,060,032, respectively (See Exhibit__(KAS-1, Schedule 6 for more detail related to the above totals). The total adjustment to the Operating Statement is found on Exhibit___(PJB-1), Schedule 8, Column G, Line 12, $828,740.

Q. ARE YOU PROPOSING ANY OTHER ADJUSTMENTS TO PLANT IN SERVICE BESIDES THOSE JUST DESCRIBED RELATED TO NEW ADDITIONS?

A. Yes. There is a change in the calculated energy and demand allocation factors as a result of the new load related to the addition of the Casselton Ethanol Plant in North Dakota. The factors are adjusted to accurately reflect the jurisdictional sales that are generated, including the new load, in relation to the total sales of the system. Therefore, the new load increases the North Dakota amount of generated sales, which decreases the South Dakota allocation percentage, which decreases the net plant allocated to South Dakota by approximately $2,054,000. (See my Exhibit__(KAS-1), Schedule 4, Column G).

Q. THE OTHER MAJOR COMPONENT TO NET PLANT IN SERVICE IS ACCUMULATED DEPRECIATION. ARE YOU PROPOSING ANY CHANGES IN HOW ACCUMULATED DEPRECIATION IS DETERMINED?

A. Yes. OTP is proposing two changes related to accumulated depreciation in addition to those related to matching new plant in service discussed above. These additional changes are fully discussed in the testimony of Ms. Bernadeen Brutlag.

Q. HAVE YOU MADE ANY OTHER ADJUSTMENTS TO PLANT OR ACCUMULATED DEPRECIATION BALANCES?

A. Yes. An adjustment has been made for the capitalization of the allowance for funds used during construction (AFUDC) on short-term CWIP.

Q. COULD YOU PLEASE EXPLAIN THIS ADJUSTMENT?

A. Yes. The capitalization of AFUDC on short-term CWIP is the result of previous South Dakota Commission orders which were upheld in the South Dakota Supreme Court. We do not record AFUDC on short-term CWIP for book purposes because both the Minnesota and North Dakota Commissions allow short-term CWIP in rate base. Because this Commission has disallowed short-term CWIP in rate base, we must record AFUDC on this CWIP for South Dakota rate case purposes. Effective January 1, 1976, we have added to rate base AFUDC attributable to short-term CWIP. As an addition to rate base, the adjustment for AFUDC becomes depreciable which results in a corresponding adjustment to accumulated depreciation and depreciation expense. (See work paper series SD-3 located in Volume 4A, Tab - State Adjustments, for detailed calculations of the following adjustments.) The total adjustment to increase plant for AFUDC on short-term CWIP is $15,196,713. The South Dakota share is approximately $1,430,000. The adjustment to increase accumulated depreciation is $8,033,774 with the South Dakota share totaling approximately $704,000. The adjustment to increase total depreciation expense is $560,518. The South Dakota share is approximately $51,000.

Q. PLEASE SUMMARIZE THE PROPOSED ADJUSTMENTS RELATED TO PLANT IN SERVICE DESCRIBED ABOVE.

A. The South Dakota share of the proposed adjustments I have described as well as the adjustments related to accumulated depreciation described in Ms. Brutlag's testimony are an increase to plant in service of approximately $15,833,000, (See my Exhibit__(KAS-1), Schedule 4) and an increase in accumulated depreciation of approximately $5,977,000 (See my Exhibit__(KAS-1), Schedule 4). As I mentioned previously, the adjustments were made to normalize the Test Year for projects that will be in service on or before December 31, 2009, and to recognize the shift in energy and demand allocation factors related to the new load coming on line in 2008.

B. CONSTRUCTION WORK IN PROGRESS

Q. PLEASE EXPLAIN THE ITEM CALLED CONSTRUCTION WORK IN PROGRESS.

A. Construction Work in Progress ("CWIP") consists of two parts: short-term and other construction activities. Short-term CWIP applies to small rebuilds, heavying up of lines and similar types of activity which benefits existing customers. These are construction projects which cost less than $10,000 and require less than 30 days to complete. AFUDC is not added to the short-term CWIP. The Commission has ruled in our preceding cases that short-term and long-term CWIP should not be included in rate base as these are amounts that have yet to be placed in service and are not used and useful.

C. CASH WORKING CAPITAL ITEMS

Q. PLEASE EXPLAIN WHAT YOU HAVE INCLUDED WITH REGARD TO WORKING CAPITAL?

A. The working capital items of materials and supplies, fuel stocks, and prepayments are included and discussed below.

Q. WHAT METHOD DOES OTP USE IN DEVELOPING THE AMOUNTS USED IN WORKING CAPITAL FOR THE 2007 TEST YEAR?

A. The dollar amount used to calculate revenue requirements for the working capital items listed above is based on a simple average as recommended by Commission Staff in OTP's most recent South Dakota rate case, Docket No. F-3691. The simple average is the average of the beginning and ending balances from December 31, 2006 and December 31, 2007, respectively.

Q. PLEASE DISCUSS WORKING CAPITAL BEGINNING WITH MATERIALS AND SUPPLIES ON LINE 16, PAGE 1 OF SCHEDULE F-1.

A. Required Schedule F-1 summarizes the materials and supplies inventory by month and shows the calculation of the total utility amount used in rate base for the 2007 Actual Year. The accounting records provide the materials and supplies inventory at the generating plants, central stores, and at various locations throughout OTP's service territory. There is an adjustment to materials and supplies in the Test Year to reflect the change in energy and demand allocation percentages related to the new ethanol plant load previously discussed. The South Dakota portion of this adjustment is approximately ($21,400).

Q. PLEASE EXPLAIN FUEL STOCKS, LINE 16, PAGE 1 OF SCHEDULE F-1?

A. Required Schedule F-1 presents the simple average inventory balances for fuel stocks. Fuel stocks include coal stockpiles and fuel oil for the peaking plants. This schedule shows the calculation of the amount for the total utility for the 2007 Actual Year. As with materials and supplies, there is an adjustment to fuel stocks in the Test Year related to the change in energy and demand allocation percentages. The South Dakota share of this adjustment is approximately ($30,200).

Q. WOULD YOU PLEASE DESCRIBE THE PREPAYMENTS SHOWN ON LINE 17, PAGE 2 OF SCHEDULE F-1?

A. Required Schedule F-1, page 2, line 17 represents Prepayments that are included in rate base. Schedule F-1 shows the calculation of Prepayments for the total utility for both 2007 Actual and 2007 Test Years. The content of this line item has changed since the last rate case. In that case, Prepayments included only prepaid insurance expense. In this current case, three separate items are grouped together under the line item of Prepayments. The three items are 1) prepaid insurance, 2) post-retirement benefits liability, and 3) post-employment benefits liability.

Q. PLEASE EXPLAIN THE TWO NEW ITEMS, BEGINNING WITH POST-RETIREMENT BENEFITS LIABILITY.

A. In December 1990, the Financial Accounting Standards Board (FASB) issued statement no. 106, Employers' Accounting for Post-retirement Benefits Other Than Pensions, effective for fiscal years beginning after December 15, 1992. Prior to this pronouncement, these benefits had been accounted for as actual costs were incurred (sometimes referred to as pay as you go). Financial Accounting Standard (FAS) No. 106 changed to an accrual method, which recognized future liability in current expense. Because future liability is now recognized along with current cash costs, the annual expense is larger. OTP adopted accrual accounting for post-retirement benefits in 1993. Since the amount collected in rates is currently larger than OTP pays out in cash benefits each year we have reduced rate base by the cumulative difference between the accrual amount collected in rates and the cash amount actually paid out. This rate base reduction recognizes the availability of customers' cash and essentially pays customers our authorized rate of return for the benefit of having the use of that cash the same as we pay our shareholders for their investments. Additional discussion of post-retirement benefits expense appears in the testimony of Mr. Beithon.

Q. IS THE ITEM OF POST-EMPLOYMENT BENEFIT LIABILITY SIMILAR?

A. Yes. The accounting change occurred in 1994 under FAS no. 112, Employers' Accounting for Post-Employment Benefits, issued in 1992, effective for fiscal years beginning after December 15, 1993. While FAS no. 106 applied to post-*retirement* benefits, FAS no. 112 is concerned with post-*employment* benefits. OTP's practice is to adopt changes in Generally Accepted Accounting Principles (GAAP) as they occur and implement each as they pertain to a regulated utility. In this case, FAS no. 112 is a similar accounting change to FAS no. 106 and OTP accounts for it in a similar manner. That is, rate base is reduced for the amount of the cumulative liability, which represents cash collected in rates but not yet paid out in cash expenses.

Q. ARE THERE KNOWN AND MEASURABLE RATE BASE ADJUSTMENTS FOR THE ABOVE THREE ITEMS IN THE 2007 TEST YEAR?

A. Yes. There are three adjustments to prepayments in the Test Year. There is an adjustment to FAS 106, Post-retirement Benefits, which Mr. Beithon addresses in his testimony (see my Exhibit__(KAS-1), Schedule 4, Column C). There also is a similar adjustment to the one affecting materials and supplies and fuel stocks related to the change in energy and demand allocation percentages associated with a new Large Customer. The South Dakota share of this adjustment is approximately $6,200 (see my Exhibit__(KAS-1), Schedule 4, Column G). Finally, there is an adjustment to eliminate the Actual Year South Dakota FAS 106, Pay-As-You-Go adjustment. This adjustment was originally designed to put South Dakota back on a pay-as-you-go basis because South Dakota had not allowed accrual accounting for post-retirement medical benefits per Docket No. EL92-016, dated January 26, 1993. The South Dakota portion of this adjustment is a reduction to rate base of approximately $3,080,000 (see my Exhibit__(KAS-1), Schedule 4, Column H). The total amount of Test Year adjustments to prepayments in South Dakota, including the piece related to FAS 106 described by Mr. Beithon, is a reduction of approximately $2,684,000.

Q. PLEASE FINISH YOUR DISCUSSION OF THE WORKING CAPITAL PORTION OF RATE BASE BY DISCUSSING STATEMENT F, LINE 42, CASH WORKING CAPITAL.

A. This item represents a determination of cash working capital requirements for operation, maintenance, and other expenses and is supported by Exhibit__(KAS-1), Schedule 3.

Q. HOW WERE SUCH CASH WORKING CAPITAL REQUIREMENTS DETERMINED?

A. A lead-lag study was performed by OTP based on calendar 2005 financial data. The results of that study are summarized on Exhibit__(KAS-1) Schedule 3, pages 1 – 3. This study analyzes the lapse of time between the average day on which the Company incurs expenses to serve its customers and the average day on which cash is received from customers in payment of that service. As reflected on

Schedule 3, page 1 of 3, on average, OTP does not receive cash from its customers until 38.1 days after service has been rendered. The 38.1 days is comprised of a 15.2 day metering period lag, a 3.5 day bill processing lag, and a 19.4 day collection period lag, which was based on the total annual billings to customers divided by the average daily utility receivable balances.

Q. PLEASE EXPLAIN OTHER COMPONENTS OF THE LEAD-LAG STUDY?

A. Page 1 of Schedule 3 calculates the revenue lead days for total utility and South Dakota. Pages 2 and 3 calculate and compare the lag or in some cases lead days, associated with certain payments to suppliers and employees. The net lead or lag period (revenue lag minus expense lead) for various items is shown in Column (F), Net Revenue Lag Dollars.

Q. WOULD YOU PLEASE EXPLAIN HOW SCHEDULE 3 DETERMINES THE CASH WORKING CAPITAL REQUIREMENT?

A. Column (A) on page 2 of Schedule 3 presents the expenses incurred during the 2007 Actual Year for OTP's South Dakota electric jurisdiction. Column (B) is a determination of the daily expenses, i.e., the total annual expenses divided by 365 days. Column (C) presents the expense lag days as determined by the lead-lag study. Column (D) then subtracts the expense lag days from the revenue lead days to develop the net revenue lag dollars (the total cash requirement) in Column (E). Page 3 of Schedule 3 presents the same information for the 2007 Test Year.

Q. IS THERE A TEST YEAR ADJUSTMENT FOR CASH WORKING CAPITAL?

A. Yes. Cash working capital is embedded in the class cost of service model. Any change to components of revenue requirements in the model changes the cash working capital amount. The adjustment for the 2007 Test Year reduces cash working capital by $658,583 (See my Exhibit (KAS-1), Schedule 1, Line 10) and represents the cumulative affect of all of the adjustments made to the 2007 Actual Year to arrive at the 2007 Test Year.

Q. WHY DOES THE CASH WORKING CAPITAL BALANCE GO DOWN IN THE TEST YEAR FROM THE ACTUAL 2007 YEAR?

A. Two of the biggest drivers of the timing of cash working capital are energy costs and property taxes. The actual 2007 cash working capital amount recognized the lag in collecting changes in cost of energy through the fuel clause adjustment. The test year, however, assumes that the current base cost of energy is now in base rates and the lag at that point in time has been reduced. The other item affecting cash working capital, property taxes, reduces cash needs. This occurs because under accrual accounting property taxes are recognized as an expense and collected in rates during the year when the assessment is determined, more than 12 months before the cash payment is due. Test year property taxes are $895,907 and lead days are 316.8. Net lead days for property taxes are 279.3. (Line 6, Columns (A), (C) and (D) on page 3 of Schedule 3.)

Q. IS THE CASH WORKING CAPITAL DETERMINATION METHODOLOGY CONSISTENT WITH OTP’S LAST ELECTRIC RATE PROCEEDINGS BEFORE THE COMMISSION?

A. Yes, the result in OTP's last rate case was based on a similar method to determine cash working capital.

D. ACCUMULATED DEFERRED INCOME TAXES

Q. PLEASE DESCRIBE ACCUMULATED DEFERRED INCOME TAXES ("ADIT").

A. Accumulated deferred income taxes are created by inter-period differences between the book and taxable income treatment of certain accounting transactions. These differences typically originate in one period and reverse in one or more subsequent periods. For utilities, the largest such timing difference is the extent to which accelerated tax depreciation generally exceeds straight-line book depreciation during the early years of an asset's service life. ADIT represents the cumulative net deferred tax amounts.

Q. WHY ARE ACCUMULATED DEFERRED INCOME TAXES DEDUCTED IN ARRIVING AT TOTAL RATE BASE?

A. To the extent deferred income taxes have been allowed for recovery in rates, they represent a non-investor source of funds. Accordingly, the average projected ADIT balance is deducted in arriving at total rate base to recognize such funds are available for the utility's use between the time they are collected in rates and ultimately remitted to the respective taxing authorities.

Q. WHAT AMOUNT OF ADIT WAS DEDUCTED IN THE TEST YEAR RATE BASE?

A. As shown on Exhibit (KAS-1), Schedule 1,, line 11, $6,403,518 was deducted. This amount reflects a simple average of the beginning and ending test year ADIT balances as well as an adjustment in the Test Year to reflect the impacts of the changes in energy and demand allocation percentages. The South Dakota portion of this impact is approximately $235,000 (see my Exhibit__(KAS-1), Schedule 4, Column G).

III. CONCLUSION

Q. WHAT IS THE AVERAGE ORIGINAL COST RATE BASE FOR THE SOUTH DAKOTA JURISDICTION AS DEVELOPED ON SCHEDULE 1?

A. The average original cost rate base for the South Dakota jurisdiction for the 2007 Test Year is $60,230,800.

Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes, it does.

Otter Tail Corporation d/b/a OTTER TAIL POWER COMPANY
Electric Utility - State of South Dakota
RATE BASE SCHEDULES
RATE BASE SUMMARY

Docket No. EL08-____
Exhibit ___ (KAS-1)
Financial Information
Schedule 1

		South Dakota Jurisdiction		
		(A)	(B)	(C)
				(C) = (B) - (A)
Line No.	Description	2007 Actual Year	2007 Test Year	$ Change
1	Electric Plant in Service	$95,511,702	$111,344,915	$15,833,213
2	Less: Accumulated Depreciation	(38,097,142)	(44,074,088)	(5,976,946)
3	Net Electric Plant in Service	$57,414,560	$67,270,827	$9,856,267
	Other Rate Base Components:			
4	Plant Held for Future Use	$2,865	$2,845	($20)
5	Construction Work in Progress	0	0	0
6	Materials and Supplies	1,223,736	1,202,429	(21,307)
7	Fuel Stocks	786,577	756,356	(30,221)
8	Prepayments	(172,228)	(2,855,820)	(2,683,592)
9	Customer Advances	(13,895)	(12,093)	1,802
10	Cash Working Capital	928,358	269,775	(658,583)
11	Accumulated Deferred Income Taxes	(6,577,600)	(6,403,518)	174,082
12	Unamortized Balance - Rate Case Expense	0	0	0
13	Unamortized Balance - Spiritwood	0	0	0
14	TOTAL	$53,592,374	$60,230,800	$6,638,427

Note: The 2007 Actual Year is based on 2007 historic financial information. The 2007 Test Year is the 2007 Actual Year with known and measureable adjustments to arrive at the Test Year.

Otter Tail Corporation d/b/a OTTER TAIL POWER COMPANY | **Docket No. EL08-____**
Electric Utility - State of South Dakota | **Exhibit ___ (KAS-1)**
RATE BASE SCHEDULES | **Financial Information**
RATE BASE COMPONENTS | **Schedule 2**

		2007 Test Year					
		Total Utility			South Dakota Jurisdiction		
		(A)	(B)	(C)	(D)	(E)	(F) = (D) + (E)
Line No.	Description	2007 Actual Year	Adjustments	2007 Test Year	2007 Actual Year	Adjustments	2007 Test Year
	Utility Plant in Service:						
1	Production	$401,831,692	$177,932,453	$579,764,145	$38,732,905	$15,052,699	$53,785,604
2	Transmission	194,997,080	12,631,899	207,628,979	18,057,632	565,653	18,623,285
3	Distribution	321,276,855	666,561	321,943,416	31,604,543	167,709	31,772,252
4	General	72,566,818	1,550,233	74,117,051	6,708,612	19,123	6,727,735
5	Intangible	4,297,528	388,106	4,685,634	397,295	28,028	425,323
6	**TOTAL Utility Plant in Service**	$994,969,974	$193,169,252	$1,188,139,225	$95,500,987	$15,833,212	$111,334,199
	Accumulated Depreciation						
7	Production	($216,528,936)	($8,643,272)	($225,172,208)	($16,511,729)	($4,344,129)	($20,855,858)
8	Transmission	(77,693,468)	35,076	(77,658,392)	(6,088,130)	(877,441)	(6,965,571)
9	Distribution	(134,596,316)	93,682	(134,502,634)	(12,646,093)	(627,828)	(13,273,921)
10	General	(30,136,963)	164,320	(29,972,643)	(2,602,710)	(117,960)	(2,720,670)
11	Intangible	(2,687,811)	(155,242)	(2,843,053)	(248,481)	(9,588)	(258,069)
12	**TOTAL Accumulated Depreciation**	($461,643,494)	($8,505,436)	($470,148,930)	($38,097,144)	($5,976,946)	($44,074,089)
13	**NET Utility Plant in Service**						
14	Production	$185,302,756	$169,289,181	$354,591,937	$22,221,176	$10,708,570	$32,929,746
15	Transmission	117,303,612	12,666,975	129,970,587	11,969,502	(311,788)	11,657,714
16	Distribution	186,680,539	760,243	187,440,782	18,958,450	(460,119)	18,498,331
17	General	42,429,855	1,714,553	44,144,408	4,105,902	(98,837)	4,007,065
18	Intangible	1,609,717	232,864	1,842,581	148,814	18,440	167,254
19	**NET Utility Plant in Service**	$533,326,480	$184,663,816	$717,990,295	$57,403,844	$9,856,266	$67,260,110
20	Big Stone Plant capitalized items	$129,351	$0	$129,351	$10,715	$0	$10,715
21	Utility Plant Held for Future Use	29,656	0	29,656	2,865	(20)	2,845
22	Construction Work in Progress	26,037,862	(7,101,042)	18,936,820	0	0	0
23	Materials and Supplies	12,708,690	0	12,708,690	1,223,736	(21,307)	1,202,429
24	Fuel Stocks	8,133,109	0	8,133,109	786,577	(30,221)	756,356
25	Prepayments	(1,600,218)	(28,885,809)	(30,486,027)	(172,228)	(2,683,592)	(2,855,820)
26	Customer Advances	(129,099)	0	(129,099)	(13,895)	1,802	(12,093)
27	Cash Working Capital*	10,116,495	(19,518,606)	(9,402,111)	928,358	(658,583)	269,775
28	Accumulated Deferred Income Taxes	(79,499,502)	(7,243,451)	(86,742,953)	(6,577,600)	174,082	(6,403,518)
29	**Total Average Rate Base**	$509,252,823	$121,914,908	$631,167,732	$53,592,374	$6,638,427	$60,230,800

* Detailed on Schedule 3, pages 1-3

Otter Tail Corporation d/b/a OTTER TAIL POWER COMPANY
Electric Utility - State of South Dakota
RATE BASE SCHEDULES
CASH WORKING CAPITAL

Docket No. EL08-____
Exhibit ___ (KAS-1)
Financial Information
Schedule 3, page 1 of 3

LINE NO	ITEM	2007 ACTUAL YEAR TOTAL UTILITY	2007 ACTUAL YEAR SOUTH DAKOTA	2007 TEST YEAR TOTAL UTILITY	2007 TEST YEAR SOUTH DAKOTA
1	CASH WORKING CAPITAL CALCULATION - REVENUE LEAD DAYS				
2					
3	REVENUES				
4	COMPUTER MAINTAINED BILLINGS	$210,328,769	$19,494,546	$256,073,150	$23,392,377
5	MANUALLY MAINTAINED BILLINGS	18,869,929	1,748,979	22,973,948	2,098,679
6	COST OF ENERGY REVENUES	40,397,002	4,261,508	0	0
7	SALES FOR RESALE	20,308,582	1,951,409	20,954,774	1,938,593
8	RENT FROM ELECTRIC PROPERTY	644,002	69,312	644,002	60,328
9	OTHER MISC ELECTRIC REVENUE	2,719,318	292,674	3,170,821	297,031
10	ITA DEFICIENCY PAYMENTS	3,651,858	393,041	3,651,858	342,093
11	WHEELING	433,023	0	433,023	0
12	LOAD CONTROL AND DISPATCH	4,459,926	480,011	4,459,926	417,790
13	RENT FROM ELECTRIC PROPERTY - BIG STONE	(20,657)	(2,223)	(20,657)	(1,935)
14	RENT FROM ELECTRIC PROPERTY - COYOTE	11,846	1,275	11,846	1,110
15	PROFIT ON MATERIALS AND SUPPLIES	0	0	0	0
16	MISCELLANEOUS SERVICES	34,025	3,662	34,025	3,187
17	RESIDENTIAL CONSERVATION SERVICES	76,895	872	76,895	872
18					
19	**TOTAL REVENUES**	$301,914,516	$28,695,065	$312,463,609	$28,550,123
20					
21	REVENUE LEAD DAYS FROM SERVICE TO COLLECTION				
22	COMPUTER MAINTAINED BILLINGS	N/A	38.1	N/A	38.1
23	MANUALLY MAINTAINED BILLINGS	N/A	43.1	N/A	43.1
24	COST OF ENERGY REVENUES	N/A	112.4	N/A	112.4
25	SALES FOR RESALE	N/A	25.4	N/A	25.4
26	RENT FROM ELECTRIC PROPERTY	N/A	(86.4)	N/A	(86.4)
27	OTHER MISC ELECTRIC REVENUE	N/A	35.0	N/A	35.0
28	ITA DEFICIENCY PAYMENTS	N/A	53.2	N/A	53.2
29	WHEELING	N/A	37.8	N/A	37.8
30	LOAD CONTROL AND DISPATCH	N/A	33.6	N/A	33.6
31	RENT FROM ELECTRIC PROPERTY - BIG STONE	N/A	48.4	N/A	37.5
32	RENT FROM ELECTRIC PROPERTY - COYOTE	N/A	48.4	N/A	37.5
33	PROFIT ON MATERIALS AND SUPPLIES	N/A	48.4	N/A	37.5
34	MISCELLANEOUS SERVICES	N/A	48.4	N/A	37.5
35	RESIDENTIAL CONSERVATION SERVICES	N/A	48.4	N/A	37.5
36					
37	REVENUE DOLLAR DAYS (REVENUES X REVENUE LEAD DAYS)				
38	COMPUTER MAINTAINED BILLINGS	$8,013,526,084	$742,742,185	$9,756,387,008	$891,249,574
39	MANUALLY MAINTAINED BILLINGS	813,293,929	75,381,013	990,177,138	90,453,049
40	COST OF ENERGY REVENUES	4,522,367,678	478,993,458	0	0
41	SALES FOR RESALE	515,837,988	49,565,782	532,251,260	49,240,257
42	RENT FROM ELECTRIC PROPERTY	(55,641,744)	(5,988,586)	(55,641,744)	(5,212,315)
43	OTHER MISC ELECTRIC REVENUE	95,176,121	10,243,575	110,978,726	10,396,082
44	ITA DEFICIENCY PAYMENTS	194,278,846	20,909,762	194,278,846	18,199,333
45	WHEELING	16,368,267	0	16,368,267	0
46	LOAD CONTROL AND DISPATCH	149,853,514	16,128,371	149,853,514	14,037,730
47	RENT FROM ELECTRIC PROPERTY - BIG STONE	(976,201)	(107,551)	(406,183)	(72,517)
48	RENT FROM ELECTRIC PROPERTY - COYOTE	559,807	61,675	232,928	41,585
49	PROFIT ON MATERIALS AND SUPPLIES	0	0	0	0
50	MISCELLANEOUS SERVICES	1,607,965	177,154	669,051	119,448
51	RESIDENTIAL CONSERVATION SERVICES	3,495,987	42,177	459,768	32,674
52					
53	**TOTAL DOLLAR DAYS**	$14,269,748,241	$1,388,149,015	$11,695,608,576	$1,068,484,899
54					
55	**AVG REVENUE LEAD DAYS (TOTAL REV DOLLAR DAYS / TOTAL REV)**	47.3	**48.4**	37.4	**37.5**
56					
57	**Calculation of Days from Service to Collection**				
58	Service Period to Date Meter is Read	(365 / 12 / 2)	15.2		
59	Read Date to Date Billing is Prepared		3.5		
60	Billing Date to Date collection is Received		19.4		
61	Total		38.1		

Calculation applying lead-lag factors

		2007 ACTUAL YEAR					
		SOUTH DAKOTA JURISDICTION					TOTAL UTILITY
		(A)	(B)	(C)	(D)	(E)	(F)
LINE NO	ITEM	Operating Expense	Expense/day at 365 day/year	Expense Lag Days	Lead Days of 48.4 Over Expense Lag Days	Net Revenue Lag Dollars	Net Revenue Lag Dollars
1	FUEL - COAL	5,149,528	$14,108	16.0	32.4	$456,768	4,543,170
2	FUEL - OIL	717,769	1,966	8.9	39.5	77,629	769,879
3	PURCHASED POWER	7,403,538	20,284	32.8	15.6	315,936	3,013,832
4	LABOR AND ASSOC PAYROLL EXPENSE	5,498,702	15,065	13.9	34.5	519,377	5,476,795
5	ALL OTHER O&M EXPENSE	3,382,994	9,268	19.4	29.0	268,562	2,850,958
6	PROPERTY TAX (EXCL COAL CONV TAX)	931,813	2,553	318.6	(270.2)	(689,845)	(6,436,067)
7	COAL CONVERSION TAXES	81,135	222	318.6	(270.2)	(60,067)	(560,404)
8	FEDERAL INCOME TAXES	471,106	1,291	43.9	4.5	5,777	62,674
9	STATE INCOME TAXES	0	0	0.0	48.4	0	(3,192)
10	INCREMENTAL FEDERAL INCOME TAXES	0	0	43.9	4.5	0	0
11	INCREMENTAL STATE INCOME TAXES	0	0	0.0	48.4	0	0
12	BANK BALANCES		0			1,012	9,400
13	SPECIAL DEPOSITS		0			84,927	789,085
14	WORKING FUNDS		0			2,441	22,679
15	TAX COLLECTIONS AVAILABLE					0	
16	FICA WITHHOLDING	(365,936)	(1,003)	0.0		0	0
17	FEDERAL WITHHOLDING	(624,154)	(1,710)	0.0		0	0
18	STATE WITHHOLDING- MN	0	0	1.9		0	(8,512)
19	STATE WITHHOLDING- ND	0	0	61.1		0	(42,939)
20	STATE SALES TAX	(1,212,766)	(3,323)	16.3		(54,159)	(301,193)
21	FRANCHISE TAXES	0	0	0.0		0	(69,670)
22							
23	**TOTAL CASH WORKING CAPITAL REQUIREMENT**					**928,358**	$10,116,495

Otter Tail Corporation d/b/a OTTER TAIL POWER COMPANY **Docket No. EL08-____**
Electric Utility - State of South Dakota **Exhibit ___ (KAS-1)**
RATE BASE SCHEDULES **Financial Information**
CASH WORKING CAPITAL **Schedule 3, page 3 of 3**
Calculation applying lead-lag factors

		2007 TEST YEAR					
		SOUTH DAKOTA JURISDICTION					TOTAL UTILITY
		(A)	(B)	(C)	(D)	(E)	(F)
LINE NO	ITEM	Operating Expense	Expense/day at 365 day/year	Expense Lag Days	Lead Days of 37.5 Over Expense Lag Days	Net Revenue Lag Dollars	Net Revenue Lag Dollars
1	FUEL - COAL	$4,965,336	$13,604	16.0	21.5	$292,149	491,025
2	FUEL - OIL	688,871	1,887	8.9	28.6	53,932	201,765
3	PURCHASED POWER	7,112,756	19,487	32.8	4.7	91,117	(2,804,668)
4	LABOR AND ASSOC PAYROLL EXPENSE	5,407,953	14,816	13.9	23.6	349,306	852,406
5	ALL OTHER O&M EXPENSE	4,184,703	11,465	19.4	18.1	207,238	(6,821)
6	PROPERTY TAX (EXCL COAL CONV TAX)	895,907	2,455	316.8	(279.3)	(685,668)	(7,786,270)
7	COAL CONVERSION TAXES	78,009	214	316.8	(279.3)	(59,703)	(677,969)
8	FEDERAL INCOME TAXES	77,225	212	43.9	(6.4)	(1,359)	(51,614)
9	STATE INCOME TAXES	0	0	73.0	(35.5)	0	(18,814)
10	INCREMENTAL FEDERAL INCOME TAXES	0	0	43.9	(6.4)	0	0
11	INCREMENTAL STATE INCOME TAXES	0	0	73.0	(35.5)	0	0
12	BANK BALANCES		0			881	9,400
13	SPECIAL DEPOSITS		0			73,919	789,085
14	WORKING FUNDS		0			2,124	22,679
15	TAX COLLECTIONS AVAILABLE						
16	FICA WITHHOLDING	(359,897)	(986)	0.0		0	0
17	FEDERAL WITHHOLDING	(613,854)	(1,682)	0.0		0	0
18	STATE WITHHOLDING- MN	0	0	1.9		0	(8,512)
19	STATE WITHHOLDING- ND	0	0	61.1		0	(42,939)
20	STATE SALES TAX	(1,212,766)	(3,323)	16.3		(54,159)	(301,193)
21	FRANCHISE TAXES	0	0	0.0		0	(69,670)
22							
23	**TOTAL CASH WORKING CAPITAL REQUIREMENT**					**269,775**	**($9,402,111)**

Otter Tail Corporation d/b/a OTTER TAIL POWER COMPANY
Electric Utility - State of South Dakota
RATE BASE SCHEDULES
RATE BASE ADJUSTMENTS
2007 Actual Year versus 2007 Test Year

Docket No. EL08-____
Exhibit ___ (KAS-1)
Financial Information
Schedule 4

Line No.	Description	(A) 2007 Actual Year	(B) Annualize Plant in Service	(C) Prepayments	(D) Depreciation Direct Assignment to Allocated	(E) Depreciation to Reflect 2008 Rates	(F) Depreciation to Reflect 2009 Rates	(G) Factor Change for New Large Customer	(H) Eliminate Actual Year FAS 106 PayGo Adjustment	(I) Changes in Allocations due to Effect of Test Year Adjustments	(J) Income Statement Adjustments Affecting CWC	(K) 2007 Test Year
	Utility Plant in Service:											
1	Production	$38,732,905	$16,515,627					($1,462,927)		($1)		$53,785,604
2	Transmission	18,057,632	1,133,018					(567,366)		1		18,623,285
3	Distribution	31,604,543	66,912					100,798		(1)		31,772,252
4	General	6,708,612	140,751					(122,260)		632		6,727,735
5	Intangible	397,295	35,229					(7,240)		39		425,323
6	**TOTAL Utility Plant in Service**	$95,500,987	$17,891,537	$0	$0	$0	$0	($2,058,995)		$670	$0	$111,334,200
	Accumulated Depreciation											
7	Production	($16,511,729)	($781,842)		($3,541,857)	($12,493)	($7,937)					($20,855,858)
8	Transmission	(6,088,130)	(25,088)		(880,587)	4,635	23,599					(6,965,571)
9	Distribution	(12,646,093)	(4,297)		(637,074)	3,839	9,704					(13,273,921)
10	General	(2,602,710)	(6,187)		(132,876)	532	20,570			1		(2,720,670)
11	Intangible	(248,481)	(14,092)					4,528		(24)		(258,069)
12	**TOTAL Accumulated Depreciation**	($38,097,144)	($831,506)	$0	($5,192,394)	($3,487)	$45,936	$4,528		($23)	$0	($44,074,088)
13	**NET Utility Plant in Service**											
14	Production	$22,221,176	$15,733,785	$0	($3,541,857)	($12,493)	($7,937)	($1,462,927)		($1)	$0	$32,929,746
15	Transmission	11,969,502	1,107,930	0	(880,587)	4,635	23,599	(567,366)		1	0	11,657,714
16	Distribution	18,958,450	62,615	0	(637,074)	3,839	9,704	100,798		(1)	0	18,498,331
17	General	4,105,902	134,564	0	(132,876)	532	20,570	(122,260)		633	0	4,007,065
18	Intangible	148,814	21,137	0	0	0	0	(2,712)		15	0	167,254
19	**NET Utility Plant in Service**	$57,403,844	$17,060,031	$0	($5,192,394)	($3,487)	$45,936	($2,054,467)		$647	$0	$67,260,111
20	Big Stone Plant capitalized items	$10,715										10,715
21	Utility Plant Held for Future Use	2,865						(20)				2,845
22	Construction Work in Progress	0						0				0
23	Materials and Supplies	1,223,736						(21,406)		99		1,202,429
24	Fuel Stocks	786,577						(30,221)				756,356
25	Prepayments	(172,228)		373,928				6,163	(3,079,845)	16,162		(2,855,820)
26	Customer Advances	(13,895)						498		1,304		(12,093)
27	Cash Working Capital	928,358						(9,498)			(649,085)	269,775
28	Accumulated Deferred Income Taxes	(6,577,600)	(678,540)					235,366		617,256		(6,403,518)
29	**Total Average Rate Base**	$53,592,374	$16,381,491	$373,928	($5,192,394)	($3,487)	$45,936	($1,873,585)		$635,468	($649,085)	$60,230,800

Column references to adjustment workpapers:
(B) W/P 2007 ND TY-01
(C) W/P 2007 ND TY-02
(D) W/P 2007 ND TY-03
(E) W/P 2007 ND TY-07
(F) W/P 2007 ND TY-08

Otter Tail Corporation d/b/a OTTER TAIL POWER COMPANY
Electric Utility - State of South Dakota
COMPARISON OF RATE BASE COMPONENTS
MOST RECENT RATE CASE WITH CURRENT PROPOSED TEST YEAR

Docket No. EL08-____
Exhibit ___ (KAS-1)
Financial Information
Schedule 5

Line No.	Description	(A) Per Order in Docket No. F-3691	(B) 2007 Test Year	(C) (C) = (B) - (A) $ Change
1	Electric Plant in Service	$47,016,635	$111,344,915	$64,328,280
2	Less: Accumulated Depreciation	(13,073,834)	(44,074,088)	(31,000,254)
3	Net Electric Plant in Service	$33,942,801	$67,270,827	$33,328,026
	Other Rate Base Components:			
4	Plant Held for Future Use	$340,552	$2,845	($337,707)
5	Construction Work in Progress	0	0	0
6	Materials and Supplies	542,166	1,202,429	660,263
7	Fuel Stocks	308,410	756,356	447,946
8	Prepayments	19,565	(2,855,820)	(2,875,385)
9	Customer Advances	(1,821)	(12,093)	(10,272)
10	Cash Working Capital	(434,946)	269,775	704,721
11	Accumulated Deferred Income Taxes	(4,408,004)	(6,403,518)	(1,995,514)
12	Unamortized Balance - Rate Case Expense	40,000	0	(40,000)
13	Unamortized Balance - Spiritwood	100,764	0	(100,764)
14	TOTAL	$30,449,487	$60,230,800	$29,781,314

Otter Tail Corporation d/b/a OTTER TAIL POWER COMPANY
Electric Utility - State of South Dakota
Test Year Plant-in-Service Adjustments for Additions by Project
Total Company and South Dakota Jurisdiction

Docket No. EL08-____
Exhibit ___ (KAS-1)
Financial Information
Schedule 6

	(A)	(B)	(C)	(D)	(E)	(F)	(G)
		Total Company			South Dakota		
Line No.	Project Description	Gross Plant	Accumulated Depreciation	Net Plant	Gross Plant	Accumulated Depreciation	Net Plant
	Projects Placed-in-Service During 2007						
1	Load Management Replacement	$666,561	($43,539)	$623,022	$66,912	($4,297)	$62,615
2	Power Network Analysis Applications Software	388,106	(155,242)	232,864	35,229	(14,092)	21,137
3	Brine Concentrator at Big Stone Plant	378,588	(25,777)	352,811	35,140	(2,393)	32,748
4	VIC Site Work at Hoot Lake Plant	400,911	(24,271)	376,640	37,212	(2,253)	34,960
5	Condenser Retube at Big Stone Plant	939,924	(63,996)	875,928	87,243	(5,940)	81,303
6	AHPC Replacement at Big Stone Plant	4,215,731	(196,349)	4,019,382	391,303	(18,225)	373,078
7	Generator Rewind at Big Stone Plant	2,329,712	(158,621)	2,171,091	216,243	(14,723)	201,520
8	Additional LWEC Investment	32,500,000	(2,600,000)	29,900,000	3,016,638	(241,331)	2,775,307
9	**Total Adjustments for Projects Placed-in-Service During 2007**	$41,819,534	($3,267,795)	$38,551,738	$3,885,921	($303,254)	$3,582,667
	Projects Started in 2007 and Placed-in-Service During 2008-2009						
10	Hi-Tech Addition	$1,550,233	($68,156)	$1,482,077	$140,751	($6,187)	$134,564
11	Burner #2 Upgrade at Hoot Lake Plant	2,438,723	(87,477)	2,351,246	226,361	(8,120)	218,242
12	Replacement of Superheater Tubes on Unit #2 at Hoot Lake	1,450,479	(52,029)	1,398,450	134,633	(4,829)	129,804
13	Generator Step-Up at Coyote Plant	2,609,041	(47,401)	2,561,640	242,170	(4,400)	237,771
14	Langdon Wind Energy Center	12,826,262	(513,589)	12,312,673	1,190,529	(47,671)	1,142,858
15	Hensel Substation	2,390,381	(51,831)	2,338,550	214,405	(4,649)	209,756
16	Appleton/Canby Transmission Line	3,040,218	(53,950)	2,986,268	272,692	(4,839)	267,853
17	**Total Adjustments for Projects Started in 2007 and Placed-in-Service During 2008-2009**	$26,305,337	($874,433)	$25,430,904	$2,421,543	($80,695)	$2,340,848
	Projects Started and Placed-in-Service During 2008-2009						
18	Replacement of Superheater Tubes on Unit #3 at Hoot Lake	$1,500,000	$0	$1,500,000	$139,229	$0	$139,229
19	Ashtabula Wind Center	116,343,081	(4,653,723)	111,689,358	10,798,923	(431,957)	10,366,966
20	Casselton Ethanol Plant	7,201,300	(173,921)	7,027,379	645,921	(15,600)	630,321
21	**Total Adjustments for Projects Started and Placed-in-Service During 2008-2009**	$125,044,381	($4,827,644)	$120,216,737	$11,584,073	($447,557)	$11,136,517
22	**Total Plant-in-Service Adjustments for 2007 Test Year**	$193,169,252	($8,969,874)	$184,199,379	$17,891,537	($831,505)	$17,060,032

Note: The Schedule above is a summary of the adjustments calculated within Work Paper TY-01 found in Volume 4A, Tab - 2007 Test Year Work Papers.