Direct Testimony and Schedule
Pamela K. Graika

Before the North Dakota Public Service Commission
State of North Dakota

In the Matter of the Application of Northern States Power Company,
a Minnesota corporation
for Authority to Increase Rates for Electric Service in North Dakota

Docket No. PU-10-___
Exhibit___(PKG-1)

Supply Operations

December 20, 2010

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Schedules

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND OCCUPATION.

A. My name is Pamela K. Graika. I am the General Manager of Power Generation for Xcel Energy Services Inc. ("XES").

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE.

A. I have a Bachelor's Degree in Chemical Engineering and have worked for Xcel Energy in various management positions since 1979. Prior positions I have held within the Company include Production Engineer, Plant Manager, and Director of Environmental and Regulatory Affairs. My resume is attached as Exhibit___(PKG-1), Schedule 1.

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

A. I am testifying on behalf of Northern States Power Company, a Minnesota corporation ("Xcel Energy," the "Company," or "NSPM"). I present Xcel Energy's 2011 Operating and Maintenance ("O&M") and capital budgets for the Energy Supply organization and demonstrate that these costs are reasonable to recover from ratepayers.

Q. HOW HAVE YOU ORGANIZED YOUR TESTIMONY?

A. First, I address Energy Supply's O&M costs. I present information in the following sections:

- *Overview*, including a summary of the Energy Supply organization and costs included in the 2011 budget;

- *Changes in the NSPM Generating System*, discussing system impacts and resulting costs related to our Metro Emissions Reduction Project, the Sherburne County Power Plant, and various wind projects; and
- *Cost Deviations*, presenting details related to major cost changes from 2008 O&M spending to our 2011 O&M budget, and then provide details on five components of the 2011 O&M Budget.

Second, I address Energy Supply's capital costs, including discussion of:

- *Capital Investments for 2011*; and
- *Capital Costs of Nobles and Merricourt Wind Projects.*

II. ENERGY SUPPLY O&M COSTS

A. Overview

Q. PLEASE DESCRIBE THE ENERGY SUPPLY ORGANIZATION'S ROLES AND RESPONSIBILITIES.

A. Energy Supply's principal role is to operate and maintain NSPM electric generating facilities in a safe, reliable, cost-effective, and environmentally sound manner. We are also responsible for managing major construction projects, dispatching electric generation resources, overseeing environmental compliance, and the coordination of generating unit dispatch with the Midwest Independent System Operator ("MISO").

Q. PLEASE DESCRIBE THE TYPES OF COSTS YOUR ORGANIZATION MANAGES.

A. Energy Supply manages all O&M, fuel, fuel-handling, and capital costs associated with the operation, maintenance, and improvement of our generating facilities. These costs range from daily operating and maintenance expenses to multi-year, multi-million-dollar capital projects. Key cost categories include labor, materials, chemicals, external contractors, suppliers and vendors.

Q. PLEASE PROVIDE AN OVERVIEW OF YOUR 2011 ENERGY SUPPLY O&M BUDGET.

A. Our total company 2011 Energy Supply O&M budget is $167 million. This amount reflects a downward adjustment related to mercury sorbent at Sherburne County Power Plant ("Sherco") based upon recent performance data. Company witness Mr. John M. Felling incorporates this adjustment into the Company's overall revenue requirement as a part of his Direct Testimony. With this adjustment, our 2011 O&M budget represents an approximate $7.5 million, or 4.7 percent increase over our forecast O&M spending for 2010.

Q. WHAT ARE THE MAIN CAUSES FOR THE INCREASE IN O&M EXPENSE FROM 2010 TO 2011?

A. Overall, we are seeing a steady increase in O&M costs primarily due to:

- the installation of new wind resources on our system;
- the increased maintenance and project costs of combined cycle natural gas facilities at our High Bridge, Riverside and Black Dog generating facilities; and
- environmental improvements at our plants.

B. Changes in the NSPM Generating System

1. Metro Emissions Reduction Project ("MERP")

a. Background Regarding MERP in Last Rate Case

Q. WERE THE MERP PROJECTS ADDRESSED IN THE COMPANY'S LAST ELECTRIC RATE CASE?

A. Yes, as noted by Company witness Ms. Laura McCarten, the Company's MERP initiative was discussed in detail as a part of the Company's last electric rate case and was addressed as a part of the settlement agreement approved in that proceeding ("2008 Rate Case Settlement"). As a part of the 2008 Rate Case Settlement, contested issues related to the rehabilitation of the Allen S. King Plant ("King") and the High Bridge projects were resolved. As a result, costs related to King were authorized for recovery; the Commission also approved 8 months of recovery of our High Bridge project. As noted by Ms. McCarten, in this application we request to pick up the remaining four months to annualize the investment in rates.

Q. WHAT BENEFITS OF MERP WERE ADDRESSED BY THE COMPANY IN THE LAST ELECTRIC RATE CASE?

A. As a part of her Rebuttal Testimony in our last electric rate case, Company witness Ms. Elizabeth M. Engelking provided a comprehensive overview of the three related projects. As a part of that testimony, the following benefits of King and High Bridge were illustrated:

- Life extensions of both King and High Bridge;
- Efficiency improvements at both plants;
- Capacity reclamation and/or additions at both plants;
- Increased system reliability and operational flexibility;
- Cost savings relative to other alternatives; and
- Significant reductions in emissions.

Q. WAS THE ISSUE OF WHETHER THE MERP PROJECTS WERE REQUIRED BY MINNESOTA LAW ADDRESSED IN THE PRIOR ELECTRIC RATE CASE?

A. Yes. Ms. Engelking's testimony clarified that these projects were not mandated under Minnesota law. Furthermore, the 2008 Rate Case Settlement clarified the parties' agreement that the refurbishment and repowering of the two MERP projects were prudent and economic investments.

b. Riverside

Q. IS THE COMPANY SEEKING RECOVERY OF COSTS RELATED TO THE THIRD MERP PROJECT IN THIS PROCEEDING?

A. Yes. Costs related to our Riverside repowering project ("Riverside") are included in this rate case.

The Riverside project involved the replacement of Unit 7 with two natural gas combustion turbines operating in a combined cycle. The project also included the retirement of Unit 8. The Riverside project provides 439 MW of accredited capacity (a net increase in URGE capacity of about 52 MW). Riverside began commercial operation in May of 2009.

Q. PLEASE FURTHER DISCUSS THE DECISION TO PURSUE THE RIVERSIDE PROJECT.

A. Riverside was originally built in 1911. While some of the original units have been retired, Units 7 and 8 have undergone several maintenance activities to improve operating efficiency and reduce air emissions. As of January 1, 2002: (1) Unit 7, which had a capacity of 150 MW, had a remaining life of 12.8 years; and (2) Unit 8, which had a capacity of 236.5 MW, had a remaining life of 6.9 years. Thus, both units would have needed significant investments in order to maintain reliability (or would have been retired in the case of Unit 8) by the time of the proposed 2009 conversion of Riverside, or shortly thereafter.

Q. What would the Company have done if Riverside was not rehabilitated?

A. The alternative to the Riverside project was to install a new, comprehensive Air Quality Control System ("AQCS") at the Riverside site. The cost of a new AQCS was estimated to be $98 million. However, this estimate neither included investments needed to address aging plant components nor the costs of obtaining 52 MW of additional capacity and energy from an alternative source.

Q. What was the cost estimate for replacing Riverside at the time it was proposed?

A. When it was proposed, Riverside was projected to cost $240 million. The cost for converting Riverside to natural gas translated to a per kW-installed value of $483, including transmission. The per kW-installed value of Riverside compared very favorably to costs for new natural gas plants, which ranged from $711 to $827 per kW-installed, including transmission.

Q. What other alternatives were considered in addition to Riverside? How did they compare in terms of cost?

A. As noted above, the Company compared the cost of the Riverside project to the cost of a new gas combined cycle generating facility, which at the time MERP was proposed would have cost between $711/kW to $827/kW.

Q. What are the benefits of the Riverside conversion?

A. The Riverside conversion allowed us to both extend the life of a plant that was nearing retirement and increase the output of the facility by 52 MW to help meet Xcel Energy's customers' future demand for electricity. The availability of the existing brownfield site and existing transmission and facility infrastructure resulted in costs for Riverside that were far lower than the cost of constructing a new plant elsewhere to replace Riverside and add capacity. The combined cycle characteristics increased the efficiency of fuel conversion from approximately 33 percent to approximately 49 percent. In addition, the facility conversion avoided the cost of substantial new air quality controls that would have been required to meet minimum federal standards in the 2009 time frame.

In addition to cost savings related to the construction of other generation alternatives, the ratepayer savings provided by Riverside resulting from avoided capacity and energy costs was estimated to reduce revenue requirements by $15 million in 2009, and rose to an average of $20-21 million per year in 2010 and thereafter.

c. Impact of the MERP Projects on the System

Q. HOW HAVE THE THREE PROJECTS AFFECTED THE SYSTEM IN RECENT YEARS?

A. All three of our MERP projects have now achieved commercial operation. The operational performance of King has improved significantly since the retrofit of the facility. As noted above, while the three projects provide benefits, some increased labor is required to operate and maintain the new emissions control equipment. In addition, more chemicals are needed for NOx and mercury reduction at King.

Furthermore, as noted above, High Bridge and Riverside were replaced or converted to combined cycle plants. Combined cycle facilities require significantly higher maintenance costs than traditional gas fired plants as I will discuss below. In addition, as High Bridge and Riverside move beyond their first years of operation, certain maintenance activities will no longer be covered by warranties, resulting in additional O&M costs.

2. Impact of Natural Gas Combined Cycle Units

Q. YOU MENTIONED THAT NATURAL GAS COMBINED CYCLE UNITS HAVE HIGHER ASSOCIATED O&M COSTS. CAN YOU PLEASE ELABORATE?

A. Yes. Combined cycle facilities (at High Bridge, Riverside and Black Dog) are designed to be more efficient than our older natural gas fired combustion turbines. However, the increase in efficiency results from operations at extreme high temperatures. As a result, the combined cycle facilities require significantly higher maintenance costs than a traditional peaking plant. As these facilities move beyond their first years of operation, certain elements will no longer be covered by warranties. Therefore, we expect increases in O&M expenses at these units to address wear and tear issues. An example of these higher maintenance costs is the hot gas path parts refurbishments at High Bridge and Black Dog Unit 5, which will take place in 2012 in order to be prepared for their next outages at a cost of $3.3 million.

3. Wind Generation

Q. WHAT WIND PROJECTS ARE AT ISSUE IN THIS RATE CASE?

A. There are three wind projects for which we seek cost recovery as a part of the Energy Supply 2011 test-year budget: (1) Grand Meadow; (2) Nobles; and (3) Merricourt. The Merricourt project is expected to achieve commercial operation in November of 2011. Accordingly, we are seeking partial cost recovery related to Merricourt in both our 2011 test-year budget and as part of the Company's request for a step-in rate increase for the 2012.

Q. HAS GRAND MEADOW BEEN REVIEWED BY THE COMMISSION PREVIOUSLY?

A. Yes. The procurement decision related to Grand Meadow was addressed in the 2008 Rate Case Settlement. In particular: (1) the Commission authorized recovery of costs associated with Grand Meadow; and (2) the Commission found that Grand Meadow was able to take advantage of existing production tax credits to produce low and stable-priced energy that will contribute to Xcel Energy's efforts to meet North Dakota's renewable energy objective.

Q. HAVE NOBLES AND MERRICOURT BEEN ADDRESSED BY THE COMMISSION PREVIOUSLY?

A. Yes. Both Nobles and Merricourt received Advance Determination of Prudence ("ADP") findings from the Commission in Case Nos. PU-08-907 and PU-08-908 respectively. Additionally, Merricourt received a Certificate of Public Convenience and Necessity ("CPCN") in Docket No. PU-08-910. As I discuss more fully below, I will provide an update to the capital costs related to those projects.

Q. WHEN WILL NOBLES AND MERRICOURT ACHIEVE COMMERCIAL OPERATION?

A. Nobles is expected to achieve commercial operation in late 2010 and, as noted above, Merricourt in November 2011.

C. O&M Cost

Q. AS PART OF THE PREPARATION FOR THIS CASE, HAVE YOU CONSIDERED HOW YOUR 2011 O&M BUDGET COMPARES TO PAST SPENDING?

A. Yes. We believe the most appropriate and useful comparison was between our O&M spending and forecasted spending levels for 2010 and the 2011 budget. The 2010 forecast includes six months of actual spending, plus six months of forecasted spending.

Q. WHY DID YOU COMPARE THE 2011 BUDGET TO 2010 FORECAST COSTS RATHER THAN TO 2008 ACTUAL COSTS?

A. 2010 forecast O&M costs are more appropriate for comparison to our 2011 O&M than prior years' actual costs because our 2010 O&M forecast, unlike prior years' actual costs, reflects costs related to the operation of all three of the MERP projects, usage of mercury sorbent for mercury emission control, and our Nobles wind project. Accordingly, the 2010 forecast is a more representative year in terms of the types of costs we expect to see in future years, i.e., 2011 and beyond.

Q. WHAT COST SAVING MEASURES HAS THE COMPANY IMPLEMENTED IN ORDER TO MITIGATE INCREASING O&M COSTS?

A. As discussed more fully by Ms. McCarten, in response to recessionary conditions in 2009, the Company searched for additional measures to reduce costs while ensuring we maintain reliability in both the near and longer term. The Energy Supply organization undertook several cost saving initiatives, some of which continue to provide cost savings in our 2011 test year O&M budget. For example:

- In 2009, we reduced employee expenses and found ways to manage reductions to fleet costs, the savings of which continue into our 2011 test-year O&M budget; and

- In early 2009, we installed a lime slaker water heating system at King, which allowed us to reduce our usage of lime. The reduced usage, as well as resulting chemical costs savings for lime, are fully reflected in our 2010 forecast and our 2011 test-year O&M budget.

Q. PLEASE PROVIDE AN OVERVIEW OF THE MAJOR DIFFERENCES BETWEEN 2010 FORECAST SPENDING FOR O&M AND 2011 BUDGET FOR O&M.

A. Table 1 below ("2011 O&M Budget Chart") shows the cost categories for which there are significant differences between the 2010 forecast and the 2011 budget. It should be noted that the individual increases and decreases are intended to provide descriptions of the primary drivers of differences.

Table 1

2011 O&M Budget Chart		
2010 Year-End Forecast for O&M		$159,533,306
Base Labor		$542,243
Regular time labor increase primarily due to wage increases for GM MN plants	$1,005,000	
Overtime reduction primarily due to nuclear plant support budgeted in nuclear ($200k) and miscellaneous minor outages in 2010.	($500,000)	
Base Non-Labor		$3,852,961
Contract Labor increase due to Nobles and Merricourt Wind facilities	$2,511,000	
Contract Labor increase due to FERC/NERC requirements	$700,000	
Increase due to land lease payments for Nobles and Merricourt Wind facilities	$1,226,000	
Decrease due to increase in credits budgeted due to activities on Sherco Unit 3	($582,000)	
Base Commodities		$3,218,500
Increase due to activated carbon at King plant for mercury control	$2,956,500	
Increase due to lime usage at the Wilmarth plant and commodity price increase	$244,000	
Increase in sulfuric acid and other chemicals due to usage at the Riverside plant and commodity price increase	$470,000	
Increase due to activated carbon at Sherco plant for mercury control	$618,000	
Adjustment for activated carbon at Sherco plant	($1,070,000)	
Overhauls		($3,206,140)
Decrease primarily due to a Sherco Unit 3 overhaul budgeted in 2011 resulting in additional payment from partner (SMMPA) ($5.5M), offset by an increase for the Black Dog Unit 3 and Unit 4 overhaul and Riverside Unit 9 warranty inspection in 2011.	($3,200,000)	
Projects		$3,031,588
Increase primarily due to the Sherco stacker/reclaimer refurbishment ($1.2M); inspection of the new High Bridge combined cycle turbine ($430k); Riverside plant site remediation and intake closure following the MERP conversion ($550k); and gearbox and generator bearing repairs at the Grand Meadow Wind facility ($1.0M). This increase is offset by a $180k decrease in the 2011 budget for boiler cleaning projects at the RDF plants.		
2011 Adjusted O&M Budget		$166,972,458

1. *Components of the 2011 Test Year O&M Budget*

a. *Base Labor Costs*

Q. PLEASE FURTHER DEFINE "BASE LABOR COSTS."

A. Base labor costs relate to labor of Energy Supply employees in a department or station and overtime for recurring activities required to operate stations or departments on a daily basis. Base labor is primarily native station employees performing native station work or a supplemental workforce performing station work of a routine and recurring nature. These costs recur annually.

Q. In the 2011 O&M budget chart, you noted an increase in wage increases. Upon what did you base the wage increases for Energy Supply employees?

A. We assumed wage increases of 2.5 percent for non-bargaining employees and a slightly different value for our bargaining employees. Wage increases are addressed by Company witness Ms. Jill H. Reed. As noted in the 2011 O&M Budget Chart, the increase in wages accounts for a $1,005,000 difference from the 2010 forecast.

Q. Please elaborate on the decrease in base labor costs attributable to the overtime reduction.

A. Our maintenance employees support the nuclear plants from time to time, primarily for their overhauls. The actual labor and overtime is posted to our generating plants. We have budgeted for a reduction in this area of approximately $500,000 in 2011.

Q. Can you provide an update on the level of staffing necessary to operate and maintain the Company's generation units?

A. We are currently using 2004 as our high water mark and have decreased the number of staff since that time. Our goal is to keep overall staffing levels consistent with 2007 levels. We have needed to make small increases in staff related to increased operating and maintenance expenses for emissions control activities. For example, the new emissions control equipment at King requires more labor to operate and maintain. The conversion of High Bridge from coal to natural gas provided for a reduction in labor to operate, as did the new Riverside combined cycle plant. However, the reduction in labor associated with High Bridge and Riverside has been partially offset by the hiring of additional employees at other plants, for example, the required additional labor needed to operate and maintain the new emissions control equipment at King. In addition, wage increases have offset the reduction in labor at High Bridge and Riverside. Despite these factors, however, our base labor costs have remained relatively flat with a net increase of $542,243 in 2011.

b. Base Non-Labor Costs

Q. PLEASE FURTHER DEFINE "BASE NON-LABOR COSTS."

A. Base non-labor costs are materials, contractor expenses, permits, dues, fleet vehicles, employee expenses and other miscellaneous costs required to operate stations or departments on a daily basis, excluding base commodity costs detailed below. These costs recur annually.

Q. DESCRIBE THE INCREASE IN BASE NON-LABOR COSTS RELATED TO THE WIND PROJECTS.

A. Operating and maintenance of our wind projects are performed by contractors. As noted in the 2011 O&M Budget Chart, a large portion of the increase in base non-labor costs relate to these maintenance contracts being implemented for Nobles and Merricourt. As I noted at the outset, Merricourt O&M costs are part of the 2011 budget.

Q. PROVIDE A SUMMARY OF THE TOTAL O&M COSTS RELATED TO THE COMPANY'S WIND PROJECTS.

A. Table 2 below provides an overview of the O&M costs related to Grand Meadow, Nobles and Merricourt:

Table 2
Wind O&M Costs

Project	2009Actual	2010 Forecast Spending*	2011 Budget
Grand Meadow	$2,610,417	$2,534,327	$3,648,025
Nobles	$0	$1,657,430	$4,025,922
Merricourt	$0	$0	$1,629,060

*September 2010 forecast, 8 months actual and 4 month forecast.

Q. WHAT PORTION OF THESE O&M COSTS ARE ALLOCATED TO NORTH DAKOTA CUSTOMERS?

A. Mr. Felling discusses the North Dakota jurisdictional portion of the O&M costs for our wind projects.

Q. HOW DO THE O&M COSTS FOR NOBLES AND GRAND MEADOW COMPARE TO FORECAST SPENDING IN 2010?

A. The 2011 O&M increase for Grand Meadow reflects a combination of two related factors. First, the two-year manufacturer's warranty on parts expires at the end of 2010. When this occurs, the Company will experience a permanent cost increase in our O&M budget, as we continue to order, stock and install replacement parts. Second, there is an associated need to incur higher maintenance costs, reflecting the start of a new and routine maintenance cycle. After two to three years of operation, generator bearing replacements and gearbox rebuilds can be expected to occur on an ongoing basis.

For Nobles, the difference between 2010 forecast spending reflects an increase in O&M for routine maintenance related to the project's construction completion and commercial operation. However, similar to Grand Meadow, it is reasonable to expect cost increases in the future for Nobles when the project manufacturers' parts warranties expire and associated increased routine maintenance expenses are necessary.

Q. WHAT DO THE 2011 O&M COSTS FOR MERRICOURT REFLECT?

A. While Merricourt is not expected to achieve commercial operation until November of 2011, it is still necessary to incur some O&M costs prior to the in-service date. For example, staffing at the site must begin months before the project commences commercial operation. This allows the turbines to be operated and maintained as they are constructed. The budgeted amount for Merricourt in 2011 is based upon our experience with Grand Meadow.

Q. WHAT IS THE COMPANY DOING TO MANAGE O&M COSTS FOR WIND PROJECTS?

A. The O&M service contract for the wind facilities is competitively bid to assure we receive competitive pricing. The maintenance necessary at the wind project sites will not change based on who provides the service, but the cost of providing the maintenance can change. In summary, using competitive bidding ensures the fairest costs but does not mean that costs will not increase.

Q. CAN YOU DESCRIBE THE INCREASE IN BASE NON-LABOR ASSOCIATED WITH THE LAND LEASE PAYMENTS FOR NOBLES AND MERRICOURT?

A. When approaching landowners for the property rights necessary to construct and operate the wind projects, two payment options were offered. Landowners were given the choice between an up-front lump sum payment and annual payments over the life of the project. The two options are designed to give land owners approximately equivalent alternatives on a present value basis. The two options, however, are treated differently by the Company for accounting purposes. The single lump sum payment is treated as a capital expenditure, while the annual payments are an O&M expense. Ultimately, more landowners chose annual payments than expected, which resulted in a reduction in capital expense and a commensurate increase in O&M over the term of the annual payments. These changes represent a cost shift between capital and O&M costs, but do not increase or decrease the cost of energy from the facility over its expected life.

Q. CAN YOU DESCRIBE THE DECREASE IN BASE NON-LABOR ASSOCIATED CREDITS FOR ACTIVITIES AT SHERCO UNIT 3?

A. Yes. Sherco Unit 3 is a jointly-owned unit between the Company and Southern Minnesota Municipal Power Agency ("SMMPA"). The Company operates and maintains Sherco Unit 3. Therefore, we incur all of the expenses and then bill SMMPA for their share. The payments from SMMPA are credits that offset Energy Supply's actual budget. These credits are reflected in our 2011 budget.

c. Base Commodity Costs

Q. PLEASE FURTHER DEFINE "BASE COMMODITY COSTS."

A. Base commodity costs are chemical and water costs used in the generation process, and for the control of emissions. Chemicals include lime, activated carbon, sulfuric acid and others. These costs recur annually.

Q. CAN YOU DESCRIBE THE INCREASE IN ACTIVATED CARBON AT THE KING AND SHERCO PLANTS FOR MERCURY CONTROL?

A. Yes. Pursuant to the Minnesota Mercury Emissions Reduction Act of 2006 (the "Act"), the Company was required to employ the available technology for mercury removal at Sherco and King to remove at least 90 percent of the mercury emitted from the units. The Act required the controls be implemented by December 31, 2010. Both plans involved the use of chemically reactive material, such as activated carbon ("mercury sorbent"), which is injected into the flue gas upstream of a particulate control device. The usage and associated commodity cost for mercury sorbent at King and Sherco Unit 3 accounts for the increase from 2010 forecast spending and the 2011 budget.

Q. WERE THE COSTS RELATED TO MERCURY EMISSIONS CONTROL ADDRESSED AS A PART OF THE 2008 RATE CASE SETTLEMENT?

A. Yes. As a part of the 2008 Rate Case Settlement the parties agreed to reduce the revenue requirement by $12,335. In particular, Section L of the 2008 Rate Case Settlement reflects a reduction in costs "related to monitoring mercury emissions reduction efforts at its King and Sherco generating plants to meet Minnesota mercury emissions requirements."

Q. IS THE REQUEST TO RECOVER COSTS FOR MERCURY EMISSIONS CONTROL INCONSISTENT WITH THE SETTLEMENT IN THE LAST RATE CASE?

A. No. There was a dispute in the last rate case related to the recovery of costs for monitoring mercury emission that was settled by removing those costs as part of an overall settlement. My understanding is that the settlement was tied to the Staff's argument that the cost of the mercury monitoring equipment was incurred in response to monitoring requirements enacted by the Minnesota legislature rather than any requirement established by federal law. The Staff initially believed $438,427 had been included in the proposed revenue requirement related to the mercury emissions reduction; however, the amount was subsequently clarified to be $12,335.

As argued by the Company in our last electric rate case, we continue to believe that it is appropriate to allow recovery of the cost of complying with state law where facilities are located. Further, since the time of our last electric rate case, the Act has been approved by the Environmental Protection Agency ("EPA") as an appropriate response to the federally-mandated requirement to reduce mercury levels in water bodies. Accordingly, the costs incurred by the Company to reduce mercury emissions are now needed to comply with federal environmental regulation.

Q. CAN YOU PROVIDE MORE BACKGROUND OF THE FEDERAL MANDATE TO REDUCE MERCURY LEVELS IN WATER BODIES?

A. The Federal Clean Water Act requires each state to evaluate its water bodies and determine whether they meet water-quality standards. For mercury, these standards define how much mercury can be in the water and in fish. Water bodies that do not meet water-quality standards are added to a list of water bodies referred to as the Impaired Waters List. Minnesota's 2008 Impaired

Waters List included 1,475 lakes and river segments that were considered impaired for mercury, usually due to fish contamination.

To address impaired waters, states are required to evaluate the sources of pollution, the reduction in the pollutant needed to meet water-quality standards, and allowable levels of future pollution. This evaluation, typically done for each water body or watershed, is called a Total Maximum Daily Load ("TMDL"). Because the source of essentially all mercury to Minnesota waters is the atmosphere, the Minnesota Pollution Control Agency ("MPCA") prepared a state wide mercury TMDL. This TMDL was approved by the U.S. EPA in March 2007.

To meet water-quality standards, the TMDL determined that human-caused, air-deposited mercury would need to be reduced by 93 percent from 1990 levels. Applying this to air emission sources in the state established a 789-pounds-per-year air emission goal. Once a TMDL is approved by the EPA, states are responsible for implementing measures to achieve the goals established in the TMDL. The MPCA, along with other stakeholders, developed a Mercury TMDL Implementation Plan for the State of Minnesota. The Mercury TMDL Implementation Plan incorporated the Act.

Because the Mercury TMDL Implementation Plan was mandated under the Federal Clean Water Act and approved by the EPA, the mercury emissions control and related costs are necessary to implement Federal requirements. Accordingly, it is appropriate to seek recovery of a portion of these costs from North Dakota ratepayers.

d. Overhauls

Q. PLEASE FURTHER DEFINE "OVERHAUL COSTS."

A. Overhaul costs relate to the overhaul outages that are scheduled and planned in advance. Budgeted overhaul costs include all costs incurred for overhauls scheduled to be performed (incremental costs). Fixed or "base" costs are budgeted as "Base" (e.g., regular time labor for native station employees) and are *not* included in overhaul costs. Overtime, contract work, materials and other expenses used for overhauls are included, as well as activities performed only during the overhaul and are overhaul dependent, are included in this category.

Q. CAN YOU DESCRIBE THE DECREASE IN OVERHAUL COSTS RELATED TO SHERCO UNIT 3?

A. Yes. An overhaul at Sherco Unit 3 occurs once every three years. As noted above, SMMPA is a co-owner of Sherco Unit 3. The overhaul at Sherco Unit 3 requires an additional payment from SMMPA, as a co-owner. The payment from SMMPA results in the decrease for Overhaul costs. Primarily as a result of this credit, our overhaul costs in 2011 are down $3.2 million from 2010 levels.

Q. ARE THERE ANY OTHER OVERHAUL COSTS IN 2011?

A. Yes, there are. In order to maintain efficient operations, a turbine overhaul is needed at Black Dog Unit 3 and a boiler overhaul is needed at Black Dog Unit 4. An overhaul warranty inspection of the new Riverside Unit 9 is also necessary to determine if there are any necessary repairs that would be covered under the warranty.

Q. ARE THE OVERHAUL COSTS BUDGETED FOR 2011 REPRESENTATIVE OF WHAT CAN BE EXPECTED IN FUTURE YEARS?

A. Yes. It is useful to consider how our 2011 budget for Overhaul costs compare to prior years overhaul spending and our forecast for 2012, which is as follows:

Table 3

2007 Actuals	2008 Actuals	2009 Actuals	2010 Forecast	2011 Budget	2012 Budget
$24,343,781	$17,974,255	$13,305,552	$19,720,019	$16,513,879	$22,314,950

An average of the six years above is $19,028,739. Thus, our 2011 budget for Overhaul costs is reasonable and, in fact, is lower than what can be expected for 2012.

e. Project Costs

Q. PLEASE FURTHER DEFINE "PROJECT COSTS."

A. Project costs are related to work that is separate and independent of overhaul costs. Items in this cost category are not overhaul dependent, even though they may be performed during the overhaul. Projects are typically larger expenses. The projects typically do not occur every year and could cross over from year to year. Overtime, contract work, materials and other expenses used for projects are included in this cost category. Examples of project costs are:

- Major coal mill overhauls;
- Major pump rebuild performed outside of an overhaul;
- Partial baghouse bag replacement; and
- Conveyor belt replacement.

Q. CAN YOU DESCRIBE THE $3,031,588 INCREASE IN PROJECT COSTS FROM 2010 TO THE 2011 BUDGET?

A. The most significant one-time projects in 2011 are:

- The refurbishment of the coal Stacker/Reclaimer at Sherco, which is $1.2 million;
- Gearbox and generator bearing projects at the Grand Meadow Wind facility, which is $1 million;
- Riverside plant site remediation and intake closure following the MERP conversion, which is $550,000;
- The first inspection of the new High Bridge combined cycle steam turbine, which is $430,000; and
- Decrease for boiler cleaning at the Refuse Derived Fuel ("RDF") plants, which is $180,000.

Q. WHY DOES THE SHERCO COAL STACKER/RECLAIMER REFURBISHMENT REQUIRE REFURBISHMENT IN 2011?

A. The coal Stacker/Reclaimer at the Sherco Plant is original plant equipment and has reached the end of its projected life. The coal Stacker/Reclaimer is a critical component as it delivers coal to the Sherco generating units, and as such, must be maintained in a reliable condition. We considered capital project alternatives to replace the Stacker/Reclaimer, but it was estimated to cost between $17 million and $40 million. We elected to perform an O&M project in 2011 that involves refurbishment of the rail track upon which the Stacker/Reclaimer travels and some parts of the travel assembly. The 2011 project is intended to ensure reliable Stacker/reclaimer operation and defer the revenue requirements associated with a major capital project as we continue to research a more cost-effective long-term alternative.

Q. DO YOU EXPECT TO HAVE PROJECTS LIKE THE STACKER/RECLAIMER EVERY YEAR?

A. While our 2011 Stacker/Reclaimer project is somewhat unique in that it has allowed us to avoid a capital project, we have other unique projects in 2012 that will cause increases in Project costs. Specifically, we will perform a Sherco Unit 3 Mill Overhaul and two Hot Gas Path parts refurbishments at Black Dog and High Bridge in 2012, which I will discuss more fully below. In addition, we expect to have additional wind-related project work in 2012 and beyond with Nobles and then Merricourt achieving commercial operation. Because we expect to continue to have additional one-time *projects* in future years, and that the level of these projects will increase, the 2011 *budget* for project costs represents a reasonable basis upon which to set prospective rates.

Q. PLEASE FURTHER DESCRIBE HOT GAS PATH PARTS REFURBISHMENTS THAT WILL OCCUR AT BLACK DOG AND HIGH BRIDGE.

A. Typical Hot Gas Path parts refurbishments are done on a prescribed frequency of 16,000 to 24,000 operating hours or 500-600 starts, whichever comes first. This frequency is established to ensure safe reliable unit operations during the life of the machine. Going much beyond these intervals can put the units at risk and drive costs higher for both repair and replacement not to mention potential collateral damage within the combustion turbine. During a Hot Gas Path inspection all components associated with a combustion inspection are pulled, repaired, and/or replaced if at end of life, plus we inspect and repair the first two rows of combustion turbine blades, vanes, ring segments, etc. associated with the hottest portion of the combustion turbine. Similar to the combustion inspection parts, these are also inspected and refurbished or replaced once they reach the end of useful life. As I discussed earlier, the Hot Gas Path parts refurbishments in 2012 for both High Bridge and Black Dog Unit 5 have a combined cost of $3.3 million.

III. CAPITAL INVESTMENTS

A. Capital Investments for 2011

Q. WHAT ARE YOUR PLANT ADDITIONS FOR NSPM IN 2011?

A. Our plant additions are $493 million, $399.8 million of which relates to Merricourt.

Q. WHAT KINDS OF CAPITAL INVESTMENTS ARE BEING MADE AT THE GENERATING PLANTS?

A. Most capital expenditures are for equipment and materials that have worn out through normal use or operation. These include: generator rewinds; boiler tubing replacements; computerized control system replacements; and turbine replacements. Also included are environmental compliance projects such as landfill management, mercury control, SCR catalyst replacement and land remediation.

Q. WHAT TYPE OF CAPITAL INVESTMENTS ARE BEING MADE AT SHERCO IN 2011?

A. Sherco has capital expenditures for:

- Replacement of: (1) computerized control system in the Sherco coal yard; (2) distributed controls; and (3) plant programmable logic controllers at Sherco Units 1 and 2. The existing systems are 10-20 years old. Thus, replacements are needed due to parts becoming obsolete and to meet new load swing requirements to better integrate wind.

- Equipment replacement at the Sherco coal yard, such as yard rails and coal chutes, which become degraded due to everyday use.
- Ongoing landfill, pond and capping projects.

Q. ARE THERE CAPITAL INVESTMENTS IN 2011 FOR SHERCO UNIT 3 SPECIFICALLY?

A. Yes. The High Pressure and Intermediate Pressure turbines and the generator step-up transformer at Sherco Unit 3 will be replaced during the overhaul outage in the Fall of 2011. This project will increase generation by 21 MW without increasing emissions. Also, a portion of the baghouse bags will be replaced and a new boiler cleaning system will be installed. These capital investments are estimated to cost approximately $17 million in 2011.

Q. ARE THERE COST SAVING CAPITAL PROJECTS FOR 2011?

A. Yes. At Sherco we will replace the demineralizer and implement slaking water heating projects, both of which will offset some of the increase in chemical costs.

Q. ARE THERE EXAMPLES OF EQUIPMENT EFFICIENCY IMPROVEMENTS?

A. Yes, as noted above, the replacement of turbines at Sherco Unit 3 will increase generation by 21 MW. In addition, new turbines will be installed at our St. Anthony Falls Hydro Plant that are more efficient and will increase generation by about 20 percent.

B. Capital Costs of Nobles and Merricourt

Q. WHAT IS THE PURPOSE OF THIS PORTION OF YOUR TESTIMONY?

A. This portion of my testimony addresses capital costs related to the Nobles and Merricourt that are incremental to costs provided as a part of the ADP proceedings.

Q. PLEASE BRIEFLY DESCRIBE HOW THE NOBLES AND MERRICOURT PROJECTS ARE BEING CONSTRUCTED.

A. As we indicated in our ADP applications, Xcel Energy entered into build/transfer agreements (also referred to as engineering and procurement or "EPC" agreements) with enXco Development Corporation to develop and construct both the Nobles and Merricourt wind projects. Under this approach, the Company obtains ownership of the projects in a progressive manner. Under our agreement with enXco, Xcel Energy was to obtain the CPCN (for Merricourt) and ADP while enXco would apply for the Certificate of Site Compatibility required pursuant to NDCC Chapter 49-22.

The cost estimates filed with our ADP accounted for the payments directly to enXco, but did not include all costs incurred by Xcel Energy during the construction management phase. As discussed more fully below, these are necessary and direct costs in order for Nobles and Merricourt to be constructed and achieve operation. It is also important to note that the additional capital costs discussed below do not materially alter the reasonableness of the selection of the two projects.

Q. WHAT ARE THE CONSTRUCTION MANAGEMENT PHASE COSTS RELATED TO NOBLES AND MERRICOURT?

A. The costs are the internal Xcel Energy costs and are not payable directly to enXco as part of the EPC agreement. The costs can be broken into three main categories: (1) labor; (2) non-labor; and (3) contingency costs. Table 5 provides the costs for each category.

Table 4

Nobles Project Costs	
Labor	$3.270 M
Non-Labor	$4.170 M
Contingency	$6.250 M
Totals	$13.703 M

Table 5

Merricourt Project Costs	
Labor	$2.26 M
Non-Labor	$3.26 M
Contingency	$8.78 M
Totals	$14.30 M

I will discuss each category in greater detail below.

Q. ARE THESE COSTS ORDINARY AND NECESSARY TO MANAGE LARGE CONSTRUCTION PROJECTS?

A. Yes. Internal project management costs are incurred for any major construction project. While enXco has original responsibility for managing the projects and their subcontractors, the Company continues to have overall oversight responsibilities. Those responsibilities should not be delegated.

a. Labor Costs

Q. WHAT DO THE LABOR COSTS CONSIST OF?

A. The labor costs consist of: (1) internal labor costs for engineering and construction oversight ("E&C"); (2) consultant costs; and (3) legal costs.

Q. PLEASE PROVIDE SOME BACKGROUND ON THE "E&C" COMPONENT OF THE LABOR COSTS.

A. During the period enXco develops and constructs the Nobles project, the Company performs an oversight role to help ensure they are adhering to the contractual requirements and maintaining a level of quality that is consistent with the Company's expectations. Eight Company employees perform this oversight role (the "project team"). Among other tasks, the project team at Nobles: (1) is on site at the project five to six days per week; (2) works with landowners to locate access roads and minimize road issues in a manner that will minimize future O&M costs and potential issues with landowners; (3) attends daily enXco morning meetings to discuss a wide array of issues, including safety and the daily construction schedule; (4) observes construction practices; (5) serves as the Company contact for site inspections/audits, including quality assessment and quality control, as well as adherence to design documents and contract specifications; and (6) coordinates the Company's substation work with enXco.

For the Merricourt project, we will use a similar project team who will perform the same types of tasks. We currently expect the project team at Merricourt to begin work in April or May 2011.

Q. HAS THE COMPANY INCURRED E&C OVERSIGHT LABOR-RELATED COSTS FOR OTHER MAJOR CONSTRUCTION PROJECTS?

A. Yes. E&C oversight labor costs are not unique to the Nobles and Merricourt projects. For example, the Company incurred and was allowed to recover these costs for Grand Meadow and our MERP projects.

Q. ARE THE E&C OVERSIGHT LABOR COSTS ASSOCIATED WITH NOBLES AND MERRICOURT COMPARABLE TO THE E&C OVERSIGHT LABOR COSTS ASSOCIATED WITH GRAND MEADOW?

A. Yes. The E&C oversight costs for these projects are summarized below in Table 6:

Table 6

E&C Oversight Costs		
Grand Meadow	$23/kW	1.15% of total project cost
Nobles	$23/kW	0.9% of total project cost
Merricourt	$23/kW	0.9% of total project cost

These costs are comparable on a total project cost basis. As explained, the E&C oversight labor costs provide significant value and represent about one percent of the total project costs for both wind projects.

Q. HAS THE COMPANY'S E&C OVERSIGHT PROVIDED BENEFITS TO THE NOBLES AND MERRICOURT PROJECTS?

A. Yes. Through the E&C process for Nobles, adjustments were made during construction which will provide improved performance and lower operating costs. For example, we are conscious of access road placement. Landowners will more readily grant easement access to areas of their property that are lower lying areas because they are less valuable agricultural production areas. However, these areas are also prone to being wetter in spring and fall and experience more drifting in winter. Thus, while enXco is responsible for obtaining all easements, we involved our E&C team during the discussions with landowners for Nobles in order to identify types of issues that could affect our access and costs from a long-term perspective. For the Merricourt project, we intend to use our E&C project team in a similar manner and, accordingly, we anticipate similar benefits.

Q. PLEASE DESCRIBE THE CONSULTANTS' ROLES AND THE LEGAL COSTS.

A. During site development and construction of the Nobles project, the Company hired a consulting firm ("URS") as an Owners-Engineer to provide technical oversight and review of certain contract deliverables. The original scope of work under the contract included items such as: review of permit applications, site studies, foundation designs, and electrical designs. All work under the contract is performed on an "as-requested" basis, with a not-to-exceed value. Under the contract, URS has reviewed the Certificate of Need and Large Wind Energy Conversion System ("LWECS") Site Permit application, project permit application schedules, wetland and avian studies and permitting requirements, and the terms and conditions of the project agreements. URS was chosen to perform these services due in part to its capability and experience in providing similar assessment and oversight of prior wind projects. The Company also used outside legal services to perform land title reviews, support contractual interpretation and compliance, and assist with contract closing activities.

The Company plans to hire URS to perform the same functions for the construction of the Merricourt project.

Q. WHAT DID THE COMPANY DO TO MAKE SURE THE CONSULTANT AND LEGAL COSTS WERE REASONABLE?

A. For the costs related to the consultant, the Company selected URS as a result of a request for proposal ("RFP") process. The Company chose the consultant based upon the competitiveness of its bid, both from a monetary standpoint and from an experience/expertise standpoint.

With regard to amount of costs related to the legal services, the Company selected the outside law firms pursuant to responses received to a law department RFP and based on our experience with these firms being able to provide cost-effective service for these types of transactions.

b. Non-Labor Costs

Q. PLEASE PROVIDE A GENERAL DESCRIPTION OF THE NON-LABOR COSTS RELATED TO NOBLES.

A. Similar to the labor cost discussion, even though the bulk of the costs related to Nobles and Merricourt stem from our EPC agreement with enXco, additional non-labor cost incurrence is necessary in order to allow the projects to be constructed and become operational. The non-labor components include: (1) landowner payments for easements; (2) compensation for crop damage caused by construction crews; (3) sales taxes related to road materials and building materials; (4) insurance premiums related to "builder's risk" property insurance, which covers property owners and builders for projects under construction; and (5) Xcel Energy's portion of the transmission interconnection costs.

Q. WHY ARE THESE COSTS NOT COVERED BY THE EPC AGREEMENT?

A. The costs are related to project development activities that remain the responsibility of Xcel Energy. Easements and other land acquisitions are required from affected landowners for the turbine footprints and access roads as well as for the substation in order to construct and operate the project. The easements also require us to pay for damage to crops during the construction period. However, the final easement amount is subject to individual negotiations with landowners. Additionally, while some generation production equipment is exempt from sales tax, Minnesota law requires sales tax to be paid on other portions of the Nobles project, such as non-generation materials. Our EPC contract with enXco requires us to pay the sales tax, and we have chosen to provide the builder's risk insurance during construction.

c. Contingency Costs

Q. PLEASE DESCRIBE WHAT IS INCLUDED IN THE LAST CATEGORY OF COSTS REFERRED TO AS "CONTINGENCY COSTS."

A. We are requesting $6.25 million in contingency costs for Nobles and $8.78 million for Merricourt. It is normal business practice to include contingencies in capital project estimates. Contingency costs are intended to account for unplanned or uncertain costs that arise during the construction process. While the build transfer approach under which enXco builds the wind project significantly reduces contingency costs to the Company by placing more of the burden on enXco, it does not completely eliminate them.

At this point during the construction of Nobles, we have identified costs of approximately $2.55 million for which Xcel Energy could be responsible that fall under the contingency category of costs. I believe the $6.25 million is a reasonable estimate of final costs, but will be able to provide an update regarding the total amount actually spent in early 2011.

Because construction has not yet begun on the Merricourt project and the in-service date is not until November 2011, we have not yet incurred any contingency costs for this project. Since the Nobles and Merricourt EPC agreements are similar, and because we have encountered contingency costs for Nobles, we anticipate we will incur contingency costs for Merricourt as well. Furthermore, we have identified additional challenges for the construction of Merricourt in comparison to Nobles, including a more hilly terrain that could result in greater costs related to the establishment of roads. In light of the likelihood of incurring contingency costs and the additional challenges related to Merricourt, I believe the $8.78 million budget for contingency costs for the Merricourt project is reasonable.

Q. PLEASE PROVIDE AN EXAMPLE OF CONTINGENCY COSTS THAT HAS BEEN IDENTIFIED FOR THE NOBLES PROJECT.

A. We are in the final stages of approving a $2.3 million change in the greasing mechanism that would result in reduced O&M and operational risks at Nobles. This change would require a vendor to modify the GE wind turbines at the project site. It is possible that the Merricourt project could require a modification to the wind turbine lube oil system, similar to what is being done now at Nobles.

Q. WHY ARE THE MERRICOURT CONTINGENCY COSTS ESTIMATED TO BE GREATER THAN THOSE ESTIMATED FOR NOBLES?

A. The contingency cost estimate for Nobles versus Merricourt reflects the fact that Nobles is much farther along in its construction than Merricourt. At this time, our estimate for Merricourt is relatively higher due to several additional uncertainties. For example, we currently do not have design plans from MISO or design plans from enXco for the operations and maintenance building. Another uncertainty regards payments to landowners. It is not known how many will take a one-time payment or an annuity. Also, the terrain of the land may bring unique challenges for construction or start-up. These uncertainties make it more difficult to predict what type of contingency costs to expect.

Q. WHAT IS THE PROCESS TO REVIEW AND APPROVE COSTS THAT FALL UNDER THE CONTINGENCY CATEGORY?

A. All contingency costs are reviewed by project management and must receive the necessary approvals. The approval process varies depending upon use, dollar amount and priority. Depending upon the dollar amount, a cost/benefit or case study may be required to justify approval. Such was the case with the greasing mechanism previously mentioned, where a case study was performed. That case study assessed the benefits of installing an improved automatic greasing system, which would provide long-term cost and reliability benefits.

Q. OVERALL, WHAT HAS THE COMPANY DONE TO MINIMIZE THE ADDITIONAL NOBLES AND MERRICOURT PROJECT COSTS?

A. As noted above, these are necessary and ordinary expenses, many of which are not within the Company's control (e.g. payments to landowners, taxes). Where the ability exists to exercise some cost control, we have taken steps to manage those costs.

First, using a build/transfer approach of an EPC puts much of the project risk on the contractor versus the owner. Thus, the build/transfer arrangement minimizes the need for contingencies to a level that is substantially less than the contingencies would have been if we self-built the projects.

Second, our active involvement in the E&C oversight process helps minimize costs by working with the contractor throughout the construction process. For example, we were able to obtain insurance cost savings by replacing enXco's builder's insurance with our own. Our involvement also leads to a better quality project. For example, it is expected that the higher up-front costs for the change in automatic greasing described above will result in long-term savings and increased reliability.

Third, we also try to minimize costs by using RFPs where appropriate for services such as the hiring of the engineering consultant and outside legal resources. Finally as I described above, we closely review change orders and contingency costs, such as the greasing mechanism change, and require approvals before they can be incurred.

Q. IS THE COMPANY REQUIRED TO PROVIDE ANNUAL FILINGS AS A PART OF THE ADPS ISSUED FOR NOBLES AND MERRICOURT?

A. Yes. North Dakota Century Code 49-05-16(3) states, "a resource addition approved by the Commission is subject to annual reporting requirements until commercial operation of the resource addition." I request that my testimony serve as the update to the Commission with respect to both ADPs.

Q. DO THE ADDITIONAL COSTS AFFECT THE COMPANY'S OPINION REGARDING THE REASONABLENESS OF NOBLES AND MERRICOURT?

A. No. At the time we submitted our ADP applications for Nobles and Merricourt, the projects were estimated to increase the total Company present value revenue requirements ("PVRR") by approximately 0.11 and 0.12 percent respectively. The additional costs change the total PVRR to 0.13 and 0.14 percent respectively. Thus, the projects are roughly in the same position as portrayed in our ADP filings.

IV. SUMMARY AND CONCLUSION

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. Based on the above, I recommend the Commission approve our adjusted 2011 test-year O&M budget of $166.9 million for Energy Supply O&M costs and our capital investments for 2011. The budget reflects costs: (1) necessary to allow our generation fleet to maintain safe and reliable operations; (2) necessary to comply with Federal environmental regulations and reliability standards; and (3) related to our wind projects. Our capital additions are also reasonable and needed to maintain the performance of our fleet in meeting our customers' energy needs.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

STATE OF NORTH DAKOTA
BEFORE THE
PUBLIC SERVICE COMMISSION

In the Matter of the Application of Northern States Power Company, a Minnesota corporation For Authority to Increase Rates for Electric Service in North Dakota	))))	Case No. PU-10-___

AFFIDAVIT OF
Pamela K. Graika

I, the undersigned, being duly sworn, depose and say that the foregoing is the Direct Testimony of the undersigned, and that such Direct Testimony and the exhibits or schedules sponsored by me to the best of my knowledge, information and belief, are true, correct, accurate and complete, and I hereby adopt said testimony as if given by me in formal hearing, under oath.

Pamela K Graika
Pamela K. Graika

Subscribed and sworn to before me, this 16 day of December, 2010.

Brianne Gregory
Notary Public

BRIANNE M. GREGORY
Notary Public
State of Minnesota
My Commission Expires
January 31, 2015

Statement of Qualifications

Pamela K. Graika
Manager, Power Generation
Xcel Energy
250 Marquette Plaza, Minneapolis MN 55102

Current Responsibilities

Manage 5 large coal and gas fired power plants and 3 smaller RDF plants, for a total of 4,500 MW's.

Previous Positions

Xcel Energy and Northern States Power Company Minnesota

General Manager, North Region Energy Supply	2002–Present
General Manager, Peaking and Renewables	2000–2002
Director, Environmental Affairs	1994–2002
Plant Manager, High Bridge Generating Plant	1990–1994
Plant Superintendent, Combustion Turbines and Hydro	1988–1990
Senior Production Engineer, Combustion and Hydro	1986–1988
Administrator Plant Permits and Compliance, Environmental Services	1982–1986
Assistant Environmental Engineer, Power Production	1980-1982
Asst. Production Engineer, High Bridge Plant	1979 - 1980

Education

Bachelor of Science, Chemical Engineering, University of Minnesota 1978