**BEFORE THE**

**PUBLIC UTILITIES COMMISSION**

**STATE OF SOUTH DAKOTA**

**IN THE MATTER OF THE APPLICATION OF NORTHERN STATES POWER COMPANY DBA XCEL ENERGY FOR AUTHORITY TO INCREASE ITS ELECTRIC RATES**

**DOCKET EL12-046**

**TESTIMONY & EXHIBITS OF JON THURBER**

**ON BEHALF OF THE COMMISSION STAFF**

**PUBLIC VERSION**

**NOVEMBER 15, 2012**

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**Q. Please state your name and business address for the record.**

A. Jon Thurber, Public Utilities Commission, State Capitol Building, 500 East Capitol Ave., Pierre, South Dakota, 57501.

**Q. By whom are you employed and in what position?**

A. I am a utility analyst for the South Dakota Public Utilities Commission ("Commission").

**Q. Please describe your education and work experience.**

A. I graduated summa cum laude from the University of Wisconsin – Stevens Point in December of 2006, with a Bachelors of Science Degree in Managerial Accounting, Computer Information Systems, Business Administration, and Mathematics.

In January of 2007, I started my employment with the State of South Dakota as an auditor for the Department of Legislative Audit. In July of 2008, I joined the Commission as a staff utility analyst. I have attended a number of seminars and workshops on utility related matters during my employment with the Commission. Attached as Staff Exhibit___(JPT-1) is a list of dockets and testimony I have prepared on behalf of Commission Staff ("Staff").

**Q. Are you familiar with Northern States Power Company's ("NSP" or "Company") application for an increase in electric rates in South Dakota, Docket EL12-046?**

A. Yes. I have reviewed the Company's prefiled testimony, exhibits, working papers and responses to data requests as it pertains to the issues that I am addressing.

**Q. What are your responsibilities in this rate proceeding?**

A. I have several responsibilities. First, I will introduce the other Staff witnesses in this proceeding. Second, I will explain Staff's approach to measuring NSP's South Dakota electric revenue requirement. Third, I will respond to policy issues raised by Mr. Kramer and Ms. McCarten regarding known and measurable changes and the rate phase-in statutes. Fourth, I have prepared exhibits and will express Staff's opinion on specific pro forma adjustments. Finally, I will respond to the concerns raised by Shetek Wind Inc. ("Shetek") regarding the contract that allows Prairie Rose Wind to use certain interconnection rights associated with NSP's Angus Anson plant.

**Q. Would you introduce the other Staff witnesses in this proceeding and briefly identify the issues that their respective testimonies address?**

A. The following Staff witnesses provide testimony in this proceeding:

- Mr. Basil Copeland
    - Capital Structure
    - Return on Equity
    - Rate of Return
- Mr. Dave Peterson
    - Nuclear Plant Decommissioning Costs
    - Steam Remaining Life - Sherco, Black Dog, Red Wing, and Wilmarth
    - Other Production Remaining Life – Riverside and Inver Hills
    - Remaining Life: Minnesota Valley
    - Remaining Life: Blue Lake, Granite City, and Key City
    - Docket EL11-019 Depreciation Adjustment
    - SFAS 106 Pay Go
    - Net Operating Loss
    - Corporate Allocations
    - Pension and Insurance
    - Class Cost of Service – Spread of the Increase

    - Monthly Customer Service Charge
- Ms. Brittany Mehlhaff
    - Weather Normalization
    - Fuel Lag
    - Production Tax Credits
    - Margin Sharing
    - Wholesale Billing
    - Weather Normalized Allocator
    - EL11-019 Outcome
    - Transmission Cost Recovery (TCR) Rider Removal
    - Environmental Cost Recovery (ECR) Rider Removal
    - Riverside/Black Dog One-Time Expenses
    - Margin Sharing Lag
    - Rider Amortization
    - Rounding
    - Rate Design
- Mr. David Jacobson
    - Incentive Compensation
    - Interest on Customer Deposits
    - Union Wage Adjustment
    - Eliminated Positions
    - Cash Working Capital
- Mr. Patrick Steffensen
    - Vegetation Management
    - Storm Damages
    - Claims and Injury Compensation
    - Docket EL12-046 Rate Case Expense
    - Employee Expense Reduction
    - Aviation Adjustment
    - Private Fuel Storage
    - SO2 Emissions
- Mr. Matthew Tysdal
    - Advertising
    - Lobbying

- Economic Development
- Association Dues
- Charitable Contributions
- Economic Development Labor Adjustment
- Foundation Administration Costs
- Conservation/DSM Cost Removal

**Q. What revenue requirement issues will you address in testimony?**

A. I will address the following pro forma adjustments in this proceeding:

- Black Dog Combustion Turbine Exhaust Replacement
- Monticello Fire Model Project
- Monticello Appendix R Cable Replacement Project
- Prairie Island ZE Piping Replacement Project
- Prairie Island TN 40 Casks
- Prairie Island Receiving Warehouse
- Prairie Island Fire Model Project
- Prairie Island H Line Protection Replacement Project
- Monticello Extended Power Uprate/Life Cycle Management (EPU/LCM)
- Prairie Island Steam Generator
- Sherco 3 Plant transferred from Held For Future Use
- Sherco 3 Cooling Towers
- Black Dog Write Off Amortization
- Fines
- Lawrence Creek Substation Land Sale
- Interest Synchronization
- Docket EL11-019 Rate Case Expense

## SUMMARY OF NSP'S CASE

**Q. What is NSP requesting in Docket EL12-046?**

A. NSP is requesting a pro forma revenue requirement of approximately $187,420,000.[1] This includes a requested rate of return on common equity of 10.65%.[2] More importantly, this represents a rate increase of approximately $19,368,000[3] to its South Dakota electric service base rates that were established in Commission Docket EL11-019 in June 2012. This equates to an approximate 11.53% overall increase in test year pro forma revenue.[4]

**Q. What is NSP's approach to measuring its revenue requirement in this case?**

A. Generally speaking, NSP starts with a twelve-month historic test year ending 12/31/11. NSP then adjusts the historic test year with fifty-seven operating income pro forma adjustments and twenty-eight additional rate base pro forma adjustments.

**Q. What are NSP's pro forma adjustments based on?**

A. For the most part NSP's adjustments are based on known and measurable changes however a few adjustments exceed those parameters. They will be discussed individually by various Staff witnesses.

## SUMMARY OF STAFF'S CASE

**Q. What was Staff's approach to measuring NSP's revenue requirement in this case?**

**A.** As in previous rate cases, Staff is measuring NSP's South Dakota electric revenue requirement on a recent historical twelve-month period (test year) basis. Staff's analysis of the South Dakota electric operations reflects a number of adjustments to NSP's revenues, expenses, and investments for that test year. These adjustments are made with the objective of conforming the test year to emulate normal, ongoing conditions, and to reflect cost and operational changes which are known and reasonably measurable.

[1] Statement N, page 11, line 22, column South Dakota Retail Electric
[2] Statement N, page 11, line 4, column Rate
[3] Statement N, page 11, line 19, column South Dakota Retail Electric
[4] Statement N, page 11, line 23, column South Dakota Retail Electric

**Q. Has Staff prepared an exhibit which summarizes Staff's positions?**

A. Yes. Staff Exhibit___(BAM-1), Schedule 3 lists Staff's positions on the specific issues relating to NSP's South Dakota electric operating income while Staff Exhibit___(BAM-2), Schedule 2 lists Staff's positions on specific issues relating to NSP's South Dakota electric rate base. Staff Exhibit___(BAM-1), Schedule 2 and Staff Exhibit___(BAM-2), Schedule 1 summarize these positions, while Staff Exhibit___(BAM-1), Schedule 1 calculates Staff's position on NSP's total revenue deficiency and revenue requirement.

**Q. Based on analysis performed, has Staff found NSP's request for approximately $19,368,000 of additional revenue to be justified?**

**A.** No. Staff's case indicates that the Company's request exceeds its requirement for additional revenue from South Dakota electric customers. Specifically, Staff determined a rate increase of approximately $6,359,000[5] allows the Company to recover its ongoing costs and allows for the opportunity to earn a reasonable and fair return on utility investment. Staff's recommendation includes an allowable rate of return on common equity of 8.75%[6], and supports the refund of spent nuclear fuel storage proceeds from the Department of Energy as previously ordered by the Commission in Docket EL11-023.

The precise revenue requirement value of the following adjustments cannot be determined until the Commission makes a final determination on the various issues in this proceeding: Net Operating Loss, Cash Working Capital, Tax Collections Available, Weather Normalized Allocators, and Interest Synchronization. These adjustments will need to be recalculated to reflect Commission approved adjustments to rate base, operating income, and rate of return.

## POLICY

**Q. Referring to Mr. Kramer's direct testimony, page 45, lines 1 through 7, do you agree that the Company is permitted by statute to recover revenue requirements associated with four projects with 2013 planned in-service dates?**

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[5] Staff Exhibit___(BAM-1), Schedule 1, column b, line 10

[6] Testimony of Basil L. Copeland Jr. and Staff Exhibit___(BLC-1), Schedule 1

A. No. The fact that a plant addition has a planned in-service date within 24 months after the end of the test year does not, in and of itself, justify a rate case adjustment. In response to data request 2-9, the Company clarified that Mr. Kramer was referencing administrative rule 20:10:13:34:

> **20:10:13:44. Analysis of system costs for a 12-month historical test year.** The statement of the cost of service shall contain an analysis of system costs as reflected on the filing utility's books for a test period consisting of 12 months of actual experience ending no earlier than 6 months before the date of filing of the data required by §§ 20:10:13:40 and 20:10:13:43 unless good cause for extension is shown. The analysis shall include the return, taxes, depreciation, and operating expenses and an allocation of such costs to the services rendered. The information submitted with the statement shall show the data itemized in this section for the test period, as reflected on the books of the filing public utility. Proposed adjustments to book costs shall be shown separately and shall be fully supported, including schedules showing their derivation, where appropriate. ***However, no adjustments shall be permitted unless they are based on changes in facilities, operations, or costs which are known with reasonable certainty and measurable with reasonable accuracy at the time of the filing and which will become effective within 24 months of the last month of the test period used for this section and unless expected changes in revenue are also shown for the same period. (emphasis added)***

While the rule allows the Commission to consider adjustments within 24 months of the last month of the test period, no adjustments shall be permitted unless they are based on changes in facilities, operations, or costs which are known with reasonable certainty and measurable with reasonable accuracy ("known and measurable") and expected changes in revenue are also shown for the same period ("matching principle"). There are other fundamental ratemaking principles not specifically identified in ARSD 20:10:13:44 that should also be considered when evaluating a plant adjustment. For example, one regulatory standard to consider is whether the plant is used and useful. Other standard ratemaking principles include reviewing the investment for prudency, reasonableness, and necessity for the rendition of electric service.

**Q. Please provide further definition of the used and useful principle.**

A. Plant is considered used and useful and should be included in rate base if it is currently providing or capable of providing service to customers. The costs for plant that is not actually in service should not be borne by current ratepayers, but instead should be borne by future ratepayers at the time the plant is ultimately dedicated to service since it is then that the ratepayer benefits from the use of the plant.

**Q. Do you apply the same standard for making an adjustment for a known and measurable change related to a capital project that Mr. Kramer described in his Direct Testimony beginning on page 37, line 21, through page 38, line 4?**

A. No. I would not adjust the test year to include a capital project based on a projected in-service date. Projected in-service dates that post-date the ratemaking analysis are not known with reasonable certainty. There are no assurances that a project will actually be constructed, let alone be completed and placed in service by the projected date. A known change in facilities is a facility that has already been placed in service or will definitely be placed in service at a specific time in the near future. In my opinion, the mere inclusion of a project in a capital budget does not qualify it as a known and measurable change.

**Q. Are the costs known and measurable for a plant addition that has not been placed in service?**

A. No. Since the plant addition is not completed and placed in service, we do not know the actual final construction cost of the project. As a result, the Company proposes to adjust the test year using the construction budget for the project. Construction budgets are based upon estimates that are developed using a number of assumptions. These assumptions include historical trends, cost projections, and a significant amount of judgment. Commission Staff does not have adequate time and resources, both financial and informational, that are necessary to critically evaluate all of the assumptions and projections used to develop construction budgets. Even if there was an agreement on the reasonableness of the estimates, the estimates may not materialize as projected and NSP would be either over-collecting or under-collecting through rates by reliance on estimates. Ratepayers are not compensated if forecasts are later proven to be inaccurate and result in overcharges. Forecasting errors, whether intentional or not, are a legitimate concern when using budgets. NSP’s use of estimates and projections is too speculative to qualify as a known and measurable change. Budgets may be adequate for planning, but lack sufficient precision for ratemaking.

Actual construction costs are accurate, reliable, and verifiable. While actual costs need to be evaluated for prudency, reasonableness, and necessity, there is little debate over whether actual costs are known and measurable.

**Q. Do you have any other concerns about making an adjustment for a projected plant addition in 2013?**

A. Yes. Plant which is not used and useful by the time final rates go into effect should not be included in rate base. On July 17, 2012, the Commission suspended the operation of the schedule of rates proposed by NSP pursuant to SDCL 49-34A-14 for 180 days after the application filing date of June 29, 2012. Staff anticipates a Commission decision in this docket around January 1, 2013. NSP is proposing to include plant which they do not expect to be placed in service until late in 2013. Customers should not have to pay for facilities on or around January 1, 2013, that will not be serving them until late 2013. Current ratepayers should only bear the cost of facilities that provide them a direct benefit.

**Q. Does the Commission's past precedent support adjustments to the test year for projected plant additions?**

A. No. In Docket F-3302, In the Matter of the Application of Minnesota Gas Company to Consolidate and Increase Rates for Gas Service based on Test Year Ended December 31, 1978, the Commission rejected projected plant adjustments as it found the adjustments were not known and measurable changes (see Staff Exhibit___(JPT-2), pages 1 through 3, for the applicable section of the Order). The Commission made the following findings in rejecting projected plant adjustments:

> The Commission finds that Minnegasco's proposed adjustments include a number of items based on expenses to be incurred in 1979 plant in service. The Commission finds that those adjustments are not known and measurable changes. Further, the Commission finds that Minnegasco's filing in this regard represents a 1979 projected test year. The Commission finds that not only is a projected test year impossible to fully evaluate and scrutinize, but, moreover, a projected test year based upon estimates is in total contravention of the rational and sound ratemaking principle of utilizing a test year adjusted for known and measurable changes. The Commission finds that utilization of an average actual test year adjusted for known and measurable changes avoids the impossible task of evaluating the reasonableness of all of the assumptions, projections and estimates involved in such a test year as we as lessens the possibilities of

> overcollection or undercollection by Minnegasco during the period the rates in this proceeding will be in effect.
>
> The Commission further finds that the fundamental ratemaking principle of matching is violated by Minnegasco's proposed adjustments. The Commission finds that Minnegasco's construction budget is an unreliable basis for establishing rates in this proceeding. The flaws of such an approach have been glaringly pointed out in this proceeding.

In Findings of Fact XXI, General Considerations, in Docket F-3302 (see Staff Exhibit___(JPT-2), pages 4 and 5, for the applicable section of the Order), the Commission described what it has found is the meaning of the terms known and measurable:

> Known and measurable changes do not relate to adjustments that cannot, by any standard or criteria, be said to be known and measurable today or the time of Minnegasco's filing. Known and measurable changes are exactly that. The antithesis of known and measurable changes are adjustments that are based on estimates, projections, or predictions which may be totally arbitrary or only partially arbitrary. Known and measurable changes, on the other hand, are exactly that: known and measurable.

**Q. Based on your interpretation of known and measurable changes, please describe the type of plant adjustments that can be reflected in this docket.**

A. Generally, Staff is able to annualize plant placed in service through October 2012, a full nine months after the end of the test year. As time progresses, NSP could offer additional known change adjustments prior to the Commission Order. Per SDCL 49-34A-8.4, NSP has the burden to account for known and measurable changes. A historic test year adjusted for known and measurable changes should make the test year reasonably reflective of conditions at the time new rates become effective.

**Q. Please refer to Ms. McCarten's direct testimony on pages 19 – 21 regarding the phase-in rate plan authorized by SDCL 49-34A-73 through 49-34A-78. Could NSP use a rate phase-in plan to recover future capital investments?**

A. Yes. Ms. McCarten stated the Company estimates investing approximately $5.9 billion during the 5 year period of 2012 – 2016, averaging approximately $1.18 billion per year. Based on NSP's current capital expenditure plan, the rate phase-in plan seems like the appropriate mechanism for cost recovery. Regardless of the Commission's decision in this case, Ms. McCarten also indicated it was likely that the Company will file another rate case in 2013. A rate phase-in plan could alleviate the need to file frequent rate cases during a major capital investment cycle.

**Q. Please explain how NSP could be allowed cost recovery for projected plant additions even though the changes are not known and measurable.**

A. Unlike a traditional application to increase rates, SDCL 49-34A-75 allows for an annual review of rates under the rate phase in plan and rates can be adjusted as necessary:

> 49-34A-75. Review of reasonableness of rates under phase in rate plan--Adjustment. At any time prior to one year after the conclusion of a phase in rate plan, the commission, upon its own motion or upon petition of the electric utility, may examine the reasonableness of the utility's rates under the plan, and adjust rates as necessary. Any phase in rate plan is subject to annual review. The electric utility shall file annually an abbreviated cost of service analysis showing that year's revenues, costs and revenue requirements, and a report of the progress of the construction or acquisition of the plant additions showing accumulative construction or acquisition costs for the year and updated cost projections to complete the plant additions.

Therefore, cost forecasts and projected in-service dates can be reconciled with actual conditions on an annual basis.

**Q. Do you think it is necessary to deviate from past Commission precedents on its finding of known and measurable changes when NSP has the ability to file for cost recovery of projected plant additions under the rate phase-in plan?**

A. No, I do not. The statutory authority already exists for NSP to recover its costs. However, NSP must make the appropriate filing and comply with the appropriate statutes to fairly balance the interests of customers and shareholders.

## BLACK DOG COMBUSTION TURBINE EXHAUST REPLACEMENT

**Q. Please describe the Company's adjustment for the Black Dog Generating Facility.**

A. As noted in Staff Exhibit___(JPT-3), page 3, the Company's response to data request 2-1, the exhaust cylinder on Unit 5 has experienced cracking requiring extended outage time for repairs. According the Company, this problem is a known industry issue for Siemens 501 CTs. Following the manufacturer's recommendation, NSP is replacing the entire exhaust cylinder assembly to avoid failure of the combustion turbine. The project was expected to be in service September 2012.

**Q. What is your recommendation in regard to the Black Dog Generating Facility adjustment?**

A. The replacement of the exhaust cylinder assembly appears needed for the reliable operation of Unit 5. The Company's total project cost was based on estimated costs and an estimated in-service date. The project went into service on August 15, 2012. I recommend accepting the adjustment related to the cylinder replacement to reflect the most recent actual costs. The detail for this adjustment can be found on Staff Exhibit__(JPT-3), page 11.

## MONTICELLO FIRE MODEL TOOL

**Q. Please describe the Company's adjustment for the Monticello Fire Model Tool.**

A. The Monticello Probabilistic Risk Assessment (PRA) Tool for fire protection was developed to evaluate compliance with regulation NFPA 805 as promulgated by the Nuclear Regulatory Commission. Although NSP ultimately decided against transitioning to NFPA 805, NSP stated that the tool was needed to gain an understanding of the costs and benefits of transitioning to NFPA 805, and was used in the decision to terminate the transition to NFPA 805 for the Monticello Nuclear Generating Plant. The Company also indicated that the tool will be used to evaluate issues regarding fire protection compliance in the future. The NRC staff accepted NSP's withdrawal of their intent to adopt NFPA 805 on October 22, 2010.

**Q. What is your recommendation regarding the Company's adjustment for the Monticello Fire Model Tool?**

A. As noted in Staff Exhibit___(JPT-4), page 1, the Company has revised its estimated in-service date from December 2012 to October 2013. As a result, I recommend rejecting the adjustment because the project is not completed at the time of this writing and the change is not known and measurable. The fire model tool is not used and useful, and should not be included in rate base.

## MONTICELLO APPENDIX R CABLE REPLACEMENT PROJECT

**Q. Please describe the Company's adjustment for the Monticello Appendix R Cable Replacement Project.**

A. The Monticello Appendix R Cable Replacement Project addresses areas of vulnerability at Monticello for fire induced circuit faults. The Nuclear Regulatory Commission has indicated that NSP must complete corrective actions associated with non-compliance by November 2012. The Company indicated that once this modification is completed, Monticello will be able to ensure that Containment Over Pressure is maintained and that the plant can be safely shut down post fire as required by 10 CFR 50 Appendix R. The original scope of the Appendix R project was installed in September 2011, with additional measures necessary to document fire protection requirements expected to be completed by November 2, 2012.

**Q. What is your recommendation in regard to the Monticello Appendix R Cable Replacement Project?**

A. The project was necessary to comply with federal regulations. I recommend annualizing the investment based on actual in service costs incurred to date, which would include the original scope of the project installed in September 2011. See Staff Exhibit___(JPT-5), pages 31 – 41, for details of the adjustment. The additional plant expected to be completed by November 2012 has not been placed in service at the time of this writing. The Company may supplement its application when these changes become known and measurable.

## PRAIRIE ISLAND ZE PIPING REPLACEMENT PROJECT

**Q. Please describe the Company's adjustment for the Prairie Island ZE Piping Replacement Project.**

A. The Company stated that the Prairie Island ZE Piping Replacement Project is required because there is inadequate cooling to critical equipment in the Auxiliary Building. NSP indicated that the pipe appears to be blocked by river silt, resulting in a significant reduction or a total loss of water flow, damaging the pipe and causing leakage. The Company claims that this project was pursued to ensure proper cooling is provided for worker safety and to prolong the life of plant equipment in the Auxiliary Building. The piping was replaced in December 2011.

**Q. What is your recommendation in regard to the Prairie Island ZE Piping Replacement Project?**

A. Prairie Island has been operating for approximately 40 years. In order to continue use of the facility for the next 20 years, it is necessary to replace equipment over the life of a plant due to performance degradation. This project seems to restore the plant to its intended operation performance. I recommend accepting the adjustment related to the ZE piping replacement to reflect the most recent actual costs. The detail for this adjustment can be found on Staff Exhibit__(JPT-6), pages 31 - 37.

## PRAIRIE ISLAND TN 40 CASKS

**Q. Please describe the Company's adjustment for the Prairie Island TN 40 Casks.**

A. In order to support the continued operation of Prairie Island, the Company indicated it will need additional on-site used fuel storage capability. The Nuclear Regulatory Commission license for the Independent Spent Fuel Storage Installation (ISFSI) authorizes the use of 48 dry casks. There are currently 29 dry casks loaded and sitting on the concrete storage pad in the ISFSI. NSP plans to load 9 additional casks to provide room for used fuel discharged from the reactor during refueling outages. The project had an expected in-service date of August 2012.

**Q. What is your recommendation in regard to the Prairie Island TN 40 Casks?**

A. As noted in Staff Exhibit___(JPT-7), page 11, the Company's response to data request 2-1 (b), the estimated in-service date has been postponed from August 2012 to May 2013. In the Company's response to data request 5-3 (a & c), or Staff Exhibit___(JPT-7), page 12, NSP intends to load and place in service 6 of the 9 casks in 2013, with the remaining three casks to be loaded in 2014. As a result, I recommend rejecting the adjustment because the project is not complete at the time of this writing and the change is not known and measurable. The casks are not used and useful, and should not be included in rate base.

## PRAIRIE ISLAND RECEIVING WAREHOUSE

**Q. Please describe the Company's adjustment for the Prairie Island Receiving Warehouse.**

A. NSP plans to construct a new warehouse and receiving facility at Prairie Island. According to the Company, the new facility is needed to free up space for other projects and allow for a more efficient scheduling of security inspections. As noted in Staff Exhibit___(JPT-8), pages 12 and 13, the Company's response to data request 6-4, the new warehouse was necessary to comply with Nuclear Electrical Insurance Limited requirements and NRC Security Requirements. The project had an expected in-service date of August 2012.

**Q. What is your recommendation in regard to the Prairie Island Receiving Warehouse?**

A. As noted in Staff Exhibit___(JPT-8), page 1, the Company's response to data request 2-6 (b), the project was placed in service on July 31, 2012. The receiving warehouse appears necessary to comply with insurance and regulatory requirements, and also improves warehousing efficiencies. I recommend accepting the adjustment related to the receiving warehouse to reflect the most recent actual costs. The detail for this adjustment can be found on Staff Exhibit__(JPT-8), pages 15 - 25.

## PRAIRIE ISLAND FIRE MODEL PROJECT

**Q. Please describe the Company's adjustment for the Prairie Island Fire Model Project.**

A. Similar to the Monticello Nuclear Generating Plant, Prairie Island was also required to develop a model to evaluate fire protection compliance with regulation NFPA 805. The Company indicated that the Probabilistic Risk Assessment model is used as a tool to identify cost-effective ways to reduce plant risk, and to resolve long standing fire protection issues. NSP also noted that the models for each nuclear plant are unique because the models incorporate plant-specific information such as location of components within each fire compartment, making the models highly dependent on the specific arrangement and geometry of the components and cables within the facility. Unlike for the Monticello plant, NSP decided to implement NFPA 805 for Prairie Island,

and the fire model will be used to support the License Amendment Request. The project had an expected in-service date of September 2012.

**Q. What is your recommendation in regard to the Prairie Island Fire Model Project?**

A. In response to data request 7-9, as shown on Staff Exhibit___(JPT-9), page 12, the Company stated that the project was scheduled to be placed in service in late September 2012. In response to both data request 2-7 and 7-9, the Company has been unable to provide actual costs or confirmation that the model is in service. I recommend rejecting the adjustment because the project is not complete at the time of this writing and the change is not known and measurable. The tool is not used and useful, and should not be included in rate base. The Company may supplement its application when these changes become known and measurable.

## PRAIRIE ISLAND H LINE PROTECTION REPLACEMENT PROJECT

**Q. Please describe the Company's adjustment for the Prairie Island H Line Protection Replacement Project.**

A. According to the Company, Foxboro H Line reactor protection equipment failures have caused unplanned Limiting Conditions for Operations and one recent reactor trip. NSP indicated that the reactor trip resulted in the development of a plan for Improvement of the Reactor Protection system in accordance with 10 CFR 50.65 a(1). Under this rule, NSP is required to develop a plan to prevent future reactor trips for the same reason. The Foxboro replacement project is the corrective action plan to remove the Reactor Protection System from a(1) status. The Company noted that Foxboro has stopped manufacturing the equipment and providing support, so refurbishment is not an option due to obsolescence of sub-components and degradation. The project had an expected in-service date of November 2012.

**Q. What is your recommendation in regard to the Prairie Island H Line Protection Replacement Project?**

A. As noted in Staff Exhibit___(JPT-10), page 1, the Company's response to data request 2-8 (b), the Prairie Island H Line Protection Replacement Project has been delayed from November 2012 to January 2013. As a result, I recommend rejecting the adjustment because the project is not complete at the time of this writing and the change is not known and measurable. The equipment is not used and useful, and should not be included in rate base.

## MONTICELLO EXTENDED POWER UPRATE/LIFE CYCLE MANAGEMENT (EPU/LCM)

**Q. Please describe the Company's adjustment for the Monticello EPU/LCM Project.**

A. The Company stated that the adjustment is for the plant additions necessary to operate the Monticello facility for the next 20 years and support increased generation capacity at the unit. The Nuclear Regulatory Commission has approved a life extension of the plant through 2030, and NSP anticipates approval of the license amendment for the extended power uprate in 2013. In the Settlement Stipulation approved in NSP's previous rate case, Docket EL11-019, the Commission allowed cost recovery of the revenue requirements related to 2011 Monticello EPU/LCM plant additions. This adjustment annualizes the previously approved Monticello EPU/LCM plant additions, and requests cost recovery of the plant additions that will be completed during the 2013 refueling outage. Mr. Kramer indicates in testimony that the project has planned in-service dates throughout 2013.

**Q. What is your recommendation in regard to the Monticello EPU/LCM Project?**

A. As noted in Staff Exhibit___(JPT-11), page 13, the Company's response to data request 6-6 (g), Attachment A, Revised Work Paper PF 24-8, no major plant additions have been placed in service for this project in 2012. The Company forecasts the next major plant addition to occur in May 2013. I recommend annualizing the plant previously approved in Docket EL11-019 and reflecting actual costs incurred to date in 2012. The plant additions forecasted to be completed in 2013 do not qualify as known and measurable changes. The 2013 forecasted plant additions are not used and useful, and should not be included in rate base. The detail for this adjustment can be found on Staff Exhibit__(JPT-11), pages 10 - 17.

## PRAIRIE ISLAND STEAM GENERATOR

**Q. Please describe the Company's adjustment for the Prairie Island Steam Generator.**

A. As noted in the Company's application, Prairie Island Unit 2's steam generators are the original plant equipment that has been operating for 39 years. According to the Nuclear

Project Authorization Form submitted in response to data request 2-11, as shown on Exhibit___(JPT-12), page 5, 71% of the tubes in one of the steam generator and 50% of the tubes in the other generator are defective/degraded. Unit 2's steam generators have more defective/degraded tubes that Unit 1's steam generators did prior to replacement in 2004. NSP indicated that the replacement of the steam generators is necessary to keep the plant operating through 2034 and support the extended power uprate. The project has a planned in-service date of November 2013.

**Q. What is your recommendation in regard to the Prairie Island Steam Generator Replacement project?**

A. I recommend rejecting the adjustment because the project is not complete at the time of this writing and the change is not known and measurable. The steam generator is not used and useful, and should not be included in rate base. A planned in-service date of November 2013 would also post-date this proceeding as it exceeds the statutory limit of 12 months to issue a final decision in this docket and maintain the ability to require a refund of increased rates per SDCL 49-34A-17.

## SHERCO 3 PLANT TRANSFERRED FROM HELD FOR FUTURE USE

**Q. Please describe the Company's adjustment for the Sherco 3 Plant transferred from Held For Future Use plant account.**

A. In 2011, the Company replaced turbine sections with a more efficient design that will increase Sherco Unit 3's output by a total of 22 MWs. While ramping the unit up during final testing, vibration levels registered well above normal causing NSP to shut the unit down. The vibrations damaged many components of the generator and turbine, and also caused a fire as a result of oil, hydrogen, and other materials released during the event. Due to the incident, this project is not currently in use and will not be in use until the unit returns to operation. The assets are currently in the Held for Future Use account because the construction of this equipment was completed but not yet in service and operational. NSP anticipates the Sherco 3 coming back online in the first quarter of 2013, and this project has a planned in-service date of March 2013.

**Q. What is your recommendation in regard to the Sherco 3 Plant transferred from Held For Future Use plant account?**

A. I recommend rejecting the adjustment because the project is not complete at the time of this writing and the change is not known and measurable. Sherco 3 is not currently operational. The project is not used and useful, and should not be included in plant in service.

## SHERCO 3 COOLING TOWERS

**Q. Please describe the Company's adjustment for the Sherco 3 Cooling Tower.**

A. According to the Company, the existing wooden cooling tower is at the end of life and needs to be replaced. In response to data request 2-13, as shown on Staff Exhibit___(JPT-13), page 2, NSP indicated that the long outage expected for the repair of Unit 3 has had a severe impact on the expected life of the existing wood structure. The wood has now dried out and is weakened due to that fact and general wear over the life of the tower. The Company proposes to replace the wood cooling tower with a fiberglass cooling tower to restore the original design capability and eliminate the risk of collapse. As noted on Staff Exhibit___(JPT-13), page 4, in the Company's response to data request 8-1, the expected in-service date of the project has been moved back from February 2013 to March 2013 to coincide with the expected return of Sherco 3.

**Q. What is your recommendation in regard to the Sherco 3 Cooling Tower?**

A. I recommend rejecting the adjustment because the project is not complete at the time of this writing and the change is not known and measurable. The cooling towers are not used and useful, and should not be included in rate base.

## BLACK DOG WRITE OFF AMORTIZATION

**Q. Please describe the Company's adjustment for the Black Dog Write Off Amortization.**

A. In its 2010 Integrated Resource Plan, the Company proposed to replace the remaining 270 megawatts of coal-fired generating capacity at its Black Dog Generating Plant with 680 megawatts of natural gas generation. The Black Dog plant has been generating power since 1952, and this proposed project was similar to NSP repowering its High Bridge and Riverside plants from coal to natural gas. According to Mr. Kramer, slow economic growth and the loss of municipal wholesale customers reduced NSP's projection of customers' electricity demand, leading the Company to determine the Black Dog Repowering project was no longer needed and the project would be evaluated in future resource plan filings. The Company's adjustment is to recover its project development costs, which it has determined have no future value, over a two year period.

**Q. What is your recommendation in regard to the Black Dog Write Off Amortization?**

A. While I have not reviewed the Company's 2010 Integrated Resource Plan (IRP) to determine the reasonableness of its load forecast and whether the Black Dog Repowering project was a prudent resource option, the Company should obtain adequate resources to meet the levels of projected customer demand and ensure reliable electric service to customers. Based on its August 2010 IRP, the Company indicated it had a capacity need of 500 MW by 2016. In December 2011, the Company updated its peak load forecast and the capacity need was almost 600 MW lower, indicating the economic recession and loss of wholesale customers as the primary drivers. Staff Exhibit___(JPT-14), pages 4 and 5, provides a comparison of the August 2010 and December 2011 demand and energy forecast. With the new forecast, it appears unanticipated changes to NSP's long-term customer demand impacted resource adequacy requirements. As a result, postponing the project until it is needed to meet demand seems reasonable. Staff Exhibit___(JPT-14), page 3, itemizes the Black Dog costs incurred as of December 31, 2011, and separates the total costs ($2.9 million) between those costs determined to have future value if the project is resurrected ($1.5 million), reimbursable costs ($0.4 million) and the $891,043 of costs determined to have no future value. I accept the Company's adjustment to write-off the preconstruction costs having no future value by amortizing the $891,043 over a two-year period with no return on the unamortized balance. I also accept the Company's proposal to refund any over-collections should the rates established in this case be in effect longer than the two-year amortization period.

## FINES

**Q. Please explain the adjustment regarding fines found on Exhibit__(BAM-1), Schedule 3, column (be).**

A. In response to data request 1-4, the Company indicated that it paid fines related to four incidents of small fish losses at the Prairie Island, Monticello, King, and Black Dog Generating Plants during 2011. NSP must comply with all applicable laws, and fines that result from imprudent management should not be borne by ratepayers. Staff Exhibit___(JPT-15) describes the fines in further details.

## LAWRENCE CREEK SUBSTATION LAND SALE

**Q. Please explain the adjustment regarding the Lawrence Creek Substation Land Sale found on Exhibit__(BAM-2), Schedule 2, column (ab).**

A. According the response to data request 4-7, the Company purchased land for the construction of the Lawrence Creek Substation that was ultimately not needed. Before the substation was built, NSP agreed to sell any post-construction excess property to the City of Taylor Falls, MN, at the same price per acre that was paid. The Company sold the property to the City in February 2012. There was a loss on this transaction as a result of closing cost associated with the transaction, but the loss was not included in the test year. This asset was improperly included in the test year as the land is no longer used to provide service to NSP customers. The Company agrees to remove the revenue requirements associated with the Lawrence Creek Substation Land per response to data request 1-8, as shown on Staff Exhibit___(JPT-16).

## INTEREST SYNCHRONIZATION

**Q. Has the Company proposed an adjustment for interest synchronization?**

A. Yes. The Company calculates the impact of debt synchronization for each adjustment as shown on Exhibit___(TEK-1), Schedule 6b, line 37.

**Q. Please explain what the adjustment accomplishes.**

A. Interest synchronization is an iterative process to synchronize the tax deduction for interest on debt with the adjusted rate base and weighted cost of long-term debt.

**Q. What are you proposing in regard to this adjustment?**

A. Instead of calculating the impact of debt synchronization on each adjustment, my adjustment uses Staff's historic test year rate base as adjusted for known and measurable changes and Staff Witness Copeland's recommendation for NSP's weighted cost of long-term debt. Although NSP's method for calculating the adjustment is different, the end result should be the same. The details for this adjustment can be found on Staff Exhibit__(JPT-17).

**Q. Do you anticipate any changes to the interest synchronization calculation during the course of the rate case proceeding?**

A. Yes. Interest synchronization will need to be recalculated to reflect Commission approved financial adjustments that impact rate base and the weighted cost of long-term debt. Staff will incorporate the impacts of any adjustments to interest synchronization in its compliance filing in this proceeding.

## DOCKET EL11-019 RATE CASE EXPENSE

**Q. Please explain the Company's adjustment for rate case expenses associated with Docket EL11-019.**

A. In Docket EL11-019, the Commission ordered the following in regard to rate case expense (Section III.8.a. of the Settlement Stipulation):

> The Parties agree that the actual rate case costs incurred (excluding accruals) through March 31, 2012, is $178,000 and is included in the Rate Case Expense identified above. The Parties also agree that rate case expenses incurred after March 31, 2012, through the conclusion of this proceeding, will be deferred on the Company's balance sheet and reviewed for recovery in the Company's next general rate filing in South Dakota.

In this proceeding, the Company is requesting to recover $210,000 in rate case expenses incurred after March 31, 2012, associated with Docket EL11-019. The Company is requesting to amortize these estimated projected expenses over 3 years, and include the average unamortized balance as a component of rate base.

**Q. What did the Company project as the total rate case expense from Docket EL11-019?**

A. When the rate case costs incurred prior to March 31, 2012, are combined with the estimated rate case costs incurred after March 31, 2012, the total requested recovery is

$388,241. The calculation and the breakdown of specific costs by category are shown on Staff Exhibit___(JPT-19), page 1, column g.

**Q. Did NSP provide the actual rate case costs incurred after March 31, 2012?**

A. Yes. In response to data request 4-2, Attachment A, as shown on Staff Exhibit___(JPT-19), page 27, the Company indicated it incurred $383,554 in rate case costs after March 31, 2012. When combined with the costs incurred prior to March 31, 2012, the total rate case costs associated with Docket EL11-019 was $561,795. NSP exceeded its revised rate case expense budget of $388,241 by $173,554 or 47%. Staff Exhibit___(JPT-19), page 1, columns f through g, compare the actual with estimated rate case costs.

**Q. In what specific rate case cost categories did NSP exceed its budget?**

A. NSP exceeded its budget for outside legal fees and ROE consulting costs. NSP incurred $229,607 in outside legal fees, exceeding its revised budget of $133,247 by $96,360 or 72%. The Company also incurred $175,834 in ROE consulting costs, exceeding its revised budget of $95,035 by $80,799 or 85%.

**Q. What explanation did the Company provide for exceeding the legal and consulting budget?**

A. In response to an informal discovery request, Company Witness Ms. Debra Paulson, Manager – Rate Cases, provided a line item breakout of costs into the four categories (Legal, Consulting, Administrative, and Commission Fees) and the following explanation to Staff Witness Patrick Steffensen:

> “Taken together costs before and after 3/31/12 are higher than the original $388,500 of estimated rate case expenses by approximately $173k due in large part to the additional consulting and legal expenses of a contested case proceeding before the Commission.”

Ms. Paulson’s complete response and the breakout of costs is shown on Staff Exhibit___(JPT-19), pages 28-29.

**Q. Did the detailed breakout of costs provided by the Company explain the cost overruns?**

A. The detailed breakout of costs provided adequate support to justify cost recovery of the actual administrative costs. In regards to legal and consulting fees, the breakout appeared to identify the checks written to Moss & Barnett, and Concentric Energy Advisors ("Concentric"). The breakout did not contain any information regarding the work performed or describe any variances from projections. As a result, the information provided did not support the reasonableness of the expenses.

**Q. Did Staff ask any additional discovery to determine the reasonableness of legal fees and ROE consultant costs?**

A. Yes. Staff asked the Company to reconcile the difference between the budgeted and actual expenses for legal and consulting costs. Ms. Paulson responded to the Mr. Steffensen's question with the following:

> "The EL11-019 was held June 13 & 14, however development of workpapers was done prior to the time of hearings in order to file the current case on June 30, 2012. Regardless of that timing, as with the court reporter fees for work at that hearing being billed/paid/posted in August, we did not have more complete knowledge of the legal and consulting fees than what was remaining in the prior estimate."

While I do not disagree that complete knowledge is obtained after the proceeding has concluded, NSP needs to justify the reasonableness and prudency of the expenses it incurs. The Company has not performed the reconciliation that Staff requested. NSP has not provided enough information to explain the significant cost overruns in legal and consulting costs. Ms. Paulson's complete response is provided on Staff Exhibit___(JPT-19), pages 30 - 31.

**Q. Did Staff request to review the legal and consulting invoices?**

A. Yes. The Company provided Staff with four Concentric invoices. The invoices contained the hours worked by each Concentric employee during the month and each employee's hourly rate. There were also expense lines for reimbursable expenses (travel, meals, and entertainment) and unit billings (conference calls, copies) for each month. While this information is useful in calculating the bill, it provides little insight into the work actually performed by the employees during the month. The Company requested confidential treatment of the invoices, and they are shown on Staff Exhibit___(JPT-19), pages 32 – 35.

Staff also requested to review Moss and Barnett invoices. In response to this request, Ms. Paulson provided the following, as documented on Staff Exhibit___(JPT-19), page 30:

> "Regarding the legal invoice, the $114,941.36 represents costs relating to the time spent on the 2011 rate case for research, drafting pleadings, and preparation for and attendance at the June hearings. The invoices themselves are subject to attorney-client privilege and include information related to litigation strategy and presentation of our case and are not subject to discovery."

**Q. Please explain why the cost overruns cannot be justified by the additional consulting and legal expenses of a contested hearing.**

A. Staff does not dispute that Docket EL11-019 was a contested case on two issues, cost of capital and cost recovery of the Nobles wind plant. However, Staff and the Company were able to resolve all other issues. As a result, I expected rate case costs to be significantly below original projections, as one of the primary reasons Staff settles a case is to save ratepayers litigation costs. Yet, the Company still exceeded its legal and consulting budgets by substantial amounts. The fact that Docket EL11-019 was a contested hearing on two issues does not justify an unlimited budget to process the case. When Staff inquires about variances from budgets and the Company cannot provide any detailed information to explain the differences, Staff becomes increasingly concerned regarding the Company's cost controls and its oversight of outside consultants.

**Q. Were any petitions to intervene granted in Docket EL11-019?**

A. No petitions to intervene were filed. Intervenors typically engage in discovery, write testimony, and file pleadings, causing the applicant to perform additional work when compared to a proceeding with just Staff and the applicant. Intervenors were not a factor in the rate case expense in this proceeding.

**Q. How many Staff discovery questions were related to cost of capital issues?**

A. Three. Staff Exhibit___(JPT-19), page 36 shows data request 5-3, 5-4, and 5-5 issued in the proceeding. I believe Staff engaged in limited discovery on cost of capital.

**Q. What did Staff pay its cost of capital witness, Mr. Basil Copeland, for his consulting services in Docket EL11-019?**

A. The total bill for Mr. Copeland's service in Docket EL11-019 was $21,840. Mr. Copeland spent a total of 136.5 hours reviewing and analyzing NSP's filings, preparing data requests necessary to complete analyses, preparing and presenting testimony and exhibits, and responding at the hearing. The hourly rate for his service was $160 per hour. When comparing the total ROE consulting bill, NSP spent over ***eight*** times the amount of Staff for its witness ($175,834 / $21,840 = 8.05). Concentric described its hours spent, hourly rate, and fee for testimony in detail in its contract and confidential invoices on Staff Exhibit___(JPT-19), pages 8, 19, and 32 - 35.

**Q. Do you have any questions regarding the Concentric invoices?**

A. Yes. The invoice for professional services from April 1, 2012, to April 30, 2012, included hours for **[confidential begins]** [redacted] **[confidential ends]**.

**Q. What is the Company estimating for legal and cost of capital consulting costs in the current case?**

A. According to work paper PF 13-2, the Company's projected legal and cost of capital consulting costs were $90,000 and $175,000, respectively. If the actual costs incurred in Docket EL11-019 were reasonable and prudent, one would assume that NSP would use those costs as a basis for developing its estimate in the current case. However, NSP did not, and they have not revised its estimate for these two cost categories through discovery.

**Q. What is your recommendation regarding rate case expense incurred after March 31, 2012, from Docket EL11-019?**

A. I accept the Company's actual administrative costs incurred after March 31, 2012, and agree that NSP was assessed a fee of $125,000 by the Commission for actual costs incurred in processing the case.

I do not believe the Company has supported its request for actual legal and cost of capital consulting costs. Staff has issued data requests to develop an understanding of the costs incurred, but NSP's responses have not provided sufficient justification for the expenses. The Company has not explained why the level of expense it is requesting is reasonable for cost recovery or why it exceeded its budget by a substantial amount. The Company may supplement its application during this proceeding.

Based on the information provided, using both estimates and actual costs incurred, I recommend accepting the legal and cost of capital consulting estimates for costs incurred after March 31, 2012, on work paper PF 13-2 of $80,000 and $50,000, respectively. Shareholders should be responsible for costs that exceed budgets that have not been justified.

I accept the Company's adjustment to include one-half of the Commission approved unamortized rate case expense as a component of rate base. My recommendations have been incorporated by Staff Witness Patrick Steffensen on Staff Exhibit___(PJS-1), Schedule 1.

**Q. What is your position on the amortization period?**

A. While the Company's proposal of three years is reasonable in most cases, NSP's recent rate case history and capital investment forecast suggests a shorter amortization is necessary to collect the costs for ratepayers over the time rates are in effect. The Company has filed three rate cases over the past four years, indicating that rates have been revised about every one and a half years. The amortization periods established in the last two rate cases, Dockets EL09-009 and EL11-019, were five and three years, respectively. As a result, rates established in this proceeding will most likely include the costs associated with processing three rate cases: Docket EL09-009, Docket EL11-019, and the current proceeding. In addition to past history, Ms. McCarten indicated it was likely that the Company will file another rate case in 2013. I would recommend a two year amortization period for rate case expense to reflect these considerations. A two year amortization period is the same period of time remaining on the rate case expense tracking mechanism established in Section III.8.a. of the Settlement Stipulation from Docket EL11-019. To protect both ratepayers and the Company in the event that two years is an inaccurate estimate, I would further recommend that the rate case costs incurred after March 31, 2012, from Docket EL11-019 be included in the previously established tracking mechanism. The tracking mechanism ensures the Company neither over recovers nor under recovers these costs.

## NET-ZERO INTERCONNECTION ARRANGEMENTS

**Q. Please explain Shetek's concerns regarding the contract that allows Prairie Rose Wind to use certain interconnection rights associated with NSP's Angus Anson plant.**

A. According to Shetek's Petition to Intervene, Xcel transferred certain generation rights with respect to the Angus Anson plant to Prairie Rose Wind, LLC, the owner of a 200MW wind project located in Minnesota. The Prairie Rose Wind interconnection rights are generically referred to as a "net zero" arrangement and were made pursuant to MISO interconnection policies. On page 2 of Shetek's Petition to Intervene, Shetek stated the following concerns regarding the ratemaking treatment of the net zero interconnection arrangement:

> "From a ratemaking perspective, now that Xcel has disposed of its generation interconnection rights, the expenses and capital costs related to the Angus Anson plant should be removed from the rate base to the extent of the disposition. Moreover, the value of the rights disposed of should be reflected as income in the rate base accruing to the benefit of ratepayers. Failure to do so will result in ratepayers paying double for the same generation capacity."

**Q. Did NSP respond to Shetek's ratemaking concerns regarding the net zero interconnection arrangement in its answer to Shetek's Petition to Intervene?**

A. No. On page 4 of the Answer of Northern States Power Company to Petition to Intervene by Shetek Wind Inc., NSP indicated that Staff could address Shetek's concerns:

> "If there is any question regarding the Prairie Rose Wind interconnection arrangement at Angus Anson and the potential impact on the Company's costs or rates, the Commission Staff can adequately investigate and address the issue."

**Q. Please describe your review of the Prairie Rose Wind interconnection arrangement at Angus Anson.**

A. I issued seven interrogatories, data requests 11-1 through 11-7, to obtain an understanding of the interconnection arrangement and determine if any adjustments should be made to test year revenues, expenses, and investments to reflect the interconnection agreement. Staff Exhibit___(JPT-18) contains the Company's responses to those interrogatories.

**Q. Please provide your recommendation regarding the ratemaking treatment of the Prairie Rose Wind interconnection arrangement at Angus Anson.**

A. According to the Company's response to data request 11-1 (a), as shown Staff Exhibit___(JPT-18), page 2, all rights of Prairie Rose Wind to utilize the interconnection capacity of the Angus Anson plant are subordinated to the rights of the Anson Plant to utilize the existing interconnection capacity. Since the Prairie Rose Wind interconnection rights are subordinate to the rights of Angus Anson, NSP has not disposed of its Angus Anson generation interconnection rights. In response to data request 11-2, as shown on Staff Exhibit___(JPT-18), page 7, NSP indicated that the interconnection rights with MISO allow the Angus Anson plant to generate and inject into the transmission grid up to 392 MW of output during all hours of the year. Based on the information provided, the Angus Anson plant appears used and useful in serving NSP customers on the system. Therefore, it would be inappropriate to remove investments and expenses associated with the Angus Anson plant. As shown on Staff Exhibit___(JPT-18), page 2, in response to data request 11-1 (c), NSP stated that it does not receive any income from the Prairie Rose facility that is offsetting any of the revenue requirements. As a result, no adjustment should be made to test year revenues.

**Q. Does this conclude your testimony?**

A. Yes.