Direct Testimony and Schedules
Thomas E. Kramer

Before the South Dakota Public Utilities Commission
State of South Dakota

In the Matter of the Application of Northern States Power Company
for Authority to Increase Rates for Electric Service in South Dakota

Docket No. EL12-_____
Exhibit___(TEK-1)

Overall Revenue Requirements
Rate Base
Income Statement

June 29, 2012

Table of Contents

Schedules

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND OCCUPATION.

A. My name is Thomas E. Kramer. I am a Principal Rate Analyst in the Revenue Requirements – North department for Xcel Energy Services Inc. (Service Company), the service company for the Xcel Energy Inc. holding company system and providing services to all of the operating utility subsidiaries of Xcel Energy Inc., including Northern States Power Company (Xcel Energy, NSPM, or the Company), operating in South Dakota.

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE.

A. I have been a Principal Rate Analyst since January 2011. Prior to that date, I held the position of Senior Rate Analyst in the same department since May 2008. My qualifications and experience are summarized in my resume provided as Exhibit___(TEK-1), Schedule 1.

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

A. I provide testimony supporting the Company's financial data and its request for a general rate increase in the State of South Dakota retail electric jurisdiction. My testimony supports the income statement and rate base portions of the South Dakota cost of service.

Q. WERE THE SCHEDULES PRESENTED WITH YOUR TESTIMONY PREPARED BY YOU OR UNDER YOUR SUPERVISION?

A. Yes, they were.

Q. IN ADDITION TO THE SCHEDULES INCLUDED WITH THIS TESTIMONY, ARE THERE ADDITIONAL SCHEDULES YOU ARE SPONSORING?

A. Yes. I am sponsoring the following Statements and supporting Schedules, which are required by South Dakota Public Utilities Commission (Commission) Rules (Sections 20:10:13:51 *et seq*.). These Statements and Schedules are located in Volume 1 of the Application:

A. Balance sheet

B. Income statement

C. Earned surplus statements

D. Cost of plant

- D-1. Detailed plant accounts
- D-2. Plant addition and retirement for test period
- D-3. Working papers showing plant accounts on average basis for test period
- D-4. Plant account working papers for previous years
- D-5. Working papers on capitalizing interest and other overheads during construction
- D-6. Changes in intangible plant working papers
- D-7. Working papers on plant in service not used and useful
- D-8. Property records working papers
- D-9. Working papers for plant acquired for which regulatory approval has not been obtained

E. Accumulated depreciation

- E-1. Working papers on record changes to accumulated depreciation
- E-2. Working papers on depreciation and amortization method
- E-3. Working papers on allocation of overall accounts

F. Working capital

F-1. Monthly balances for materials, supplies, fuel stocks, and prepayments

F-2. Monthly balances for two years immediately preceding pro forma year

F-3. Data used in computing working capital

G. Cost of Capital, Long Term Debt and Stock

G-1. Stock Dividends, Stock Splits, or Changes in Par or Stated Value

G-2. Common Stock Information

G-3. Reacquisition of NSPM Bonds or Xcel Energy Inc. Preferred Stock

G-4. Earnings Per Share for Claimed Rate of Return

H. Operating and maintenance expenses

H-1. Adjustments to operating and maintenance expenses

H-2. Cost of power and gas

H-3. Working papers for listed expense accounts

H-4. Working papers for Interdepartmental Transactions

I. Operating revenue

J. Depreciation expense

J-1. Expense charged other than prescribed depreciation

K. Income taxes

K-1. Working papers for federal income taxes

K-2. Differences in book and tax depreciation

K-3. Working papers for consolidated federal income tax

K-4. Working papers for an allowance for current tax greater than tax calculated at consolidated rate

K-5. Working papers for claimed allowances for state income taxes

L. Other taxes

L-1. Working papers for adjusted taxes

M. Overall cost of service

N. Allocated cost of service

P. Fuel cost adjustment factor

R. Purchases from affiliated companies

To the extent the Commission's rules require a discussion of the content of these required Schedules, that discussion is provided with the required Schedule. Company witness Ms. Laura McCarten sponsors Statement Q, providing the required description of utility operations. Company witness Mr. Michael Peppin provides the support for the Statement O in his Direct Testimony.

Q. HAVE YOU RELIED ON INFORMATION PROVIDED BY OTHER WITNESSES IN PREPARING YOUR TESTIMONY AND SCHEDULES?

A. Yes. I relied on and incorporated information provided by other witnesses in this proceeding. Where applicable, I indicate in my testimony where the pro forma year cost information is based on information provided by other witnesses.

Q. ARE YOU PROPOSING A NUCLEAR COST RECOVER RIDER AS A PART OF THIS CASE?

A. No. However, we continue to believe a rider may be the most appropriate mechanism for recovery of these costs. If we file for approval of such a rider, we would submit our proposal for the Commission's consideration in a separate docket.

II. PRO FORMA YEAR REVENUE DEFICIENCY

Q. DID YOU PREPARE A COSS THAT SUPPORTS THE REVENUE REQUIREMENT AMOUNT AND REVENUE DEFICIENCY FOR THE PRO FORMA YEAR?

A. Yes, a COSS was prepared under my direction. Exhibit___(TEK-1), Schedule 2 (COSS Pages 1-6) contains a copy of the jurisdictional cost of service study.

Q. WHAT IS THE AMOUNT OF THE JURISDICTIONAL REVENUE REQUIREMENT FOR SOUTH DAKOTA?

A. The jurisdictional retail revenue requirement for South Dakota electric utility operations is $187,420,000, based on average rate base and net operating income for the 2011 pro forma year, as adjusted for known and measurable changes occurring in 2012 and 2013, making the 2011 pro forma year appropriate for the final rates that will go into effect in 2013. The jurisdictional retail revenue requirement is also based on the average 2011 capital structure, long-term debt and 10.65 percent cost of equity, based on the return on equity (ROE) recommended by Company witness Mr. James C. Coyne in his Direct Testimony.

Q. WHAT IS THE AMOUNT OF THE REVENUE DEFICIENCY FOR THE PRO FORMA YEAR?

A. The amount of the revenue deficiency for the pro forma year is $19,368,000. A summary of the revenue deficiency is shown in Exhibit___(TEK-1), Schedule 2 (Cost of Service Study or COSS), Page 5 of 6) as a comparison of the jurisdictional revenue requirement amount for the 2011 pro forma year with the revenues for the same period under present rates as approved by the Commission in Docket No. EL11-019. In order to earn an overall rate of return of 8.51 percent, South Dakota retail electric rates need to be increased by this amount, as developed in Exhibit___(TEK-1), Schedule 2 (COSS, Page 5 of 6).

Q. WHAT IS THE PERCENTAGE INCREASE IN RETAIL REVENUES PROPOSED IN THIS CASE?

A. The revenue deficiency amount represents a 11.53 percent overall increase in retail revenues compared to 2011 retail revenues (adjusted for fuel recovery timing and weather) at present rates as shown in Exhibit___(TEK-1), Schedule 2 (COSS, Page 5 of 6).

Q. IS THE COMPANY PROPOSING ANY COST RECOVERY CHANGES THAT ARE REVENUE NEUTRAL TO THE RATEPAYERS?

A. No, not in this proceeding. No rider projects were completed prior to 2011 so accordingly, the Company is not proposing to move any projects currently being recovered in riders to base rates.

III. PRIMARY REASONS RATE INCREASE NEEDED

Q. WHAT ARE THE PRIMARY DRIVERS FOR THE CURRENT REVENUE SHORTFALL?

A. Current rates were established based on a pro forma 2010 year in Docket No. EL11-019. Consequently, I will provide a comparison to the final authorized pro forma 2010 year. Exhibit___(TEK-1), Schedule 3 (Case Drivers) contains a summary of the case drivers. The following Table 1 lists the primary drivers for an increase in the revenue requirement that have occurred since the approved pro forma 2010 year.

Table 1

Case Drivers

Dollars in Millions	**Increase over 2010**
Capital Recovery	14.0
Non-Fuel O&M Expense (includes Payroll Taxes)	3.6
Amortization	0.2
Subtotal	17.8
Less Retail Margins (including reclasses)	(1.6)
2011 Pro Forma Deficiency	19.4

Q. THE LARGEST INCREASE IN REVENUE REQUIREMENTS RELATES TO CAPITAL NEEDS. PLEASE PROVIDE ADDITIONAL INFORMATION CONCERNING THE INCREASED CAPITAL INVESTMENTS MADE BY THE COMPANY SINCE 2010.

A. Table 2 provides a high level breakdown of the principal capital investments and related costs since 2010, resulting in an additional revenue requirement of $14.0 million.

Table 2

Case Drivers – Capital Recovery

Dollars in Millions	**Total Revenue Requirement**
Generation Projects	
Nuclear	4.2
All Other Generation	0.3
Total Generation Projects	4.5
Transmission Projects	0.5
South Dakota Distribution Projects	0.6
Total Identified Projects	5.6
Other Increases / (Decreases)	(0.6)
Total Rate Base	5.0
Depreciation	3.6
Property Taxes	(0.4)
Other Return & Tax Related	5.8
Total Capital Recovery Items	14.0

Q. PLEASE BRIEFLY DESCRIBE THE GENERATION PROJECTS.

A. We continue to make critical improvements to the nuclear facilities, (Monticello Extended Power Uprate, Prairie Island Steam Generator Replacement, Fire Models). Since the last rate filing, we have planned upgrades at the Sherburne County (Sherco) generating facility Unit 3, and the Black Dog generating station. In total, the South Dakota jurisdiction has increased approximately $32.2 million in net generation plant in service since 2010. We believe we have done so in a cost effective manner and ensured that efficient and reliable generation is available to serve customers, while at the same time being environmentally responsible.

Q. PLEASE DESCRIBE THE TRANSMISSION PROJECTS.

A. The Company continues to make significant investments in transmission plants in two separate groups: (i) investments qualifying for rate rider treatment, primarily transmission investments supporting increased delivery of wind generation; and (ii) system performance and interconnection investments. However, Xcel Energy has also made significant investments in transmission projects that were not included in the TCR Rider. The Company has invested in transmission projects mainly related to system performance through increased investment in station equipment and additional system interconnection investments, resulting in an increase in plant investment of approximately $5.1 million for the South Dakota jurisdiction.

Q. PLEASE DESCRIBE THE SOUTH DAKOTA DISTRIBUTION PROJECTS.

A. These project costs were specific to South Dakota and were for the purpose of adding to or improving distribution service in South Dakota and, therefore, have been directly assigned to the South Dakota jurisdiction. The Company's average investment in South Dakota distribution net plant in service has increased by approximately $5.7 million since 2010.

Q. WHAT ARE THE MAJOR INCREASES IN OPERATIONS AND MAINTENANCE (O&M) COSTS?

A. As shown in Table 3, the major changes in O&M costs are non-fuel production expense, transmission expense, and Administration & General (A&G).

Table 3

Non-Fuel O&M Cost Drivers

Dollars in Millions	**Change in O&M**	**Revenue Requirement Impact**
Non-Fuel Production Expense	2.4	1.9
Transmission	1.1	0.1
Distribution	0.4	0.4
Customer Accounts	(0.0)	(0.1)
Customer Information	0.0	0.0
A&G	1.0	1.0
Payroll Taxes	0.2	0.2
Total	5.1	3.6

Q. PLEASE DESCRIBE TABLE 3.

A. Table 3 compares the change in O&M as reflected in the Cost of Service between the 2010 approved level and the 2011 pro forma year. Some O&M costs that are not recovered in the Fuel Clause are reflected as fuel expense in the Cost of Service rather than as O&M; for example, fuel handling. Table 3 also shows the revenue requirement change associated with the change in O&M. Changes in O&M generally result in a dollar for dollar impact to revenue requirements. However, production and transmission O&M costs that are partially offset with revenue have less than a dollar for dollar impact;

for example, costs shared with Northern States Power Company – Wisconsin (NPSW) through the Interchange Agreement, or transmission costs offset with MISO revenue. See Exhibit___(TEK-1), Schedule 3 (O&M Drivers, Page 2 of 2) for detail supporting the expense and revenue re-classifications and interchange impacts.

Q. WHAT ARE THE DRIVERS FOR THE CHANGE IN O&M EXPENSE?

A. The increased revenue requirement for operating expenses can be attributed to increased operating costs at the nuclear facilities, and higher pensions and benefit cost between the two periods.

Q. DID YOU INCLUDE COMPARISONS OF THE CHANGE IN THE FUEL AND PURCHASED ENERGY EXPENSE AS PART OF THE O&M EXPENSE ANALYSIS?

A. No. Although the cost of fuel and purchased energy are considered to be an operating expense, recovery occurs through the separate fuel clause adjustment (FCA) mechanism and true-up process.

Q. HOW MUCH HAS DEPRECIATION EXPENSE CHANGED SINCE 2010?

A. As shown in Exhibit___(TEK-1), Schedule 4 (Income Statement 2010 Approved Level & 2011 Pro Forma with Increase, Page 2 of 2), depreciation expense has increased $3,588,000 since 2010. Additional plant in service of $72.0 million, as can be seen in Exhibit___(TEK-1), Schedule 11, Page 1 of 2, has been partially offset by the extended lives of the plant in service.

Q. HOW WAS DEPRECIATION EXPENSE AFFECTED BY ANY REMAINING LIFE STUDIES?

A. Included in the known and measurable pro forma adjustment section in my testimony, I address the impact on the unadjusted test year of the remaining life and net salvage estimate changes for several generation related facilities

IV. DATA PROVIDED AND SELECTION OF PRO FORMA YEAR

Q. PLEASE DEFINE THE FISCAL PERIODS FOR WHICH FINANCIAL DATA IS PROVIDED IN THIS PROCEEDING.

A. Following the rules of the Commission, financial data is provided for the calendar year 2011 (the "unadjusted test year") and the 2011 pro forma year that includes 2012 and 2013 known and measurable adjustments.

Financial data is first normalized to remove any unusual conditions in the actual year (*e.g.,* weather normalization) that should be adjusted for rate setting purposes. Next, the actual year is adjusted for regulatory adjustments (*e.g.,* foundation administration expenses, lobbying expenses, advertising, etc.). Finally, I make pro forma adjustments to reflect known and measurable changes occurring in 2012 and 2013 (a South Dakota statute permits a period of up to 24 months to be considered in developing known and measurable adjustments.), so that final rates, which will become effective in 2013, reflect the Company's revenues and expenses at the time the rates go into effect.

I also provide schedules for the unadjusted 2011 test year showing: the actual unadjusted average rate base; unadjusted operating income; overall rate of return; the calculation of required income; the income deficiency and revenue requirements. Exhibit___(TEK-1), Schedules 6a and 6b are separate rate base and income statement bridge schedules that identify the adjustments described in my testimony to the unadjusted 2011 test year that create the pro forma year reflecting: the normalizing adjustments; regulatory adjustments; and the known and measureable adjustments for 2012 and 2013.

V. JURISDICTIONAL COST OF SERVICE STUDY

A. Components of Jurisdictional COSS

Q. PLEASE DESCRIBE THE COMPONENTS OF THE JURISDICTIONAL COST OF SERVICE STUDY FOR THE 2011 PRO FORMA YEAR.

A. The complete jurisdictional cost of service is included in Volume 3 (Work papers) of this filing. The jurisdictional cost of service includes: a revenue requirement, rate base, income statement, income tax, and a cash working capital computation.

Q. PLEASE DESCRIBE THE JURISDICTIONAL COST OF SERVICE SUMMARY SCHEDULES.

A. The pro forma year jurisdictional cost of service summary is included at Exhibit___(TEK-1), Schedule 2 (COSS, Pages 1-6). In order to facilitate a comparison to the unadjusted 2011 test year, we have also included the unadjusted 2011 test year jurisdictional cost of service summary as Exhibit___(TEK-1), Schedule 2A (COSS, Pages 1-6).

- The cover page to Schedule 2 identifies the South Dakota retail jurisdiction requested ROE, and shows the earned ROE under current rates, the revenue deficiency, and the percent of increase that would result if rates were increased to earn the requested ROE (in this case 10.65 percent).

- The "Rate Base Summary" for total Company electric operations and the South Dakota jurisdiction is shown on Schedule 2 (COSS, Page 2).
- An "Income Statement Summary" for total Company electric operations and the South Dakota jurisdiction is shown on Schedule 2 (COSS, Page 3). The income statement shows the determination of total operating income at present authorized retail rates.
- The "Income Tax Summary" for total Company electric operations and the South Dakota jurisdiction is shown on Schedule 2 (COSS, Page 4). The schedule shows adjustments to book income necessary to determine state and federal taxable income. The federal and state income tax calculations are carried back to the income statement on Schedule 2 (COSS, Page 3).
- The "Revenue Requirement and Return Summary" for total Company electric operations and the South Dakota jurisdiction is shown on Schedule 2 (COSS, Page 5). Specifically, the schedule shows: the earned overall rate of return on rate base, the earned ROE, the revenue deficiency that needs to be recovered to enable the South Dakota jurisdiction electric operations to earn the requested ROE, the total revenue requirements and the percent of increase that would result by increasing retail billing rates by the amount of the revenue deficiency.
- The computation of cash working capital, Schedule 2 (COSS, Page 6), is carried back to the rate base on Schedule 2 (COSS, Page 2).

Q. ARE THE REVENUE CONVERSION FACTOR CALCULATION AND THE SOUTH DAKOTA COMPOSITE INCOME TAX RATES INCLUDED IN THIS FILING?

A. Yes. The revenue conversion factor calculation, using a South Dakota composite tax rate of 35 percent, is included in my exhibits at Exhibit___(TEK-1) Schedule 2 (COSS, Page 5) line 18.

B. Income Statement Schedules

Q. PLEASE EXPLAIN HOW THE INTEREST DEDUCTION FOR DETERMINING TAXABLE INCOME IS CALCULATED.

A. The interest deduction applicable to the income tax calculation is the result of a calculation commonly referred to as "interest synchronization." The amount of interest deducted for income tax purposes is the weighted cost of debt capital multiplied by the average rate base.

Q. DESCRIBE THE SCHEDULES IN YOUR EXHIBITS THAT ARE RELATED TO THE INCOME STATEMENT.

A. I have provided two schedules related to the income statements: Exhibit___(TEK-1), Schedule 4, Page 1 (Total Available for Return with Present and Final Rates, 2011 Pro Forma) and Page 2 (2010 Final Decision versus 2011 Pro Forma); and Exhibit___(TEK-1), Schedule 5, Page 2 of 2 (Income Statement Comparison - 2011 Pro Forma to Unadjusted Test Year).

Q. WHAT DOES EXHIBIT___(TEK-1), SCHEDULE 4 INCLUDE?

A. Schedule 4 (Income Stmts – 10 Final Decision and 11 Pro Forma with Increase) consists of two comparative income statements for the pro forma year. Page 1 of Schedule 4 is a comparative income statement for the 2011 pro forma year showing the income effect of present authorized rates and proposed rates. This comparative income statement was prepared from the results of the jurisdictional cost of service study and includes the proposed revenue to offset the deficiency in the South Dakota jurisdiction electric utility operations. Page 2 of Schedule 4 shows a comparative income statement of the 2011 pro forma year after the proposed rate increase, and the 2010 income statement after the final decision in Docket No. EL11-019.

C. Compliance with Commission Orders

Q. DID YOU REVIEW COMMISSION ORDERS AS PART OF THE DEVELOPMENT OF THE PRO FORMA YEAR REVENUE REQUIREMENT?

A. Yes. The following list briefly describes the various Commission Orders that were reviewed and addressed in preparing the pro forma year. I will discuss required adjustments relating to these later in my testimony. The Compliance Matrix included in the testimony of Ms. McCarten, Exhibit___(LM-1), Schedule 2, documents how our rate case filing includes information submitted in compliance with these prior Commission orders.

- Post Retirement Medical Benefits (OPEBs) – Pay as you go. In Docket No. EL11-019 the Commission reaffirmed its position to not use accrual accounting and instead to use pay as you go as the appropriate mechanism for recovering the cost of OPEBs. We have adjusted the 2011 actual year to reflect the use of pay as you go accounting.
- Non-Asset Based Margins. The Commission's approval of the Settlement Stipulation in Docket No. EL11-019 approved a non-asset based sharing mechanism under which the Company provided 30 percent of the non-asset based margins to the ratepayers through the fuel adjustment clause. To test the ongoing reasonableness of that sharing mechanism, the Company was directed to update the incremental and fully allocated cost studies in this proceeding. I will

discuss those studies and our recommendation to retain the existing sharing mechanism later in my Direct Testimony.

- Moving Completed TCR and ECR Projects to Base Rates. In Docket No. EL11-019 the Company was directed to move the costs of completed TCR and ECR projects into the base rate revenue requirement. No rider projects have been completed and therefore we are not proposing to roll any rider projects into base rates in this proceeding.
- Amortization. In the Settlement Stipulation approved by the Commission in Docket No. EL11-019 the Company and Commission Staff reaffirmed the six-year amortization period for the Private Spent Fuel Storage Facility; and the five-year amortization period for SO_2 emissions. Because we are filing a rate case within three years, those costs have not been fully amortized. Therefore, it is reasonable to retain the existing amortization period for those costs and no adjustment to the 2011 actual year costs was needed for the Private Fuel Storage or the SO_2 emissions. The Settlement Stipulation approved by the Commission also established a three year amortization period for Rate Case Expenses. Since the settlement on the Rate Case expenses related to Docket No. EL11-019 was not approved until May 2012, an adjustment to the 2011 test year was made to incorporate the updated Rate Case amortization level.
- Wind Production Tax Credits (PTCs). In the Settlement Stipulation approved by the Commission in Docket No. EL11-019 the Company and the South Dakota Staff agreed that PTCs in that case and in the future would be passed through to the ratepayers through the Fuel

Clause Rider. Accordingly, an adjustment has been made in this proceeding to remove PTC include in the unadjusted test year.

- MISO Schedule 26 Costs. In the Settlement Stipulation approved by the Commission in Docket No. EL11-019 the Company and Commission Staff agreed that Schedule 26 expenses and revenues should be removed from the unadjusted test year and included for Commission review in the TCR Rider on a going forward basis. Therefore, an adjustment has been made in the filing to remove from the unadjusted test year both Schedule 26 revenues and expenses.
- The Company has used the Commission approved nuclear fuel outage deferral/amortization methodology. That methodology was included in the 2011 unadjusted year and no adjustment was necessary.
- In the Settlement Stipulation approved by the Commission in Docket No. EL11-019 the Company and Commission Staff agreed on a depreciation adjustment of $2,273,000. That adjustment has been reflected in the unadjusted 2011 column in Schedule 6a and a separate adjustment was not necessary.

D. Jurisdictional Allocations

Q. PLEASE BRIEFLY DESCRIBE THE METHODS USED TO ALLOCATE COSTS TO THE COMPANY'S ELECTRIC UTILITY OPERATIONS.

A. The pro forma year includes both costs incurred directly by the Company's electric operating business and costs directly assigned or allocated by the Service Company for corporate functions (*e.g.,* accounting, human resources, law, etc.). The Service Company cost allocation and billing process is subject to Federal Energy Regulatory Commission (FERC) jurisdiction and authorization under a Utility Services Agreement between Xcel Energy and the Service Company. O&M cost assignments and allocations were the same as used by the Company in the recent South Dakota electric rate case (Docket No. EL11-019), the Minnesota electric rate case filed with the Minnesota Commission (MPUC Docket No. E002/GR-10-971) and the rate case filed with the North Dakota Public Service Commission (PU-10-657). Non-O&M costs include such items as book depreciation expense, deferred income taxes and property taxes. All of the common investments and their related costs, be they software or other common investments, are evaluated by asset location as to whether they should be direct assigned to Electric or Gas, or allocated based on Customers, Customer Bills, Transportation Studies, or the Three Factor Allocator (revenues, utility plant in service, and supervised O&M). Additional information regarding this process and the reason for selecting a particular allocator is also included in the Cost Assignment and Allocation Manual (CAAM) included in Volume 4 of this Application.

Q. PLEASE DESCRIBE THE METHODS USED TO ALLOCATE COSTS FOR ELECTRIC UTILITY OPERATIONS IN SOUTH DAKOTA.

A. Expenses are generally determined on a functional basis (*i.e.,* Production, Transmission, Distribution, Customer Accounts, Customer Information, Sales, Administrative and General). These functional amounts are directly assigned to the South Dakota jurisdiction electric utility operations or allocated to the electric operations based on cost causation. A summary and description of the allocation factors used to allocate expenses and capital items to the South Dakota jurisdictional electric operations income statement and rate base are contained in the CAAM included in Volume 4.

Q. PLEASE EXPLAIN THE PROCESS FOR ASSIGNING THE COMPANY'S INVESTMENT IN ELECTRIC PLANT TO THE SOUTH DAKOTA JURISDICTION.

A. A summary and description of the allocation factors used to allocate expenses and capital items to the South Dakota jurisdictional electric operations income statement and rate base is contained in Exhibit___(TEK-1) Schedule 7 (Allocation Factors). Plant investments are accounted for in the manner prescribed by the FERC Uniform System of Accounts. Detailed records are maintained on a functional basis (*i.e.,* Production, Transmission, Distribution, etc.). The capital budgets, from which the projected plant balances in rate base were developed, are also prepared on a functional basis. These functional amounts are assigned to the appropriate jurisdiction directly, or allocated based on the use of such assets in providing electric service in a particular jurisdiction and the underlying elements of cost causation.

Q. PLEASE EXPLAIN THE NEED FOR JURISDICTIONALLY ALLOCATING THE INVESTMENT IN PRODUCTION AND TRANSMISSION FACILITIES.

A. The Company's production and transmission system is designed, built, and operated to provide an integrated source of electricity shared by the Company's electric customers first between NSPM and NSPW operating companies through the Interchange Agreement approved by the FERC and discussed later in my testimony. With respect to allocations involving transmission and generation, it is first necessary to allocate expenses and investments between NSPW and NSPM. Those allocations are performed in accordance with the Interchange Agreement. Pursuant to that Interchange Agreement, approximately 16 percent of the costs are allocated to NSPW with a remaining 84 percent allocated to NSPM. The NSPM costs are then allocated between South Dakota, Minnesota, North Dakota, and a small group of wholesale customers taking service under rates regulated by FERC. The result is that those investments and expenses that are subject to the Interchange Agreement are allocated approximately 4.8 percent to South Dakota. Those investments and expenses that are not subject to the Interchange Agreement are allocated approximately 5.8 percent to South Dakota.

Q. PLEASE DESCRIBE THE METHODS OF ALLOCATING COSTS BETWEEN THE JURISDICTIONS SERVED BY NSPM.

A. To allocate NSPM investment in production and bulk transmission facilities to jurisdictional areas, I used the average of the 12-monthly coincident peak demands (12 CP Method) for the actual year ended December 31, 2011. The Commission accepted this method of allocation in previous rate proceedings (Docket Nos. EL11-019, EL09-009, EL92-016, F-3764, and F-3780). It is reasonable to use coincident peak demands as an allocation basis, because these facilities are designed to meet peak requirements and operate as an integrated system across all jurisdictions. Similarly, fixed operating costs, which are not sensitive to changes in the amount of energy produced, also have been allocated on a demand basis. Expenses and investment related to units of output, such as nuclear fuel, were allocated on the basis of energy requirements. Items of plant that serve only the jurisdiction in which they are located are directly assigned to that jurisdiction.

Q. HOW WERE THE DISTRIBUTION INVESTMENT AMOUNTS ASSIGNED TO THE SOUTH DAKOTA JURISDICTION?

A. The Company's electric distribution plant investment amounts have been directly assigned based upon the jurisdiction(s) served by each of the individual distribution facilities.

Q. PLEASE DESCRIBE ANY ADJUSTMENTS MADE TO THE ALLOCATION FACTORS FOR USE IN THE PRO FORMA YEAR ENDED DECEMBER 31, 2011.

A. To allocate investment in production and bulk transmission facilities for the 2011 year, I used the 2011 12-month coincident peak demands and energy allocators unadjusted for weather. In order to remove the effect of weather on the demand and energy allocators, an adjustment was applied to the unadjusted test year data. This adjustment is discussed in greater detail under the section Known and Measurable Pro Forma Adjustments. The same customer allocation factor is used for the unadjusted and pro forma years ending December 31, 2011. The allocation factors used in the development of data in the unadjusted and pro forma year-end December 31, 2011 may be found on Exhibit___(TEK-1) Schedule 7 (Allocation Factors). The revenues and expenses allocated to South Dakota can be found on Exhibit___(TEK-1), Schedule 2, (Cost of Service Study, Page 3 of 6) for the pro forma year and Exhibit___(TEK-1), Schedule 2A (Unadjusted Cost of Service Study, Page 3 of 6) for the unadjusted test year.

E. Pro Forma Adjustments

Q. PLEASE IDENTIFY ALL THE PRO FORMA ADJUSTMENTS MADE TO THE UNADJUSTED TEST YEAR TO DEVELOP THE PRO FORMA YEAR ENDED DECEMBER 31, 2011.

A. The following is a comprehensive list of all the adjustments included in the rate case to arrive at the 2011 pro forma year. It was necessary to make four categories of changes to the 2011 actual year to make the resulting pro forma 2011 year appropriate for setting rates that will be finalized and applied to service provided in 2013 and after. The first category of change is to normalize the 2011 data. The second category of change is to reflect prior regulatory decisions for what may be appropriately included in a pro forma year. The third category of changes is for known and measurable changes occurring in 2012 and 2013 that need to be reflected in order for rates to appropriately reflect the cost of service when charged in 2013. The forth category of changes is to reflect amortization of expenses for both prior authorized and currently requested amounts that should not be fully recovered in a single year.

Normalization of 2011 Unadjusted Base Data:

1) Weather Normalization;
2) Fuel Lag Adjustment;
3) Incentive Compensation;
4) Vegetation Management;
5) Strom Damage; and
6) Claims & Injury Compensation.

Adjustments Reflecting Regulatory Practice:

7) Advertising Expenses;
8) Economic Development Costs;
9) Interest on Customer Deposits;
10) Professional and Utility Association Dues;
11) Charitable Contributions/Donations;
12) SFAS 106 Post Retirement Medical;
13) 2012 Rate Case Expense;
14) PTC moved to Fuel Clause; and

15) Economic Development Labor Costs.

Known and Measurable Adjustments:

16) Black Dog CT Exhaust Replacement;
17) Monticello Fire Model Project;
18) Monticello Appendix R Cable Replacement Project;
19) Prairie Island ZE Piping Replacement Project;
20) Prairie Island TN 40 Casks;
21) Prairie Island Receiving Warehouse;
22) Prairie Island NFPA805 Fire Model;
23) Prairie Island H Line Protection Replacement Project ;
24) Monticello EPU/LCM;
25) Prairie Island Steam Generator;
26) Sherco 3 Plant Additions;
27) Sherco 3 Cooling Towers;
28) Nuclear Decommissioning;
29) Remaining Lives (Sherco, Black Dog, Red Wing, Wilmarth);
30) Remaining Lives (Riverside, Inver Hills);
31) Remaining Lives (MN Valley);
32) Remaining Lives (Blue Lake, Granite City, Key City);
33) Depreciation (Production, Transmission, Distribution);
34) Net Operating Loss;
35) Union Wage Adjustment;
36) Margin Sharing on Trading Activity;
37) Wholesale Billing Adjustment;
38) Foundation Administrative Expenses;
39) Employee Expense Reduction;
40) Pension and Insurance Adjustment;

41) Weather Normalized Allocator;

42) EL11-019 Outcome Adjustment;

43) Aviation Expense Adjustment;

44) Corporate Allocations;

45) Removal of DSM Costs;

46) Withholding Tax Availability;

47) Remove TCR Revenue and Costs; and

48) Remove ECR Revenue and Costs.

Amortizations:

49) Private Fuel Storage Amortization;

50) SO_2 Emission Amortization;

51) Incremental Rate Case Amortization for Docket No. EL11-019;

52) Rider Amortization; and

53) Black Dog Write Off Amortization.

A list of these pro forma year adjustments is shown on Exhibit___(TEK-1), Schedule 8 (Rate Case Adjustments). I will also discuss each adjustment later in my testimony. In addition, I have provided a bridge schedule (Exhibit___(TEK-1), Schedule 6a (Rate Base) and Exhibit___(TEK-1), Schedule 6b (Income Statement) that show all normalized, regulatory and known and measurable change adjustments included in Exhibit___(TEK-1), Schedule 8.

1. *Pro Forma Year Normalizing Adjustments*

Q. YOU MENTIONED THAT YOU MADE ADJUSTMENTS TO THE 2011 ACTUAL DATA FOR THE PURPOSE OF NORMALIZING THE EXPENSES. PLEASE EXPLAIN.

A. The purpose of the pro forma year is to set rates based on a representative set of revenues and expenses. Consequently, it is necessary to normalize certain 2011 actual data.

Q. WHAT IS THE WEATHER NORMALIZATION ADJUSTMENT?

A. Our 2011 actual year reflects actual sales. Sales are affected by weather. Therefore, it was necessary to weather normalize the retail sales margin. For 2011, the estimated weather impact on sales was a positive 13,195 MWhs, meaning that weather had a favorable effect on sales relative to the budgeted sales. Therefore an adjustment is needed to reflect revenues in the pro forma year based upon normal weather. This adjustment is needed to lower the unadjusted test year revenues and associated fuel costs in order to reflect a non-weather affected pro forma year.

The detailed jurisdictional operating income impact of this adjustment is reflected on Exhibit___(TEK-1), Schedule 6b, page 1, column 2. As shown on Schedule 6b, page 1, column 2, row 28, this adjustment increases the pro forma year revenue requirements by $816,000.

Q. DO RETAIL OPERATING REVENUES REFLECT CALENDAR MONTH SALES VOLUMES IN THE PRO FORMA YEAR?

A. Yes. Non-fuel unadjusted test year revenues are on a calendar-month basis. However, the unadjusted test year reflects fuel revenues and fuel expenses that include a recovery lag of approximately 2.5 months. A pro forma adjustment was made to adjust the timing of both fuel revenue and expenses to an actual 2011 calendar-month basis. This adjustment has no impact on the revenue deficiency as the adjustment to revenue is offset by an equal adjustment to fuel expense. The adjustment reduces both retail revenues and fuel expense by $223,000, resulting in no change to revenue requirements.

The detailed jurisdictional operating income impact of this adjustment is reflected on Exhibit___(TEK-1), Schedule 6b, page 1, column 3. As shown on Schedule 6b, page 1, column 3, row 28, this adjustment had no impact on the pro forma year revenue requirements.

Q. IS THE COMPANY MAKING ANY OTHER SALES ADJUSTMENTS FOR THE PRO FORMA YEAR 2011?

A. No. It would not be appropriate to make an adjustment for the 2012 sales forecast because that would amount to a complete adjustment to revenues as compared to limited adjustments to expenses, resulting in a mismatched pro forma year. In addition, the budgeted 2012 South Dakota sales are currently estimated to be 0.91 percent higher than the actual 2011 sales, (on a weather normalized basis the increase is 1.58 percent). Actual weather normalized sales growth 2011 over 2010 was only 0.52 percent and 2010 over 2009 was 1.04 percent. Given the recent actual results when compared to the budgeted 2012 sales estimate, I am not recommending any pro forma adjustments related to sales.

Q. WHAT ADJUSTMENT DID YOU MAKE REGARDING THE 2011 INCENTIVE COMPENSATION PAYMENTS?

A. Incentive compensation payouts can vary from year to year based upon the actual results for the year compared to the plan objectives. For example, in the 2008 plan year, no Annual Incentive Plan (AIP) payment was awarded. Consistent with the treatment of AIP in the Settlement Stipulation in Docket

No. EL11-019, this adjustment is designed to normalize AIP costs based upon actual payouts multiplied by the performance indicators other than financial for the payout periods 2008 through 2011. In addition, the Settlement Stipulation allowed recovery on payouts for four of the nine Environmental Plan targets from the restricted stock plan. See the incentive pay work papers at Volume 3 for this calculation.

The detailed jurisdictional operating income impact of this adjustment is reflected on Exhibit___(TEK-1), Schedule 6b, page 1, column 4. As shown on Schedule 6b, page 1, column 4, row 28, this adjustment decreases the pro forma year revenue requirements by $839,000.

Q. WHAT ADJUSTMENT DID YOU MAKE REGARDING VEGETATION MANAGEMENT/TREE TRIMMING?

A. The Commission approved Settlement Stipulation in Docket No. EL11-019, normalized tree trimming based upon the five-year average of the actual experience. Therefore, I applied the same methodology, and replaced the 2011 actual year vegetation and tree trimmings costs with the average tree trimming costs for the five-year period 2007 through 2011.

The detailed jurisdictional operating income impact of this adjustment is reflected on Exhibit___(TEK-1), Schedule 6b, page 1, column 5. As shown on Schedule 6b, page 1, column 5, row 28, this adjustment decreases the pro forma year revenue requirements by $76,000.

Q. WHAT ADJUSTMENT DID YOU MAKE REGARDING STORM DAMAGE EXPENSE?

A. The Commission approved Settlement Stipulation in Docket No. EL11-019 normalized annual storm damage based upon the five-year average of the actual experience. Consequently, I normalized the annual storm damage by replacing the actual storm damage costs in the unadjusted 2011 test year with the average storm damage costs for the five-year period 2007 through 2011.

The detailed jurisdictional operating income impact of this adjustment is reflected on Exhibit___(TEK-1), Schedule 6b, page 1, column 6. As shown on Schedule 6b, page 1, column 6, row 28, this adjustment decreases the pro forma year revenue requirements by $54,000.

Q. WHAT ADJUSTMENT DID YOU MAKE REGARDING CLAIMS AND INJURIES COMPENSATION EXPENSE?

A. The Commission approved Settlement Stipulation in Docket No. EL11-019 normalized annual claims and injuries compensation expense based upon the five-year average of the actual experience. Therefore, I applied the same methodology, and included an adjustment equal to the difference between the actual claims and injuries compensation costs included in the 2011 actual year and the average claims and injuries compensation costs for the five-year period 2007 through 2011.

The detailed jurisdictional operating income impact of this adjustment is reflected on Exhibit___(TEK-1), Schedule 6b, page 1, column 7. As shown on Schedule 6b, page 1, column 7, row 28, this adjustment decreases the pro forma year revenue requirements by $238,000.

2. Pro Forma Year Adjustments Reflecting Regulatory Practices

Q. YOU MENTIONED THAT YOU MADE ADJUSTMENTS TO THE 2011 ACTUAL DATA FOR CERTAIN REGULATORY ADJUSTMENTS.

A. In this section I discuss the following adjustments made to the 2011 actual data to be consistent with prior regulatory adjustments made by the Commission:

- Advertising Expenses;
- Economic Development Costs;
- Interest on Customer Deposits;
- Professional and Utility Association Dues;
- Charitable Contributions/Donations;
- SFAS 106 Post Retirement Medical;
- 2012 Rate Case Expense;
- PTCs moved to Fuel Clause; and
- Economic Development Labor Costs.

Q. WHAT ADVERTISING ADJUSTMENT DID YOU MAKE?

A. The Company is required to reduce general and administrative expense for brand and image advertising costs that are not allowed to be recovered from South Dakota customers. The allowed advertising expense is primarily related to providing information on safety and customer information. Representative advertisements for which we are asking recovery and the relative dollar values are included in Statement H in Volume 1. Because we recorded the cost of brand and image advertising below the line, most of those costs were not included in the 2011 unadjusted expenses. However, I removed $181,000 for advertisements that had the purpose of promoting the Company's brand or image along with other advertising expenses not recoverable from South Dakota customers that were included in the unadjusted 2011 year expenses.

The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit___(TEK-1), Schedule 6b, page 1, column 8. As shown on Schedule 6b, page 1, column 8 row 28, this adjustment decreases the pro forma year revenue requirements by $181,000.

Q. HOW HAVE YOU TREATED ECONOMIC DEVELOPMENT COSTS?

A. The Commission approved Settlement Stipulation in Docket No. EL11-019 allowed the Company to recover 50 percent of its annual economic development expense up to $100,000 incurred for the benefit of South Dakota communities. Consequently, $50,000 of economic development costs has been included in the pro forma year.

The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit___(TEK-1), Schedule 6b, page 1, column 9. As shown on Schedule 6b, page 1, column 9 row 28, this adjustment increases the pro forma year revenue requirements by $50,000.

Q. WHY DID YOU MAKE AN ADJUSTMENT FOR INTEREST ON CUSTOMER DEPOSITS?

A. Customer deposits are treated as customer supplied capital and thus it is appropriate to pay ratepayers a return on their investment. The average balance of customer deposits is deducted from rate base while at the same time a pro forma year operating expense is increased to permit the recovery of the interest paid on these deposits.

The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit___(TEK-1), Schedule 6b, page 1, column 10. As shown on Schedule 6b, page 1, column 10, row 28, this adjustment increases the pro forma year revenue requirements by $1,000.

Q. WHY DID YOU MAKE AN ADJUSTMENT TO ASSOCIATION DUES?

A. We are requesting recovery of our association dues, excluding the portion of the dues that pays for social organizations or lobbying activities. Lobbying expenses are recorded below the line and consequently we do not have a separate lobbying adjustment. However, certain association dues include a component for social or lobbying activities of the organization. An analysis was prepared to eliminate that portion of the dues from the unadjusted 2011 test year.

The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit___(TEK-1), Schedule 6b, page 1, column 11. As shown on Schedule 6b, page 1, column 11, row 28, this adjustment decreases the pro forma year revenue requirements by $13,000.

Q. HOW HAVE YOU REFLECTED CHARITABLE CONTRIBUTIONS?

A. We are aware that the Commission has historically not approved charitable contributions. This was reinforced once again in the Commission approved Settlement Stipulation in Docket No. EL09-009. As a result, no charitable contributions were included in the 2011 actual year expenses. Although the Company believes requesting recovery of 50 percent of our charitable contributions made to South Dakota charities and institutions would be appropriate, we made no adjustment to include any charitable contributions in the pro forma year.

The detailed jurisdictional operating income impacts of making no adjustment are reflected on Exhibit___(TEK-1), Schedule 6b, page 1, column 12. As shown on Schedule 6b, page 1, column 12, row 28, there is no impact on the pro forma year revenue requirements.

Q. WHY HAVE YOU INCLUDED AN ADJUSTMENT FOR STATEMENT OF FINANCIAL STANDARD (SFAS) 106 POST RETIREMENT MEDICAL EXPENSES?

A. Prior to the issuance of SFAS 106, businesses recorded post-retirement benefit expenses other than pensions (primarily health care provided to retirees) on a pay-as-you-go basis. SFAS 106, which became effective in 1993, established an accrual accounting process under which the future projected cost of other post employment benefits or OPEBs was recognized at the time the benefits were earned. SFAS 106 also established a transition period of up to 30 years to recover the amounts that had not been previously recovered under the pay-as-you-go method but which would have been recognized under the SFAS 106 accrual method.

Fundamentally, using an actuarial estimate, the annual recorded amount is the current period expense for future postretirement benefits, such that the expense is fully recovered over the working life of the future retiree. The actuarially estimated amount is debited as expense and credited to the accumulated provision for OPEBs, creating a liability. When actual post-retirement health care costs are incurred, the liability is debited and cash is credited to pay the bill.

Q. HAS THE COMMISSION ADOPTED SFAS 106 FOR RATEMAKING PURPOSES?

A. No. In a January 26, 1993 Order in Docket No. EL92-016, the Commission declined to adopt SFAS 106 for ratemaking purposes. In Docket No. EL11-019, the Commission accepted the Settlement Stipulation, which included the Company's adjustment that converted the unadjusted 2011 test year SFAS 106 method of accounting used for financial reporting purposes to the Pay-Go method.

Q. WHAT ADJUSTMENT IS THE COMPANY REQUESTING IN THIS RATE REQUEST?

A. The Company is required to comply with SFAS 106 for financial reporting purposes. In addition, the Company is required to use SFAS 106 in the other jurisdictions in which it provides service. Consequently, it was necessary to convert from recognition of SFAS 106 to Pay-Go in the 2011 pro forma year.

The detailed jurisdictional rate base impacts of this adjustment are reflected on Exhibit___(TEK-1), Schedule 6a, page 1, column 2. The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit___(TEK-1), Schedule 6b, page 1, column 13. As shown on Schedule 6b, page 1, column 13, row 28, this adjustment increases the pro forma year revenue requirements by $341,000.

Q. PLEASE EXPLAIN THE AMORTIZATION OF RATE CASE EXPENSES IN THIS PROCEEDING.

A. The Company is projecting direct expenses associated with this rate case docket of $408,000. In addition the Company is requesting recovery of direct expenses associated with Docket No. EL11-019 that were incurred after

March 31, 2012. This deferral of rate case costs for review in this current case is permitted in the Settlement Stipulation for Docket No. EL11-019. These deferred costs have been estimated to be $210,000 for purposes of this adjustment. Therefore rate case expenses being included in this proceeding total $618,000. We propose to amortize these expenses over a three year period because we reasonably expect to file our next electric rate case within three years. Amortizing these expenses over a three-year period results in an annual amortization of $206,000. The development of our projected rate case costs is shown on Exhibit___(TEK-1), Schedule 10 (Rate Case Expenses). In addition to the amortization of rate case costs, the Company has increased rate base for the average unamortized balance consistent with treatment of the 2011 rate case costs in the Settlement Stipulation in Docket No. EL11-019

The detailed jurisdictional rate base impacts of this adjustment are reflected on Exhibit___(TEK-1), Schedule 6a, page 1, column 3. The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit___(TEK-1), Schedule 6b, page 2, column 14. As shown on Schedule 6b, page 2, column 14, row 28, this adjustment increases the pro forma year revenue requirements by $238,000.

Q. WHAT IS THE RECLASS OF PRODUCTION TAX CREDITS (PTCS) TO FUEL CLAUSE?

A. The Company receives federal income tax credits based upon the actual production from eligible wind projects. In the Commission approved Settlement Stipulation in Docket No. EL11-019, the annual level of PTCs allocated to the South Dakota jurisdiction are passed on to ratepayers through the Company's Fuel Clause Rider as the credits are earned based on actual wind production.

This adjustment removes the South Dakota jurisdiction total level of PTCs included in the unadjusted test year.

The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit___(TEK-1), Schedule 6b, page 2, column 23. As shown on Schedule 6b, page 2, column 15, row 28, this adjustment increases the pro forma year revenue requirements by $1,688,000.

Q. WHAT IS THE ECONOMIC DEVELOPMENT LABOR ADJUSTMENT?

A. As discussed earlier, the Commission allows the Company to recover 50 percent of its current economic development expense up to $100,000. This recovery cap is designed to allow the Company to recover both payments made to various organizations but also the administrative cost associated with managing the program. The Company's practice has been to provide the entire authorized amount to the organizations. As such, the administrative costs for processing the contributions is over and above the Commission authorized cap. Therefore the Company is making an adjustment to remove the estimated administrative labor cost associated with Economic Development activities. The adjustment level was based of the estimated time spent by three individuals for the South Dakota economic development activities. This calculated labor estimate is than removed from the unadjusted 2011 test year.

The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit___(TEK-1), Schedule 6b, page 2, column 16. As shown on Schedule 6b, page 2, column 16, row 28, this adjustment decreases the pro forma year revenue requirements by $23,000.

3. Known and Measurable Pro Forma Adjustments

Q. DID YOU FURTHER ADJUST THE BASE 2011 DATA TO DEVELOP THE PRO FORMA YEAR?

A. Yes. I made additional pro forma known and measurable adjustments to the unadjusted 2011 test year data. These adjustments are necessary to have final rates reflect the cost of service at the time the final rates become effective. These adjustments are:

- Black Dog CT 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 NFPA805 Fire Model;
- Prairie Island H Line Protection Replacement Project;
- Monticello EPU/LCM;
- Prairie Island Steam Generator;
- Sherco 3 Plant Additions;
- Sherco 3 Cooling Towers;
- Nuclear Decommissioning;
- Remaining Life: Sherco, Black Dog, Red Wing, Wilmarth;

- Remaining Life: Riverside, Inver Hills;
- Remaining Life: Minnesota Valley;
- Remaining Life: Blue Lake, Granite City, Key City;
- Depreciation Adjustment: Production, Transmission & Distribution
- Net Operating Loss;
- Union Wage Adjustment;
- Margin Sharing on Trading Activity;
- Wholesale Billing Adjustment;
- Foundation Administrative Expenses;
- Employee Expense Reductions;
- Pension and Insurance Adjustment;
- Weather Normalization Allocator;
- EL11-019 Outcome Adjustment;
- Aviation Expense Adjustment;
- Corporate Allocations;
- Removal of DSM costs;
- Withholding Tax Availability Adjustment;
- Remove TCR Revenues and Costs; and
- Removal of ECR Revenues and Costs.

Q. WHAT STANDARD DO YOU APPLY WHEN ASSESSING WHETHER TO MAKE AN ADJUSTMENT FOR A KNOWN AND MEASURABLE CHANGE?

A. In order to be considered for a known and measurable change, there needs to be compelling evidence that the adjustment yields a more accurate ongoing level of cost. Factors such as the following would be considered:

- A signed contract in place (*e.g.,* union wage increases);

- Action already taken by the Company (*e.g.,* employee expense reductions); and
- Major capital projects with actual or projected 2012 or 2013 in-service dates.

Q. WHAT ADJUSTMENTS DID YOU MAKE WITH RESPECT TO GENERATION THAT BECAME OPERATIONAL IN LATE 2011 OR 2012 ?

A. I made adjustments to reflect the 2013 revenue requirements associated with either late 2011 in service or 2012 planned in service capital projects for the Black Dog Generating facility, two projects at the Monticello Nuclear Generating Plant; and five projects at the Prairie Island Generating Plant

Q. PLEASE DESCRIBE THE BLACK DOG GENERATING FAILITY ADJUSTMENT.

A. The Black Dog Unit 5 Combustion Turbine Exhaust Replacement project was initiated as a result of the failure of various exhaust component parts subject to normal operating combustion temperatures and cyclic operations over the past 10 years. This project replaces most of these components in whole along with supporting equipment. The replacement project is necessary to ensure safe reliable operations going forward.

The project has an expected in-service date of September 2012. The adjustment was determined by comparing the 2013 capital related revenue requirement to the 2011 capital related revenue requirement included in the unadjusted 2011 test year.

The detailed jurisdictional rate base impacts of this adjustment are reflected on Exhibit___(TEK-1), Schedule 6a, page 1, column 4. The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit___(TEK-1), Schedule 6b, page 2, column 17. As shown on Schedule 6b, page 2, column 17, row 28, this adjustment increases the pro forma year revenue requirements by $102,000.

Q. PLEASE DESCRIBE THE TWO MONTICELLO PROJECTS AND THE ASSOCIATED ADJUSTMENTS?

A. The two Monticello projects included in this proceeding relate to mandated regulatory initiatives. The first is the Fire PPA Model Tool and the second is the Appendix R Hot Shorts Cable Replacements.

With respect to the Monticello PPA Fire Model Tool, the Nuclear Regulatory Commission (NRC) promulgated a new regulation for compliance with certain fire protection regulations. The new regulation (NFPA 805) prescribes the process that can be followed at the licensee's discretion to assess the risk of fire protection issues identified. As part of Monticello's assessment of whether to take advantage of NFPA 805, we developed a probabilistic risk assessment tool to support that decision. This project was for the development of that tool and, although Monticello decided to not incorporate the use NFPA 805 into its operating license, the tool will be used in the future to support evaluation of fire protection issues at the site.

The current planned in-service data for the project is December 2012. The adjustment was determined by comparing the 2013 capital related revenue requirement to the 2011 capital related revenue requirement included in the unadjusted 2011 test year.

The detailed jurisdictional rate base impacts of this adjustment are reflected on Exhibit___(TEK-1), Schedule 6a, page 1, column 5. The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit___(TEK-1), Schedule 6b, page 2, column 18. As shown on Schedule 6b, page 2, column 18, row 28, this adjustment increases the pro forma year revenue requirements by $167,000.

The Monticello Appendix R Hot Shorts Cable Replacement project relates to compliance with NRC fire protection requirements at Monticello. Recently, the NRC indicated that it will no longer allow compensatory measures to be taken in response to fire vulnerabilities, but rather, expects vulnerabilities to be fixed. This project addressed the areas of vulnerability to fire that were identified.

This project went into service in September 2011. The adjustment was determined by comparing the 2013 capital related revenue requirement to the 2011 capital related revenue requirement included in the unadjusted 2011 test year.

The detailed jurisdictional rate base impacts of this adjustment are reflected on Exhibit___(TEK-1), Schedule 6a, page 1, column 6. The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit___(TEK-1), Schedule 6b, page 2, column 19. As shown on Schedule 6b, page 2, column 19, row 28, this adjustment increases the pro forma year revenue requirements by $10,000.

Q. PLEASE DESCRIBE THE FIVE PRAIRIE ISLAND PROJECTS AND THE ASSOCIATED ADJUSTMENTS?

A. The first Prairie Island project represents cost associated with the ZE Piping replacement project. This ZE piping system is used to remove heat from the Auxiliary Building in the plant. Over the years silt has built up inside of the piping and microbiologically induced cracking has damaged the pipes. This piping is being replaced to restore cooling to the Auxiliary Building and the equipment housed there.

The project went into service in December 2011. The adjustment was determined by comparing the 2013 capital related revenue requirement to the 2011 capital related revenue requirement included in the unadjusted 2011 test year.

The detailed jurisdictional rate base impacts of this adjustment are reflected on Exhibit___(TEK-1), Schedule 6a, page 1, column 7. The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit___(TEK-1), Schedule 6b, page 2, column 20. As shown on Schedule 6b, page 2, column 20, row 28, this adjustment increases the pro forma year revenue requirements by $38,000.

The second Prairie Island project represents cost associated with the on-site storage casks. Prairie Island has limited used fuel storage capability in the used fuel storage pool in the plant. In order to provide room in the used fuel storage pool for used fuel discharged from the reactor during a refueling outage Prairie Island moves older, cooler used fuel to the Independent Spent Fuel Storage Installation (ISFSI). The Prairie Island ISFSI is licensed by the

Nuclear Regulatory Commission to utilize TN-40 casks. This project is for the 30th through the 38th TN-40 casks.

The project has a projected in service date of August 2012. The adjustment was determined by comparing the 2013 capital related revenue requirement to the 2011 capital related revenue requirement included in the unadjusted 2011 test year.

The detailed jurisdictional rate base impacts of this adjustment are reflected on Exhibit___(TEK-1), Schedule 6a, page 1, column 8. The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit___(TEK-1), Schedule 6b, page 2, column 21. As shown on Schedule 6b, page 2, column 21, row 28, this adjustment increases the pro forma year revenue requirements by $235,000.

The third Prairie Island project represents cost associated with the warehouse and receiving facility. The new receiving warehouse will consolidate some of the existing warehouses which, in-turn, will free up space for other projects. This project will improve warehousing efficiencies as well as reduce the burden on security because it will allow deliveries outside of the Owner Controlled Area, eliminating the need for security inspections. Delivered materials will be inspected inside of the new warehouse as scheduled by security and prior to distribution to the plant.

The project has a projected in service date of August 2012. The adjustment was determined by comparing the 2013 capital related revenue requirement to the 2011 capital related revenue requirement included in the unadjusted 2011 test year.

The detailed jurisdictional rate base impacts of this adjustment are reflected on Exhibit___(TEK-1), Schedule 6a, page 1, column 9. The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit___(TEK-1), Schedule 6b, page 2, column 22. As shown on Schedule 6b, page 2, column 22, row 28, this adjustment increases the pro forma year revenue requirements by $40,000.

The forth Prairie Island project represents cost associated with Prairie Island's NPRA Fire Model. The Fire Model relates to compliance with NRC fire protection requirements at Prairie Island. Recently, the NRC indicated it will no longer allow compensatory measures to be taken in response to fire vulnerabilities, but rather, expects vulnerabilities to be fixed. Recognizing that not all of the vulnerabilities may represent a significant risk to safety the NRC has also promulgated regulations that allow licensees to use probabilistic risk assessment to evaluate whether or not a potential vulnerability is risk significant. This project is to develop the model to assess the plant risks associated with these issues.

The project has a projected in service date of September 2012. The adjustment was determined by comparing the 2013 capital related revenue requirement to the 2011 capital related revenue requirement included in the unadjusted 2011 test year.

The detailed jurisdictional rate base impacts of this adjustment are reflected on Exhibit___(TEK-1), Schedule 6a, page 1, column 10. The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit___(TEK-1), Schedule 6b, page 2, column 23. As shown on Schedule 6b, page 2, column 23, row 28, this adjustment increases the pro forma year revenue requirements by $354,000.

The fifth Prairie Island project represents cost associated with the H Line protection. The Foxboro H-Line Protection is part of the reactor protection and steam exclusion system. The Foxboro modules are over 30 years old and were refurbished once in the 1980s. Foxboro H-Line equipment failures have caused unplanned Limiting Conditions for Operations and can lead to a trip of the reactor. Replacement is necessary to ensure reliable plant operation.

The project has a projected in service date of November 2012. The adjustment was determined by comparing the 2013 capital related revenue requirement to the 2011 capital related revenue requirement included in the unadjusted 2011 test year.

The detailed jurisdictional rate base impacts of this adjustment are reflected on Exhibit___(TEK-1), Schedule 6a, page 1, column 11. The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit___(TEK-1), Schedule 6b, page 2, column 24. As shown on Schedule 6b, page 2, column 24, row 28, this adjustment increases the pro forma year revenue requirements by $50,000.

Q. WHAT ADJUSTMENTS DID YOU MAKE WITH RESPECT TO GENERATION THAT BECOMES OPERATIONAL IN 2013?

A. As permitted by South Dakota statute, the Company is requesting recovery of the 2013 revenue requirements associated with four projects with 2013 planned in service dates. One at the Monticello Nuclear Generating Plant, one at the Prairie Island Nuclear Generating Plant, and two at the Sherburne County Generating Facility Unit 3.

Q. PLEASE DESCRIBE THE MONTICELLO GENERATING FACILITY 2013 IN SERVICE ADJUSTMENT.

A. The Monticello adjustment is the continuation of the Life Cycle Management/Extended Power Uprate (LCM/EPU) project. The Monticello project received a Certificate of Need for license extension in 2007 and a Certificate of Need for the Extended Power Uprate in 2009.

Life cycle management is a set of activities to ensure that the plant continues to run safely and reliably for the next 20 years. Some of the components under life cycle management are also being sized to support increased power generation that will become available as a result of increasing the reactor's thermal power limit under the NRC operating license (*i.e.,* Extended Power Uprate). The project activities during the 2013 refueling outage will include the final modifications necessary to produce the increased generation capacity. The activities are scheduled to be completed during the spring 2013 refueling outage are: 1) replacing: the 13.8 kV switchgear, 1R and 2R transformers, feedwater pumps and motors, reactor recirculation pumps and motors, condensate pump impellers and motors, number 13 feedwater heaters; 2) completion of: the moisture separator drain tank injection, and feedwater heater drain line work that was started during the spring 2011 refueling

The project has planned in-service plant additions throughout 2013. The adjustment was determined by comparing the 2013 capital related revenue requirement to the 2011 capital related revenue requirement included in the unadjusted 2011 test year.

The detailed jurisdictional rate base impacts of this adjustment are reflected on Exhibit___(TEK-1), Schedule 6a, page 1, column 12. The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit___(TEK-1), Schedule 6b, page 2, column 25. As shown on Schedule 6b, page 2, column 25, row 28, this adjustment increases the pro forma year revenue requirements by $2,507,000.

Q. PLEASE DESCRIBE THE PRAIRIE ISLAND GENERATING FAILITY 2013 IN SERVICE ADJUSTMENT.

A. The Prairie Island adjustment is associated with the Unit 2 steam generator replacement. Steam generators are the plant components that allow the thermal energy from the water in the primary loop that is heated in the reactor core to be transferred to the water in the secondary loop of the plant causing the water in the secondary loop to boil. The resulting steam then drives the generators. Prairie Island Unit 2's current steam generators are original plant equipment that have been operating for 39 years. Over time, the tubes inside of the steam generators are subject to aging which can lead to cracking. Tubes showing indications of cracking are plugged decreasing the steam generators efficiency. Eventually the steam generators need to be replaced. This project is to replace the Unit 2 steam generators. Unit 1's steam generators were replaced in 2004.

The project has a planned in-service date of November 2013. The adjustment was determined by comparing the 2013 capital related revenue requirement to the 2011 capital related revenue requirement included in the unadjusted 2011 test year.

The detailed jurisdictional rate base impacts of this adjustment are reflected on Exhibit___(TEK-1), Schedule 6a, page 1, column 13. The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit___(TEK-1), Schedule 6b, page 3, column 26. As shown on Schedule 6b, page 2, column 26, row 28, this adjustment increases the pro forma year revenue requirements by $690,000.

Q. PLEASE DESCRIBE THE TWO SHERCO UNIT 3 GENERATING FACILITY 2013 IN SERVICE ADJUSTMENTS.

A. As stated earlier, Sherco 3 has two significant projects with 2013 in service dates, the first relates to plant uprate projects that will be transferred from held for future use plant accounts and the second is for replacements of the units cooling towers.

With respect to the plant uprate transfers, during 2011, various projects were completed and would have been placed in service during the year. Those Sherco Unit 3 uprate projects included:

1. Replacement of the high pressure steam turbine rotor, diaphragms, and inner casing.
2. Replacement of the intermediate pressure steam turbine rotor and diaphragms.
3. Replacement of the Generator Step-up Transformer.
4. Replacement of the Automatic Voltage Regulator.
5. Replacement of the Water Cooled Rectifier.
6. Installation of an Iso-Phase BUS Duct cooling system.
7. Rewinding of the exciter rotor and stator.
8. Included associated support system updates and changes such as the control system, cooling water tie-ins, and instrumentation for monitoring of the equipment

The equipment listed above for this project was installed and initial commissioning was completed. The final testing and operational verifications at all load points was not completed due to an event at the Unit which has temporarily prevented its operation. Consequently, in December 2011, these capital projects were transferred to a held for future use plant account and will continue to be held there until the plant is fully operational and final testing can be completed. The planned return of Sherco 3 to operations is in early in 2013.

The project has a planned in-service date of March 2013. The adjustment was determined by comparing the 2013 capital related revenue requirement to the 2011 capital related revenue requirement included in the unadjusted 2011 test year.

The detailed jurisdictional rate base impacts of this adjustment are reflected on Exhibit___(TEK-1), Schedule 6a, page 1, column 14. The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit___(TEK-1), Schedule 6b, page 3, column 27. As shown on Schedule 6b, page 2, column 27, row 28, this adjustment increases the pro forma year revenue requirements by $138,000.

With respect to the Cooling Tower replacement project, the existing wooden cooling tower was at the end of life and is being replaced. The new fiberglass cooling tower consists of 26 cells arranged in 2 rows of 13. Each cell is approximately 40 feet wide by 70 long by 50 feet high. In addition to the structure, there is a 28 foot diameter fan, 150 HP motor, and gearbox for each cell. Approximately 13,000 gallons per minute of water flows over each cell. The cooling tower function is to remove residual heat from the power generation cycle and is critical to efficient operation.

The project has a planned in-service date of February 2013. The adjustment was determined by comparing the 2013 capital related revenue requirement to the 2011 capital related revenue requirement included in the unadjusted 2011 test year.

The detailed jurisdictional rate base impacts of this adjustment are reflected on Exhibit___(TEK-1), Schedule 6a, page 2, column 15. The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit___(TEK-1), Schedule 6b, page 3, column 28. As shown on Schedule 6b, page 2, column 28, row 28, this adjustment increases the pro forma year revenue requirements by $89,000.

Q. WHAT ADJUSTMETNS ARE BEING PROPOSED BY THE COMPANY WITH RESPECT TO NUCLEAR PLANT DECOMMISSIONING COSTS?

A. The Company is proposing an accrual start of January 1, 2013 for nuclear plant decommissioning costs based on the results of a recently completed decommissioning cost study estimate. In addition, the Company is proposing to offset the majority of this accrual requirement using funds received from the DOE under the settlement between the Company and the DOE over the DOE's cost responsibility for storing spent nuclear fuel.

Q. WHAT ACCRUAL RESULTED FROM THE NEW DECOMMISSIONING COST STUDY?

A. Based on the updated decommissioning costs estimates, combined with recent fund performance and the amounts previously provided for decommissioning by South Dakota customers, the 2013 decommissioning accrual is $2,184,000.

Q. HOW MUCH OF THIS ACCRUAL REQUIREMENT DOES THE COMPANY PROPOSE OFFSETTING USING FUTURE DOE PAYMENTS?

A. The Company is recommending that these funds be utilized to reduce the decommissioning accrual requirement by $1,169,000. As a result, the net accrual being proposed in this case beginning January 1, 2013 is $1,015,000.

The detailed jurisdictional rate base impacts of this adjustment are reflected on Exhibit___(TEK-1), Schedule 6a, page 1, column 16. The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit___(TEK-1), Schedule 6b, page 3, column 29. As shown on Schedule 6b, page 2, column 29, row 28, this adjustment increases the pro forma year revenue requirements by $893,000.

Q. PLEASE GENERALLY DESCRIBE THE REMAINING LIFE ADJUSTMENTS INCLUDED IN THIS CASE.

A. We are proposing changes to remaining lives that have either been previously approved by the Minnesota Public Utilities Commission in Docket Nos. E,G002/D-10-173 or E,G002/D-11-144, or have been proposed in Docket No. E,G002/D-12-151, currently pending before the Minnesota Commission. We are requesting approval consistent with the prior decisions of the Minnesota Commission, and consistent with prior practice, we request that the final decision with respect to those life extension requests in Docket No. E,G002/D-12-151 be reflected in our final rates that result from this proceeding.

Q. WHAT IS THE STEAM REMAINING LIFE ADJUSTMENT?

A. The Steam Remaining Life adjustment reflects the proposed changes in the remaining lives for the following plants:

- Black Dog Units 3 and 4 steam production plant (Docket 11-144);
- Red Wing refuse-derived fuel steam production plant (Docket 10-173),
- Wilmarth refuse-derived fuel steam production plant (Docket 10-173), and
- Sherburne County Unit 3 steam production plant (Docket 10-173).

In addition, this adjustment recognizes the new net salvage values for all steam production plants

The detailed jurisdictional rate base impacts of this adjustment are reflected on Exhibit___(TEK-1), Schedule 6a, page 1, column 21. The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit___(TEK-1), Schedule 6b, page 3, column 30. As shown on Schedule

6b, page 2, column 30, row 28, this adjustment decreases the pro forma year revenue requirements by $626,000.

Q. WHAT IS THE OTHER PRODUCTION FACILITY REMAINING LIFE ADJUSTMENT?

A. The Other Production Facility Remaining Life adjustment reflects the proposed changes in the remaining lives for the following plants:

- Inver Hills production plant (Docket 10-173); and
- Riverside production facility (Docket 10-173).

In addition, this adjustment recognizes the new net salvage values for these production plants

The detailed jurisdictional rate base impacts of this adjustment are reflected on Exhibit___(TEK-1), Schedule 6a, page 1, column 22. The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit___(TEK-1), Schedule 6b, page 3, column 31. As shown on Schedule 6b, page 2, column 31, row 28, this adjustment increases the pro forma year revenue requirements by $221,000.

Q. WHAT IS THE MINNESOTA VALLEY PRODUCTION FACILITY REMAINING LIFE ADJUSTMENT?

A. The Minnesota Valley Production Facility Remaining Life adjustment reflects the proposed changes in the remaining life associated with the Minnesota Valley production plant (Docket 12-151).

The detailed jurisdictional rate base impacts of this adjustment are reflected on Exhibit___(TEK-1), Schedule 6a, page 1, column 24. The detailed jurisdictional operating income impacts of the adjustment are reflected on

Exhibit___(TEK-1), Schedule 6b, page 3, column 32. As shown on Schedule 6b, page 2, column 32, row 28, this adjustment increases the pro forma year revenue requirements by $65,000.

Q. WHAT IS THE BLUE LAKE, GRANITE CITY, AND KEY CITY PRODUCTION FACILITY REMAINING LIFE ADJUSTMENT?

A. The Blue Lake, Granite City, and Key City Production Facility Remaining Life adjustment reflects the proposed changes in the remaining life associated with the Blue Lake, the Granite City, and the Key City production facilities (Docket 12-151).

The detailed jurisdictional rate base impacts of this adjustment are reflected on Exhibit___(TEK-1), Schedule 6a, page 1, column 25. The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit___(TEK-1), Schedule 6b, page 3, column 33. As shown on Schedule 6b, page 2, column 33, row 28, this adjustment decreases the pro forma year revenue requirements by $251,000.

Q. WHAT DOES THE DEPRECIATION ADJUSTMENT: PRODUCTION, TRANSMISSION, AND DISTRIBUTION REPRESENT?

A. In Docket No. EL11-019 the Company agreed to a depreciation adjustment. Based upon a similar adjustment approved by the Minnesota Public Utilities Commission in the most recent Minnesota Electric rate proceeding. This adjustment related to planned changes in depreciation rates for certain production, transmission, and distribution facilities. The adjustment was not recorded in the financial statements of the Company until 2012; therefore, this adjustment is needed to reflect the lower depreciation values in the pro forma year. We will be filing a new Five-Year Depreciation Study for Transmission, Distribution, and Other Assets in July, 2012. As with our proposed changes in remaining lives in Docket No. E,G002/D-12-151, we propose that the decision concerning our Five-Year Study be reflected in the final rates that result from this current proceeding.

The detailed jurisdictional rate base impacts of this adjustment are reflected on Exhibit___(TEK-1), Schedule 6a, page 1, column 23. The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit___(TEK-1), Schedule 6b, page 3, column 34. As shown on Schedule 6b, page 2, column 34, row 28, this adjustment decreases the pro forma year revenue requirements by $1,878,000.

Q. YOU INCLUDE A NET OPERATING LOSS ADJUSTMENT; WHAT IS A NET OPERATING LOSS?

A. Recent tax law changes have resulted in the Company generating a larger amount of tax depreciation than in prior years and more deductions than the Company can utilize in the current period. The result is the generation of a Net Operating Loss (NOL) for 2011.

Q. PLEASE EXPLAIN THE NET OPERATING LOSS ADJUSTMENT?

A. Because the Company has more tax deductions than it can utilize in 2011 (creating an NOL) the unused tax deductions need to be carried forward to a future period. The Company has determined the value of the NOL and made appropriate pro forma adjustments to both current and deferred tax items. The unadjusted 2011 test year has been adjusted to reduce the accumulated deferred income taxes and deferred income tax expense.

The detailed jurisdictional rate base impacts of this adjustment are reflected on Exhibit___(TEK-1), Schedule 6a, page 2, column 26. The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit___(TEK-1), Schedule 6b, page 3, column 35. As shown on Schedule 6b, page 3, column 35, row 29, this adjustment is $65,000.

Q. WERE ADDITIONAL REVENUES ASSOCIATED WITH A RATE INCREASE CONSIDERED WHEN CALCULATING THE IMPACT OF THE NOL ON THE PRO FORMA YEAR REVENUE REQUIREMENT?

A. No. The Company did not include the additional revenues it is seeking in this proceeding when calculating the NOL adjustment. Any rate increase granted by the Commission will create additional taxable income and consume a portion of the tax deductions that cannot be utilized in the current period.

Q. WHAT IS REQUIRED TO FINALIZE THE NOL ADJUSTMENT AT THE CONCLUSION OF THIS CASE?

A. Once all items of revenue and expense have been determined in this case, a recalculation of the NOL is necessary to determine the level of deductions that must be carried forward to a future period. As with the current determination, the recalculation at the end of the case will be affected by current tax depreciation deductions, annual deferred tax expense, and the accumulated deferred tax balance.

Q. PLEASE EXPLAIN THE UNION WAGE INCREASES.

A. We have completed contract negotiations with our union employees and the wage increases for both 2012 and 2013 are known and measurable. The increase for 2012 is 2.75 percent and for 2103 is 3.25 percent. These wage increases were applied to the actual union labor costs for 2011 to arrive at the adjustment amount.

The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit___(TEK-1), Schedule 6b, page 3, column 36. As shown on Schedule 6b, page 3, column 36, row 28, this adjustment increases the pro forma year revenue requirements by $440,000.

Q. WHAT NON-UNION WAGE INCREASE ARE YOU INCLUDING?

A. None. The Company suspended any wage increases for non-union employees for 2012. As a result of this suspension, the level of 2011 non-union wages represents current non-union wages.

Q. WHAT IS THE COMPANY RECOMMENDING IN THIS CASE REGARDING THE CURRENTLY APPROVED ASSET/NON ASSET COST SHARING?

A. The Company recommends continuing the existing sharing mechanism that was agreed to in the Settlement Stipulations approved by the Commission in both Docket No. EL11-019 and EL09-009 as an appropriate balance of ratepayer and Company interests.

Q. WHAT WAS AGREED TO IN THE SETTLEMENT STIPULATION IN DOCKET NO. EL11-019?

A. The Commission approved Settlement Stipulation provided for the flow back to rate payers of 100 percent of the asset based margins and 30 percent of the non-asset based margins through the Fuel Clause Adjustment factor.

Q. HAS THE COMPANY CONDUCTED THE INCREMENTAL AND EMBEDDED COST STUDIES PROVIDED FOR UNDER THE SETTLEMENT STIPULATION, AND IF SO, WHAT WERE THE RESULTS?

A. Yes, it has. Exhibit___(TEK-1), Schedule 9 is a report of those studies, explaining the methodologies used and the results. In summary, the incremental cost represents the costs that would cease to be incurred if the non-asset based business were to be terminated. The fully allocated cost methodology includes the incremental costs and a full allocation of common costs. The following table shows the results of those two studies and compares them to the existing 30 percent sharing mechanism. The three-year average period of 2009 to 2011 was used for this analysis.

	Incremental Cost Method	**Fully Allocated Cost Method**
30% Margin Sharing	$76,565	$76,565
Cost Estimate	$35,184	$70,877
Sharing Compared to Cost	$41,381	$5,6887

Q. PLEASE EXPLAIN WHY THE CURRENT SHARING MECHANISM PROVIDES A REASONABLE BALANCE OF INTEREST.

A. Incremental costs represent the costs that would cease to exist if the Company eliminated its non-asset based energy trading. The fully allocated costs include all incremental costs and include an assignment of overhead costs – or costs that would not go away if the Company ceased non-asset based trading.

The 30 percent sharing mechanism, based on a three year average, exceeds both the incremental and fully allocated costs and therefore provides a reasonable balance. Thus, the current 30 percent sharing mechanism has benefitted and would continue to benefit the ratepayers.

Q. WHAT SPECIFICALLY IS THE PURPOSE OF THE ASSET/NON-ASSET ADJUSTMENT?

A. For fiscal year 2011, the Company had positive non-asset margins that are included in the other revenue section of the income statement. Based upon the sharing agreement for non-asset margins, (South Dakota customers keep 30 percent of their jurisdictional share and shareholders keep the remaining 70 percent). The pro forma adjustment removes the 70 percent shareholder portion of the margin included in the unadjusted 2011 test year. Failure to remove the shareholder portion from other revenue would understate revenue requirements for the pro forma year.

The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit___(TEK-1), Schedule 6b, page 3, column 37. As shown on Schedule 6b, page 3, column 37, row 28, this adjustment increases the pro forma year revenue requirements by $753,000.

Q. PLEASE DESCRIBE THE WHOLESALE BILLING ADJUSTMENT.

A. In a review of cost assignments to our wholesale jurisdiction, we determined that the costs assigned to the wholesale jurisdiction in 2011 did not fairly represents the cost of providing billing and account management services to these customers. This adjustment directly assigns additional costs related to customer billing and account management expenses to the wholesale jurisdiction and likewise decreases costs assigned to the retail jurisdictions.

The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit___(TEK-1), Schedule 6b, page 4, column 38. As shown on Schedule 6b, page 4, column 38, row 28, this adjustment decreases the pro forma year revenue requirements by $7,000.

Q. HOW HAVE YOU TREATED THE XCEL ENERGY FOUNDATION ADMINISTRATION COSTS?

A. In Docket No. EL09-009, the Company was denied recovery of the Xcel Energy Foundation administration expenses. Therefore, an adjustment was made to remove these costs from the unadjusted 2011 test year.

The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit___(TEK-1), Schedule 6b, page 4, column 39. As shown on Schedule 6b, page 4, column 39, row 28, this adjustment decreases the pro forma year revenue requirements by $19,000.

Q. WHY HAVE YOU INCLUDED AN ADJUSTMENT REDUCING EMPLOYEE EXPENSES?

A. Based upon a review of the 2011 actual employee expense transactions, we have determined there were instances where some social expenses (*e.g.,* athletic tickets) should have been recorded below the line but were not. This adjustment is the Company's estimate of South Dakota portion of those employee's expenses.

The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit___(TEK-1), Schedule 6b, page 4, column 40. As shown on Schedule 6b, page 4, column 40, row 28, this adjustment decreases the pro forma year revenue requirements by $7,000.

Q WHY ARE YOU REQUESTING A KNOWN AND MEASUREABLE INCREASE IN PENSION EXPENSE?

A. The cost of pension expense has increased in 2012 by $13.5 million on a total Company basis compared to the 2011 actual year. This is a known increase for 2012. The South Dakota jurisdictional portion of this change equals $704,000. While costs will continue to increase through 2013, we have not included an adjustment for the increase in costs in 2013.

This increase is primarily caused by three factors:

1. The 2012 qualified pension cost includes the amortization of an additional layer of the 2008 asset losses, which are being phased into the pension expense calculation over five years (20 percent each year). As such, the full loss will not be recognized until 2013. The manner in which this loss is cumulatively phased in caused the 2012 pension costs to increase 2011 levels and is expected to increase pension costs through at least 2013.
2. The expected return on asset (EROA) assumption for NSPM and Xcel Energy Services Inc. (XES) decreased to 7.50 percent in 2012 from 8.00 percent in 2011, which contributes to the recognition of a higher level of pension expense. This decrease in EROA is primarily attributable to projected lower returns on bonds as a result of lower long term interest rates.
3. A decrease in the discount rate assumption, which contributes to the recognition of a higher level of pension expense.
    - NSPM pension costs are determined under the Aggregate Cost Method (ACM). Under the ACM method, the discount rate is

the same as the expected return on asset assumption, which decreased from 8.00 percent to 7.50 percent as described above.

- XES pension costs are determined under FAS 87, which uses a discount rate equal to the expected yield on high grade corporate bonds. The discount rate used in developing the 2012 year costs for XES has decreased to 5.00 percent from 2011's discount rate of 5.50 percent.

Q. PLEASE DESCRIBE WHAT ADDITIONAL ADJUSTMENTS ARE BEING PROPOSED BY THE COMPANY RELATED TO EMPLOYEE BENEFITS.

A. Although the Company is projecting an increase in active healthcare costs in 2012, the amount of this increase is not yet known and therefore does not meet the known and measurable criteria for making an adjustment. The projected increase on a total Company basis is approximately $5.0 million.

The Company has determined the 2012 levels associated with retiree medical, long-term disability and workers compensation will be a net reduction. Given this decrease an adjustment to the unadjusted 2011 test year was deemed proper. The net impact of these three known changes represents a decrease to the South Dakota jurisdictional cost of $27,000.

The detailed jurisdictional operating income impacts of the adjustment for pension and health insurance are reflected on Exhibit___(TEK-1), Schedule 6b, page 4, column 41. As shown on Schedule 6b, page 4, column 41, row 28, this adjustment increases the pro forma year revenue requirements by $677,000.

Q. WHY HAVE YOU INCLUDED A WEATHER ADJUSTED ALLOCATOR ADJUSTMENT?

A. The Company's demand and energy allocation factors are developed based upon sales. At the time the baseline inputs for the cost of service study for the case were developed, the weather normalized factors had not yet been finalized. This adjustment estimates the impact of the weather-normalized demand and energy allocators on expenses allocated the South Dakota jurisdiction using actual demand and energy allocators.

The detailed jurisdictional rate base impacts of this adjustment are reflected on Exhibit___(TEK-1), Schedule 6a, page 2, column 27. The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit___(TEK-1), Schedule 6b, page 4, column 42. As shown on Schedule 6b, page 4, column 42, row 28, this adjustment increases the pro forma year revenue requirements by $140,000.

Q. WHY HAVE YOU INCLUDED AN AVIATION EXPENSE REDUCTION?

A. In the Commission approved Settlement Stipulation in Docket No. EL11-019, an aviation expense reduction for the South Dakota jurisdiction was included that was consistent with similar adjustments made in both the Minnesota and North Dakota jurisdictions. The adjustment effectively allows for cost recovery of expenses associated with one leased corporate aircraft.

The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit___(TEK-1), Schedule 6b, page 4, column 43. As shown on Schedule 6b, page 4, column 43, row 28, this adjustment decreases the pro forma year revenue requirements by $58,000.

Q. PLEASE DESCRIBE THE CORPORATE ALLOCATIONS ADJUSTMENT.

A. We discovered the costs of a large number of computers and phones used by employees in Nuclear operation had been recovered as an XES expense in 2011, and recovered from all the operating companies rather than directly assigned to Nuclear. The adjustment is needed to correct the allocation in the unadjusted 2011 test year. Initially, the affected computers and phones were the property of the Nuclear Management Company (NMC) and were assigned to a few Business Systems employees within NMC who managed those assets. When NMC was brought back into NSPM, those Business Systems employees were moved into XES, along with the affected computers and phones. Subsequently, including in 2011, the costs of those computers and phones were allocated along with other XES equipment to all the operating companies, rather than being directly assigned to NSPM. During 2011, as part of the initiative to move employees out of XES who supported only one operating company, those Business System employees who supported only Nuclear were moved from XES to NSPM, along with the affected computers and phones. The resulting large shift in property from XES to NSPM brought this misallocation to light in 2012. The adjustment corrects the misallocation of these costs in 2011.

The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit___(TEK-1), Schedule 6b, page 4, column 44. As shown on Schedule 6b, page 4, column 44, row 28, this adjustment increases the pro forma year revenue requirements by $641,000.

Q. PLEASE DESCRIBE THE CONSERVATION/DSM COST REMOVAL ADJUSTMENT.

A. In October 2011 the Company received approval for a Demand Side Management Cost Recovery Tariff (Docket No. EL11-013), as a result of this new recovery mechanism, future conservation and DSM costs will be recovered through this tariff. The unadjusted 2011 test year still included conservation and DSM costs in the O&M expenses. This adjustment removes these 2011 costs from the pro forma year.

The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit___(TEK-1), Schedule 6b, page 4, column 45. As shown on Schedule 6b, page 4, column 45, row 28, this adjustment decreases the pro forma year revenue requirements by $189,000.

Q. PLEASE DESCRIBE THE EL11-019 OUTCOME ADJUSTMENT.

A. The Commission held the hearing on the Company's 2011 rate case filing (Docket No. EL11-019) in June 2012. The hearing resulted in the determination of a final revenue requirement granted to the Company for rates effective January 2012. This adjustment is needed to include in the pro forma year the 2012 revenue rate increase granted in that case.

The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit___(TEK-1), Schedule 6b, page 4, column 46. As shown on Schedule 6b, page 4, column 45, row 28, this adjustment decreases the pro forma year revenue requirements by $8,045,000.

Q. WHY HAVE YOU INCLUDED A WITHHOLDING TAX AVAILABILITY ADJUSTMENT?

A. Consistent with a similar adjustment made in Docket No. EL11-019, the Company has included a rate base adjustment to reflect the cash flow related benefit it receives associated to the timing between when the Company receives sales tax funds and employee withholding taxes and remits the funds to the taxing authorities. Since these forms of tax collection do not flow through the Company's income statement, they are not part of the traditional lead lag study.

The detailed jurisdictional rate base impacts of this adjustment are reflected on Exhibit___(TEK-1), Schedule 6a, page 2, column 20. The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit___(TEK-1), Schedule 6b, page 4, column 47. As shown on Schedule 6b, page 4, column 47, row 28, this adjustment decreases the pro forma year revenue requirements by $39,000.

Q. WHAT IS THE PURPOSE OF THE TCR REVENUE AND COST REMOVAL ADJUSTMENT?

A. The 2011 unadjusted test year data included recovery of both revenues the costs included in the TCR Rider. Therefore, in developing the 2011 pro forma year deficiency it is necessary to remove the revenues and costs of those uncompleted projects that will continue to be recovered through the riders.

The detailed jurisdictional rate base impacts of this adjustment are reflected on Exhibit___(TEK-1), Schedule 6a, page 2, column 28. The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit___(TEK-1), Schedule 6b, page 4, column 48. As shown on Schedule 6b, page 4, column 48, row 28, this adjustment decreases the pro forma year revenue requirements by $557,000.

Q. WHAT IS THE PURPOSE OF THE ECR REVENUE AND COST REMOVAL ADJUSTMENT?

A. The 2011 unadjusted test year data included recovery of both revenues and the costs that were recovered in the ECR Rider. All projects that had previously been collected under the ECR were rolled into base rates in Docket No. EL11-019. Beginning in January 2012 the ECR rider rate was set to zero. However since there were some residual ECR revenues and expenses recorded in 2011, the adjustment is needed to remove these revenues and cost from the pro forma year.

The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit___(TEK-1), Schedule 6b, page 4, column 49. As shown on Schedule 6b, page 4, column 49, row 28, this adjustment increases the pro forma year revenue requirements by $263,000.

4. Amortization Pro Forma Adjustments

Q. DID YOU FURTHER ADJUST THE BASE 2011 DATA TO DEVELOP THE PRO FORMA YEAR?

A. Yes. I made additional pro forma amortization adjustments to the unadjusted 2011 test year data. These adjustments are necessary to avoid over recovery of these otherwise one-time costs. Some of these adjustments follow the amortization periods established in the Docket No. EL11-019 Settlement Stipulation. These amortization adjustments are:

- Incremental Prior Rate Case;
- Private Fuel Storage;
- SO_2 Emission;
- Black Dog Write-Off; and

- Rider Amortization.

Q WHAT IS THE INCREMENTAL RATE CASE AMORTIZATION YOU HAVE INCLUDED IN THE PRO FORMA YEAR?

A. In the Settlement Stipulation for Docket No. EL11-019, the Company was authorized to record an annual rate case amortization of $133,333. This amortization is made up of the remaining amortization associated with Docket No. EL09-009 and rate case expenses incurred in Docket EL11-019 through March 31, 2012. Included in the base line adjustment to the cost of service model is the authorized amortization under Docket No. E09-009. This adjustment records the incremental increase between the amortization level authorized in Docket No. EL11-019 and the level authorized in EL09-009.

The detailed jurisdictional rate base impacts of this adjustment are reflected on Exhibit___(TEK-1), Schedule 6a, page 2, column 19. The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit___(TEK-1), Schedule 6b, page 4, column 50. As shown on Schedule 6b, page 4, column 50, row 28, this adjustment increases the pro forma year revenue requirements by $57,000.

Q WHAT IN THE PRIVATE FUEL STORAGE AMORTIZATION YOU HAVE INCLUDED IN THE PRO FORMA YEAR?

A. In the Commission approved Settlement Stipulation for Docket No. EL11-019, the Company was authorized to continue to record an annual amortization expense of $168,000 related to Private Fuel Storage amortization authorized in Docket No. EL09-009.

The detailed jurisdictional rate base impacts of this adjustment are reflected on Exhibit___(TEK-1), Schedule 6a, page 2, column 17. The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit___(TEK-1), Schedule 6b, page 5, column 51. As shown on Schedule 6b, page 5, column 51, row 28, this adjustment increases the pro forma year revenue requirements by $141,000.

Q WHAT IN THE SO_2 EMISSION AMORTIZATION YOU HAVE INCLUDED IN THE PRO FORMA YEAR?

A. In the Commission approved Settlement Stipulation for Docket No. EL11-019, the Company was authorized to continue to record an annual amortization of $(44,000) related to SO_2 Emission amortization authorized in Docket No. EL09-009.

The detailed jurisdictional rate base impacts of this adjustment are reflected on Exhibit___(TEK-1), Schedule 6a, page 2, column 18. The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit___(TEK-1), Schedule 6b, page 5, column 52. As shown on Schedule 6b, page 5, column 52, row 28, this adjustment decreases the pro forma year revenue requirements by $40,000.

Q WHAT IS THE BLACK DOG AMORTIZATION ADJUSTMENT YOU HAVE INCLUDED IN THE PRO FORMA TEST YEAR?

A. In August 2010, the Company proposed to repower the Black Dog Generating Plant to add about 680 MW of natural gas capacity and retire units 3 and 4 with 270 MW of capacity.

In December 2011, as a result of continued slow economic growth and the loss of municipal wholesale customers, the Company filed an update to the 2010 Resource Plan indicating that the Black Dog Repowering project was no longer needed at this time and the project would be evaluated in future resource plan filings. The Company filed requests with the Minnesota Commission on December 7, 2011 to withdraw the Black Dog certificate of need application and the companion generation site permit and transmission line route permit and suspended the project. As a result of the project suspension, the Capital Asset Accounting group performed an evaluation of the costs incurred to date associated with the project and determined that approximately $0.9M of the costs had no future value and were expense in 2011.

This adjustment removes the South Dakota jurisdictional portion of the write-off from the test-year and seeks to recovery the cost through an amortization expense beginning in 2013.

The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit ___ (TEK-1), Schedule 6b, page 5, column 53. As shown on Schedule 6b, page 5, column 53, row 28, this adjustment decreases test-year revenue requirements by $21,000.

Q WHAT IN THE RIDER AMORTIZATION ADJUSTMENT YOU HAVE INCLUDED IN THE PRO FORMA YEAR?

A. Associated with the TCR and ECR rider accounting is an amortization expense. Since this amortization expense in not recorded in the operating costs included in the unadjusted test year, this adjustment bring that amortization into the pro forma year. This adjustment is then accounted for and removed as part of the TCR and ECR cost removal adjustments discussed previously.

The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit___(TEK-1), Schedule 6b, page 5, column 54. As shown on Schedule 6b, page 5, column 54, row 28, this adjustment increases the pro forma year revenue requirements by $167,000.

Q. PLEASE EXPLAIN THE CASH WORKING CAPITAL, ROE, COST OF CAPITAL, AND ROUNDING ADJUSTMENTS INCLUDED IN SCHEDULE 6B, PAGE 5, COLUMNS 55, 56, 57 AND 58.

A. The adjustments made in developing the pro forma year affect the cash working capital requirements. As a result, it is necessary to recalculate the change in the cash working capital. This recalculation will need to be repeated once the final Commission approved adjustments are known.

The ROE and cost of capital columns in the schedule quantifies the revenue requirement effect of the proposed change in the ROE and capital structure from that authorized in Docket No. EL11-019.

Similarly, the numerous components of the adjustments can result in a slight deviation between the actual total revenue requirement and the sum of all of the parts. The rounding adjustment is to bring the final 2010 pro forma income statement back into proper balance. Like the cash working capital adjustment, it will need to be recalculate one the final Commission approved adjustments are known.

Q. WITH THESE PRO FORMA CHANGES, IS THE PRO FORMA YEAR AN ACCURATE AND RELIABLE BASIS UPON WHICH TO SET RATES?

A. Yes. With the adjustments I previously described, the pro forma year is a reasonable projection of Company costs and revenues on which to base this request for rate relief.

VI. RATE BASE

Q. IS THE 2011 PRO FORMA RATE BASE REASONABLE FOR PURPOSES OF DETERMINING FINAL RATES IN THIS PROCEEDING?

A. Yes. The pro forma year rate base was developed on sound ratemaking principles in a manner similar to prior Company electric rate cases. As a result of the above-described pro forma adjustments, the pro forma rate base appropriately represents the costs and investments in place at the time rates take affect in 2013.

Q. PLEASE EXPLAIN WHAT RATE BASE REPRESENTS.

A. Rate base primarily reflects the capital expenditures made by a utility to secure plant, equipment, materials, supplies and other assets necessary for the provision of utility service, reduced by amounts recovered from depreciation and non-investor sources of capital.

Q. PLEASE IDENTIFY THE MAJOR COMPONENTS OF THE PRO FORMA YEAR RATE BASE.

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

- Net Utility Plant;
- Construction Work In Progress
- Accumulated Deferred Income Taxes; and
- Other Rate Base.

Q. PLEASE DESCRIBE THE SCHEDULES IN YOUR EXHIBIT THAT ARE RELATED TO THE PRO FORMA YEAR AVERAGE INVESTMENT IN RATE BASE.

A. Exhibit___(TEK-1), Schedule 12 (Rate Base unadjusted test year to pro forma year for both total Company and South Dakota jurisdiction) and Exhibit___(TEK-1), Schedule 11, page 1 (reflecting the results of EL11-019 as the unadjusted 2011 test year with 2011 pro forma) and page 2 (rate base comparisons for 2011 actual, unadjusted 2011 test year reflecting the decision in EL11-019, and 2011 pro forma).

A. Net Utility Plant

Q. WHAT DOES NET UTILITY PLANT REPRESENT?

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

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

A. The net utility plant is included in rate base at depreciated original cost reflecting the 13-month average of projected net plant balances. This presentation is consistent with the net utility plant calculation in Docket No. EL11-019.

Q. WHAT HISTORICAL BASE DID XCEL ENERGY RELY ON AS A STARTING POINT TO DEVELOP THE NET PLANT BALANCES FOR THE PRO FORMA YEAR?

A. The historical base used was Xcel Energy's actual net investment (Plant in Service less Accumulated Depreciation) on the books and records of the Company for the period ending December 1, 2010 through December 31, 2011.

Q. WHAT WAS THE AVERAGE NET UTILITY PLANT INCLUDED IN THE PRO FORMA YEAR RATE BASE?

A. The average net utility plant included in the pro forma year rate base is $408,136,000, as shown on Exhibit___(TEK-1), Schedule 12, Page 1. This is comprised of an average plant balance of $796,836,000 as detailed on Exhibit___(TEK-1), Schedule 12, Page 1, minus an average depreciation reserve of $388,700,000 also shown by component on Exhibit___(TEK-1), Schedule 12, Page 1.

B. Construction Work In Progress

Q. HAS CONSTRUCTION WORK IN PROGRESS (CWIP) BEEN INCLUDED IN THE PRO FORMA YEAR RATE BASE?

A. No. CWIP is not included in rate base, and there is no corresponding offset of Allowance for Funds Used During Construction (AFUDC) added to operating income.

C. Accumulated Deferred Income Taxes

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

A. Inter-period differences exist between the book and taxable income treatment of certain accounting transactions. These differences typically originate in one period and reverse in one or more subsequent periods. For utilities, the largest such timing difference typically is the extent to which accelerated tax depreciation generally exceeds book depreciation during the early years of an asset's service life. ADIT represents the cumulative net deferred tax amounts that have been allowed and recovered in rates in previous periods.

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

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

Q. WHAT AMOUNT OF ADIT WAS DEDUCTED IN THE PROJECTED PRO FORMA YEAR RATE BASE?

A. As shown on Exhibit___(TEK-1), Schedule 12, Page 1, $77,620,000 was deducted. This amount reflects a 13-month average of pro forma year ADIT balances.

D. Other Rate Base

Q. PLEASE SUMMARIZE THE ITEMS YOU HAVE INCLUDED IN OTHER RATE BASE.

A. Other Rate Base is comprised of primarily what is referred to as Working Capital. It also includes certain unamortized balances that are the result of specific ratemaking amortizations as discussed further in my testimony.

Q. PLEASE EXPLAIN WHAT WORKING CAPITAL REPRESENTS.

A. Working Capital is the average investment in excess of net utility plant provided by investors that is required to provide day-to-day utility service. It includes items such as materials and supplies, fuel inventory, prepayments, and various non-plant assets and liabilities. The net cash requirements, also referred to as Cash Working Capital, is shown separately.

Q. HOW WERE PRO FORMA YEAR MATERIALS AND SUPPLIES AND FUEL INVENTORY REQUIREMENTS CALCULATED?

A. The Materials and Supplies and Fuel Inventory amounts shown on Exhibit___(TEK-1), Schedule 2, Page 2, are based on the 13-month average balances for December 2010 through December 2011, respectively. The Materials and Supplies average balance included in the pro forma year rate base equals $7,206,000. The pro forma year average rate base amount for Fuel Inventory is $4,958,000.

Q. HOW WERE PRO FORMA YEAR NON-PLANT ASSETS AND LIABILITIES DETERMINED?

A. These balances as shown on Exhibit___(TEK-1), Schedule 2, Page 2, represent the December 2010 to December 2011 actual 13-month average balances. Any book/tax timing differences associated with these items has been reflected in the determination of current and deferred income tax provision and accumulated deferred tax balances previously discussed. This group is primarily comprised of liabilities that reduce pro forma year rate base by $713,000.

Q. HOW WERE PRO FORMA YEAR PREPAYMENTS AND OTHER WORKING CAPITAL ITEMS DETERMINED?

A. Items of Prepayments and Other Working Capital, such as customer advances and deposits, are based on the actual 13-month average balances during the period ended December 2011. The net impact of these various items increase pro forma year rate base by $9,643,000 as shown on Exhibit___(TEK-1), Schedule 2, Page 2.

Q. HOW WERE PRO FORMA YEAR CASH WORKING CAPITAL REQUIREMENTS DETERMINED?

A. Cash Working Capital requirements have been determined by applying the results of a comprehensive lead/lag study to the pro forma year revenues and expenses.

Q. PLEASE BRIEFLY EXPLAIN HOW A LEAD/LAG STUDY MEASURES CASH WORKING CAPITAL.

A. A lead/lag study is a detailed analysis of the time periods involved in the utility's receipt and disbursement of funds. The study measures the difference in days between the date services to a customer are rendered and the revenues for that service are received, and the dates the costs of rendering the services are incurred until the related disbursements are actually made.

Q. HAS XCEL ENERGY UPDATED ANY COMPONENT OF THE LEAD/LAG STUDY SINCE THE LAST SOUTH DAKOTA ELECTRIC RATE CASE (DOCKET NO. EL11-019)?

A. Yes. An update to the South Dakota computer billed revenue lag component of the study was prepared using data through December 2011. All the expense related line items in the lead/lag calculations are based upon data through December 2011. In addition, the Company also incorporated revisions to the lead/lag information based upon the Settlement Stipulation in Docket No. EL09-009 for the computer billing revenue lag days and revised the revenue lag and expense lead days for interchange revenue and expenses. The Company felt these South Dakota adjustments were reasonable and were consistent with the cash working capital calculations used by the Company. The results of the updated lead/lag study for electric operations were incorporated into the South Dakota jurisdiction cash working capital calculations as shown on Exhibit___(TEK-1), Schedule 2 (COSS, Page 6 of 6). The lead/lag study can be found in Volume 4 of our Application.

Q. WHAT IS THE PRO FORMA YEAR CASH WORKING CAPITAL AMOUNT?

A. The amount included in the average rate base is a negative $2,247,000, as shown on Exhibit___(TEK-1), Schedule 2, (COSS Page 2 of 6). The pro forma adjustment, of $251,000 that brings 2011 unadjusted test year to the pro forma year amount is provided on Schedule 6a, column 29. This calculation will need to be revised after the Commission determines the final revenue requirement and rate of return, as these decisions will impact the pro forma year level of cash working capital.

Q. WHAT IS INDICATED BY THE NEGATIVE CASH WORKING CAPITAL AMOUNT?

A. The negative cash working capital indicates overall revenue collections lead the date when the associated costs of service are paid. This means that, on average, cash working capital is being provided by the ratepayers. Accordingly, the negative cash working capital included as a decrease to rate base and will lower the annual revenue requirement.

VII. INCOME STATEMENT

A. Revenues

Q. HAVE YOU CONSIDERED OTHER OPERATING REVENUES AS AN OFFSET TO THE RETAIL REVENUE REQUIREMENT?

A. Yes. The pro forma year includes items such as revenues from transmission-related revenue and specific tariff charges including service activation fees, reconnection fees and others. One other source of revenues comes from billings to NSPW under the Interchange Agreement, which I discuss in more detail below.

B. Operating and Maintenance Expenses

Q. HOW DOES XCEL ENERGY DEVELOP ITS PRO FORMA YEAR PRODUCTION EXPENSE?

A. The major cost in production expense is fuel and purchased energy. The pro forma year expenses are based on unadjusted 2011 test year fuel and purchased energy, adjusted for normal weather and fuel recovery timing so that a base cost of fuel and purchased energy is derived that only includes the appropriate South Dakota jurisdictional share of these NSP System costs on a calendar month basis.

Q. PLEASE DESCRIBE THE INTERCHANGE AGREEMENT WITH NSPW THAT YOU REFERENCED EARLIER.

A. The Company and NSPW operate a single integrated electric generation and transmission system and a single electrical "control area." The integrated system jointly serves the electric customers and loads of the Company and NSPW. However, the specific generators and transmission facilities making up the integrated system are owned by the two separate legal entities, with the ownership boundary at the Minnesota-Wisconsin border. The Interchange Agreement is a FERC approved contractual mechanism that provides a means to share the costs of the integrated system between the two legal entities.

Q. PLEASE DESCRIBE THE COSTS ALLOCATED BETWEEN THE COMPANY AND NSPW UNDER THE INTERCHANGE AGREEMENT.

A. Under the Interchange Agreement, the Company and NSPW share annual system generation (production) and transmission costs. Under the Interchange Agreement formulas, approximately 16 percent of the costs of the Company system are allocated to NSPW, and approximately 84 percent of the NSPW system costs are allocated to the Company, because approximately 84 percent of the load on the integrated system is the Company load and 16 percent is NSPW load. The exact allocation percentages are determined by the allocation factors updated and filed at FERC annually. The Interchange Agreement also provides for an allocation of revenues received by the Company and NSPW, such as revenues from off-system wholesale sales.

The unadjusted 2011 test year Interchange Revenue and Interchange Expenses have been calculated using 2011 Company and NSPW actual information. This is consistent with the treatment of Interchange Revenues and Interchange Expenses in the Company's 2010 unadjusted test year in Docket No. EL11-019.

Q. TO WHAT FERC ACCOUNTS ARE INTERCHANGE REVENUE AND INTERCHANGE EXPENSES RECORDED?

A. Interchange Agreement revenues related to fixed and variable production as well as transmission system costs are recorded to FERC Account 456 – Other Electric Revenues. Interchange Agreement expense (billings from NSPW to the Company) are recorded to the following FERC Accounts:

Interchange Agreement Cost	**FERC Account and Description**
Fixed Production	557 – Other Power Supply Expenses-Other
Variable Production	557 – Other Power Supply Expenses-Other
Transmission	566 – Miscellaneous Transmission Expenses

Work papers supporting the calculation for Interchange Agreement revenues (billings from the Company to NSPW) can be found in Volume 3, Section R1, Tab - Interchange Agreement. Work papers supporting the calculation of Interchange Agreement expenses (billings from NSPW to the Company) can be found in Volume 4, Section O1, Tab - Interchange Agreement.

C. Depreciation Expense

Q. WHAT IS THE BASIS OF THE DEPRECIATION RATES AND EXPENSE USED IN THIS PROCEEDING?

A. Depreciation expense for the pro forma year reflects the depreciation rates last certified by the Minnesota Commission, and is consistent with the ongoing practice followed by the Company, with the Commission's approval, in South Dakota rate case proceedings.

The pro forma year also includes the effect on depreciation expense related to the depreciation adjustment agreed to in the Commission approved Settlement Stipulation in Docket No. EL11-019. The impact of this adjustment is reflected on Exhibit___(TEK-1), Schedule 6b, page 3, column 34.

VII. CONCLUSION

Q. CAN YOU SUMMARIZE YOUR RECOMMENDATION TO THE COMMISSION?

A. I recommend that the Commission determine an overall retail revenue requirement of $187,420,000 and revenue deficiency of $19,368,000 for the Company's South Dakota jurisdictional electric operation, determined by the cost of service for the unadjusted 2011 test year adjusted to reflect those pro forma adjustments needed to make the pro forma year representative of the conditions facing the Company when it implements final rates in 2013.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes, it does.