Direct Testimony and Schedules
Charles R. Burdick

Before the Minnesota Public Utilities Commission
State of Minnesota

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

Docket No. E002/GR-15-826
Exhibit___(CRB-1)

Multi-Year Rate Plan

November 2, 2015

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Schedules

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND OCCUPATION.

A. My name is Charles R. Burdick and I am the Manager of Revenue Analysis in the Revenue Requirements – North department for Xcel Energy Services Inc. (Service Company). Xcel Energy Services Inc. is the service company for the Xcel Energy Inc. holding company system, and provides services to all of the operating utility subsidiaries of Xcel Energy Inc., including Northern States Power Company–Minnesota (NSPM or the Company).

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE.

A. Since August 2011, I have worked in the Revenue Requirements–North department, first as a Principal Rate Analyst and now as the Manager of Revenue Analysis. In these positions, I prepare and present cost-of-service studies, revenue requirement determinations, and jurisdictional annual reports for the electric and gas operations of NSPM to the Minnesota Public Utilities Commission (Commission), the South Dakota Public Utilities Commission (SDPUC) and the North Dakota Public Service Commission (NDPSC). Prior to 2011, I worked outside the Company in technology, finance and energy-related fields. My resume is included as Exhibit___(CRB-1), Schedule 1.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony focuses on the Company's three-year multi-year rate plan (MYRP or Plan) proposal in this proceeding and the Company's five-year settlement plan offer (Offer). In my testimony, I will:

- Give an overview of the Company's three-year MYRP proposal and associated revenue requests covering calendar years 2016 (the Test

Year), 2017 and 2018 (the Plan Years), summarized shown in Table 1 below:

Table 1
2016-2018 Revenue Requests
($000s Minn. Jurisdictional costs net of Interchange)

Plan Year	**2016**	**2017**	**2018**
Amount, cumulative	$194,612	$246,667	$297,133
Amount, incremental		$52,055	$50,466
Average % increase, incremental[1]	6.4%	1.7%	1.7%

- Provide a detailed discussion of the mechanics of the Company's 3-year MYRP request, including the ratemaking mechanisms and procedures the Company proposes for the term of the plan;
- Discuss the Company's experience with MYRPs in other jurisdictions and the criteria that should be considered when evaluating a MYRP proposal; and
- Present an overview of the Company's five-year settlement offer.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony is organized as follows:

- Section I – Introduction and Qualifications
- Section II – The Company's Three-Year MYRP Proposal
- Section III – The Details of the Company's MYRP Proposal
- Section IV – The Company's MYRP Experience in Other Jurisdictions
- Section V – The Company's Five-Year Settlement Offer
- Section V – Conclusion

II. THE COMPANY'S THREE-YEAR MYRP PROPOSAL

Q. PLEASE SUMMARIZE THE COMPANY'S PROPOSED THREE-YEAR MYRP.

A. As discussed by Company witness Mr. Aakash Chandarana, the Company is proposing a three-year MYRP, with 2016 as the Test Year, and using a traditional 2016 full Test Year cost of service approach for that year. For years two and three, we propose developing the revenue requirements with a similar cost of service approach, by using capital additions forecasts and a mixture of forecasted and escalated operations and maintenance (O&M) expenses, as discussed more fully below. Table 2 provides summaries of our 2017 and 2018 Plan Year revenue requirements. Company witness Ms. Anne Heuer discusses the Company's 2016 Test Year revenue requirement in detail in her testimony.

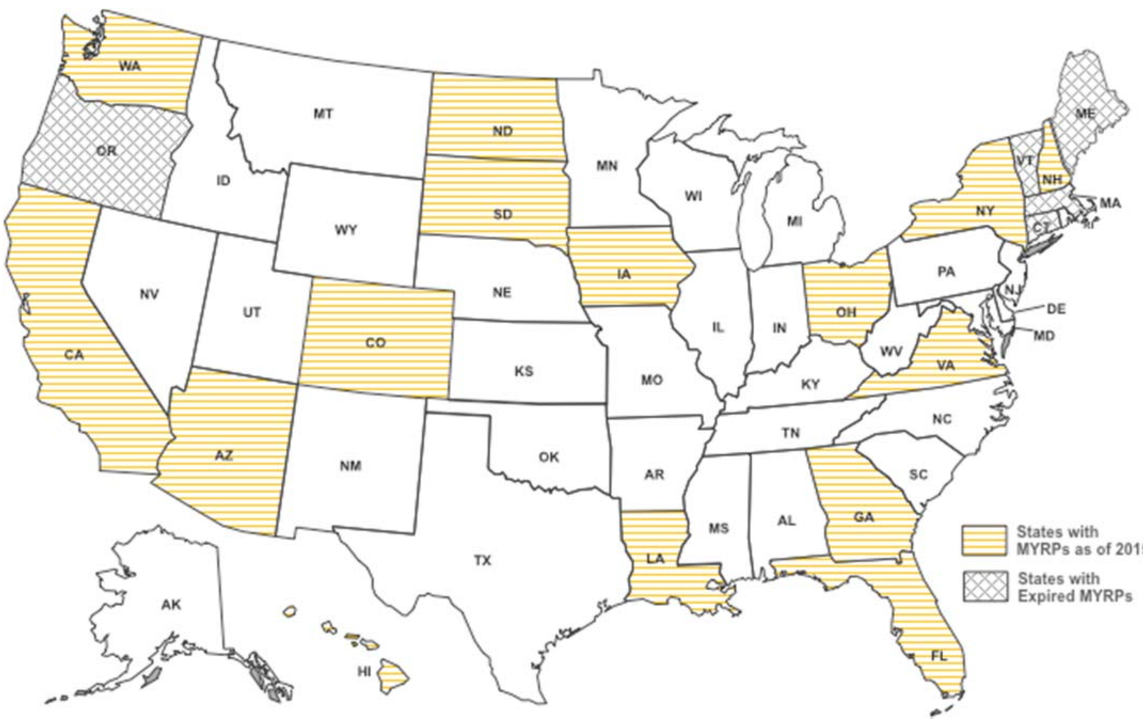
Table 2
2016-2018 Plan Summary
($000s Minn. Jurisdictional costs net of Interchange)

		INCREMENTAL	
Plan Year	**2016**	**2017**	**2018**
Rate Base	$7,836,115	($96,427)	($58,529)
Operating Revenues	3,621,078	8,694	8,330
O&M	2,342,900	17,754	22,490
Depreciation, Amortization and Taxes	838,637	34,534	13,287
Total Revenue Requirements	3,815,690	60,749	58,796
Revenue Deficiency	$194,612	$52,055	$50,466
Average % increase, incremental	6.4%	1.7%	1.7%
Customer Protections	• Capital True-up • Sales True-up • Property Tax True-up		

Q. WHAT MYRP METHODS DID YOU USE AS POINTS OF REFERENCE TO DEVELOP THE METHOD PRESENTED IN THIS CASE?

A. At least 20 states have implemented MYRPs for periods of three or more years, as shown in Figure 1 below.

Figure 1
States with MYRPs of Three or More Years[1]



The MYRPs in these various jurisdictions take a number of forms and use a variety of mechanisms to set rates, including capital forecasts to determine rate base additions, O&M expense escalation using various adjustment factors for inflation and mechanisms to ensure that over and under-recovery of costs are minimized.

[1] "Multiyear Rate Plans for Minnesota Electric Utilities", Mark Newton Lowry and Matthew Makos, Pacific Economics Group Research LLC, March 13, 2015.

The Company has specific experience with MYRPs in Colorado, North Dakota, South Dakota and Wisconsin, which I discuss in more detail in Section IV of my testimony.

Q. WHY IS THE COMPANY PROPOSING A MYRP IN THIS PROCEEDING?

A. Mr. Chandarana explains that continual rate cases can impede the Company's and the Commission's ability to fully address the policy challenges for the benefit of our customers. An MYRP can therefore offer benefits not achievable through serial rate case filings.

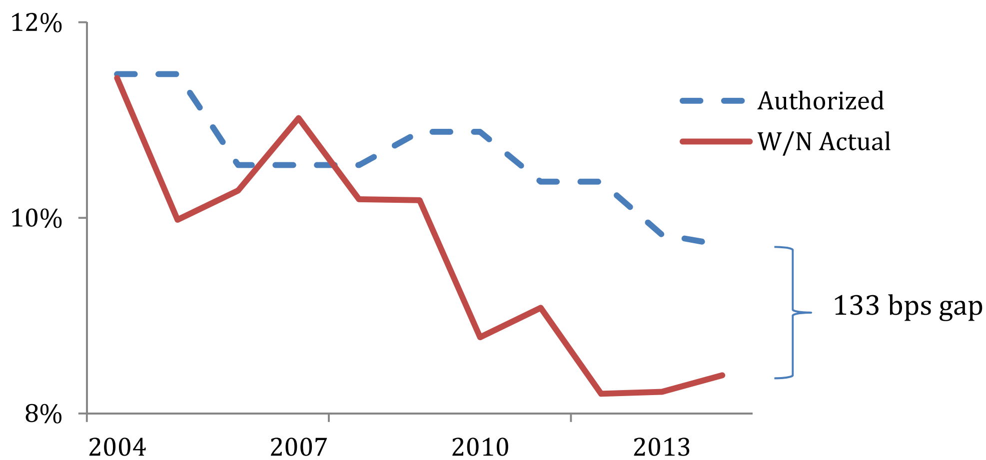
I present some of the financial issues to consider.

Traditional rate cases can work well to address course corrections during periods of slower investment and greater load growth. During such times, a rate case can be conducted relatively quickly, from the development of the budget and financial information necessary to file a case through to setting of final rates, with longer-lasting effect.

However, during periods of higher investment and slow or no load growth, traditional ratemaking can lead to the need for continual rate case filings, in an effort to minimize the gap between authorized returns and realized returns. The Company has seen exactly this kind of gap over the past several years (Figure 2).

Figure 2

Gap Between Authorized ROE and Actual Earned ROE

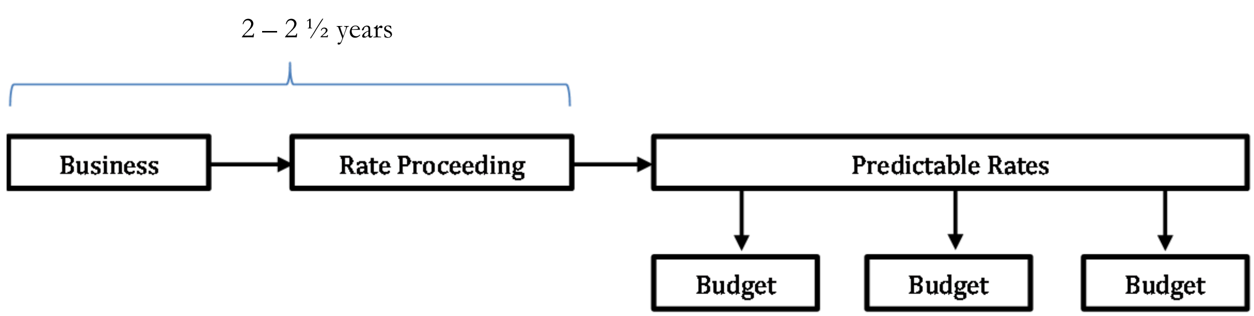


Company witness Mr. Brian J. Van Abel explains the challenges of attracting the capital needed to achieve the state's policy goals and the relationship between regulatory outcomes and the cost of capital.

In addition, during these times of continual investment and slow to no growth, traditional ratemaking cannot provide the same level of predictability or stability for customers, nor can it inform a utility's budget planning process. In this case, we seek to have at least one budget cycle informed by the rate case proceeding. We are requesting a three-year rate plan and, following the statutory timeline, the rate proceeding would conclude during 2017 and inform the budget for 2018.

However, capital projects span many years of planning and implementation. Therefore, the Company also offers a five-year settlement path that could turn the typical ratemaking pattern around. Rather than budgeting first, then rates second, the Commission could establish just and reasonable rates first, which would then inform several years of budgets and demand that the Company manage its business within that established framework.

Figure 3



Q. DO YOU EXPECT THE COMPANY TO PURSUE ITS CURRENT FORECAST IN 2018 REGARDLESS OF OUTCOME IN THIS CASE?

A. No. I expect the Company will modify its forecast and budget for 2018 once the case outcome is known, to optimize returns while maintaining safety and reliability and best meeting customer and other stakeholder needs.

III. DETAILS OF THE COMPANY'S MYRP PROPOSAL

Q. PLEASE DESCRIBE THE BASIS OF THE COMPANY'S MYRP PROPOSAL.

A. The Company's three-year plan utilizes 2016 as the base Test Year, with 2017 and 2018 as additional Plan Years developed using forecasted capital additions and a mixture of forecasted and escalated O&M expenses. Also included in the proposal are impacts to other rate base items, sales adjustments, and other adjustments impacting the revenue requirements for these years, so that each year represents a cost of service approach to rate setting.

As I will discuss, our proposal treats costs in one of four ways:

1. Certain costs are held at the level of the 2016 Test Year;
2. Other costs are changed per the Company's corporate forecast, after regulatory adjustments;
3. For some items, 2016 Test Year amounts (after regulatory adjustments) have been escalated according to one of the following:
    a. Escalation factors by Federal Energy Rregulatory Commission (FERC) Account;
    b. Labor-specific escalation factor; or
    c. A composite escalation factor developed from individual FERC Account factors; and
4. We incorporated dynamic, secondary calculations for the model as necessary.

We applied the following reasoning to develop this approach:

1. Capital-related costs should follow the Company's forecast. Therefore, our MYRP proposal includes recognition of:
    a. Capital-related costs including rate base, depreciation expense, AFUDC and tax depreciation expense.
    b. Revenues and expenses that are capital-related, including:
        i. Purchased demand;
        ii. Transmission facilities that are regionally shared through MISO; and
        iii. Capital-related revenues and expenses from Northern States Power Company–Wisconsin (NSPW) through the Interchange Agreement.

c. Transmission Cost Recovery (TCR) Rider revenues to match the roll-in assets that will remain in the TCR Rider until the conclusion of the case.

2. Items that have separate true-up mechanisms should remain at the 2016 level, meaning:
   a. Fuel revenues and expenses will be handled through the Fuel Clause Adjustment mechanism
   b. Conservation Improvement Program (CIP) and Renewable Development Fund (RDF) revenues and expenses will be handled through the CIP Rider and RDF Rider; and
   c. Revenues related to decoupled customer classes will be handled through the Decoupling mechanism.
3. Consideration should be given for non-decoupled sales growth and sales-related expenses following the Company's forecast, so our proposal includes:
   a. Forecasted growth in revenue margins from non-decoupled customer classes; and
   b. Forecasted bad debt expense.
4. Expenses that have jurisdiction-specific regulatory treatment should follow that treatment. Therefore:
   a. The Company amortizes nuclear fueling outage costs over the periods between outages. These costs should follow the Company's forecast; and
   b. Expenses related to the Company's pension and benefit costs have several regulatory adjustments based on the outcome of the most recent rate case, Docket No. E002/GR-13-868. These

costs should be adjusted according to their related regulatory mechanisms, not an escalation factor.

5. O&M expenses related specifically to labor should be escalated according to an IHS Global Insights, Inc. (IHS) labor escalator, specifically FERC 920, Administrative and General Salaries.
6. O&M expenses should be escalated on a FERC Account basis, according to IHS cost factors except for the reasons above.
7. O&M expenses for which IHS does not provide an escalation factor for that specific FERC Account should have a reasonable composite factor applied for escalation. We developed a composite factor using IHS data on the 2016 Test Year amounts by FERC Account for
   a. FERC Account 556, Load Dispatch
8. Miscellaneous non-retail revenues and O&M credits that offset the revenue requirement should also be escalated using the composite factor, including:
   a. FERC Account 450, Forfeited Discounts (revenue)
   b. FERC Account 451, Miscellaneous Service (revenue)
   c. FERC Account 454, Rent from Electric Property (revenue)
   d. FERC Account 922, Administrative Transfer (credit)
   e. FERC Account 929, Duplicate Charge (credit)
9. Secondary calculations necessary for a full cost of service study should be based on the results of the above items.
   a. Cash Working Capital balance related to the revenues and expenses developed above
   b. Deferred Tax Asset balance and deferred tax expense related to a Net Operating Loss calculation

c. Change in debt interest expense related to the forecasted change in debt costs and the forecast of rate base.

A summary of this plan is provided as Exhibit___(CRB-1), Schedule 2 to my testimony.

I have organized all of these into 13 major adjustments to bridge from the 2016 Test Year to the 2017 Plan Year, then from the 2017 Plan Year to the 2018 Plan Year, as shown on Exhibit___(CRB-1), Schedule 6, Rate Base Bridge Schedule and Exhibit___(CRB-1), Schedule 7, Income Statement Bridge Schedule. A summary of these adjustments is attached as Exhibit___(CRB-1), Schedule 3.

<u>Forecast Adjustments:</u>

1. Capital Forecast
2. Other Rate Base and Nonplant Items
3. Purchased Demand
4. Bad Debt Expense
5. FERC 925 & 926
6. Non-Decoupled Sales
7. Change in TCR Revenue
8. Transmission Revenue and Expense

<u>Escalated Adjustments:</u>

9. Escalated O&M
10. Non-Retail Revenue

Secondary Calculations:

11. Cash Working Capital
12. Net Operating Loss
13. Cost of Capital

I provide additional detail for each component of this plan below.

Q. PLEASE DESCRIBE THE METHODOLOGY USED TO CALCULATE REVENUE REQUIREMENTS.

A. Company witness Ms. Anne E. Heuer describes the Company's practice for calculating revenue requirements for base rates in the State of Minnesota. I apply those same methods for the calculation of average rate base, operating revenue, operating expense, income taxes, billings to and from NSPW through the Interchange Agreement, cash working capital balances and net operating losses (NOL) to arrive at revenue requirements.

Q. PLEASE DESCRIBE THE METHODOLOGY USED TO DEVELOP JURISDICTIONAL ALLOCATIONS IN YOUR CALCULATIONS.

A. Ms. Heuer describes the Company's practice for applying cost-causative allocation factors to the many items in the Cost of Service Study. I applied the same jurisdictional allocation factors in the same manner as Ms. Heuer applied in the 2016 Test Year.

Q. CAN YOU PLEASE EXPLAIN WHAT YOU MEAN BY IHS ESCALATION FACTORS AND HOW ARE THEY APPLIED?

A. Yes. IHS provides price analysis that helps corporations better manage supplier relationships, assess supplier quotes and negotiate long-term contracts. The IHS Power Planner Service maintains a model that provides cost escalators applicable to specific accounts within the FERC Uniform System of Accounts for electric and gas utilities. The information in the model can be used to determine inflation or cost escalation rates for a utility's O&M expenses. The Company utilized those escalation rates to develop O&M expenditure forecasts, for the 2017 and 2018 Plan Years for certain expenses.

Company witness Mr. John Mothersole discusses the process for determining the factors for O&M expense escalation and he provides an assessment of whether the Company's model accurately applies these factors.

Q. WHY IS THE USE OF IHS ESCALATION FACTORS A REASONABLE APPROACH TO DEVELOP O&M-RELATED REVENUE REQUIREMENTS FOR THE 2017 AND 2018 PLAN YEARS?

A. The Statute[2] provides for "recovery of operations and maintenance expenses, based on an electricity-related price index or other formula." Further, the Department of Commerce, Division of Energy Resources (Department) proposed adjustments based on IHS escalation factors in the E002/GR-10-971 and E002/GR-12-961 rate cases. The Commission ordered an adjustment based on IHS escalation factors in the E002/GR-12-961 rate case. The Commission specifically required the IHS escalation factors in rate cases since its Order in Docket No. E002/GR-91-001, which states as item 5, the following requirement:

[2] Minnesota Statue Section 216 B. 16, subd. 19

The Company shall incorporate the DRI Index, or a comparable industry standard as a guideline in future rate cases." (Page 92 of the November 27, 1991 Order)

IHS acquired DRI and now maintains the quarterly indexes.

Q. Why did the Company use additional methods beyond the IHS escalation factors for establishing certain O&M expenses for the 2017 and 2018 Plan Years?

A. Some expenses are too specific to the Company to model using factors, e.g., bad debt expense or purchased demand costs, which come from specific contracts. For these cost accounts, we applied specific forecasts.

Q. Did you consider using other escalation factors?

A. Yes. IHS publishes two types of escalation factors. One set measures materials and supplies only. The other set measures labor, materials, and supplies. The set with labor, materials, and supplies was somewhat higher than just materials and supplies. In total, the MYRP model yields a $1.5 million higher deficiency in 2017 and $3.3 million higher deficiency in 2018 when using the factors including labor, compared to those without. We felt that including the lower set was better in line with the Company's budget goals and demonstrates a measure of efficiency the Company aims to attain.

We also considered using other economic measures of inflation shown on Exhibit___(CRB-1), Schedule 12 such as the Consumers Price Index (CPI). However because the Company's costs are due to wires, poles, and labor more than they are, say, eggs and milk, we felt that price indices specific to energy and utilities would be more appropriate.

Since this rate case presents the first such use of escalators in Minnesota, the Company may reevaluate its choice of escalation metrics in a future case, depending on the facts at that time.

A. Adjustments to Develop the Plan Years

1. Capital Forecast

Q. HOW DID YOU DEVELOP THE CAPITAL FORECAST ADJUSTMENT FOR PLAN YEARS 2017 AND 2018?

A. The information I used to calculate the capital-related revenue requirements is developed as a part of the Company's annual budget process. The difference between all capital-related revenue requirements for 2017 and the 2016 Test Year is shown as the Capital Forecast adjustment on Column 2 of Schedule 6 and Column 2 of Schedule 7. Similarly, the difference between the 2018 forecast revenue requirements and the 2017 forecast is shown on Columns 7 and 16 of Schedules 6 and 7, respectively. The amounts have been allocated to State of Minnesota, Electric jurisdiction in the same manner as described by Ms. Heuer in her Direct Testimony.

To calculate capital-related revenue requirements, I use forecasted beginning and ending Plant In Service, Accumulated Depreciation, Construction Work in Progress, Accumulated Deferred Income Taxes and capital-related Regulatory Amortization balances for 2016, 2017 and 2018. Rate base for each year is calculated using an average of the beginning of year and end of year balances. I then use forecasted 2016, 2017 and 2018 Depreciation, Property Taxes, Deferred Income Taxes and Investment Tax Credits, Allowance for Funds Used During Construction (AFUDC), capital-related Tax Additions and Deductions and capital-related State and Federal Tax Credits to develop the income statement.

The 2016 baseline capital-related revenue requirement was then compared to the projected 2017 revenue requirement and the difference between the two was applied as the Capital Forecast adjustment for 2017. This same process was followed for 2018. The 2017 forecasted capital-related revenue requirement was compared to the 2018 revenue requirement and was applied as the Capital Forecast adjustment for 2018.

Q. DOES THIS ADJUSTMENT REPRESENT DISCRETE CAPITAL PROJECTS OR THE COMPANY'S ENTIRE CAPITAL FORECAST?

A. This adjustment represents the Company's entire capital forecast, as budgeted by the business areas.

Each business area is responsible for preparing detailed cost information associated with each project, which is then systematically gathered by the Capital Asset Accounting (CAA) function of the Company. Information provided by the business areas includes monthly capital expenditures, the estimated in-service date for the project, the type of costs being incurred and the type of equipment for proper classifications under the FERC Uniform System of Accounts.

CAA develops all of the rate base-related items for these projects –AFUDC, capital-related loadings, total dollars being placed in-service, monthly depreciation expense, tax depreciation deductions, capital-related tax income items and deferred tax expenses associated with timing differences between book and tax recognition of income and expenses. Company witness Ms. Lisa H. Perkett describes these processes in more detail in her direct testimony.

Also, ongoing monthly balances are generated for the various components of rate base including plant in-service, Construction Work In Progress (CWIP), accumulated depreciation expense, and accumulated deferred taxes. This information is generated for the current year, and forecast information is produced for the next five years. CAA then provides this data to the Revenue Requirements function to develop the Company's revenue requirements. I have used the information provided by CAA to make my revenue requirement determinations for the 2017 and 2018 Plan Years proposed in this case. Please see Volume 4A for supporting information.

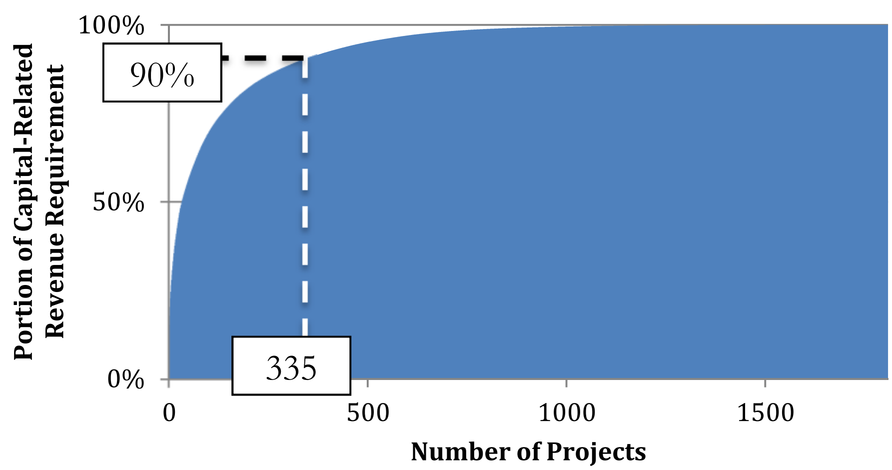
Q. WHY DID YOU PRESENT ALL CAPITAL RATHER THAN DISCRETE PROJECTS?

A. The Company's budget for 2016-2018 includes approximately 1,810 capital projects.[3] In addition, the capital forecast does not have many discrete, extremely large new projects of the nature seen in previous cases such as the Monticello LCM/EPU project, the Border Winds and Pleasant Valley Wind projects, or the Prairie Island Steam Generator Replacement. Rather, the revenue requirements are spread across thousands of projects. I estimate we would need to itemize the largest 335 discrete projects in order to capture 90 percent of the capital-related revenue requirement. It is impractical to present, calculate and track revenue requirements for each project individually through

[3] We assume each unique parent workorder is a project for the purpose of this analysis.

the course of this proceeding. Moreover, as Company witness Mr. Gregory J. Robinson and various business unit witnesses describe, the Company manages its budgets based on overall operational needs, a point lost when the focus shifts to discrete projects.

Figure 4



Q. DO YOU EXPECT EACH OF THESE PROJECTS TO BE EXECUTED EXACTLY AS STATED IN 2017 AND 2018?

A. No. As other Company witnesses discuss, the budget process develops a reasonable and representative capital plan. The actual experience of that plan often includes movement of specific projects in terms of scope and schedule, but the Company still manages within the overall budget.

Q. IS THAT A CONCERN FOR RATE SETTING PURPOSES?

A. It should not be. While some movement will inevitably occur to meet changing circumstances, the business unit witnesses and the supporting documentation accompanying our filing provides significant information regarding the major investments we have planned for this time period. As the

Company's business unit witnesses and Mr. Robinson discuss, the Company's capital budgets are both reasonable and representative of the work that will be performed. Moreover, as these witnesses discuss, these budgets have proven to be conservative over time. Finally, as both Mr. Chandarana and I discuss, the Company proposes an overall capital true-up as part of our MYRP proposal. For all of these reasons, the Commission can have confidence that using the Company's capital forecasts as a basis for setting rates will result in just and reasonable rates.

Q. HOW DOES THIS ADJUSTMENT ADDRESS DEPRECIATION OF EXISTING ASSETS (THE "PASSAGE OF TIME")?

A. Because the Company's capital forecast includes a forecast of deprecation, both on existing assets and on new additions, the adjustments presented are net of depreciation on existing assets, as discussed by Ms. Perkett.

I note that this is evidenced by the plant growth of 3.9 percent included in the 2017 and 2018 Plan Years being offset by depreciation reserve growth of 7.4 percent resulting in a net plant growth of only 1.0 percent.

Table 3

	2016 Test Year	2017 Plan Year	2018 Plan Year	CAGR*
Plant	$16,425,447	$17,036,345	$17,728,323	3.9%
Less: Reserve	7,267,758	7,809,137	8,386,448	7.4%
Net Plant**	$9,157,689	$9,227,208	$9,341,875	1.0%

*CAGR stands for Compound Average Growth Rate.
**Amounts are average balances. Table includes nuclear fuel.

Q. DID YOU INCLUDE THE EFFECT OF ANY REGULATORY ADJUSTMENTS TO THE CAPITAL BUDGET IN 2017 AND 2018?

A. Yes, we applied the same regulatory adjustments to the 2017 and 2018 Plan Years as were applied to the 2016 Test Year. The amounts for these regulatory adjustments included in the Capital Forecast bridge column are shown on Volume 4B, Tab M1, pages 3-12. The 2017-2018 details for each of these adjustments are presented in their respective work papers:

- Black Dog Screenhouse, WP-A1
- Monticello LCM/EPU Return, WP-A12
- Nobles Amounts over CON, WP-A13
- Like Kind Exchange Program, WP-A20
- Remaining Life Study: NSPM, WP-A25
- Remaining Life Study: NSPW, WP-A26
- PI EPU Recovery, WP-A31
- Sherco 3 Depr Deferral, WP-A33
- Rider Removal: RES, WP-A35
- Rider Removal: TCR, WP-A36
- ADIT Prorate for IRS, WP-A38

Note that the Renewable Energy Standard (RES) and TCR Rider removal adjustments ensure that no double-recovery will occur between the forecasted riders and the forecasted base rates.

Q. HAVE YOU PREPARED SCHEDULES THAT SUPPORT THE REVENUE REQUIREMENTS FOR THESE PROJECTS?

A. Yes. Volume 4B, Tab M1 provides the revenue requirement calculations by forecast item. Amounts are presented as allocated to State of Minnesota, Electric jurisdiction. Pages 1-2 show the 2016, 2017 and 2018 totals as well as the 2017 Increment which is calculated as the difference between 2016 and 2017. Similarly, the 2018 Increment is calculated. These amounts tie to Schedule 6 and Schedule 7. Pages 3-12 provide additional detail with references to other Volume 4A and 4B workpapers to find supporting data.

Q. WHY DOES THE ADJUSTMENT INCLUDE SOME OTHER OPERATING REVENUE AND SOME PRODUCTION AND TRANSMISSION EXPENSE?

A. These amounts are to reflect billings to and from NSPW through the Interchange Agreement. The Company operates an integrated production and transmission system across the NSPM and NSPW operating companies. Any production and transmission expenses are assigned to one of the operating companies, and then the other operating company pays for its share.

The revenues are for NSPM production and transmission capital revenue requirements, for which NSPW will pay approximately 16 percent. The expenses are related to NSPW production and transmission capital revenue requirements, for which NSPM will pay approximately 84 percent.

Q. HOW DID YOU CALCULATE THE CAPITAL-RELATED PORTION OF REVENUES RECEIVED FROM NSPW THROUGH THE INTERCHANGE AGREEMENT?

A. We simulated an interchange bill from NSP-Minnesota to NSPW for each of 2016, 2017 and 2018 using the same capital-related balances and income statement items listed above. We input the Company's forecast of NSPM rate base, depreciation, tax depreciation and AFUDC, and calculated revenue requirements to find NSPW's portion. This revenue, which offsets NSPM's revenue requirement, is shown in the Other Revenue line as part of this

Capital Forecast adjustment. The simulated Interchange bills are included in Volume 4B, Tab M7.

Q. HOW DID YOU CALCULATE THE CAPITAL-RELATED PORTION OF EXPENSES BILLED BY NSPW THROUGH THE INTERCHANGE AGREEMENT?

A. Similar to above, we simulated an interchange bill from NSPW to NSPM for each of 2016, 2017 and 2018 using the same escalation rules as above. We input the Company's forecast of NSPW rate base, depreciation, tax depreciation and AFUDC. The portion of the bill related to NSPW capital revenue requirements appear as production and transmission expenses on NSPM's income statement. The simulated Interchange bills are included in Volume 4B, Tab M7.

2. Other Rate Base and Nonplant Items

Q. HOW DID YOU DEVELOP THE OTHER RATE BASE AND NONPLANT FORECAST ADJUSTMENT FOR PLAN YEARS 2017 AND 2018?

A. We used the Company's forecasted balances for Nonplant Assets and Liabilities and Prepayments that are developed as part of the Company's annual budget process. The difference between these balances in 2016 and 2017 is shown on Volume 4B, Tab M2 for the adjustment to develop the 2017 Plan Year. Similarly, the difference between the balances in 2017 and 2018 is shown for the adjustment to develop the 2018 Plan Year.

These amounts for the 2017 increment are shown as the Other Rate Base and Nonplant adjustment on Column 3 of Schedule 6 and Column 3 of Schedule 7. Similarly, the difference between the 2018 forecast and the 2017 forecast is shown on Columns 8 and 17 of Schedules 6 and 7, respectively.

3. Purchased Demand

Q. WHY DID YOU ADJUST FOR PURCHASED DEMAND AND WHY USE THE COMPANY'S FORECAST OF THESE COSTS RATHER THAN THE IHS ESCALATION FACTORS?

A. Purchased demand costs are company-specific. Certain utilities may purchase a great deal of capacity, while others may not purchase any, depending on each utility's generation fleet. Purchased demand costs are recorded in FERC Account 555, for which IHS does not provide an escalation factor, presumably because of their company-specific nature. The Company's year-over-year changes in purchased demand costs are material (a $4.3 million decrease from 2016 to 2017, and a further $4.0 million decrease from 2017 to 2018). The costs could be considered capital-related, since they are dependent on the Company's generation fleet compared to load demands.

Q. HOW DID YOU DEVELOP THE PURCHASED DEMAND FORECAST ADJUSTMENT FOR PLAN YEARS 2017 AND 2018?

A. We used the Company's forecasted expenses for purchased demand contracts in each year. Purchased demand costs are not recovered through the fuel cost adjustment mechanism. Rather, they are an operating expense in base rates and are shown in the Production Expense line of the Cost of Service. The difference between these annual expense amounts in 2016 and 2017 is shown on Exhibit___(CRB-1), Schedule 10 to develop the 2017 Plan Year adjustment. Similarly, the difference between the balances in 2017 and 2018 is shown for the adjustment to develop the 2018 Plan Year.

Details behind the purchased demand contracts are provided as Exhibit___(AEH-1), Schedule 13, Capacity Cost Study, to Ms. Heuer's direct testimony.

4. Bad Debt Expense

Q. WHY DID YOU ADJUST FOR BAD DEBT EXPENSE AND WHY USE THE COMPANY'S FORECAST OF THESE COSTS RATHER THAN THE IHS ESCALATION FACTORS?

A. Bad debt expenses are recorded in FERC Account 904. IHS does not provide an escalation factor for this account, presumably because of their company-specific nature. Bad debt expenses have been a specific topic examined in previous rate cases. Therefore, we felt that a specific calculation based on regulatory precedent would be the best approach.

Q. HOW DID YOU DEVELOP THE BAD DEBT FORECAST ADJUSTMENT FOR PLAN YEARS 2017 AND 2018?

A. As discussed in the direct testimony of Company witness Mr. Michael C. Gersack, the commodity bad debt expense is primarily driven by billed customer revenue. Therefore, the factor most relevant to commodity bad debt expense is the sales forecast, rather than the factors underlying the index used for 2017 and 2018 Plan Year O&M expenses in this case. To determine forecasted bad debt expense for 2017 and 2018, the Company applied the bad debt ratio to forecasted commodity revenues and allocates it between its electric and natural gas operations consistent with the calculation for the 2016 Test Year. The results of the calculations discussed by Mr. Gersack resulted in a State of Minnesota Electric jurisdiction commodity bad debt expense level for 2017 of $10.744 million and for 2018 an expense level of $10.593 million.

Please see Exhibit__(MCG-1), Schedule 7, page 2 for the detailed calculations supporting the 2017 and 2018 Plan Year commodity bad debt expense.

Q. WHAT IS THE BAD DEBT EXPENSE ADJUSTMENT INCLUDED IN THE 2017 AND 2018 BRIDGE SCHEDULES?

A. The bad debt adjustment included in the 2017 and 2018 bridge schedules reflect the incremental change in the Minnesota Electric jurisdiction commodity bad debt expense levels relative to the 2016 Test Year. The 2017 State of Minnesota Electric jurisdiction forecast has a decrease in commodity bad debts of $0.246 million from the 2016 Test Year level, as shown in Schedule 7, Column 5, Line 13. An additional reduction of $0.151 million from 2017 Plan Year to 2018 Plan Year is shown in Schedule 7, Column 19, Line 13.

5. FERC Accounts 925 and 926

Q. WHY DID YOU USE THE COMPANY'S FORECAST OF THESE COSTS RATHER THAN THE IHS ESCALATION FACTORS?

A. FERC Accounts 925 and 926 reflect worker's compensation insurance, pension expense and other labor benefits. The forecast of these expenses is calculated in accordance with accounting rules and standards and is based on actuarial assumptions specific to the Company. In addition, these expense types have been a specific topic examined in previous rate cases, with several regulatory treatments prescribed in the Commission's Order from the Company's last two electric rate cases (Dockets Nos. E002/GR-12-961 and E002/GR-13-868). Therefore, we felt the Company's specific forecast reflecting regulatory treatment, rather than the IHS escalation factors, would be the best approach.

Q. HOW DID YOU DEVELOP THE FERC ACCOUNTS 925 AND 926 FORECAST ADJUSTMENT FOR PLAN YEARS 2017 AND 2018?

A. FERC Accounts 925 and 926 expense forecasts are calculated in adherence to related Commission Order Points from Dockets No. E002/GR-12-961 and E002/GR-13-868. Please see Table 1 in the direct testimony of Company witness Mr. Richard R. Schrubbe for a complete list of Order Points, and their impact on the forecast. In some cases, regulatory adjustments have been made to ensure compliance. For example, Order Point 13 in Docket No. E002/GR-13-868 states the discount rate used to calculate retiree medical benefit costs for ratemaking purposes shall be set to equal the five-year average of the FAS 106-based discount rate. An adjustment was made to Retiree Medical Benefits to reach that authorized level, and is discussed in the direct testimony of Ms. Heuer.

The FERC Accounts 925 and 926 forecast adjustment for the Plan Years is shown on Schedule 7, columns 6 and 20. Workpaper M3 provides a summary of forecast amounts for each year with references to supporting data found in Volume 4A.

Q. WHY DOES THE ADJUSTMENT INCLUDE SOME OTHER OPERATING REVENUE AND SOME PRODUCTION AND TRANSMISSION EXPENSE?

A. These amounts are to reflect billings to and from NSPW through the Interchange Agreement. The revenues are for NSPM production and transmission-related pension and benefit costs, for which NSPW will pay approximately 16 percent. The expenses are related to NSPW production and transmission-related pension and benefit costs, for which NSPM will pay approximately 84 percent.

6. *Non-Decoupled Sales*

Q. WHY DID YOU ADJUST FOR NON-DECOUPLED SALES?

A. In order to create a representative cost level for the Plan Years, and to incorporate offsetting revenues as discussed in the Commission's MYRP Order, we felt it appropriate to adjust for changes in revenues from non-decoupled customer classes.

Q. HOW DID YOU DEVELOP THE NON-DECOUPLED SALES FORECAST ADJUSTMENT FOR PLAN YEARS 2017 AND 2018?

A. Company witness Mr. Steven V. Huso calculated the revenue margin associated with growth in the non-decoupled customer classes using his rate revenue determination model. The calculations are based on 2017 and 2018 sales forecast data developed by Company witness Ms. Jannell E. Marks. Mr. Huso's calculation is provided as Volume 4B, Tab M4, page 3. It shows a $4.8 million increase in revenues for 2017, and a further $5.2 million increase in 2018. These amounts are reflected in the Other Operating Revenue line 4, columns 7 and 21 of Schedule 7. We chose to show these amounts on Other Operating Revenue line instead of the Retail Revenue line to make clear that we are reflecting a margin change, and not changing present revenues for the measurement of rate increases.

Q. WHY DIDN'T YOU ADJUST FOR CHANGES IN REVENUE FROM ALL CUSTOMER CLASSES?

A. Revenue decoupling was an important policy action in the most recent case. If we were to adjust changes in revenues for all customer classes, then it would make more sense to also reflect changes in sales volumes, thereby effectively resetting the basis for decoupling during the entire plan period. If we were to do that, there would be no revenue decoupling (aside from capturing weather related changes) until 2019 at the earliest, which seemed counter to the Commission's intent in its Order from the most recent case.

Q. DID YOU CHANGE SALES ALLOCATORS TO MATCH THIS ADJUSTMENT?

A. No, I did not. I used sales and customer allocators from the 2016 Test Year, again to preserve the revenue decoupling mechanism during the plan period.

7. Change in TCR Rider Revenue

Q. WHY DID YOU ADJUST FOR CHANGES IN TCR RIDER REVENUE?

A. Because two large CAPX2020 projects are proposed to move from TCR Rider recovery to base rate recovery at the conclusion of this rate case, it was necessary to include for each of the Plan Years the annual TCR Rider revenue in order to match the 2017 and 2018 capital forecast adjustments which are presented above. However, for most retail revenue-related components of the Plan Years, we left the components at the 2016 Test Year levels. This includes the RES, CIP, and RDF Riders that are included in the Test Year Cost of Service.

Q. HOW DID YOU DEVELOP THE CHANGE IN TCR RIDER REVENUE FORECAST ADJUSTMENT FOR PLAN YEARS 2017 AND 2018?

A. The change in the revenue forecast was created by starting with the 2016 revenue requirement requested in Minnesota TCR Rider Docket No.

E002/M-15-891 for CAPX2020 Fargo and CAP2020 Brookings. This 2016 baseline amount of $59,087,069 was then compared to the projected 2017 revenue requirement of $57,601,624 and the difference between the two values of $(1,485,446) was applied as a TCR Rider revenue forecast adjustment for 2017. This same process was followed for 2018. The 2017 forecasted revenues of $57,601,624 were compared with the 2018 revenue requirement of $56,167,213 and a decrease of $(1,434,411) was applied as a TCR Rider revenue forecast adjustment for 2018. This adjustment is shown on columns 8 and 22 of Schedule 7. A summary of the TCR revenue forecast adjustment is shown on Workpaper M4.

8. *Transmission Revenue and Expense*

Q. WHY DID YOU ADJUST FOR REVENUES AND EXPENSES RELATED TO REGIONALLY SHARED FACILITIES AND WHY USE THE COMPANY'S FORECAST OF THESE COSTS RATHER THAN THE IHS ESCALATION FACTORS?

A. As discussed in detail by Company witness Mr. Ian R. Benson, transmission revenues and expenses for regionally shared facilities are company-specific. Certain utilities may be in a region with significant sharing of facilities across its system, while others may be self-sufficient. NSPM operates within the Midcontinent Independent System Operator (MISO) footprint and experiences a high level of regional facility sharing, both of its own transmission assets and those of other utilities. Regionally shared transmission expenses are recorded in FERC Accounts 565, 566, and 575. IHS does not provide an escalation factor for accounts 565, 566 and 575, presumably because of their company-specific nature. The Company's year-over-year changes in regionally shared facility costs are material, and could be considered capital-related, since they are related to both the Company's transmission capital and those of neighboring utilities that are needed to support the Company's operation. Revenues that the Company receives related to other utilities sharing of Company facilities are recorded in FERC 456.

Q. HOW DID YOU DEVELOP THE TRANSMISSION REVENUE AND EXPENSE FORECAST ADJUSTMENT FOR PLAN YEARS 2017 AND 2018?

A. The change in the transmission revenue and expense forecast was created by starting with the 2016 Test Year amounts in FERC Accounts 456, 565, 566, and 575. This 2016 baseline amount was then compared to the forecasted 2017 amount and the difference between the two values is the Transmission Revenue and Expense forecast adjustment for 2017. This same process was followed for 2018. The 2017 forecasted amounts were compared with the 2018 amounts and applied as the adjustment for 2018.

The adjustment is shown on Schedule 7, columns 9 and 23. A summary of the forecast amounts is shown on Workpaper M3 with references to supporting forecast base data for 2016-2018 found in Volume 4A.

9. Escalated O&M

Q. HOW WERE THE O&M EXPENSES FOR PLAN YEARS 2017 AND 2018 DEVELOPED?

A. There are three approaches that the Company used to develop the O&M expenses included in the Plan Years for this case:

1. Escalated 2016 Test Year amounts based on factors from IHS[4] (91 of 109 FERC Accounts),
2. 2017 and 2018 budgeted amounts (13 of 109 FERC Accounts), and
3. 2017 and 2018 expenses held at 2016 Test Year levels (5 of 109 FERC Accounts).

Different approaches were used for different FERC accounts, depending on the underlying facts, in order to develop a just and reasonable level of expenses for each year.

A summary of the IHS escalation factors selected is attached as Exhibit___(CRB-1), Schedule 8. Schedule 10 shows the 2016 amounts for each line of the Cost of Service Study by FERC account. For accounts that were escalated using IHS escalation factors, I reference the matching IHS escalation factor for that FERC account and use it to escalate the 2016 cost level, first to a representative 2017 level, and then to a representative 2018 level. For all other accounts, we either used the forecast for 2017 and 2018 or held the expense levels flat, as discussed above.

For example, FERC Account 500 is for Steam Production Operations and Supervision. The 2016 Test Year amount in this account is $6.542 million. The 2017 IHS escalation factor for this account is 2.42 percent. Multiplying $6.542 million by the 2.42 percent factor yields $0.159 million, which is shown in the 2017/2016 increment column on Schedule 10. Similarly, the 2018 factor for this account is 2.73 percent, which is applied to the 2017 total (2016

[4] Of the 91 accounts, 78 are escalated directly from IHS escalation factors, 10 use a hybrid of IHS and forecast, and 3 use a composite factor developed using IHS data. These are explained further below.

Test Year plus 2017 Plan Year increment) to yield $0.183 million increment for the 2018 Plan Year.[5]

The cumulative contributions of each FERC Account from 500 through 557, except those related to fuel, are shown on the Production Expense line of Schedule 7, and the resulting Exhibit___(CRB-1), Schedules 4 and 5 Cost of Service Summary for 2017 and 2018.

Q. DOES THE ESCALATED O&M REFLECT REGULATORY ADJUSTMENTS USUALLY MADE TO O&M EXPENSE CATEGORIES FOR RATEMAKING?

A. Yes. The escalated O & M numbers were developed by starting with the 2016 Test Year amount, including adjustments, for each FERC Account, and then applying the escalators. This has the same effect as starting with the unadjusted amount plus the adjustments and escalated each piece separately. For example, the Company's 2016 budget indicates $2.792 million in FERC 930.1 for General Advertising. However $2.647 million is removed as part of the Advertising adjustment to develop the Test Year.

Table 4
Example Regulatory Adjustment Escalation

FERC 930.1 General Advertising	2016 Budget	Factor	2017 Increment
Total Budgeted	$2.792 m	2.28%	$0.063 m
Removed in Adjustment	($2.647 m)	2.28%	($0.060 m)
Test Year / Plan Year Amount	$0.144 m	2.28%	$0.003 m

[5] ($6.542 + $0.159) x 2.73% = $0.183.

In this way, all regulatory adjustments for O&M are already reflected in the calculations and do not need to be made again.

Q. WHY DID YOU APPLY A COMPOSITE IHS ESCALATION FACTOR TO CERTAIN COST ACCOUNTS?

A. For some of the accounts that IHS does not forecast, we developed a composite escalator to best represent a just and reasonable level of expense for the Plan Year. This was done for FERC 556 Load Dispatch, FERC 922 Admin Transfer Credits and FERC 929 Duplicate Charge Credits.

Q. HOW WAS THIS COMPOSITE FACTOR DEVELOPED?

A. The composite factor is a weighted average (using 2016 Test Year O&M costs) of the individual IHS escalation factors for the FERC accounts for which the factors are published. The calculation is provided in Exhibit___(CRB-1), Schedule 9.

Q. HOW WERE NUCLEAR O&M COSTS FOR THE PLAN YEARS 2017 AND 2018 DEVELOPED?

A. Two different methodologies were combined to develop the 2017 and 2018 Plan Years. Part of the expenses in each nuclear-related FERC Account (517-532) are forecasted using the Company's budget and part of the expenses are escalated using the IHS escalation factor. The portion that are forecasted are outage expenses that reflect the Company's planned outage schedule and are amortized between outages. Therefore the 2017 and 2018 Plan Year includes budgeted amounts for these amortization expenses. The base O&M portion of expenses in nuclear related FERC accounts are escalated 2016 Test Year amounts based on escalation factors from IHS.

Workpaper M5, page 4 shows the escalation calculation for base O&M expenses and the budgeted amortization amounts in each nuclear FERC Account, from which a hybrid escalation factor was calculated. The hybrid escalation factor is reflected in Schedule 10, Summary by FERC Account, in FERC Accounts 517-532.

Q. WHERE DO YOU HOLD 2017 AND 2018 PLAN YEAR COSTS AT 2016 TEST YEAR LEVELS?

A. In general, costs that have true-ups or other cost recovery mechanisms should not be escalated since any deviations from the 2016 level are already handled more specifically in those other methods, whether inside or outside the rate case. For example, most fuel-related revenues and expenses have monthly true-ups through the Fuel Clause Adjustment. Therefore, we did not escalate the Fuel and Purchased Energy line of the Cost of Service Study from the 2016 levels. Similarly, FERC 908 CIP expense was also held to 2016 levels.

Q. WHY DOES THE ADJUSTMENT INCLUDE SOME OTHER OPERATING REVENUE AND SOME PRODUCTION AND TRANSMISSION EXPENSE FROM NSPW?

A. These amounts are to reflect billings to and from NSPW through the Interchange Agreement. The revenues are for NSPM production and transmission-related O&M costs, for which NSPW will pay approximately 16 percent. The expenses are related to NSPW production and transmission-related O&M costs, for which NSPM will pay approximately 84 percent.

To calculate these amounts, we simulated the Interchange Agreement bills to and from NSPW using the same escalation factors for each FERC Account in the input data as for developing the Plan Year.

Q. HAVE YOU COMPARED THE COMPANY'S REQUEST USING IHS ESCALATION FACTORS AGAINST OTHER ECONOMIC INDICATORS TO ASSESS THEIR REASONABLENESS?

A. Yes I have. I compared our overall requested increases in 2017 and 2018 against several economic indicators including the Gross Domestic Product (GDP) Price Deflator, personal consumption expenditures (PCE) inflation, and Core PCE inflation. The PCE factors are developed and used by the United States Federal Reserve Bank in deciding economic policy for the United States[6]. Table 5 below compares the Company's ask against these three economic projections.

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[6] Monetary Policy Report, July 15, 2015
http://www.federalreserve.gov/monetarypolicy/files/20150715_mprfullreport.pdf

Table 5
2017-2018 Reasonableness Comparison

Item	2017	2018
NSPM Requested Increase	1.7%	1.7%
GDP Price Deflator*	1.79%	1.75%
PCE Inflation**	1.6% – 1.9%	1.9% – 2.0%
Core PCE Inflation***	1.6% – 1.9%	1.9% – 2.0%

*Economic Outlook No. 95 – Long-Term Baseline Projections, Organisation for Economic Cooperation and Development, May 2014.
http://stats.oecd.org/Index.aspx?DataSetCode=EO95_LTB#
**Central tendency value in Table 1. Economic projects of Federal Reserve Board members and Federal Reserve Bank presidents, July 15, 2015.
http://www.federalreserve.gov/monetarypolicy/files/20150715_mprfullreport.pdf
***ibid

As can be seen in the above table, our requested increases are at or below where the Federal Reserve is predicting that major inflation indices will trend in the next few years. The requested increases are also below the GDP price deflator forecasts. As a result of this comparison, we conclude that our approach to developing the estimates for 2017 and 2018 are reasonable.

Q. DID YOU COMPARE THE IHS ESCALATION FACTORS AGAINST THE COMPANY'S ACTUAL EXPENSES OVER THE LAST SEVERAL YEARS?

A. Yes. In total, the Company's O&M has trended higher than the IHS Total Electric Operations and Maintenance index, particularly due to nuclear, transmission, and administrative and general costs, which include pension expenses. Included as Exhibit___(CRB-1), Schedule 11 is historic data by FERC account allocated to State of Minnesota, Electric jurisdiction for 2010-2014 budget versus actual, as well as comparison to Docket Nos. E002/GR-10-971, E002/GR-12-961 and E002/GR-13-868 rate case outcomes.

Table 6
IHS Escalation Factors versus
NSPM 2010-2014 O&M Expense Growth Rate

2010-2014 Actuals CAGR	Percent of 2010-2014 Total	2010-2014 Actuals CAGR (excluding fuel, purchased power, shared transmission, and CIP)	2016-2018 IHS CAGR
Total Electric O&M	100%	3.35%	2.59%
Steam Production	13%	0.10%	2.68%
Nuclear Production	36%	4.83%	2.57%
Other Production	4%	1.98%	2.55%
Transmission	5%	4.33%	1.84%
Distribution	12%	0.83%	2.51%
Customer Accounts	6%	-0.56%	2.62%
Administrative and General	24%	5.34%	2.90%

Q. HAVE YOU PREPARED SCHEDULES THAT SUPPORT THE REVENUE REQUIREMENTS CONSISTENT WITH THESE OPERATING EXPENSES LEVELS?

A. Yes. Workpaper M5 shows the calculation for each FERC Account that was escalated as part of this adjustment with subtotals by Cost of Service line item that can be compared to Schedule 7, columns 10 and 24.

10. Non-Retail Revenue

Q. WHY DID YOU ADJUST FOR NON-RETAIL MISCELLANEOUS REVENUES?

A. The Company receives miscellaneous revenues such as rent income from property, pole attachments, and engineering study fees. These are recorded in FERC Accounts 450, 451, and 454. The revenues serve as an offset to the revenue requirement otherwise proposed to customers in a rate case and need to be included to present a full cost of service for the Plan Years.

Q. HOW DID YOU DEVELOP THE NON-RETAIL REVENUE ADJUSTMENT FOR PLAN YEARS 2017 AND 2018?

A. We applied the composite escalation factor developed from IHS data as a proxy for inflation that could be experienced in this category. We began with the 2016 Test Year amount, as adjusted by Ms. Heuer and allocated to the State of Minnesota, Electric jurisdiction. We then multiplied by the 2017 composite factor to arrive at a representative increment for 2017 and multiplied the 2016 amount plus the 2017 increment by the 2018 factor to arrive at a representative 2018 increment. These are shown on Schedule 10 and also in Workpaper M6. The adjustment appears on Schedule 7, columns 11 and 25.

11. Cash Working Capital

Q. HOW DID YOU DEVELOP THE CASH WORKING CAPITAL ADJUSTMENT FOR PLAN YEARS 2017 AND 2018?

A. The cash working capital adjustment is calculated in the same manner as the 2016 Test Year. Using the lead and lag days per revenue and expense category in the Plan Year, we measure an appropriate amount of cash working capital for that Plan Year. This is shown on page 5 of Schedule 4, and Schedule 5. The change in calculated Cash Working Capital balance for each year is shown on Schedule 6, columns 4 and 9.

12. NOL

Q. HOW DID YOU DEVELOP THE NOL ADJUSTMENT FOR PLAN YEARS 2017 AND 2018?

A. The NOL adjustment is calculated in the same manners as the 2016 Test Year. We use the Plan Year income statement, add back the TCR and RES Riders that were removed in the forecast to get an "all-in" view, then maximize the amount of accumulated deferred income taxes that could be used to reduce the cost of service income tax. The change in Accumulated Deferred Income Taxes is shown in columns 5 and 10 of Schedule 6. These changes in Deferred Tax Expense, Income Tax Deductions, and Federal Tax Credits are shown in columns 13 and 27 of Schedule 7.

A summary of the changes is shown on Workpaper M8.

Q. WHAT WOULD HAPPEN TO THIS ADJUSTMENT IF LESS REVENUE IS AUTHORIZED FOR 2016?

A. If fewer revenues are granted in final rates than those requested in the Company's request, taxable income will be reduced. As a result, fewer deductions and credits will be utilized from prior periods causing the deferred tax asset included in rate base to not decline as quickly with this slowdown in utilization. This will cause an increase in revenue requirements.

Q. WHAT WOULD HAPPEN TO THIS ADJUSTMENT IF THE UNITED STATES CONGRESS VOTES TO EXTEND BONUS TAX DEPRECIATION AS THEY DID IN 2014?

A. Similar to reducing taxable income by having a reduced level of revenues granted, if the Bonus Tax Depreciation provisions are extended, an additional deduction will be available reducing taxable income. To the extent the Company was utilizing deductions and credits from prior years and generating Section 199 manufacturing production deductions, the generation of these deductions will be reduce or eliminated and the utilization of prior deductions and credits will be deferred to future periods. The result will be an increase in the short term deficiency (2016 and 2017), with a reduction in the 2018 future deficiency once the prior period utilization and Section 199 deductions resume. Please see the direct testimony of Ms. Heuer, Section VII. Adjustments to the Test Year, Part G. Rebuttal adjustments for an additional discussion and quantification of this potential change.

13. Cost of Capital

Q. HOW DID YOU DEVELOP THE COST OF CAPITAL ADJUSTMENT FOR PLAN YEARS 2017 AND 2018?

A. Mr. Van Abel presents changes in the cost of debt for 2017 and 2018. These changes in cost of debt impact the Required Operating Income (rate base x required rate of return) and the Debt Interest Expense (rate base x cost of debt). The cost of capital adjustment presents the change in revenue requirements due to the change in these two calculations for 2017 and 2018. We make the calculations on all rate base for the Plan Years. The resulting amounts are shown on columns 14 and 28 of Schedule 7. A summary calculation of the cost of capital adjustment is shown on Workpaper M9.

B. Customer Protections

Q. HAVE YOU CONSIDERED CUSTOMER AND COMPANY PROTECTIONS AS PART OF THE MYRP PLAN?

A. Yes. I discuss observations on various customer and company protection mechanisms in Section IV of my testimony, along with the Company's experience with those mechanisms in other jurisdictions. For the three-year plan, we chose to expand and continue the customer protection mechanisms that were most constructive from most recent case to help achieve just and reasonable rates.

Q. WHAT CUSTOMER PROTECTION MECHANISMS DOES THE COMPANY PROPOSE AS PART OF ITS MYRP PLAN?

A. We are proposing true-ups for several items that would be combined with a net tracker balance and implemented each August of the plan period. The true-ups proposed are:

1. A symmetrical true-up for sales and retail revenues from non-decoupled classes.
    a. The 2016 actual level would be reflected in final rates.
    b. If the 2017 actual level were greater than the approved 2017 Plan Year level in final rates, a refund would occur, net of other true-ups (described further below); if lower, the balance would be deferred, net of other true-ups.
    c. If the 2018 actual level were greater than the approved 2018 Plan Year level in final rates, a refund would occur, net of other true-ups; if lower, the balance would be deferred, net of other true-ups.
2. A symmetrical true-up for property taxes.
    a. The 2016 actual level would be reflected in final rates.
    b. If the 2017 actual level were less than the approved 2017 Plan Year level in final rates, a refund would occur, net of other true-ups; if higher, the balance would be deferred, net of other true-ups.
    c. If the 2018 actual level were less than the approved 2018 Plan Year level in final rates, a refund would occur net of other true-ups; if higher, the balance would be deferred, net of other true-ups.

3. A one way true-up for capital-related revenue requirements.
    a. If the 2016, 2017, or 2018 total actual capital-related revenue requirement were less than the approved 2016, 2017, or 2018 Plan Year level, a refund would occur, net of other true-ups.

I summarize the timing of these events in relation to the overall case and decoupling events in Section III.A. of my testimony.

1. Capital True-Up

Q. HOW WILL THE CAPITAL TRUE-UP BE MEASURED AND IMPLEMENTED?

A. We propose that the Company will submit a compliance filing by May 1 of each year 2017, 2018 and 2019 that calculates the prior year actual plant related base rate revenue requirements. This compliance filing will compare the Actual Plant Related Revenue Requirements (Actuals) to the Capital Forecast Revenue Requirements shown on Volume 4B, Tab M1 (excluding property taxes). As with the Capital Forecast, the Actuals will include average balances of Plant in Service, Accumulated Depreciation, CWIP, Accumulated Deferred Income Taxes and capital-related Regulatory Amortization balances. Actuals will also include Depreciation, Deferred Income Taxes and Investment Tax Credits, AFUDC, capital-related Tax Additions and Deductions and capital-related State and Federal Tax Credits to develop the income statement items for that year.

For the 2016 Test Year compliance in the event the Actuals are lower than the approved Test Year, the Company will include update as an adjustment for calculation of final rates or otherwise provide a refund plan, depending on the timing of final rate implementation. We note that the 2016 Test Year is based on actuals through April, 2015. Therefore the 2016 capital forecast compliance report will update 20 months of actual data, from April, 2015 through December, 2016. Some of the difference between the Test Year Capital Forecast and the Actuals could be due to variances dating back to mid-2015.

For the 2017 and 2018 Plan Years, we anticipate the rate proceeding to have concluded by the time the Actuals compliance reports are filed in May, 2018 and May, 2019. Similar to the 2016 Actuals, these calculations will propose a one-time refund if the prior year Actuals are less than the prior approved Plan Year. This refund could be included with other rate case related refunds each August.

Q. IS THIS THE SAME AS THE TRUE-UP METHOD IN THE MOST RECENT CASE?

A. This method is very similar to the 2014 Actual Capital Related Revenue Requirement true-up that was implemented as part of the last rate case. In that case, the Company filed a detailed compliance report on April 24, 2015 with the Actuals, which were compared against the Commission-approved capital-related revenue requirements for 2014. However, the subsequent Plan Years are different. In the most recent case, the 2015 Step included a list of discrete projects, each of which were monitored with periodic compliance filings and detailed at a project by project level.

In this rate case, since the Company is proposing all incremental capital for the Plan Years, the compliance reports would also measure all capital for Actuals, similar to the 2014 capital true-up in the last case.

2. *Sales True-Up*

Q. HOW WILL THE NON-DECOUPLED SALES TRUE-UP BE MEASURED AND IMPLEMENTED?

A. We propose that the Company will submit a compliance filing by February 1 of each year 2017, 2018, and 2019 that provides the prior year actual sales. Ms. Marks discusses how actual sales are measured for a true-up in her Direct Testimony, including weather normalization methods and decoupling effects.

For the 2016 Test Year, the sales true-up compliance filing would be filed by February 1, 2017 so that it could inform the Commission's decision in the case, which would occur in March 2017 assuming the statutory timeline for rate cases. The compliance filing would compare the 2016 actual, weather normalized sales and revenues to the 2016 Test Year. This is similar to what was implemented in our last rate case. An adjustment would be calculated, either upward or downward, as an adjustment for final rates.

For the 2017 and 2018 Plan Years, we anticipate the rate proceeding to have concluded by the time the Actuals compliance reports are filed in February, 2018 and February, 2019. Therefore, these calculations will propose a one-time refund if the prior year actual revenues are higher than the prior Plan Year. If actual revenues are lower, the balance would be recorded as a regulatory asset. This refund deferral would be included with other rate case related refunds deferrals each August.

3. *Property Tax True-Up*

Q. HOW WILL THE PROPERTY TAX TRUE-UP BE MEASURED AND IMPLEMENTED?

A. We propose that the Company will submit a compliance filing by July 1 of each year 2017, 2018 and 2019 that calculates the prior year property tax expense. Company witness Ms. Leanna M. Chapman discusses the technical details of how actual property taxes are measured for a true-up in her Direct Testimony.

For the 2016 Test Year, a preliminary property tax true-up compliance filing would be filed by February 1, 2017 based on 2016 actual accruals so that it could inform the Commission's decision in the case, which would be anticipated in March 2017 assuming the statutory timeline for rate cases. The compliance filing would compare the 2016 actual accrued property tax expense to the 2016 Test Year. This is similar to what was implemented in the last rate case. An adjustment would be calculated, either upward or downward, to set rates.

Once final tax statements are received in the spring of 2017 related to 2016 property taxes, the Company would file a final property tax compliance report by July 1, 2017 for inclusion in final rate implementation.

For the 2017 and 2018 Plan Years, we anticipate the rate proceeding to have concluded by the time the Actuals compliance reports are filed in July, 2018 and July, 2019. These calculations will propose a one-time refund if the prior year actual property tax accruals are lower than the prior Plan Year. If actual expenses are higher, the balance would be recorded as a regulatory asset. This refund deferral would be included with other rate case related refunds deferrals each August.

4. *Refunds or Deferrals*

Q. HOW WILL THESE POTENTIAL BILL IMPACTS APPEAR ON CUSTOMERS' BILLS?

A. We proposed to combine the true-up mechanisms so that they only appear once on customer bills, if at all. With this set of proposals, and the continuation of previous true-up mechanisms, we now have six potential refunds or surcharges related to base rates.

1. Interim rates (potential refund or surcharge, in 2017 only)
2. Sales true-up (February filing, potential refund or deferral)
3. Capital true-up (May filing, potential refund)
4. Annual Incentive Plan (June filing, potential refund)
5. Net Operating Loss (June filing, potential refund)
6. Property tax true-up (July filing, potential refund or deferral)

For all true-up measurements that occur before proposed Final Rate Compliance, those upward or downward true-ups would get incorporated into final rates.

For true-up measurements after Final Rate Compliance, we propose to create a regulatory asset or liability and maintain a tracker balance for the rate case true-up increases or decreases. In August, 2018, if the net tracker balance is negative after including the 2017 true-ups, a refund would occur to customers. If the balance is positive, it would be carried forward to 2019.

In August 2019, we would again calculate the tracker balance including 2018 true-ups and refund to customers if the net balance is negative. If the balance is positive, it would be deferred to the Company's next rate case.

In order to effect this streamlining of the various true-up mechanisms, the Company would need an authorization in the Commission's rate case order to create a regulatory asset or liability. This is required for the Company to meet accounting requirements.

Decoupling is a separate mechanism that would have a separate tracker and separate listing on customer bills.

Q. DO YOU SEE ANY ALTERNATIVES TO ACCOMPLISH THESE OBJECTIVES?

A. Yes. An earnings test would expand the concept of line item true-ups to the entire Cost of Service and could be implemented in one annual compliance filing, rather than the multiple mechanisms and filings proposed above. I describe earnings tests in more detail in Section IV of my testimony.

C. Potential Adjustments as the Case Progresses

Q. WOULD ADJUSTMENTS TO THE 2016 TEST YEAR REQUIRE SIMILAR ADJUSTMENTS IN THE 2017 AND 2018 PLAN YEARS?

A. Yes, most likely. Since 2017 Plan Year is presented as incremental change from the 2016 Test Year, and since many of the changes are driven by specific forecast rather than escalation factors, adjustments to the 2016 Test Year should also be reflected in the calculations for the 2017 and 2018 Plan Years. Where possible, the Company will quantify adjustments for all three years so that each issue and its impact on each year can be identified.

Q. ARE YOU AWARE OF ANY MATERIAL CHANGES IN FACTS THAT MAY JUSTIFY ADJUSTMENTS APPROPRIATE TO INTRODUCE LATER IN THE CASE?

A. Yes. Ms. Heuer lists the following thirteen issues that may require rebuttal adjustments.

1. Cost of capital to reflect the most currently available data.
2. Sales forecasts using available actual sales through December 2015.
3. Assumptions used for calculating Qualified Pension expense based on information as of December 31, 2015.
4. O&M active health care may be updated to reflect actual 2015 active medical and pharmacy claims.
5. Capital projects more than $1 million currently planned to be in service in December 2016 to determine whether those projects will be completed within the 2016 Test Year.
6. Property tax forecasts based upon property tax data that will become available during 2016.
7. Any final decision related to the November 2013 MISO Return on Equity (ROE) Complaint.
8. Reflection of the Commission's October 22, 2015 decision in the 2015 Remaining Lives proceeding, Docket No. E,G002/D-15-46.
9. Removal of a 2017 capital addition (Hollydale) that was included in the capital forecast in error.
10. Allocation of Prairie Island Indian Community Settlement Agreement Costs.
11. Removal of Economic Development Administration costs.
12. Reflection of the October 12, 2015 Decision of the Minnesota Department on CIP expenditures in Docket No. E,G002/CIP-12-447.
13. Possible extension of the "Tax Increase Prevention Act of 2014" by Congress.

D. Compliance Activities Associated with the Company's MYRP Proposal

Q. PLEASE DESCRIBE THE KEY COMPLIANCE ACTIVITIES THE COMPANY IS PROPOSING TO PERFORM DURING THE 2015 THROUGH 2018 TIME PERIOD TO IMPLEMENT ITS MYRP PROPOSAL?

A. After submission of the MYRP case on November 2, 2015, the Company is planning to take a number of actions that are closely associated with its proposed MYRP plan. Table 7 below and Exhibit___(CRB-1), Schedule 15 summarize those actions, assuming the statutory rate case schedule as an example. This suggested compliance calendar should be updated to reflect any milestones ordered as a result of the Contested Case Pre-Hearing Conference as well as other agreements among parties as the case progresses.

Table 7
Proposed Compliance Activities for the Plan Period (2016 – 2018)

Rate Case Event	Compliance Event	Date
Application filed		11/2/2015
2016 Interim Rates in effect		1/1/2016
	Monthly decoupling deferral calculations begin	1/1/2016
	2015 Jurisdictional Annual Report	5/1/2016
	2015 Incentive Compensation annual compliance report; 2015 NOL annual compliance report	6/1/2016
	2015 AIP, NOL refunds, if any	8/1/2016
	TCR petition for 2017 rates; 2016 TCR roll-in compliance report for rate case adjustment	10/1/2016
2017 Interim Rates in effect		1/1/2017
	2016 actual Sales compliance report; 2016 preliminary actual Property Tax compliance report; 2016 Preliminary Decoupling compliance report	2/1/2017

Rate Case Event	Compliance Event	Date
MPUC Order	(assumes statutory timeline)	3/1/2017
Final Rates Compliance Filing	Final rates compliance for 2017 and 2018 including true-up measurements to-date as adjustments to final rates; 2016 Final Decoupling deferral calculation and Proposed Factors; Proposed interim rate refund or surcharge	4/1/2017
	2016 Jurisdictional Annual Report; 2016 Capital true-up compliance report	5/1/2017
	2016 Incentive Compensation annual compliance report; 2016 NOL annual compliance report	6/1/2017
MPUC Order on Compliance Filing	(typical timeframe after compliance filing)	6/1/2017
2017 Final Rates in effect	Implementation of Decoupling credit/surcharge factors; Final 2016 actual Property Tax compliance	7/1/2017
	Interim refund; AIP and NOL refunds, if any	8/1/2017
2018 Final Rates in effect		1/1/2018
	2017 actual Sales compliance report; 2017 Decoupling compliance report	2/1/2018
	2017 Decoupling refunds/surcharge	4/1/2018
	2017 Jurisdictional Annual Report; 2017 Capital true-up compliance report	5/1/2018
	2017 Incentive Compensation annual compliance report; 2017 NOL annual compliance report	6/1/2018
	2017 Property Tax compliance report	7/1/2018
	Sales, Capital, Property Tax, AIP, NOL and capital true-up net refund/deferral	8/1/2018
	2018 Sales compliance report; 2018 Decoupling compliance report	2/1/2019
	2018 Decoupling refunds/surcharge	4/1/2019
	2018 Jurisdictional Annual Report, 2018 Capital true-up compliance report	5/1/2019
	2018 Incentive Compensation annual compliance report; 2018 NOL annual compliance report	6/1/2019
	2018 Property Tax compliance report	7/1/2019
	Sales, Capital, Property Tax, AIP, NOL and capital true-up net refund/deferral	8/1/2019

The Company files a Jurisdictional Annual Report (Annual Report) every May 1, which can be used as a monitoring tool for the Company's performance during the term of the plan. The Annual Report provides a calculation of the Company's earned ROE for the previous year. The calculation begins with actual books and records as recorded for the previous year, adjusted for current regulatory practice, and allocated to jurisdiction. It provides an "all in" view with the Company's earnings across all recovery mechanisms including base rates, fuel, and all rate riders. We would supplement the Annual Report with a comparison of the actual costs and revenues to those included in each Plan Year. This information could then enable regulatory review to monitor the Company's financial performance during the plan period.

The Company will start using interim rates in January 2016. Monthly decoupling deferral calculations also begin in January 2016, as discussed by Company witness Ms. Lisa R. Peterson. We anticipate the remainder of 2016 will be focused on discovery related to the rate case, testimony (including Intervener Direct, Rebuttal and Surrebuttal testimony) and evidentiary hearings.

Calendar year 2017 will start with implementation of interim rates proposed for the second year of the MYRP period. The Company will also perform a true-up of property taxes in the month of March 2017. If we have the Commission's final Order in this case in March, consistent with the statutory timeline for rate proceedings, that would lead to final rate implementation in approximately July 2017. At that same time, the Decoupling pilot program true-up credit or surcharge factors using final rates from this case will be implemented, as approved by the Commission in our last rate case. Any necessary interim rate refunds would be processed in August of that year. The annual report will be submitted in May 2017, with a review period of 90 days, allowing any necessary capital true-up refund to be implemented with the interim refund in August 2017.

The Company is also planning to file RES, RDF, CIP and TCR Riders in September or October of 2016 and 2017. We plan to report on our Decoupling pilot annually on February 1 2017, 2018 and 2019, with surcharge or credit factors effective July 2017, April 2018 and April 2019, respectively. In 2018, the annual report will be submitted on May 1.

Ms. Peterson provides additional details around the Decoupling mechanism in this multi-year rate case.

Q. WHAT DO YOU CONCLUDE AFTER REVIEWING THIS POTENTIAL SCHEDULE?

A. As the table above demonstrates, a MYRP can be structured to provide for the systematic and thorough review of resulting rates. Should the timeline change during the proceeding, we believe these concepts provide guidance as to how the calendar can be updated to accommodate the new timeline. In this way, the Commission can have confidence that ratepayers continue to receive the level of service desired, while paying just and reasonable rates for those services.

Q. WILL THE COMPANY CONTINUE ITS PRACTICE OF AN ANNUAL COMPLIANCE FILING FOR INCENTIVE COMPENSATION AND THE NOL?

A. Yes. By June 1 of each year, the Company will file an annual compliance report that offers a refund to customers if the Company distributed incentive compensation less than the level in the Plan Year. It will also file a report by June 1 that offers a refund if consumption of the Deferred Tax Asset related to the NOL is greater than the level in the Plan Year.

IV. THE COMPANY'S MYRP EXPERIENCE IN OTHER JURISDICTIONS

Q. EARLIER IN YOUR TESTIMONY YOU MENTION THAT SEVERAL STATES HAVE ADOPTED MYRPS. WHY DO YOU THINK THIS IS THE CASE?

A. An MYRP allows the Company, its stakeholders and the Commission to have a conversation about the appropriate levels of investment to match policy goals over a period of time. Once rates are set under such a plan, the Company can work to maximize customer benefits and manage its returns over the plan period, with stakeholders and the Commission still having the opportunity to ensure that the Company is providing safe, reliable, environmentally sound and customer focused energy services at just and reasonable rates. This represents a significant opportunity, different from past practice, for all interests involved, including the Company, to be open and transparent about the desired level of service and the costs and rate impacts associated with that level of service.

Q. HAS THE COMPANY HAD EXPERIENCE WITH MYRP PLANS IN OTHER JURISDICTIONS AND HAVE THOSE EXPERIENCES INFORMED YOUR PROPOSAL FOR THIS PROCEEDING?

A. Yes. In my testimony below, I will briefly describe the features of several MYRP methods (or models) that have been implemented in Xcel Energy's other jurisdictions. I also briefly discuss FERC formula rates, which Xcel Energy operating companies file in several regional markets around the country. Finally, I discuss what we believe to be the important criteria in judging the reasonableness of a MYRP.

- First is the biannual rate case that NSPW follows in Wisconsin. The Company is required to file a rate case at least every two years. It is a two-year ratemaking proceeding based on a forward Test Year and is supported by detailed information from each expense and revenue account. For example, according to the biennial rate case filing schedule adopted by the Public Service Commission of Wisconsin, the Company would file full rate cases in odd-numbered years for subsequent even numbered forecast Test Years. This year, the Company filed a full rate case application on May 29, 2015 (Docket No. 4220-UR-121) requesting an increase in rates for the 2016 Test Year, and the Company expects to have a final Decision and Order by December 31, 2015. The Wisconsin jurisdiction also has the option to file an "off-year" rate case or a "limited reopener rate case." The limited reopener rate case option allows the Company to request rate relief in the off year, but requires the Company to commit to limiting the size and scope of the off-year cycle rate cases. For example, for the 2015 Test Year limited reopener rate case (Docket No. 4220-UR-120), NSPW reached an agreement with interested stakeholders to limit the size and scope of the 2015 costs to an update of fuel and purchased power costs, and an update of fixed production and transmission costs that flow through the interchange agreement only.

- A rider-based model has been used by NSPM in South Dakota, and Public Service Company of Colorado has implemented a similar approach in Colorado. In this method, cost recovery riders capture most of the growth in capital costs and are used to bridge across several years between rate cases. Additionally, earnings test filings are required based on prior year results to true up revenues.

  In the EL14-058 electric rate case, South Dakota approved a base rate increase of 3.6 percent plus an "infrastructure rider" authorized under the SDPUC's broad ratemaking authority. The rider is also somewhat guided by the legislative basis for a "phase-in rider" that allows large generation, transmission, and distribution projects to be recovered.[7] This cost recovery mechanism allowed the Company to commit to a stay-out provision for three years without requesting new base rates.

  In Colorado, the Company is on its fourth year of earnings test measurements as part of multi-year rate case outcomes involving large riders.
- NSPM has also implemented a "negotiated rate shape" approach in North Dakota. Rate setting is informed by a five-year forecast submitted by the utility, but revenues are not directly tied to this forecast. Rather, the Company and the Commission settle on a rate structure for the plan period with the understanding that the settled rates will enable several broad policy and investment objectives for

[7] SDCL 49-34A-73 through 49-34A-78.

customers. The Company may adjust its budget internally to optimally meet those objectives under those rates.

In the most recent North Dakota rate case, the case was filed in 2012 with a 2013 forward Test Year. The Company also provided a high-level summary of its five-year forecast. Staff for the NDPSC submitted a number of formal and informal data requests to scrutinize the forecast plan. The North Dakota Commissioners also expressed strong interest in a rate freeze year. The Company and Staff negotiated over several months, and presented the Commission with a four-year settlement to cover 2013–2016. The Commission slightly modified the settlement and authorized base rate increases of 4.9 percent each year for 2013–2015 with a base rate freeze (0 percent increase) for 2016.

Table 8
North Dakota Case No. PU-12-813 Outcome

Year	2013	2014	2015	2016
Base Rate Increase	4.9%	4.9%	4.9%	0.0%
Authorized ROE	9.75%	9.75%	10.00%	10.25%

The settlement also included an earnings test to provide a refund to customers should the Company earn more than its authorized return in each year. The settlement also authorized a step-wise increase in the Company's authorized return on equity in 2014 through 2016.

- The last method is the FERC Formula method where each year, a forward Test Year is used to estimate rates for the following calendar year, based on forecasted revenue requirements. In this case, a detailed true up of rate base, capital structure, revenues and expenses also occurs, resulting in a carry-forward revenue requirements balance (upward or downward) into the next year, plus interest. The Company uses FERC formulae to submit proposed annual rates for transmission with MISO, Southwest Power Pool and in Colorado, as well as for wholesale generation in Colorado, Texas and New Mexico.

Q. WHAT CRITERIA DO YOU SUGGEST THE COMMISSION CONSIDER AS IT REVIEWS THE COMPANY'S PROPOSAL?

A. The Company's MYRP, or any other MYRP proposal, should be judged on the following types of attributes:

- Rate setting frequency, to minimize "rate case fatigue" resulting from annual or biannual filings;
- Procedural simplicity, to reduce the administrative burden for all parties;
- Clarity and transparency, to foster improved understanding of the relevant issues by all parties;
- Resiliency to changing circumstances, so the Test Year and Plan Years remain representative of future conditions; and
- Protections against unreasonable outcomes, for both customers and the Company.

Q. PLEASE DESCRIBE HOW THE COMPANY'S PROPOSAL ADDRESSES THESE ATTRIBUTES.

A. The attributes, and how the Company's proposal addresses them, can be summarized as follows:

Rate Setting Frequency

Some MYRP methods have the Commission set a rate plan up-front, which then enables a series of approved rates to be implemented each year of the plan. For example, the MYRP approved in North Dakota provides greater certainty and predictability to all parties and ratepayers. Our three-year plan will provide at least one year between the Commission decision and the filing of a subsequent plan. Our five-year alternate proposal would provide at least a three year break between the conclusion of this case and the next base rate case.

Procedural Simplicity

Our three-year rate proposal will require the typical large number of person-hours involved in a single Test Year rate case, plus modest hours (compared to rate cases) related to annual true-up protections over the three years. However, this proposal translates to much less administrative burden than, for example, three individual Test Year rate cases.

Clarity and Transparency

The clarity and transparency of any MYRP filing can be challenging. The simpler the calculation, the more understandable the method becomes to parties and the Commission. Our three-year proposal attempts to provide a balance of detail to enable review, while using estimation methods where appropriate, to result in just and reasonable rates. For this rate case, we sought a bridge between previous applications and more formulaic rate making. In future cases, it may be possible to simplify the calculation method. Exhibit___(CRB-1), Schedule 14 provides one such alternative method for developing rates that relies on greatly simplified inputs when compared to the detailed Cost of Service, yet yields similar inflationary results.

<u>Resiliency to Changing Circumstances</u>

This refers to the company's ability to meet its customers' needs and survive the changes in its business environment as well as unpredictable events that could affect the company's performance and ability to fulfill its responsibility towards its customers and shareholders. The Company's proposal attempts to do so by identifying rate riders as the mechanism for the Company to pursue additional State policy objectives, such as renewable generation or grid modernization opportunities.

<u>Protections for Customers and the Company</u>

This proposal continues the customer protections related to sales, property taxes, and capital in service for the Test Years that were in the most recent case. These mechanisms provided a reasonable balance between the Company's need for current recovery of these costs and the ratepayer's desire to only pay for a reasonable and up-to-date amount.

Q. CAN YOU PROVIDE MORE EXPLANATION OF THE DIFFERENT RATEMAKING METHODS THAT CAN BE IMPLEMENTED TO PROTECT BOTH THE CUSTOMERS AND THE COMPANY?

A. Yes. There are three main options for protecting customers. First, line-item true-ups can be used. These may be one way refunds to customers if Company costs are less than initially forecast, or may be symmetrical as well, meaning the company could recover additional costs if actual results exceed the amount built in to rates. Second, annual earnings tests can be used to provide for earnings sharing with customers, should the Company experience significant cost reductions or sales growth. Lastly, a thorough detailed audit review of the company's financial data can be conducted to determine appropriate cost recovery.

On the other hand, the options for Company protection include the use of balancing accounts, the use of riders or other mechanisms to respond to particular or unforeseen expenses and re-openers. Balancing accounts are essentially a two-way true up of costs and are used for certain categories of cost recovery. This enables the company to recover costs through surcharges if actuals are higher than forecast, but also requires a refund to customers if the converse is true. Another option includes the use of riders or other rate adjustment mechanisms to provide a company the flexibility to recover costs related to future unforeseen projects between the rate cases. The new MYRP legislation specifically allows for such mechanisms by allowing for "adjustments to the rates approved under the multiyear plan for rate changes that the commission determines to be just and reasonable, including, but not limited to, changes in the utility's cost of operating its nuclear facilities, or other significant investments not addressed in the plan." Re-opening the case is another option when large forecast changes occur and the company is significantly under-earning – and thus not able to sustain the interests of its shareholders.

It is important that any combination of these options used strike a balance between the interests of the utility and its customers. The best plans are where customers can be assured of reliable, affordable and sustainable services, while the utility is able to manage its risks and earn required returns.

Q. THE REFUND MECHANISMS IN THE MODELS DESCRIBED ABOVE INCLUDE TRUE-UPS AND EARNINGS SHARING. CAN YOU EXPLAIN MORE ABOUT THE PROS AND CONS OF TRUE-UP MECHANISMS?

A. True-up mechanisms are based on line item reviews for an account that was under or over spent. Some cost recovery methods use two-directional true-ups, as is the case in rate riders for Minnesota. Assuming an opportunity for full review of the costs at issues, these mechanisms provide a balance of ratepayer and shareholder interests. Other true-ups are one-directional, as in the sales, capital, and property tax refunds in the last case. These one directional true-ups provide a customer refund if actuals are less than the amount built in to rates, but do not involve provide the utility any relief if actuals exceed that amount.

The challenge with true-up mechanisms is that the utility does not necessarily manage its business line item by line item but rather in total. Selected true-ups ignore that the line items outside the true-up will also vary between a budget and actuals. As an example, assume that regulators approve a true-up on tree trimming. If the business incurs unexpected costs due to storm damage, it may choose to defer some tree trimming in order to hold the overall budget constant. With a true-up on only tree trimming, the utility now owes customers a refund because tree trimming is down, ignoring the fact that storm response costs are up. Such a system can create counter-productive incentives. In the example above, a utility may be artificially incented to over-spend its budget by maintaining the original tree trimming plan plus the storm damage costs. Or worse, a utility could feel incented maintain tree trimming and have a weak storm response to hold the overall budget because storm response is not included in the true-up.

Q. CAN YOU EXPLAIN MORE ABOUT THE PROS AND CONS OF EARNINGS TEST MECHANISMS?

A. Earnings test mechanisms expand on the concept of line-item true-ups by covering the entire Cost of Service, not just select cost categories or accounts. They provide a platform for revenue sharing with customers for weather-normalized earnings in excess of the authorized ROE. The Company refunds to customers a certain percentage (NSPM has used 50 percent in North Dakota) of revenue that corresponds to the earnings in excess of its authorized ROE for a particular year. These refunds typically occur after the utility's weather-normalized earnings are reported in its jurisdictional annual report each year. This mechanism is more comprehensive for regulators, and provides a balanced safeguard for customers.

Using the example from above, a utility is free to balance its storm response and its tree trimming in the best interest of customers. If the utility finds sufficient cost savings to its overall budget, those cost savings are refunded to customers through the earnings test. If in-service dates change, property taxes are lower, sales are higher, or plant lives are extended, all of those possibilities can contribute towards a refund to customers if in total, they reduce the actual Cost of Service during a fiscal year.

V. THE COMPANY'S FIVE-YEAR MYRP OPTION

Q. IS THE COMPANY OFFERING ANY PROPOSED ALTERNATIVES TO THE THREE-YEAR MYRP?

A. Yes. As Mr. Chandarana discusses, the Company believes that settlement for a period of up to five years may be of interest to parties and may yield constructive outcomes.

Q. HAS THE COMPANY PERFORMED ANY ADDITIONAL ANALYSES IN SUPPORT OF A POTENTIAL FIVE-YEAR PLAN?

A. Yes. To evaluate its reasonableness, I examined the cost drivers and compound average growth rates contained in the three year plan against the five year forecast. This is provided in Exhibit___(CRB-1), Schedule 13. I also provide in Schedule 14 a simplified formula to provide a cost basis for rates going out beyond three years. This formula begins with the 2016 Test Year, just like the three-year plan. However from then on it uses growth rates for capital based on the forecast, IHS escalation factors for O&M, and growth rates for sales to estimate a reasonable, smooth and inflationary deficiency pattern. This alternate method can be used to help guide high-level settlement discussions over longer periods of time than the three year plan. Schedules 13 and 14 show that the Company's five-year option provides lower rates than those indicated by either the forecast or the formula.

Q. WOULD YOU USE THE SAME REPORTING AND COMPLIANCE APPROACH YOU OUTLINED FOR THE THREE-YEAR MYRP FOR A FIVE YEAR PLAN?

A. Not necessarily. The amount of detail involved in our three-year proposal can yield a false sense of precision, particularly when looking out five years. As we go out in time, the budget and forecast information becomes more representative and less prescriptive. If parties and the Commission can develop a five-year plan, we would instead suggest an earnings test mechanism, as discussed by Mr. Chandarana. The earnings test would also further simplify and streamline the suggested compliance calendar discussed above by eliminating the need for separate true-up measurements and compliance filings.

To facilitate an earnings test, we would rely on the Annual Report, which we already file with the Commission by May 1 every year. As discussed in Section III above, the Annual Report provides a calculation of the Company's earned ROE for the previous year. For an earnings test, we could supplement the Annual Report with additional detail such as rate base and income statement bridge schedules that demonstrate each regulatory adjustment, plant summaries by function and income statement summaries by FERC Account. This data could then enable regulatory review to monitor the Company's financial performance during the plan period.

VI. CONCLUSION

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. MYRPs offer an opportunity for regulators to strongly influence the Company's budgeting process. The Company seeks at least one and up to three budget cycles to be informed by the rate setting in this case. The three-year proposal includes a capital forecast, escalated O&M where reasonable and consideration for sales increases and cost decreases. The resulting proposed costs are just and reasonable, resulting in increases that are similar to inflation after the first year. The proposal also includes several rate payer protections, in particular the true-ups for sales, property tax, and capital. The Company has experience using MYRPs in other jurisdictions and has found them to be a constructive way to refocus the regulatory interface from frequent rate proceedings towards policy objectives.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

Resume of Charles R. Burdick

Manager of Revenue Analysis
Revenue Requirements North

Xcel Energy Services Inc.
414 Nicollet Mall
Minneapolis, MN 55401

Current Responsibilities

Since August 2011, I have worked in the Revenue Requirements – North department, first as a Principal Rate Analyst and now as a Manager. In this position, I prepare and present cost of service studies, revenue requirement determinations, and jurisdictional annual reports for the electric and gas operations of Northern States Power Company to the Minnesota Public Utilities Commission, the South Dakota Public Utilities Commission, and the North Dakota Public Service Commission.

Prior Testimony

South Dakota – Electric Rate Case
Docket No. EL14-058

Minnesota – Wind Energy Siting
Docket No. IP6701/WS-08-1233

Energy-Related Employment History

Xcel Energy – Minneapolis, MN

- Manager of Revenue Analysis, July 2015 to Present
- Principal Rate Analyst, August 2011 to July 2015

National Wind, LLC – Minneapolis, MN

- Senior Wind Energy Developer, August 2009 to August 2011
- Wind Energy Developer, April 2008 to August 2009

Education

University of North Carolina at Chapel Hill, May 2005
Master of Business Administration

Macalester College, May 1999
Bachelor of Arts – Mathematics, Computer Science, Music

Item			Basis	Adjustment presentation
1.	Rate Base			
	a.	Plant in Service	forecast	Capital Forecast
	b.	Depreciation Reserve	forecast	Capital Forecast
	c.	CWIP	forecast	Capital Forecast
	d.	ADIT	forecast (plus NOL)	Capital Forecast / NOL
	e.	Other Rate Base	forecast	Other Rate Base Forecast
2.	Revenues			
	a.	Retail, interdepartmental	2016 level	none
	b.	TCR revenue	forecast	Change in TCR Revenues
	c.	Retail non-decoupled	side calc adjustment	Non-Decoupled Sales
	d.	Other (I/A)	simulated Interchange bill / forecast	[various]
	e.	Transmission Revenues	forecast	Transmission Rev/Exp
	f.	Other misc revenues	composite escalation factor	Non-Retail Revenues
3.	Expenses			
	a.	500-935	IHS Global Insight escalation factors	Escalated O&M
	b.	Except:		
	i.	501 Fuel	2016 level	none
	ii.	518 Fuel	2016 level	none
	iii.	547 Fuel	2016 level	none
	iv.	517-532 Nuclear	IHS factor / Nuclear outage amortization	Escalated O&M
	v.	555 Purchased Pwr	forecast	Purchased Demand
	vi.	556 Load Dispatch	composite escalation factor	Escalated O&M
	vii.	557 IA Exp from WI	simulated Interchange bill	[various]
	viii.	565 Transm Exp	forecast	Transmission Rev/Exp
	ix.	566 Transm Exp	simulated Interchange bill / forecast	Transmission Rev/Exp
	x.	575 Transm Exp	forecast	Transmission Rev/Exp
	xi.	904 Bad Debts	forecast	Bad Debt Expense
	xii.	908 CIP	2016 level	none
	xiii.	920 Salaries	IHS Global Insight - Labor-specific	Escalated O&M
	xiv.	922 Credit	composite escalation factor	Escalated O&M
	xv.	925 Workers Comp	forecast	FERC 925 & 926
	xvi.	926 Pension & Ben	forecast	FERC 925 & 926
	xvii.	929 Credit	composite escalation factor	Escalated O&M
	xviii.	408 Taxes Other than Income	forecast	Capital Forecast / Esc O&M
4.	Capital-related expenses			
	a.	Depreciation	forecast	Capital Forecast
	b.	Current and Def Tax exp	forecast (plus NOL)	Capital Forecast / NOL
	c.	Tax Credits	forecast (plus NOL)	Capital Forecast / NOL
	d.	AFUDC	forecast	Capital Forecast
5.	Amortization		forecast (capital related)	Capital Forecast
6.	Secondary Calculations			
	a.	Cash Working Capital	calculated	Cash Working Capital
	b.	NOL	calculated	NOL
	c.	Change in Cost of Debt	calculated	Cost of Capital

Amounts in Thousands

2016 Test Year			$ 194,612	6.4%
2017 Forecast Adjustments		Reference		
Capital Forecast	66,631	WP M1		
Other Rate Base and Nonplant	365	WP M2		
Purchased Demand	(4,266)	WP M3		
Bad Debt Expense	(246)	WP M3		
FERC 925 & 926	1,981	WP M3		
Non-Decoupled Sales	(4,766)	WP M4		
Change in TCR Revenue	1,485	WP M4		
Transmission Rev/Exp	(1,090)	WP M3		
2017 Escalated Adjustments				
Escalated O&M	16,477	WP M5		
Non-Retail Revenue	(860)	WP M6		
2017 Secondary Calculations				
Cash Working Capital	(411)	WP A39		
Net Operating Loss	(24,548)	WP M8		
Cost of Capital	1,301	WP M9		
Total 2017 Adjustments	52,055			
2017 Plan Year			$ 246,667	1.7%
2018 Forecast Adjustments		Reference		
Capital Forecast	47,023	WP M1		
Other Rate Base and Nonplant	533	WP M2		
Purchased Demand	(3,992)	WP M3		
Bad Debt Expense	(151)	WP M3		
FERC 925 & 926	2,622	WP M3		
Non-Decoupled Sales	(5,150)	WP M4		
Change in TCR Revenue	1,434	WP M4		
Transmission Rev/Exp	(871)	WP M3		
2018 Escalated Adjustments				
Escalated O&M	16,500	WP M5		
Non-Retail Revenue	(377)	WP M6		
2018 Secondary Calculations				
Cash Working Capital	(418)	WP A39		
Net Operating Loss	(6,515)	WP M8		
Cost of Capital	(170)	WP M9		
Total 2018 Adjustments	50,466			
2018 Plan Year			$ 297,133	1.7%

ROE = 6.44%
Deficiency = $246,667 (Cumulative)
% Increase = 8.13% (Cumulative)
Required ROE = 10.00%

Northern States Power Company (MN)
Electric Utility - Minnesota Retail Jurisdiction
Cost of Service Study
Proposed 2017 Plan Year

Summary Reports

November 2015

Line No.	NSPM - 01 Rate Base Schedule with BOY/EOY	Total			MN Electric			Other		
		BOY	EOY	BOY/EOY Avg	BOY	EOY	BOY/EOY Avg	BOY	EOY	BOY/EOY Avg
1	**Rate Base**									
2	Plant Investment	19,229,488	19,957,375	19,593,431	16,722,727	17,349,962	17,036,345	2,506,761	2,607,413	2,557,087
3	Depreciation Reserve	8,614,317	9,275,762	8,945,040	7,520,789	8,097,485	7,809,137	1,093,528	1,178,278	1,135,903
4	Net Utility Plant	10,615,171	10,681,613	10,648,392	9,201,938	9,252,478	9,227,208	1,413,233	1,429,135	1,421,184
5	CWIP	552,332	556,692	554,512	472,539	475,361	473,950	79,793	81,331	80,562
6										
7	Accumulated Deferred Taxes	2,611,438	2,651,828	2,631,633	2,287,151	2,320,385	2,303,768	324,287	331,443	327,865
8	DTA - NOL Average Balance	(72,266)	38,723	(16,771)	(43,310)	43,611	150	(28,956)	(4,888)	(16,922)
9	DTA - Federal Tax Credit Average Balance	(176,325)	(126,358)	(151,341)	(155,453)	(102,461)	(128,957)	(20,872)	(23,897)	(22,384)
10	Total Accum Deferred Taxes	2,362,847	2,564,193	2,463,520	2,088,388	2,261,535	2,174,961	274,459	302,659	288,559
11										
12	Cash Working Capital	(124,899)	(124,899)	(124,899)	(111,884)	(111,884)	(111,884)	(13,015)	(13,015)	(13,015)
13	Materials and Supplies	155,470	155,470	155,470	135,797	135,797	135,797	19,672	19,672	19,672
14	Fuel Inventory	84,138	84,138	84,138	73,476	73,476	73,476	10,662	10,662	10,662
15	Non-plant Assets and Liabilities	1,014	11,910	6,462	906	10,427	5,666	108	1,484	796
16	Customer Advances	(8,227)	(8,227)	(8,227)	(5,562)	(5,562)	(5,562)	(2,665)	(2,665)	(2,665)
17	Customer Deposits	(28,480)	(28,480)	(28,480)	(28,127)	(28,127)	(28,127)	(352)	(352)	(352)
18	Prepaids and Other	90,151	108,581	99,366	78,724	94,821	86,772	11,427	13,761	12,594
19	Regulatory Amortizations	59,047	55,660	57,353	59,047	55,660	57,353	0	0	0
20	Total Other Rate Base Items	228,214	254,153	241,184	202,377	224,607	213,492	25,837	29,546	27,692
21										
22	**Total Rate Base**	**9,032,870**	**8,928,265**	**8,980,567**	**7,788,465**	**7,690,911**	**7,739,688**	**1,244,404**	**1,237,354**	**1,240,880**

Line No.	NSPM - 02 Income Statement Schedule	Dec - 2017		
		Total	MN Electric	Other
1	**Operating Revenues**			
2	Retail	3,486,447	3,031,800	454,647
3	Interdepartmental	808	808	0
4	Transportation	0	0	0
5	Other Operating Rev - Non-Retail	681,548	597,164	84,384
6	**Total Operating Revenues**	**4,168,802**	**3,629,772**	**539,031**
7				
8	**Expenses**			
9	Operating Expenses:			
10	Fuel	1,138,449	995,513	142,936
11	Variable IA Production Fuel	5,771	5,040	731
12	Purchased Energy - Windsource	583	583	0
13	**Fuel & Purchased Energy Total**	1,144,803	1,001,136	143,667
14	Production - Fixed	455,635	397,866	57,769
15	Production - Fixed IA Investment	53,917	47,094	6,823
16	Production - Fixed IA O&M	(4,861)	(4,246)	(615)
17	Production - Variable	124,706	108,903	15,803
18	Production - Purchased Demand	149,256	130,369	18,887
19	Production - Other	(0)	(0)	0
20	**Production Total**	778,653	679,987	98,666
21	Regional Markets	8,211	7,172	1,039
22	Transmission IA	113,335	98,994	14,341
23	Transmission	126,881	110,800	16,081
24	Distribution	127,122	110,120	17,002
25	Customer Accounting	58,774	49,956	8,818
26	Customer Service & Information	92,474	91,125	1,348
27	Sales, Econ Dvlp & Other	121	70	52
28	Administrative & General	243,235	211,296	31,938
29	**Total Operating Expenses**	**2,693,608**	**2,360,654**	**332,953**
30				
31	Depreciation	622,164	543,044	79,120
32	Amortization	39,447	39,585	(138)
33				
34	**Taxes:**			
35	Property Taxes	219,746	195,116	24,629
36	ITC Amortization	(1,486)	(1,340)	(145)
37	Deferred Taxes	81,818	67,050	14,769
38	Deferred Taxes - NOL	15,989	0	15,989
39	Less Deferred Federal Tax Credits	49,967	52,991	(3,025)
40	Deferred Income Tax & ITC	146,288	118,701	27,588
41	Payroll & Other Taxes	32,405	28,238	4,167
42	**Total Taxes Other Than Income**	**398,439**	**342,055**	**56,384**
43	**Total State & Federal Income Taxes**	**(57,697)**	**(51,514)**	**(6,183)**
44				
45	**Total Taxes**	**340,742**	**290,541**	**50,201**
46	**Total Expenses**	**3,695,961**	**3,233,825**	**462,136**
47	**Total Operating Income**	**472,841**	**395,947**	**76,895**
48				
49	AFDC Debt	17,374	15,234	2,140
50	AFDC Equity	29,024	25,449	3,575
51				
52	**Net Income**	**519,239**	**436,630**	**82,609**

Line No.	NSPM - 03 Income Tax Schedule	Dec - 2017		
		Total	MN Electric	Other
1	**Income Before Taxes**			
2	Total Operating Revenues	4,168,802	3,629,772	539,031
3	less: Total Operating Expenses	2,693,608	2,360,654	332,953
4	Book Depreciation	622,164	543,044	79,120
5	Amortization	39,447	39,585	(138)
6	Taxes Other than Income	398,439	342,055	56,384
7	**Total Before Tax Book Income**	**415,144**	**344,433**	**70,712**
8				
9	**Tax Additions**			
10	Book Depreciation	622,164	543,044	79,120
11	Deferred Income Taxes and ITC	146,288	118,701	27,588
12	Nuclear Fuel Burn (ex D&D)	117,750	102,850	14,900
13	Nuclear Outage Accounting	68,915	60,188	8,727
14	Avoided Tax Interest	14,490	12,210	2,280
15	Other Book Additions	3,387	3,387	0
16	**Total Tax Additions**	**972,995**	**840,379**	**132,615**
17				
18	**Tax Deductions**			
19	Total Rate Base	8,980,567	7,739,688	1,240,880
20	Weighted Cost of Debt	2.26%	2.26%	2.26%
21	Debt Interest Expense (Line 19 x Line 20)	202,961	174,917	28,044
22	Nuclear Outage Accounting	87,345	76,284	11,061
23	Tax Depreciation and Removals	904,833	780,386	124,447
24	NOL Utilization	39,179	0	39,179
25	Other Tax / Book Timing Differences	11,276	9,853	1,423
26	**Total Tax Deductions**	**1,245,594**	**1,041,440**	**204,154**
27				
28	**State Taxes**			
29	State Taxable Income	142,545	143,372	(827)
30	State Income Tax Rate	9.80%	9.80%	9.80%
31	State Taxes before Credits (Line 31 x Line 32)	13,969	14,050	(81)
32	Less State Tax Credits	(559)	(559)	0
33	**Total State Income Taxes**	**13,410**	**13,491**	**(81)**
34				
35	**Federal Taxes**			
36	Federal Sec 199 Production Deduction	33,100	31,435	1,665
37	Federal Taxable Income	96,034	98,445	(2,411)
38	Federal Income Tax Rate	35.00%	35.00%	35.00%
39	Federal Tax before Credits (Line 39 x Line 40)	33,612	34,456	(844)
40	Less Federal Tax Credits	(54,753)	(46,470)	(8,283)
41	Deferred Federal Tax Credits due to NOL	(49,967)	(52,991)	3,025
42	**Total Federal Income Taxes**	**(71,107)**	**(65,005)**	**(6,102)**
43				
44	**Total Taxes**			
45	**Total Federal and State Income Taxes**	**(57,697)**	**(51,514)**	**(6,183)**

Line No.	NSPM - 04 Revenue Deficiency Schedule	Dec - 2017		
		Total	MN Electric	Other
1	**Weighted Cost of Capital**			
2	Cost of Short Term Debt	3.57%	3.57%	3.57%
3	Cost of Long Term Debt	4.81%	4.81%	4.81%
4	Cost of Preferred Stock			
5	Cost of Common Equity	10.00%	10.00%	10.00%
6	Ratio of Short Term Debt	1.46%	1.46%	1.46%
7	Ratio of Long Term Debt	46.04%	46.04%	46.04%
8	Ratio of Preferred Stock			
9	Ratio of Common Equity	52.50%	52.50%	52.50%
10	Weighted Cost of STD	0.05%	0.05%	0.05%
11	Weighted Cost of LTD	2.21%	2.21%	2.21%
12	Weighted Cost of Debt	2.26%	2.26%	2.26%
13	Weighted Cost of Preferred Stock			
14	Weighted Cost of Equity	5.25%	5.25%	5.25%
15	**Required Rate Of Return**	**7.51%**	**7.51%**	**7.51%**
16				
17	**Composite Income Tax Rate**			
18	State Tax Rate	9.80%	9.80%	9.80%
19	Federal Statuatory Tax Rate	35.00%	35.00%	35.00%
20	Federal Effective Tax Rate	31.57%	31.57%	31.57%
21	**Composite Tax Rate**	**41.37%**	**41.37%**	**41.37%**
22				
23	**Rate of Return (ROR)**			
24	Total Operating Income	519,239	436,630	82,609
25	Total Rate Base	8,980,567	7,739,688	1,240,880
26	**ROR (Operating Income / Rate Base)**	**5.78%**	**5.64%**	**6.66%**
27				
28	**Return on Equity (ROE)**			
29	Total Operating Income	519,239	436,630	82,609
30	Debt Interest (Rate Base * Weighted Cost of Debt)	(202,961)	(174,917)	(28,044)
31	Earnings Available for Common	316,278	261,713	54,566
32	Equity Rate Base (Rate Base * Equity Ratio)	4,714,798	4,063,336	651,462
33	**ROE (earnings for Common/Equity Rate Base)**	**6.71%**	**6.44%**	**8.38%**
34				
35	**Revenue Deficiency**			
36	Required Operating Income (Rate Base * Required Return)	675,192	581,251	93,942
37	Total Operating Income	519,239	436,630	82,609
38	Operating Income Deficiency	155,953	144,621	11,332
39				
40	Revenue Conversion Factor (1/(1-Composite Tax Rate))	1.705611	1.705611	1.705611
41	**Revenue Deficiency (Income Deficiency * Conversion Factor)**	**265,995**	**246,667**	**19,328**
42				
43	**Total Revenue Requirements**			
44	Total Retail Revenues	3,487,255	3,032,608	454,647
45	Revenue Deficiency	265,995	246,667	19,328
46	**Total Revenue Requirements**	**3,753,250**	**3,279,275**	**473,975**

Northern States Power Company
Electric Utility - State of Minnesota
COST OF SERVICE SUMMARY
2017 Plan Year

Line No.	NSPM - 05 Summary Cash Working Capital	Lead/Lag	Total		MN Electric		Other	
		Days	Dollars	Dollar x Days	Dollars	Dollar x Days	Dollars	Dollar x Days
1	**Fuel Expenses**							
2	Coal and Rail Transport	19.07	325,216	6,201,877	284,004	5,415,963	41,212	785,914
3	Gas for Generation	37.68	231,181	8,710,887	201,885	7,607,026	29,296	1,103,861
4	Oil	19.87	399	7,931	349	6,926	51	1,005
5	Nuclear and EOL	0	117,751	0	102,830	0	14,922	0
6	Nuclear Disposal	0	0	0	0	0	0	0
7	**Subtotal Fuel Expenses**		**674,548**	**14,920,695**	**589,068**	**13,029,915**	**85,480**	**1,890,780**
8								
9	**Purchased Power**							
10	Purchases	35.62	616,614	21,963,802	538,559	19,183,464	78,056	2,780,337
11	Interchange	38.21	108,474	4,144,801	94,748	3,620,322	13,726	524,479
12	**SubTotal Purchased Power**		**725,089**	**26,108,603**	**633,307**	**22,803,787**	**91,782**	**3,304,816**
13								
14	**Labor and Related**							
15	Regular Payroll	11.56	421,208	4,869,168	366,972	4,242,195	54,236	626,973
16	Incentive	253.17	26,026	6,588,935	22,745	5,758,413	3,280	830,521
17	Pension and Benefits	35.67	88,129	3,143,579	76,731	2,736,995	11,398	406,583
18	**SubTotal Labor and Related**		**535,364**	**14,601,681**	**466,448**	**12,737,604**	**68,915**	**1,864,077**
19								
20	**All Other Operating Expenses**	43.76	758,608	33,196,688	671,832	29,399,361	86,776	3,797,327
21	Property taxes	355.31	219,746	78,077,843	195,116	69,326,781	24,629	8,751,062
22	Employer's Payroll Taxes	33.72	32,405	1,092,701	28,238	952,200	4,167	140,501
23	Gross Earnings Tax	55.46	53,210	2,951,047	53,210	2,951,047	0	0
24	Federal Income Tax	36.75	(71,107)	(2,613,197)	(65,005)	(2,388,951)	(6,102)	(224,245)
25	State Income Tax	29.50	13,410	395,607	13,491	397,998	(81)	(2,391)
26	State Sales Tax Customer Billings	35.20	136,608	4,808,617	136,608	4,808,617	0	0
27	**Total Expenses**		**3,077,880**	**173,540,286**	**2,722,314**	**154,018,359**	**355,567**	**19,521,927**
28	Net Annual Expense			475,453		421,968		53,485
29								
30	**Revenues**							
31	Retail Revenue	41.42	3,486,447	144,408,615	3,031,800	125,577,141	454,647	18,831,474
32	Late Payment	0	7,031	0	6,058	0	973	0
33	Interdepartmental	0	808	0	808	0	0	0
34	Misc Services	41.42	3,221	133,409	2,506	103,813	715	29,596
35	CIP Incentive	0	228	0	0	0	228	0
36	Rentals	(40.86)	5,205	(212,694)	4,547	(185,793)	658	(26,901)
37	Interchange	38.21	523,876	20,017,307	457,547	17,482,883	66,329	2,534,424
38	Sales for Resale	38.27	0	0	0	0	0	0
39	Retail Rev Lag Days	38.27	1,741	66,620	1,642	62,837	99	3,783
40	MISO	14.00	(140,961)	(1,973,450)	(123,323)	(1,726,516)	(17,638)	(246,934)
41	Wholesale Lag Days	38.27	250,939	9,603,419	219,184	8,388,167	31,755	1,215,252
42	**Total Revenues**		**4,138,534**	**172,043,226**	**3,600,770**	**149,702,531**	**537,764**	**22,340,695**
43								
44	Net Annual Amount			471,351		410,144		61,207
45	Expense/Revenue Factor			10.400292		3.780183		6.620109
46	Allocated Revenue Amount		-	350,554	-	310,084	-	40,470
47	**Net Cash Working Capital**			**(124,899)**		**(111,884)**		**(13,015)**

ROE =	5.68%	
Deficiency =	$297,133	(Cumulative)
% Increase =	9.80%	(Cumulative)
Required ROE =	10.00%	

Northern States Power Company (MN)
Electric Utility - Minnesota Retail Jurisdiction
Cost of Service Study
Proposed 2018 Plan Year

Summary Reports

November 2015

Line No.	NSPM - 01 Rate Base Schedule with BOY/EOY	Total			MN Electric			Other		
		BOY	EOY	BOY/EOY Avg	BOY	EOY	BOY/EOY Avg	BOY	EOY	BOY/EOY Avg
1	**Rate Base**									
2	Plant Investment	19,957,375	20,844,505	20,400,940	17,349,962	18,106,684	17,728,323	2,607,413	2,737,821	2,672,617
3	Depreciation Reserve	9,275,762	9,938,447	9,607,104	8,097,485	8,675,411	8,386,448	1,178,278	1,263,036	1,220,657
4	Net Utility Plant	10,681,613	10,906,058	10,793,835	9,252,478	9,431,273	9,341,875	1,429,135	1,474,785	1,451,960
5	CWIP	556,692	420,151	488,422	475,361	369,461	422,411	81,331	50,690	66,011
6										
7	Accumulated Deferred Taxes	2,693,256	2,732,517	2,712,886	2,354,200	2,386,754	2,370,477	339,056	345,764	342,410
8	DTA - NOL Average Balance	38,723	(45,540)	(3,408)	43,611	(43,310)	150	(4,888)	(2,230)	(3,559)
9	DTA - Federal Tax Credit Average Balance	(126,358)	(58,869)	(92,614)	(102,461)	(40,313)	(71,387)	(23,897)	(18,557)	(21,227)
10	Total Accum Deferred Taxes	2,605,621	2,628,108	2,616,864	2,295,350	2,303,131	2,299,240	310,271	324,977	317,624
11										
12	Cash Working Capital	(129,003)	(129,003)	(129,003)	(115,714)	(115,714)	(115,714)	(13,289)	(13,289)	(13,289)
13	Materials and Supplies	155,470	155,470	155,470	135,797	135,797	135,797	19,672	19,672	19,672
14	Fuel Inventory	84,138	84,138	84,138	73,476	73,476	73,476	10,662	10,662	10,662
15	Non-plant Assets and Liabilities	11,910	24,446	18,178	10,427	21,379	15,903	1,484	3,066	2,275
16	Customer Advances	(8,227)	(8,227)	(8,227)	(5,562)	(5,562)	(5,562)	(2,665)	(2,665)	(2,665)
17	Customer Deposits	(28,480)	(28,480)	(28,480)	(28,127)	(28,127)	(28,127)	(352)	(352)	(352)
18	Prepaids and Other	108,581	89,239	98,910	94,821	77,927	86,374	13,761	11,312	12,536
19	Regulatory Amortizations	55,660	52,273	53,966	55,660	52,273	53,966	0	0	0
20	Total Other Rate Base Items	250,049	239,855	244,952	220,777	211,449	216,113	29,272	28,406	28,839
21										
22	**Total Rate Base**	**8,882,733**	**8,937,956**	**8,910,345**	**7,653,266**	**7,709,052**	**7,681,159**	**1,229,467**	**1,228,904**	**1,229,186**

Line No.	NSPM - 02 Income Statement Schedule	Dec - 2018		
		Total	MN Electric	Other
1	**Operating Revenues**			
2	Retail	3,485,013	3,030,366	454,647
3	Interdepartmental	808	808	0
4	Transportation	0	0	0
5	Other Operating Rev - Non-Retail	692,096	606,928	85,168
6	**Total Operating Revenues**	**4,177,916**	**3,638,101**	**539,814**
7				
8	**Expenses**			
9	Operating Expenses:			
10	Fuel	1,138,449	995,513	142,936
11	Variable IA Production Fuel	5,844	5,104	741
12	Purchased Energy - Windsource	583	583	0
13	**Fuel & Purchased Energy Total**	1,144,876	1,001,199	143,676
14	Production - Fixed	464,744	405,820	58,924
15	Production - Fixed IA Investment	55,004	48,044	6,960
16	Production - Fixed IA O&M	(5,218)	(4,557)	(660)
17	Production - Variable	125,574	109,661	15,913
18	Production - Purchased Demand	144,685	126,377	18,308
19	Production - Other	0	(0)	0
20	**Production Total**	784,790	685,344	99,445
21	Regional Markets	8,376	7,316	1,060
22	Transmission IA	119,113	104,041	15,072
23	Transmission	129,825	113,370	16,454
24	Distribution	130,212	112,784	17,428
25	Customer Accounting	59,809	50,820	8,989
26	Customer Service & Information	92,492	91,140	1,352
27	Sales, Econ Dvlp & Other	124	71	53
28	Administrative & General	249,713	217,058	32,656
29	**Total Operating Expenses**	**2,719,330**	**2,383,145**	**336,185**
30				
31	Depreciation	652,925	569,829	83,096
32	Amortization	39,447	39,585	(138)
33				
34	**Taxes:**			
35	Property Taxes	225,901	200,621	25,281
36	ITC Amortization	(1,486)	(1,340)	(145)
37	Deferred Taxes	78,586	64,884	13,701
38	Deferred Taxes - NOL	4,653	0	4,653
39	Less Deferred Federal Tax Credits	67,489	62,149	5,340
40	Deferred Income Tax & ITC	149,241	125,692	23,549
41	Payroll & Other Taxes	33,008	28,763	4,245
42	**Total Taxes Other Than Income**	**408,150**	**355,076**	**53,074**
43	**Total State & Federal Income Taxes**	**(83,834)**	**(78,033)**	**(5,802)**
44				
45	**Total Taxes**	**324,316**	**277,043**	**47,272**
46	**Total Expenses**	**3,736,017**	**3,269,602**	**466,415**
47	**Total Operating Income**	**441,898**	**368,499**	**73,399**
48				
49	AFDC Debt	16,280	14,271	2,009
50	AFDC Equity	22,672	19,876	2,796
51				
52	**Net Income**	**480,850**	**402,646**	**78,204**

Line No.	NSPM - 03 Income Tax Schedule	Dec - 2018		
		Total	MN Electric	Other
1	**Income Before Taxes**			
2	Total Operating Revenues	4,177,916	3,638,101	539,814
3	less: Total Operating Expenses	2,719,330	2,383,145	336,185
4	Book Depreciation	652,925	569,829	83,096
5	Amortization	39,447	39,585	(138)
6	Taxes Other than Income	408,150	355,076	53,074
7	**Total Before Tax Book Income**	**358,064**	**290,466**	**67,598**
8				
9	**Tax Additions**			
10	Book Depreciation	652,925	569,829	83,096
11	Deferred Income Taxes and ITC	149,241	125,692	23,549
12	Nuclear Fuel Burn (ex D&D)	123,700	108,047	15,653
13	Nuclear Outage Accounting	66,621	58,184	8,437
14	Avoided Tax Interest	12,499	10,531	1,968
15	Other Book Additions	3,387	3,387	0
16	**Total Tax Additions**	**1,008,373**	**875,671**	**132,702**
17				
18	**Tax Deductions**			
19	Total Rate Base	8,910,345	7,681,159	1,229,186
20	Weighted Cost of Debt	2.26%	2.26%	2.26%
21	Debt Interest Expense (Line 19 x Line 20)	201,374	173,594	27,780
22	Nuclear Outage Accounting	47,278	41,291	5,988
23	Tax Depreciation and Removals	969,711	838,641	131,070
24	NOL Utilization	11,401	0	11,401
25	Other Tax / Book Timing Differences	13,040	11,394	1,647
26	**Total Tax Deductions**	**1,242,804**	**1,064,919**	**177,885**
27				
28	**State Taxes**			
29	State Taxable Income	123,633	101,218	22,415
30	State Income Tax Rate	9.80%	9.80%	9.80%
31	State Taxes before Credits (Line 31 x Line 32)	12,116	9,919	2,197
32	Less State Tax Credits	(559)	(559)	0
33	**Total State Income Taxes**	**11,557**	**9,360**	**2,197**
34				
35	**Federal Taxes**			
36	Federal Sec 199 Production Deduction	38,298	34,024	4,274
37	Federal Taxable Income	73,778	57,834	15,943
38	Federal Income Tax Rate	35.00%	35.00%	35.00%
39	Federal Tax before Credits (Line 39 x Line 40)	25,822	20,242	5,580
40	Less Federal Tax Credits	(53,725)	(45,486)	(8,238)
41	Deferred Federal Tax Credits due to NOL	(67,489)	(62,149)	(5,340)
42	**Total Federal Income Taxes**	**(95,391)**	**(87,393)**	**(7,998)**
43				
44	**Total Taxes**			
45	**Total Federal and State Income Taxes**	**(83,834)**	**(78,033)**	**(5,802)**

Line No.	NSPM - 04 Revenue Deficiency Schedule	Dec - 2018		
		Total	MN Electric	Other
1	**Weighted Cost of Capital**			
2	Cost of Short Term Debt	4.45%	4.45%	4.45%
3	Cost of Long Term Debt	4.77%	4.77%	4.77%
4	Cost of Preferred Stock			
5	Cost of Common Equity	10.00%	10.00%	10.00%
6	Ratio of Short Term Debt	1.09%	1.09%	1.09%
7	Ratio of Long Term Debt	46.41%	46.41%	46.41%
8	Ratio of Preferred Stock			
9	Ratio of Common Equity	52.50%	52.50%	52.50%
10	Weighted Cost of STD	0.05%	0.05%	0.05%
11	Weighted Cost of LTD	2.21%	2.21%	2.21%
12	Weighted Cost of Debt	2.26%	2.26%	2.26%
13	Weighted Cost of Preferred Stock			
14	Weighted Cost of Equity	5.25%	5.25%	5.25%
15	**Required Rate Of Return**	**7.51%**	**7.51%**	**7.51%**
16				
17	**Composite Income Tax Rate**			
18	State Tax Rate	9.80%	9.80%	9.80%
19	Federal Statuatory Tax Rate	35.00%	35.00%	35.00%
20	Federal Effective Tax Rate	31.57%	31.57%	31.57%
21	**Composite Tax Rate**	**41.37%**	**41.37%**	**41.37%**
22				
23	**Rate of Return (ROR)**			
24	Total Operating Income	480,850	402,646	78,204
25	Total Rate Base	8,910,345	7,681,159	1,229,186
26	**ROR (Operating Income / Rate Base)**	**5.40%**	**5.24%**	**6.36%**
27				
28	**Return on Equity (ROE)**			
29	Total Operating Income	480,850	402,646	78,204
30	Debt Interest (Rate Base * Weighted Cost of Debt)	(201,374)	(173,594)	(27,780)
31	Earnings Available for Common	279,477	229,052	50,425
32	Equity Rate Base (Rate Base * Equity Ratio)	4,677,931	4,032,609	645,323
33	**ROE (earnings for Common/Equity Rate Base)**	**5.97%**	**5.68%**	**7.81%**
34				
35	**Revenue Deficiency**			
36	Required Operating Income (Rate Base * Required Return)	669,913	576,855	93,058
37	Total Operating Income	480,850	402,646	78,204
38	Operating Income Deficiency	189,063	174,209	14,854
39				
40	Revenue Conversion Factor (1/(1-Composite Tax Rate))	1.705611	1.705611	1.705611
41	**Revenue Deficiency (Income Deficiency * Conversion Factor)**	**322,468**	**297,133**	**25,335**
42				
43	**Total Revenue Requirements**			
44	Total Retail Revenues	3,485,820	3,031,173	454,647
45	Revenue Deficiency	322,468	297,133	25,335
46	**Total Revenue Requirements**	**3,808,288**	**3,328,306**	**479,982**

Northern States Power Company
Electric Utility - State of Minnesota
COST OF SERVICE SUMMARY
2018 Plan Year

Docket No. E002/GR-15-826
Exhibit __ (CRB-1), Schedule 5

Line No.	NSPM - 05 Summary Cash Working Capital	Lead/Lag	Total		MN Electric		Other	
		Days	Dollars	Dollar x Days	Dollars	Dollar x Days	Dollars	Dollar x Days
1	**Fuel Expenses**							
2	Coal and Rail Transport	19.07	335,322	6,394,588	292,829	5,584,253	42,493	810,335
3	Gas for Generation	37.68	204,534	7,706,831	178,615	6,730,206	25,919	976,625
4	Oil	19.87	545	10,821	476	9,450	69	1,371
5	Nuclear and EOL	0	123,699	0	108,023	0	15,676	0
6	Nuclear Disposal	0	0	0	0	0	0	0
7	**Subtotal Fuel Expenses**		**664,099**	**14,112,241**	**579,943**	**12,323,909**	**84,156**	**1,788,331**
8								
9	**Purchased Power**							
10	Purchases	35.62	654,714	23,320,909	571,837	20,368,846	82,877	2,952,064
11	Interchange	38.21	113,896	4,351,951	99,483	3,801,259	14,412	550,691
12	**SubTotal Purchased Power**		**768,609**	**27,672,860**	**671,321**	**24,170,105**	**97,289**	**3,502,755**
13								
14	**Labor and Related**							
15	Regular Payroll	11.56	418,185	4,834,217	363,828	4,205,848	54,357	628,369
16	Incentive	253.17	26,757	6,774,083	23,384	5,920,196	3,373	853,887
17	Pension and Benefits	35.67	89,638	3,197,389	78,132	2,786,962	11,506	410,428
18	**SubTotal Labor and Related**		**534,580**	**14,805,689**	**465,344**	**12,913,006**	**69,236**	**1,892,683**
19								
20	**All Other Operating Expenses**	43.76	752,041	32,909,335	666,537	29,167,677	85,504	3,741,659
21	Property taxes	355.31	225,901	80,265,009	200,621	71,282,532	25,281	8,982,476
22	Employer's Payroll Taxes	33.72	33,008	1,113,013	28,763	969,887	4,245	143,126
23	Gross Earnings Tax	55.46	53,210	2,951,047	53,210	2,951,047	0	0
24	Federal Income Tax	36.75	(95,391)	(3,505,630)	(87,393)	(3,211,698)	(7,998)	(293,932)
25	State Income Tax	29.50	11,557	340,932	9,360	276,131	2,197	64,800
26	State Sales Tax Customer Billings	35.20	136,608	4,808,617	136,608	4,808,617	0	0
27	**Total Expenses**		**3,084,223**	**175,473,113**	**2,724,314**	**155,651,214**	**359,909**	**19,821,899**
28	Net Annual Expense			480,748		426,442		54,307
29								
30	**Revenues**							
31	Retail Revenue	41.42	3,485,013	144,349,223	3,030,366	125,517,748	454,647	18,831,474
32	Late Payment	0	7,031	0	6,058	0	973	0
33	Interdepartmental	0	808	0	808	0	0	0
34	Misc Services	41.42	3,242	134,280	2,520	104,369	722	29,911
35	CIP Incentive	0	228	0	0	0	228	0
36	Rentals	(40.86)	5,205	(212,694)	4,547	(185,793)	658	(26,901)
37	Interchange	38.21	527,175	20,143,375	460,429	17,592,998	66,746	2,550,377
38	Sales for Resale	38.27	(0)	(0)	(0)	(0)	0	0
39	Retail Rev Lag Days	38.27	1,542	59,026	1,469	56,205	74	2,821
40	MISO	14.00	(151,368)	(2,119,145)	(132,406)	(1,853,686)	(18,961)	(265,459)
41	Wholesale Lag Days	38.27	265,030	10,142,684	231,492	8,859,194	33,538	1,283,490
42	**Total Revenues**		**4,143,906**	**172,496,749**	**3,605,282**	**150,091,035**	**538,624**	**22,405,714**
43								
44	Net Annual Amount			472,594		411,208		61,386
45	Expense/Revenue Factor			10.467494		3.778227		6.689267
46	Allocated Revenue Amount		-	351,746	-	310,728	-	41,018
47	**Net Cash Working Capital**			**(129,003)**		**(115,714)**		**(13,289)**

Northern States Power Company
Electric Utility - State of Minnesota
RATE BASE BRIDGE SCHEDULE
Amounts in thousands

Docket No. E002/GR-15-826
Exhibit___(CRB-1), Schedule 6
Page 1 of 1

Line No.		2016 Test Year	Adjustments: Capital Forecast	Adjustments: Other Rate Base and Nonplant	Adjustments: Cash Working Capital	Adjustments: Net Operating Loss	2017 Plan Year	Adjustments: Capital Forecast	Adjustments: Other Rate Base and Nonplant	Adjustments: Cash Working Capital	Adjustments: Net Operating Loss	2018 Plan Year	2017 over 2016	2018 over 2017
	Work Paper Reference		**M1**	**M2**	**A39**	**M8**		**M1**	**M2**	**A39**	**M8**		**col (6) - (1)**	**col (11) - (6)**
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
1	Plant as booked													
2	Production	9,192,783	283,706				9,476,488	392,435				9,868,923	283,706	392,435
3	Transmission	2,690,961	60,190				2,751,152	38,473				2,789,625	60,190	38,473
4	Distribution	3,272,959	118,837				3,391,796	124,505				3,516,302	118,837	124,505
5	General	727,748	49,549				777,297	50,641				827,938	49,549	50,641
6	Common	540,996	98,614				639,611	85,924				725,535	98,614	85,924
7	Total Utility Plant in Service	16,425,447	610,897				17,036,345	691,978				17,728,323	610,897	691,978
8														
9	Reserve for Depreciation													
10	Production	4,947,590	361,551				5,309,141	368,884				5,678,024	361,551	368,884
11	Transmission	551,324	28,597				579,921	42,543				622,464	28,597	42,543
12	Distribution	1,232,993	44,300				1,277,293	55,853				1,333,146	44,300	55,853
13	General	267,760	61,103				328,863	61,332				390,194	61,103	61,332
14	Common	268,091	45,828				313,919	48,700				362,619	45,828	48,700
15	Total Reserve for Depreciation	7,267,758	541,378				7,809,137	577,311				8,386,448	541,378	577,311
16														
17	Net Utility Plant													
18	Production	4,245,193	(77,845)				4,167,348	23,551				4,190,899	(77,845)	23,551
19	Transmission	2,139,637	31,593				2,171,231	(4,070)				2,167,161	31,593	(4,070)
20	Distribution	2,039,966	74,538				2,114,503	68,653				2,183,156	74,538	68,653
21	General	459,988	(11,554)				448,435	(10,691)				437,744	(11,554)	(10,691)
22	Common	272,905	52,786				325,691	37,224				362,916	52,786	37,224
23	Net Utility Plant in Service	9,157,689	69,519				9,227,208	114,667				9,341,875	69,519	114,667
24														
25	Construction Work in Progress	444,412	29,538				473,950	(51,539)				422,411	29,538	(51,539)
26														
27	Less: Accumulated Deferred Income Taxes	1,979,773	87,652	3,945		103,592	2,174,961	62,358	4,350		57,570	2,299,240	195,188	124,279
28														
29	Other Rate Base Items													
30	Cash Working Capital	(108,129)			(3,756)		(111,884)			(3,830)		(115,714)	(3,756)	(3,830)
31	Materials and Supplies	135,797					135,797					135,797		
32	Fuel Inventory	73,476					73,476					73,476		
33	Non Plant Assets and Liabilities	(3,716)		9,382			5,666		10,237			15,903	9,382	10,237
34	Customer Advances	(5,562)					(5,562)					(5,562)		
35	Customer Deposits	(28,127)					(28,127)					(28,127)		
36	Prepayments	89,307		(2,535)			86,772		(398)			86,374	(2,535)	(398)
37	Regulatory Amortizations	60,741	(3,387)				57,353	(3,387)				53,966	(3,387)	(3,387)
38	Total Other Rate Base	213,787	(3,387)	6,847	(3,756)		213,492	(3,387)	9,838	(3,830)		216,113	(296)	2,621
39														
40	Total Average Rate Base	7,836,115	8,018	2,902	(3,756)	(103,592)	7,739,688	(2,617)	5,488	(3,830)	(57,570)	7,681,159	(96,427)	(58,529)

Northern States Power Company
Electric Utility - State of Minnesota
INCOME STATEMENT BRIDGE SCHEDULE
Amounts in thousands

Docket No. E002/GR-15-826
Exhibit___(CRB-1), Schedule 7

Line No.		2016 Test Year	Forecast Adjustments						
			Capital Forecast	Other Rate Base and Nonplant	Purchased Demand	Bad Debt Expense	FERC 925 & 926	Non-Decoupled Sales	Change in TCR Revenue
	Work Paper Reference		**M1**	**M2**	**M3**	**M3**	**M3**	**M4**	**M4**
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	Operating Revenues								
2	Retail Revenue	3,033,285						0	(1,485)
3	Interdepartmental	809							(1)
4	Other Operating	586,984	1,231				100	4,766	
5	Total Revenue	3,621,078	1,231				100	4,766	(1,485)
6									
7	Expenses								
8	Operating Expenses								
9	Fuel & Purchased Energy	1,001,096	(1)				(13)		
10	Power Production	681,521	(111)		(4,266)		(69)		
11	Transmission	205,186	1,364				(20)		
12	Distribution	108,023							
13	Customer Accounting	49,315				(246)			
14	Customer Service and Information	91,110							
15	Sales, Econ Dev, & Other	69							
16	Administrative and General	206,579					2,183		
17	Total Operating Expenses	2,342,900	1,252		(4,266)	(246)	2,081		
18									
19	Depreciation	471,286	71,758						
20	Amortization	39,585	0						
21									
22	Taxes								
23	Property	186,751	8,365						
24	Deferred Income Tax and ITC	186,991	(32,085)	212					
25	Federal and State Income Tax	(73,527)	(2,182)	(211)	1,765	102	(820)	1,972	(615)
26	Payroll and Other	27,550							
27	Total Taxes	327,766	(25,902)	1	1,765	102	(820)	1,972	(615)
28									
29	Total Expenses	3,181,537	47,108	1	(2,501)	(144)	1,261	1,972	(615)
30									
31	AFUDC	33,283	7,400						
32									
33	Total Operating Income	472,824	(38,477)	(1)	2,501	144	(1,162)	2,794	(871)
34									
35	Calculation of Revenue Requirements								
36	Average Rate Base	7,836,115	8,018	2,902					
37	Required Operating Income	586,925	589	213					
38	Operating Income	472,824	(38,477)	(1)	2,501	144	(1,162)	2,794	(871)
39	Income Deficiency	114,101	39,066	214	(2,501)	(144)	1,162	(2,794)	871
40	**Revenue Deficiency**	**194,612**	**66,631**	**365**	**(4,266)**	**(246)**	**1,981**	**(4,766)**	**1,485**
41									
42	Calculation of Income Taxes								
43	Operating Revenue	3,621,078	1,231				100	4,766	(1,485)
44	-Operating Expense	2,342,900	1,252		(4,266)	(246)	2,081		
45	-Amortization	39,585	0						
46	-Taxes Other then Income	214,302	8,365						
47	Operating Income Before Adjs	1,024,290	(8,385)		4,266	246	(1,981)	4,766	(1,485)
48	Additions to Income	180,252	(1,618)						
49	Deductions from Income	1,174,993	(13,170)	445					
50	Debt Synchonization	175,529	180	65					
51	State Taxable Income	(145,980)	2,987	(510)	4,266	246	(1,981)	4,766	(1,485)
52	State Income Tax Before Credits	(14,306)	293	(50)	418	24	(194)	467	(146)
53	State Tax Credits	1,118							
54	Federal Tax Deductions	3,426							
55	Federal Taxable Income	(133,982)	2,694	(460)	3,848	222	(1,787)	4,299	(1,340)
56	Federal Income Tax Before Credits	(46,894)	943	(161)	1,347	78	(625)	1,505	(469)
57	Federal Tax Credits	11,209	3,418						
58	Total Income Taxes	(73,527)	(2,182)	(211)	1,765	102	(820)	1,972	(615)
59									
60	Required ROR	7.49%	7.34%	7.34%	7.34%	7.34%	7.34%	7.34%	7.34%
61	Cost of Debt	2.24%	2.24%	2.24%	2.24%	2.24%	2.24%	2.24%	2.24%

Amounts in thousands

Line No.		Fcst adj (cont)	Escalated Adjustments		Secondary Calculations			2017 Plan Year
		Transmission Rev/Exp	Escalated O&M	Non-Retail Revenue	Cash Working Capital	Net Operating Loss	Cost of Capital	
	Work Paper Reference	**M3**	**M5**	**M6**	**A39**	**M8**	**M9**	
		(9)	(10)	(11)	(12)	(13)	(14)	(15)
1	Operating Revenues							
2	Retail Revenue							3,031,800
3	Interdepartmental							808
4	Other Operating	3,748	486	860		(1,012)		597,164
5	Total Revenue	3,748	486	860		(1,012)		3,629,772
6								
7	Expenses							
8	Operating Expenses							
9	Fuel & Purchased Energy		54					1,001,136
10	Power Production	123	9,960					687,159
11	Transmission	2,536	728					209,793
12	Distribution		2,097					110,120
13	Customer Accounting		887					49,956
14	Customer Service and Information		15					91,125
15	Sales, Econ Dev, & Other		1					70
16	Administrative and General		2,534					211,296
17	Total Operating Expenses	2,658	16,275					2,360,654
18								
19	Depreciation							543,044
20	Amortization							39,585
21								
22	Taxes							
23	Property							195,116
24	Deferred Income Tax and ITC					(36,418)		118,701
25	Federal and State Income Tax	451	(6,817)	356	35	28,617	(640)	(51,514)
26	Payroll and Other		688					28,238
27	Total Taxes	451	(6,128)	356	35	(7,800)	(640)	290,541
28								
29	Total Expenses	3,109	10,147	356	35	(7,800)	(640)	3,233,825
30								
31	AFUDC							40,683
32								
33	Total Operating Income	639	(9,660)	504	(35)	6,789	640	436,630
34								
35	Calculation of Revenue Requirements							
36	Average Rate Base				(3,756)	(103,592)		7,739,688
37	Required Operating Income				(276)	(7,604)	1,403	581,251
38	Operating Income	639	(9,660)	504	(35)	6,789	640	436,630
39	Income Deficiency	(639)	9,660	(504)	(241)	(14,392)	763	144,621
40	**Revenue Deficiency**	**(1,090)**	**16,477**	**(860)**	**(411)**	**(24,548)**	**1,301**	**246,667**
41								
42	Calculation of Income Taxes							
43	Operating Revenue	3,748	486	860		(1,012)		3,629,772
44	-Operating Expense	2,658	16,275					2,360,654
45	-Amortization							39,585
46	-Taxes Other then Income		688					223,355
47	Operating Income Before Adjs	1,090	(16,477)	860		(1,012)		1,006,177
48	Additions to Income							178,635
49	Deductions from Income					(295,746)		866,523
50	Debt Synchonization				(84)	(2,320)	1,548	174,917
51	State Taxable Income	1,090	(16,477)	860	84	297,055	(1,548)	143,372
52	State Income Tax Before Credits	107	(1,615)	84	8	29,111	(152)	14,050
53	State Tax Credits					(559)		559
54	Federal Tax Deductions					28,009		31,435
55	Federal Taxable Income	983	(14,862)	776	76	239,375	(1,396)	98,445
56	Federal Income Tax Before Credits	344	(5,202)	272	27	83,781	(489)	34,456
57	Federal Tax Credits					84,834		99,461
58	Total Income Taxes	451	(6,817)	356	35	28,617	(640)	(51,514)
59								
60	Required ROR	7.34%	7.34%	7.34%	7.34%	7.34%	7.51%	7.51%
61	Cost of Debt	2.24%	2.24%	2.24%	2.24%	2.24%	2.26%	2.26%

Amounts in thousands

Line No.		2017 Plan Year	Forecast Adjustments						
			Capital Forecast	Other Rate Base and Nonplant	Purchased Demand	Bad Debt Expense	FERC 925 & 926	Non-Decoupled Sales	Change in TCR Revenue
	Work Paper Reference		**M1**	**M2**	**M3**	**M3**	**M3**	**M4**	**M4**
		(15)	(16)	(17)	(18)	(19)	(20)	(21)	(22)
1	Operating Revenues								
2	Retail Revenue	3,031,800							(1,434)
3	Interdepartmental	808							(1)
4	Other Operating	597,164	1,619				120	5,150	
5	Total Revenue	3,629,772	1,619				120	5,150	(1,434)
6									
7	Expenses								
8	Operating Expenses								
9	Fuel & Purchased Energy	1,001,136	(3)				5		
10	Power Production	687,159	150		(3,992)		29		
11	Transmission	209,793	4,824				(1)		
12	Distribution	110,120							
13	Customer Accounting	49,956				(151)			
14	Customer Service and Information	91,125							
15	Sales, Econ Dev, & Other	70							
16	Administrative and General	211,296					2,709		
17	Total Operating Expenses	2,360,654	4,971		(3,992)	(151)	2,742		
18									
19	Depreciation	543,044	26,785						
20	Amortization	39,585							
21									
22	Taxes								
23	Property	195,116	5,504						
24	Deferred Income Tax and ITC	118,701	(2,764)	599					
25	Federal and State Income Tax	(51,514)	(11,652)	(689)	1,652	63	(1,085)	2,131	(593)
26	Payroll and Other	28,238							
27	Total Taxes	290,541	(8,912)	(90)	1,652	63	(1,085)	2,131	(593)
28									
29	Total Expenses	3,233,825	22,844	(90)	(2,341)	(89)	1,657	2,131	(593)
30									
31	AFUDC	40,683	(6,536)						
32									
33	Total Operating Income	436,630	(27,761)	90	2,341	89	(1,537)	3,020	(841)
34									
35	Calculation of Revenue Requirements								
36	Average Rate Base	7,739,688	(2,617)	5,488					
37	Required Operating Income	581,251	(192)	403					
38	Operating Income	436,630	(27,761)	90	2,341	89	(1,537)	3,020	(841)
39	Income Deficiency	144,621	27,569	312	(2,341)	(89)	1,537	(3,020)	841
40	**Revenue Deficiency**	**246,667**	**47,023**	**533**	**(3,992)**	**(151)**	**2,622**	**(5,150)**	**1,434**
41									
42	Calculation of Income Taxes								
43	Operating Revenue	3,629,772	1,619				120	5,150	(1,434)
44	-Operating Expense	2,360,654	4,971		(3,992)	(151)	2,742		
45	-Amortization	39,585							
46	-Taxes Other then Income	223,355	5,504						
47	Operating Income Before Adjs	1,006,177	(8,856)		3,992	151	(2,622)	5,150	(1,434)
48	Additions to Income	178,635	1,515						
49	Deductions from Income	866,523	23,261	1,541					
50	Debt Synchonization	174,917	(59)	124					
51	State Taxable Income	143,372	(30,543)	(1,665)	3,992	151	(2,622)	5,150	(1,434)
52	State Income Tax Before Credits	14,050	(2,993)	(163)	391	15	(257)	505	(141)
53	State Tax Credits	559							
54	Federal Tax Deductions	31,435							
55	Federal Taxable Income	98,445	(27,550)	(1,502)	3,601	137	(2,365)	4,646	(1,294)
56	Federal Income Tax Before Credits	34,456	(9,642)	(526)	1,260	48	(828)	1,626	(453)
57	Federal Tax Credits	99,461	(984)						
58	Total Income Taxes	(51,514)	(11,652)	(689)	1,652	63	(1,085)	2,131	(593)
59									
60	Required ROR	7.51%	7.34%	7.34%	7.34%	7.34%	7.34%	7.34%	7.34%
61	Cost of Debt	2.26%	2.26%	2.26%	2.26%	2.26%	2.26%	2.26%	2.26%

Northern States Power Company
Electric Utility - State of Minnesota
INCOME STATEMENT BRIDGE SCHEDULE
Amounts in thousands

Line No.		Fcst adj (cont)	Escalated Adjustments		Secondary Calculations			2018 Plan Year
		Transmission Rev/Exp	Escalated O&M	Non-Retail Revenue	Cash Working Capital	Net Operating Loss	Cost of Capital	
	Work Paper Reference	M3	M5	M6	A39	M8	M9	
		(23)	(24)	(25)	(26)	(27)	(28)	(29)
1	Operating Revenues							
2	Retail Revenue							3,030,366
3	Interdepartmental							808
4	Other Operating	2,906	911	377		(1,319)		606,928
5	Total Revenue	2,906	911	377		(1,319)		3,638,101
6								
7	Expenses							
8	Operating Expenses							
9	Fuel & Purchased Energy		61					1,001,199
10	Power Production	144	9,172					692,660
11	Transmission	1,891	904					217,411
12	Distribution		2,664					112,784
13	Customer Accounting		1,016					50,820
14	Customer Service and Information		15					91,140
15	Sales, Econ Dev, & Other		1					71
16	Administrative and General		3,052					217,058
17	Total Operating Expenses	2,035	16,887					2,383,145
18								
19	Depreciation							569,829
20	Amortization							39,585
21								
22	Taxes							
23	Property							200,621
24	Deferred Income Tax and ITC					9,157		125,692
25	Federal and State Income Tax	360	(6,826)	156	36	(10,071)		(78,033)
26	Payroll and Other		525					28,763
27	Total Taxes	360	(6,302)	156	36	(913)		277,043
28								
29	Total Expenses	2,395	10,585	156	36	(913)		3,269,602
30								
31	AFUDC							34,147
32								
33	Total Operating Income	511	(9,674)	221	(36)	(406)		402,646
34								
35	Calculation of Revenue Requirements							
36	Average Rate Base				(3,830)	(57,570)		7,681,159
37	Required Operating Income				(281)	(4,226)	(99)	576,855
38	Operating Income	511	(9,674)	221	(36)	(406)		402,646
39	Income Deficiency	(511)	9,674	(221)	(245)	(3,820)	(99)	174,209
40	**Revenue Deficiency**	**(871)**	**16,500**	**(377)**	**(418)**	**(6,515)**	**(170)**	**297,133**
41								
42	Calculation of Income Taxes							
43	Operating Revenue	2,906	911	377		(1,319)		3,638,101
44	-Operating Expense	2,035	16,887					2,383,145
45	-Amortization							39,585
46	-Taxes Other then Income		525					229,384
47	Operating Income Before Adjs	871	(16,500)	377		(1,319)		985,988
48	Additions to Income							180,150
49	Deductions from Income							891,325
50	Debt Synchonization				(87)	(1,301)		173,594
51	State Taxable Income	871	(16,500)	377	87	(18)		101,218
52	State Income Tax Before Credits	85	(1,617)	37	8	(2)		9,919
53	State Tax Credits							559
54	Federal Tax Deductions					2,588		34,024
55	Federal Taxable Income	785	(14,883)	340	78	(2,605)		57,834
56	Federal Income Tax Before Credits	275	(5,209)	119	27	(912)		20,242
57	Federal Tax Credits					9,157		107,635
58	Total Income Taxes	360	(6,826)	156	36	(10,071)		(78,033)
59								
60	Required ROR	7.34%	7.34%	7.34%	7.34%	7.34%	7.51%	7.51%
61	Cost of Debt	2.26%	2.26%	2.26%	2.26%	2.26%	2.26%	2.26%

Amounts in thousands

Line No.		2017 over 2016	2018 over 2017
	Work Paper Reference	col (15) - (1)	col (29) - (15)
		(30)	(31)
1	Operating Revenues		
2	Retail Revenue	(1,485)	(1,434)
3	Interdepartmental	(1)	(1)
4	Other Operating	10,179	9,764
5	Total Revenue	8,694	8,330
6			
7	Expenses		
8	Operating Expenses		
9	Fuel & Purchased Energy	39	64
10	Power Production	5,638	5,502
11	Transmission	4,607	7,618
12	Distribution	2,097	2,664
13	Customer Accounting	641	865
14	Customer Service and Information	15	15
15	Sales, Econ Dev, & Other	1	1
16	Administrative and General	4,717	5,762
17	Total Operating Expenses	17,754	22,490
18			
19	Depreciation	71,758	26,785
20	Amortization		
21			
22	Taxes		
23	Property	8,365	5,504
24	Deferred Income Tax and ITC	(68,290)	6,992
25	Federal and State Income Tax	22,013	(26,519)
26	Payroll and Other	688	525
27	Total Taxes	(37,224)	(13,498)
28			
29	Total Expenses	52,288	35,777
30			
31	AFUDC	7,400	(6,536)
32			
33	Total Operating Income	(36,194)	(33,984)
34			
35	Calculation of Revenue Requirements		
36	Average Rate Base	(96,427)	(58,529)
37	Required Operating Income	(5,674)	(4,396)
38	Operating Income	(36,194)	(33,984)
39	Income Deficiency	30,520	29,588
40	**Revenue Deficiency**	**52,055**	**50,466**
41			
42	Calculation of Income Taxes		
43	Operating Revenue	8,694	8,330
44	-Operating Expense	17,754	22,490
45	-Amortization		
46	-Taxes Other then Income	9,053	6,029
47	Operating Income Before Adjs	(18,113)	(20,189)
48	Additions to Income	(1,618)	1,515
49	Deductions from Income	(308,470)	24,802
50	Debt Synchonization	(612)	(1,323)
51	State Taxable Income	289,352	(42,154)
52	State Income Tax Before Credits	28,356	(4,131)
53	State Tax Credits	(559)	
54	Federal Tax Deductions	28,009	2,588
55	Federal Taxable Income	232,427	(40,611)
56	Federal Income Tax Before Credits	81,349	(14,214)
57	Federal Tax Credits	88,252	8,174
58	Total Income Taxes	22,013	(26,519)
59			
60	Required ROR		
61	Cost of Debt		

Individual FERC Accounts		2014	2015	2016	2017	2018	2019	2020	2017 / 2016	2018 / 2017
500	Supervision and Eng. 500: JS&EMS	1.036	1.043	1.064	1.090	1.120	1.150	1.175	2.4245%	2.7268%
501	Fuel 501*: JEF501MS	1.153	0.911	0.914	0.969	0.992	1.030	1.067	6.0157%	2.3807%
502	Steam Plant 502: JEF502MS	1.008	0.980	0.993	1.043	1.086	1.134	1.171	5.0181%	4.1607%
505	Electric Plant 505: JEF505MS	1.000	0.958	0.954	0.999	1.045	1.092	1.127	4.7057%	4.5648%
506	Miscellaneous 506: JEF506MS	1.022	1.017	1.026	1.042	1.060	1.079	1.095	1.5467%	1.7963%
507	Rents 507: JRENT	1.007	1.014	1.018	1.043	1.069	1.089	1.105	2.4885%	2.5142%
510	Supervision and Eng. 510: JS&EMS	1.036	1.043	1.064	1.090	1.120	1.150	1.175	2.4245%	2.7268%
511	Structures 511: JEF511MS	1.011	0.962	0.995	1.032	1.074	1.116	1.135	3.7288%	4.0171%
512	Boiler Plant 512: JEF512MS	1.030	1.037	1.050	1.071	1.096	1.122	1.145	2.0152%	2.3173%
513	Electric Plant 513: JEF513MS	1.006	1.001	1.013	1.035	1.060	1.084	1.105	2.2221%	2.3971%
514	Miscellaneous 514: JEF514MS	1.037	1.049	1.059	1.078	1.100	1.125	1.147	1.7504%	2.1268%
517	Supervision and Eng. 517: JS&EMS	1.036	1.043	1.064	1.090	1.120	1.150	1.175	2.4245%	2.7268%
519	Coolants and Water 519: JEN519MS	1.011	0.984	0.994	1.037	1.077	1.118	1.149	4.3880%	3.8192%
520	Steam Expenses 520: JEN520MS	1.005	0.974	0.979	1.015	1.045	1.078	1.103	3.7120%	2.9901%
523	Electric Expenses 523: JEN523MS	1.002	0.971	0.950	0.981	1.020	1.062	1.089	3.3266%	3.9635%
524	Miscellaneous 524: JEN524MS	1.022	1.017	1.026	1.042	1.060	1.079	1.095	1.5467%	1.7963%
525	Rents 525: JRENT	1.007	1.014	1.018	1.043	1.069	1.089	1.105	2.4885%	2.5142%
528	Supervision and Eng. 528: JS&EMS	1.036	1.043	1.064	1.090	1.120	1.150	1.175	2.4245%	2.7268%
529	Structures 529: JEN529MS	1.011	0.962	0.995	1.032	1.074	1.116	1.135	3.7288%	4.0171%
530	Reactor Plant 530: JEN530MS	1.012	1.007	1.018	1.046	1.076	1.107	1.134	2.7273%	2.8958%
531	Electric Plant 531: JEN531MS	1.006	1.001	1.013	1.035	1.060	1.084	1.105	2.2221%	2.3971%
532	Miscellaneous 532: JEN532MS	1.019	1.018	1.030	1.048	1.069	1.091	1.106	1.7621%	2.0250%
535	Supervision and Eng. 535: JS&EMS	1.036	1.043	1.064	1.090	1.120	1.150	1.175	2.4245%	2.7268%
537	Hydraulic Plant 537: JEH537MS	0.968	0.906	0.900	0.937	0.976	1.017	1.032	4.0600%	4.1240%
538	Electric Plant 538: JEH538MS	0.945	0.909	0.868	0.900	0.947	0.997	1.024	3.7669%	5.1978%
539	Miscellaneous 539: JEH539MS	1.015	0.991	1.008	1.033	1.053	1.079	1.103	2.4614%	1.9737%
540	Rents 540: JRENT	1.007	1.014	1.018	1.043	1.069	1.089	1.105	2.4885%	2.5142%
541	Supervision and Eng. 541: JS&EMS	1.036	1.043	1.064	1.090	1.120	1.150	1.175	2.4245%	2.7268%
542	Structures 542: JEH542MS	1.011	0.962	0.995	1.032	1.074	1.116	1.135	3.7288%	4.0171%
543	Reserv.; Dams; Waterways 543: JEH543MS	1.038	1.032	1.054	1.082	1.116	1.150	1.175	2.7092%	3.0612%
544	Electric Plant 544: JEH544MS	1.006	1.001	1.013	1.035	1.060	1.084	1.105	2.2217%	2.3967%
545	Miscellaneous 545: JEH545MS	1.036	1.047	1.057	1.076	1.098	1.124	1.145	1.7806%	2.0963%
546	Supervision and Eng. 546: JS&EMS	1.036	1.043	1.064	1.090	1.120	1.150	1.175	2.4245%	2.7268%
547	Fuel 547*: JEO547MS	1.153	0.911	0.914	0.969	0.992	1.030	1.067	6.0157%	2.3807%
548	Generation Expenses 548: JEO548MS	0.994	0.989	0.977	1.015	1.065	1.118	1.157	3.9047%	4.8912%
549	Miscellaneous 549: JEO549MS	1.017	1.000	1.021	1.048	1.070	1.098	1.125	2.6522%	2.0811%
550	Rents 550: JRENT	1.007	1.014	1.018	1.043	1.069	1.089	1.105	2.4885%	2.5142%
551	Supervision and Eng. 551: JS&EMS	1.036	1.043	1.064	1.090	1.120	1.150	1.175	2.4245%	2.7268%
552	Structures 552: JEO552MS	1.011	0.962	0.995	1.032	1.074	1.116	1.135	3.7288%	4.0171%
553	Generation and Elec. Plant 553: JEO553MS	1.027	1.035	1.045	1.063	1.085	1.107	1.127	1.7654%	2.0359%
554	Miscellaneous 554: JEO554MS	1.037	1.049	1.059	1.078	1.100	1.125	1.147	1.7504%	2.1268%

Individual FERC Accounts		2014	2015	2016	2017	2018	2019	2020	2017 / 2016	2018 / 2017
560	Supervision and Eng. 560: JS&EMS	1.036	1.043	1.064	1.090	1.120	1.150	1.175	2.4245%	2.7268%
561	Load Dispatching 561: JET561MS	1.006	0.994	0.992	0.990	0.986	0.986	0.987	-0.2960%	-0.3247%
562	Station Expenses 562: JET562MS	1.014	1.009	1.014	1.039	1.069	1.100	1.123	2.4339%	2.9463%
563	Lines 563&4: JET563&4MS	1.033	1.025	1.037	1.057	1.082	1.106	1.123	1.8891%	2.3787%
564	Lines 563&4: JET563&4MS	1.033	1.025	1.037	1.057	1.082	1.106	1.123	1.8891%	2.3787%
566	Miscellaneous 566: JET566MS	1.013	1.012	1.017	1.028	1.038	1.050	1.061	1.0600%	1.0048%
567	Rents 567: JRENT	1.007	1.014	1.018	1.043	1.069	1.089	1.105	2.4885%	2.5142%
568	Supervision and Eng. 568: JS&EMS	1.036	1.043	1.064	1.090	1.120	1.150	1.175	2.4245%	2.7268%
569	Structures 569: JET569MS	1.001	0.993	0.998	1.010	1.026	1.042	1.053	1.1432%	1.5765%
570	Station Equipment 570: JET570MS	1.010	1.005	1.020	1.047	1.078	1.103	1.126	2.6364%	2.9427%
571	Overhead Lines 571: JET571MS	1.009	1.001	1.008	1.027	1.056	1.085	1.108	1.8978%	2.7509%
572	Underground Lines 572: JET572MS	1.012	1.004	1.016	1.040	1.072	1.100	1.123	2.3561%	3.0888%
573	Miscellaneous 573: JET573MS	1.028	1.020	1.019	1.038	1.062	1.082	1.097	1.8833%	2.3255%
580	Supervision and Eng. 580: JS&EMS	1.036	1.043	1.064	1.090	1.120	1.150	1.175	2.4245%	2.7268%
581	Load Dispatching 581: JED581MS	1.020	1.006	1.014	1.024	1.036	1.050	1.059	0.9928%	1.2036%
582	Station Expenses 582: JED582MS	1.007	0.995	0.996	1.018	1.046	1.074	1.093	2.2330%	2.7620%
583	Lines 583&4: JED583&4MS	1.034	1.033	1.046	1.072	1.105	1.134	1.157	2.4807%	3.0367%
584	Lines 583&4: JED583&4MS	1.034	1.033	1.046	1.072	1.105	1.134	1.157	2.4807%	3.0367%
585	Street Lighting & Signals 585: JED585MS	1.025	1.021	1.034	1.053	1.078	1.103	1.120	1.8522%	2.3937%
586	Meters 586: JED586MS	1.039	1.030	1.044	1.064	1.088	1.113	1.130	1.8886%	2.3285%
587	Customer Installations 587: JED587MS	1.032	1.026	1.038	1.063	1.090	1.117	1.138	2.3621%	2.5758%
588	Miscellaneous 588: JED588MS	1.013	1.013	1.020	1.032	1.043	1.056	1.068	1.1434%	1.1181%
589	Rents 589: JRENT	1.007	1.014	1.018	1.043	1.069	1.089	1.105	2.4885%	2.5142%
590	Supervision and Eng. 590: JS&EMS	1.036	1.043	1.064	1.090	1.120	1.150	1.175	2.4245%	2.7268%
591	Structures 591: JED591MS	1.011	0.962	0.995	1.032	1.074	1.116	1.135	3.7288%	4.0171%
592	Station Equipment 592: JED592MS	1.010	1.005	1.020	1.047	1.078	1.103	1.126	2.6364%	2.9427%
593	Overhead Lines 593: JED593MS	1.009	1.001	1.008	1.027	1.056	1.085	1.108	1.8978%	2.7509%
594	Underground Lines 594: JED594MS	1.012	1.004	1.016	1.040	1.072	1.100	1.123	2.3561%	3.0888%
595	Line Transformers 595: JED595MS	1.002	0.995	1.005	1.022	1.039	1.054	1.069	1.6082%	1.6864%
596	Street Lighting & Signals 596: JED596MS	1.010	1.003	1.013	1.036	1.060	1.085	1.105	2.2348%	2.3383%
597	Meters 597: JED597MS	1.027	1.031	1.044	1.063	1.084	1.105	1.125	1.8545%	1.9576%
598	Miscellaneous 598: JED598MS	1.002	1.000	1.009	1.035	1.066	1.090	1.110	2.6250%	2.9812%
901	Supervision 901: JS&MS	1.037	1.040	1.062	1.089	1.119	1.150	1.174	2.4805%	2.8113%
902	Meter Reading Exp. 902: JECA902MS	1.038	1.036	1.053	1.075	1.100	1.121	1.138	2.1019%	2.3194%
903	Cus. Records and Collections 903: JECA903MS	1.055	1.056	1.076	1.103	1.134	1.161	1.184	2.4861%	2.8075%
905	Miscellaneous 905: JECA905MS	1.008	0.998	1.002	1.006	1.007	1.011	1.016	0.3758%	0.1574%
907	Supervision 907: JS&MS	1.037	1.040	1.062	1.089	1.119	1.150	1.174	2.4805%	2.8113%
908	Customer Assistance 908: JECSI908MS	1.026	1.017	1.029	1.048	1.069	1.090	1.108	1.8229%	2.0277%
909	Info. and Instruc. Advertising 909: JECSI909MS	1.034	1.041	1.060	1.084	1.108	1.128	1.148	2.3111%	2.2103%
910	Miscellaneous 910: JECSI910MS	1.028	1.024	1.034	1.045	1.055	1.062	1.071	1.0935%	0.9310%
911	Supervision 911: JS&MS	1.037	1.040	1.062	1.089	1.119	1.150	1.174	2.4805%	2.8113%

Individual FERC Accounts		**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2017 / 2016**	**2018 / 2017**
912	Demonstr. and Selling 912: JESAL912MS	1.026	1.023	1.035	1.053	1.075	1.097	1.115	1.7392%	2.1465%
913	Advertising 913: JESAL913MS	1.040	1.049	1.068	1.093	1.117	1.137	1.157	2.3051%	2.2352%
916	Miscellaneous 916: JESAL916MS	1.028	1.024	1.034	1.045	1.055	1.062	1.071	1.0935%	0.9310%
921	Office Supplies 921: JEADG921MS	1.031	1.031	1.046	1.065	1.085	1.103	1.119	1.8059%	1.8572%
923	Outside Services 923: JEADG923MS	1.021	1.040	1.059	1.081	1.105	1.128	1.149	2.1421%	2.1515%
924	Property Insurance 924: JEADG924MS	1.039	1.064	1.086	1.112	1.136	1.158	1.178	2.3845%	2.1954%
925	Injuries and Damages 925: JEADG925MS	1.032	1.049	1.067	1.089	1.110	1.130	1.150	2.0243%	1.9536%
926	Pensions and Benefits 926: JEADG926MS	1.052	1.081	1.123	1.171	1.219	1.263	1.308	4.3074%	4.0583%
927	Franchise Fees 927: JEADG927MS	1.022	1.025	1.044	1.069	1.095	1.123	1.151	2.3782%	2.4447%
928	Regulatory Commission Exp. 928: JEADG928MS	1.030	1.034	1.053	1.077	1.103	1.128	1.150	2.2607%	2.4267%
930.1	General Advertising 930.1: JEADG9301MS	1.040	1.047	1.066	1.090	1.114	1.133	1.153	2.2836%	2.1874%
930.2	Miscellaneous 930.2: JEADG9302MS	1.026	1.032	1.047	1.066	1.084	1.101	1.117	1.7905%	1.7599%
931	Rents 931: JRENT931	1.029	1.068	1.080	1.095	1.116	1.135	1.152	1.3995%	1.9500%
935	General Plant 935: JEADG935MS	1.019	1.009	1.016	1.025	1.039	1.053	1.061	0.9623%	1.3208%

Functional Group		**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2017 / 2016**	**2018 / 2017**
500-514	Steam Production Plant: JEFOMMS	1.020	1.017	1.029	1.055	1.083	1.112	1.135	2.5602%	2.6743%
517-532	Nuclear Production Plant: JENOMMS	1.019	1.013	1.025	1.049	1.076	1.102	1.123	2.3796%	2.5205%
535-545	Hydro Production Plant: JEHOMMS	1.010	0.995	1.005	1.031	1.061	1.092	1.114	2.6734%	2.8673%
546-554	Other Production Plant: JEOOMMS	1.020	1.021	1.031	1.055	1.082	1.109	1.132	2.3080%	2.5119%
560-573	Transmission Plant: JETOMMS	1.012	1.008	1.014	1.027	1.043	1.060	1.074	1.3211%	1.5757%
580-598	Distribution Plant: JEDOMMS	1.015	1.010	1.019	1.040	1.066	1.092	1.114	2.0056%	2.5583%
901-905	Customer Accounts: JECAOMS	1.048	1.048	1.067	1.091	1.119	1.144	1.165	2.2884%	2.5620%
907-910	Customer Service and Information: JECSIOMS	1.026	1.019	1.031	1.050	1.071	1.091	1.109	1.8026%	1.9792%
911-916	Sales: JESALOMS	1.028	1.026	1.039	1.057	1.078	1.099	1.116	1.7422%	2.0388%
921-935	Administrative and General: JEADGOMMS	1.037	1.056	1.083	1.115	1.147	1.177	1.206	2.9419%	2.8810%

Functional Group		**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2017 / 2016**	**2018 / 2017**
ALL	Total Elec Operation and Maintenance: JETOTALMS	1.027	1.031	1.048	1.073	1.101	1.127	1.151	2.4178%	2.5583%

Wage Factor for FERC 920 and payroll taxes	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2017 / 2016**	**2018 / 2017**
US, Wages and Sal, Private, Management, Business, Financial, Units: 2005:4=100: ECIPWMBFNS	121.9	124.5	127.8	131.4	135.2	139.0	142.9	2.8581%	2.8469%

A		B	C	D = B x C	E	F = (B + D) x E	
FERC Account		2016 TY Amount	Escalator	2017 Amount	Escalator	2018 Amount	
500-Stm Prod Op & Supr	500	6,542,292	2.4245%	158,620	2.7268%	182,723	
501-Stm Gen Fuel	501	424,976,099	6.0157%	25,565,245	2.3807%	10,726,101	
502-Steam Expenses Major	502	19,840,603	5.0181%	995,616	4.1607%	866,941	
505-Stm Gen Elec Exp. Major	505	1,225,696	4.7057%	57,677	4.5648%	58,583	
506-Misc Steam Pwr Exp	506	18,639,034	1.5467%	288,284	1.7963%	339,999	
507-Stm Pow Gen Rents	507	3,001,893	2.4885%	74,703	2.5142%	77,351	
510-Stm Maint Super&Eng	510	1,754,283	2.4245%	42,533	2.7268%	48,996	
511-Stm Maint of Structures	511	2,431,987	3.7288%	90,683	4.0171%	101,337	
512-Stm Maint of Boiler Plt	512	34,672,811	2.0152%	698,721	2.3173%	819,651	
513-Stm Maint of Elec Plant	513	4,306,730	2.2221%	95,700	2.3971%	105,530	
514-Stm Maint of Misc Stm Plt	514	16,006,492	1.7504%	280,171	2.1268%	346,390	
517-Nuc Oper Supervision&Eng	517	63,095,465	2.4245%	1,529,767	2.7268%	1,762,224	
518-Nuclear Fuel Expense	518	104,716,448	0.0000%		0.0000%		No Glob Ins factor
519-Nuclear Coolants & Water	519	7,807,535	4.3880%	342,594	3.8192%	311,273	
520-Nuclear Steam Expense	520	44,657,833	3.7120%	1,657,682	2.9901%	1,384,877	
523-Nuclear Electric Expense	523	1,951,814	3.3266%	64,930	3.9635%	79,933	
524-Nuclear Power Misc Exp	524	127,616,761	1.5467%	1,973,808	1.7963%	2,327,887	
525-Nuclear Gener Rents	525	11,147,593	2.4885%	277,411	2.5142%	287,246	
528-Nuc Mtce Supervision&Eng	528	5,399,932	2.4245%	130,923	2.7268%	150,817	
529-Nuc Mtce of Structures	529	8,183	3.7288%	305	4.0171%	341	
530-Nuc Mtce Rctr Plant Equip	530	42,732,995	2.7273%	1,165,464	2.8958%	1,271,224	
531-Nuc Mtce of Elec Plant	531	11,809,217	2.2221%	262,414	2.3971%	289,368	
532-Nuc Mtce of Misc Nuc Plant	532	22,240,946	1.7621%	391,911	2.0250%	458,306	
535-Hyd Oper Super & Eng	535	31,772	2.4245%	770	2.7268%	887	
536-Hyd Oper Water for Pwr	536		0.0000%		0.0000%		No Glob Ins factor
537-Hydro Oper Hydraulic Exp	537	413	4.0600%	17	4.1240%	18	
538-Hyd Oper Electric Exp	538	10,482	3.7669%	395	5.1978%	565	
539-Hydro Oper Misc Gen Exp	539	249,197	2.4614%	6,134	1.9737%	5,040	
540-Hyd Oper Rents	540	19,286	2.4885%	480	2.5142%	497	
541-Hydro Mtc Super& Eng	541	4,811	2.4245%	117	2.7268%	134	
542-Hyd Maint of Structures	542	19,216	3.7288%	717	4.0171%	801	
543-Hydro Mtc Resv, Dams	543	19,216	2.7092%	521	3.0612%	604	
544-Hyd Maint of Elec Plant	544	76,974	2.2217%	1,710	2.3967%	1,886	
545-Hyd Mt Misc Hyd Plnt Mjr	545	52,157	1.7806%	929	2.0963%	1,113	
546-Oth Oper Super&Eng	546	1,903,935	2.4245%	46,161	2.7268%	53,176	
547-Fuel - Other Power	547	16,896,500	6.0157%	1,016,441	2.3807%	426,456	
548-Oth Oper Gen Exp	548	6,730,799	3.9047%	262,819	4.8912%	342,069	
549-Oth Oper Misc Gen Exp	549	13,362,821	2.6522%	354,404	2.0811%	285,471	
550-Oth Oper Rents	550	1,267,466	2.4885%	31,541	2.5142%	32,660	
551 - Other Oper Super & Eng	551	271,075	2.4245%	6,572	2.7268%	7,571	
552-Oth Maint of Structures	552	2,831,892	3.7288%	105,595	4.0171%	118,001	
553-Oth Mtc of Gen & Ele Plant	553	15,046,096	1.7654%	265,628	2.0359%	311,731	
554-Oth Mtc Misc Gen Plt Mjr	554	1,630,353	1.7504%	28,537	2.1268%	35,282	
555-Purchased Power	555	573,497,374	0.0000%		0.0000%		No Glob Ins factor
556-Load Dispatch	556	961,151	0.0000%		0.0000%		No Glob Ins factor
557-Purchased Power Other	557	63,047,753	0.0000%		0.0000%		No Glob Ins factor
557.1-Deferred Elec Energy Cost	557.1		0.0000%		0.0000%		No Glob Ins factor
560-Trans Oper Super & Eng	560	6,063,219	2.4245%	147,004	2.7268%	169,343	
561.1-Load Disp-Reliability	561.1	41,936	-0.2960%	(124)	-0.3247%	(136)	
561.2-Load Disp-Monitor/Operat	561.2	6,109,656	-0.2960%	(18,086)	-0.3247%	(19,779)	

A		B	C	D = B x C	E	F = (B + D) x E	
FERC Account		2016 TY Amount	Escalator	2017 Amount	Escalator	2018 Amount	
561.3-Load Disp-Trans Serv/Sch	561.3	22,461	-0.2960%	(66)	-0.3247%	(73)	
561.4-Load Disp-Sch/Con/Disp Serv	561.4	5,616,156	-0.2960%	(16,625)	-0.3247%	(18,182)	
561.5 - Rel/Plan/Stnd/Dev	561.5	809,682	-0.2960%	(2,397)	-0.3247%	(2,621)	
561.6-Trans Service Studies	561.6	33,266	-0.2960%	(98)	-0.3247%	(108)	
561.7-Gen Interconn Studies	561.7	120,689	-0.2960%	(357)	-0.3247%	(391)	
561.8-Rel/Plan/Standards Dev Serv	561.8	2,289,759	-0.2960%	(6,778)	-0.3247%	(7,413)	
562-Trans Oper Station Exp	562	1,633,211	2.4339%	39,751	2.9463%	49,291	
563-Trans Oper OH Lines	563	1,954,182	1.8891%	36,917	2.3787%	47,361	
564-Trans Oper UG Lines	564	702	1.8891%	13	2.3787%	17	
565-Purchased Power	565	61,604,004	0.0000%		0.0000%		No Glob Ins factor
566-Trans Oper Misc Exp	566	102,308,973	1.0600%	1,084,439	1.0048%	1,038,868	
567-Trans Rents	567	2,058,496	2.4885%	51,226	2.5142%	53,042	
568-Trans Mtce Super & Eng	568	106,950	2.4245%	2,593	2.7268%	2,987	
570-Tran Mnt of Station Equip	570	6,739,100	2.6364%	177,671	2.9427%	203,540	
571-Trans Mt of Overhead Lines	571	7,463,565	1.8978%	141,643	2.7509%	209,215	
572-Trans Mt of Underground Lines	572	191,305	2.3561%	4,507	3.0888%	6,048	
573-Trans Miscellaneous Plant	573	19,039	1.8833%	359	2.3255%	451	
575.1-Operations Supervision	575.1	181,628	0.0000%		0.0000%		No Glob Ins factor
575.2-DA & RT Mkt Admin	575.2	337,503	0.0000%		0.0000%		No Glob Ins factor
575.5-Ancillary Serv Mkt Admin	575.5	157,988	0.0000%		0.0000%		No Glob Ins factor
575.6-Mkt Monitoring/Compliance	575.6	34,115	0.0000%		0.0000%		No Glob Ins factor
575.7-Mkt Fac/Mon/Comp Serv	575.7	6,322,460	0.0000%		0.0000%		No Glob Ins factor
575.8-Regional Market Rents	575.8	15,431	0.0000%		0.0000%		No Glob Ins factor
580-Dist Oper Sup & Eng	580	8,561,400	2.4245%	207,574	2.7268%	239,116	
581-Dist Load Dispatching	581	6,849,595	0.9928%	68,000	1.2036%	83,259	
582-Dist Op Station Exp	582	2,769,266	2.2330%	61,838	2.7620%	78,194	
583-Dist Oper Overhead Lines	583	1,219,108	2.4807%	30,243	3.0367%	37,939	
584-Dist Op UG Elec lines	584	5,473,242	2.4807%	135,777	3.0367%	170,330	
585-Dist Oper Streetlight	585	1,413,858	1.8522%	26,187	2.3937%	34,470	
586-Dist Oper Meter Exp	586	2,683,158	1.8886%	50,675	2.3285%	63,658	
587-Dist Oper Cust Install	587	3,614,250	2.3621%	85,374	2.5758%	95,293	
588-Dist Oper Misc Exp	588	15,941,650	1.1434%	182,277	1.1181%	180,277	
589-Dist Rents	589	3,764,610	2.4885%	93,683	2.5142%	97,005	
590-Dist Mtc Super & Eng	590	355,585	2.4245%	8,621	2.7268%	9,931	
592-Dist Mt of Station Equip	592	7,066,102	2.6364%	186,293	2.9427%	213,416	
593-Dist Mtc of Overhead LInes	593	34,588,561	1.8978%	656,419	2.7509%	969,569	
594-Dist Mt of Undergrnd Line	594	10,428,264	2.3561%	245,696	3.0888%	329,699	
595-Dist Mt of Line Transform	595	2,419,845	1.6082%	38,916	1.6864%	41,464	
596-Dist Mtc of Streetlights	596	744,091	2.2348%	16,629	2.3383%	17,788	
597-Dist Mtc of Meters	597	130,396	1.8545%	2,418	1.9576%	2,600	
598 - Dist Mtc of Misc Plant	598	330	2.6250%	9	2.9812%	10	
901-Cust Acct Supervise	901	119,416	2.4805%	2,962	2.8113%	3,440	
902-Cust Acct Meter Read	902	15,586,121	2.1019%	327,612	2.3194%	369,111	
903-Cust Acct Recrds &Coll	903	22,373,428	2.4861%	556,230	2.8075%	643,756	
904-Cust Acct Uncollect	904	11,964,825	0.0000%		0.0000%		No Glob Ins factor
905-Cust Acct Misc	905	30	0.3758%	0	0.1574%	0	
908-Customer Asst Expense	908	90,452,848	1.8229%	1,648,833	2.0277%	1,867,552	
909-Cust Serv Instruct Adver	909	657,456	2.3111%	15,194	2.2103%	14,868	
912-Sales Demo & Sales	912	68,502	1.7392%	1,191	2.1465%	1,496	
920-A&G Salaries	920	47,577,934	0.0000%		0.0000%		Wage factor

A		B	C	D = B x C	E	F = (B + D) x E	
FERC Account		2016 TY Amount	Escalator	2017 Amount	Escalator	2018 Amount	
921-A&G Office & Supplies	921	45,442,357	1.8059%	820,650	1.8572%	859,176	
922-A&G Admn Transfer Crdt	922	(40,273,583)	0.0000%		0.0000%		No Glob Ins factor
923-A&G Outside Services	923	21,091,269	2.1421%	451,792	2.1515%	463,506	
924-A&G Property Insurance	924	8,932,835	2.3845%	213,008	2.1954%	200,786	
925-A&G Injuries & Damages	925	13,343,632	2.0243%	270,114	1.9536%	265,962	
926-A&G Pen & Ben	926	79,116,399	4.3074%	3,407,880	4.0583%	3,349,047	
926.3-SPS Deferred Pension Exp	926.3	(4,488,836)	4.3074%	(193,353)	4.0583%	(190,015)	
928-A&G Regulatory Comm Exp	928	5,372,676	2.2607%	121,459	2.4267%	133,324	
929-A&G Duplicate Chrg Crdt	929	(4,355,301)	0.0000%		0.0000%		No Glob Ins factor
930.1-A&G General Advertising	930.1	144,272	2.2836%	3,295	2.1874%	3,228	
930.2-A&G Misc General Exp	930.2	4,753,735	1.7905%	85,115	1.7599%	85,161	
931-A&G Rents	931	30,275,189	1.3995%	423,688	1.9500%	598,641	
935-A&G Maint of Gen PLT	935	1,065,093	0.9623%	10,249	1.3208%	14,204	
Total		2,343,992,464		50,178,789		36,699,784	
Composite Percent Change				**2.1407%**		**1.5329%**	

Nothern States Power Company
Electric Utility - State of Minnesota
2016-2018 Summary by FERC Account
Amount in Thousands

Revenue and Expense by FERC Account	Modeling Method	Amount in Plan Year 2016	Amount in Plan Year 2017	Amount in Plan Year 2018	Year over Year Change 2017 / 2016	Year over Year Change 2018 / 2017	Year over Year Percent 2017 / 2016	Year over Year Percent 2018 / 2017	Global Insights FERC Acct Factor 2017 / 2016	Global Insights FERC Acct Factor 2018 / 2017
Operating Revenues - Retail										
440-Retail Rate Revenues	No escalation except for change in TCR revenue	3,033,285	3,031,800	3,030,366	(1,485)	(1,434)	(0.05%)	(0.05%)	#N/A	#N/A
Sub-Total Operating Revenues - Retail		3,033,285	3,031,800	3,030,366	(1,485)	(1,434)	(0.05%)	(0.05%)		
Operating Revenues - Interdepartmental										
440-Retail Rate Revenues	No escalation except for change in TCR revenue	809	808	808	(1)	(1)	(0.07%)	(0.06%)	#N/A	#N/A
Sub-Total Operating Revenues - Interdepartmental		809	808	808	(1)	(1)	(0.07%)	(0.06%)		
Other Operating Rev - Non-Retail										
450-Forfeited Discounts	Composite factor from Global Insights data	6,058	6,188	6,283	130	95	2.14%	1.53%	#N/A	#N/A
451-Misc Service Revenues	Composite factor from Global Insights data	2,493	2,546	2,585	53	39	2.14%	1.53%	#N/A	#N/A
454-Rent from Electric Property	Composite factor from Global Insights data	4,472	4,568	4,638	96	70	2.14%	1.53%	#N/A	#N/A
456-Other Electric Revenues	Simulated IA bill to NSPW / Forecast transm revenue	551,270	558,123	564,229	6,852	6,107	1.24%	1.09%	#N/A	#N/A
499	Forecast non-decoupled growth / No-return adjs	22,691	25,739	29,192	3,048	3,454	13.43%	13.42%	#N/A	#N/A
Sub-Total Other Operating Rev - Non-Retail		586,984	597,164	606,928	10,179	9,764	1.73%	1.64%		
Operating Expenses - Fuel and Purchased Energy										
501-Stm Gen Fuel	No escalation	424,976	424,976	424,976	-	-	0.00%	0.00%	(93.98%)	(97.62%)
518-Nuclear Fuel Expense	No escalation	101,749	101,749	101,749	-	-	0.00%	0.00%	#N/A	#N/A
547-Fuel - Other Power	No escalation	16,896	16,896	16,896	-	-	0.00%	0.00%	(93.98%)	(97.62%)
555-Purchased Power	No escalation	440,511	440,511	440,511	-	-	0.00%	0.00%	#N/A	#N/A
557-Purchased Power Other	Simulated Interchange Agreement bill to NSPW	16,964	17,003	17,067	39	64	0.23%	0.37%	#N/A	#N/A
Sub-Total Operating Expenses - Fuel and Purchased Energy		1,001,096	1,001,136	1,001,199	39	64	0.00%	0.01%		
Operating Expenses - Production										
500-Stm Prod Op & Supr	Global Insights factor by FERC Account	6,542	6,701	6,884	159	183	2.42%	2.73%	(97.58%)	(97.27%)
502-Steam Expenses Major	Global Insights factor by FERC Account	19,841	20,836	21,703	996	867	5.02%	4.16%	(94.98%)	(95.84%)
505-Stm Gen Elec Exp. Major	Global Insights factor by FERC Account	1,226	1,283	1,342	58	59	4.71%	4.56%	(95.29%)	(95.44%)
506-Misc Steam Pwr Exp	Global Insights factor by FERC Account	18,639	18,927	19,267	288	340	1.55%	1.80%	(98.45%)	(98.20%)
507-Stm Pow Gen Rents	Global Insights factor by FERC Account	3,002	3,077	3,154	75	77	2.49%	2.51%	(97.51%)	(97.49%)
510-Stm Maint Super&Eng	Global Insights factor by FERC Account	1,754	1,797	1,846	43	49	2.42%	2.73%	(97.58%)	(97.27%)
511-Stm Maint of Structures	Global Insights factor by FERC Account	2,432	2,523	2,624	91	101	3.73%	4.02%	(96.27%)	(95.98%)
512-Stm Maint of Boiler Plt	Global Insights factor by FERC Account	34,673	35,372	36,191	699	820	2.02%	2.32%	(97.98%)	(97.68%)
513-Stm Maint of Elec Plant	Global Insights factor by FERC Account	4,307	4,402	4,508	96	106	2.22%	2.40%	(97.78%)	(97.60%)
514-Stm Maint of Misc Stm Plt	Global Insights factor by FERC Account	16,006	16,287	16,633	280	346	1.75%	2.13%	(98.25%)	(97.87%)
517-Nuc Oper Supervision&Eng	Global Insights factor / Nucl amortization forecast	63,095	65,362	67,144	2,267	1,782	3.59%	2.73%	(97.58%)	(97.27%)
518-Nuclear Fuel Expense	No escalation	2,373	2,373	2,373	-	-	0.00%	0.00%	#N/A	#N/A
519-Nuclear Coolants & Water	Global Insights factor / Nucl amortization forecast	7,808	8,031	8,327	224	296	2.87%	3.68%	(95.61%)	(96.18%)
520-Nuclear Steam Expense	Global Insights factor / Nucl amortization forecast	44,658	45,315	46,165	657	850	1.47%	1.88%	(96.29%)	(97.01%)
523-Nuclear Electric Expense	Global Insights factor / Nucl amortization forecast	1,952	1,938	2,013	(14)	75	(0.70%)	3.87%	(96.67%)	(96.04%)
524-Nuclear Power Misc Exp	Global Insights factor / Nucl amortization forecast	127,617	129,451	131,783	1,834	2,332	1.44%	1.80%	(98.45%)	(98.20%)
525-Nuclear Gener Rents	Global Insights factor by FERC Account	11,148	11,425	11,712	277	287	2.49%	2.51%	(97.51%)	(97.49%)
528-Nuc Mtce Supervision&Eng	Global Insights factor / Nucl amortization forecast	5,400	6,013	6,385	613	372	11.35%	6.19%	(97.58%)	(97.27%)
529-Nuc Mtce of Structures	Global Insights factor / Nucl amortization forecast	8	0	-	(8)	(0)	(94.81%)	(100.00%)	(96.27%)	(95.98%)
530-Nuc Mtce Rctr Plant Equip	Global Insights factor / Nucl amortization forecast	42,733	46,653	45,949	3,920	(704)	9.17%	(1.51%)	(97.27%)	(97.10%)
531-Nuc Mtce of Elec Plant	Global Insights factor / Nucl amortization forecast	11,809	8,638	8,687	(3,171)	49	(26.85%)	0.57%	(97.78%)	(97.60%)
532-Nuc Mtce of Misc Nuc Plant	Global Insights factor / Nucl amortization forecast	22,241	21,190	20,339	(1,051)	(851)	(4.73%)	(4.02%)	(98.24%)	(97.98%)
535-Hyd Oper Super & Eng	Global Insights factor by FERC Account	32	33	33	1	1	2.42%	2.73%	(97.58%)	(97.27%)
537-Hydro Oper Hydraulic Exp	Global Insights factor by FERC Account	0	0	0	0	0	4.06%	4.12%	(95.94%)	(95.88%)

Amount in Thousands

Revenue and Expense by FERC Account	Modeling Method	2016	2017	2018	2017 / 2016	2018 / 2017	2017 / 2016	2018 / 2017	2017 / 2016	2018 / 2017
538-Hyd Oper Electric Exp	Global Insights factor by FERC Account	10	11	11	0	1	3.77%	5.20%	(96.23%)	(94.80%)
539-Hydro Oper Misc Gen Exp	Global Insights factor by FERC Account	249	255	260	6	5	2.46%	1.97%	(97.54%)	(98.03%)
540-Hyd Oper Rents	Global Insights factor by FERC Account	19	20	20	0	0	2.49%	2.51%	(97.51%)	(97.49%)
541-Hydro Mtc Super& Eng	Global Insights factor by FERC Account	5	5	5	0	0	2.42%	2.73%	(97.58%)	(97.27%)
542-Hyd Maint of Structures	Global Insights factor by FERC Account	19	20	21	1	1	3.73%	4.02%	(96.27%)	(95.98%)
543-Hydro Mtc Resv, Dams	Global Insights factor by FERC Account	19	20	20	1	1	2.71%	3.06%	(97.29%)	(96.94%)
544-Hyd Maint of Elec Plant	Global Insights factor by FERC Account	77	79	81	2	2	2.22%	2.40%	(97.78%)	(97.60%)
545-Hyd Mt Misc Hyd Plnt Mjr	Global Insights factor by FERC Account	52	53	54	1	1	1.78%	2.10%	(98.22%)	(97.90%)
546-Oth Oper Super&Eng	Global Insights factor by FERC Account	1,904	1,950	2,003	46	53	2.42%	2.73%	(97.58%)	(97.27%)
548-Oth Oper Gen Exp	Global Insights factor by FERC Account	6,731	6,994	7,336	263	342	3.90%	4.89%	(96.10%)	(95.11%)
549-Oth Oper Misc Gen Exp	Global Insights factor by FERC Account	13,363	13,717	14,003	354	285	2.65%	2.08%	(97.35%)	(97.92%)
550-Oth Oper Rents	Global Insights factor by FERC Account	1,267	1,299	1,332	32	33	2.49%	2.51%	(97.51%)	(97.49%)
551 - Other Oper Super & Eng	Global Insights factor by FERC Account	271	278	285	7	8	2.42%	2.73%	(97.58%)	(97.27%)
552-Oth Maint of Structures	Global Insights factor by FERC Account	2,832	2,937	3,055	106	118	3.73%	4.02%	(96.27%)	(95.98%)
553-Oth Mtc of Gen & Ele Plant	Global Insights factor by FERC Account	15,046	15,312	15,623	266	312	1.77%	2.04%	(98.23%)	(97.96%)
554-Oth Mtc Misc Gen Plt Mjr	Global Insights factor by FERC Account	1,630	1,659	1,694	29	35	1.75%	2.13%	(98.25%)	(97.87%)
555-Purchased Power	Corporate forecast for Purchased Demand	134,635	130,369	126,377	(4,266)	(3,992)	(3.17%)	(3.06%)	#N/A	#N/A
556-Load Dispatch	Composite factor from Global Insights data	961	982	997	21	15	2.14%	1.53%	#N/A	#N/A
557-Purchased Power Other	Simulated Interchange Agreement bill to NSPW	46,084	46,400	47,102	316	702	0.68%	1.51%	#N/A	#N/A
Sub-Total Operating Expenses - Production		674,472	679,987	685,344	5,515	5,358	0.82%	0.79%		
Operating Expenses - Transmission										
560-Trans Oper Super & Eng	Global Insights factor by FERC Account	6,063	6,210	6,380	147	169	2.42%	2.73%	(97.58%)	(97.27%)
561.1-Load Disp-Reliability	Global Insights factor by FERC Account	42	42	42	(0)	(0)	(0.30%)	(0.32%)	(100.30%)	(100.32%)
561.2-Load Disp-Monitor/Operat	Global Insights factor by FERC Account	6,110	6,092	6,072	(18)	(20)	(0.30%)	(0.32%)	(100.30%)	(100.32%)
561.3-Load Disp-Trans Serv/Sch	Global Insights factor by FERC Account	22	22	22	(0)	(0)	(0.30%)	(0.32%)	(100.30%)	(100.32%)
561.4-Load Disp-Sch/Con/Disp Serv	Global Insights factor by FERC Account	5,616	5,600	5,581	(17)	(18)	(0.30%)	(0.32%)	(100.30%)	(100.32%)
561.5 - Rel/Plan/Stnd/Dev	Global Insights factor by FERC Account	810	807	805	(2)	(3)	(0.30%)	(0.32%)	(100.30%)	(100.32%)
561.6-Trans Service Studies	Global Insights factor by FERC Account	33	33	33	(0)	(0)	(0.30%)	(0.32%)	(100.30%)	(100.32%)
561.7-Gen Interconn Studies	Global Insights factor by FERC Account	121	120	120	(0)	(0)	(0.30%)	(0.32%)	(100.30%)	(100.32%)
561.8-Rel/Plan/Standards Dev Serv	Global Insights factor by FERC Account	2,290	2,283	2,276	(7)	(7)	(0.30%)	(0.32%)	(100.30%)	(100.32%)
562-Trans Oper Station Exp	Global Insights factor by FERC Account	1,633	1,673	1,722	40	49	2.43%	2.95%	(97.57%)	(97.05%)
563-Trans Oper OH Lines	Global Insights factor by FERC Account	1,954	1,991	2,038	37	47	1.89%	2.38%	(98.11%)	(97.62%)
564-Trans Oper UG Lines	Global Insights factor by FERC Account	1	1	1	0	0	1.89%	2.38%	(98.11%)	(97.62%)
565-Purchased Power	Forecast regionally shared Transm expense	61,604	64,222	66,072	2,618	1,850	4.25%	2.88%	#N/A	#N/A
566-Trans Oper Misc Exp	Forecast regionally shared Transm expense	102,309	103,741	108,816	1,432	5,075	1.40%	4.89%	(98.94%)	(99.00%)
567-Trans Rents	Global Insights factor by FERC Account	2,058	2,110	2,163	51	53	2.49%	2.51%	(97.51%)	(97.49%)
568-Trans Mtce Super & Eng	Global Insights factor by FERC Account	107	110	113	3	3	2.42%	2.73%	(97.58%)	(97.27%)
570-Tran Mnt of Station Equip	Global Insights factor by FERC Account	6,739	6,917	7,120	178	204	2.64%	2.94%	(97.36%)	(97.06%)
571-Trans Mt of Overhead Lines	Global Insights factor by FERC Account	7,464	7,605	7,814	142	209	1.90%	2.75%	(98.10%)	(97.25%)
572-Trans Mt of Underground Lines	Global Insights factor by FERC Account	191	196	202	5	6	2.36%	3.09%	(97.64%)	(96.91%)
573-Trans Miscellaneous Plant	Global Insights factor by FERC Account	19	19	20	0	0	1.88%	2.33%	(98.12%)	(97.67%)
575.1-Operations Supervision	Forecast regionally shared Transm expense	182	187	192	5	5	2.85%	2.74%	#N/A	#N/A
575.2-DA & RT Mkt Admin	Forecast regionally shared Transm expense	338	340	343	3	3	0.82%	0.78%	#N/A	#N/A
575.5-Ancillary Serv Mkt Admin	Forecast regionally shared Transm expense	158	158	159	0	0	0.22%	0.16%	#N/A	#N/A
575.6-Mkt Monitoring/Compliance	Forecast regionally shared Transm expense	34	34	33	(0)	(0)	(1.27%)	(1.43%)	#N/A	#N/A
575.7-Mkt Fac/Mon/Comp Serv	Forecast regionally shared Transm expense	6,322	6,437	6,574	115	137	1.82%	2.12%	#N/A	#N/A
575.8-Regional Market Rents	Forecast regionally shared Transm expense	15	15	15	(0)	0	(0.97%)	1.03%	#N/A	#N/A
Sub-Total Operating Expenses - Transmission		212,235	216,965	224,727	4,730	7,762	2.23%	3.58%		

Operating Expenses - Distribution

Amount in Thousands

Revenue and Expense by FERC Account	Modeling Method	2016	2017	2018	2017 / 2016	2018 / 2017	2017 / 2016	2018 / 2017	2017 / 2016	2018 / 2017
580-Dist Oper Sup & Eng	Global Insights factor by FERC Account	8,561	8,769	9,008	208	239	2.42%	2.73%	(97.58%)	(97.27%)
581-Dist Load Dispatching	Global Insights factor by FERC Account	6,850	6,918	7,001	68	83	0.99%	1.20%	(99.01%)	(98.80%)
582-Dist Op Station Exp	Global Insights factor by FERC Account	2,769	2,831	2,909	62	78	2.23%	2.76%	(97.77%)	(97.24%)
583-Dist Oper Overhead Lines	Global Insights factor by FERC Account	1,219	1,249	1,287	30	38	2.48%	3.04%	(97.52%)	(96.96%)
584-Dist Op UG Elec lines	Global Insights factor by FERC Account	5,473	5,609	5,779	136	170	2.48%	3.04%	(97.52%)	(96.96%)
585-Dist Oper Streetlight	Global Insights factor by FERC Account	1,414	1,440	1,475	26	34	1.85%	2.39%	(98.15%)	(97.61%)
586-Dist Oper Meter Exp	Global Insights factor by FERC Account	2,683	2,734	2,797	51	64	1.89%	2.33%	(98.11%)	(97.67%)
587-Dist Oper Cust Install	Global Insights factor by FERC Account	3,614	3,700	3,795	85	95	2.36%	2.58%	(97.64%)	(97.42%)
588-Dist Oper Misc Exp	Global Insights factor by FERC Account	15,942	16,124	16,304	182	180	1.14%	1.12%	(98.86%)	(98.88%)
589-Dist Rents	Global Insights factor by FERC Account	3,765	3,858	3,955	94	97	2.49%	2.51%	(97.51%)	(97.49%)
590-Dist Mtc Super & Eng	Global Insights factor by FERC Account	356	364	374	9	10	2.42%	2.73%	(97.58%)	(97.27%)
592-Dist Mt of Station Equip	Global Insights factor by FERC Account	7,066	7,252	7,466	186	213	2.64%	2.94%	(97.36%)	(97.06%)
593-Dist Mtc of Overhead LInes	Global Insights factor by FERC Account	34,589	35,245	36,215	656	970	1.90%	2.75%	(98.10%)	(97.25%)
594-Dist Mt of Undergrnd Line	Global Insights factor by FERC Account	10,428	10,674	11,004	246	330	2.36%	3.09%	(97.64%)	(96.91%)
595-Dist Mt of Line Transform	Global Insights factor by FERC Account	2,420	2,459	2,500	39	41	1.61%	1.69%	(98.39%)	(98.31%)
596-Dist Mtc of Streetlights	Global Insights factor by FERC Account	744	761	779	17	18	2.23%	2.34%	(97.77%)	(97.66%)
597-Dist Mtc of Meters	Global Insights factor by FERC Account	130	133	135	2	3	1.85%	1.96%	(98.15%)	(98.04%)
598 - Dist Mtc of Misc Plant	Global Insights factor by FERC Account	0	0	0	0	0	2.62%	2.98%	(97.38%)	(97.02%)
Sub-Total Operating Expenses - Distribution		108,023	110,120	112,784	2,097	2,664	1.94%	2.42%		
Operating Expenses - Customer Accounting										
901-Cust Acct Supervise	Global Insights factor by FERC Account	119	122	126	3	3	2.48%	2.81%	(97.52%)	(97.19%)
902-Cust Acct Meter Read	Global Insights factor by FERC Account	15,586	15,914	16,283	328	369	2.10%	2.32%	(97.90%)	(97.68%)
903-Cust Acct Recrds &Coll	Global Insights factor by FERC Account	22,373	22,930	23,573	556	644	2.49%	2.81%	(97.51%)	(97.19%)
904-Cust Acct Uncollect	Corporate forecast	11,236	10,990	10,838	(246)	(151)	(2.19%)	(1.38%)	#N/A	#N/A
905-Cust Acct Misc	Global Insights factor by FERC Account	0	0	0	0	0	0.38%	0.16%	(99.62%)	(99.84%)
Sub-Total Operating Expenses - Customer Accounting		49,315	49,956	50,820	641	865	1.30%	1.73%		
Operating Expenses - Customer Service & Information										
908-Customer Asst Expense	No escalation	90,453	90,453	90,453	-	-	0.00%	0.00%	(98.18%)	(97.97%)
909-Cust Serv Instruct Adver	Global Insights factor by FERC Account	657	673	688	15	15	2.31%	2.21%	(97.69%)	(97.79%)
Sub-Total Operating Expenses - Customer Service & Information		91,110	91,125	91,140	15	15	0.02%	0.02%		
Operating Expenses - Sales, Econ Dvlp & Other										
912-Sales Demo & Sales	Global Insights factor by FERC Account	69	70	71	1	1	1.74%	2.15%	(98.26%)	(97.85%)
Sub-Total Operating Expenses - Sales, Econ Dvlp & Other		69	70	71	1	1	1.74%	2.15%		
Operating Expenses - Administrative & General										
920-A&G Salaries	Global Insights factor for Labor	47,578	48,938	50,331	1,360	1,393	2.86%	2.85%	#N/A	#N/A
921-A&G Office & Supplies	Global Insights factor by FERC Account	45,434	46,255	47,114	820	859	1.81%	1.86%	(98.19%)	(98.14%)
922-A&G Admn Transfer Crdt	Composite factor from Global Insights data	(40,274)	(41,136)	(41,766)	(862)	(631)	2.14%	1.53%	#N/A	#N/A
923-A&G Outside Services	Global Insights factor by FERC Account	21,091	21,543	22,007	452	464	2.14%	2.15%	(97.86%)	(97.85%)
924-A&G Property Insurance	Global Insights factor by FERC Account	8,933	9,146	9,347	213	201	2.38%	2.20%	(97.62%)	(97.80%)
925-A&G Injuries & Damages	Corporate forecast	13,344	14,698	15,383	1,354	686	10.15%	4.66%	(97.98%)	(98.05%)
926-A&G Pen & Ben	Corporate forecast	77,707	76,731	78,132	(976)	1,401	(1.26%)	1.83%	(95.69%)	(95.94%)
926.3-SPS Deferred Pension Exp	Corporate forecast	(4,489)	(2,684)	(2,061)	1,805	623	(40.20%)	(23.20%)	#N/A	#N/A
928-A&G Regulatory Comm Exp	Global Insights factor by FERC Account	5,373	5,494	5,627	121	133	2.26%	2.43%	(97.74%)	(97.57%)
929-A&G Duplicate Chrg Crdt	Composite factor from Global Insights data	(4,355)	(4,449)	(4,517)	(93)	(68)	2.14%	1.53%	#N/A	#N/A
930.1-A&G General Advertising	Global Insights factor by FERC Account	144	148	151	3	3	2.28%	2.19%	(97.72%)	(97.81%)
930.2-A&G Misc General Exp	Global Insights factor by FERC Account	4,754	4,839	4,924	85	85	1.79%	1.76%	(98.21%)	(98.24%)

Amount in Thousands

Revenue and Expense by FERC Account	Modeling Method	2016	2017	2018	2017 / 2016	2018 / 2017	2017 / 2016	2018 / 2017	2017 / 2016	2018 / 2017
931-A&G Rents	Global Insights factor by FERC Account	30,275	30,699	31,298	424	599	1.40%	1.95%	(98.60%)	(98.05%)
935-A&G Maint of Gen PLT	Global Insights factor by FERC Account	1,065	1,075	1,090	10	14	0.96%	1.32%	(99.04%)	(98.68%)
Sub-Total Operating Expenses - Administrative & General		206,579	211,296	217,058	4,717	5,762	2.28%	2.73%		
Amortization										
407-Amortization	No escalation	39,585	39,585	39,585	-	-	0.00%	0.00%	#N/A	#N/A
Sub-Total Amortization		39,585	39,585	39,585	-	-	0.00%	0.00%		
Taxes Other than Income										
408.2-Property Taxes	Corporate forecast	186,751	195,116	200,621	8,365	5,504	4.48%	2.82%	#N/A	#N/A
408.3-Payroll Taxes	Corporate forecast	27,550	28,238	28,763	688	525	2.50%	1.86%	#N/A	#N/A
Sub-Total Taxes Other than Income		214,302	223,355	229,384	9,053	6,029	4.22%	2.70%		

Amounts in thousands

Account Title	Include	2010	2011	2012	2013	2014	5-yr CAGR	Pct of Total
1. POWER PRODUCTION EXPENSES								
A. Steam Power Generation								
Operation								
Operation Supervision and Engineering (500)	X	5,043	5,000	4,804	5,015	5,521	2.29%	
Fuel (501)		-	-	-	-	-		
Steam Expenses (502)	X	21,921	21,087	18,422	17,869	19,381	-3.03%	
Steam from Other Sources (503)		-	-	-	-	-		
(Less) Steam transferred Cr. (504)		-	-	-	-	-		
Electric Expenses (505)	X	3,921	4,532	4,410	3,881	1,945	-16.08%	
Misc Steam Power Expenses (506)	X	16,856	18,293	16,876	16,196	18,960	2.99%	
Rent (507)	X	3,908	2,713	2,791	2,604	2,417	-11.32%	
Allowances (509)		-	-	-	-	-		
Total Operations		**51,649**	**51,624**	**47,304**	**45,564**	**48,225**	**-1.70%**	
Maintenance								
Maintenance Supervision and Engineering (510)	X	1,446	1,370	1,695	1,958	1,668	3.64%	
Maintenance of Structures (511)	X	5,860	9,845	7,170	6,393	3,698	-10.87%	
Maintenance of Boiler Plant (512)	X	33,032	33,932	33,085	37,219	38,038	3.59%	
Maintenance of Electric Plant (513)	X	7,618	6,382	9,885	14,503	5,621	-7.32%	
Maintenance of Misc Steam Plant (514)	X	12,150	13,131	12,999	12,949	14,964	5.34%	
Total Maintenance		**60,106**	**64,660**	**64,834**	**73,023**	**63,988**	**1.58%**	
Total Power Production Expenses-Steam Power		**111,755**	**116,284**	**112,138**	**118,587**	**112,213**	**0.10%**	**13%**
B. Nuclear Power Generation								
Operation								
Operation Supervision and Engineering (517)	X	63,761	58,983	59,610	67,723	59,853	-1.57%	
Fuel (518)		-	-	-	-	-		
Coolants and Water (519)	X	6,096	6,076	6,476	6,724	7,713	6.06%	
Steam Expenses (520)	X	31,812	38,294	38,554	40,893	44,225	8.58%	
Steam from Other Sources (521)		-	-	-	-	-		
(Less) Steam Transferred-Cr (522)		-	-	-	-	-		
Electric Expenses (523)	X	2,230	1,730	2,019	2,468	2,882	6.62%	
Misc Nuclear Power Expenses (524)	X	100,737	108,221	110,809	116,096	123,097	5.14%	
Rents (525)	X	4,580	9,006	8,577	9,109	9,555	20.18%	
Total Operation		**209,216**	**222,310**	**226,045**	**243,014**	**247,325**	**4.27%**	
Maintenance								
Maintenance Supervision and Engineering (528)	X	9,307	10,121	11,138	14,053	7,560	-5.07%	
Maintenance of Structures (529)	X	557	534	611	525	135	-29.81%	
Maintenance of Reactor Plant Equipment (530)	X	17,066	28,906	28,202	28,548	38,051	22.20%	
Maintenance of Electric Plant (531)	X	22,723	11,526	10,719	13,471	16,150	-8.18%	
Maintenance of Misc Nuclear Plant (532)	X	21,594	24,676	22,715	25,719	29,527	8.14%	
Total Maintenance		**71,248**	**75,763**	**73,384**	**82,316**	**91,424**	**6.43%**	
Total Power Production Expense-Nuc Power		**280,463**	**298,073**	**299,429**	**325,330**	**338,749**	**4.83%**	**36%**
C Hydraulic Power Generation								
Operation								
Operation Supervision and Engineering (535)	X	0	(1)	1	1	30	304.58%	
Water for Power (536)	X	(0)	(0)	-	(0)	-	-100.00%	
Hydraulic Expense (537)	X	3	1	0	7	0	-42.20%	
Electric Expenses (538)	X	203	172	167	174	16	-47.16%	
Misc Hydraulic Power Generation Expenses (539)	X	131	167	149	111	287	21.62%	
Rents (540)	X	9	16	18	17	40	45.29%	
Total Operation		**347**	**355**	**336**	**310**	**373**	**1.85%**	
Maintenance								
Maintenance Supervision and Engineering (541)	X	1	0	3	18	4	41.41%	
Maintenance of Structures (542)	X	45	53	66	85	6	-39.00%	
Maintenance of Reservoirs, Dams and Waterways (54	X	62	38	142	118	(3)	0.00%	
Maintenance of Electric Plant (544)	X	99	11	24	158	79	-5.45%	
Maintenance of Misc Hydraulic Plant (545)	X	6	3	5	4	47	68.27%	
Total Maintenance		**214**	**105**	**240**	**382**	**133**	**-11.15%**	
Total Power Production Expenses-Hydraulic Power		**560**	**460**	**576**	**692**	**506**	**-2.51%**	**0.1%**

Amounts in thousands

Account Title	Include	2010	2011	2012	2013	2014	5-yr CAGR	Pct of Total
D. Other Power Generation								
Operation								
Operation Supervision and Engineering (546)	X	1,748	1,439	1,079	1,091	1,971	3.06%	
Fuel (547)		-	-	-	-	-		
Generation Expenses (548)	X	5,495	5,176	4,829	4,997	6,890	5.82%	
Misc Other Power Generation Expenses (549)	X	5,182	5,377	5,513	4,932	7,838	10.90%	
Rents (550)	X	1,270	1,174	1,096	1,044	1,090	-3.74%	
Total Operation		**13,694**	**13,167**	**12,517**	**12,063**	**17,788**	**6.76%**	
Maintenance								
Maintenance Supervision and Engineering (551)	X	271	281	455	556	306	3.03%	
Maintenance of Structures (552)	X	5,218	3,729	3,722	2,748	1,848	-22.86%	
Maintenance of Generating and Electric Plant (553)	X	11,086	12,338	11,399	11,991	11,228	0.32%	
Maint. of Misc Other Power Generation Plant (554)	X	407	1,052	1,309	1,237	2,010	49.03%	
Total Maintenance		**16,983**	**17,400**	**16,885**	**16,531**	**15,392**	**-2.43%**	
Total Power Production Expenses-Other Power		**30,677**	**30,567**	**29,402**	**28,594**	**33,180**	**1.98%**	**4%**
E. Other Power Supply Expenses								
Purchased Power (555)		-	-	-	-	-		
System Control and Load Dispatching (556)		-	-	-	-	-		
Other Expenses (557)		-	-	-	-	-		
Total Other Power Supply Exp		**-**	**-**	**-**	**-**	**-**		
Total Power Production Expenses		**423,456**	**445,384**	**441,545**	**473,204**	**484,648**	**3.43%**	
2. TRANSMISSION EXPENSES								
Operation								
Operation, Supervision and Engineering (560)	X	6,523	7,094	7,555	9,703	8,094	5.54%	
Load Dispatching (561)	X	11	-	-	-	-	-100.00%	
Load Dispatch-Reliability	X	86	70	41	39	61	-8.37%	
Load Dispatch-Monitor and Operate Transm. System	X	4,706	4,872	4,095	4,153	4,530	-0.95%	
Load Dispatch-Transmission Service and Scheduling	X	42	44	45	43	18	-18.74%	
Scheduling, System Control and Dispatch Services	X	5,803	6,629	6,512	5,700	6,298	2.07%	
Reliability, Planning and Standards Development	X	230	321	449	411	710	32.55%	
Transmission Service Studies	X	-	34	58	(41)	27		
Generation Interconnection Studies	X	8	(146)	(8)	47	2	-30.45%	
Reliability, Planning and Standards Development Servi	X	417	1,990	2,070	2,306	2,240	52.21%	
Station Expenses (562)	X	1,004	1,328	1,368	1,330	1,052	1.17%	
Overhead Line Expenses (563)	X	1,626	1,796	2,855	2,085	2,512	11.50%	
Underground Line Expenses (564)	X	13	10	7	4	-	-100.00%	
Transmission of Electricity by Others (565)		-	-	-	-	-		
Misc Transmission Expenses (566)		-	-	-	-	-		
Rents (567)	X	2,525	1,722	1,869	1,947	1,636	-10.29%	
Total Operation		**22,995**	**25,765**	**26,916**	**27,727**	**27,178**	**4.27%**	
Maintenance								
Maintenance Supervision and Engineering (568)	X	146	215	139	149	71	-16.39%	
Maintenance of Structures (569)	X	28	14	5	-	-	-100.00%	
Maintenance of Computer Hardware	X	-	-	-	-	-		
Maintenance of Computer Software	X	-	-	-	-	-		
Maintenance of Communication Equipment	X	-	-	-	-	-		
Maintenance of Misc Regional Transmission Plant	X	-	-	-	-	-		
Maintenance of Station Equipment (570)	X	6,050	5,148	6,057	6,344	8,137	7.69%	
Maintenance of Overhead Lines (571)	X	6,173	6,576	6,544	7,406	6,701	2.08%	
Maintenance of Underground Lines (572)	X	0	11	212	6	198	1026.62%	
Maintenance of Misc Transmission Plant (573)	X	389	249	(95)	2	106	-27.70%	
Total Maintenance		**12,785**	**12,214**	**12,861**	**13,907**	**15,214**	**4.44%**	
Total Transmission Expenses		**35,780**	**37,978**	**39,777**	**41,635**	**42,392**	**4.33%**	**5%**

Amounts in thousands

Account Title	Include	2010	2011	2012	2013	2014	5-yr CAGR	Pct of Total
3. DISTRIBUTION EXPENSES								
Operation								
Operation Supervision and Engineering (580)	X	7,660	8,085	8,301	8,522	7,460	-0.66%	
Load Dispatching (581)	X	5,477	5,612	5,596	5,425	6,394	3.94%	
Station Expenses (582)	X	2,506	2,594	2,298	2,236	1,620	-10.34%	
Overhead Line Expenses (583)	X	938	481	733	1,004	1,514	12.73%	
Underground Line Expenses (584)	X	5,556	5,462	4,508	4,507	7,046	6.12%	
Street Lighting and Signal System Expenses (585)	X	1,710	1,717	1,481	2,197	1,708	-0.04%	
Meter Expenses (586)	X	2,294	2,171	2,215	2,612	2,249	-0.50%	
Customer Installation Expenses (587)	X	2,221	1,859	2,255	1,716	3,343	10.76%	
Misc Expenses (588)	X	13,780	14,094	13,784	13,736	13,216	-1.04%	
Rents (589)	X	2,506	3,697	3,525	3,297	3,232	6.57%	
Total Operation		**44,649**	**45,773**	**44,697**	**45,252**	**47,782**	**1.71%**	
Maintenance								
Maintenance Supervision and Engineering (590)	X	573	654	646	273	486	-4.02%	
Maintenance of Structures (591)	X	-	-	-	0	-		
Maintenance of Station Equipment (592)	X	8,023	6,452	6,666	8,188	7,554	-1.50%	
Maintenance of Overhead Lines (593)	X	32,677	33,850	32,217	38,702	31,989	-0.53%	
Maintenance of Underground Lines (594)	X	8,633	9,186	9,679	9,918	9,729	3.03%	
Maintenance of Line Transformation (595)	X	1,681	1,999	2,560	2,689	2,164	6.52%	
Maintenance of Street Lighting (596)	X	1,312	1,362	1,215	1,258	1,051	-5.40%	
Maintenance of Meters (597)	X	35	44	114	120	108	32.63%	
Maintenance of Misc Distribution Plant (598)	X	3	2	3	38	1	-18.58%	
Total Maintenance		**52,937**	**53,551**	**53,101**	**61,187**	**53,081**	**0.07%**	
Total Distribution Expenses		**97,586**	**99,323**	**97,798**	**106,439**	**100,863**	**0.83%**	**12%**
4. CUSTOMER ACCOUNTS EXPENSES								
Operations								
Supervision (901)	X	132	109	121	154	108	-4.86%	
Meter Reading Expenses (902)	X	17,037	16,121	14,672	14,864	15,330	-2.61%	
Customer Record and Collection Expenses (903)	X	22,717	23,287	23,096	22,250	22,351	-0.40%	
Uncollectible Accounts (904)	X	10,375	11,343	8,029	10,073	11,431	2.45%	
Misc Customer Accounts Expenses (905)	X	71	58	52	0	-	-100.00%	
Total Customer Accounts Expenses		**50,332**	**50,918**	**45,970**	**47,340**	**49,220**	**-0.56%**	**6%**
5. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES								
Operations								
Supervision (907)	X	-	-	-	-	-		
Customer Assistance Expenses (908)		-	-	-	-	-		
Informational and Instructional Expenses (909)	X	1,744	1,447	1,538	1,014	792	-17.91%	
Misc Customer Service and Informational Expenses (91	X	-	-	-	-	-		
Total Cust Service and Information Expenses		**1,744**	**1,447**	**1,538**	**1,014**	**792**	**-17.91%**	**0%**
6. SALES EXPENSES								
Operations								
Supervision (911)	X	-	-	-	-	-		
Demonstrating and Selling Expenses (912)	X	87	51	64	16	24	-27.72%	
Advertising Expense (913)	X	-	-	-	-	-		
Misc Sales Expenses (916)	X	-	-	-	-	-		
Total Sales Expenses		**87**	**51**	**64**	**16**	**24**	**-27.72%**	**0%**

Amounts in thousands

Account Title	Include	2010	2011	2012	2013	2014	5-yr CAGR	Pct of Total
7. ADMINISTRATIVE AND GENERAL EXPENSES								
Operations								
Administration and General Salaries (920)	X	49,881	52,382	51,060	54,186	59,036	4.30%	
Office Supplies and Expenses (921)	X	35,265	33,708	34,163	44,113	51,198	9.77%	
(Less) Administrative Expenses Transferred-Credit (922	X	(13,824)	(30,880)	(18,900)	(23,736)	(35,873)	26.92%	
Outside Services Employed (923)	X	12,219	8,294	13,748	17,530	21,176	14.74%	
Property Insurance (924)	X	7,280	8,365	9,418	8,402	9,092	5.72%	
Injuries and Damage (925)	X	13,593	14,343	13,876	13,215	13,551	-0.08%	
Employee Pensions and Benefits (926)	X	61,623	62,094	77,468	71,901	76,283	5.48%	
Franchise Requirements (927)	X	-	-	-	-	-		
Regulatory Commission Expenses (928)	X	5,825	5,424	6,839	14,231	7,257	5.65%	
(Less) Duplicate charges-Cr (929)	X	(3,274)	(3,280)	(2,772)	(3,499)	(5,088)	11.65%	
General Advertising Expenses (930.1)	X	4,618	5,023	4,779	5,570	5,418	4.08%	
Misc General Expenses (930.2)	X	-	-	-	-	-		
Rents (931)	X	12,809	22,580	17,849	19,275	26,277	19.68%	
Total Operation		**186,015**	**178,053**	**207,527**	**221,185**	**228,327**	**5.26%**	
Maintenance								
Maintenance of General Plant (935)	X	424	622	282	609	1,223	30.32%	
Total Admin and General Expenses		**186,439**	**178,676**	**207,809**	**221,794**	**229,550**	**5.34%**	**24%**
Total Elec Op and Maintenance Expenses		**795,424**	**813,778**	**834,501**	**891,443**	**907,489**	**3.35%**	**100%**
Other Categories: Minimal impact, no Global Insights CAGR available		2,392	1,958	2,178	1,722	1,322	**-13.78%**	**0%**

EXPENSE SUMMARY BY FERC GROUP
Amounts in dollars

Line No.	FERC Group	2010 Budget	2011 Budget	2012 Budget	2013 Budget	2014 Budget	3-yr CAGR	5-yr CAGR
1	Steam	112,680,898	120,167,635	117,916,690	117,887,544	115,937,695	-0.84%	0.71%
2	Nuclear	271,024,150	285,074,873	296,419,390	306,543,360	349,587,987	8.60%	6.57%
3	Hydro	515,302	558,720	562,597	537,192	510,398	-4.75%	-0.24%
4	Other Production	34,435,503	34,153,970	32,055,491	28,210,155	29,867,340	-3.47%	-3.50%
5	Transmission	36,817,666	39,001,292	40,338,659	44,400,738	42,981,827	3.22%	3.95%
6	Distribution	95,319,259	92,904,282	93,847,227	96,728,524	106,005,025	6.28%	2.69%
7	Customer Acct, Service, Sales	59,232,948	55,789,951	52,774,538	52,203,808	50,096,155	-2.57%	-4.10%
8	A&G	173,966,203	187,661,831	194,627,690	215,247,038	227,008,471	8.00%	6.88%
9								
10	TOTAL Excluding Line 12	783,991,928	815,312,554	828,542,282	861,758,359	921,994,898	5.49%	4.14%
11								
12	Fuel, purchased power, shared transmission, CIP	1,545,765,196	1,575,238,497	1,623,069,352	1,606,277,258	1,626,112,626	0.09%	1.27%
13								
14	TOTAL	2,329,757,124	2,390,551,051	2,451,611,634	2,468,035,617	2,548,107,524	1.95%	2.26%

Notes:

Full detail of individual FERC Account provided on CD.
Budget data is not adjusted for regulatory treatment.

Northern States Power Company
Electric Utility - State of Minnesota
EXPENSE SUMMARY BY FERC GROUP
Amounts in dollars

Line No.	FERC Group	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Actual	3-yr CAGR	5-yr CAGR
1	Steam Power Generation	111,755,028	116,284,140	112,137,997	118,587,098	112,213,070	0.03%	0.10%
2	Nuclear Power Generation	280,463,288	298,073,479	299,428,757	325,330,446	338,748,763	6.36%	4.83%
3	Hydraulic Power Generation	560,444	459,714	575,977	691,874	506,173	-6.26%	-2.51%
4	Other Production	30,676,911	30,567,153	29,402,221	28,594,326	33,180,370	6.23%	1.98%
5	Transmission Expense	35,779,928	37,978,413	39,777,251	41,634,606	42,392,014	3.23%	4.33%
6	Distribution Expense	97,586,248	99,323,246	97,797,873	106,439,481	100,863,197	1.56%	0.83%
7	Customer Acct, Service, Sales	52,163,319	52,416,507	47,572,086	48,370,686	50,035,808	2.56%	-1.04%
8	A&G Expense	186,438,557	178,675,758	207,809,086	221,794,210	229,549,999	5.10%	5.34%
9								
10	TOTAL Excluding Line 12	795,423,722	813,778,410	834,501,247	891,442,727	907,489,394	4.28%	3.35%
11								
12	Fuel, purchased power, shared transmission, CIP	1,553,551,414	1,540,405,381	1,542,521,023	1,624,042,818	1,593,509,598	1.64%	0.64%
13								
14	TOTAL	2,348,975,136	2,354,183,791	2,377,022,271	2,515,485,545	2,500,998,992	2.57%	1.58%

Notes:

Full detail of individual FERC Account provided on CD.
Actual data is not adjusted for regulatory treatment.

Line No.	FERC Group	2011 Approved	2013 Approved	2014 Approved	3-yr CAGR
1	Steam Power Generation	118,871,791	117,887,544	120,316,783	0.61%
2	Nuclear Power Generation	283,360,012	306,543,360	346,140,358	10.52%
3	Hydraulic Power Generation	558,720	(956,808)	510,432	-4.42%
4	Other Production	29,644,311	28,210,155	28,807,413	-1.42%
5	Transmission Expense	26,476,292	7,346,335	(18,414,625)	0.00%
6	Distribution Expense	93,346,282	96,727,687	103,317,432	5.21%
7	Customer Acct, Service, Sales	52,656,951	50,924,186	48,902,347	-3.63%
8	A&G Expense	164,576,840	183,933,817	190,740,935	7.66%
9					
10	TOTAL Excluding Line 12	769,491,199	790,616,276	820,321,075	3.25%
11					
12	Fuel, purchased power, shared transmission, CIP	1,567,926,601	1,569,659,325	1,594,671,266	0.85%
13					
14	TOTAL	2,337,417,800	2,360,275,601	2,414,992,341	1.65%

Notes:
Full detail of individual FERC Account provided on CD.

Price Indices

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Consumer Price Index[1]	2.367	2.371	2.414	2.469	2.532	2.593	2.644	2.704	2.774	2.849	2.922	2.991
Employment Cost Index[1]	1.212	1.244	1.278	1.315	1.356	1.400	1.445	1.492	1.541	1.592	1.645	1.699
GDP Price Index[1]	108.320	109.531	111.604	113.653	115.673	117.811	120.034	122.393	124.916	127.547	130.185	132.858
Producers Price Index[1]	2.003	1.923	1.946	1.995	2.044	2.092	2.122	2.163	2.224	2.290	2.347	2.395
Corporate Escalation Index[2]	1.102	1.087	1.106	1.136	1.167	1.199	1.225	1.255	1.293	1.333	1.371	1.407
GDP Price Deflator[3]	1.080	1.100	1.120	1.140	1.160	1.190	1.210	1.240	1.260	1.290	1.310	1.340

Year-Over-Year Growth Rates

		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Consumer Price Index			0.171%	1.799%	2.287%	2.547%	2.406%	1.978%	2.258%	2.587%	2.716%	2.563%	2.370%
Employment Cost Index			2.673%	2.696%	2.937%	3.115%	3.213%	3.212%	3.229%	3.298%	3.315%	3.320%	3.325%
GDP Price Index			1.119%	1.892%	1.836%	1.777%	1.849%	1.887%	1.965%	2.062%	2.106%	2.068%	2.053%
Producers Price Index			-4.013%	1.205%	2.513%	2.473%	2.323%	1.434%	1.927%	2.818%	2.977%	2.485%	2.046%
Corporate Escalation Index			-1.389%	1.813%	2.694%	2.737%	2.690%	2.178%	2.474%	3.028%	3.117%	2.843%	2.596%
GDP Price Deflator			1.852%	1.818%	1.786%	1.754%	2.586%	1.681%	2.479%	1.613%	2.381%	1.550%	2.290%
PCE Inflation[4]	LOW		0.6%	1.6%	1.9%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
PCE Inflation[4]	HIGH		0.8%	1.9%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
Core PCE Inflation[4]	LOW		1.3%	1.6%	1.9%								
Core PCE Inflation[4]	HIGH		1.4%	1.9%	2.0%								

Sources:

1 Global Insight U.S. Macro Forecasts, July 2015
2 Forecast based on Global Insight employment cost and producer price U.S. 2010 = 1.0. Labor weighted at 40%, non-labor weighted at 60%
3 Economic Outlook No. 95 – Long-Term Baseline Projections, Organisation for Economic Cooperation and Development, May 2014.
http://stats.oecd.org/Index.aspx?DataSetCode=EO95_LTB#
4 Central tendency value in Table 1. Economic projects of Federal Reserve Board members and Federal Reserve Bank presidents, July 15, 2015.
http://www.federalreserve.gov/monetarypolicy/files/20150715_mprfullreport.pdf

Nothern States Power Company
Electric Utility - State of Minnesota
2016-2020 COST DRIVERS
Amounts in $ millions

		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
		13-868 Outcome	**3 year plan + 2 years of forecast**						**Year over Year Change**				
		2014 TY +	**15-826**					'16-'20	2016 TY over	2017 Plan over	2018 Plan over	2019 Fcst over	2020 Fcst over
		2015 Step	2016 Test Year	2017 Plan Year	2018 Plan Year	2019 Fcst Year	2020 Fcst Year	CAGR	last case	2016 Test	2017 Plan	2018 Plan	2019 Fcst
1	**Capital-Related**												
2	Nuclear (excl Monti LCM/EPU & PI Unit 2 LCM)	157.0	197.3	209.2	219.8	239.3	249.4	6.0%	40.3	11.9	10.6	19.6	10.1
3	*Monticello LCM/EPU*	40.9	52.1	50.5	49.0	47.5	46.1	-3.0%	11.2	(1.6)	(1.5)	(1.5)	(1.5)
4	*PI Unit 2 LCM*	2.2	7.7	7.4	7.1	6.8	6.5	-4.1%	5.5	(0.3)	(0.3)	(0.3)	(0.3)
5	Energy Supply	207.7	203.8	201.6	216.2	232.5	240.4	4.2%	(3.8)	(2.2)	14.5	16.3	7.9
6	Wind (excl PV & Border)	22.5	17.8	16.1	16.6	23.3	25.5	9.5%	(4.8)	(1.6)	0.5	6.7	2.2
7	*Pleasant Valley & Border Winds*	9.1	26.4	18.0	13.7	10.2	7.0	-28.2%	17.3	(8.4)	(4.3)	(3.5)	(3.1)
8	Transmission net of TCR	169.7	188.1	181.3	191.1	222.4	243.8	6.7%	18.4	(6.8)	9.8	31.3	21.4
9	Distribution	235.6	248.2	257.4	267.5	278.2	291.8	4.1%	12.6	9.2	10.1	10.8	13.6
10	General & Intangible	88.3	114.1	125.1	128.9	130.8	130.6	3.4%	25.8	11.0	3.8	1.9	(0.2)
11	*Theoretical Reserve (13-868 rate moderation)*	(58.5)	(32.5)	18.6	18.6	18.6	18.6	NA	26.0	51.0	(0.0)	(0.0)	0.1
12	Other Rate Base	10.6	7.9	8.2	8.3	8.7	9.6	4.9%	(2.7)	0.2	0.2	0.4	0.9
13	NOL and Fed Tax Items	22.3	16.0	(8.6)	(15.1)	(22.7)	(31.0)	NA	(6.3)	(24.5)	(6.5)	(7.6)	(8.3)
14	Property Taxes	146.0	176.2	183.8	188.9	194.1	195.6	2.6%	30.2	7.6	5.2	5.2	1.5
15	*ROE*	-	20.0	19.8	19.7	19.7	20.0	0.0%	20.0	(0.2)	(0.1)	0.1	0.3
16	TOTAL Capital-Related	1,053.4	1,243.2	1,288.5	1,330.2	1,409.5	1,454.0	4.0%	189.8	45.3	41.7	79.3	44.5
17													
18	**O&M**												
19	Nuclear (excl Outage Amortization)	221.4	222.9	226.7	230.4	232.7	236.0	1.4%	1.5	3.8	3.8	2.2	3.3
20	*Outage Amortization*	66.0	51.1	51.6	51.3	49.5	48.9	-1.1%	(14.9)	0.5	(0.3)	(1.8)	(0.6)
21	Energy Supply	161.1	165.4	168.7	172.7	170.7	175.6	1.5%	4.4	3.3	4.0	(2.0)	4.9
22	Transmission	37.9	40.3	40.9	41.7	38.8	39.3	-0.6%	2.5	0.6	0.8	(2.9)	0.5
23	Distribution (MN only)	103.0	107.7	109.7	112.4	110.8	111.7	0.9%	4.7	2.1	2.7	(1.6)	0.9
24	Customer Acctg, Info, Sales	49.9	50.3	51.0	51.8	51.6	52.4	1.0%	0.4	0.6	0.9	(0.3)	0.9
25	A&G and Other O&M	197.3	216.6	221.4	227.5	235.5	239.2	2.5%	19.3	4.8	6.1	8.0	3.8
26	Amortizations	1.8	1.1	1.1	1.1	-	-	-100.0%	(0.7)	0.0	-	(1.1)	-
27	Payroll Taxes	29.4	27.6	28.2	28.8	29.9	30.5	2.6%	(1.9)	0.7	0.5	1.1	0.6
28	TOTAL O&M	867.7	883.0	899.3	917.7	919.4	933.6	1.4%	15.3	16.3	18.4	1.7	14.2
29													
30	**Margins**												
31	Retail Revenue & COGS	(2,001.0)	(2,015.4)	(2,016.2)	(2,017.2)	(2,027.6)	(2,038.6)	0.3%	(14.4)	(0.8)	(0.9)	(10.5)	(10.9)
32	*Purchase Demand*	131.2	113.4	109.7	106.3	107.6	107.9	-1.2%	(17.8)	(3.7)	(3.4)	1.3	0.3
33	*DOE Payment (13-868 rate moderation)*	(25.7)	-	-	-	-	-	NA	25.7	-	-	-	-
34	Non-Retail Revenue	(25.5)	(29.6)	(34.6)	(40.0)	(29.3)	(29.2)	-0.3%	(4.0)	(5.1)	(5.3)	10.7	0.0
35	TOTAL Margins	(1,921.0)	(1,931.6)	(1,941.1)	(1,950.8)	(1,949.3)	(1,959.9)	0.4%	(10.5)	(9.6)	(9.6)	1.5	(10.6)
36													
37	**TOTAL Deficiency**	**-**	**194.612**	**246.667**	**297.133**	**379.622**	**427.677**		**194.612**	**52.055**	**50.466**	**82.489**	**48.056**
38	implied % revenue change over 2016 present revenues								6.4%	1.7%	1.7%	2.7%	1.6%

Amounts in millions

	A	B		C = A * (1+B)	D	E = C * (1+D)	F	G = E * (1+F)	H	I = G * (1+H)
	2016 TY[1]	Growth Rate		2017	Growth Rate	2018	Growth Rate	2019	Growth Rate	2020
Capital-related[5]	1,243	4.0%	2	1,293	4.0%	1,345	4.0%	1,398	4.0%	1,454
O&M-related	883	2.1%	3	902	2.1%	921	2.1%	941	2.1%	961
Margin-related	(1,932)	0.7%	4	(1,945)	0.7%	(1,959)	0.7%	(1,972)	0.7%	(1,986)
Deficiency, cumulative	195			250		307		367		429
Deficiency, incremental	195			55		57		60		62
Rate increase	6.4%			1.8%		1.9%		2.0%		2.1%

Note	Reference
1	CRB-1, Schedule 13, 2016-2020 Cost Drivers, col. (2), rows 16, 28, 35
2	2016-2020 Forecast Compound Avg Growth Rate (CAGR). CRB-1, Sch 13, col. (7), row 16
3	Composite factor based on Global Insights. CRB-1, Sch 9, Composite Factor
4	2016-2020 Forecast Compound Avg Growth Rate (CAGR). JEM-1, Sch 4. See below.
5	Does not reflect changes in revenue requirements for indexed ROE as discussed by Mr. Coyne

	Sales (MWh)	Customers
2016	30,689,986	1,269,747
2017	30,695,949	1,278,408
2018	30,755,235	1,287,084
2019	30,866,808	1,296,389
2020	31,002,405	1,306,182
CAGR	0.3%	0.7%

PROPOSED COMPLIANCE CALENDAR

(assuming statutory timeline, subject to update as case progresses)

Rate Case Event	Compliance Event	Date
Application filed		11/2/2015
2016 Interim Rates in effect		1/1/2016
	Monthly decoupling deferral calculations begin	1/1/2016
	2015 Jurisdictional Annual Report	5/1/2016
	2015 Incentive Compensation annual compliance report; 2015 NOL annual compliance report	6/1/2016
	2015 AIP, NOL refunds, if any	8/1/2016
	TCR petition for 2017 rates; 2016 TCR roll-in compliance report for rate case adjustment	10/1/2016
2017 Interim Rates in effect		1/1/2017
	2016 actual Sales compliance report; 2016 preliminary actual Property Tax compliance report; 2016 Preliminary Decoupling compliance report	2/1/2017
MPUC Order	(assumes statutory timeline)	3/1/2017
Final Rates Compliance Filing	Final rates compliance for 2017 and 2018 including true-up measurements to-date as adjustments to final rates; 2016 Final Decoupling deferral calculation and Proposed Factors; Proposed interim rate refund or surcharge	4/1/2017
	2016 Jurisdictional Annual Report; 2016 Capital true-up compliance report	5/1/2017
	2016 Incentive Compensation annual compliance report; 2016 NOL annual compliance report	6/1/2017
MPUC Order on Compliance Filing	(typical timeframe after compliance filing)	6/1/2017
2017 Final Rates in effect	Implementation of Decoupling credit/surcharge factors; Final 2016 actual Property Tax compliance	7/1/2017
	Interim refund; AIP and NOL refunds, if any	8/1/2017
2018 Final Rates in effect		1/1/2018
	2017 actual Sales compliance report; 2017 Decoupling compliance report	2/1/2018
	2017 Decoupling refunds/surcharge	4/1/2018

Rate Case Event	Compliance Event	Date
	2017 Jurisdictional Annual Report; 2017 Capital true-up compliance report	5/1/2018
	2017 Incentive Compensation annual compliance report; 2017 NOL annual compliance report	6/1/2018
	2017 Property Tax compliance report	7/1/2018
	Sales, Capital, Property Tax, AIP, NOL and capital true-up net refund/deferral	8/1/2018
	2018 Sales compliance report; 2018 Decoupling compliance report	2/1/2019
	2018 Decoupling refunds/surcharge	4/1/2019
	2018 Jurisdictional Annual Report, 2018 Capital true-up compliance report	5/1/2019
	2018 Incentive Compensation annual compliance report; 2018 NOL annual compliance report	6/1/2019
	2018 Property Tax compliance report	7/1/2019
	Sales, Capital, Property Tax, AIP, NOL and capital true-up net refund/deferral	8/1/2019