BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF SOUTH DAKOTA

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

STAFF MEMORANDUM SUPPORTING SETTLEMENT STIPULATION

DOCKET EL11-019

Commission Staff (Staff) submits this Memorandum in support of the Settlement Stipulation of May 7, 2012, between Staff and Northern States Power Company (NSP or Company) in the above-captioned matter.

BACKGROUND

On June 30, 2011, the Company filed an application with the South Dakota Public Utilities Commission (Commission) seeking an increase in annual base rate revenues of approximately $14,583,000 or a 9.28 percent increase in retail revenue for electric service to customers in its South Dakota retail service territory. NSP is proposing to move the recovery of investments and expenses through the Transmission Cost Recovery (TCR) Rider and Environmental Cost Recovery (ECR) Rider into base rates. This shift in cost recovery is responsible for approximately $680,000 of the $14,583,000 revenue deficiency. The resulting increase in current charges to ratepayers is $13,903,000 or approximately 8.84%.

NSP's proposed increase was based on an historic test year ended December 31, 2010, adjusted for what NSP believes to be known and measurable changes, an 11.0 % return on common equity, and a 8.78 % overall rate of return on rate base. NSP witnesses submitted testimony stating that the increase is needed to: (1) maintain, improve, and replace infrastructure on its system; (2) manage cost increases related to general economic trends, at a time of expected reduced sales growth; and (3) comply with new and increasing regulatory requirements.

The Commission officially noticed NSP's filing on July 7, 2011, and set an intervention deadline of September 9, 2011. No petitions to intervene were filed. On July 20, 2011, the Commission issued an Order of Assessment of Filing Fee and Suspension of Imposition of Tariff. On November 4, 2011, the Company filed its Notice of Intent to Implement Interim Rates based on current rate design for service provided on and after January 2, 2012, pursuant to SDCL 49-34A-17. NSP implemented the interim rate increase at 8.09 percent or approximately $12,717,000, a level lower than the rate increase proposed in the initial application.

On March 13, 2012, after extensive discovery, Staff provided NSP a copy of its revenue requirement determination. Thereafter, Staff and NSP (jointly the Parties) held several settlement discussions in an effort to arrive at a mutually acceptable resolution of the issues presented in NSP's rate filing. Ultimately, the Parties reached an agreement on all issues presented in the case except rate of return and the addition of the Nobles wind farm. The Parties are unable to reach a resolution regarding rate of return and the cost recovery of the Nobles wind farm and will notice these items for Commission consideration.

OVERVIEW OF SETTLEMENT

Staff based its revenue requirement determination on its comprehensive analysis of NSP's filing and the information obtained during discovery. Staff accepted some Company adjustments, made corrections where necessary, modified other adjustments, and rejected those that do not qualify as known and reasonably measurable. Lastly, Staff introduced new adjustments not reflected in NSP's filed case.

Company and Staff positions were discussed thoroughly at the settlement conferences. As a result, some Party positions were modified and others were accepted where consensus was found. Ultimately, the Parties agreed on a comprehensive resolution of all issues except rate of return and the addition of the Nobles wind farm. Staff believes the settlement is based on sound regulatory principles.

Staff and NSP agree NSP's revenue deficiency using Staff's litigation positions for rate of return and the Nobles wind farm is approximately $6,315,000 justifying an approximate 4.02% increase in retail revenue. The revenue requirement and supporting calculations described in this Memorandum and attachments depict Staff's positions regarding all components of NSP's South Dakota jurisdictional revenue requirement.

If the Commission were to accept NSP's litigation positions for rate of return and the Nobles wind farm, Staff and NSP agree NSP's revenue deficiency is $11,886,000 justifying an approximate 7.57% increase in retail revenue.

STAFF OVERVIEW OF SETTLEMENT

Staff's determination of the settlement revenue requirement begins with December 31, 2010, total Company test year costs and allocates total Company amounts to the South Dakota retail jurisdiction. Staff then adjusted the December 31, 2010, test year results for known and measurable post-test year changes. Staff Exhibit___ (BAM-1), Schedule 3 illustrates Staff's determination of NSP's pro-forma operating income under present rates including Staff's litigation positions. Staff Exhibit___ (BAM-2), Schedule 2 illustrates Staff's calculation of NSP's South Dakota retail rate base including Staff's litigation positions, and Staff Exhibit___ (BAM-1), Schedule 2 and Staff Exhibit___ (BAM-2), Schedule 1 summarize the positions. Staff Exhibit___ (BAM-1), Schedule 1 supports NSP's revenue deficiency and total revenue requirement with Staff's litigation positions on rate of return and the Nobles wind farm.

Staff Exhibit___(BAM-4), Schedule 1 supports the revenue deficiency and total revenue requirement with NSP's litigation position for rate of return and the Nobles wind farm. Staff Exhibit___ (BAM-4), Schedule 3 illustrates Staff's determination of NSP's pro-forma operating income with NSP's litigation positions on the contested issues. Staff Exhibit___ (BAM-5), Schedule 2 illustrates Staff's calculation of NSP's South Dakota retail rate base using NSP's litigation positions. Staff Exhibit___ (BAM-4), Schedule 2 and Staff Exhibit___ (BAM-5), Schedule 1 summarize the positions. The adjustments in yellow on Exhibit___ (BAM-4), Schedule 3 and Exhibit___ (BAM-5), Schedule 2 identify the differences in the cost of service as a result of Staff's and NSP's litigation positions on rate of return and the Nobles wind farm.

Unless otherwise noted, all of the changes discussed below are changes from the Company's filed position.

RATE BASE

Average rate base – Both the Company and Staff arrived at a test year average rate base based on an average of the 13 month-end account balances, December 31, 2009, through December 31, 2010.

SFAS 106 PAYGO – Prior to 1993, NSP and other companies accounted for post-retirement benefits other than pensions on a pay-as-you-go ("PAYGO") basis for both accounting and ratemaking purposes. Under the PAYGO method, the amount expensed on the Company's books matches the cost of the benefits provided during the year to retirees. In December 1992, the Financial Accounting Standards Board issued an accounting pronouncement, SFAS 106 – Accounting for Postretirement Benefits Other than Pensions, requiring public companies to account for postretirement benefits other than pensions on an accrual basis rather than PAYGO for financial reporting purposes. Following issuance of the accounting pronouncement, the Commission thoroughly examined the issue and decided to keep South Dakota utilities on the PAYGO accounting method for ratemaking purposes. Thus, in its filing, NSP adjusted its test year financial statements to reflect the PAYGO expense in its South Dakota operating results. The settlement accepts this adjustment.

Monticello Nuclear Plant Life Cycle Management/Extended Power Uprate (LCM/EPU) – The Company's rate filing included test year adjustments for 2011 capital expenditures supporting the Life Cycle Management/Extended Power Uprate (LCM/EPU) projects. Both projects have been approved by the MPUC; the NRC has approved the LCM project while the EPU is still under consideration. The settlement revises the Company's adjustment to reflect actual completed capital costs, accumulated depreciation, and accumulated deferred income taxes through the end of 2011. The adjustment decreases rate base by approximately $73,000.

Prairie Island Nuclear Plant Life Extension Projects – The Company requested test year adjustments for 2011 capital projects supporting the 20-year Prairie Island life extension granted by the NRC. The settlement revises the Company adjustment to reflect actual capital costs, accumulated depreciation, and accumulated deferred income taxes through the end of 2011. The updated life-extension project costs decrease rate base by approximately $598,000.

King Mercury – In Docket EL10-012, the Commission approved cost recovery for the revenue requirements associated with the King generating facility mercury control systems through the ECR Rider. The Company requested to shift cost recovery from the ECR rider to base rates by annualizing the investments and costs associated with the control system placed in-service during December 2010. The settlement accepts this adjustment.

Merricourt – NSP has cancelled a proposed wind project in Merricourt, ND and its rate filing eliminates all related costs. Because the project costs were recorded in the Construction Work In-Progress account that is not a component of rate base in South Dakota, the eliminations are limited to deferred taxes. The settlement accepts this adjustment.

Steam Production Plant Remaining Life - NSP proposed depreciation rate revisions to reflect extensions of the estimated remaining lives and changes in salvage values of four steam production plants – Black Dog Units 3 and 4, Sherco Unit 3, and the refuse-fueled Red Wing and Wilmarth plants. The settlement accepts this adjustment.

Other Production Plant Remaining Life - NSP proposed depreciation rate revisions to reflect reductions in the estimated remaining lives and changes in salvage values of two additional steam production plants – Inver Hills and Riverside. The settlement accepts this adjustment.

Bonus Tax Depreciation – The Tax Relief Act of 2010, which was signed into law in December 2010, extended the "bonus" depreciation tax deduction allowance and allowed for a 100 percent bonus tax depreciation for certain projects placed into service from September 9, 2010, through December 31, 2011. The guidelines issued following enactment of the Tax Relief Act contained provisions that required different treatment for certain items during 2010 than what NSP had reflected on its books. Therefore, it was necessary for NSP to adjust its 2010 financial statements to reflect the new tax guidelines. The settlement accepts the adjustment.

Net Operating Loss - The tax deduction allowance that a utility receives for depreciating a newly acquired asset exceeds the book depreciation expense allowance. This is because an asset is generally depreciated on a straight-line basis over its useful life for financial reporting purposes, but the IRS allows an accelerated depreciation allowance for income tax purposes. While the utility's current tax expense is immediately reduced because of tax depreciation, the utility is required to "normalize" the tax effect of the difference between tax and book depreciation by recording a "deferred tax expense". In this manner, the benefit of tax depreciation is spread over the depreciable life of the asset. Until the asset is retired, however, rate base is reduced by the amount of accumulated deferred taxes.

Primarily because of the 50% and 100% bonus depreciation allowances that have been authorized by Congress over the past couple of years, NSP's tax deductions exceeded its income in 2010 and resulted in a net operating loss for the utility. That is, NSP had tax deductions that it could not use to offset income generated in 2010. It would be unreasonable to credit ratepayers for the increase in accumulated deferred taxes if NSP could not use the tax deduction. NSP, however, will be allowed to carry-forward the unused tax deduction to offset income it generates in future years. Therefore, an adjustment is necessary to reduce the accumulated deferred tax balance to remove the effect of the bonus depreciation tax deductions that NSP could not utilize because of the net operating loss. NSP and Staff agree on the mechanics of the adjustment that is required. However, the required adjustment is dependent upon the pro forma income that is generated by the rate increase and expenses authorized by the Commission in this rate case. Therefore, the precise value of net operating loss adjustment cannot be quantified until the Commission makes a final determination on all of the issues in the case, including the rate of return and Nobles Wind Farm issues that are set for hearing.

Chisago Transmission Line – The Company proposed to remove the Chisago transmission project from the test year as part of its *Remove Riders* adjustment on Exhibit___(TEK-1), Schedule 6a, column 12 and Exhibit___(TEK-1), Schedule 6b, column 34. The Company requested cost recovery of the Chisago transmission project in the pending TCR filing, Docket EL12-035. Since the Chisago transmission project was placed in-service during the latter half of 2010 and a full year of costs and revenues cannot be accurately reflected in the test year, the Company proposed to collect the revenue requirements associated with the Chisago transmission project through the TCR filing. The settlement accepts this adjustment.

Cash Working Capital – The settlement determination modifies NSP's working capital claim by: 1. Including net payment leads and lags for interest on long term debt, depreciation expense, investment tax credit, and deferred income taxes; 2. Modifying lead days to reflect statutory payment dates rather than actual payment dates; 3. Correcting a transposition error regarding the revenue lag and expense lead days for interchange revenues and expenses; 4. Separately identifying the expense lead days for vacation pay; and 5. Recognizing the payment lags associated with tax collections available from sales tax related to the revenue deficiency and employee contributed FICA and federal withholding taxes. NSP and Staff agree on the mechanics of the adjustment that is required. However, the required adjustment is dependent upon the pro forma revenues and expenses that will not be known until the Commission makes a final determination on all of the issues in the case. Therefore, the precise value of the cash working capital adjustment cannot be quantified at this time.

Fox Lake Transmission Line – The Company sold the Lakefield Junction – Fox Lake transmission line (Fox Lake Transmission Line) to ITC Midwest on January 7, 2011. There was no gain or loss as a result of this transaction. This asset was improperly included in the test year as the transmission line is no longer owned by NSP. The settlement determination removes the revenue requirements associated with the Fox Lake Transmission Line. The adjustment decreases rate base by approximately $715,000.

Docket EL09-009 Amortizations – In the Settlement Stipulation approved in Docket EL09-009, the Commission authorized a six year amortization period for the Private Spent Fuel Storage Facility and a five year amortization period for SO2 emission allowance sales. Since the Company filed a rate case within two years of the date rates were implemented, those costs have not been fully amortized. The Company included the 13 point end of month average for the unamortized expenses from December 2009 to December 2010 as a component of other rate base in the test year. The Settlement Stipulation approved in Docket EL09-009 allows the average unamortized balances to be included as a component of other rate base until the costs are fully amortized. The settlement reflects the average unamortized balances as stipulated, decreasing rate base by approximately $336,000.

Depreciation to Reflect 2012 Rates – In a late 2011 Minnesota rate settlement, NSP agreed to numerous adjustments to production, transmission, and distribution depreciation rates based upon an extensive review with the objective of "restoring intergenerational equity and providing rate mitigation benefits to consumers". Also, the Company anticipates that these rates will be supported by the periodic, five-year depreciation study it will file with the MPUC in July 2012. The rate settlement was approved by the presiding Minnesota Administrative Law Judge on February 22, and, with minor modifications, by the MPUC on March 29, 2012. The settlement reflects the application of these Company-supported rates to plant assigned or allocated to South Dakota during the test year. The effect of these changes is to increase rate base by one-half of the $2,273,000 reduction in depreciation expenses, or approximately $1,137,000.

Rate Case Expense – Rate case expense from Docket EL09-009 was amortized over a five year period beginning January 18, 2010. Interim rates in this case were put into effect on January 3, 2012, leaving approximately three more years of cost recovery until the expenses are completely amortized. The Company included the 13 month average, from December 2009 to December 2010, for the unamortized rate case expense from Docket EL09-009 as a component of other rate base in the test year. The settlement reflects the average unamortized balance of rate case expense from Docket EL09-009.

In this proceeding, NSP proposed to amortize $388,100 of direct expenses over a two year period. The Company did not request rate base treatment of the unamortized balance. The settlement allows the average unamortized balance of actual rate case expense through March 31, 2012, as an addition to rate base. The net effect of these changes reduces rate base by approximately $73,000.

Working Capital Updates – The settlement reflects the most recent 13-month average for materials and supplies, fuel stocks, prepayments, and customer advances. The net effect of these changes increases rate base by approximately $578,000.

Monticello "No Single Event" Capital Project - During discovery, the Company proposed an adjustment for a capital addition to the Monticello nuclear unit that was not included in the original application. The No Single Event capital project was placed in-service during July 2011 and was designed to meet the requirements of the "no single act" portions of the NRC's rule change to 10 CFR 73.55, "Requirements for Physical

Protection of Licensed Activities in Nuclear Power Reactors Against Radiological Sabotage". Specifically, under Section 73.55 (i), "Detection and assessment systems", subsection (4):

> *Both alarm must be designed and equipped to ensure that a single act cannot disable both alarm stations prior to detection.*

The capital additions necessary to comply with this provision included:

- Constructing a new search train entrance building and extending out the protected area boundary;
- Installing a new search train building of typical frame style construction along the new protected area perimeter;
- Relocating and/or adding new detection & assessment equipment, including PIDs, microwave, protected area lighting, cameras & poles, cable & conduit, and gates to support the new protected area boundary;
- Relocating the existing search train equipment to the new search train entrance building; and
- Placing the current search train area in an acceptable condition for future remodeling efforts.

The settlement accepts this adjustment as this capital project was necessary to comply with federal law, is non-revenue producing, and qualifies as a known and measurable adjustment. The adjustment increases rate base by approximately $194,000.

Weather Normalized Allocator – The Company proposed an adjustment to reflect the impact on expenses due to the difference between weather normalized demand and energy allocators and actual demand and energy allocators. The settlement revises this adjustment to reflect the rate base portion of the adjustment on the rate base schedules as opposed to including an estimate of the rate base impact as a part of the operating expense adjustment. NSP and Staff agree on the mechanics of the adjustment that is required. However, the required adjustment is dependent upon the pro forma investments, revenues and expenses that are allocated to the South Dakota retail jurisdiction based on energy and demand. Therefore, the precise value of the weather normalized allocator adjustment cannot be quantified until the Commission makes a final determination on all of the issues in the case.

Depreciation Annualization – During discovery, the Company proposed an adjustment to modify the depreciation expense included in the test year from three nuclear plant adjustments. The Monticello LCM/EPU, Prairie Island Life Extension, and Monticello "No Single Event" plant adjustments all included the actual 2011 depreciation expense in the test year. NSP proposed to reflect a full year of depreciation expense based on the actual investment cost. The settlement accepts this adjustment, decreasing rate base by approximately $171,000.

OPERATING INCOME

Weather Normalization – The Company proposed an adjustment to 2010 test year sales and revenues to reflect normal weather based on the 20 year moving average of historical heating degree day (HDD) and temperature humidity index (THI) data. The settlement revises the Company's adjustment to: 1. Calculate the weather effect from heating based on the 30 year National Oceanic and Atmospheric Administration (NOAA) HDD normals developed using the thirty-year period, 1981-2010; 2. Calculate the weather effect from cooling based on normal THI scaled to reflect 30 year NOAA normals by using the ratio of actual CDDs to normal CDDs per NOAA applied to the actual THI; and 3. Include an adjustment to test year fuel expenses. The details for this adjustment can be found on Exhibit_(BAM-3), Schedules 1 through 3. The net effect of these changes reduces operating revenues by approximately $167,000 and reduces operating expenses by approximately $488,000.

Fuel Lag - The Company proposed an adjustment to adjust test year revenues and expenses to an actual 2010 calendar-month basis, eliminating the recovery lag of approximately 2.5 months. The settlement accepts this adjustment.

Fuel Recovery Timing – The Company proposed an increase to operating revenues to reflect the January 2011 accrual reversal of unbilled deferred fuel cost revenues. In September 2010, the Company began accruing revenue for the unbilled deferred fuel cost at the end of the month and recording an accrual reversal at the beginning of the following month. The fuel recovery timing adjustment reflects the January 2011 accrual reversal corresponding to the December 2010 accrual included in the test year. The settlement accepts this adjustment.

Incentive Compensation – The Company proposed an adjustment to eliminate three of the four incentive plans from the test year. The one incentive plan which NSP seeks cost recovery, Annual Incentive Program (AIP), has many performance targets related to corporate, business area, and individual employee performance. The test year AIP amount was revised to reflect a four year average of costs from 2007 through 2010 using a factor based on the differential between targeted compensation and actual payouts.

Staff's primary concern regarding incentive compensation plans relates to the use of financial targets as the threshold for plan payouts. Shareholders are the overwhelming beneficiaries of incentive plans that promote the financial performance of the Company and therefore should be responsible for the cost of such compensation. The settlement modifies NSP's incentive compensation costs by (1) normalizing AIP costs based on actual payouts for performance indicators other than financial for the period of 2007 through 2010; (2) removing AIP compensation paid to non-exempt employees who are no longer eligible for incentive compensation; and (3) including payouts related to four of the nine Environmental Plan targets that were eliminated in the Company's original filing. The net effect of these changes reduces operating expenses by approximately $655,000.

Vegetation Management – The Company proposed to normalize vegetation management expense using a five year average of actual experience from 2006 through

2010 because the expense fluctuates widely from year to year. The settlement reflects a more recent five year average of actual experience from 2007 through 2011. The adjustment reduces operating expenses by approximately $36,000.

Storm Damage – The Company proposed to normalize storm damage expense using a five year average of actual experience from 2006 through 2010 because the expense fluctuates widely from year to year. The settlement reflects a more recent five year average of actual experience from 2007 through 2011. The adjustment increases operating expenses by approximately $8,000.

Claims and Injury Compensation – The Company proposed to normalize claims and injury compensation expense using a five year average of actual experience from 2006 through 2010 because the expense fluctuates widely from year to year. The settlement reflects a more recent five year average of actual experience from 2007 through 2011. The adjustment increases operating expenses by approximately $64,000.

Fuel Expense Write-Off - In 2010, the Company discovered its deferred fuel methodology was incorrect and the balance sheet calculated too large of an asset which had gradually built up over time. To correct the over-stated asset, the Company recorded a write-off to expense in the amount of the excess deferred fuel balance. This adjustment removes this one-time write-off from the test year. The settlement accepts this adjustment.

Advertising – The Company proposed to remove promotional advertisements from the test year. The settlement accepts this adjustment and removes the advertising expenses related to 1. Two advertisements that were erroneously included; 2. The saver switch program that is collected through the Demand Side Management Cost Recovery Tariff; and 3. NSP's 2010 Supplier Diversity Campaign as the advertisements' primary purpose is to enhance the image of the Company. The net effect of these changes reduces operating expenses by approximately $7,000.

Economic Development – The Company proposed to continue the current economic development plan approved by the Commission in the amount of $100,000 shared equally between ratepayers and shareholders. The settlement reflects the continuance of the current plan approved by the Commission.

Interest on Customer Deposits - The Company proposed an adjustment to reflect the interest paid on customer deposits as an expense along with the corresponding reduction to rate base recognizing that customers supplied these funds as opposed to investors. The settlement accepts this adjustment.

Association Dues – The Company proposed an adjustment to remove dues that included a component for lobbying and social activities of the organization. The settlement accepts this adjustment, corrects an error in calculating the dues to exclude, and eliminates dues paid to organizations which promote social and economic development activities. Please see Exhibit___(MAT-1), Schedule 2 for details. The net effect of these changes reduces operating expenses by approximately $7,000.

SFAS 106 PAYGO – Please see the SFAS 106 PAYGO explanation in the Rate Base section. The settlement accepts this adjustment.

Rate Case Expense – In this proceeding, NSP proposed to amortize $388,100 of direct expenses over a two year period. The Company proposed using a two year amortization period to reflect the anticipated time period until the next rate case filing. Although NSP's proposal of a two year amortization is supported by the time elapsed between this case and Docket EL09-009, it was approximately 17 years between rate filings in Docket EL92-016 and Docket EL09-009. Staff's basis for the amortization period is a reasonable estimate of the number of years before the utility is expected to file its next rate case. Since NSP has filed very few rate cases in the past 20 years, it is difficult to look at history as a guide. Considering current economic conditions and forecasted capital investments, the settlement reflects a three year period as a reasonable period of time to expect that the rates established here will remain in effect. To protect both ratepayers and the Company in the event that three years is an inaccurate estimate, the settlement includes a tracking mechanism for the recovery of rate case costs so that the Company neither over recovers nor under recovers these costs.

Since the Parties are unable to resolve their differences on rate of return and the cost recovery of the Nobles wind farm, the Company will incur additional rate case costs presenting the case. The settlement reflects actual rate case expense through March 31, 2012, and additional costs incurred in this proceeding will be deferred until the next rate filing. The deferral accounting method and the resulting creation of a regulatory asset (the deferred balance) shall not preclude Commission review of these amounts for reasonableness for rate recovery in any determination of rates, including both rate filings by the Company and rate reviews initiated by the Commission.

Rate case expense from Docket EL09-009 was amortized over a five year period beginning January 18, 2010. Interim rates in this case were put into effect on January 3, 2012, leaving approximately three more years of cost recovery until the expenses are completely amortized. The settlement combines the unamortized rate case expense from Docket EL09-009 with the actual rate case expense from this rate proceeding, using the same amortization period and tracking mechanism as used for the current rate case costs. Including previous rate case costs in the tracking mechanism ensures that rate case costs from both cases are accounted for and fully recovered. The net effect of these changes reduces operating expenses by approximately $135,000.

Monticello Nuclear Plant Life Cycle Management/Extended Power Uprate (LCM/EPU) – The Company's rate filing included test year adjustments for 2011 capital expenditures supporting the Life Cycle Management/Extended Power Uprate (LCM/EPU) projects. Both projects have been approved by the MPUC; the NRC has approved the LCM project while the EPU is still under consideration. The settlement revises the Company's adjustment to reflect actual depreciation expense, property taxes, deferred income taxes and current income taxes through the end of 2011. The adjustment decreases operating expenses by approximately $190,000.

Prairie Island Nuclear Plant Life Extension Projects – The Company requested test year adjustments for 2011 capital projects supporting the 20-year Prairie Island life extension granted by the NRC. The settlement revises the Company's adjustment to reflect actual depreciation expense, property taxes, deferred income taxes and current income taxes through the end of 2011. The adjustment increases operating expenses by approximately $61,000.

King Mercury – In Docket EL10-012, the Commission approved cost recovery for the revenue requirements associated with the King generating facility mercury control systems through the ECR Rider. The Company requested to shift cost recovery from the ECR rider to base rates by annualizing the investments and costs associated with the control system placed in-service during December 2010. The settlement accepts this adjustment.

Merricourt – NSP has cancelled a proposed wind project in Merricourt, ND and its rate filing eliminates all related costs. Because the project costs were recorded in the Construction Work In-Progress account that is not a component of rate base in South Dakota, the eliminations are limited to deferred taxes. The settlement accepts this adjustment.

Steam Production Plant Remaining Life - NSP proposed depreciation rate revisions to reflect extensions of the estimated remaining lives and changes in salvage values of four steam production plants – Black Dog Units 3 and 4, Sherco Unit 3, and the refuse-fueled Red Wing and Wilmarth plants. The settlement accepts this adjustment.

Other Production Plant Remaining Life - NSP proposed depreciation rate revisions to reflect reductions in the estimated remaining lives and changes in salvage values of two additional steam production plants – Inver Hills and Riverside. The settlement accepts this adjustment.

Bonus Tax Depreciation – The Tax Relief Act of 2010, which was signed into law in December 2010, extended the "bonus" depreciation tax deduction allowance and allowed for a 100 percent bonus tax depreciation for certain projects placed into service from September 9, 2010, through December 31, 2011. The guidelines issued following enactment of the Tax Relief Act contained provisions that required different treatment for certain items during 2010 than what NSP had reflected on its books. Therefore, it was necessary for NSP to adjust its 2010 financial statements to reflect the new tax guidelines. The settlement accepts the adjustment.

Net Operating Loss - Please see the Net Operating Loss explanation in the Rate Base section. The settlement accepts this adjustment.

Union and Non-Union Wage Increases - The Company proposed an adjustment to test year Union labor costs to recognize increases taking place on January 1, 2011, based on contracts in place. The Company also proposed a non-Union test year adjustment for actual increases experienced on March 1, 2010, and 2011. The settlement accepts both adjustments.

Margin Sharing – The Company proposed an adjustment to remove the shareholders' portion of the non-asset based margin sharing arrangement that existed during the test year. The settlement accepts this adjustment.

Wholesale Billing – The Company proposed an adjustment to decrease operating expenses in order to assign additional costs to the wholesale jurisdiction, properly reflecting the costs of providing billing and account management services to wholesale customers. The settlement accepts this adjustment.

Xcel Energy Foundation Administration – The Company proposed to remove the costs associated with the administration of the Xcel Energy Foundation. The Xcel Energy Foundation is in charge of the administration of donations and charitable contributions. The settlement accepts this adjustment.

Employee Expense Reduction – NSP proposed an adjustment to eliminate certain employee expenses (sports events, tickets, sponsorships) which should have been recorded below the line but were not so recorded. The settlement accepts this adjustment.

Pension and Insurance - Following the close of the 2010 test year, NSP received a new actuarial determination of its annual pension expense for 2011. Also for 2011, NSP determined that its insurance expenses for retiree medical, long-term disability and workers compensation will decrease from their 2010 test year levels. The settlement accepts these known and measurable adjustments.

Weather Normalized Allocator – The Company proposed an adjustment to reflect the impact on expenses due to the difference between weather normalized demand and energy allocators and actual demand and energy allocators. The settlement revises this adjustment to reflect the change in other operating revenues due to the weather normalized allocators. NSP and Staff agree on the mechanics of the adjustment that is required. However, the required adjustment is dependent upon the pro forma investments, revenues and expenses that are allocated to the South Dakota retail jurisdiction based on energy and demand. Therefore, the precise value of the weather normalized allocator adjustment cannot be quantified until the Commission makes a final determination on all of the issues in the case.

Rider Removal – The Company requested to remove all revenues collected through the TCR and ECR riders from the test year and move the revenue requirements to base rates. The adjustment also removes the revenue requirements associated with the Chisago transmission project from the test year. The Company proposed to collect the revenue requirements associated with the Chisago transmission project through the pending TCR filing, Docket EL12-035. The settlement accepts this adjustment.

Rounding – The Company proposed an adjustment to reflect potential rounding differences. NSP and Staff agree on the mechanics of the adjustment that is required. However, this adjustment cannot be quantified until the Commission makes a final determination on all of the issues in the case.

Fox Lake Transmission Line – The Company sold the Lakefield Junction – Fox Lake transmission line (Fox Lake Transmission Line) to ITC Midwest on January 7, 2011. There was no gain or loss as a result of this transaction. This asset was improperly included in the test year as the transmission line is no longer owned by NSP. The settlement determination removes the revenue requirements associated with the Fox Lake Transmission Line. The adjustment decreases operating expenses base by approximately $34,000.

Fines – The Company paid fines related to one air quality incident at the King Generating Plant and three incidents of small fish losses as a result of zebra mussel treatments at the Prairie Island Nuclear Generating Unit during 2010. NSP must comply with all applicable laws and fines that result from imprudent management and these fines should not be borne by ratepayers. The settlement removes these expenses, decreasing operating expenses by $1,000.

Property Tax Update - During discovery, the Company proposed an adjustment to reflect the most recent actual property taxes paid. In place of the estimate included in the filing, the settlement reflects the actual 2010 property taxes paid on South Dakota property. The settlement also updates the test year to include the 2011 property taxes paid on Minnesota property owned as of the end of 2010. The most recent actual tax paid on property is more reflective of current operational expenses. The adjustment increases operating expenses by approximately $462,000.

Aviation Expense - The Company included the costs associated with two aircraft in the test year. In rate cases filed before the Minnesota Public Utilities Commission and North Dakota Public Service Commission, the Company only included the costs associated with one aircraft in the test year. In both filings, Company witnesses stated, "After carefully reviewing the costs and benefits associated with these aircraft, we are reducing the costs included in our test year to include only the costs of one of our corporate aircraft. We believe that this adjustment results in a conservative cost in relation to the benefits obtained." The settlement allocates the cost of one aircraft, supported by NSP's analysis of the costs and benefits associated with the aircraft. The adjustment decreases operating expenses by approximately $64,000.

Economic Development Labor – The settlement removes labor expenses associated with economic development activity that the Company did not include in its 2010 economic development plan. This adjustment reduces operating expenses by approximately $43,000.

Energy Efficiency – The settlement removes the conservation and demand side management costs that will be recovered through its Demand Side Management Cost Recovery rider from the test year. This adjustment reduces operating expenses by approximately $230,000.

Interest Synchronization - The settlement synchronizes the tax deduction for interest expense with the weighted cost of long-term debt and the historic test year rate base as adjusted for known and measurable changes. NSP and Staff agree on the mechanics of the adjustment that is required. However, the required adjustment is dependent upon the weighted cost of long-term debt and pro forma rate base. Therefore, the precise value of the interest synchronization adjustment cannot be quantified until the Commission makes a final determination on all of the issues in the case.

Schedule 26 Expenses and Revenue – The settlement reflects an adjustment to remove the Schedule 26 expenses and revenues from the test year so that going forward these expenses and revenues may be addressed in the pending TCR rider, Docket EL12-035. The effect of this adjustment reduces operating revenues by approximately $232,000 and reduces operating expenses by approximately $292,000.

Depreciation to Reflect 2012 Rates – In a late 2011 Minnesota rate settlement, NSP agreed to numerous adjustments to production, transmission, and distribution depreciation rates based upon an extensive review with the objective of "restoring intergenerational equity and providing rate mitigation benefits to consumers". Also, the Company anticipates that these rates will be supported by the periodic, five-year depreciation study it will file with the MPUC in July 2012. The rate settlement was approved by the presiding Minnesota Administrative Law Judge on February 22, and, with minor modifications, by the MPUC on March 29, 2012. The settlement reflects the application of these Company-supported rates to plant assigned or allocated to South Dakota during the test year. The net effect of these changes reduces operating expenses by approximately $2,273,000.

Executive Foreign Travel Expense - The settlement removes expenses for foreign travel by Xcel executives in the amount of approximately $1,000. Such costs are not necessary for safe, adequate and reliable service to South Dakota customers.

Gain on Sale of Emission Allowances - Consistent with the Commission's decision in Dockets EL09-018 and EL10-011, the settlement removes the gain on the sale of emission allowances from the test year so that the gain is not reflected in base rates. One hundred percent of the South Dakota jurisdictional share of the gain on the sale of emission allowances will be credited to the fuel clause rider beginning January 2, 2012. The allocation of emission allowances is directly related to the fuel used in electric generation, and the market price and the number of emission allowances sold can fluctuate so that we cannot accurately reflect the credit in base rates. This adjustment increases operating expenses by approximately $2,000.

Monticello "No Single Event" Capital Project - Please see the Monticello "No Single Event" Capital Project explanation in the Rate Base section. The settlement accepts this adjustment, increasing operating expenses by approximately $71,000.

Depreciation Annualization – During discovery, the Company proposed an adjustment to modify the depreciation expense included in the test year from three nuclear plant adjustments. The Monticello LCM/EPU, Prairie Island Life Extension, and Monticello "No Single Event" plant adjustments all included the actual 2011 depreciation expense in the test year. NSP proposed to reflect a full year of depreciation expense based on the actual investment cost. The settlement accepts this adjustment, increasing operating expenses by approximately $342,000.

Wind Production Tax Credits – NSP receives federal income tax credits based on the actual production from eligible wind projects. Currently, an allowance for these credits, based on the rate case test year wind production, is treated as a reduction in the Company's base rates. Recognizing that wind production is highly variable and unpredictable and that test year conditions are not likely to be repeated, the settlement passes Production Tax Credits (PTCs) on to ratepayers through the Company's Fuel Clause Rider (FCR), as the credits are earned based on actual wind production.

Removing the test year PTCs from the base rate revenue requirement increases the requirement by $551,000; however, under test year conditions, FCR charges would be reduced by that same amount. Under the terms of the settlement, FCR charges in the future will be reduced by the actual amount of the PTCs then earned by NSP.

RATE DESIGN ISSUES

The parties agree in principle on all issues regarding rate design and the class revenue distribution. Tariffs will be filed with the Commission after a decision is rendered on rate of return and the Nobles wind farm. Staff concurred with the changes made by NSP for all rate schedules. The settlement positions reached between Staff and NSP regarding the distribution of the increase and miscellaneous service charge increases are discussed below.

Distribution of the Increase - NSP's rate filing included a class cost of service study ("CCOSS"). NSP's CCOSS showed that under current rates the large commercial and industrial customers have been subsidizing customers in the residential, commercial and street lighting classes. Based on this finding, NSP proposed larger rate increases, on a percentage basis, for the residential, commercial and street lighting classes and a smaller than system-wide average increase for the large commercial and industrial rate class.

The Commission Staff determined that NSP's CCOSS results are largely driven by the "minimum distribution system" approach upon which the Company relied on in order to allocate certain distribution costs (primarily conductors, transformers, and poles) among the rate classes. Under the minimum distribution system approach, the theoretical cost of a hypothetical distribution system composed solely of minimum sized components is allocated among the classes based on the relative number of customers within each rate class. The cost difference between the Company's actual system and the theoretical minimum sized distribution system is allocated using class non-coincident peak demands. The alternative to using the minimum distribution system approach is to allocate all of the costs of the conductors, transformers and poles actually installed on a peak demand basis. Had NSP used the alternate approach rather than the minimum distribution system approach, the CCOSS results would have been much different. That is, the subsidies shown in NSP's CCOSS would have been significantly reduced and/or eliminated completely.

The use of the minimum distribution system approach in CCOSS is controversial and not universally accepted by all state regulatory commissions. Staff does not endorse using the minimum distribution system approach in CCOSS. However, Staff cannot recall any previous rate case in which this issue has been addressed by the Commission. Therefore, for settlement purposes, Staff proposed and NSP agreed to distribute the increased revenue requirement on an equal percentage basis among all the Company's rate classes. A uniform percentage increase for all rate classes represents a reasonable middle ground between the results indicated in NSP's CCOSS using the minimum distribution system approach and a CCOSS using the alternative peak demand method.

Miscellaneous Service Charge Increases – The Company proposed increases to the following service charges: service reconnection charge, dedicated switching service, excess footage charges, and winter construction charges. The settlement revises the request to: 1. Derive the dedicated switching service revenue using the number of hours as opposed to the number of occurrences since the charge is based on an hourly amount; and 2. Reflect a service reconnection charge of $35 as opposed to the Company proposed $50 charge in an effort to avoid rate shock. The adjustment incorporating these two changes is reflected on Exhibit___(BAM-6), Schedule 1. The net effect of these changes reduces other operating revenues by approximately $12,000.

OTHER ISSUES

Nuclear Cost Recovery Rider – NSP withdrew its proposed Nuclear Cost Recovery rider during settlement negotiations.

Non-Asset Based Margins – NSP seeks to profit from energy trading activities, some of which are dependent on utility-owned or controlled power resources whose costs are reflected in utility rates (the so-called "Asset-based" transactions) while others are conducted without the direct support of these assets (Non-asset based transactions). The profit "margins" earned from these on-going activities are shared with ratepayers through the fuel adjustment clause at rates of 100% and 25%, respectively of the margins earned on Asset-based and Non-asset based transactions.

No change is proposed in the 100% sharing arrangement for Asset-based transactions. However, the Settlement increases ratepayers' share of the margins from Non-asset based transactions from 25% to 30% effective January 2, 2012.

Staff recommended the larger sharing rate for Non-asset based transactions after examining the results of two cost studies submitted by NSP in this case pursuant to the Settlement Stipulation in EL09-009. Staff concluded that, based on recent and anticipated experience, the 25% sharing rate would insure that ratepayers are not burdened with the incremental costs but that the 25% rate was insufficient to protect ratepayers from all costs (fully allocated costs) that are reasonably related to the Non-asset based transactions. Staff believed that the studies indicated that a 30% share would provide this protection and that the cost studies should be updated and submitted again in NSP's next rate filing.