PUBLIC UTILITIES COMMISSION
STATE OF SOUTH DAKOTA

Gary Hanson	Chairman
Chris Nelson	Vice Chairman
Kristie Fiegen	Commissioner

IN THE MATTER OF THE PETITION OF NORTHERN STATES POWER COMPANY, A MINNESOTA CORPORATION FOR APPROVAL OF A CREDIT MECHANISM FOR A DEPARTMENT OF ENERGY SETTLEMENT PAYMENT ALONG WITH DEFERRED ACCOUNTING AND APPROVAL TO DEPART FROM ITS FUEL CLAUSE TARIFF, AS NECESSARY.

SDPUC DOCKET NO.: EL11-___

PETITION

INTRODUCTION

Pursuant to S.D. Codified Laws § 49-34A-6, Northern States Power Company, a Minnesota corporation ("Xcel Energy" or the "Company") operating in South Dakota, petitions the South Dakota Public Utilities Commission (the "Commission") for an Order approving a credit mechanism for funds received pursuant to a Settlement ("Settlement") with the United States Department of Energy ("DOE"). As indicated in our July 8, 2011 letter, these Settlement amounts have been recovered for the benefit of ratepayers and we file this Petition for approval to credit the Settlement amounts to our customers. Our goal is to seek an administratively efficient and timely return of the funds to our customers. The gross amount currently available for credit is $99,966,841 on a total NSP system basis, or approximately $4.3 million on a South Dakota jurisdictional basis. In addition, the Company requests that the amount of the credit be net of South Dakota's share of outside legal costs of just over $0.25 million incurred in pursuit of the Settlement and an Order granting deferred accounting be issued on or before December 31, 2011.

The amount to be credited reflects the South Dakota jurisdictional amount of the damages recovered pursuant to the Settlement with the DOE regarding DOE's partial breach of its contract to take spent nuclear fuel beginning January 31, 1998. The nuclear spent fuel storage damages qualifying for compensation by the DOE include the following cost categories:

a. additional pool storage and other plant modifications;

b. dry cask storage and costs directly related to such storage (e.g. internal labor, overhead, operation and maintenance, training and security); and
c. additional property taxes resulting from the on-site dry cask storage or other plant modifications.

The initial payment of $99,966,841 was received on August 1, 2011 and includes damages for nuclear spent fuel storage costs incurred through December 31, 2008. The Company has placed the funds into a separate interest bearing account and will include the interest received in calculating the amount of the credit. The Company requests authority to net $264,420 in litigation expenses incurred through 2009 against the South Dakota jurisdictional amount of $4,285,234.

The Settlement also provides a mechanism for the Company to recover its nuclear spent fuel storage damages incurred from January 1, 2009 through December 31, 2013. We believe that these additional damage payments will total approximately $98 million on a total Company basis, or approximately $4.6 million on a South Dakota jurisdictional basis. These future payments are based on our current estimates and must be approved by the DOE prior to the receipt of any amounts. The first supplemental payment, recovering damages incurred during 2009 and 2010, is expected to be received in the first quarter of 2012. Settlement payments covering the qualified damages incurred by the Company in 2011, 2012 and 2013 are expected to be received by year end of 2012, 2013 and 2014 respectively (assuming the damage claim is approved by the DOE without the need for binding arbitration and the attendant delay).

In the event that the Commission is unable to issue an Order on the appropriate credit mechanism by the end of the year, the Company seeks approval for deferred accounting treatment by December 31, 2011, with recognition that these amounts are to be returned to our South Dakota customers.

Table 1 contains a summary of the Settlement payments and estimated amounts to be credited to South Dakota retail customers.[1]

[1] The 2009 Settlement payment will be reduced by the South Dakota jurisdictional share of the 2009 legal costs to determine amount available for crediting to customers (See Attachment D).

Table 1

	Total Company (NSPM & NSPW)	SD Jurisdiction	Payment Due
Initial Payment Amount	$99,966,841	$4,285,234	Paid August 2, 2011
Less Legal Fees through 2008		$264,420	
		$4,020,814	
Supplemental Payments			
Estimated 2nd Payment	$15,000,000	$685,959	1st Quarter 2012
Less 2009 Legal Fees[2]		$50,558	
		$635,401	
Estimated 3rd Payment	$25,000,000	$1,168,597	Year-End 2012
Estimated 4th Payment	$31,000,000	$1,449,060	Year-End 2013
Estimated 5th Payment	$27,000,000	$1,262,084	Year-End 2014

I. GENERAL FILING INFORMATION

A. Utility Employee Responsible for Filing

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C. Date of Filing and Date Modified Rates Take Effect

Xcel Energy submits this Petition for approval on August 16, 2011. The effective date and method used to credit the Settlement payment is to be determined by the Commission.

[2] South Dakota's retail jurisdictional share of legal fees (See Attachment D).

II. DESCRIPTION AND PURPOSE OF FILING

The Company requests Commission approval of a credit mechanism to flow through to customers funds received pursuant to a Settlement with the DOE. The Company request approval to include the interest earned on the single purpose account established to receive the initial payment and the authority to net the outside legal costs incurred through 2008 against the damages available for credit. The Company also requests an Order authorizing deferred accounting by December 31, 2011 if the Commission has not issued an Order on a credit approach by that time and an Order approving deferred accounting and a departure from the Company's Fuel Clause Tariff, as needed, to support the credit mechanism selected by the Commission.

In support of this filing, Xcel Energy provides:

- History of the case
- Public interest benefits of the Settlement
- A description of the proposed credit mechanism
- A request for deferred accounting and approval of a departure from the Company's Fuel Clause Tariff, as needed, to support the credit mechanism selected by the Commission

III. HISTORY OF THE CASE

The Nuclear Waste Policy Act[3] established a framework for the permanent disposal of high-level radioactive waste.[4] Under the Act and subsequent regulations, utilities are required to enter into Standard Contracts for Disposal of Spent Nuclear Fuel ("Standard Contracts").[5] In exchange for the DOE's commitment to dispose of the spent nuclear fuel, utilities contribute 1.0 mil for every kilowatt-hour of electricity generated by their nuclear power plants to the Nuclear Waste Fund ("NWF").[6] Pursuant to the Standard Contracts, the DOE was required to take title to, transport, and dispose of the spent nuclear fuel beginning no later than January 31, 1998.[7] The DOE has not accepted any spent nuclear fuel to this point. However, it continues to acknowledge its obligation to accept the spent nuclear fuel from Prairie Island and Monticello.

Between 1994 and 1998, the Company had numerous discussions with the DOE in an effort to obtain information about the DOE's plans to begin accepting spent nuclear

[3] 42 U.S.C. §§ 10101 et seq (2006).
[4] 42 U.S.C. § 10131(a)(4).
[5] 10 C.F.R. § 961.11 (2010).
[6] 42 U.S.C. § 10222(a)(2).
[7] 42 U.S.C. § 1022(a)(5)(B).

fuel ("SNF"). By 1998, it was clear that the DOE was denying that it had an obligation to accept SNF and was denying that it had any financial liability for its delay. In 1997, the Company petitioned for a writ of mandamus and obtained a ruling affirming the DOE's unconditional obligation to accept SNF. Shortly thereafter, in 1998, the Company filed suit against the DOE seeking to recover damages stemming from the DOE's partial breach of the Standard Contracts.[8] This first lawsuit sought damages through 2004. The Company filed a second lawsuit for damages through 2008. Xcel Energy's lawsuits were among 74 filed by utilities alleging a partial breach by the DOE.

The Company sought damages on behalf of our customers based on the costs incurred for: a private Independent Spent Fuel Storage Installation ("ISFSI"); an Alternative Storage Facility in Goodhue County; a Minnesota legislatively created biomass mandate; a Minnesota legislatively created Renewable Development Fund ("RDF"); the Minnesota legislatively mandated payments to the Mdewakanton Dakota Tribal Community; and, cost of capital.[9] The United States Court of Federal Claims generally allowed the Company's claims except for the cost of capital (essentially interest on the damages determined from the date the recoverable costs were incurred).[10] The DOE appealed that decision, challenging the Company's right to recover costs for the private ISFSI and any costs that arose out of legislative mandates (i.e. the biomass mandate, RDF, and payments to the Mdewakanton Dakota Tribal Community).[11]

During the same period as the appeal, several decisions were issued by the U.S. Court of Appeals for the Federal Circuit that raised issues concerning some of the factors in the Company's case.[12] In addition, precedent strongly suggested that the Appellate

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[8] The Court in *Maine Yankee Atomic Power Co. v. United States,* determined that DOE was in partial breach, leaving the need to determine damages. *Maine Yankee Atomic Power Co. v. United States*, 225 F.3d 1336, 1343 (3rd Cir. 2000). Where there is a partial breach, Federal law only allows Xcel Energy to sue for past damages. *Indiana Michigan Power Co. v. United States,* 422 F3d. 1369, 1376 (3rd Cir 2005).

[9] *Id.*

[10] *Northern States Power Co. v. the United States,* 78 Fed. Cl. 449 (2007)

[11] Court of Appeals for the Federal Circuit Docket Nos. 2008-5037, 2008-5041.

[12] In *Energy Northwest v. United States,* the Court disallowed any interest payment, adversely affecting the ability of Xcel Energy to improve on the Federal Court of Claim's decision. *See* 641 F.3d 1300 (2011). *Energy Northwest* also established a strict standard for determining damages, requiring that the resulting damages needed to be reasonably foreseeable consequences of the partial breach by the DOE. In *Southern Nuclear Operating Company,* the Court placed the burden of proof on the utility with respect to both the claimed costs and also with respect to DOE's claims that some of the costs would have been incurred even if there had not been a partial breach on the utility. *See* 637 F.3d 1297 (2011).

Court would not support inclusion in the damages award of the costs incurred for the private ISFSI investment or for compliance with Minnesota legislative mandates.[13] At the same time, other changes favored utilities.

Utilities that settled with DOE prior to 2008 will recover costs associated with on-site storage based upon an acceptance rate of approximately 900 metric tons uranium ("MTU")/year. In contrast, our Settlement reflects the recovery of costs based upon the more favorable acceptance rate prescribed by the Federal Circuit in 2008 of approximately 2,650 MTU/year. Under the Settlement, the DOE agreed to reimburse the following fuel storage costs incurred by the Company, and collected through rates from customers, as a result of DOE's failure to remove the spent nuclear fuel and high-level radioactive waste from Prairie Island and Monticello by January 31, 1998:

a) any additional pool storage and other plant modifications;
b) dry casks storage and costs directly related to such storage (e.g. internal labor, and overhead, operation and maintenance, training and security); and
c) additional property taxes resulting from the on-site dry cask storage or other plant modifications.

We note that eight utilities have entered into settlements with the DOE in 2011. This includes PPL Susquehanna LLC and Nebraska Public Power District. Both utilities continue to operate nuclear generating facilities, and both have recently entered into comparable settlements.

IV. THE SETTLEMENT IS IN THE PUBLIC INTEREST

The Company believes the Settlement is in the public interest. The litigation that resulted in the Settlement has spanned more than a decade. During that period, the DOE advocated against any damages, asserting the legal defense of impossibility, and in the alternative, that damages should be significantly limited. In particular, the DOE argued that it was not obligated to take spent fuel more rapidly than was provided for in a DOE developed schedule, and, as a result, the utilities were required to self-provide some storage facilities. Under this theory, cost recovery would have been prevented or significantly reduced.

[13] *See* 422. F.3d at 1376 (concluding the evidence showed that the utility's investment in the private storage facility was speculative and that the high cost of the venture was unforeseeable); *see also Dairyland Power Coop. v. United States,* 2011 WL 2519519 (Fed. Cir. June 24, 2001) (remanding the determination of what portion of the private fuel storage investment was speculative). A similar argument that the legislative mandates were unforeseeable had been presented to the Appellate Court by the DOE.

The Settlement fairly represents the status of current federal law on this issue and, in addition, holds the DOE to higher standards than the DOE had accepted in litigation. In particular, the DOE 's obligations are not limited to a certain level of spent nuclear fuel per year (a position that the DOE has indicted it will forcefully argue in future litigation)[14] and the DOE agrees to damages covering O&M, overhead and other operating costs.[15]

The Settlement also provides a mechanism for the Company to recover its spent nuclear fuel storage damages through December 31, 2013. We believe that the additional damage payments will be approximately $98 million on a total Company basis, or approximately $4.6 million on a South Dakota jurisdictional basis. These are estimates of future payments and must be approved by the DOE prior to the receipt of any amounts. The first supplemental payment, covering 2009 and 2010, is expected to be received in the first quarter of 2012. Payments covering the qualified costs incurred by the Company in 2011, 2012 and 2013 are expected to be received by year end of 2012, 2013 and 2014 respectively (assuming the claim amounts are resolved without the need for binding arbitration and the attendant delay).

Finally, while the Settlement resolves the level of damages due from DOE's partial breach for the nearly sixteen year period between January 31, 1998 to December 31, 2013, it does not limit our right to pursue damages on behalf of our customers against the DOE for costs related to ongoing nuclear waste storage that we incur after December 31, 2013.[16]

V. JURISDICTIONAL ALLOCATIONS

The funds are payable to Northern States Power Company – Minnesota ("NSPM"), and will first be allocated between NSPM and NSP-Wisconsin ("NSPW") Companies. The NSPM portion will be further allocated by jurisdiction (North Dakota, South

[14] In *Rochester Gas and Electric Corp., and R.E. Ginna Nuclear Power Plant, L.L.C., v. United States,* No. 04-118C, filed July 29, 2011, the Court of Federal Claims allowed the DOE to assert the defense of unavoidable in opposition to a demand for damages. No decision on the merits of the defense has occurred.

[15] The proceeds from the Settlement will be in the form of one-time payments for capital and O&M costs recovered in past and current base rates. These costs were not recovered through the fuel clause adjustment.

[16] NSP's Settlement for partial breach in this matter forecloses the remedy of restitution for amounts paid into the Nuclear Waste Fund for the settlement period. However, that alternative remedy would require that the federal government actually provide notice that it does not intend to fulfill its contractual obligations, an event that has not yet occurred nor do we believe is likely to occur. The DOE continues to acknowledge its obligations to accept SNF from Prairie Island and Monticello.

Dakota, Minnesota and wholesale) and then to customer classes. Finally, they will be credited to individual customers.

To allocate between NSPM and NSPW, the Company proposes using an allocation process consistent with how the funds were collected. Nuclear plant production is shared by the two companies through the Interchange Agreement ("IA") based on the IA prescribed demand charge ratio.[17] The initial payment to be received covers costs incurred through 2008, so the Company proposes to use the average IA demand charge ratio in place over the eleven year period (1998-2008) to allocate the initial payment.[18] The second payment covers costs incurred in 2009 and 2010, so we would use the average IA demand charge ratio from those years to allocate the second payment and each of the subsequent payments will use the IA demand charge ratio for that year to allocate that year's payment.

A similar process will be used to allocate to the NSPM jurisdictions. Again, the process is consistent with how the nuclear production costs were collected from the jurisdictions. For the initial payment, the allocation would be based on the average 12 month coincident peak ("12 CP") allocator over the past 11 years to allocate between North Dakota retail, South Dakota retail, Minnesota retail, and wholesale jurisdictions. The second payment will use the 12 CP allocators from 2009 and 2010, and subsequent payments will use the 12 month CP allocators from the respective years.[19] Use of the 12 month CP for jurisdictional allocation is consistent with the collection of the nuclear production costs from the jurisdictions.

The allocation between NSPM and NSPW and the allocation process to the North Dakota jurisdictional level will remain the same regardless of the credit mechanism chosen. See Attachment A for an example of the allocation between NSPM and NSPW and the NSPM jurisdictional allocation.

VI. ALTERNATIVE CREDIT MECHANISMS

A. Analysis of Alternatives

There is no mechanism provided by rule or statute for crediting the DOE payments, therefore, the matter falls under the Commission's general authority for establishing just and reasonable utility rates. S.D. Codified Laws § 49-34A-6.

[17] The Interchange Agreement demand charge ratio is calculated based on 36 month coincident peak: 18 months of actual and 18 month's forecast.

[18] An eleven year period was chose as this is the lawsuit period from breach through 2008 and for which the necessary information is readily available.

[19] See Attachment A for an estimate of cost allocations.

The Company identified three potential mechanisms for Commission consideration that could fairly and efficiently be used to credit the funds to current South Dakota customers. They are:

1) a one-time bill credit;
2) a per kWh credit calculated similar to Fuel Clause Rider ("FCR"); and
3) an offset to the Company's revenue requirement in a rate case.

The one-time credit mechanism applies to existing customer accounts and the FCR and Revenue Requirement credits would apply to future rates. We recognize that previous customers that are no longer on our system may seek a credit for amounts related to their contribution to these costs between 1998 and 2008. However, determining the amount each customer class' contribution to these costs during this long historic period would be extremely difficult; and determining each individual customer's share of these costs would not be possible.[20]

In recognition that customers, due to their individual circumstances, may express concerns related to past cost contributions or the credit mechanism chosen, the Commission could consider the use of future Settlement payments to fund individual claims upon receipt of documentation from a requesting customer. In the alternative, the Commission could set aside a portion of the current Settlement payment for these types of claims and include any amounts not used in future credits.

1. One-Time Bill Credit

A one-time bill credit could be provided within 90 days after the Order approving the use of that mechanism. Using a one-time credit, future Settlement payments could also be made within 90 days of receipt of the payments. This mechanism is the most straightforward and has the advantage of providing customers the benefits of the credit as quickly as possible.[21]

As outlined in the example found in Attachment B, once the credit amounts have been calculated for each jurisdiction, the credit amount by class is determined by

[20] The Company changed billing systems in 2005 and no longer has complete individual billing records before 2006.

[21] Xcel Energy is making a similar filing in all five upper Midwest jurisdictions it serves (Minnesota, North Dakota, South Dakota, Wisconsin and Michigan). Economies would be gained by implementing a consistent credit method in all jurisdictions. Not all states have fuel clauses and each state has a different rate case status. The bill credit option is best suited for consistent and efficient credit to customers in all five jurisdictions.

multiplying the combined allocator and the total available credit amount. [22] A credit factor is developed by dividing each class' share of the credit amount by the class' recent twelve month energy sales. The class credit factor is then be applied to each active customer's actual 12 months of total actual kWh usage (from July 1, 2010 through June 30, 2011) to determine the actual credit amount for each customer. Using 12-months of usage avoids the problems inherent with selecting a particular point in time to calculate the credit (e.g. customers with fluctuations in monthly or seasonal energy use).

2. Fuel Clause Rider Credit ("FCR")

Another mechanism for crediting the settlement payments is through the fuel clause adjustment. This mechanism was used in Docket No. EL-06-026 to pass through the DOE Settlement payment to the Company related to nuclear fuel enrichment overcharges. In that Case, the use of the FCR to pass through the DOE Settlement payment was appropriate because the DOE nuclear fuel enrichment charges had been recovered from customers through the FCR. However, in this current case, the damage payments are different in that they are for nuclear plant-related capital and O&M costs and consequently were not recovered through the FCR.

If the FCR credit method is chosen, the credit process can be modeled similar to the non-asset based margins sharing refund currently implemented through the FCR. As explained above and outlined in Attachment A, the allocation between NSPM and NSPW would use the IA demand charge ratio and the jurisdictional allocation within NSPM would use the 12CP allocators. Then, as with the non-asset based margins sharing, an equal monthly credit amount would be determined based on the number of months chosen to return the funds. An overall average class per unit (per kWh) credit would be calculated by dividing the class's monthly credit amount by the class's forecast sales for that month. The resulting average class per unit credit would then be multiplied by the "fuel adjustment factor" specified in the current FCR tariff to calculate the adjustment factor used for that class. The class per unit adjustment factor is then multiplied by the units (kWh) used by each customer that month to determine the customer's monthly credit.

The class per unit charge credited to the monthly class fuel cost charges would be combined with the normal monthly FCR, but would be accounted for separately and would include a true up from the prior month's credit. Crediting through the FCR

[22] The combined allocator used for nuclear plant investment costs was developed using a stratification process. That process resulted in an allocation factor that was approximately 81% "energy-related" and 196%"demand-related." The combined allocator is determined in the most recent Class Cost of Service Study.

mechanism would be implemented by offsetting the normal monthly FCR charge over the course of the next 3 to 6 months. See Attachment C for an example calculation.

The Commission's fuel adjustment rules do not generally contemplate or provide for such payments to be passed through the FCR. Although this credit would technically not be included in the fuel cost inputs to the FCR itself, it would be calculated in a similar, separate manner and then added to the FCR for the prescribed number of months. Therefore, depending upon how the Commission's fuel adjustment rules are interpreted, the Commission may wish to vary its rule to accommodate this type of credit. The variance would be justified on the need to establish an administratively efficient credit mechanism. Use of the FCR mechanism would not impose an excess burden, and granting a variance (if deemed necessary) would not conflict with legal obligations or adversely affect the public interest.

The Company recognizes that some of the issues associated with crediting customers discussed under the one-time credit method may also apply if the FCR method is used. Therefore, if the Commission chooses the FCR method, the Company is also willing to work with the Commission and parties to further refine this approach.

3. Rate Case Revenue Requirement Credit

A third alternative is to defer recording the proceeds of the Settlement as current revenues and credit the Settlement payments against the revenue requirement in the first available general rate case. While this option may delay the return of the funds to customers when compared to the one-time bill credit and FCR methods, the Commission may choose to use the initial and future Settlement payments in a more comprehensive manner to off-set some of the increasing costs anticipated in the near future.

If the Commission adopts this approach, the Commission could reduce the revenue deficiency by the Settlement amounts when it decides the matter in Docket No. EL-11-019. Because of the significant amount of the reduction, the Company would be faced with a significant future increase, unless a plan were developed to amortize the current proceeds over a two year period and to apply future proceeds against requests for future rate relief otherwise needed to mitigate the single year "rate cliff" impacts for both the Company and its customers.

If this alternative is selected, the best structure is somewhat dependent on Commission decision's on the amount of rate relief to be afforded, and consequently, the best timing for a decision may be in conjunction with deliberations in the pending rate case. Based on the Company's position in that case, we believe that a reduction

would be appropriate of roughly $2.0 million (a two year credit of that amount would exhaust the currently available amount of approximately $4.0 million). In addition, if the first quarter payment in 2012 can reasonably be determined at the time the final compliance filing is made in Docket No. EL-11-019, an additional estimated credit of $635,401 ($685,959 settlement payment less $50,558 in 2009 litigation costs) (plus interest) could be included in the amortized credit to the 2010 revenue requirement. Future Settlement payments not reflected in final rates for EL-11-019 could be used to offset increases we expect to incur as we continue to invest in system infrastructure.

This approach is more complicated than either the bill credit or FCR credit options. Nonetheless, the Company's costs will likely continue to rise beyond 2010 test year levels as we continue to invest in our infrastructure. We intend to explore this option with Commission Staff to determine if there is interest in this approach. To the extent there is not, we do not seek to complicate this matter, and would likely recommend either the bill credit or FCR option.

B. Litigation Expenses

We propose to reduce the amount of the initial credit by $264,420, which represents the South Dakota jurisdictional share of the outside legal fees and other litigation expenses incurred to obtain the DOE Settlement through 2008. The Company will not be seeking recovery for outside legal costs incurred after 2009 because base rates set in Docket EL09-009 included the outside legal costs budgeted for the DOE litigation. See Attachment D for litigation cost detail.

The Commission has approved recovery of litigation expenses in similar circumstances. In a very analogous case referenced above, Docket No. EL06-026, the Commission allowed the Company to offset its outside legal costs against the repayment by the DOE of an overcharge for fuel-related costs.[23] The Commission allowed similar offsets for litigation expenses incurred in arbitration proceedings involving coal expenses in Docket Nos. EL00-002, EL00-003, and EL00-009.

Like the examples cited above, we incurred the litigation expenses to recover damages that will be returned to our customers. Therefore, we believe it is appropriate to net

[23] *In the Matter of the Filing by Northern States Power Company d/b/a Xcel Energy for Approval of a Refund of a Department of Energy Settlement,* Order Approving Refund of Department of Energy Settlement (November 4, 2006), which involved a refund of $27.5 million in DOE uranium processing costs, that had been recovered through the FCA and therefore was appropriately credited through the FCA.

the outside legal fees with the Settlement Agreement proceeds and return the resulting amount to ratepayers similar to the dockets outlined above.

The Company's most recent general rate case was filed in 2009 with a 2008 historic test year. Docket No. EL09-009. Prior to that case, the Company had not increased its base rates since 1992. None of the litigation costs incurred in this matter were included in the rates set in 1992. Accordingly, we propose the DOE litigation expenses for 1997 through 2008 be netted against the settlement award in their entirety and that the 2009 outside legal fees be net against the appropriate future Settlement payment.

The Company does not seek to recoup unrecovered litigation expenses for 2010 (when the rates set in Docket No. EL09-009 became effective) and after. The Company filed a petition for a general rate increase in 2009 utilizing a 2008 historic test year and the rates set in that proceeding went into effect in 2010. Because the litigation was active at that time, litigation expenses related to this case were included in rates starting in 2010. Although we incurred expenses to the direct benefit of our customers that exceeded the amounts recovered in base rates, the Company does not seek to true-up those incremental litigation expenses.

It would not have been possible to obtain the Settlement and its significant benefits if we had not incurred these expenses. Furthermore, permitting recovery of these costs not included in rates through 2009 provides the proper incentive for utilities to pursue other litigation for the benefit of the ratepayers. Accordingly, it is appropriate to offset the Settlement Agreement proceeds by the amount of incremental outside legal fees and return the net amount to our customers.

C. Interest

Given the magnitude of the amount of the Settlement award, the Company has placed the funds in a separate interest-bearing account. Placing the funds in a separate interest-bearing account protects both customers and the Company and ensures the funds are accurately accounted for pending the actual credit . The Company considered various alternatives to maintaining the funds, but found that the separate interest-bearing account provided the greatest transparency, the least amount of risk given that the credit may occur relatively quickly if a bill credit or FCR credit were selected and, therefore, was the preferred option for holding the funds for ratepayers. The funds were placed in an interest bearing sweep account earning 0.25% annually and posted daily. The Company requests that the credit amount include the actual amount of interest earned by the Company on these funds.

In Docket Nos. EL00-002, EL00-003, EL00-009, and EL06-026 the Commission directed that interest be added to the refund computed at the Company's last approved overall rate of return. However, in those cases, the amounts had not been segregated in a separate interest bearing account. In this current case, using the Company's average cost of capital for the interest component of the credit would impose a penalty on the Company. Any other action, such as using the funds to temporarily replace short term debt, would have commingled the Settlement funds with other Company operational revenues and would greatly increase the difficulty of managing the credit. Given the magnitude of the Settlement and the need to manage the funds efficiently and transparently for the benefit of our customers across five states, we determined that the most effective means to do so was to deposit the funds in a separate account and include with the credit the actual interest received.

If a base rate option is used, we request that the interest calculation terminate with our compliance filing for the rate case as the funds would be included in final rates and deployed in the most efficient manner for Company use.

D. Compliance Filings and Customer Billing Statements

If the Commission approves either a bill credit or a credit through the FCA, we would provide a billing statement to the Commission for review and approval within 30 days of the Commission Order selecting that method. We would also provide a Compliance filing within 30 days of completing the credit process showing the amount of the DOE settlement and interest actually credited.

VII. DEFERRED ACCOUNTING AND WAIVER OF DEPARTURE FROM TARIFF REQUEST

The Company has received a one-time payment of revenue with no offsetting change in ongoing costs. Therefore, until a credit is made, the payment will affect the Company's revenues. The purpose of this section is to address and eliminate that imbalance.

The Company recognizes that the Commission is presented with a significant number of matters to review and determine and that the remaining time available this year is limited. However, the Company respectfully requests that if the Commission has not issued an order on a credit approach by year-end, that the Commission review this particular portion of our request and issue an Order by December 31st of this year granting deferred accounting of the Settlement proceeds. The Company seeks to avoid having potential income in 2011 that will be returned to customers in 2012. A grant of deferred accounting will avoid recognition of book income and any concurrent tax effects this year, preserving the entire net proceeds for our customers.

More specifically, the Company requests an Order issued no later than December 31, 2011 granting permission to defer recording the proceeds of the Settlement as current revenues and to place the net amount not credited in FERC account 242, miscellaneous current and accrued liabilities. In addition, the Company requests that the Commission authorize deferred accounting for any anticipated future payments from DOE if the amounts cannot be credited to ratepayers in the year received. Deferral treatment recognizes that the significant amount of revenues are from both the Company's and the Commission's view appropriately retained by the Company for return to our customers and deferral of these amounts by 2011 year end will clarify any ambiguity as to the potential distortive impacts this additional revenue could have on the Company's financial statements if the Commission is still working through the logistics of precisely how the funds should be returned. We do not expect there to be any disagreement on this point and a deferral order issued separately from a credit order should not place an added burden on timing pressures facing parties and the Commission given that the proposed use of the proceeds on behalf of our customers will not be contested, but potentially the manner of the credit and specific rate design may be contested.

To the extent the Commission chooses to use the FCR method to credit customers, the Company requests a waiver of any departure from its tariff, if necessary, since the FCR tariff does not generally contemplate or provide for such payments to be passed through the FCR. The Commission has authority under ASRD § 20:10:13:08 to waive any departure from the specific wording of a public utility's tariff.

VIII. MISCELLANEOUS INFORMATION

The Company requests that the following persons be placed on the Commission's official service list for this matter:

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CONCLUSION

The Company respectfully requests the Commission approve a credit mechanism to provide the Company's current electric customers of the State of South Dakota the appropriate portion of the proceeds received as a result of a Settlement reached with the DOE, net of the outside legal fees incurred in pursuit of the Settlement. The

Company has identified three options and will work to determine if there is stakeholder support for a particular option. The payments will be deposited in a separate interest-bearing bank account and if approved by the Commission, the actual interest earned will be included with the credit provided to customers. We respectfully request an Order authorizing deferred accounting by December 31, 2011 if the Commission has not issued an Order on a credit approach by that time.

Dated: August 16, 2011

Respectfully submitted,

Northern States Power Company,
a Minnesota corporation

/s/
By: _____
BRIAN R. ZELENAK
MANAGER, REGULATORY ADMINISTRATION