Xcel Energy®

414 Nicollet Mall
Minneapolis, Minnesota 55401

— VIA ELECTRONIC & U.S. MAIL—

August 11, 2011

Darrell Nitschke
Executive Secretary and Director of Administration
North Dakota Public Service Commission
State Capital Building
600 East Boulevard, Dept. 408
Bismarck, ND 58505-0408

RE: PETITION FOR APPROVAL OF A CREDIT MECHANISM FOR A DOE SETTLEMENT PAYMENT WITH DEFERRED ACCOUNTING
CASE NO.PU-11-____

Dear Mr. Nitschke:

Enclosed please find the Petition of Northern States Power Company, a Minnesota corporation ("Xcel Energy" or the "Company"), operating in North Dakota, requesting approval of a customer credit mechanism for funds received from a Settlement ("Settlement") with the United States Department of Energy ("DOE"). The Settlement resolves DOE's partial breach of its contract to begin accepting spent nuclear fuel on or before January 31, 1998, through 2013.

As described in our July 8, 2011, letter, the Company recently reached the Settlement. The recovered Settlement funds will be credited to benefit our customers.

You may direct any questions regarding this Petition to David Sederquist (701) 241-8632 or Matthew Loftus (612) 215-4501.

Sincerely,

/s/

BRIAN R. ZELENAK
MANAGER, REGULATORY ADMINISTRATION

Enclosure

STATE OF NORTH DAKOTA
BEFORE THE
PUBLIC SERVICE COMMISSION

Tony Clark	Chairman
Kevin Cramer	Commissioner
Brian P. Kalk	Commissioner

IN THE MATTER OF THE PETITION OF NORTHERN STATES POWER COMPANY, A MINNESOTA CORPORATION FOR APPROVAL OF A CUSTOMER CREDIT MECHANISM FOR A DEPARTMENT OF ENERGY SETTLEMENT PAYMENT ALONG WITH DEFERRED ACCOUNTING AND RULE VARIANCE, AS NECESSARY.

Case No. PU-11-___

PETITION

INTRODUCTION

Pursuant to ND Century Code § 49-02-03 (2011), Northern States Power Company, a Minnesota corporation ("Xcel Energy" or the "Company") operating in North Dakota, petitions the North Dakota Public Service Commission ("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. The Company's goal is to seek an administratively efficient and prompt return of the funds to our customers. The amount currently available for credit is $99,966,841 on a total Company basis and approximately $4.9 million on a North Dakota jurisdictional basis. In addition, the Company requests that the amount of the credit be net of North Dakota's jurisdictional share of legal costs of just under $0.3 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 North 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 nuclear spent fuel storage damages incurred through December 31, 2008. The Company has placed the funds into a separate interest bearing escrow account and will include the interest received in calculating the amount of the credit. The Company requests authority to net $288,794 in litigation expenses incurred through 2007 against the North Dakota jurisdictional amount of $4,956,690.

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 $4.7 million on a North 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 North Dakota customers.

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

Table 1

	Total Company (NSPM & NSPW)	ND Jurisdiction	Payment Due
Initial Payment Amount	$99,966,841	$4,956,690	Paid August 2, 2011
Less Legal Fees through 2007		$288,794	
Available for Credit		**$4,667,896**	
Supplemental Payments			
Estimated 2nd Payment	$15,000,000	$706,897	1st Quarter 2012
Estimated 3rd Payment	$25,000,000	$1,217,369	Year-End 2012
Estimated 4th Payment	$31,000,000	$1,509,538	Year-End 2013
Estimated 5th Payment	$27,000,000	$1,314,759	Year-End 2014

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 rule variance, as needed, to support the credit mechanism selected by the Commission

A. Name, Address and Telephone Number of Utility Attorney

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B. Utility Employee Responsible for Filing

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I. HISTORY OF THE CASE

The Nuclear Waste Policy Act[1] established a framework for the permanent disposal of high-level radioactive waste.[2] Under the Act and subsequent regulations, utilities are required to enter into Standard Contracts for Disposal of Spent Nuclear Fuel ("Standard Contracts").[3] 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").[4] 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.[5] 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 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.[6] 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,

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[1] 42 U.S.C. §§ 10101 et seq (2006).
[2] 42 U.S.C. § 10131(a)(4).
[3] 10 C.F.R. § 961.11 (2010).
[4] 42 U.S.C. § 10222(a)(2).
[5] 42 U.S.C. § 1022(a)(5)(B).
[6] 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).

cost of capital.[7] 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).[8] 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).[9]

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.[10] In addition, precedent strongly suggested that the Appellate 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.[11] 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) 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

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[7] *Id.*

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

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

[10] 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).

[11] *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.

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 also continue to operate nuclear generating facilities, and both have recently entered into comparable settlements.

II. 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.

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)[12] and the DOE agrees to damages covering O&M, overhead and other operating costs.[13]

The Settlement also provides a mechanism for the Company to recover its spent nuclear fuel storage damages from January 1, 2009 through December 31, 2013 on a timely basis without pursuit of further litigation. We expect that the additional damage payments will be approximately $98 million on a total Company basis, or approximately $4.7 million on a North 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

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[12] 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 delay in opposition to a demand for damages. No decision on the merits of the defense has occurred.

[13] 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 Rider.

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.[14]

III. 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 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.[15] 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.[16] 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 NSP-Minnesota 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.

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[14] 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.

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

[16] 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.

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.[17] 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.

IV. ALTERNATIVE CREDIT MECHANISMS

A. Analysis of Alternatives

There is no existing 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. N.D.Cent. Code § 49-02-03 (2011).

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

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

Each of these alternatives has been previously approved by the Commission to direct credits to customers.

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.[18]

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

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

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 straightforward and has the advantage of providing customers the benefits of the credit as quickly as possible.[19]

The one-time bill credit alternative is consistent with Commission precedent. In Case No. PU-06-525, the Commission approving a cap on future earnings at 10.75 percent with a one-time bill credit if earnings exceeded that threshold; and in Case No. PU-400-94-514 a one-time bill credit was used to correct an erroneous demand allocator used when establishing rates.

As outlined in the example found in Attachment B, once the refund amounts have been calculated for each jurisdiction, the credit amount by class is determined by multiplying the combined allocator and the total available credit amount.[20] 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 refund 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).

As with any method selected, we recognize that there may be some perceived inequities in this method. While straightforward and administratively simple to administer, current

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[19] 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.

[20] 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 84% "energy-related" and 16%"demand-related." The combined allocator is determined in the most recent Class Cost of Service Study.

customers receive a benefit regardless of how long they have been a customer and the credit is based on the most recent 12 months of actual usage. This issue can be more apparent with larger customers. A current customer may have only been a customer for a portion of the period covering the initial payment, or their usage could have fluctuated significantly over the years (increases or decreases) through business cycles, expansions and contractions, yet would qualify for a credit as a current customer based on their recent 12 months usage. We recognize this potential inequity and are willing to work with the Commission and parties if the one-time bill credit method is chosen and it is determined that adjustments are appropriate. However, as mentioned, imbalances will occur with any credit mechanism chosen and our goal is to balance the inequities to the degree possible while pursuing an administratively efficient and prompt return of these funds to our customers in all our jurisdictions.

2. *Fuel Cost Rider Credit ("FCR")*

Another mechanism for crediting the settlement payments is through the FCR. This mechanism was used in Case No. PU-06-475 to pass through the DOE Settlement payment to the Company related to nuclear fuel enrichment overcharges. In that Case, the use of the FCR mechanism to pass through that DOE Settlement payment was appropriate because the DOE nuclear fuel enrichment charges had been recovered from ratepayers 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 "Service Category Ratio" 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 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.

Using the FCR would result in some delay in returning the funds to customers, but would have the impact of lowering rates during the credit period. This would moderate the impacts of these increases without complicating the determination of either the normal FCR or the base rates.

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 refund. The variance would be justified on the need to establish an administratively efficient refund 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. This method was used in Case No. PU-07-776, where the surplus Monticello nuclear decommissioning escrow costs contributed by North Dakota customers was used to lower base rates. While this option may delay the return of the funds to customers when compared to the one-time bill credit method, 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 Case No. PU-10-657/PU-11-55. Because of the significant amount of the reduction, however,.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 (for 2011 and 2012) 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 most appropriate structure is somewhat dependent on the Commission's decision on the amount of rate relief to be afforded in 2011 and 2012 and, consequently, the best timing for a decision on this matter 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 to the 2011 test year rates of roughly $2.4 million applied to the interim rate refund and final rates applied in 2012 would be appropriate (a credit of $2.4 million toward 2011 interim rates and in 2012 rates would exhaust the currently available amount of approximately $4.7 million). In addition, if the first quarter payment in 2012 can reasonably be determined at the time the final compliance filing is made in Case No. PU-10-657/PU-11-55, an additional estimated credit of roughly $0.7 million can be included in the amortized credit. Future Settlement payments could be used to offset increases we expect to incur as we continue to invest in system infrastructure or dealt with separately.

The rate case revenue requirement credit approach might be more complicated than either the bill credit or FCR credit options. Nonetheless, the Company's costs will likely continue to rise beyond 2011 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. If not, we would likely recommend either the bill credit or FCR option.

B. Litigation Expenses

We propose to reduce the amount of the credit by $288,794, which represents the North Dakota jurisdictional share of the outside legal fees and other litigation expenses incurred from 1998-2007 to obtain the DOE Settlement. The Company is not seeking recovery for outside legal costs incurred after 2007 because base rates set in Case No. PU-07-776 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 Case No. PU-06-475, the Commission allowed the Company to offset its outside legal costs against the repayment by the DOE of the overcharge for fuel-related costs.[21] In that case, as in the present matter, we incurred the litigation expenses to recover damages that will be returned to our customers. Therefore, we believe it is appropriate

[21] *In the Matter of Petition of Northern States Power Company d/b/a Xcel Energy for Approval of a Refund of a DOE Settlement,* which involved a refund of $27.5 million in DOE uranium processing costs, that had been recovered through the FCR and therefore was appropriately credited through the FCR.

to net the outside legal fees with the Settlement Agreement proceeds and return the resulting net amount to ratepayers.

The first lawsuit that is the subject of the Settlement was initiated by the Company in 1998. However, the rates in effect at the time were set using a 1993 test year and, accordingly, did not include the expenses related to this litigation. The Company did not file a general rate case until December 2007, using a 2008 test year. Therefore, for the years 1998-2007, the Company's actual legal department costs exceeded what was included in the rates. Accordingly, we propose the DOE litigation expenses for 1998 through 2007 be netted against the settlement award in their entirety.

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 2007 provides the proper signal 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 ratepayers and the Company and ensures the funds are accurately accounted for pending the actual refund. 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 refund 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 contrast to setting up the funds in a separate account, the Company could have included the funds in our operations, and used to temporarily reduce short-term debt. However, such action would greatly increase the difficulty of managing the credit. Accordingly, we chose the separate interest bearing account as the preferable alternative. 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 FCR, we would provide an example bill message 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 refunded.

V. DEFERRED ACCOUNTING AND RULE VARIANCE 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. Because these amounts were not included in the rate case, 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 refund 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 also requests a rule variance if necessary since the FCR rules do not generally contemplate or provide for such payments to be passed through the FCR.

VI. MISCELLANEOUS INFORMATION

Xcel Energy 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 ratepayers of the State of North 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 ratepayers. We respectfully request an Order authorizing deferred accounting by December 31, 2011 if the Commission has not issued an Order on a refund approach by that time.

Dated: August 11, 2011

Respectfully submitted,
By

/s/

Brian R. Zelenak

NSP v DOE Settlement

Interchange Agreement and Jurisdictional Allocation Methodology

		Column 1					
		Settlement Amount	**NSPM**	**Minnesota Retail**	**North Dakota Retail**	**South Dakota Retail**	**Wholesale**
Initial Settlement Amount	*Column 1 X Row 1*	**$99,966,841**	$84,543,050	$74,349,034	$4,956,690	$4,285,234	$952,093
Estimated using Avg 1998 to 2008 allocation							
Outside Legal and Expert Witness Costs (Notes (1))			$ (2,166,112)	$ (1,908,090)	$ (288,794)	$ (314,978)	$ (20,358)
Amount Available for Initial Credit			**$ 82,376,939**	**$ 72,440,943**	**$ 4,667,895**	**$ 3,970,256**	**$ 931,735**
Estimated Additional Payments							
Estimated using Avg 2009 & 2010 allocation	*Column 1 X Row 2*	**$15,000,000**	$12,564,383	$10,997,453	$706,897	$685,959	$174,073
Estimated using 2011 allocation	*Column 1 X Row 3*	**$25,000,000**	$20,950,475	$18,539,578	$1,217,369	$1,168,597	$24,931
Estimated using 2011 allocation	*Column 1 X Row 3*	**$31,000,000**	$25,978,589	$22,989,077	$1,509,538	$1,449,060	$30,915
Estimated using 2011 allocation	*Column 1 X Row 3*	**$27,000,000**	$22,626,513	$20,022,744	$1,314,759	$1,262,084	$26,926
Additional Payment Totals		**$98,000,000**	$82,119,960	$72,548,853	$4,748,563	$4,565,699	$256,844
Total Payments (jurisdictional amounts are less legal fees)		**$197,966,841**	**$164,496,898**	**$144,989,796**	**$9,416,459**	**$8,535,955**	**$1,188,580**

Allocation Factors

Average 1998 to 2008		**Total**	**NSPM**	**NSPW**		
Interchange Agreement - 36 Mo CP Demand		100.0000%	**84.5711%**	15.4289%		
		NSPM	**Minnesota Retail**	**North Dakota Retail**	**South Dakota Retail**	**Wholesale**
NSPM Jurisdictional Allocation - 12 CP Demand		100.0000%	87.9422%	5.8629%	5.0687%	1.1262%
Composite NSPM Demand Including Interchange Agreement	*Row 1*	**84.5711%**	**74.3737%**	**4.9583%**	**4.2867%**	**0.9524%**
Average 2009 and 2010		**Total**	**NSPM**	**NSPW**		
Interchange Agreement - 36 Mo CP Demand		100.0000%	**83.7626%**	16.2375%		
		NSPM	**Minnesota Retail**	**North Dakota Retail**	**South Dakota Retail**	**Wholesale**
NSPM Jurisdictional Allocation - 12 CP Demand		100.0000%	87.5288%	5.6262%	5.4596%	1.3855%
Composite NSPM Demand Including Interchange Agreement	*Row 2*	**83.7626%**	**73.3164%**	**4.7126%**	**4.5731%**	**1.1605%**
2011 Budget		**Total**	**NSPM**	**NSPW**		
Interchange Agreement - 36 Mo CP Demand		100.0000%	**83.8019%**	16.1981%		
		NSPM	**Minnesota Retail**	**North Dakota Retail**	**South Dakota Retail**	**Wholesale**
NSPM Jurisdictional Allocation - 12 CP Demand		100.0000%	88.4924%	5.8107%	5.5779%	0.1190%
Composite NSPM Demand Including Interchange Agreement	*Row 3*	**83.8019%**	**74.1583%**	**4.8695%**	**4.6744%**	**0.0997%**

Notes:
(1) Actual Litigation costs were allocated between NSPM and NSPW as well as NSPM jurisdictions based on actual demand allocators for each individual year.
NSPM Retail legal fees are through 2005.
North Dakota Retail legal fees are through 2007.
South Dakota Retail legal fees are through 2009.
(See Attachment D for yearly detail on legal fees by jurisdiction)

One-Time Credit Allocation Methodology

	Settlement Amount	NSPM	Minnesota Retail	North Dakota Retail	South Dakota Retail	Wholesale
Initial Settlement Amount	**$99,966,841**	**$84,543,050**	**$74,349,034**	**$4,956,690**	**$4,285,234**	**$952,093**
Outside Legal and Expert Witness Costs (Notes (1))		($2,166,112)	($1,908,090)	($288,794)	($314,978)	($20,358)
Amount Available for Initial Credit		**$82,376,939**	**$72,440,943**	**$4,667,895**	**$3,970,256**	**$931,735**
Estimated Additional Payments						
2009 & 2010 Payment	**$15,000,000**	$12,564,383	$10,997,453	$706,897	$685,959	$174,073
2011 Payment	**$25,000,000**	$20,950,475	$18,539,578	$1,217,369	$1,168,597	$24,931
2012 Payment	**$31,000,000**	$25,978,589	$22,989,077	$1,509,538	$1,449,060	$30,915
2013 Payment	**$27,000,000**	$22,626,513	$20,022,744	$1,314,759	$1,262,084	$26,926
Estimated Additional Payment Totals	**$98,000,000**	$82,119,960	$72,548,853	$4,748,563	$4,565,699	$256,844
Total Payments (jurisdictional amounts are less legal fees)	**$98,000,000**	**$164,496,898**	**$144,989,796**	**$9,416,459**	**$8,535,955**	**$1,188,580**

Stratification	**Weight ****	**Res**	**Small Non Demand**	**C&I Demand**	**Lighting**	**Total**
Capacity Component (D10C)	15.58%	32.81%	7.38%	59.54%	0.26%	100.00%
Energy Component (E8760)	84.42%	35.11%	6.46%	57.83%	0.60%	100.00%
Combined		**34.75%**	**6.61%**	**58.10%**	**0.54%**	**100.00%**
[1] Initial Settlement Amount		**$1,622,108**	**$308,443**	**$2,711,979**	**$25,365**	**$4,667,895**
[2] MWh Sales July 2010 through June 2011		**792,411**	**125,693**	**1,308,764**	**18,918**	
[3] Credit Factor ($/kWh) [3] = [1] / [2] / 1000		**$ 0.002047**	**$ 0.002454**	**$ 0.002072**	**$ 0.001341**	
Estimated Additional Payments						
2009 & 2010 Payment		$245,649	$46,710	$410,697	$3,841	$706,897
2011 Payment		$423,040	$80,441	$707,274	$6,615	$1,217,369
2012 Payment		$524,569	$99,747	$877,019	$8,203	$1,509,538
2013 Payment		$456,883	$86,876	$763,856	$7,144	$1,314,759
Estimated Additional Payment Totals		$1,650,141	$313,774	$2,758,845	$25,804	$4,748,563
Estimated Total Payments		**$3,272,249**	**$622,217**	**$5,470,824**	**$51,169**	**$9,416,459**

Notes:

(1) Actual Litigation costs were allocated between NSPM and NSPW as well as NSPM jurisdictions based on actual demand allocators for each individual year.
NSPM Retail legal fees are through 2005.
North Dakota Retail legal fees are through 2007.
South Dakota Retail legal fees are through 2009.
(See Attachment D for yearly detail on legal fees by jurisdiction)

Fuel Cost Rider Methodology

	Settlement Amount	NSPM	Minnesota Retail	North Dakota Retail	South Dakota Retail	Wholesale
Initial Settlement Amount	**$99,966,841**	**$84,543,050**	**$74,349,034**	**$4,956,690**	**$4,285,234**	**$952,093**
Outside Legal and Expert Witness Costs (Notes (1))		($2,166,112)	($1,908,090)	($288,794)	($314,978)	($20,358)
Amount Available for Initial Credit		**$82,376,939**	**$72,440,943**	**$4,667,895**	**$3,970,256**	**$931,735**
Estimated Additional Payments						
2009 & 2010 Payment	**$15,000,000**	$12,564,383	$10,997,453	$706,897	$685,959	$174,073
2011 Payment	**$25,000,000**	$20,950,475	$18,539,578	$1,217,369	$1,168,597	$24,931
2012 Payment	**$31,000,000**	$25,978,589	$22,989,077	$1,509,538	$1,449,060	$30,915
2013 Payment	**$27,000,000**	$22,626,513	$20,022,744	$1,314,759	$1,262,084	$26,926
Additional Payment Totals	$98,000,000	$82,119,960	$72,548,853	$4,748,563	$4,565,699	$256,844
Total Payments (jurisdictional amounts are less legal fees)	**$197,966,841**	**$164,496,899**	**$144,989,796**	**$9,416,458**	**$8,535,955**	**$1,188,579**

Initial Settlement

		January	February	March	April	May	June	6 Months Total
[1] Monthly Credit								
	Jurisdictional Settlement Payment	$ 777,983	$ 777,983	$ 777,983	$ 777,983	$ 777,983	$ 777,980	$ **4,667,895**
	Interest Accrual	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	True Up of Prior Month Credit	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Net Monthly Credit Balance	$ 777,983	$ 777,983	$ 777,983	$ 777,983	$ 777,983	$ 777,980	$ 4,667,895
[2] 2011 MWh Sales								
	Residential	99,111	83,320	86,238	59,524	53,251	51,748	433,192
	C&I Non-Demand	14,191	11,949	12,922	9,574	10,155	8,668	67,459
	C&I Demand Non-TOD	72,443	57,938	70,769	53,152	58,714	58,924	371,940
	C&I Demand TOD On-Pk	16,560	16,999	22,007	18,572	17,438	19,267	110,843
	C&I Demand TOD Off-Pk	29,313	27,539	32,833	27,669	27,857	30,957	176,168
	Outdoor Lighting	2,237	1,948	1,700	1,574	1,312	1,221	9,992
	ND State Total	233,855	199,693	226,469	170,065	168,727	170,785	1,169,594
[3] Overall Average Class per Unit Credit ($/kWh) [1]/[2]/1000		$ 0.003327	$ 0.003896	$ 0.003435	$ 0.004575	$ 0.004611	$ 0.004555	$ 0.003991
[4] Service Category Ratio								
	Residential	0.9956	0.9956	0.9956	0.9956	0.9956	0.9956	
	C&I Non-Demand	1.0548	1.0548	1.0548	1.0548	1.0548	1.0548	
	C&I Demand Non-TOD	1.0219	1.0219	1.0219	1.0219	1.0219	1.0219	
	C&I Demand TOD On-Pk	1.3135	1.3135	1.3135	1.3135	1.3135	1.3135	
	C&I Demand TOD Off-Pk	0.7726	0.7726	0.7726	0.7726	0.7726	0.7726	
	Outdoor Lighting	0.7088	0.7088	0.7088	0.7088	0.7088	0.7088	
[5] Class per Unit Adjustment Factors ($/kWh) [3]x[4]								
	Residential	0.003312	0.003879	0.00342	0.004555	0.004591	0.004535	
	C&I Non-Demand	0.003509	0.00411	0.003623	0.004826	0.004864	0.004805	
	C&I Demand Non-TOD	0.0034	0.003981	0.00351	0.004675	0.004712	0.004655	
	C&I Demand TOD On-Pk	0.00437	0.005117	0.004512	0.006009	0.006057	0.005983	
	C&I Demand TOD Off-Pk	0.00257	0.00301	0.002654	0.003535	0.003562	0.003519	
	Outdoor Lighting	0.002358	0.002761	0.002435	0.003243	0.003268	0.003229	
[6] Monthly Credit Added to FCR [5]x[2]x1000								
	Residential	$ 328,256	$ 323,198	$ 294,934	$ 271,132	$ 244,475	$ 234,677	$ 1,696,672
	C&I Non-Demand	$ 49,796	$ 49,110	$ 46,816	$ 46,204	$ 49,394	$ 41,650	$ 282,970
	C&I Demand Non-TOD	$ 246,306	$ 230,651	$ 248,399	$ 248,486	$ 276,660	$ 274,291	$ 1,524,793
	C&I Demand TOD On-Pk	$ 72,367	$ 86,984	$ 99,296	$ 111,599	$ 105,622	$ 115,274	$ 591,142
	C&I Demand TOD Off-Pk	$ 75,334	$ 82,892	$ 87,139	$ 97,810	$ 99,227	$ 108,938	$ 551,340
	C&I Demand Total	$ 394,007	$ 400,527	$ 434,834	$ 457,895	$ 481,509	$ 498,503	$ 2,667,275
	Outdoor Lighting	$ 5,275	$ 5,378	$ 4,140	$ 5,104	$ 4,288	$ 3,943	$ 28,128
	ND State Credit Total	$ 777,334	$ 778,213	$ 780,724	$ 780,335	$ 779,666	$ 778,773	$ 4,675,045
[7] Cumulative Credit (at Month End)		$ 777,334	$ 1,555,547	$ 2,336,271	$ 3,116,606	$ 3,896,272	$ 4,675,045	
[8] % Credited		16.7%	33.3%	50.0%	66.8%	83.5%	100.2%	

Notes:

(1) Actual Litigation costs were allocated between NSPM and NSPW as well as NSPM jurisdictions based on actual demand allocators for each individual year.
NSPM Retail legal fees are through 2005.
North Dakota Retail legal fees are through 2007.
South Dakota Retail legal fees are through 2009.
(See Attachment D for yearly detail on legal fees by jurisdiction)

NSP v DOE Litigation Cost Summary
General Counsel Outside Legal and Expert Witness Expenses

Actual NSP v DOE Litigation Cost (1)

Year	Total Litigation Cost	Total NSPW	Total NSPM	NSPM State of MN	NSPM State of ND	NSPM State of SD	NSPM Wholesale
1998	$ 70,195	$ 10,804	$ 59,390	$ 52,424	$ 3,576	$ 2,994	$ 397
1999	$ 448,624	$ 67,996	$ 380,629	$ 337,045	$ 21,932	$ 18,840	$ 2,812
2000	$ 18,477	$ 2,781	$ 15,696	$ 13,936	$ 899	$ 759	$ 102
2001	$ 284,979	$ 44,399	$ 240,581	$ 212,478	$ 14,124	$ 12,335	$ 1,644
2002	$ 171,146	$ 26,410	$ 144,736	$ 127,763	$ 8,462	$ 7,382	$ 1,129
2003	$ 155,121	$ 23,155	$ 131,965	$ 116,505	$ 8,024	$ 6,416	$ 1,020
2004	$ 293,178	$ 44,570	$ 248,607	$ 219,059	$ 14,681	$ 12,554	$ 2,314
2005	$ 1,121,041	$ 176,534	$ 944,507	$ 828,882	$ 55,768	$ 48,916	$ 10,941
2006	$ 2,553,985	$ 407,077	$ 2,146,908	$ 1,881,291	$ 129,192	$ 113,316	$ 23,109
2007	$ 670,171	$ 105,308	$ 564,863	$ 489,461	$ 32,135	$ 29,367	$ 13,901
1998 to 2007	$ 5,786,917	$ 909,034	$ 4,877,883	$ 4,278,842	$ 288,794	$ 252,879	$ 57,368
2008	$ 266,276	$ 41,479	$ 224,797	$ 194,970	$ 12,736	$ 11,541	$ 5,550
2009	$ 1,132,297	$ 182,493	$ 949,804	$ 827,052	$ 53,897	$ 50,558	$ 18,297
2010	$ 1,015,641	$ 166,136	$ 849,504	$ 747,407	$ 47,384	$ 47,539	$ 7,174
2008 to 2010	$ 2,414,214	$ 390,109	$ 2,024,104	$ 1,769,428	$ 114,017	$ 109,638	$ 31,021
YTD 2011	$ 310,780	$ 50,340	$ 260,439	$ 230,469	$ 15,133	$ 14,527	$ 310
Total	$ 8,511,911	$ 1,349,484	$ 7,162,427	$ 6,278,740	$ 417,945	$ 377,044	$ 88,699

Note:
(1) Actual Litigation costs were allocated between NSPM and NSPW as well as NSPM jurisdictions based on actual demand allocators for each individual year.

NSP v DOE Litigation Cost Summary
General Counsel Outside Legal and Expert Witness Expenses

Amount Recovered Through Jurisdictional Rates

				NSPM			
Year	Total Litigation Cost	Total NSPW	Total NSPM	State of MN	State of ND	State of SD	Wholesale
1998	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1999	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2000	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2001	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2002	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2003	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2004	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2005	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2006	$ 177,807	$ -	$ 177,807	$ 176,564	$ -	$ -	$ 1,242
2007	$ 177,807	$ -	$ 177,807	$ 176,564	$ -	$ -	$ 1,242
1998 to 2007	$ 355,613	$ -	$ 355,613	$ 353,129	$ -	$ -	$ 2,484
2008	$ 186,725	$ -	$ 186,725	$ 176,564	$ 8,919	$ -	$ 1,242
2009	$ 319,445	$ -	$ 319,445	$ 305,641	$ 8,919	$ -	$ 4,886
2010	$ 334,135	$ -	$ 334,135	$ 305,641	$ 8,919	$ 14,690	$ 4,886
2008 to 2010	$ 840,306	$ -	$ 840,306	$ 787,846	$ 26,756	$ 14,690	$ 11,014
2011	$ 486,800	$ -	$ 486,800	$ 442,462	$ 29,054	$ 14,690	$ 595
Total	$ 1,682,719	$ -	$ 1,682,719	$ 1,583,437	$ 55,810	$ 29,379	$ 14,093

NSP v DOE Litigation Cost Summary

General Counsel Outside Legal and Expert Witness Expenses

Amount of Over / (Under) Recovery

				NSPM			
Year	**Total Litigation Cost**	**Total NSPW**	**Total NSPM**	**State of MN**	**State of ND**	**State of SD**	**Wholesale**
1998	$ (70,195)	$ (10,804)	$ (59,390)	$ (52,424)	$ (3,576)	$ (2,994)	$ (397)
1999	$ (448,624)	$ (67,996)	$ (380,629)	$ (337,045)	$ (21,932)	$ (18,840)	$ (2,812)
2000	$ (18,477)	$ (2,781)	$ (15,696)	$ (13,936)	$ (899)	$ (759)	$ (102)
2001	$ (284,979)	$ (44,399)	$ (240,581)	$ (212,478)	$ (14,124)	$ (12,335)	$ (1,644)
2002	$ (171,146)	$ (26,410)	$ (144,736)	$ (127,763)	$ (8,462)	$ (7,382)	$ (1,129)
2003	$ (155,121)	$ (23,155)	$ (131,965)	$ (116,505)	$ (8,024)	$ (6,416)	$ (1,020)
2004	$ (293,178)	$ (44,570)	$ (248,607)	$ (219,059)	$ (14,681)	$ (12,554)	$ (2,314)
2005	$ (1,121,041)	$ (176,534)	$ (944,507)	$ (828,882)	$ (55,768)	$ (48,916)	$ (10,941)
2006	$ (2,376,179)	$ (407,077)	$ (1,969,102)	$ (1,704,726)	$ (129,192)	$ (113,316)	$ (21,867)
2007	$ (492,365)	$ (105,308)	$ (387,057)	$ (312,897)	$ (32,135)	$ (29,367)	$ (12,659)
1998 to 2007	$ (5,431,304)	$ (909,034)	$ (4,522,270)	$ (3,925,713)	$ (288,794)	$ (252,879)	$ (54,884)
2008	$ (79,551)	$ (41,479)	$ (38,071)	$ (18,406)	$ (3,817)	$ (11,541)	$ (4,308)
2009	$ (812,852)	$ (182,493)	$ (630,358)	$ (521,411)	$ (44,978)	$ (50,558)	$ (13,411)
2010	$ (681,506)	$ (166,136)	$ (515,369)	$ (441,766)	$ (38,466)	$ (32,849)	$ (2,288)
2008 to 2010	$ (1,573,908)	$ (390,109)	$ (1,183,799)	$ (981,582)	$ (87,261)	$ (94,949)	$ (20,007)
YTD 2011	$ 176,020	$ (50,340)	$ 226,361	$ 211,993	$ 13,920	$ 163	$ 285
Total	$ (6,829,192)	$ (1,349,484)	$ (5,479,708)	$ (4,695,302)	$ (362,135)	$ (347,665)	$ (74,606)

Note:

(1) Actual Litigation costs were allocated between NSPM and NSPW as well as NSPM jurisdictions based on actual demand allocators for each individual year.