EL05-008

Xcel Energy[SM]

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March 11, 2005

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SOUTH DAKOTA PUBLIC
UTILITIES COMMISSION

Ms. Pam Bonrud, Executive Director
South Dakota Public Utilities Commission
State Capitol Building
500 East Capitol Avenue
Pierre, South Dakota 57501-5070

Re: In the matter of the petition of Northern States Power Company d/b/a Xcel Energy for affirmation that MISO Day 2 costs are recoverable under the Fuel Clause Adjustment Statute and Tariffs and request for approval of tariff modifications.

Dear Ms. Bonrud:

Enclosed for filing is an original and ten copies of a petition from Northern States Power Company d/b/a Xcel Energy requesting South Dakota Public Utility Commission confirmation that the net costs and revenues associated with serving the Company's retail electric customers in South Dakota through participation in the Midwest ISO's "Day 2" wholesale electric energy market are appropriate for inclusion in the Company's Fuel Clause Rider Tariff as set forth in its Electric Rate Book and provided for under SDCL 49-34A-25.

The Company also requests that the Commission approve these proposed revisions to become effective as of April 1, 2005, the planned implementation date for the Day 2 Market. In addition, Attachment A to the filing lists a number of example Day 2 Market transactions, and Attachment B contains the revised Fuel Clause Rider Tariff.

If anyone has any questions, please call me at 339-8350

Sincerely,

JCWilcox

Jim Wilcox

Enclosures

STATE OF SOUTH DAKOTA
BEFORE THE
SOUTH DAKOTA PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE PETITION OF NORTHERN STATES POWER COMPANY D/B/A XCEL ENERGY FOR AFFIRMATION THAT MISO DAY 2 COSTS ARE RECOVERABLE UNDER THE FUEL CLAUSE ADJUSTMENT STATUTE AND TARIFFS AND REQUEST FOR APPROVAL OF TARIFF MODIFICATIONS	DOCKET NO. EL05-__ **PETITION**

OVERVIEW

As the South Dakota Public Utilities Commission ("SD PUC" or "the Commission) is aware, the Midwest Independent Transmission System Operator, Inc. ("MISO" or "Midwest ISO") is preparing for the transition to the "Day 2 Market" under the direction of the Federal Energy Regulatory Commission ("FERC") and pursuant to the Midwest ISO's Transmission and Energy Markets Tariff ("TEMT"). Implementation of the Day 2 Market will change the manner in which MISO utilities procure electric energy and how they are charged for resources needed to serve their customers.

With this Petition, Northern States Power Company d/b/a Xcel Energy ("Xcel Energy" or "the Company") seeks Commission affirmation that certain charges under the TEMT reflect the costs for *wholesale rates for energy delivered* that Xcel Energy will incur to provide electric service to retail customers. As such, the Company believes these expenses should be eligible for recovery pursuant to the Commission's fuel clause process provided by SDCL 49-34A-25 and the Company's Fuel Clause Tariff Rider. Consistent with this affirmation, the Company also seeks approval of a revised Fuel Clause Rider Tariff to specify additional terms in our South Dakota Electric Rate Book. The proposed Fuel Clause Tariff Rider changes would allow certain revenues associated with Day 2 wholesale transactions to flow to customers, similar to the approach used with financial instruments purchased to limit wholesale electric supply cost volatility (Docket No. EL99-021, order dated May 10, 2000). We respectfully ask the Commission for an order affirming the Company's recovery authority and approving our proposed changes to the Fuel Clause Rider Tariff.

The MISO TEMT is presently scheduled to go into effect on April 1, 2005. The Company respectfully requests that the Commission allow this revised tariff to be placed into effect as of April 1, 2005 or by the effective date of the MISO Day 2 Market if later than April 1, 2005. The Company respectfully requests the Commission allow the proposed Fuel Clause Rider revisions to go into effect on less than thirty (30) days notice pursuant to SDCL 49-34A-12 and ARSD 20:10:13:20. Alternatively, the Company requests the Commission grant any necessary waiver to the express terms of the existing Fuel Clause Tariff Rider to allow recovery of the MISO TEMT charges and revenues until the proposed Fuel Clause Tariff Rider provisions are placed into effect.

General Filing Information

Xcel Energy provides the following information.

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THE PROPOSED FINDINGS AND TARIFF CHANGES WOULD SERVE THE PUBLIC INTEREST

Background

In the January 2000 FERC order approving the Xcel Energy Inc. merger, the FERC required the Company to join the Midwest ISO as a condition of merger approval. *Northern States Power Company et al.*, 90 FERC ¶ 61,020 (2000). In May 2000, the FERC issued an order approving the transfer of functional control over the Company's transmission system to the Midwest ISO effective with the start of Midwest ISO RTO operations. *Northern States Power Company et al.*, 91 FERC ¶ 61,157 (2000). Under the doctrine of federal preemption (and SDCL 49-34A-38, to the extent it applies) the Company was not required to obtain Commission authorization to transfer functional control of its transmission facilities in South Dakota to the Midwest ISO because such transfer had been approved by a federal agency. MISO began "Day 1" RTO operations on February 1, 2002, and MISO has been responsible for, *inter alia*, transmission services and certain regional reliability functions since that time.

On March 31, 2004, the Midwest ISO filed its proposed TEMT to establish its "Day 2" market operations effective December 1, 2004. On May 26, 2004, FERC issued a preliminary order accepting the TEMT for filing subject to certain procedures, and delayed the effective date to March 1, 2005. On August 6, 2004, FERC issued a second order conditionally accepting for filing MISO's TEMT.[1] On November 8, 2004, FERC denied all requests for rehearing of the August 6 Order.[2] The Organization of MISO States ("OMS"), to which the Commission is a member, actively participated in many aspects of the TEMT proceedings at FERC.

The TEMT contains several modules. Module A is a list of general terms. Module B relates to the provision of network and point-to-point transmission service and sets forth the related charges for transmission access, including MISO Schedule 10 fees associated with MISO's operational control over transmission. Most relevant to this filing, Module C includes the rates, terms and conditions necessary for the implementation of a region-wide, security constrained, centralized economic dispatch platform energy market. Day-Ahead and Real-Time Energy Markets, based on Locational Marginal Pricing ("LMP") and hedged with Financial Transmission Rights

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1 Midwest Independent Transmission System Operator, Inc., 108 FERC ¶101,163 (2004) ("August 6 Order").

2 Midwest Independent Transmission System Operator, Inc., 109 FERC ¶61,157 (2004) ("November 8 Order"). Several parties have filed appeals of the FERC orders, which are pending before the D.C. Circuit Court of Appeals. However, the appeals are not expected to affect Day 2 Market implementation.

("FTRs"), support this wholesale market platform. This new Day 2 market design for wholesale energy transactions is currently slated to begin on April 1, 2005.

Implementation of the TEMT and Day 2 Market will change the way the Company generates and purchases energy for delivery to serve retail native load customers in South Dakota. All Company generation and load will participate in the Day Ahead and Real Time Markets, and generation is subject to economic dispatch by MISO. As a result, MISO member utilities must submit load bids into the market, and these purchases of energy from the Midwest ISO and made by Xcel Energy will result in an additional cost associated with delivery of generation. However, to the extent that the Company's generation is offered into the market and clears the market, it will be dispatched by MISO. For "self scheduled" or "must run" transactions (as well as bilateral transactions), a "Transmission Usage Charge" consisting of congestion costs and marginal losses is applied to the delivery. MISO will pay generators at market-clearing prices, and the Company proposes to treat these revenues as a credit to our purchased energy expense. The MISO pricing formula is such that the load purchases and generator credits are offsetting except for congestion and marginal losses.

Presently, Xcel Energy and other South Dakota electric utilities recover the cost of purchased energy, fuel, delivered losses, and congestion (in the form of redispatched generating units under the NERC Transmission Loading Relief or "TLR" process) through the fuel clause. When MISO implements the Day 2 Market, the Company will continue to incur these costs, but the name, form and means of calculating costs and revenue will change. As explained below, these new charges and credits will still reflect the costs of "wholesale rates for energy delivered" needed for serving our retail electric customers. As such, the cost recovery in rates should continue in a manner similar to recovery under the Day 1 market.

We believe that under the new MISO methodology, the overall cost for energy included in electric rates will be comparable to the costs contemplated to be recovered by the fuel clause statute (SDCL 49-34A-25) and the Fuel Clause Rider in our South Dakota Electric Rate Book. Our approach is not an expansion of the scope of the fuel clause. Rather, this proposal attempts to reflect all of the different costs and credits to expense that will compose the cost of energy delivered to our customers under the TEMT. In implementing this approach, the Company will continue to use the same principles for allocating native and intersystem wholesale costs assuring that native load has first call on least cost generation resources. As such, we believe that the Commission can and should make the affirmative findings requested by this Petition and approve the proposed Fuel Clause Rider Tariff changes effective on the implementation date of the Day 2 Market.

Summary of Request

The Company respectfully requests that the Commission affirm that the Company's Fuel Clause Rider (as revised) and South Dakota Statutes (specifically SDCL 49-34A-25) allow for fuel clause recovery of the costs of providing energy delivered to South Dakota retail customers and thus accommodate recovery and pass through of various MISO Day 2 charges and revenues. Specifically, we ask that the Commission:

- Affirm that existing South Dakota Statutes and Fuel Clause Rider (SOUTH DAKOTA ELECTRIC RATE BOOK - SDPUC NO. 2 – Section No. 5 – 2nd Revised Sheet No. 64) allows for fuel clause recovery of the costs of providing energy to South Dakota retail electric customers and thus accommodate recovery and pass through of various Day 2 costs and revenues billed or paid by MISO.

- Approve the proposed revised Fuel Clause Rider Tariff that reflects the anticipated MISO charges and credits and their treatment in the Company's fuel clause effective as of April 1, 2005, and grant any waiver necessary to allow the proposed tariff change to be effective on less than 30 days notice.

- Grant any Fuel Clause Rider waivers needed to effect this affirmation, primarily by (a) allowing the Company to pass through certain revenues received from MISO, (b) allowing for accounting of Financial Transmission Rights and load bid costs and generator credits to be netted in Account 555, and (c) granting any waivers to the existing Fuel Clause Rider to allow fuel clause treatment of the costs and revenues, if necessary, prior to the effective date of the proposed change to the Fuel Clause Rider tariff.

Detailed Description of the Company's Request

1. Overview and Benefits of the Day 2 Market Design

The Day 2 Market is the result of a tariff filing made by the Midwest ISO pursuant to a FERC Order pursuant to Order No. 2000. As a member of the Midwest ISO RTO, Xcel Energy will be subject to the TEMT as a tariff on file with FERC and will be required to participate in the Day 2 Market. Xcel Energy will offer generation into a Day Ahead and Real Time Market. We will bid our load into the Day Ahead Market. Prices for energy will be based upon the market-clearing price for energy plus the cost of congestion and marginal losses. The Company will be allocated Financial Transmission Rights ("FTRs") to hedge its exposure to congestion costs. In addition, in its Order approving the TEMT, the FERC required the Midwest ISO to reimburse load-serving entities for the difference between marginal and average losses. Entities will be allowed to self-schedule both owned and contracted generation so as to avoid exposure to daily market prices. With the appropriate accounting treatment and waivers, these transactions can be effectively netted, preserving low cost resources for native load customers.

The purpose of the Day 2 Market is to produce greater short-term energy supply efficiencies through the region-wide economic dispatch of generation and greater long-term efficiencies by sending price signals as to the most cost-effective locations for adding generation or transmission to the grid. The Midwest ISO has conducted analyses submitted to the FERC showing that there are benefits to the region from an LMP market design.

The larger dispatch footprint offered by MISO compared to our current generation and purchases offers the potential for energy savings. These savings will occur whenever MISO can dispatch generation units within its footprint at a lower cost than would otherwise have been incurred by individual member market participants (and thus their ratepayers). While it is difficult to predict the magnitude or timing of any potential savings, it is worthwhile to point to specific instances where the Company can expect benefits to accrue to ratepayers. While it is difficult to quantify the benefits of a new market design (since the Company has not operated under it) or the timing of when those benefits will accrue, there are several ways that we anticipate potential savings may occur.

First, while bilateral energy exchanges in today's wholesale environment have enabled the Company to reduce costs for ratepayers, the centrally dispatched market offered by MISO expands the potential for beneficial exchanges. A centralized market should offer greater liquidity and transparency that should provide for more efficient pricing than a bilateral market. As a significant purchaser of energy, Xcel Energy views this as a positive development for its ratepayers. We currently look to reduce fuel costs by making purchases at a price below our incremental cost of production. To the extent MISO's expanded footprint and increased liquidity provide additional opportunities to buy down our costs of generation, savings will accrue to our ratepayers.

Second, the Company currently is forced to operate generation units or make purchases out of economic merit order to maintain reliability for the entire region. In these circumstances, our ratepayers pay higher rates by virtue of the increased fuel costs associated with operating facilities out of merit order. To the extent MISO can redispatch the region to reduce the magnitude of out of merit order generation, savings will accrue to the Company's ratepayers.

Third, the congestion management system being implemented by MISO in Day 2 will promote more efficient use of our limited transmission resources. The existing approach to managing transmission congestion relies on estimating Available

Flowgate Capacity (AFC) for purposes of reserving and scheduling available capacity and curtailments of transmission service under Transmission Loading Relief (TLR) procedures. The TLR procedure is a form of rationing that is based on non-economic criteria: all transmission service schedules affecting the constrained transmission element are curtailed, and often dozens (or hundreds) of transactions may be affected to cause a small reduction in physical flow on the constrained facility. Like all physical rationing mechanisms, this system creates inefficiencies compared to a market-based congestion management system provided in MISO Day 2, which will allow MISO to target specific transactions that can most effectively reduce the constraint, allowing the remaining transactions to continue. Specifically, the inherently imprecise TLR procedures result in underutilization of transmission capacity, thus limiting additional economic exchanges between participants. The Day 2 market will replace the "shotgun" approach of TLR with the "rifle shot" approach to congestion management.

There are also long-term benefits associated with locational price signals. Load-serving entities like Xcel Energy will be able to determine with greater precision where additional generation or transmission facilities can provide the greatest benefit to ratepayers. That is, where locational prices are consistently high, additions of generation or transmission will provide the greatest likelihood of lowering costs for all ratepayers. While transmission studies can be performed currently that help to inform such decisions, they cannot provide the market-based information that is so critical to a cost/benefit analysis of large resource additions.

Finally, there are reliability benefits associated with Day 2. MISO's improved ability to redispatch generation over a larger footprint will lessen the potential impacts that transmission outages will have on the grid during periods of adverse operating conditions. As discussed above, the current TLR based congestion management system underutilizes transmission capacity compared to a market-based congestion management system. Therefore, transition to the market-based congestion management system being implemented by MISO in Day 2 is expected to improve reliability for all market participants.

There are also costs associated with implementation of the Day 2 Market and risks associated with the movement to an LMP market design. It is difficult to predict the extent of any costs related to energy or congestion until we begin to experience congestion charges to determine the adequacy of the FTR allocation process. We also do not know the extent of certain market "uplift" costs under the TEMT (e.g., costs allocated by MISO to all users under the TEMT). Finally, while we can reasonably predict the normalized value of costs associated with operations of an energy market, these costs will be incurred primarily on a MWH basis and thus will vary every month based on actual customer energy demand.

We expect that over time, the benefits of the new market structure will outweigh these costs. However, this may not occur upon implementation, as a market designed to garner efficiencies from optimized use of the grid will take time for participants in the market to adjust to in making decisions regarding generation offers that will enhance efficiency. Further, savings from more efficient generation and transmission locational decisions may take years to fully realize.

Our petition seeks to address the changes occurring under the new MISO market structure by linking Day 2 costs and revenues/credits through the fuel clause such that ratepayers pay the net cost of energy delivered under this new market structure.

2. Affirmation regarding fuel clause statutes.

South Dakota Statutes govern the Company's fuel clause process and tariffs. SDCL 49-34A-25 provides that:

> *The commission shall permit a public utility to file rate schedules containing provisions for the automatic adjustment of charges for public utility service in direct relation to changes in wholesale rates for energy delivered, the delivered costs of fuel used in generation of electricity, the delivered cost of gas, ad valorem taxes paid, or commission approved fuel incentives.*

This statute requires the Commission to allow the Company to file rate schedules (such as the Fuel Clause Rider) allowing recovery of "wholesale rates for energy delivered." MISO charges and revenues to the Company will be billed (or paid) pursuant to MISO's wholesale TEMT rates on file with FERC. We respectfully request that the Commission affirm that this statute allows for recovery and pass through of TEMT charges (costs) and credits (revenues) from MISO to reflect the actual costs of providing fuel and purchased energy on behalf of retail customers. Because the various components of the Day 2 Market are in aggregate comparable to many of our current activities and costs incurred that are recoverable under the fuel clause statute and the Company's fuel clause tariff, the Company believes that the Commission should affirm the appropriateness of their recovery.

The Company's South Dakota utility operation is not alone in needing to address the impact of a Day 2 Market design. Xcel Energy has also filed applications with the Minnesota PUC and the North Dakota PSC that seek similar state regulatory acknowledgement and fuel clause tariff changes.

3. Description of Day 2 Costs and Revenues Subject to the Fuel Clause Process

We illustrate the comparability of anticipated Day 2 Market costs and revenues to components of today's environment below. The Company also provides several examples of how costs and revenues under specific transactions would be reflected in the fuel clause in Attachment A to this petition.

- *Day-Ahead Market.* The Day-Ahead Market, which provides a means for parties to lock in prices for energy in advance of real-time, is an augmentation of economic dispatch currently conducted by individual utilities. It will not differ markedly from how we currently dispatch our system in terms of function. Xcel Energy will perform the same functions we do now in dispatching generating plants, except that dispatch will be under MISO's centralized security constrained dispatch market regime and units will be dispatched based on prices offered to the market (unless the unit is self-scheduled and/or designated as a "must-run" resource).

  The generation resources of utilities (including the Company) will be offered into the Day Ahead Market and if accepted, will receive LMP prices at the location of the resource. Load serving companies will make purchases from this market based on Day Ahead LMP prices at various load locations (referred to as "nodes"). The LMP prices include the market-clearing cost of energy and the cost of congestion and marginal losses at various nodes. This structure tends to separate generation from retail load. However the MISO has mechanisms that assure that the Company will retain control over our generation through self-scheduling and/or must run designations and Xcel Energy's generating resources will remain available to serve native load through the combination of appropriate ratemaking and resource scheduling strategies.

- *Preserving Native Transactions.* There are several approaches we expect to use to ensure that our native load continues to have first call on our low-cost resources. For transactions in the Day 2 Market with MISO, the most common means of achieving this result is to designate a unit as must run or to self-schedule units, assuring that the electric output is taken by the market. Our generation fleet will be making sales to the MISO at the same time our load is purchasing from the MISO. By flowing the cost of fuel through Account 501 and netting what is referred to as the generation market sale and load purchase along with revenues or expenses from FTRs and Marginal Loss Compensation revenues (discussed below) through the fuel clause, native load customers in South Dakota will pay a cost that is comparable to the cost of producing the electricity from rate based generation, as is the case today, with the new feature of optimized congestion management. Under our proposal certain revenue streams related to generator payments and FTR revenues will be credited to expense in Account 555 thereby netting the costs of congestion and load purchases made on behalf of retail load.

- *Bilateral Agreements.* The Company has many longstanding bilateral wholesale power contracts, where the Company can purchase from or sell to another market participate (e.g., Ottertail Power Company or Manitoba Hydro) when it is economically advantageous to do so. Bilateral contracts scheduled in the Day-Ahead Market will be treated as if the resource is an owned generation resource of the Company. With Day 2, a Transmission Usage charge is applied to the transactions based on LMP prices at the point of injection and the point of delivery.

- *Real-Time Market.* MISO's Real-Time Market will coordinate energy flows throughout the operating day. The Real-Time Market provides a mechanism for market participants to cover imbalances and deviations from their Day-Ahead schedules, similar to what the Company currently does on an hourly basis. Unlike the Day Ahead Market, congestion in the MISO Real Time Market is not capable of being hedged through the use of FTRs.

- *MISO Operations and uplift costs.* The Company will be charged for MISO market operations and for certain energy market costs that will be allocated to all load. These charges are incurred as part of the wholesale tariff that establishes the LMP market and they will be billed primarily on a per MWH basis and are an extension of the variable costs of procuring energy. (These costs are described in more detail below).

- *Financial Transmission Rights.* MISO will administer a system of financial transmission rights ("FTRs") to allow parties to hedge against price risk from the congestion component of Day Ahead LMP prices. The primary objective of FTRs is to keep current transmission customers whole with respect to congestion costs to the extent possible. An FTR is a financial instrument, not a physical right to transmission capacity.[3] Xcel Energy will be allocated FTRs based on preexisting physical transmission rights to deliver energy to hedge against the congestion charge components of an LMP energy price. In

[3] The primary advantage of organizing dispatch around financial -- as compared to physical -- rights to the grid is that FTRs do not restrict economic dispatch. In strict, physical-rights systems (*i.e.*, the historic MAPP trading practices or MISO Day 1), the physical transmission rights must match the supply transaction to guarantee physical access, and the value of any rights not "used" is lost.

addition, we may participate in future MISO FTR auctions for such rights to hedge ongoing incremental transmission use.

The Company plans to account for FTR revenues /credits to expense and expenses on a unit specific, transaction basis (retail vs. wholesale) as the allocated FTRs will be associated with paths for a generation unit or a bilateral transaction. To the extent that we are assigned either positive (revenues/credits to expense) or negative (expenses) FTRs for resources not taken by the Day Ahead Market, we will allocate these revenues and expenses to native load. Additionally, we will buy and sell FTRs to optimize our position in a secondary FTR market, when this market is developed.

- *Marginal Losses Compensation.* In its Order approving the TEMT, FERC required MISO to return to transmission customers the difference between marginal losses and average or historical losses for a five-year transition period. The net effect is that there should be little impact on fuel clause costs from including both LMP costs and this revenue stream. Today, the Company recovers the cost of system average delivered losses in the fuel clause. The Company proposes to flow the marginal loss revenues to retail customers through the fuel clause and to the extent possible will allocate these revenues on a transactional basis.

- *Schedules 16 and 17.* Schedules 16 and 17 to the MISO TEMT contain charges associated with MISO's administration of the FTR and Energy Market functions. Schedule 16 provides for the recovery of all costs incurred by MISO in providing FTR services and includes costs associated with: 1) coordination of FTR bilateral trading; 2) administration of FTRs allocation, assignment, or auction and 3) simultaneous feasibility analyses to determine the total combination of FTRs that can be outstanding and accommodated by the Midwest ISO at a given point in time. Schedule 17 provides for the recovery of all costs incurred by the Midwest ISO in providing: 1) market modeling and scheduling functions; 2) market bidding and LMP support; 3) enabling least-cost Security Constrained Economic Dispatch; and 4) market monitoring functions. The Company will be billed Schedule 16 and 17 fees and will be obligated to pay them to MISO as filed rates.

- *Uplift Charges.* FERC has approved four "uplift" charges to be assessed to all Day 2 market participants, including Xcel Energy. These uplift charges will also be billed to the Company and payment will be required under the TEMT as a filed rate.

The first is an Offer Revenue Sufficiency Guarantee Charge. The TEMT guarantees recovery of a market participant's generation offer for resources committed by MISO and scheduled in the MISO market operations. By guaranteeing that costs will be met, MISO is able to select and commit resources at minimum cost while preserving reliability. Without such resources committed in the forward market, MISO would have to commit units with higher production costs. Hence, in the event that there is a shortfall experienced by a generator (when comparing its offer to the market-clearing price), this deficiency will be borne by MISO and "uplifted" by recovering the cost from all market participants based on the energy delivered to their load.

The second uplift charge, termed Option B uplift, compensates market participants in highly congested areas who may incur significant congestion costs compared to other market participants. FERC required MISO to establish an optional, voluntary FTR protocol for transmission customers in these highly congested areas. In exchange for forgoing certain rights and abiding by certain rules, these customers will be assured that -- to the extent their FTRs are insufficient to cover congestion charges -- the difference will be made up by other MISO customers through this uplift charge. These costs would be borne by all other market participants, including Xcel Energy's native load.

The third uplift charge is for Uncollectible Default Accounts. This charge recovers MISO's costs associated with the default of market participants regarding their obligations in MISO's market. FERC has found it reasonable for this cost to be borne by all participants in all regional transmission organization.

The last uplift is the "revenue neutrality uplift" which assures that any excess costs or excess revenues be assessed or returned to load serving market participants.

Because these charges are (or will be) contained in FERC-approved filed wholesale rates required in the procurement of energy services for our customers, we believe they are appropriate for recovery as a cost of energy delivered. The majority of these costs will be assessed on a per MWH basis and thus charged very much like an energy purchase.

As noted above, we anticipate that there is the potential for both short term and long run benefits in the form of lower energy costs and optimized investments in generation and transmission that will accrue to customers. Thus, we believe that a continuation of the current mechanism for recovery of all variable fuel and energy related net costs through the Company's Fuel Clause Rider is appropriate.

While our proposal attempts to ensure that customers retain the same value that they have today, taking into consideration new market conditions, we recognize that there is uncertainty involved with implementation of major market changes as provided by the TEMT. For example:

- There is the potential that the allocation of FTRs could be limited if insufficient rights are available and that we are allocated negative FTRs.

- There is the potential that Xcel Energy could be allocated "counterflow" FTRs to allow FTRs to be allocated to other MISO participants, and such counterflow FTRs could produce negative values (e.g., expenses to be recovered).

- On days of higher load than was settled in the Day Ahead market, real time purchases will be subject to congestion charges based on market conditions.

Given these factors and other uncertainties, no one can guarantee the ultimate impact on customers, although it is our expectation that over time benefits will accrue to customers from a market that optimizes the use of the transmission grid and provides access to a broader set of resources in a more efficient manner than exists today. With this filing and our participation in the development of the Day 2 Market, we are working to ensure customers obtain the value of the new market while retaining the benefit of the existing framework to the extent possible.

Attachment A provides examples of how we expect to apply these new market features to specific transactions and the resulting outcome under today's environment, our proposal and the TEMT with no modification to the fuel clause.

4. *Fuel Clause Treatment of Both Costs and Revenues is Appropriate*

The costs Xcel Energy will incur under Module C of MISO's TEMT are clearly linked to the purchase of least-cost energy for our native load customers. Participation in this Market is required by FERC for participants in MISO, and it represents how we will procure most of our energy for our customers going forward.[4] By proposing to

[4] The transition to MISO Day 2 is analogous to the transition in the wholesale natural gas market starting in the late 1980s. At that time, FERC prohibited interstate gas pipelines from making bundled wholesale natural gas sales, and required structural separation of the transmission function from the wholesale gas sales and storage functions. FERC ordered pipelines to modify their FERC tariffs accordingly. The wholesale natural gas procurement function of retail local distribution companies ("LDCs') regulated by the Commission had no option but to implement these federal mandates: the LDCs were required to begin direct procurement of natural gas supplies, storage services, etc., and

flow through the fuel clause both the costs credits and revenues associated with the Day 2 Market, we believe that – even though the approach is new -- the fuel clause will reflect the same policy in place today: that the fuel clause mechanism, rather than a base rate approach, be used to capture the cost of energy delivered to retail customers. The net costs under the proposal are incurred for energy under a Day 2 regime. As such, we believe the Commission can find that its purpose in establishing the fuel clause, to reflect changes in these costs outside of rate cases, is satisfied by granting this Petition.

With respect to other key components of the Day 2 Market, we note that FTRs are financial instruments, not direct costs of purchased energy, making them similar to the financial instruments previously approved for recovery through the Fuel Clause Rider. Because FTRs hedge congestion costs and are an integral part of the new market design, including the applicable portion of FTR revenues/credits or costs is likewise appropriate and consistent with previous Commission precedent.

Since the purpose and application of the fuel clause statute and the Company's Fuel Clause Tariff Rider is to provide for recovery of the cost of energy delivered to customers, the Commission should affirm that recovery of Day 2 Market costs through the fuel clause and the proposed modifications to the Fuel Clause Tariff Rider are appropriate.

5. Proposed Fuel Clause Tariff Rider And Implementation

a. The Proposed Fuel Clause Tariff Rider Revisions

Attachment B contains our proposed Fuel Clause Rider to implement the Day 2 Market changes and reflect TEMT costs. As discussed previously, the Company respectfully requests approval of this tariff to be effective April 1 with the implementation of MISO's TEMT.

The proposed tariff changes provide for inclusion in the fuel clause, costs and revenues resulting from generation resources (including bilateral agreements), offers to the market and load purchases from the market as linked to the underlying fuel or purchased energy costs. In addition, FTR revenues and expenses, operational costs of an RTO (e.g. Schedule 16, 17 and uplift costs) and Marginal Loss Compensation revenues associated with underlying native load fuel or purchased energy costs are also considered linked to the cost of energy and included in the fuel clause. Because

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reflected those costs in their Purchased Gas Adjustment tariffs, also filed pursuant to SCDL 49-34A-25. The resulting wholesale gas market proved to be significantly more efficient than the prior structure, however.

all components of the new energy market and their names may evolve, the language focuses on costs and revenues associated with FERC approved RTO markets excluding those costs and revenues associated with intersystem sales. The revised proposed tariff rider, Attachment B, adds a new Paragraph 5 to reflect the treatment of these various new RTO costs and credits to expense as well as the Marginal Loss compensation revenues.

b. Accounting and Settlements

The Company seeks Commission approval to book payments from generation offers and FTR payments to the market made on behalf of retail load to Account 555 and Marginal Loss Compensation revenues in Account 456. Load purchases (which include the costs of congestion and marginal losses) and native load FTR expenses would be booked to Account 555. We anticipate establishing sub-accounts or business unit codes for capturing native transactions to more easily identify linked costs and revenues. We have pursued net accounting where payments are treated as a credit to expense to avoid jurisdictional concerns raised if native generation is treated as a wholesale sale. As such, we seek approval of this accounting treatment.[5]

The settlements process involved with the Day 2 Market will add a significant layer of complexity to our billing and accounting processes. The Midwest ISO will bill the Company weekly. The bill will be settled for Day Ahead, Real Time and settle LMPs and FTRs. Each bill will be supported with individual settlement statements and a summary settlement statement for each operating days over multiple periods including a 7 day ("S7"), 14 day ("S14"), a 55 day ("S55") and 105 day settlement period as well as a dispute process following settlement. Xcel Energy has been actively preparing for implementing the back office support for Day 2 and we are willing to provide additional information to the Commission of how we intend to manage this process.

6. Waivers

While the Company believes its proposal for treating Day 2 Market costs is consistent with the purpose of the fuel clause statute (SDCL 49-34A-25) and should be affirmed, and our Fuel Clause Tariff Rider (as amended) should be approved, we recognize that the currently effective Fuel Clause Tariff Rider did not anticipate all of the charges provided by the TEMT or provide for the pass-through of associated credits/revenue.

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[5] We note that the FERC is seeking comment on the need for a rulemaking regarding RTO accounting. See Docket No. RM-04-[insert]. Thus, these designations are likely to evolve.

Moreover, the Company is filing the proposed tariff change on March 11, 2005, less than thirty (30) days before the proposed effective date.

Consequently, to allow fuel clause treatment of the TEMT costs and revenues on the April 1, 2005 effective date of the MISO Day 2 market, the Company respectfully requests that the Commission waive the 30 day notice requirement of ARSD 20:10:13:20 pursuant to the discretionary waiver authority provided in SDCL 49-34A-12, so the revised Fuel Clause Tariff Rider may be placed into effect on April 1, 2005 as proposed.

Alternatively, until the proposed tariff changes are approved, the Company requests that the Commission allow the Company to waive the express terms of the Fuel Clause Tariff Rider to allow fuel clause treatment of the TEMT expenses and revenues effective April 1, 2005, if the effective date of the proposed changes to the Rider are not allowed to be effective April 1, 2005 as proposed. We respectfully request any other waivers that are deemed necessary to implement fuel clause treatment of the TEMT expenses and revenues pending approval of the proposed tariff.

Essentially the FERC has mandated a fundamental modification of the wholesale electric marketplace for the Midwest. The Company's Fuel Clause Tariff is being updated to reflect this change. The Company believes that SDCL 49-34A-25 provides the flexibility to respond to market changes. This petition attempts to demonstrate that there is good cause to make these changes at this time. As the MISO Day 2 Market is implemented, the Commission can determine if or how the fuel clause process may need to change to reflect this evolution in the broader wholesale market as mandated by FERC.

7. Additional Fuel Clause Reporting

We recognize that the transition to the Day 2 Market is of significant interest to the Commission. To ensure on-going information exchange regarding the transition, we propose to provide in our monthly fuel clause filings a breakdown of the various components of TEMT charges charged to retail customers including:

- Total Purchases from MISO related to linked transactions;
- Total payments from MISO related to self-scheduled or must run transactions;
- Total congestion and marginal loss costs charges;

- Total FTR credits and expenses; and
- Total Marginal Loss Compensation revenue.

We propose to begin this additional reporting in the second month after MISO Day 2 Market operations begin. This type of reporting should permit the Commission to monitor the impact of Day 2 on our costs to customers.

CONCLUSION

The MISO Day 2 Market poses a significant change for utilities and regulators. We believe that this proposal for treatment of the various charges associated with Day 2 will most appropriately retain the current balance between customers and the Company offered by the fuel clause process. For that reason, we respectfully request that the Commission:

- Affirm the appropriateness of recovery through the Company's Fuel Clause Rider;
- Approve the net accounting treatment so that payments by MISO to generators and payments associated with FTRs are credited to expense in the Fuel Clause Rider.
- Approve our proposed Fuel Clause Tariff Rider that implements these changes effective April 1, 2005.

We believe these proposals are reasonable and appropriate, providing a path toward the new energy marketplace. We are willing to provide any additional information the Commission may require when considering this proposal.

Respectfully submitted,

J C Wilcox

James C. Wilcox
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Northern States Power Company d/b/a Xcel Energy

ATTACHMENT A
MISO DAY 2 TRANSACTION EXAMPLES

The following examples show how the proposed fuel clause treatment for TEMT related costs and revenues would apply, and compares the results the costs currently included in the fuel clause and the new wholesale purchase cost.

Scenario 1
Self-Scheduling And No Congestion

Xcel Energy self schedules 500 MW of generation to load from Sherco Plant for 24 hours in the Day-Ahead market. The Day-Ahead market settles at an LMP price of $21.00/MWH ($20 energy and $1 of marginal losses) for energy from this bus to the designated load node (the LMP price for generation). 500 MW of Xcel Energy load gets picked up at the Day Ahead price of $21.50/MWH. (The difference in load vs. generation LMP prices is caused by a different marginal loss component for each.) The fuel cost for Sherco for this period is $10/MWH. FTRs are not a factor in this example as there is no congestion in the Day Ahead market.

Resulting Charges:

- Xcel Energy pays $21.50/MWH (for 500MW*24 hours) to the Midwest ISO.
- The Company incurs costs of $10/ MWH for fuel.
- Xcel Energy receives a payment of $21.00/MWH (for 500 MW*24 hours) from the Midwest ISO for its generation.

Alternative Fuel Clause Outcomes for Customers:

- Today: Customers are charged $10/MWH for cost of fuel.
- Company's Day 2 Proposal: Customers are charged the net of all costs and revenues associated with serving native load, or $10.50/MWH (reflecting the differential in LMP prices due to marginal losses).[6]

[6] Although not shown, Xcel Energy will be compensated for the difference between marginal and average losses by the Midwest ISO and we propose to return these amounts associated with native load through the FCR. The mechanism for the return of this revenue is not known at this time. Also, we do not attempt to reflect MISO operational costs in this or any of the other examples.

Scenario 2
Self - Scheduling With Congestion

Xcel Energy self schedules 500 MW of generation to load from Sherco for 24 hours in the Day-Ahead market. The Day-Ahead market settles at an LMP price of $21.00/MWH ($20 energy and $1 of marginal losses) for energy from this bus to the designated load node (the LMP price for generation). 500 MW of Xcel Energy load gets picked up at the Day Ahead price of $51.50/MWH. (Comprised of $20 energy, $30 for congestion and $1.50 for marginal losses). The difference in load vs. generation LMP prices is caused by a congestion cost and different marginal loss component for each.) The fuel cost for Sherco for this period is $10/MWH. This example assumes that the Company attained FTRs for the Sherco path for the entire 500 MW and the entire 24 hours.

Resulting Charges:

- Xcel Energy pays $51.50/MWH (for 500MW*24 hours) to the Midwest ISO.
- The Company incurs costs of $10/ MWH for fuel.
- Xcel Energy receives a payment of $21.00/MWH (for 500 MW*24 hours) from the Midwest ISO for its generation.
- Xcel Energy receives FTR payments of $30/MWH (for 500 MW*24 hours) from the Midwest ISO.

Alternative Fuel Clause Outcomes for Customers:

- Today: Customers are charged $10/MWH for cost of fuel.

- Company's Day 2 Proposal: Customers are charged the net of all costs and payments associated with serving native load, or $10.50/MWH (reflecting the differential in LMP prices due to marginal losses, as congestion costs are fully hedged)[7]

[7] As noted above, Xcel Energy will be compensated for the difference between marginal and average losses by the Midwest ISO and will flow the retail amounts through the FCR.

Scenario 3[8]
Negative FTRs In Day Ahead Market.

In this example, we bid our load in the day-ahead market and determine that we need to take 500 MW from Sherco for 24 hours in the Day Ahead market. Load is picked up by at a price of $25/MWH (consisting of energy at $25/MWH and no congestion). We self-schedule the Sherco plant into the market and it was purchased by MISO at a price of $40/MWH ($25/MWH for energy and $15/MWH for congestion). The fuel cost for Sherco generation is $10/MWH. The Company holds FTRs for all 500 MW from Sherco for this day.

Resulting Charges:

- Xcel Energy pays $25/MWH (for 500MW*24) to the Midwest ISO.
- The Company incurs costs of $10/ MWH for fuel.
- Xcel Energy receives a payment of $40 /MWH (for 500 MW*24) from the Midwest ISO for its generation.
- Xcel Energy makes an FTR payment of $15/MWH (for 500 MW*24) to the Midwest ISO for holding a negative FTR.

Alternative Fuel Clause Outcomes for Customers:

- Today: Customers are charged $10/MWH for cost of fuel.
- Company's Day 2 Proposal: Customers are charged the net of all costs and payments associated with serving native load or $10/MWH (reflecting the that the FTRs were negative)

[8] This example and the remaining ones do not address the costs associated with marginal losses or Marginal Loss Compensation revenues in order to simplify the transactions.

Scenario 4
Bilateral Purchase

This example involves a long-term bilateral purchase of 500 MW for 16 hours at a pre-established contract price of $35/MWh. Assume the Day Ahead market at the bilateral agreement's injection point clears at $25/MWH (inclusive of energy at $25/MWH and $0/MWH for congestion). Also, assume that the Day Ahead market for load clears at $65/MWH (consisting of energy at $25/MWH and congestion of $40/MWH). Xcel Energy holds 500 MW FTRs for all 16 hours on this long-term purchase.

Resulting Charges:

- Xcel Energy pays the holder of the bilateral agreement $35/MWH for the energy delivered.
- Xcel Energy pays $65/MWH (for 500MW*16 hours) to the Midwest ISO.
- The Company is paid $25/MWH for the LMP rice at the injection point..
- Xcel Energy receives a payment of $40/MWH (for 500 MW*16 hours) from the Midwest ISO for the value of its FTRs.

Alternative Fuel Clause Outcomes for Customers:

- Today: Customers are charged $35/MWH for the energy cost.
- Company's Day 2 Proposal: Customers are charged the net of all costs and payments revenues (including FTR payments) associated with serving native load or $35/MWH.

Scenario 5
Real-Time Purchase With Load Above Forecast

Xcel Energy native load is greater than settled in the Day Ahead Market for 3 hours and we purchase 200 MWHs real time at a price of $100/MWH (which includes an energy price of $80/MWH and a congestion price of $20/MWH). Because Black Dog was not committed day ahead it can inject at our load in real time. An equal amount of generation from Black Dog (200 MWHs) was picked up in real time at a price of $80/MWH. The cost of fuel for the Black Dog natural gas unit during real time was $50/MWH).

Resulting Charges:

- Xcel Energy pays an LMP cost for energy of $100/MWH (for 200MW*3 hours) to the Midwest ISO.
- The Company incurs fuel costs of $50/MWH.
- Xcel Energy receives a payment of $80/MWH from the Midwest ISO for its generation.
- FTRs are not available to hedge congestion costs in the Real Time market.

Alternative Fuel Clause Outcomes for Customers

- Today: Customers are charged $50/MWH for the fuel cost.
- Company's Day 2 Proposal: Customers are charged the net of all costs and revenues associated with serving native load or $70.00/MWH.

There shall be added to or deducted from the net monthly bill $0.00001 per kilowatt-hour for each $0.00001 increase above or decrease below $0.01092 in the fuel cost per kilowatt-hour sales.

The fuel cost shall be the sum of the following for the most recent two month period plus unrecovered (or less over recovered) prior cumulative energy costs:

1. The fossil and nuclear fuel consumed in the Company's generating stations as recorded in Accounts 151 and 518.

2. The net energy cost of energy purchases as recorded in Account 555 exclusive of capacity or demand charges, when such energy is purchased on an economic dispatch basis. Account 555 includes hedging program gains, losses and transaction costs related to system supply, pursuant to Docket No. EL99-021.

3. The actual identifiable fossil and nuclear fuel costs associated with energy purchased for reasons other than identified in (2) above, less

4. The fuel related costs recovered through intersystem sales.

5. Net costs or revenues recorded in Accounts 456, 501 and 555 (and other appropriate accounts as determined by the Commission) linked to the Company's load serving obligation, associated with participation in wholesale electric energy markets operated by Regional Transmission Organizations, Independent System Operators or similar entities that have received Federal Energy Regulatory Commission approval to operate the energy markets. N
N

The kilowatt-hour sales shall be all kilowatt-hours sold excluding intersystem sales for the same period.

A carrying charge or credit will be included in the determination of monthly fuel adjustment factors. Said charge or credit will be determined by applying one-twelfth of the overall rate of return granted by the South Dakota Public Utilities Commission in the most recent rate decision to the recorded balance of deferred fuel cost as of the end of the month immediately preceding the fuel adjustment factor determination.