minnesota power / 30 west superior street / duluth, minnesota 55802-2093 / 218-723-3961 / www.allete.com

Christopher D. Anderson
Associate General Counsel
Fax 218-723-3955
e-mail canderson@allete.com

September 28, 2007

VIA eFiling

Dr. Burl W. Haar
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101-2147

Re: In the Matter of an Investigation into the Appropriateness of Continuing to Permit Electric Energy Cost Adjustments
Docket No. E-999/CI-03-802

Dear Dr. Haar:

Minnesota Power provides the following response to the Department of Commerce July 27 request to update the FCA Docket with current information. Within this filing letter, Minnesota Power proposes a change in the fuel clause review process that provides the Commission, the Department and other stakeholders greater information regarding how the utilities each prepare their annual fuel clause budget forecast. The intent of this proposal is to get more information to stakeholders upfront, so they have the opportunity to question individual utilities in advance of each utility implementing fuel clause related activities for a given year. A benefit of this proposal is to allow for a greater and more timely understanding by stakeholders of the issues driving each utility's fuel clause for the upcoming year as well as an advance opportunity to ask questions about utility FCA budget assumptions. In addition to the proposal contained in this filing letter, Minnesota Power provides a document that overviews the Company's fuel clause operation. This comprehensive report updates the record in this proceeding in order to account for changes that have occurred to utility operations that affect the fuel clause since the time that the investigation spawned by this Docket first began in 2003. Of particular note, the document also includes an overview of Minnesota Power's outage planning and maintenance practices in order to address the Department's more recent focus on the impact of outages on utility FCAs. It also discusses related issues that have arisen in the course of this Docket such as timely customer pricing notification.

1. THE FUEL CLAUSE INVESTIGATION

The FCA is an important and complex subject as is evidenced by the record to date in these and related proceedings. The current fuel clause process does not need to be drastically modified to provide for adequate oversight considering recently implemented revisions to reporting requirements, along with the additional information that would be provided through Minnesota Power's suggestion of an adjustment in the regulatory process to provide front end utility budgeting assumptions for stakeholder review. Additionally, even if some significant change in the FCA regulatory process appeared worth considering, Minnesota Power strongly believes that current fuel clause regulation should not be modified until the Department and other stakeholders have worked with the Commission to create a better understanding of all the fuel clause inputs and their dynamics. The fuel clause is too important and too complex to be significantly altered without a complete understanding by all parties of how it works and what the (unintended) consequences may be of a change. Certainly, precipitous change based on an incomplete understanding of how the fuel clause works and what consequences changes may bring should be avoided. Much focus in this and related dockets is on the impact of market energy prices and the degree to which market purchases, including purchases for forced and scheduled outages, have a material impact on customer bills through the fuel clause adjustment. There is, by comparison, little in the record and little understood about outage management, plant maintenance and fuel procurement. This Docket would be misguided if it were to focus solely on understanding the energy market component and then short-shrift an understanding of the other aspects of the FCA with which the energy markets inter-relate. This would result in an incomplete understanding of how the FCA works in practice and likely encourage both unwarranted conclusions about "problems" and the development of problematic "solutions".

Given the extent of the record to date and the complexity of the subjects it covers and in an effort to supply the information that is wanted, Minnesota Power believes it would be helpful to focus the further discussion by parties in this Docket on actually answering the primary questions that have arisen. To this end, Minnesota Power has made an attempt to distill the inquiries made by the Department and other stakeholders regarding the FCA down to the primary issues Minnesota Power believes regulators and others seek to address in this Docket in order to feel comfortable that FCA regulation is adequate. In terms of these issues, Minnesota Power understands that:

- Stakeholders want to know that utilities aggressively manage FCA costs to keep them reasonable and as low as possible using good business practices.
- There should be measurable performance targets for the FCA to which the utilities are or can be held accountable.
- Timely, useful energy pricing notification should be provided to customers so they can make informed energy usage choices.
- Utilities should follow maintenance practices and outage management procedures that minimize FCA costs.
- Small- to moderate-sized business customers and residential customers should receive information on FCA performance that they would find useful, in addition to the reports currently provided to mostly larger customers.

Minnesota Power believes these issues must be clearly addressed and the utility responses to them fully understood by stakeholders in this Docket before any conclusions or decisions about the need to change FCA are reached. Minnesota Power believes the record developed in this Docket plus recently-updated existing reporting requirements, with the addition of an annual FCA budget forecast review, can address the points noted above to stakeholders' satisfaction.

Minnesota Power believes an examination and understanding of all aspects of the FCA ultimately will show that it is appropriate and important to continue with the FCA in its present form especially considering that the FCA's original purpose – moderating cost recovery for variable fuel costs to the benefit of both utilities and customers – is just as valid if not more so today than it was when originally established.

It is very important to recognize that, while energy market dynamics have changed, and utility procedures have been modified to adjust to those changes, basic fuel clause inputs and operation have not fundamentally been altered by the introduction of the MISO Day 2 market. The fundamental fuel clause inputs of plant operating performance, fuel purchases, energy market purchases, and plant maintenance management are the same primary inputs that existed when the fuel clause was established under existing regulatory procedures. Fuel clause regulation needs to cover the same basic components it covered a decade or more ago. The Department may have more awareness of the dynamics of fuel clause management now than it did several years ago, though what needs to be managed well in the FCA is fundamentally no different than it was in the many years before this Docket began. The FCA review process fundamentally has no less ability to validate the reasonableness of costs now versus a review that took place five years ago, despite the fact that the Department and other stakeholders may now have a better understanding of fuel clause issues.

As FCA costs have increased, the Department has expressed newfound concern regarding its inability to verify the reasonableness of costs flowing through utility fuel clause adjustments. The Department has gone so far as to indicate that it may cease signing off on monthly fuel clause filings by the utilities until its concerns regarding the reasonableness of costs are addressed. The Department appears to have recognized that it may not know of or be able to review each utility decision that affects fuel clause costs. As a result, the Department appears to have begun to assume that FCA costs are unreasonable unless it can verify the reasonableness of the ongoing decisions affecting each fuel clause component. While this goal is laudable, the Department simply does not have the workforce or expertise to monitor each utility's fuel clause activity to the degree necessary for it to verify that individual costs arising from real time, day-to-day utility decision making are reasonable. Minnesota Power maintains that it is not necessary for the Department to monitor FCA activity to this level to provide regulatory oversight considering recently modified FCA reporting requirements in combination with Minnesota Power's proposal on annual FCA budget forecast review.

Additionally, the Department has recently indicated a desire to consider changes to fuel clause regulation. The greater transparency of the many variable factors affecting the fuel adjustment clause resulting from the MISO Day 2 market introduction as well as the increase in utility reporting requirements related to fuel clause activity has allowed a greater understanding of the complex interplay between these factors and how they are interwoven by utility decision making, adding to the Department's awareness of how the fuel clause really operates on a practical level. However, so many factors affect the fuel clause adjustment, and so many decisions are made at a utility on a daily basis, that the Department has no feasible way of knowing whether a fuel clause adjustment cost being passed through by the utilities is reasonable. Since the Department appears to be uncomfortable being able to verify that a fuel clause adjustment is reasonable without undertaking the impractical effort of understanding and judging every decision that a utility makes which affects fuel clause management, it may assume FCA costs are unreasonable until proven otherwise. Minnesota Power would argue again, as it did earlier in this letter, that the fuel clause is not fundamentally different in its operation from when it was first established many years ago. While the relatively recent advent of the MISO Day 2 market prompted appropriate changes in FCA reporting, the effect of market energy price increases on fuel clause costs is not, in and of itself, a cause for dramatically changing fuel clause regulation.

The Department has indicated that in light of its recent concerns it is considering the concept of a "fixed" fuel clause for each utility at the beginning of each year. The utility would then bear the risk if costs exceeded that fixed FCA number, and the utility would benefit if costs came in below the established FCA amount. Minnesota Power would strongly oppose this type of concept for a number of reasons:

- First and foremost, this type of approach runs counter to insuring that customers pay the true costs for the energy they use. The basic purpose of the FCA is to allow the utility to recover the actual costs of fuel and purchased energy that can vary significantly by month and are not totally controllable or predictable. In addition, the fixed fuel clause amount by definition would be an artificial energy cost paid by consumers that would not be the true cost of their energy.

- Minnesota Power has no interest in realizing the benefit of a fuel clause incentive. If the actual FCA is lower than projected, that benefit should flow straight to the ratepayers. An incentive is merely an additional ratepayer cost. A fixed fuel clause will incentivize utilities to manage to a number. In other words, the utilities will now have an additional layer of fuel clause drivers to assess in its decision making: how each action will affect whether or not the utility meets the number established by the Department. Ultimately, Minnesota Power fears that this will incentivize the utilities to manage to a number rather than focus on the primary responsibility of ensuring that the lowest costs possible are passed through the fuel clause. Minnesota Power also does not want to be in the position of achieving a lower fuel clause adjustment than the number established by the Department – that amount will unjustly benefit Minnesota Power at the expense of its customers.
- A fixed energy cost is no more reasonable than the variable cost that results from the year's activity. In other words, the Department wants to attempt to establish a "reasonable" number up front and then shift the burden to the utility to match that number. While this concept could relieve the Department of its responsibility to assess reasonableness at the conclusion of the fuel clause year, it does nothing to ensure that ratepayer costs are in fact reasonable because events may occur during the course of the year that cause the ultimate fuel clause number to be higher or lower than the established amount.
- The Department has not identified for utilities or other stakeholders what process it would use to establish a fixed fuel clause number. The Department has already communicated that it has concerns with its ability and comfort assessing the reasonableness of the fuel clause number after the fact; Minnesota Power does not understand how the Department will be any more able to establish a reasonable number up front.

- A concept such as this would fail to recognize the other FCA cost drivers aside from market energy purchases. For example, there may be changes within an annual budget year with respect to fuel procurement costs. In addition, this type of proposal fails to recognize state law–authorized modifications to the fuel clause that occur pursuant to various riders, such as Minnesota Power's AREA rider or cost recovery related to renewable legislation. Some of these costs may not be identified with certainty a year in advance of their being incurred.
- It should also be noted that a risk premium would likely be necessary in order to set some variable FCA cost elements at fixed levels in advance. For example, Minnesota Power could enter into forward purchase contracts or buy energy call options with fixed prices to cover energy purchases needed during planned or unplanned generating unit maintenance outages. Such options or advance purchases may be more expensive than short-term energy purchases, but they would have less risk of cost variability. Similarly, Minnesota Power may also be able to purchase weather risk management products to cover replacement energy required during times of lower-than-budgeted hydro production, but such a weather risk product would involve added cost to customers.

Minnesota Power understands the desire of regulators and other stakeholders to ensure the FCA is being properly managed, considering changes in energy markets and other factors. Minnesota Power believes the information required to meet regulatory needs and answer the questions of concern either already exists or can be derived from information in this Docket. We believe existing reports combined with the potential addition of some new information/procedures can provide what is needed for regulatory oversight. Thus we believe it is not only important and appropriate to continue the FCA, we believe it is wholly possible for the Department and other stakeholders to ensure reasonable and fair FCA costs without resorting to unnecessary changes in the FCA that would create cost recovery timing issues, increase regulatory and utility costs and lead to financial issues for utilities.

2. MINNESOTA POWER'S PROPOSAL

A. Annual Forecast Preview

Minnesota Power believes that increasing assurance that the five issues bulleted on page 3 are addressed can be dealt with in part through a change to the fuel clause review process. Minnesota Power has worked with the Large Power Interveners and the Minnesota Chamber of Commerce to arrive at a suggested addition to the fuel clause review provided by the MISO Day 2 Order that is described below.

Each utility is already required to provide a fuel clause forecast for the upcoming year with the AAA report or sometime shortly thereafter. (Minnesota Power submits its forecast in the fall as part of its annual budgeting process). Minnesota Power proposes that the utilities each independently meet with stakeholders (Department, customers, Chamber, OAG and other interested parties) to review their respective fuel clause budgets for the upcoming year and explain key drivers of the budget/forecast numbers for the next year. These meetings would be intended to provide the Department and others with information on how each utility's budget was put together and a context to understand what events are expected to occur that will affect the fuel clause. Minnesota Power believes this process will allow stakeholders to better measure, assess, and understand budget assumptions and the potential for deviations from budget that will occur over the course of the year. This process enhancement will also allow the stakeholders to question each utility on front end assumptions it is making and whether the cost impacts forecasted by the utility can be moderated or altered. The purpose of this meeting is to facilitate communication on fuel clause drivers prior to a forecast year; additional meetings or written follow-up by the utility may be necessary to address or resolve questions that arise.

The goal of this process is to make the stakeholders more knowledgeable about the foundation for utility budgeting assumptions and what specific circumstances will impact the fuel clause. A primary concern to the utility in this process will be the confidentiality of the information provided in each meeting – each utility will be sharing confidential cost and operating information that can not be shared with or communicated to other parties, including the other utilities the stakeholders will be meeting with as part of this process.

B. Rule Variance Regarding Fuel Clause Year

Minnesota Power proposes that for forecast purposes that utilities be allowed to provide their forecast of fuel clause costs on a calendar year basis rather than the current fuel clause year required by Minnesota Rules 7825.2800-7825.2900 (requiring a July 1 – June 30 fuel clause year). Utility and customer budgets are generally prepared on a calendar year basis, and the fuel clause forecast and subsequent performance review should follow a similar schedule. This variance may be utilized by each utility or each utility could continue to provide its forecast under current practices.

C. Broader Communication of FCA Information

Minnesota Power intends to prepare a public version of its annual fuel clause report to its Large Power Customers that will be available on its website for review by small commercial and residential customers that normally do not see the information provided by Minnesota Power.

Currently, Minnesota Power prepares an annual fuel clause report for its Large Power Customers that reviews the past year's fuel clause performance and forecasts a fuel clause budget for the upcoming calendar year. This report is confidential and trade secret because it contains specific cost information as well as market sensitive practice and procedures. A similar version of this report that relates wholesale fuel clause information is prepared for Minnesota Power's municipal customers. The wholesale fuel clause report is distributed to municipal customers on a public basis since the distribution of that information generally occurs at an open meeting. Minnesota Power now proposes to prepare a third report that redacts the confidential information contained in the retail fuel clause report. Minnesota Power would make that report available on its website for review by small commercial and residential customers who currently do not see the information provided by Minnesota Power.

Minnesota Power respectfully requests that the Commission both adopt Minnesota Power's proposals as well as review the attached document that outlines Minnesota Power's FCA in order to gain a greater understanding of how the fuel clause operates at Minnesota Power. This document also meets the Department's and other stakeholders request that the utilities update previously filed information so that any decision made in this Docket can be made with current information.

Yours truly,

Christopher D. Anderson

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Attachment
c: Service List

STATE OF MINNESOTA)
) ss
COUNTY OF ST. LOUIS)

AFFIDAVIT OF SERVICE VIA
EFILING AND
FIRST CLASS MAIL

Kristie Lindstrom of the City of Duluth, County of St. Louis, State of Minnesota, says that on the 28th day of September, 2007 she served Minnesota Power's Comments in Response to the Commission's Notice of Comment Period dated August 16, 2007 in Docket No. E-999/CI-03-802 to the Minnesota Public Utilities Commission and the Department of Commerce via eFiling. The persons on the attached Service List were served via First Class Mail.

Kristie Lindstrom

Subscribed and sworn to before
me this 28th day of September, 2007.

Susan Romans
Notary Public

SUSAN ROMANS
Notary Public-Minnesota
My Commission Expires Jan 31, 2010

Affidavit of service.doc

E999/CI-03-802

Dr. Burl W Haar
MN Public Utilities Commission
Suite 350
121 7th Place East
St. Paul, MN 55101-2147

Sharon Ferguson
MN Department of Commerce
Suite 500
85 7th Place East
St. Paul, MN 55101-2198

Curtis C Nelson
Attorney General's Office
900 BRM Tower
445 Minnesota Street
St. Paul, MN 55101-2130

Julia Anderson
MN Office of Attorney General
1400 BRM Tower
445 Minnesota Street
St. Paul, MN 55103-2131

Ronald Giteck
Attorney General's Office
900 BRM Tower
445 Minnesota Street
St. Paul, MN 55101-2130

Bruce Gerhardson
Otter Tail Power
215 South Cascade Street
Fergus Falls, MN 56538-0496

Bernadeen Brutlag
Otter Tail Power
215 South Cascade Street
Fergus Falls, MN 56538-0496

Mark Dahlberg
President
NW Wisconsin Electric Company
P O Box 9
Grantsburg, WI 54840-0009

William Glahn
Dahlen, Berg & Co
Suite 300
200 South Sixth Street
Minneapolis, MN 55402

Scot McClure
Interstate Power and Light
4902 N. Biltmore Lane
P O Box 77007
Madison, WI 53707-1007

Douglas Larson
Power System Engineering, Inc.
Suite 250
12301 Central Avenue NE
Blaine, MN 55434

Todd Guerrero
Lindquist & Vennum
4200 IDS Center
80 South Eighth Street
Minneapolis, MN 55402-2205

Marilyn Foreman
Dakota Electric Association
4300 220th Street West
Farmington, MN 55024-9583

Jennifer Moore
Alliant Energy
200 First Street SE
P O Box 351
Cedar Rapids, IA 52406-0351

Phillip Zins
Xcel Energy
414 Nicollet Mall, 7th Floor
Minneapolis, MN 55401

James P Johnson
Xcel Energy
414 Nicollet Mall, 5th Floor
Minneapolis, MN 55401

SaGonna Thompson
Xcel Energy
414 Nicollet Mall, 7th Floor
Minneapolis, MN 55401

Judy Poferl
Xcel Energy
414 Nicollet Mall, 7th Floor
Minneapolis, MN 55401

Stephen G Kozey
Midwest ISO
701 City Center Drive
Carmel, IN 46032-7574

Jeffrey Landsman
Wheeler, VanSickle & Anderson
25 West Main Street, Suite 801
Madison, WI 53703-3398

Jerry Larsen
HPC-LLC
4610 IDS Center
80 South 8th Street
Minneapolis, MN 55402

Robert S Lee
Mackall, Crounse & Moore, PLC
1400 AT&T Tower
901 Marquette Avenue
Minneapolis, MN 55402-2859

Annette Henkel
Minnesota Utility Investors
405 Sibley Street, #227
St. Paul, MN 55101

Andrew Moratzka
Mackall, Crounse & Moore, PLC
1400 AT&T Tower
901 Marquette Avenue
Minneapolis, MN 55402-2859

Christopher Sandberg
Lockridge Grindal Nauen & Holstein
100 Washington Avenue South
Suite 2200
Minneapolis, MN 55401

Beth Soholt
Wind on the Wires
1619 Dayton Avenue, Suite 203
St. Paul, MN 55104-6206

Eric F Swanson
Winthrop & Weinstine
225 South 6th Street, Suite 3500
Minneapolis, MN 55402-4629

Kelly Hunter
Manitoba Hydro
820 Taylor Avenue
Winnipeg MB R3C 2P4
Canada

E999/CI-03-802

Christopher D Anderson
Associate General Counsel
Minnesota Power
30 West Superior Street
Duluth, MN 55802

Margaret Hodnik
Minnesota Power
30 West Superior Street
Duluth, MN 55802

David R Moeller
Attorney
Minnesota Power
30 West Superior Street
Duluth, MN 55802

MINNESOTA POWER

FUEL CLAUSE UPDATE

REPORT

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I. INTRODUCTION AND OVERVIEW TO FUEL CLAUSE INVESTIGATION DOCKET

On July 27, the Department of Commerce provided notice to the Commission stating that the Minnesota investor-owned utilities (Minnesota Power, Xcel Energy, Interstate Power Company, and Otter Tail Power Company,) the Department, the Office of Attorney General, the Large Power Intervenors and the Minnesota Chamber of Commerce had been meeting regarding fuel clause related issues. The parties had reached agreement that the utilities would provide information to the Commission in the above-referenced Docket, updating the record with "current" information, in order for the Commission to proceed with the main purpose of the investigation: analyzing the continuing usefulness of the fuel clause as a regulatory tool in Minnesota. This document represents Minnesota Power's update to the Docket in accordance with the Commission's August 16, 2007 Notice.

II. HISTORY OF FUEL CLAUSE INVESTIGATION

The Commission opened this Docket on June 4, 2003 by issuing its *Order Approving Proposal, Requiring Compliance Filing, and Opening Investigation into the Continuing Usefulness of Fuel Clause Adjustments for Electric Utilities*. After a series of comment periods, The Commission issued on December 19, 2003 its *Order Determining Scope and Setting Procedural Framework*. While the environment in which the electric utilities operate has changed significantly since December 19, 2003, the fundamental purpose and application of the fuel clause adjustment has not changed. The utilities continue to operate and maintain their low cost generating units with the obligation to provide the output to their retail customers, and the utilities continue to seek low cost energy in the energy market to the extent that the energy requirements on their systems exceed supply (either due to generating derates or outages, or in the event system load exceeds system supply).

On June 12, 2003, the Minnesota Public Utilities Commission ("Commission") issued a Notice of Comment Period on Scope and Procedures ("Notice") regarding an investigation into the continuing usefulness of the fuel clause adjustment as a regulatory tool.[1] The investigation is intended to determine the appropriateness of continuing to permit electric energy cost adjustments under Minnesota Statutes, Section 216B.16, subd. 7. The Notice references Minnesota Rules, Parts 7825.2390 through 7825.2920, which establish the requirements for implementing such adjustments.

The Notice identifies the scope of the investigation as the appropriateness of continuing to permit electric energy cost adjustments under Minnesota Statute 216B.16, subd.7. The Commission has the authority under Minnesota Rule 7825.2920, subp. 3 to continue, modify, or eliminate an individual utility's fuel clause adjustment.[2]

Minnesota Rule 7825.2920, subp.3 allows individual treatment of the utility's fuel clause adjustment. The investigation process must recognize the differences among the utilities, and the outcome of the investigation should be applied to each individual utility appropriate to that utility's circumstance. Aside from the different load profiles and generating resources among the regulated utilities, the application of the fuel clause adjustment varies in other ways between utilities. These differences are illustrated by the fact that Minnesota Power currently applies the fuel clause adjustment on a rolling two-month lag basis, while Xcel uses a monthly forecast and true-up method.

There are specific circumstances that appropriately differentiate each utility's application and use of the fuel clause adjustment as a regulatory tool. These differences may exclude a utility from certain portions of the investigation, or may cause the outcomes of the investigation to have a greater or lesser impact on that utility. The

[1] This investigation was authorized in an Order date June 4, 2003 in the Matter of Northern States Power Company d/b/a Xcel Energy's Fuel Clause Adjustment, Petition for Approval of Base Cost of Energy Revision and Compliance Filing (Docket No. E-002/M-02-2097).

[2] Minnesota Rule 7825.2920, subp. 3 states "The Commission, on complaint or on its own motion, and after appropriate investigation, notice, and hearing, may issue an order to fix at current levels, discontinue, or modify an automatic adjustment provision for an individual utility."

outcome of the investigation should consider these differences, and any resulting changes in the fuel clause adjustment as a regulatory tool must be made on a case-by-case basis.

Improved quality of customer price signals and improved utility fuel cost management are goals of the investigation. Both topics should be examined further with an understanding of each developed in the record so that their relationship to utility fuel clause adjustment application and performance is fully understood. There are different load profiles, rate structures, and energy supply resources among utilities that impact the circumstances when (and the extent to which) the fuel clause adjustment provides appropriate price signals to customers. Fuel cost management is also implemented and exhibited differently among the utilities. While both price signals and fuel cost management activities are common to utilities, their relationship and effect on fuel clause adjustment outcomes may vary widely by utility. For that reason, the fuel clause adjustment must be understood before any changes are contemplated.

In the December 19, 2003 Order ("Order") attached to the Notice, the Commission stated that the FCA is intended to make rates more accurate and to conserve regulatory and utility resources. Since fuel and purchased power costs can fluctuate significantly between rate cases, building these costs into non-adjustable rates could cause significant, recurring mismatches between expenses and rates. The fluctuation might also strain utility and regulatory resources by forcing frequent rate cases and earnings investigations to address changes in the cost of fuel and purchased power. The Commission noted that it has current oversight of the FCA with utilities filing detailed monthly and annual reports that are reviewed for accuracy and prudence by the Department of Commerce ("Department"). These reports provide regular updates on FCA costs.

The Commission further stated in the Order that while the advantages of the FCA are understood, the disadvantages have not been carefully examined since the initial adoption of the FCA. Furthermore, there has been some change over time to the kinds of costs recovered through the FCA. These changes in costs may pose different issues in terms of risk management, price signals, oversight and accountability than previously was the case. Consequently, the Commission elected to conduct a detailed examination and focus the investigation on the central question of whether the FCA continues to be an appropriate regulatory tool today.

The Order directed all utilities to provide a review of the original purpose, structure and rationale of the current FCA, current operation of the FCA and relevance to the current regulatory environment. With respect to changes in costs that may pose different issues in terms of risk management, price signals, oversight and accountability, the record developed thus far demonstrates that the FCA continues to be an appropriate tool for use in the current regulatory environment.

A. Purpose of the FCA

The FCA was originally established to provide for rate changes in the fuel and purchased energy component of delivered energy cost. The overall objective of the FCA is to incorporate short-term changes in the cost of fuel and purchased energy (either up or down) into monthly adjustments in rates. This allows utilities to adjust rates to reflect changes in the cost of energy delivered to customers from those costs authorized in the utility's most recent general rate case. Because such costs are the largest variable component of the cost of providing electric service, having a fuel adjustment that varies monthly enables utilities to match customer rates more closely with the costs that are incurred.

Minnesota Statute 216B.16, subd. 7 allows the automatic pass-through of charges in direct relation to changes in wholesale rates for energy delivered through interstate facilities and in the costs for fuel used in generation of electricity. Minnesota Rules, Parts 7825.2390 to 7825.2920, set out the requirements for implementing such adjustments. Minnesota Rules, Part 7825.2390 specifically provides that the purpose of the automatic adjustment of charges is to enable regulated electric utilities to adjust rates to reflect changes in the cost of energy delivered to customers from those costs authorized by the Commission in the utility's most recent general rate case. Minnesota Rules, Part 7825.2500 gives the Commission authority to permit the filing of rate schedules containing provisions for the automatic adjustment of charges.

Minnesota Power addressed in an earlier filing in this Docket the specific action steps it has taken to assure that its current administration and operation of the FCA continue to be appropriate even though there have been changes to electric energy markets in the past several years. These steps include: 1) balancing Minnesota Power generating assets, customer generating assets, and wholesale energy purchases and sales with projected electric usage of Minnesota Power's retail customers; 2) managing those key drivers that are within Minnesota Power's control such as delivered fuel cost, generation outage scheduling, and prudent wholesale energy purchases, in order to manage the FCA impacts; and 3) adhering to strict internal and external process controls.

Yet, even with these measures in place, fuel and purchased power costs represent large expense items, and there are still key FCA drivers that are less subject to control by Minnesota Power, including the availability of Minnesota Power's hydro generation and the cost of replacement market energy purchases. As indicated by other commenting parties, the size and variability of costs included in the FCA, combined with limited control over some key FCA drivers, make the FCA mechanism for recovery of cost fluctuations more important than ever. Minnesota Power further agrees with the report from Standard & Poor's Ratings Services that was attached to Interstate Power and Light's comments (included as Appendix A to this document). The Standard & Poor's document describes the positive impact that the FCA, through matching of customer rates with expenses, has on utility credit ratings.

B. Structure of the FCA

Minnesota Power explained in an earlier filing in this Docket that its Rider for Fuel Adjustment incorporates the applicable two-month average cost of the total fuel consumed for Minnesota Power's generation and the fuel component of purchased and interchange energy, which includes the costs of some specific energy purchases previously approved by the Commission in earlier dockets. The rationale for including these costs was referenced and it was noted that some of the more specific costs included under Minnesota Power's Rider for Fuel Adjustment (e.g., Released Energy Credits and Buyback Energy Credits) are included to reduce the FCA costs for all customers by paying Large Power customers to reduce energy usage to avoid higher-cost energy purchases. Minnesota Power showed that these are appropriate (and approved) costs and credits for inclusion in the FCA.

Although some changes have occurred during the past several years to the specific energy-related costs incurred by electric utilities and the costs suitable for inclusion in the FCA, the FCA still serves its original intended purpose well. Two such changes are the transition within the Mid-Continent Area Power Pool ("MAPP") from no-cost wheeling between members to fees for transmission and a subsequent transition to the Midwest Independent Transmission System Operator ("MISO"). These changes reflect the fact that the FCA is well suited to adjust to changes in the wholesale energy market, as well as changes in federal energy policy.

Minnesota Rules, Part 7825.2600 specifies the general computation procedures for electric energy adjustments. The adjustment per kWh is the sum of the current period cost of energy purchased and the cost of fuel consumed per kWh less the base electric cost per kWh.

1. Base Cost of Fuel

The starting point for the FCA is the determination of a base cost of fuel. This is typically done at the time of a rate case, and all firm power tariffs include the same base cost of fuel as a component of their energy rates. Pursuant to Minnesota Rules, Part 7825.2400, subpart 4, the base electric cost of fuel is the cost of fuel consumed in the generation of electricity and the cost of purchased power in the base period expressed as a cost per kilowatt-hour sold. Expenses allowed in the base cost of fuel include the projected fuel component of company-owned generation and the energy component (delivered variable cost) of purchased power required to supply customers subject to FCA during the test year. Expenses not allowed in determining the base cost of fuel include the fixed (capacity) costs of generating assets and/or purchased power contracts and the fixed or variable operating and maintenance expenses incurred during the test year.

The lowest-cost resources (purchased or generated) as projected for the test year are reserved to supply FCA sales. The remaining energy supply (if any) may allow for projected sales to other customers not subject to the FCA or for off-system sales to other utilities. The cost used for such sales would be made up of the highest-cost mix of purchases and/or company generation that remains.

The base cost of fuel is essentially the sum of all projected test year fuel and purchased energy expenses (as stated above) related to supplying the forecasted test year kWh sales subject to FCA divided by these kWh.

2. Monthly FCA

The calculation of the FCA uses a similar approach to the base cost of fuel calculation in determining an actual two-month average cost of fuel to supply FCA customers. Minnesota Power's retail fuel adjustment calculation for a given month is based on costs and energy sales for the first two of the previous three months. For example, the fuel adjustment for the June billing is the actual average cost for March and April. Use of such an average reduces monthly price fluctuations for retail customers, and the month delay allows time for actual cost and kWh sales data to become available. The monthly fuel adjustment is the difference between this actual average cost of fuel and the base cost of fuel determined for the test year. It is applied to customers' kWh usage in the applicable billing month (for June in our example above). This slight lag in application results in some differences between revenue collected by the FCA and the expenses used for its calculation. However, the net effect of these differences fluctuates up and down over time and in theory does not deviate substantially from zero on a cumulative basis.[3] Historically, however, Minnesota Power has under-recovered FCA expenses. Minnesota Power's under-recovery for the 12 months ending June 2007 was $13.1 million. Under recovery from when Minnesota Power started tracking in July 1998 through August 2007 is $16.9 million.

3. <u>Minnesota Power's Rider for Fuel Adjustment</u>

Minnesota Power's current Rider for Fuel Adjustment specifies that there shall be added to or deducted from the monthly bill an amount per kilowatt-hour determined as the amount by which the Fuel Cost divided by the Kilowatt-Hour Sales is greater than or less than 1.018 cents per kilowatt-hour (Minnesota Power's base cost of fuel).

The Fuel Cost is the applicable two months' average of the sum of the following:

(a) the fossil and nuclear fuel consumed in Minnesota Power's generating stations,
(b) the net energy cost of energy purchases, exclusive of capacity or demand charges (irrespective of the designation assigned to such transaction) when such energy is purchased on an economic dispatch basis, this encompasses energy being purchased to substitute for Minnesota Power's own higher cost energy,
(c) the actual identifiable fossil and nuclear fuel costs associated with energy purchased for reasons other than identified in (b) above,
(d) the cost of steam from other sources used in the generation of electricity at Minnesota Power's generating stations,
(e) the cost of the Released Energy Credit paid to Customer(s) for avoided energy purchases under the Rider for Released Energy,
(f) the cost of the Buyback Energy Credit paid to Customer(s) for avoided energy purchases under the Rider for Voluntary Energy Buyback, and
(g) expenses incurred by the Company over the duration of any Commission approved contract, as provided for by Section 216B.1645, to satisfy the renewable energy objectives set forth in Section 216B.1619 and
less
(h) the cost of fossil and nuclear fuel and the cost of steam from other sources recovered through inter-system sales including the fuel and steam costs related to economy energy sales and other energy sold on an economic dispatch basis.

[3] This is demonstrated in Minnesota Power's Annual Report of Automatic Adjustment Charges that is filed pursuant to Minn. Rules Part 7825.2810.

The Kilowatt-Hour Sales are Minnesota Power's total Kilowatt-Hour Sales of Electricity, excluding inter-system sales referred to in (g) above, for the first two of the preceding three months.

4. Sample FCA Calculation

A sample calculation of Minnesota Power's fuel adjustment for the month of March 2004 was originally supplied in a previous filing in this Docket. Minnesota Power provides both that filing and the most recent filing for September 2007 (as Appendix B) to show how the FCA is calculated, and to illustrate how the reporting structure and format has changed.

Cost of Fuel

Line 1, All Stations – Total Burned for Generation, corresponds with item (a) of the Fuel Cost listed above. Line 2, Fuel Component of Purchased & Interchange, includes items (b) through (f) of Fuel Cost. Items (b) through (f) are specific components within the broader category of energy purchases. Purchased steam cost, item (d), represents the cost of steam generation off of Minnesota Power's Hibbard generating station. Since steam was not identified as a fossil or nuclear fuel under Minn. Rule 7825.2400, subpart 9, Minnesota Power sought specific approval to include the cost of Hibbard's steam generation in the FCA.[4] Released Energy Credits and Buyback Energy Credits paid to customers for avoided energy purchases, items (e) and (f), represent the cost of payments to customers who reduce energy usage to enable Minnesota Power to avoid higher-cost energy purchases for firm system requirements. Both of the Credits identified above are included within the FCA to reduce FCA cost for all customers. They are recoverable costs previously approved by the Commission under the Rider for Fuel Adjustment.[5] Line 3, Fuel Cost recovered through Inter-System Sales, corresponds with item (g) above and includes fuel cost associated with off-system energy sales, Large Power Interruptible energy sales, Incremental Production Service, and any other energy sales that are not subject to the FCA. This language represents Minnesota Power's "top-down" approach to the FCA calculation under its approved Rider, where all fuel and purchased energy costs are included in the monthly total calculation, and then non-applicable costs are subtracted out in the final step. Lines 4 and 5 are the monthly and two-month Total Cost of Fuel that remain in the calculation for FCA purposes.

It should be noted that the energy cost of market purchases is defined to be the total delivered cost of the energy purchase. Delivered cost includes the cost of energy from the seller, any transmission fees required for delivery of the energy to Minnesota Power and energy losses to the point of delivery. Not included in this cost are fixed (capacity) charges for purchased power.

When MAPP first formed in the early 1970s, wheeling for non-firm energy transactions between members – primarily outage replacement energy and economy purchases – was at no cost except for energy loss compensation. Members could purchase firm transmission paths for a fixed fee (typically by six-month Pool season) and once purchased, firm energy could be scheduled with no additional wheeling fee similar

[4] Docket No. E-015/M-98-492.
[5] Pursuant to MPUC Docket Nos. E-015/M-98-1414 and E-015/M-01-514.

to the non-firm transactions. In the mid-1990s however, MAPP implemented transmission fees for all transactions. In recent years, firm transmission has been necessary to increase the reliability of the energy delivery.

Minnesota Power's supply decisions are made each day and each hour as to the least-cost supply alternative for customers subject to the FCA. An energy purchase – including the required transmission to ensure delivery to Minnesota Power's control area – is made anytime it reflects the least-cost alternative at the time. For this reason, Minnesota Power has treated MAPP transmission fees for energy purchase transactions as costs of purchased power for its FCA since the mid-1990s when the change in the federal energy markets allowed MAPP to implement such fees for transmission.

Following the transition within MAPP from no-cost wheeling between members to fees for transmission, a subsequent transition from MAPP to MISO as the regional provider of transmission service occurred.[6] No MISO transmission fees or other MISO charges are included in Minnesota Power's FCA. MISO charges currently cannot be passed through the FCA. If Minnesota Power wishes to include such costs in the FCA in the future, it must first seek Commission approval.

KWH Sales

Line 6, Total Sales of Electricity is Minnesota Power's total retail and resale energy sales. In Line 7, similar to how costs are treated in Line 3, the kWh of off-system and other non-FCA energy sales are subtracted. Lines 8 and 9 are monthly and two-month total kWh sales for FCA purposes.

Fuel Adjustment

In Line 10, the two-month average fuel cost in ¢/kWh is determined. In Line 11, the Base Cost of Fuel is then subtracted from this amount resulting in the Fuel Adjustment for the month as shown in Line 12.

C. FCA Application and Operation

The FCA key drivers that are less subject to control by Minnesota Power are the availability of Minnesota Power's hydro generation and the cost of replacement market energy purchases. Hydro generation is driven by the amount of precipitation received in the northern third of the state within Minnesota Power's hydro generation watershed area. Minnesota Power's hydro generation makes up about 5 percent of the FCA energy requirements during a normal precipitation year.

The cost of market energy purchases can vary considerably due to generating unit and transmission line availability, weather impacts on electricity demand, Western Area Power Administration and Manitoba Hydro water supply, the price of natural gas and oil used as generator fuel, the pricing and availability of electricity in neighboring regions and market expectations. To help limit the impact of market energy purchase costs on the FCA and to provide the least-cost supply energy to our customers, Minnesota Power has taken a portfolio approach to planning for its replacement energy needs. Based on

[6] Docket No. E-015/PA-01-539.

projected system requirements and supply costs, Minnesota Power determines its market purchase strategy for the upcoming year. This strategy typically includes buying a portion of its energy needs on the forward market one or more months in advance, a week in advance or a day in advance (or some combination of the three) and then purchasing any remaining energy needs on the daily/hourly spot market. The intent of this approach is to help limit the volatility and risk associated with buying large quantities of energy in the short term market when market prices are the highest. This approach is generally most beneficial when major scheduled outages are planned or at times when loads are high, such as peak summer or winter months.

Minnesota Power's average purchased replacement energy costs fluctuate from year to year depending on generating unit availability and market energy prices. For example, Minnesota Power generation reached near record levels in 2003 which kept the amount of required market energy purchases low. Generation represented 92% of the total FAC energy supply. However, market energy purchase prices were much higher in 2003 than in 2002. The average on-peak price in 2003 was more than $40/MWh compared to about $25/MWh in 2002. In 2002, purchases for scheduled outages, forced outages, and other reasons made up 8% of the annual FCA energy supply, but contributed 13% of the total cost. In 2003, purchases for scheduled outages, forced outages, and other reasons again made up only 8% of the annual FCA energy supply, but contributed a much larger 23% of the total cost. By 2006, market energy prices were even higher. Purchases made up 13% of the annual FCA energy supply but 29% of the total cost. In 2007, projected purchases for scheduled outages, forced outages, and other reasons make up 21% of the annual FCA energy supply, but are expected to contribute a much larger 58% of the total cost. The increase in the overall level and volatility of market energy purchase prices, which are largely outside Minnesota Power's control, makes the FCA mechanism for recovery of cost fluctuations more important than ever.

Although there have been a myriad of changes to electric energy markets in the past several years, certain guiding principles regarding the administration of the FCA have remained the same at Minnesota Power. The primary underlying principles and policies governing decisions by Minnesota Power regarding the FCA are summarized below:

1. <u>Obligation to Provide Least-Cost Supply</u>

Minnesota Power's least-cost generating resources are dedicated to supplying energy sales subject to the FCA. Off-system sales are made from the highest-cost resources available after satisfying sales subject to the FCA. Market purchases required to supply FCA sales – typically during generator outages or peak load conditions – are the lowest-cost available at the time the purchase commitment is made. Purchases required for supplying off-system sales are the higher-cost purchases remaining after FCA sales are satisfied.

Least-cost sourcing is the number one priority for Minnesota Power's Energy Supply group. This experienced group of traders, marketers, analysts and operating personnel manage Minnesota Power's capacity and energy portfolio by participating in the wholesale electric market 24 hours every day, and by using a number of computer tools (including forecasting, pricing, accounting, transmission scheduling, and risk management programs).

The native load energy portfolio is managed by securing supply resources sufficient to meet long-term and short-term native load forecasts. This is accomplished by managing Minnesota Power generating assets, customer generating assets and wholesale energy purchases and sales with projected electric usage of Minnesota Power's retail customers. In today's marketplace, Minnesota Power's generating units are almost always committed to meet native load requirements because their cost is usually much lower than other purchase alternatives. These low-cost resources are not sold to the wholesale market unless lower-cost power is available or Minnesota Power experiences an excess supply situation. When purchases are required, Minnesota Power makes purchases/sales for three different time horizons (multi-month, monthly, short-term daily and hourly). Whether a purchase or sale is made, and when it is made, is a subjective (but educated) decision influenced by many market conditions, such as customer load requirements, generating unit availability, historical and forward energy prices, weather conditions, and transmission availability.

2. <u>Incentive to Minimize FCA Costs</u>

Due to its significant concentration of sales to large industrial customers who face intense international competition, Minnesota Power has perhaps more incentive to minimize its FCA costs than any other utility in the state. Minnesota Power's largest customers are extremely cost-conscious, and they carefully scrutinize any changes to pricing for their electric service, including fuel adjustment changes. Because of the huge impacts that even very small deviations in Minnesota Power's FCA have on large industrial customers, Minnesota Power has provided periodic verbal presentations and detailed mid-year and year-end FCA reports to these customers. The reports describe the current year's results, explain any deviations from initial projections, and provide estimates for the upcoming year. The scrutiny given Minnesota Power's operations and the FCA by these major stakeholders coincidentally benefits all customers subject to the FCA. The key drivers of fluctuations in Minnesota Power's fuel adjustment include availability of system hydro generation, availability of Minnesota Power's thermal generation, delivered fuel costs to Minnesota Power's generating stations and market replacement energy purchases.

The FCA key drivers that are most within Minnesota Power's control are delivered fuel cost and Minnesota Power generation outage scheduling.

3. <u>Fuel Procurement</u>

Minnesota Power has worked successfully to negotiate rail and coal contracts which have resulted in favorable average delivered fuel costs. Minnesota Power has also made a concerted effort to reduce the frequency and length of outages while ensuring generation reliability. These efforts related to fuel cost and generating unit outages are discussed in more detail below.

Minnesota Power's fuel procurement practices are aimed at strategically minimizing our customers' energy costs while being in compliance with current environmental regulations and, simultaneously, taking action to assure cost-effective compliance with future environmental requirements. Attaining these objectives requires that many factors be continuously evaluated, including purchases and sales of energy, applicable coal and rail contract provisions, current and projected emissions, mine plans of our suppliers, requirements of customers, fuel delivery schedules, and fuel and rail costs. Balancing these parameters requires superimposing both short-term and long-term planning objectives on near-term operations.

Minnesota Power uses a multi-disciplinary fuels procurement and strategy team to achieve fuel cost minimization and environmental compliance objectives. The team meets regularly to coordinate all activities related to fuel procurement. Objectives include:

1. Implement strategies for short-term and long-term fuel procurement which provide a high-quality, reliable fuel supply to Minnesota Power facilities to achieve the lowest attainable electric rates;

2. Optimize fuel costs and quality through developing, implementing and managing the short-term strategy for fuel scheduling and deliveries within operating and contract parameters; and

3. Focus environmental compliance planning efforts on the formulation, implementation and minimization of short-term and long-term corporate strategies for fuel quality issues and the impact of fuel on plant performance and compliance with existing and emerging environmental regulations.

Minnesota Power's average delivered cost of fuel has been stable or on a downward trend for several years. Through periodic negotiations with rail and coal suppliers and identification of fuel supply alternatives, Minnesota Power has been able to achieve substantial reductions in its delivered coal costs. From 1991 through 2003, Minnesota Power realized a reduction of more than 25 percent in its average delivered fuel cost, which is the largest and most controllable component of the FCA. Furthermore, for each year from 2004 through 2006, Minnesota Power's average delivered coal cost was less than in 2003. Due to long-term contractual escalation provisions, 2007 delivered coal cost is higher than 2006, and the delivered cost of coal is expected to increase somewhat in the future as existing coal supply contracts expire.

4. <u>Use of Internal and External Controls</u>

Minnesota Power has strict internal processes in place to assure prioritization of the least-cost sourcing obligation. Senior-level Minnesota Power management has direct oversight of the energy accounting activity, and is responsible to communicate and make certain that policies and procedures are in place to ensure least-cost supply to customers. Minnesota Power has staff dedicated to reviewing the fuel adjustment clause accounting each month and reporting to the Finance (Accounting and Rates) and Marketing groups regarding the energy supply used to meet retail needs.

Minnesota Power's fuel adjustment clause operation is audited internally on a regular basis. Minnesota Power's Internal Audit department also participates in Minnesota Power's annual independent audit performed by PricewaterhouseCoopers

LLP. PricewaterhouseCoopers issues a one-page letter report to Minnesota Power's Board of Directors outlining the general procedures used during the annual review of the FCA and any observations noted during that review. The letter is included in the annual report to the Commission pursuant to Minn. Rules, Part 7825.2820. Minnesota Power's FCA is also audited periodically by the Federal Energy Regulatory Commission (FERC). The primary focus of all of these audits is to assure that only appropriate costs are recovered through the FCA and that procedures adhere to applicable statutes and FERC and Commission rules.

In addition, Minnesota Power reports its fuel clause activities to the Department of Commerce on a monthly and annual basis pursuant to Minnesota Rules, Parts 7825.2800 to 7825.2900. Minnesota Rules, Part 7825.2900 specifies that when an electric utility changes its automatic adjustment of charges, prior to the effective date of the change, the utility must file a summary of the computation of the adjustment and an explanation of significant changes between the base cost and current cost, thus providing regular monthly oversight of the FCA.

Minnesota Power's risk policy has volumetric limit recommendations on how short Minnesota Power can be on our forward energy position. This limit was set to reduce our exposure to spot market prices. Advance purchases ensure that Minnesota Power falls within those volumetric limits. The guidelines set out in our risk policy do allow for some exceptions if forecast energy prices appear to be too great.

III. PLANT MAINTENANCE AND OUTAGE PLANNING

Minnesota Power engages in a number of activities to minimize the impact of generating unit outages on FCA costs. Scheduled outages are planned during times of anticipated low replacement energy purchase prices, usually in the spring or the fall. In addition, Minnesota Power has been moving toward reliability-centered predictive maintenance techniques to help limit the amount of time units are down and to optimize the maintenance activities accomplished during each outage. These techniques focus on being proactive instead of reactive. Just-in-time maintenance practices are used within the predictive maintenance scheme to allow more time between major outages. Minnesota Power is also encouraging generation maintenance staff to complete specialized training in predictive maintenance techniques. These efforts have resulted in increased output from Minnesota Power's generation.

A. Overview

Outage management has two major streams of very different activity occurring at different locations yet simultaneously and in conjunction with each other. One activity is planning and managing the actual unit outage; the other is planning and managing the replacement energy supply. This may seem obvious on one level—on the other hand what may not be obvious is that each activity requires its own information and expertise with sometimes "many moving parts" to perform successfully. Furthermore, each of these major activities has to be smoothly synchronized with the other in order to optimize outcomes in real time environments with dynamic events. To some degree data, information, models and planning and best practices are all employed in these endeavors. Outage management and energy supply procurement are individually and in combination an art as well as a science, where judgment and decision making using human expertise is required for success.

Minnesota Power has several functional areas that play coordinated roles in outage management and replacement energy supply. They are:

- individual generating unit management teams,
- the Generation Desk which provides coordination across all MP resources,
- the Reliability Team which provides engineering resources across all MP units and
- Energy Supply which procures replacement energy.

B. Production Cost Model and Energy Supply Information Systems

Minnesota Power has a long term (2 to 15 years) production cost model and a mid-term production cost model that it uses as foundational tools to plan energy supplies. The long term model is used for resource planning purposes. The mid-term model is the production cost model that is continuously run on a monthly basis and looks at the upcoming 14-26 month period; it is used by our Energy Supply group to address our energy needs due to planned outages.

The inputs into our mid-term production cost model are customer loads, firm energy purchases, forecasted forward energy prices, firm energy commitments, and generator capabilities. The “generator capabilities” include our forced outage rates and our planned outages. Minnesota Power runs the production cost model monthly and uses that output to determine how much energy is going to be supplied by our generation, how much is covered with longer term purchases, and how much must be covered with short-term (spot) market purchases. Of course, during the times when our generators are going to be out of service, the model shows a need for more market purchases.

Finally, for short-term needs Minnesota Power has developed an Energy Supply Information System to monitor our forward position for seven days out. It uses all of the inputs of the production cost model, but is finer-tuned to incorporate real-time information relating to our generation availability, purchases, firm sales and customer load forecasts. This is also the model that incorporates weather conditions. If there are forecasted temperature extremes, our loads are going to be higher. That will affect our supply position because our native resources are going to be the same. In the short term, our options are to buy in the day-ahead or real-time market from MISO; buy in another market (like PJM or the Ontario Market) and bring that energy into MISO; or make a bilateral purchase from another party. We choose among these options to find the lowest cost alternative for our customers.

C. Short-term Energy Purchasing Strategies

The best way to discover “lowest cost” prices for general purchases and shorter term forced outage supplies is to look at forward energy price information. One of the tools Minnesota Power uses is the Intercontinental Exchange (ICE) – a bulletin board where energy market participants can go out and make forward energy purchases or compare forward bids and offers. Monthly, weekly, daily, and balance of the day energy products can be bought and sold on ICE. Minnesota Power primarily uses the ICE and the specific energy hubs that comprise that bulletin board (Cinergy Hub, Minnesota Hub, Illinois Hub, and Michigan Hub) for price discovery, to determine a reasonable bid for energy. If counterparties with whom Minnesota Power has an enabling agreement have something posted on ICE, Minnesota Power can make purchases directly.

Regarding additional tools for price discovery aside from ICE, Minnesota Power monitors the actual MISO prices, MISO historical LMP’s and we make phone call inquiries to counterparties in the over-the-counter bilateral market.

D. Minnesota Power’s Load Forecasting

Minnesota Power’s load forecast modeling is highly dependent on our Key Account Managers and Engineers inputting changes and information about what they know about the different large industrial customer loads. Key Account Managers and Engineers monitor Large Power customer activity, continuously communicating customer load information to the central database that Energy Supply uses for load forecasting.

Minnesota Power breaks loads down between weather-affected and non-conforming loads which are loads that generally do not respond to weather. Minnesota Power considers the 12 Large Power customers non-conforming loads. Minnesota Power's transmission control area will forecast our weather-affected load, and the Key Account Managers forecast non-conforming load. (For those customers that have on-site generation, we will also forecast the anticipated customer generation.) Energy Supply will then combine the weather-affected load and the non-conforming customer load forecasts and arrive at a commercial load forecast to determine what amount (if any) of energy Minnesota Power will have to buy in the market to cover our loads.

As noted, residential customers and the smaller customer loads are part of the weather-affected load. The System Operations group uses a load forecasting program called Metrix to forecast weather-affected and reliability load. Metrix uses temperature inputs and historical loads to determine expected short-term weather-affected load. Energy Supply has the ability to override components of the Commercial load forecast if conditions change. If Energy Supply has been observing a trend where real time prices are turning out a lot lower than day-ahead, during certain hours of the day, we may make a conservative estimate on the forecast to avoid ending up selling day-ahead energy back at lower real time prices if loads come in lower than expected.

E. Local Weather vs Regional Weather

Energy Supply is as concerned with regional weather (in some of the major load centers like Chicago, Minneapolis, etc.) as it is with local weather for two main reasons. First, we watch the areas where there are large concentrations of load because they impact market purchase prices more than extreme weather in northern Minnesota. Second, because half of Minnesota Power's load is non-conforming load, temperatures do not necessarily affect our operations like they would with a utility with a greater concentration of weather-affected load. Irrespective of what the weather is doing, Large Power consumers are going to run at whatever level they need to be running for their production purposes. And because Minnesota Power is trying to forecast market prices, regional temperatures like those in Minneapolis, are going to have a big impact on market energy prices because of the weather's effect on these types of large load centers.

When we know that market energy prices are increasing due to weather, if we get an opportunity to buy energy at a reasonable price, we will fill a short position prior to the extreme weather hitting. Energy Supply will also discuss the situation with Generation Operations to make sure they can take action if there is anything Minnesota Power's generators have to address before extreme weather hits. Generation Operations will then undertake maintenance (if necessary) to make sure our units are as healthy as possible going into the weather event. If supply is tightening in advance of the event, we might go into more conservative operation mode and not do any maintenance on our generators that might jeopardize the generating unit being on-line when prices are expected to be highest.

F. Communication Between Energy Supply and the Generation Desk

A weather-event situation will be triggered by an advisory issued by Energy Supply through an e-mail sent to the Generation Desk. The Generation Desk would contact all the generators –using telephone, e-mail and/or a scheduled meeting to convey the message. The Generation Desk is meant to be the central reporting/data accumulation spot for all of Minnesota Power's generation, and they usually coordinate any outages, and maintenance events. The Generation Desk works closely with Energy Supply to determine the best time to do any work, communicating with the individual unit managers via e-mail and verbal conversations with each plant every day. The Generation Desk performs this communication each morning to get a status report to find out if any actual issues are looming at each plant and if there are any suspected issues. They then keep that information on record and follow-up as needed.

G. Ongoing Performance Measurement for Energy Supply

Minnesota Power staff measure the fuel adjustment costs on a daily basis – the actual fuel adjustment versus budget and versus the latest estimate from our medium term production cost model (the previous month's run). Minnesota Power breaks down day-to-day decisions that affect the fuel adjustment clause – including such things as our load forecast error margin, the cost and impact of our bilateral purchases, and our virtual transaction strategy, with the intent to examine and, where possible, improve our performance in these categories of activity.

H. Square Butte – Minnesota Power's PPA from Young 2

Minnesota Power purchases about 250 MW from Square Butte's Young 2. Planned outages at Young 2 are known two years in advance. Minnkota Power Cooperative operates and maintains Young 2. While Minnesota Power has no control over the maintenance, we do have input into operations.

For example, in the past, Minnkota has scheduled quarterly boiler cleaning outages during the business weekdays (Monday-Friday) when replacement energy costs are highest. Minnesota Power influenced them to take advantage of a weekend outage whenever possible in order to reduce replacement energy costs. Minnesota Power now works closely with Minnkota to increase and maintain awareness of the plant's operation on Minnesota Power customers.

I. Managing Planned Outages

Using the information from the production cost modeling, Minnesota Power will go to the market and purchase monthly forward energy supplies so that we reduce our exposure to the spot market. As explained previously, Minnesota Power's portfolio approach to covering our planned generator outages balances energy price forecasts with advance and short-term purchases, so that we normally purchase at least half of our replacement energy well in advance of an outage, and purchase the remaining needs on a short term basis. This strategy reduces volatility by limiting short term energy price exposure, and allows Minnesota Power flexibility to adjust to changes in energy prices.

For example, if Minnesota Power has a scheduled outage, the mid-term production cost model will show well in advance the short energy position that Minnesota Power will have to cover. Market conditions will dictate our replacement energy purchase strategy, so if there are good advance energy prices, Minnesota Power might start purchasing six months before. Minnesota Power attempts to fill our target replacement amount in total approximately 2-3 weeks before the outage starts. Our target amount might vary depending on what market conditions are. If prices are high compared to our budget, obviously, we will look harder for a purchase opportunity by exploring outside of the MISO market and canvassing counter-parties for bilateral arrangements. If market prices are very high and Minnesota Power feels that day-ahead and real time prices are going to be lower, Minnesota Power might leave a little more exposure to the day-ahead and real time market. These kinds of judgments are made based on a combination of the factual data that is available from models and other sources and our energy market purchasing expertise. Data and information without the perspective of energy market experience are insufficient for making the best decisions.

If forward energy offer prices in Minnesota are too high, Minnesota Power may take an energy position outside of the area and assume the congestion risk. We then go out to the monthly Financial Transmission Right (FTR) auction and try to secure an FTR to hedge that congestion.

J. Managing Forced Outages

There are two different types of forced outage situations 1) those that require a unit come down immediately or at the very latest during the next off peak period, or 2) those that likely can be nursed along for a day or two, perhaps even until the weekend. The question that is always asked if a problem occurs during a peak period is whether or not there is a way to put the outage off at least until off-peak. Usually that decision is made by the generator's staff. On the outages that can be nursed along, if the problem is not in a critical area, then the decision on when to take the unit down is made through the Generation Desk with Energy Supply's input. They determine jointly what the best time is by evaluating the operating and energy supply risks. For example, a tube leak in one tube may allow the generator to hold on for the weekend, but there is the risk that the leak may start damaging other tubes. Energy prices and price trends are also considered. Once these evaluations are made, the final decision is actually a combination of effort between the unit's management, the Generation Desk and Energy Supply.

Leadership meetings within Generation stress the fact that if there is even a suspected problem at a generator, the management of each unit must communicate all the conditions that are out there so that we can use our best judgment to decide what level of risk we want to have. For example, if there is an inkling of a problem, should Energy Supply be starting to hedge the possibility that a generator might go down sooner or not? Our goal is to take an educated and well-considered action based on where the problem lies and the history with the unit in the particular area having a problem.

K. Managing Forced Outages to Weekends

Typically, weekend market energy prices are probably 15-20% lower than weekday prices. Outages are “managed” or nursed along when possible in an attempt to be taken over the weekend. We are always factoring in weather and expected loads to decide if the outage should be instituted over the weekend or taken immediately. Residential and commercial load is lower on the weekend, but our large power loads are actually higher during the weekend because those customers do their maintenance during the week, and start gearing up production on Thursday or Friday so that they are running hard on the weekend when the prices are lower.

If a generator develops a problem during the day, there is a good chance the unit probably cleared the day-ahead market, so we determine first whether the unit can run for the rest of the day. If the unit has cleared the market, we see whether it can then come off that night in the off-peak (unless continued operation would damage the equipment). If the unit has to come down, then our options are to buy from MISO at the real time prices, go to other markets (Ontario or PJM) and buy and bring the energy into MISO, or to look at companies outside of MISO and set up bilateral transactions with them and bring the energy into our system. In most cases, the best option is to buy from MISO at the real time prices, but we are continuously monitoring all of our options in real time to make our decisions.

L. Forced Outage Scoping – Critical Path Work and the “Hot List”

Energy Supply is in constant communication with Generation to determine how long the outage is expected to go. If a unit develops a severe tube leak, and needs to be shut down immediately, it usually takes eight hours before the unit cooled down enough where the Maintenance staff can safely go in to assess the situation, evaluate the severity of the problem and determine the scope of the outage. Severity and scope depend on where the problem occurs. If it is a waterwall tube leak, for example, the scope is known quickly, and the severity may be the only issue. If it is in a reheater or super heater the scope may not be known until further in-person examination. Sometimes it becomes difficult to even find the leaks because there are so many tubes, and when they cool, leaks in certain locations can be difficult to find. With most of the units taking eight to ten hours to cool down enough so someone can safely enter them, probably the quickest outage is 24 hours for a small unit (approximately 75MW) and 36 hours for a big unit (more than 350MW). Minnesota Power makes arrangements immediately to get people onsite as soon as the unit is cooled down so that when eight hours is over, and it reaches a safe temperature in the boiler, they are ready to go in and start working.

Minnesota Power has entered into strategic partnerships with various key contractors to assist during outages for the very purpose of minimizing down time. As a result, contractor availability has not been an issue with the time it takes to cool the unit down usually being sufficient to get contractors secured and present. Complicating issues can be whether we have to clean something first, which may involve two contractors working parallel paths. With any outage a single maintenance process may be the critical path, but there might be eight or ten things that must be completed that compete for the scheduled outage time. All of this must be balanced and managed real time which, again, is where human expertise and judgment based on previous experience and what is happening on the ground come into play. There is no cookbook that provides play-by-play steps for outages.

When we have the necessary parts in inventory (such as tubing) available on site during outages, we will take advantage of the outage as an opportunity for other maintenance we were scheduling or anticipating. Each generating unit has a “hot list” of outstanding issues, and unit management has a plan to address those with other parts in line for known issues. We are always very careful that a hot list does not interfere with the critical path for a return to service. If the critical path is to get the tube leak repaired , a hot list item not related to the tube leak might be deferred to the next planned or unplanned outage.

M. Learning from Outages: The Reliability Team and the Engineer Group

Minnesota Power has what is known as a Reliability Team which is a group of internal engineers that have a high degree of technical expertise in specialized areas. A turbine expert essentially runs the turbine outages and manages every turbine outage at our company. A boiler expert does the same thing with boilers. Also on the team is a generalist engineer who can deal with most any problem at a plant. The predictive maintenance group is also a part of the Reliability Team and provides input on the monitored condition of equipment to the unit management on a regular basis.

The Reliability Team is a roving group of strategizers and troubleshooters that each of the plants utilizes in an outage situation. This provides expertise as well as consistency in knowing what is going on with any particular unit, so as we go into our outage cycle, we have a core base of internal expertise that knows what to expect based on the previous outages at that unit, as well as having expertise as to similar occurrences around the Minnesota Power system. The Reliability Team provides information to the generation management and the management of each specific unit. As a “best practice”, Minnesota Power tries to do as much of the major outage work as possible under the guidance of the Reliability Team to take advantage of this wealth of knowledge and expertise.

As a further effort to capitalize on what is learned from outages, an engineers’ group, made up of engineers from all the plants, and led by a Reliability Team engineer, jointly reviews findings from the various outages. They pick out particular issues occurring in outages that are not usual maintenance situations in order to learn from them to lessen the potential for and the impact and scope of unexpected occurrences at each plant. That group also helps develop younger engineers so they can get up to speed on plant issues more quickly. This practice of learning from outages provides a good knowledge base across all of our generation staff.

N. Performance Measurement for Generation

Minnesota Power Generation measures the availability of its units using GADS, the Generator Availability Data System. We review GADS for the last five years for a list of top five reasons that Minnesota Power has had outages – five reasons by year. We also examine our rates and also our overall generation availability compared to our peers. We use this information to help improve our performance.

A few years ago, Minnesota Power started measuring something we call Operational Flexibility which is the cost and benefit realized by delaying an outage through avoided purchased energy costs. Minnesota Power also measures our forced outage rate. All of these measurements are tracked, evaluated and utilized with the goal of improving performance.

Minnesota Power also has been moving into a more formal critique of all of our planned and forced outages; what went well and what did not go well – similar to an accident investigation. Engineers all have to have a lot of input into the details in an attempt to drive down to the root cause of an outage, and obtain conclusions based on facts to improve future performance.

Minnesota Power compares itself with the top 25% of our peer generation owners and our goal is to be better than the top 10% of the peer group. A consultant researches and chooses the peers in our peer group based on the same style generation, vintage, emission control equipment, and all other matters that could affect reliability and cost.

IV. THE MISO DAY 2 MARKET

The most fundamental change occurring to the FCA since the 2003 Order is the advent of the MISO Day 2 market. The MISO energy market allows utilities and their regulators to identify specific charges and credits contained in the MISO Transmission and Energy Markets Tariff ("TEMT"). This results in greater transparency of energy market costs. To be understood in context, it is important to understand that the advent of the MISO Day 2 market coincided with two key events: (1) the constricting availability of existing infrastructure (both generation and transmission) causing supply scarcity and increased congestion; and (2) an increase in natural gas prices that set an increasingly higher market price for intermediate and peaking resources that were being developed to alleviate tightening generation supplies. This confluence of events has created the impression of a cause and effect relationship (where none exists) between the advent of the MISO Day 2 market and increased energy costs.

Minnesota Power will not reiterate the comments it provided to the Commission on April 30, 2007 in response to the Commission's updated *Notice for Comments* regarding this Docket (dated March 30, 2007) regarding MISO Day 2. Instead, this document reminds the Commission that a framework for analyzing utility fuel clause performance is already established within the framework of the Commission's December 20, 2006 MISO Day 2 Order (Paragraph 7. A-H).

Within the context of Paragraph 7 of the MISO Day 2 Order, each utility is required to submit an annual FCA Forecast of the cost per megawatt hour of fuel and purchased power costs for the upcoming 12 month period. The Order requires that utilities also identify major changes that impact the stability of forecast resulting from underlying changes in cost inputs, as well as projected variances in fuel costs and purchased power due to increased volatility in fuel markets. Most importantly, each utility must explain reasons for deviations in the forecast from actual costs in the previous year. Additionally, each utility must update its FCA forecast whenever deviations from the forecast are sufficiently material that it would require a reforecast for the 12 month period. As identified in Paragraph 7.E., to the extent that monthly fuel and purchased energy FCA forecast exceeds the budget for a month by more than 10%, the utility must provide an explanation of the cause or causes for the change. Paragraph 7.F. includes the opportunity for the utility to prepare monthly deviation explanation if the forecast for a month deviates from actual fuel and energy cost by 15% or more.

Minnesota Power believes that Paragraph 7 of the MISO Day 2 Order provides a framework for the Department and the Commission, as well as interested customers and other stakeholders, to monitor and analyze utility FCA performance.

V. CONTINUED RATIONALE FOR THE FCA

Although some changes have occurred during the past several years to the specific energy-related costs incurred by electric utilities and the costs suitable for inclusion in the FCA, the FCA still serves its original intended purpose well. It is an efficient mechanism for recovery of volatile costs that fluctuate to a large extent beyond the utility's control or ability to forecast. It allows utilities and stakeholders to avoid the administrative costs associated with frequent rate cases driven by fuel and energy purchase cost changes.

A. Price Signals

One of the issues discussed in various parties' comments regarding the scope and procedures to be used in this Docket was how fuel adjustment changes might influence customer energy usage.

Minnesota Power's generation resource energy production generally matches retail firm load requirements except during periods of peak load or reduced generation availability. Minnesota Power's fuel adjustment is most greatly affected by the costs of purchased power during times of low system hydroelectric generation and generator outages. With the exception of scheduled generation maintenance outages, these are variable events that are highly unpredictable and difficult to forecast in advance. Otherwise, the average fuel cost for operating Minnesota Power's generating resources is relatively constant due to long-term fuel supply contracts.

Because generation and retail firm energy requirements are normally in balance, Minnesota Power's energy market purchases primarily occur to serve the higher-cost portion of its supply requirements for interruptible and incremental energy customers, whose energy is priced separately from the firm energy sales subject to fuel adjustment. Large Power and Large Light and Power customers account for between 50 and 60 percent of Minnesota Power's system requirements. Although these customers are subject to the FCA for their firm energy requirements, the portion of their load served as interruptible and incremental energy is priced based on Minnesota Power's incremental cost to allow such customers to respond to daily or hourly price signals. The need for these customers to maintain high production levels usually causes them to continue operations in high-priced markets – except in those circumstances when market energy prices exceed $100 or more per MWh, where their ability to institute load curtailments provides the necessary benefit to offset losses in production. These customers are, in fact, given daily and, at times, hourly energy market pricing information for the purposes of making operating decisions. Since interruptible and incremental energy is provided at incremental cost-based rates that are paid directly by such customers, the cost of this energy does not flow through to the fuel clause. Therefore, the majority of Minnesota Power's customer base has the ability to adjust usage in reaction to energy costs. Since those customers generally pay the direct costs for such energy to serve the most flexible portions of their load, it is unlikely that they would be able to respond significantly to monthly fuel adjustment price signals based on projected costs. However, Minnesota Power continues to review the positives and negatives of switching from the current lagging FCA method to a monthly forecast, in the event circumstances would indicate the potential for enough benefits to explore such a change.

It is questionable whether price signals that may be provided by the monthly fuel clause forecast will have a significant impact on customer demand on Minnesota Power's system, considering its load profile and energy requirements. Minnesota Power's load profile does not lend itself to load management through fuel adjustment cost signals in the same way other utilities' systems may be affected by fuel costs, because of the lack of customer class diversity and the relatively constant nature of Minnesota Power's retail customer needs. At some time in the future, Minnesota Power may explore the benefits and impacts of shifting our current FCA two-month lag to a forward-looking fuel clause forecast similar to that utilized by Xcel Energy. Such a change may make greater sense in the context of rate and tariff changes that introduce time of day rates in order to fully realize the benefits of price information and price signals to customers. Minnesota Power's current rate structure and tariffs do not lend themselves to the types of price signals that the Department has been discussing.

B. Cost Recovery

As stated on page 2 of the Commission's December 19, 2003, Order Determining Scope and Setting Procedural Framework in this Docket, the FCA is intended to make rates more accurate and to conserve regulatory and utility resources. Since fuel and purchased power costs can fluctuate significantly between rate cases, building these costs into non-adjustable rates could cause significant, recurring mismatches between expenses and rates. It might also strain utility and regulatory resources by forcing frequent rate cases and earnings investigations to address changes in the cost of fuel and purchased power. The variability in FCA costs will have a greater financial impact on smaller utilities. Introducing greater uncertainty in cost recovery mechanisms will impact the utilities' credit ratings and earnings stability, and a shift in methodology should not be undertaken without understanding those effects. Minnesota Power also believes that the identified ongoing benefits of the FCA, along with the current reporting requirements which were recently expanded and updated, outweigh any concerns regarding the changes in the types of costs recovered through the FCA.

VI. ENCOURAGING LARGE CUSTOMERS TO PARALLEL MP OUTAGE TIMEFRAMES

Minnesota Power's Large Power customers proposed an idea to incentivize the customers to take their outages at the same time as Minnesota Power. Upon further reflection, this proposal is more likely to negatively impact customer costs.

There is very tight pool of trade workers in northern Minnesota. As an example, last year Minnesota Power had a turbine outage scheduled, which we can only do in certain times of the year because of the length of time the unit is down. One of our large power customers also wanted to do an outage at the same time, and asked us to shift our outage, but because of the shortage of people there were not enough people to do work at both sites. Minnesota Power did not shift its work. With all of the construction that is anticipated in northern Minnesota, the labor pool will grow even tighter.

Minnesota Power believes the best way to incentivize outage coordination for positive results is to place a premium on synchronizing significant plant work so that the labor force can move from project to project rather than be forced to choose between projects.

VII. CONCLUSION

Minnesota Power believes that the FCA continues to be an appropriate tool for use in the current regulatory environment. The original purpose of the FCA, to provide the automatic adjustment of rates to reflect changes in the cost of energy delivered to customers, still holds true today. Although some changes have occurred during the past several years to the energy-related costs incurred by specific electric utilities and which costs are suitable for inclusion in the FCA, the FCA still serves its original intended purpose well for Minnesota Power and its customers.

A primary objective of the FCA is to allow cost recovery with regard to short-term changes in the cost of fuel and purchased energy through monthly billing adjustments. The FCA allows utilities to automatically adjust rates to reflect changes in the cost of energy delivered to customers from those costs authorized in the utility's most recent general rate case. Because such costs are the largest variable component of the cost of providing electric service, having a fuel adjustment that varies monthly enables utilities to match customer rates more closely with the costs that are incurred.

Even with the automatic pass-through of these charges, however, Minnesota Power follows certain policies and practices that lead to the successful administration of its FCA, including: 1) balancing Minnesota Power generating assets, customer generating assets, and wholesale energy purchases and sales with projected electric usage of Minnesota Power's retail customers; 2) carefully and aggressively managing those key drivers that are within Minnesota Power's control such as delivered fuel cost and generation outage scheduling; and 3) adhering to strict internal and external process controls.

Yet, even with fuel clause measures in place to minimize fuel and energy purchase costs, there are still key FCA drivers that are outside of Minnesota Power's control, including the availability of the Minnesota Power's hydro generation and the market cost of replacement market energy purchases. Hydro generation is driven by the amount of precipitation received in the region. Minnesota Power's average purchased replacement energy costs fluctuate from year to year depending on generating unit availability and the overall level and volatility of market energy prices. Since fuel and purchased power costs can fluctuate significantly between rate cases, building these costs into non-adjustable rates could cause significant, recurring mismatches between expenses and rates. It could also cause more frequent rate cases and earnings investigations to address changes in the cost of fuel and purchased power. These factors make the FCA mechanism for recovery of cost fluctuations more appropriate and important than ever.

ATTACHED HERETO
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APPENDIX A

Transmission & Distribution World

S&P: Utility Regulation Determines Its Ratings

Standard & Poor's

Online Exclusive, Feb 3 2004

Standard & Poor's Ratings Services has been tracking the ups and downs of utility regulation for years, and in the past year or so has noted the recent upswing in the amount of attention that regulators and their activities are attracting (see, for instance, "State Utility Regulation Coming Back In Vogue," published Oct. 3, 2002, and "U.S. Electricity Regulation Evolves as Transition to Competition Continues," published Sept. 25, 2003). With the renewed and increasing influence that regulators are asserting on the creditworthiness of utilities, especially as many managements scramble back under the protective umbrella of comprehensive regulation, Standard & Poor's offers this primer on how we analyze the effect of regulation on utility credit ratings. The entire range of regulatory actions and inactions is examined, but inevitably it is the analysis of rate case decisions that provides the key indicator of the level of support.

First, however, it is useful to remember the legal status of utility regulatory bodies when developing the basic analytical approach to their activities and decisions. Most utility commissions are, in a legal sense, "creatures of the legislature"; that is, the role they play is essentially legislative and not judicial. The responsibility for setting utility rates and for other various functions is actually that of legislators, but has been delegated to regulators for practical reasons. Thus, despite the trappings of a court (testimony, rules of evidence, administrative law "judges") and a long history of accumulated case law governing their activities, the decision-making process of utility commissioners more often resembles that of legislators, with its emphasis on compromise and political considerations, than that of jurists who weigh evidence, construe the law, follow legal precepts, and the like.

The implication for the analyst is that the behavior of regulators can more often be explained by looking to political factors than to analyzing legal precedents or assessing the arguments of opposing parties. That's why Standard & Poor's analysts spend considerable time meeting with regulators and staff members and accumulating knowledge about the local and regional political climate and its effect on a utility, in addition to analyzing the impact of a particular rate decision or other commission pronouncements. Nevertheless, rate cases, once thought to be obsolete as competition spread across the country, appear to be returning to the forefront again.

For major rate cases that can directly affect ratings, the analyst will follow the developments in a rate proceeding from the initial filing. The company's request for rate relief, the local public reaction to the filing, the rebuttals of important parties and intervenors, and the conduct of the hearings are all monitored, assessed, and commented upon, if necessary, as the case proceeds through its schedule. The ability of the commission to render a fair and balanced decision that appropriately considers the interests of all the participants in the process can sometimes be affected by incidents that occur while the case is developing. Standard & Poor's tracks whether the case is drawing a lot of attention, influential parties are staking out extreme positions, or outside events such as upcoming elections are affecting the chances of a rate decision that is consistent with the financial projections the ratings are based on.

Once a decision is reached, Standard & Poor's analyzes its effect on the financial forecast for the company, and also to assess whether the actions and precedents being set by the commission in its decision will have a long-term effect on Standard & Poor's opinion of the regulatory environment in that jurisdiction. The analysis of the rate case fundamentally explores a two-fold question: Are the new rates based on a rate of return consistent with the company's ratings, and is the utility being afforded a legitimate opportunity to actually earn that rate of return?

On the former question, the analyst looks to equity returns being authorized for other utilities of the same credit quality, as well as the capital structure employed to arrive at the overall rate of return being used to set rates. On the latter, the test year and all of the adjustments made to the company's filed data are inspected to arrive at the final conclusion. Generally, decisions that feature the most up-to-date information in determining rates, including current test years and all "known-and-measurable" changes, are viewed as providing companies with the best chance to earn a reasonable and cash-rich return.

Importantly, credit analysis also incorporates the cash-flow effect of a decision, especially if it is the result of a full or partial settlement between the parties. A common method to achieve the compromise often sought by the parties or the regulators is to defer cost recovery into the future, which can preserve earnings but weaken cash flow. Standard & Poor's places much emphasis on cash flow protection measures when assessing credit quality, and a rate decision that ostensibly looks favorable for investors can sometimes come at the expense of bondholders. Attention to the details is crucial in analyzing a rate decision because some that appear to be favorable on the surface can hide the "bite" that regulators took in the less conspicuous parts of the case, such as a change in the depreciation rate.

Finally, one of the most important issues affecting ratings may or may not be part of the rate-case process, but is constantly tracked by Standard & Poor's: the recovery of fuel and purchased-power and gas costs. The analysis concentrates on stability of cash flows and the relative certainty of full recovery of these items, the largest expenses for almost all utilities, in arriving at a consensus on the level of a utility's business risk.

The stability that leads to improved credit quality can be supported by legislators and regulators either through rate design or by carving out fuel and commodity expenses and treating them separately from the normal rate case process. Rate design is established as part of a rate-case decision, and can be used to promote stability by allocating a greater percentage of fixed costs for recovery through the standard monthly charge. The more common method is a separate clause in the tariff that fluctuates automatically or near-automatically as commodity costs rise and fall. The presence of a fuel and purchased-power or gas clause that helps a utility manage its exposure to commodity price moves is positive for credit ratings. Not all are created equal, however, and each mechanism is studied to determine how closely it allows for matching of customer rates with expenses.

Many other factors outside the scope of this commentary can play an important part in the overall assessment of the regulatory environment in which a utility operates. Incentive ratemaking, special rate riders to recover extraordinary costs (e.g., environmental compliance), deregulation developments, the degree to which regulation insulates a utility from its parent, legislative initiatives, and other non-ratemaking considerations can all affect Standard & Poor's opinion of the quality of regulation. The ability of management to control its regulatory risk and the historical attitude of regulators toward the interests of utility bondholders also enter into the analysis. In the end, the regulation of public utilities is the defining element of the industry and is often the determining factor in the ratings of a utility.

ATTACHED HERETO
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APPENDIX B

FUEL CLAUSE ADJUSTMENT - RETAIL

Line No.			
	COST OF FUEL	December 2003	January 2004
1	All Stations - Total Burned for Generation	7,362,933	7,022,780
2	Plus : Fuel Component of Purchased & Interchange	8,207,766	9,657,833
3	Less : Fuel Cost recovered thru Inter-System Sales	3,802,436	5,381,645
4	Total Monthly Fuel Cost	11,768,263	11,298,968
5	Current 2-Month Total Cost of Fuel		23,067,231
	KWH SALES		
6	Total Sales of Electricity	924,710,196	1,008,916,369
7	Less : Inter-System Sales	161,429,113	169,610,226
8	Total Monthly KWH Sales	763,281,083	839,306,143
9	Current 2-Month Total KWH Sales		1,602,587,226
	FUEL CLAUSE # 16 & 17		
10	**Fuel Cost - cents/kWh (Line 5 / Line 9)**		**1.439**
11	Less : Base Cost of Fuel - cents/kWh		1.018
			0.421
12	**FUEL ADJUSTMENT - cents/kWh**		**0.421**
	BILLING MONTH :		March 2004

Minnesota Power
Fuel Adjustment Clause Data to the
Minnesota Department of Commerce

Fuel adjustment clause data for the billing month of: October-07

Line No.	Cost of Fuel	July-07	August-07	Total
1	Company's Generating Stations (Account 151)	$10,349,579	$9,826,127	$20,175,706
2	Plus Fuel Cost Component of Purchased Energy	$15,523,417	$13,485,592	$29,009,009
2a	Less MISO Schedule 16 & 17	$0	$0	$0
2b	Less MISO Schedule 16 & 17	$144,118	$123,154	$267,272
2c	Less Amortization of Prior Months Collection of Schedule 16 & 17	$198,712	$198,712	$397,424
3	Less Fuel Cost Recovered through Inter-System Sales	$7,513,819	$6,898,139	$14,411,958
4	Total Cost of Fuel	$18,016,347	$16,091,714	$34,108,061
	KWh Sales			
5	Total Sales of Electricity	1,110,364,034	1,116,935,021	2,227,299,055
6	Less Inter-System Sales	236,815,093	235,546,378	472,361,471
7	Total kWh	873,548,941 0	881,388,643	1,754,937,584
8	Cost of Fuel per kWh (cents/kWh)			1.944

Fuel Adjustment per kWh

9 Fuel Adjustment Clause #16 :

Fuel Cost	1.944	
Less Base	1.018	
Fuel Adjustment	0.926	cents/kwh

10 Fuel Adjustment Clause #17 :

Fuel Cost	2.936	
Less Base	1.018	
Fuel Adjustment	1.918	cents/kwh

Minnesota Power
Fuel Adjustment Clause Data to the
Minnesota Department of Commerce

Kilowatt-hour Information for the Billing Month of: **August-07**

Line No.		Kilowatt-Hour Sales	
	Minnesota Jurisdiction - Retail Sales		
1	Subject to Fuel Clause #16	735,222,138	kWh
2	Subject to Fuel Clause #17*	1,330,095	kWh
3	Non-Fuel Clause Sales	20,805,869	kWh
4	Total	757,358,102	kWh
	Non-Minnesota Jurisdiction Sales		
5	Sales for Resale	359,576,919	kWh
6	Total Sales of Electricity	1,116,935,021	kWh
7	Less Inter-System Sales	235,546,378	kWh
8	Total kWh Sales	881,388,643	kWh

Notes:

The October 2007 bills will be mailed between October 1, 2007 and November 1, 2007.

A majority of the kWh usage to which the fuel clause adjustment rates on this form are applicable will occur during the calendar month of October 2007 for all customers on Company's Large Power Service rate. A majority of the kWh usage for all other retail customers will occur during the calendar month of September 2007.

Fuel Adjustment Clause #17: Because the rates containing this adjustment are based on annual kWh use, the fuel adjustment per kilowatt-hour applicable for the June billing period applies for the entire annual period (June through May).

Prepared by: Patty Toivonen

Patty Toivonen
Senior Accounting Analyst

Date: September 26, 2007