**Public Document - Does Not Contain Trade-Secret Information**

# Minnesota Public Utilities Commission

***Staff Briefing Papers***

**Meeting Date**: **November 29, 2007** . . . . . . . . . . . . . . . . . . . . . . . . . . . . . **Agenda Item #____**

**Companies:** All Commission-Regulated Natural Gas Utilities

**Docket Nos.**

E,G-999/AA-06-1208
In the Matter of the Review of the 2006 Annual Automatic Adjustment of Charges for All Electric and Gas Utilities

G-008/M-07-561
In the Matter of the Request of CenterPoint Energy Resources, Inc. d/b/a CenterPoint Energy Minnesota Gas, for a Change in Demand Units

G-002/M-07-1395
In the Matter of the Petition of Northern States Power Company, a Minnesota Corporation and Wholly Owned Subsidiary of Xcel Energy Inc., for Approval of Changes in Contract Demand Entitlements

G-001/M-07-1397
In the Matter of the Request of Interstate Power and Light Company, an Alliant Energy Company, to Change Its Demand Entitlements

G-022/M-07-1398
In the Matter of the Petition of Greater Minnesota Gas, Inc., a Wholly-Owned Subsidiary of Greater Minnesota Synergy, Inc., for Approval of Changes in Contract Demand Entitlements

G-004/M-07-1401
In the Matter of the Request of Great Plains Natural Gas Co., a Division of MDU Resources Group, Inc., to Change Its Demand Entitlements

G-007/M-07-1402
In the Matter of the Petition of Minnesota Energy Resources Corporation-NMU for Approval of a Change in Demand Entitlements

G-011/M-07-1403
In the Matter of the Petition of Minnesota Energy Resources Corporation-PNG for Approval of a Change in Demand Entitlements for its Viking Gas Transmission System

G-011/M-07-1404
In the Matter of the Petition of Minnesota Energy Resources Corporation-PNG for Approval of a Change in Demand Entitlements for its Great Lakes Gas Transmission System

G-011/M-07-1405
In the Matter of the Petition of Minnesota Energy Resources Corporation-PNG for Approval of a Change in Demand Entitlements for its Northern Natural Gas Transmission System

**Issues:**

1. Should the Commission accept the natural gas utilities' 2005-2006 annual automatic adjustment reports and true-up filings?

2. Should the Commission require the natural gas utilities to address the Department's questions about the allocation of producer demand and storage costs to firm or firm and interruptible sales customers in the natural gas utilities' 2007-2008 demand entitlement dockets?

**Staff:** Robert C. Harding . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 651-201-2237

---

***Relevant Documents***

Review of the Natural Gas Utilities' 2005-2006 AAA Reports
Department of Commerce - Review, Vol. II - Natural Gas Utilities . . . . . . . . . . . . Apr. 16, 2007
Department of Commerce - Errata . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . Apr. 26, 2007

Reply Comments
Great Plains . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . May 31, 2007
Interstate Gas . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . May 31, 2007
Aquila (Aquila Networks-NMU & Aquila Networks-PNG) . . . . . . . . . . . . . . . . . . Jun. 1, 2007
Minnesota Energy Resources Corp. (MERC-NMU & MERC-PNG) . . . . . . . . . . Jun. 15, 2007
CenterPoint Energy . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . Jun. 1, 2007
Xcel Gas . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . May 25, 2007

Response Comments
Department of Commerce . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . Oct. 19, 2007

Reply to DOC Response Comments
CenterPoint Energy . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . Oct. 30, 2007
Great Plains . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . Nov. 5, 2007
Interstate Gas . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . Nov. 9, 2007
Xcel Gas . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . Nov. 9, 2007

The attached materials are work papers of the Commission Staff. These work papers are intended for use by the Public Utilities Commission and are based upon information already in the record unless noted otherwise.

This document can be made available in alternative formats (i.e. large print or audio tape) by calling 651-201-2202 (voice). Citizens with hearing or speech disabilities may call us through Minnesota Relay at 1-800-627-3529 or by dialing 711.

November 26, 2007

## Statement of the Issues

1. Should the Commission accept the natural gas utilities' 2005-2006 annual automatic adjustment reports and true-up filings?

2. Should the Commission require the natural gas utilities to address the Department's questions about the allocation of producer demand and storage costs to firm or firm and interruptible sales customers in the natural gas utilities' 2007-2008 demand entitlement dockets?

## Introduction

Every year the Commission reviews the automatic adjustment of charges reported in the utilities' annual automatic adjustment reports and annual true-up filings. The most significant events during this reporting period were hurricanes Katrina (August 23) and Rita (September 24), which disrupted natural gas production in the Gulf of Mexico, and are the reason given for natural gas price increases in the latter half of 2005. The 2005-2006 heating season was warmer than normal.

Attachment A describes the process the Commission has used to conduct these reviews.

The electric utilities' annual fuel reports and any issues remaining after this meeting will be taken up at a future Commission meeting.

## Background

On or about September 1, 2006, all of the Commission-regulated natural gas utilities submitted annual automatic adjustment ("AAA") reports and annual true-up filings ("true-ups") covering the twelve-month period from July 1, 2005 through June 30, 2006. These AAA reports, and annual true-up filings, were prepared in accordance with Minn. Rules, parts 7825.2390 through 7825.2920, and include compliance information required by Commission order in previous AAA dockets and compliance information required by Commission order in other dockets.[1, 2]

The following gas utilities submitted filings:

•Greater Minnesota Gas, Inc., a wholly-owned subsidiary of Greater Minnesota Synergy, Inc. ("GMG")

---

[1] The electric utilities also submitted annual automatic adjustment (AAA) reports covering this same twelve-month time period.

[2] Copies of the electric and natural gas utilities 2006 annual automatic adjustment reports and annual true-up filings are available through the Internet-based "Edockets" system. [https://www.edockets.state.mn.us/EFiling/search.jsp]

• Great Plains Natural Gas Co., a Division of MDU Resources Group, Inc. ("Great Plains")
• Interstate Power and Light Company, an Alliant Energy Company - Gas Utility ("Interstate Gas")
•Aquila, Inc. ("Aquila") d/b/a Aquila Networks-NMU ("Aquila Networks-NMU" or "NMU")[3, 4, 5]
•Aquila, Inc. ("Aquila") d/b/a Aquila Networks-PNG ("Aquila Networks-PNG" or "Peoples")[6, 7, 8]
•CenterPoint Energy Resources, Inc. d/b/a CenterPoint Energy Minnesota Gas ("CenterPoint Energy")
•Northern States Power Company, a Minnesota corporation and wholly owned subsidiary of Xcel Energy Inc. ("Xcel Gas").[9]

On September 29, 2006, the Commission granted the Minnesota Department of Commerce's ("Department's") request for an extension to file comments on these annual filings until March 16, 2007. The filing date for reply comments was extended until April 6, 2007.

On March 14, 2007, the Commission granted the Department's second request for an extension until April 16, 2007, and extended the filing date for replies until May 7, 2007.

On April 16, 2007, the Department submitted non-public Volumes I and II of its *Review of the 2005-2006 Annual Automatic Adjustment Reports* (Review or Report). Volume II of the

---

[3] In 2002, UtiliCorp United, Inc. changed its name to Aquila, Inc. ("Aquila") At that time, Peoples Natural Gas Company's name was changed to Aquila Networks-PNG ("Peoples") and Northern Minnesota Utilities' name was changed to Aquila Networks-NMU ("NMU"). (Department, Review, footnote 38)

[4] On October 17, 2005 Aquila filed a petition (Docket No. G-007/011-PA-05-1676) for the approval of the sale of Peoples and NMU to WPS Minnesota Utilities, Inc., a wholly-owned subsidiary of WPS Resources Corporation. (This entity is now known as Minnesota Energy Resource Corporation ("MERC")). This petition for the approval of sale was approved by the Commission on June 1, 2006 and on July 1, 2006, Aquila officially transferred its assets and control to MERC. Thus, for the current true-up year, Aquila filed the true-up petition rather than MERC. (Department, Review, footnote 40)

[5] Minnesota Energy Resource Corporation ("MERC") currently operates this utility as MERC-NMU.

[6] See footnote 3.

[7] See footnote 4.

[8] Minnesota Energy Resource Corporation ("MERC") currently operates this utility as MERC-PNG.

[9] The electric utilities also submitted annual automatic adjustment (AAA) reports covering this same twelve-month time period.

Department's Review covers the natural gas utilities' annual reports and true-up filings, and contains reports requested by the Commission in previous AAA dockets. In its Review, the Department recommended the Commission accept the fiscal year-end 2006 AAA reports as filed, and subsequently amended, by the natural gas utilities as being complete as to Minnesota Rules, parts 7825.2390 through 7825.2920. The Department also commented on: (1) the accuracy of the gas utilities' annual reports and annual true-up filings, (2) the information submitted by the gas utilities in compliance with Commission reporting requirements in various fuel cost-related and other dockets, (3) the gas utilities' fiscal year 2006 gas costs and gas purchasing practices, (4) the gas utilities' financial hedging practices, and (5) each gas utilities' treatment of demand costs. In addition, the Department's Review contains comparative cost and operating data for all the gas utilities.

On April 25, 2007, the Commission granted Aquila's request for an extension of the reply comment deadline to May 21, 2007. On May 2, 2007, the Commission granted requests from Otter Tail Power and Xcel Electric for an extension of the reply comment deadline to June 1, 2007. On June 4, 2007, the Commission granted Minnesota Energy Resources Corporation request for an extension of the reply comment deadline to June 15, 2007.

The gas utilities submitted their reply comments on the following dates: Xcel Gas - May 25, 2007; Great Plains and Interstate Gas - May 31, 2007; Aquila and CenterPoint - June 1, 2007; and MERC - June 15, 2007. (Greater Minnesota Gas did not submit reply comments.)

On October 19, 2007, the Department submitted response comments recommending the Commission accept all of the gas utilities' annual reports as complete, as well as all of their annual true-up filings. The Department also recommended the gas utilities address in their 2007-2008 demand entitlement dockets how and why they allocate producer demand and storage costs to firm or firm and interruptible sales customers, and provide a rate impact analysis that demonstrates the impact of any proposed change in the allocation of these costs.

On October 30, 2007, CenterPoint Energy submitted reply comments.

On October 31, 2007, at the request of Otter Tail Power, the Commission extended the reply comment deadline to November 9, 2007.

On November 5, 2007, Great Plains submitted reply comments.

On November 9, 2007, Interstate Gas, and Xcel gas submitted reply comments.

## Annual Automatic Adjustment Reports & True-up Amounts

In its April 16, 2007 Review, the Department found that the natural gas utilities incurred approximately $2.19 billion in natural gas commodity, transportation, storage and related costs for fiscal year 2006, and recovered approximately $2.16 billion in natural gas costs in their base rates and purchased gas adjustment (PGA) mechanisms. In fiscal year 2006, the natural gas utilities under-recovered their natural gas costs by approximately $31.5 million, or -1.44%. The amount of an individual customer's responsibility for these under-recovered true-up dollars depends on each utility's total true-up amount and, within each utility, the amount of each customer class' over- or under-recovery of its assigned costs.

| **Summary of Gas Utilities Annual Fuel-Cost Recovery, July 1, 2005 through June 30, 2006 (Department Review, Vol. II, Table G1, p. 4)** | | | | |
|---|---|---|---|---|
| Utility | Gas Costs Recovered ($) | Cost of Gas Actual ($) | Over/Under Recovery ($) | Over/Under Recovery (%) |
| Greater Minnesota | $ 2,945,366 | $ 2,986,208 | $ (40,842) | -1.37% |
| Great Plains | | | | |
| North | $ 14,271,879 | $ 14,931,244 | $ (659,365) | -4.42% |
| Southern | $ 18,798,764 | $ 19,385,591 | $ (586,827) | -3.03% |
| Interstate Gas | $ 16,168,817 | $ 16,667,484 | $ (498,667) | -2.99% |
| NMU (Aquila) | $ 57,753,576 | $ 58,670,527 | $ (916,951) | -1.56% |
| Peoples-MN (Aquila) | | | | |
| Northern | $ 188,934,710 | $ 192,011,716 | $ (3,077,006) | -1.60% |
| Great Lakes | $ 7,382,293 | $ 7,751,476 | $ (369,183) | -4.76% |
| Viking | $ 6,861,952 | $ 7,132,772 | $ (270,820) | -3.80% |
| CenterPoint Energy - Consolidated | $ 1,230,677,271 | $ 1,247,331,081 | $ (16,653,810) | -1.34% |
| Xcel Gas | $ 614,940,701 | $ 623,360,131 | $ (8,419,430) | -1.35% |
| Minnesota Total | $ 2,158,735,329 | $ 2,190,228,230 | $ (31,492,901) | -1.44% |

In its Review, the Department checked: (1) the accuracy of the gas utilities' annual reports and annual true-up filings, and (2) the information submitted by the gas utilities in compliance with Commission reporting requirements in various fuel cost-related and other dockets. In addition, the Department's Review contains comparative cost and operating data for all the gas utilities.

In its Review, the Department checked the accuracy of each utilities' filings, and requested explanations and further information about any part of a utilities' proposed true-up with an over or under-recovered amount in excess of plus or minus five percent. (The five percent threshold test comes from the PGA errors rule, in Minn. Rules, part 7825.28920, subpart 2.) Based on this approach, the Department requested explanations from several of the companies about their proposed true-ups, and other miscellaneous compliance-related reporting issues. In their reply comments, the utilities provided explanations that, for the most part, addressed the Department's concerns.

•Great Plains - regarding its proposed adjustment to collect under-recovered demand costs: Great Plains explained that its demand costs were under-recovered because it was warmer than normal, and there is a timing difference between the pipeline contract year, and the PGA gas year. (Department, Review, pp. 13-20; Great Plains, reply comments, pp. 2-4; and Department, response comments, pp. 2-6)

•Aquila Networks-NMU - regarding Aquila Networks-NMU"s proposed adjustment to collect under-recovered demand costs, compliance with procedures required for trade secret information, and the incurrence of Zone D penalties due to its negative reserve margin: Aquila Networks-NMU explained that the under-recovery of demand costs was due to warmer than normal weather, and normalized volumes in the 2005-2006 reporting period were lower than the test-year volumes that were used to calculate the monthly PGA. Aquila indicated that MERC would be responsible for filing future reports and complying with the requirements pertaining to the submission of trade secret information, and MERC agreed. Aquila did not incur any Zone D penalties due to its negative reserve margin. (Department, Review, pp. 28-31; Aquila, reply comments, pp. 7-9; MERC, reply comments, p. 2; and Department, response comments, pp. 11-12)

•Aquila Networks-PNG - regarding compliance with the procedures required for trade secret information, and the incurrence of Zone D penalties due to its negative reserve margin: Aquila indicated that MERC would be responsible for filing future reports and complying with the requirements pertaining to the submission of trade secret information, and MERC agreed. Aquila did not incur any Zone D penalties due to its negative reserve margin. (Department, Review, pp. 23-28; Aquila, reply comments, pp. 1 & 3; MERC, reply comments, p.2; and Department, response comments, pp. 8 & 10)

•Xcel Gas - regarding the proposed termination of Xcel's agency services gas cost pricing methodology: Xcel terminated its agency service program and believes this allocation pricing methodology is no longer applicable. (Department, Review, pp. 37-43; Xcel Gas, reply comments, p. 3; and Department, response comments, pp. 14-16)

The Department also noted that CenterPoint Energy's annual automatic adjustment reports and annual true-up filing combine its Northern and Viking PGAs.[10]

In its April 16, 2007 Review, the Department recommended the Commission accept the fiscal year end 2006 AAA reports as filed, and subsequently amended, by the natural gas utilities as being complete as to Minnesota Rules, parts 7825.2390 through 7825.2920, and in its October 19, 2007 response comments, the Department recommended the Commission accept all of the gas utilities' annual true-up filings. The Department did, however, caution Great Plains that it does not endorse Great Plains' method of normalizing weather volumes, and while the Department believes Great Plains assertion that timing differences between demand-cost incurrence and GCR recovery (i.e. the timing differences related to the difference between the contract year and the PGA year) are part of the reason for Great Plains' under-recovery of its demand costs, the Department does not believe Great Plains has quantitatively substantiated its argument. The Department stated that "if Great Plains identifies the timing difference issue as a reason for any under-recovery or over-recovery of demand costs in its next annual fuel report, the Department expects that Great Plains will be able to provide and substantiate a quantitative analysis on this issue." (Department, response comments, pp. 2-6)

[10] The Commission approved consolidation in its June 8, 2005 general rate case order in Docket No. G008/GR-04- 901.

**PUC Staff Comment**

Staff agrees with the Department's conclusions and recommendations except for two points. Staff also has a comment on Xcel's request to terminate reporting its gas pricing methodology for its one remaining agency service customer.

**1. Commission's directive relating to NYMEX futures or options transactions**[11]

In its Review, the Department recommended that Great Plains address whether it "engaged in any NYMEX natural gas futures or options transactions during the class [action lawsuit] period of June 1, 1999 through December 31, 2002", and if so, indicate whether Great Plains has filed a claim for a share of the settlement fund. The Department requested this information because Great Plains did not provided it in its initial filing. In its reply comments, Great Plains stated that it "did not engage in any NYMEX natural gas futures during the referenced time period." In its response comments, the Department stated that Great Plains has satisfied the Commission's directive in Docket No. E,G-999/AA-05-1403 relating to NYMEX futures or options transactions, and recommended the Commission find that Great Plains satisfied in the present docket the Commission's directive in Docket No. E,G-999/AA-05-1403 relating to NYMEX futures or options.

All of the other gas utilities complied with the Commission's July 19, 2006 directive, and, as it turns out, none of them engaged in NYMEX transactions during the class period. (Xcel Electric did engage in NYMEX natural gas futures or options transactions during the class period but is not eligible to participate in this settlement because its affiliate at that time, e-prime, is one of the defendants in the class action lawsuit.)

Staff believes that rather than identifying only Great Plains as having complied with the Commission's directive, it would be appropriate to make a finding in its order in this docket that none of the gas utilities engaged in NYMEX natural gas futures or options transactions during the class period, and none were eligible to file claims for a share of the class action settlement fund. Ordinarily, staff would not suggest this was necessary because responding to Commission directives to provide information is usually treated as a compliance matter that does not require a formal Commission order either for the Department to enforce or to acknowledge that the information has been provided and no further action is needed. However, in this case, because this issue was the subject of a formal, one-issue Commission order, staff believes a general finding of compliance in this docket would be appropriate.

**2. Acceptance of CenterPoint Energy's 2005-2006 AAA reports and annual true-up filing**

The Commission's decision on CenterPoint Energy's 2004-2005 true-up is pending. In its

---

[11] ORDER REQUIRING ADDITIONAL INFORMATION IN 2006 ANNUAL AUTOMATIC ADJUSTMENT REPORTS AND REQUESTING COMMENTS, In the Matter of the Review of the 2005 Annual Automatic Adjustment of Charges for All Electric and Gas Utilities, Docket No. E,G-999/AA-05-1403 (July 19, 2006)

decisions on the 2004-2005 AAA reports and true-up filings,[12] the Commission deferred taking action on CenterPoint's filings to permit further fact-finding and discussion, and to allow time for an independent audit of CenterPoint's financial statements, gas cost calculations, annual automatic adjustment reports, and annual PGA true-up filings. The Commission also denied CenterPoint's request for a rule variance that, if granted, would have allowed CenterPoint to include prior period amounts in the 2004-2005 true-up that were related to errors in the calculation of un-billed revenue and lost-and-unaccounted-for-gas.

CenterPoint's appeal of the Commission's decision to deny CenterPoint's request for a rule variance is pending.

The independent audit auditor's report is not expected until January 2008. Two of the tasks that the independent auditor is charged with completing are (1) an examination of the Company's estimated un-billed revenue and/or receivables, and (2) a comparison of the strengths, weaknesses and propriety of he Company's previous and proposed methodologies for calculating un-billed revenue and/or receivables.

According to CenterPoint, the Company's 2005-2006 true-up filing does not contain any of the out of period true-up amounts that are at issue in the Company's appeal of the denied variance, or any of the 2004-2005 true-up amounts that can be attributed to the recalculation of un-billed revenues. However, the calculations in the Company's 2005-2006 true-up filing are based on CenterPoint's revised methodology for calculating the value of un-billed sales volumes. This revised methodology was first proposed in CenterPoint's October 31, 2006 additional supplemental comments on its 2004-2005 true-up, in docket # 05-1403. This October 31, 2006 filing contained the third version of CPE's 2004-2005 true-up. (The first was filed on September 1, 2005, the second on April 5, 2006, and the third on October 31, 2006.)

Staff believes the Commission should defer taking any action on CenterPoint's 2005-2006 AAA reports and true-up filings until after the Commission has reviewed the independent auditor's report and made a decision on CenterPoint's 2004-2005 AAA reports and true-up filings.

### 3. Xcel Gas' proposal to terminate the agency services gas cost allocation pricing methodology

In its Review, the Department recommended that Xcel Gas explain whether it intended to continue the allocation pricing methodology ordered by the Commission, in Docket No. G-002/AA-01-1360, for its agency services program.[13] [DOC Review, pp. 37-43] Xcel indicated

---

[12] ORDER ACTING ON CERTAIN GAS UTILITIES' ANNUAL REPORTS AND TRUE-UP PROPOSALS, DEFERRING ACTION ON OTHERS, AND SETTING FURTHER REQUIREMENTS (February 28, 2006), and ORDER DENYING VARIANCE AND ORDERING INDEPENDENT AUDIT (December 6, 2006), In the Matter of the Review of the 2005 Annual Automatic Adjustment of Charges for All Electric and Gas Utilities, Docket No. E,G-999/AA-05-1403.

[13] In Docket Nos. E,G-999/AA-01-838, and G-002/AA-01-1360, "the Commission required Xcel Gas to recalculate the true-up balance carried forward to the September 2003

that the pricing methodology ordered by the Commission was specifically related to the Company's Agency Service program. The Company has terminated the Agency Service program and, believes this allocation methodology is no longer applicable. (Xcel, reply comments, p. 3) In its response comments, the Department indicated that it believes Xcel's provided an adequate explanation for the Commission to authorize Xcel to discontinue the allocation methodology for its agency services program. (Department, response comments, pp. 14-16)

Staff was concerned about Xcel's proposal because in Xcel's testimony in its 2006 rate case, Xcel indicated that it continues to serve one of its largest customers on an agency basis, (Robinson, pre-filed direct testimony, pp. 59-60, Docket No. G-002/GR-06-1429, November 9, 2006), despite claims that it has terminated its agency services program. I

In response to staff inquiries, Xcel identified this customer as *****Xcel non-public information begins***** *****Xcel non-public information ends***** Xcel does not believe the service it provides this customer is the same as the service it provided its agency services program customers, and which led to the Commission ordering Xcel to follow the gas cost allocation pricing methodology. Xcel explained that its contract with this customer *****Xcel non-public information begins***** *****Xcel non-public information ends***** The terms of this pricing arrangement are clear, and do not require an allocation methodology to sort out. According to Xcel, the amount of gas Xcel *****Xcel non-public information begins***** *****Xcel non-public information ends***** of Xcel's system gas supply, and all of the gas Xcel has contracted for recently *****Xcel non-public information begins***** *****Xcel non-public information ends***** At the time this contract was entered into in *****Xcel non-public information begins***** *****Xcel non-public information ends***** Today, however, more economic pricing alternatives are available to Xcel. This contract expires in *****Xcel non-public information begins***** *****Xcel non-public information ends*****

Staff believes this reporting requirement can be terminated.

---

true-up filing to reflect the disallowance of 2000-2001 gas costs in the amount of $165,943 and to use the allocation pricing methodology to calculate future true-ups until superseded by a Commission-approved methodology. Xcel Gas states the correction was made in the Company's December 31, 2003 revised PGA true-up filing in Docket No. G-999/AA-03-1264 and was approved by the Commission in its Order dated August 10, 2004 completing the compliance."

"Xcel Gas requests that the Commission terminate this compliance reporting with the 2005-06 AAA reporting year. The Department notes that Xcel Gas did not report this item in its last AAA report. It appears that Xcel Gas is not required to report this compliance item on an annual basis. However, the Commission also required that Xcel Gas use the allocation-pricing methodology to calculate future true-ups until superseded by a Commission-approved methodology. The Department invites Xcel Gas to explain in its Reply comments whether it intends to continue the allocation pricing methodology ordered by the Commission." (Department, Review, pp. 41-42)

## LDC Gas Purchasing Practices & Gas Supply Portfolio by Component

The Department's analysis of the LDCs' purchasing practices is on pp. 67-73 of the Department's April 16, 2007 Review. The Department's Review of the LDCs' purchasing practices includes an analysis of the price of different kinds of gas supply (for example, monthly and daily index priced gas compared to fixed-price and spot priced gas supply.) The Department also looked at how much of each LDCs' gas supply during the heating season consisted of each type of gas supply.

The lowest cost purchasing strategy varies from year-to-year. In fiscal year 2006, daily spot market gas was the lowest cost type of natural gas, on average, at $7.7519/Mcf, and twelve-month fixed price gas was the highest cost, on average, at $10.4969/Mcf. On p. 66, table G-19, and in attachment G-21, of the Department's Review, the Department provided a table that compares the average cost of each type of gas supply for each regulated Minnesota LDCs.

The following table compares the average cost of each type of gas supply for 2004, 2005, and 2006.

| Annual non-weighted average price for various types of gas supply in $ per Mcf | Fiscal year 2004 | Fiscal year 2005 | Fiscal year 2006 |
|---|---|---|---|
| Daily spot market purchased gas | $5.3737 (5) | $5.5715 (1) | $7.7519 (1) |
| Storage withdrawn | $5.1141 (3) | $5.8083 (2) | $7.7882 (2) |
| Daily index priced purchased gas | $5.2939 (4) | $6.5948 (6) | $8.3482 (3) |
| Monthly index priced purchased gas | $5.0711 (2) | $6.1584 (4) | $8.5277 (4) |
| Five-month fixed priced purchased gas | $5.3915 (6) | $6.6549 (7) | $8.5402 (5) |
| Monthly spot market purchased gas | $4.9400 (1) | $5.9900 (3) | $10.30 (6) |
| Twelve-month fixed priced purchased gas | $5.8086 (7) | $6.4082 (5) | $10.4969 (7) |

On p. 69 of the Department's Review, the Department provided table G-20, which compares the composition of each LDC's supply portfolio for the 2005-2006 heating season. On a non-weighted, aggregated basis for all seven Commission-regulated LDCs, the composition of their supply portfolios varied within the following ranges for the twelve-month periods ending June 30, 2003, 2004, 2005, and 2006.

| Portfolio Component | Fiscal year 2003 | Fiscal year 2004 | Fiscal year 2005 | Fiscal year 2006 |
|---|---|---|---|---|
| Index-Gas - Monthly | 36 – 98% | 34 - 99% | 25 - 99% | 37 - 100% |
| Index-Gas - Daily | 0 – 15% | 0 - 21% | 0 - 18% | 0 - 11% |
| Fixed-Gas - 12-month | 0 – 23% | 0 - 29% | 0 - 31% | 1.5 - 28% |
| Fixed-Gas - 5 month | 0 – 30% | 0 - 56% | 0 - 41% | 0 - 64% |

| Portfolio Component | Fiscal year 2003 | Fiscal year 2004 | Fiscal year 2005 | Fiscal year 2006 |
|---|---|---|---|---|
| Storage | 0 – 22% | 0 - 26% | not reported separately[14] | not reported separately |
| Spot Gas - Monthly | 0 – 6% | 0 - 4% | 0 - 0.6% | 0 - 6% |
| Spot Gas - Daily | 0.5 – 37% | 0 - 28% | 0 - 27% | 0.5 - 25% |

Every year, the Department reviews the gas purchasing performance of each gas utility by comparing the utility' performance to a Minnesota average. The Department typically requests additional information if a company's cost for a particular type of gas supply (i.e. the company's performance) varies by more than one standard deviation from the average of all companies. In this year's Review, the Department requested explanations from Great Plains, Interstate Gas, Aquila Networks-PNG, and Xcel Gas. In their reply comments, the utilities provided explanations that, with the exception of Interstate Gas, addressed the Department's concerns.

•Great Plains - The Department recommended that Great Plains "fully explain its rationale for the high reliance on daily spot gas and what measures it will take to mitigate its high reliance on daily spot gas in the future." Great Plains explained that it "utilizes the relatively high level of daily spot gas because of the current contracts, pipeline tariffs and the low load factor of its customers' requirements. Great Plains relies on its base load contracts to provide the main source of supply with the swing gas filling in the peaks during the winter heating season due to temperature fluctuations. .... Great Plains utilizes a Request for Proposal (RFP) process to obtain its base load supply and contracts for the swing gas through negotiations with suppliers.."“At this time, because of the low load factor and the existing contracts and pipeline tariffs, Great Plains must continue to rely on its swing gas to meet its winter requirements. ... Great Plains reviews its contracted base load levels on an annual basis and believes it has optimized the amount of gas it can take under this contract without incurring additional costs. Great Plains will continue to evaluate its gas supply portfolio to provide its firm customers with reliable gas supply on a best cost basis and to mitigate the use of spot priced gas where appropriate." (Department, Review, p. 70; Great Plains, Reply Comments, pp. 6-7; and Department, response comments, p. 5)

•IPL Gas - The Department recommended that "Interstate Gas should fully explain why its overall commodity costs, daily index gas, and storage costs for its system were high and what measures it will take to mitigate high costs in the future." IPL Gas believes its overall gas costs are higher than average because it is dependent on one pipeline, i.e. Northern Natural, and does not have gas supply or storage alternatives. IPL believes its storage costs are high because a large portion of its storage gas was purchased after Hurricane Katrina when prices were high. IPL states that it purchased small amounts of daily index priced gas (i.e. approximately 0.14% of its total gas purchases) just after Hurricane Katrina. (Department, Review, p. 66; IPL Gas, reply comments, pp. 2-3; and Department, response comments, pp. 6-8)

•Aquila Networks-PNG - Peoples should fully explain why its monthly index gas costs for its

[14] The Department assumes storage (is included) as part of the monthly index.

Great Lakes system were high and what measures it will take to mitigate high costs in the future." According to Aquila Networks-PNG, "the higher average annual purchase price on the Aquila Networks-PNG Great Lakes system ... was largely driven by the higher requirements on that system during the months of October 2005 through January 2006, a period during which prices increased dramatically as a result of infrastructure damage and related impact on production in the Gulf of Mexico from Hurricanes Katrina and Rita." MERC stated that ... "it will continue the portfolio approach used by Aquila; and that for the upcoming year, prices on the Great Lakes system should be in line with the Viking system. In addition, MERC stated that prices on the Viking system over the 2005-2006 true up period were inside the reasonable range, indicating that MERC has undertaken appropriate measures to mitigate high prices." (Department, Review, pp. 66-67; Aquila Networks-PNG, reply comments, pp. 4-5; MERC-PNG, p. 2, and Department, response comments, p. 10)

•Xcel Gas - The Department recommended "Xcel Gas should fully explain why its daily spot gas costs were high and what measures it will take to mitigate high costs in the future." Xcel explained that the "high" spot prices "were primarily due to purchases made after the supply disruptions caused by hurricanes Katrina and Rita, price volatility caused by cold weather, and the Company's reluctance to use its storage gas early in the heating season. Xcel " believes these types of costs will be mitigated in the future as it has acquired additional underground storage capacity that should allow it to minimize the impact of the spot market on its gas supply portfolio during the heating season." (Department, Review, p. 67; Xcel, reply comments, p. 2; and Department, response comments, p. 15)

In its response comments, the Department stated "that although IPL Gas has adequately explained the reasons for its high gas costs, it has not sufficiently addressed how IPL Gas plans to mitigate high gas costs in the future. Thus, the Department invites IPL Gas to address the issue of gas cost mitigation during the Commission's Energy Agenda discussion of this report. The Department also intends to pursue this issue in the current AAA Docket, G,E-999/AA-07-1130." (Department, response comments, pp. 6-8) In its November 9 reply comments, Interstate Gas accepted the Department's invitation. (Interstate Gas, reply comments, p. 2)

The Department also noted concerns about the "continued significant reliance on daily spot-priced gas because of the increased volatility and low liquidity levels of the natural gas market, especially at the level that some utilities utilized daily spot-priced gas in their portfolio." (Department, Review, pp. 65-70)

**PUC Staff Comment**

Staff agrees with the Department's conclusions and recommendation. The Commission should decide, however, whether to take comments from IPL Gas on its plans to mitigate high gas costs in the future: (1) at its agenda meeting, (2) in writing in this docket, or (3) as part of the Department's investigation and review of Interstate Gas' 2006-2007 AAA reports and annual true-up filing, in Docket Nos. E,G-999/AA-07-1130, and G-001/AA-07-07-1172.

## LDC Financial Hedging Practices

The three (or four, depending on how they are counted) largest Minnesota LDCs are authorized to engage in a limited amount of financial hedging activity as part of their gas purchasing and cost minimization and stabilization strategies. The companies are required to report on their hedging activity in their AAA reports. In the section of the Department's Review that discusses financial hedging practices, the Department looked at financial hedging, and did not attempt to directly compare financial hedging to "physical" hedging tools such as fixed-price commodity contracts or natural gas storage.

### 1. Aquila

"In Docket No. G-007,011/M-03-821, Aquila (on behalf of Peoples and NMU) requested and received permission from the Commission to recover through the PGA the costs associated with using financial instruments in securing natural gas supplies."

According to the Department, *****Aquila non-public information begins*****

*****Aquila non-public information ends***** [15]

| | 2004-2005 | 2005-2006 |
|---|---|---|
| *****Aquila non-public information begins***** | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| *****Aquila non-public information ends***** | | |

The Department indicated it was concerned about whether Aquila had exceeded the twenty percent limit on the amount of financial hedging costs that may be recovered through Aquila's

[15] In its 2003 and 2004 Reviews, the Department reported that while Aquila was authorized to use financial call options as part of its hedging strategy, it did not do so. In fiscal year 2003, Aquila reported using Producer Demand Caps for hedging purposes, and this is probably the same strategy Aquila was using for its hedging program in fiscal year 2004.

PGA.[16] ... The Department also suggested that MERC provide a "narrative discussing the events which led to the ratepayer financial impacts as a result of its specific application of financial tools." (DOC Review, pp. 26-27, and 71-73)

Aquila responded by stating that "the appropriate measure for determining compliance with the hedging limitation is based on cost, not volumes. However, ... using either measure, the 20 percent limitation was not exceeded. [Aquila, reply comments, pp. 2-3, and 8] In response to the Department's request for a narrative explanation of the events which led to the ratepayer financial impacts as a result of its specific application of financial tools, Aquila used a portfolio approach to hedging for the 2005-2006 winter season. This strategy included *****Aquila non-public information begins*****

*****Aquila non-public information ends***** Aquila's goal of minimizing price fluctuations is best achieved through this type of multi-product portfolio. (Aquila, reply comments, pp. 5-6, and 8-9)

In its response comments, the Department indicated that Aquila has provided information that shows that on an actual volumetric or a dollar-cost basis, the Company is operating within the twenty percent hedging limit that is in the Commission's October 13, 2003 Order. "Thus, the Department concludes that Peoples' response reasonably addresses the Department's concern with its compliance with the 20 percent limitation imposed by the Commission, as discussed above." (Department, response comments, pp. 9-10, and 12)

**2. CenterPoint Energy**

"In Docket No. G-008/M-01-540 (Financial Call Options), CenterPoint Energy received Commission approval to recover the costs of financial hedging tools (i.e. the costs associated with financial call options related to swing gas) through its PGA. ... However, during this reporting period, CenterPoint Energy did not purchase any financial hedging tools.[17] Instead, CenterPoint Energy purchased swing contracts with reservation fees, which may be considered a form of physical rather than financial (or economic) hedging because the payment of reservation fees guarantees CenterPoint Energy a firm supply of swing gas at a non-spot market price.[18]

---

[16] In its October 13, 2003 ORDER GRANTING VARIANCES, in Docket No. G-007,011/M-03-821, the Commission required Aquila to report in future AAA Reports certain information, limited the type of hedging activity that Aquila may participate in, and stated that the "total amounts recovered for the cost of financial instruments shall not exceed the combined maximum of 20 percent of the annual total firm commodity gas costs for Aquila Networks-PNG and Aquila Networks-NMU."

[17] CenterPoint did not purchase any financial call options in fiscal years 2004 or 2005 either.

[18] In Docket No. G-008/M-04-368, CenterPoint "received Commission approval to use forward futures contracts and put options .... However, CenterPoint concluded that there currently is no advantage to using the financial market and secured all its fixed-price supply

The Department suggested CenterPoint Energy take the opportunity in reply comments to further discuss its strategy regarding its decision not to engage in the natural gas financial market."

The following information compares the performance of CenterPoint Energy's hedging program in 2005-2006 to the previous year.

| | 2004-2005 | 2005-2006 |
|---|---|---|
| *****CPE non-public information begins***** | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| *****CPE non-public information ends***** | | |

(Department, Review, pp. 34-35, and 71)

In its reply comments, CenterPoint Energy stated that "has continued to use fixed priced physical gas supplies in place of an index based purchase combined with a financial swap instrument in order to assure its gas purchasing process remains competitive (through a bidding process) and transparent to reviews and audits. These fixed price physical transactions have the same end result and competitive price as combining index priced gas and a financial swap instrument."[19]

---

through fixed-price contracts rather than using the financial markets." [Department, Review, footnote 57, p. 35.

[19] "As discussed in the initial filing in Docket G-008/M-04-368, CenterPoint Energy, Inc. has an established and documented Risk Control Policy that is designed to ensure that the use of financial instruments is a carefully controlled operation monitored at the highest level of authority within the organization. This policy requires all business units, including Minnesota Gas, to execute financial transactions through a 'central derivatives execution desk.' Many transactions each day are conducted with affiliated and non-affiliated customers through this desk. The centralization of financial transactions execution is a best practice in risk control because it allows the corporation to have a single point for monitoring and controlling its risks and credit exposure, gain cost benefits by having only one group of employees dealing with financial brokerage accounts, and saving on transaction and clearing fees by utilizing one account with each financial institution to gain economies of scale. The transactions of the various CenterPoint Energy business units are therefore commingled and not easily segregated as we had assumed."

"Thus, while the policy establishes a risk control framework, it creates a less transparent audit

(CenterPoint, reply comments, p. 2)

The Department believes "CenterPoint Energy's response reasonably addresses the Department's request for further information on its decision not to participate in the natural gas financial market." (Department, response comments, p. 14)

### 3. Xcel Gas

Xcel Gas requested and received Commission approval, in Docket Nos. G-002/M-01-1336 and G-002/M-03-1627, to recover through the PGA the costs associated with using financial instruments in securing natural gas supplies.

| | 2004-2005 | 2005-2006 |
|---|---|---|
| *****Xcel non-public information begins***** | | |
| | | |
| | | |
| | | |
| *****Xcel non-public information ends***** | | |

The Department recommended that Xcel Gas "provide a complete narrative discussing the events that led to the ratepayer financial impacts as a result of its specific application of financial tools during 2005-2006. Additionally, the Department notes that it requests this information annually via discovery from Xcel Gas during its review of the true-up. For efficiency, the Department suggests that Xcel Gas report its financial hedging detail (fees, gains or loss on commodity and net gain or loss on hedging) in its future true-up reports." (Department, Review, pp. 41, and 73)

In its reply comments, Xcel explained its "hedging strategy for the 2005-06 heating season was to use a combination of physical storage and financial instruments to hedge approximately *****Xcel non-public information begins***** *****Xcel non-public information ends***** of the Company's anticipated heating season requirements. ... The use of call options provides the Company's retail ratepayers with protection from catastrophic upward price movements while limiting their exposure if prices fall to the premiums paid for the options. While the net result of the Company's hedge program for the 2005-06 heating season was a loss, ... the benefits could have been significant if the weather had turned colder than normal in the aftermath of Hurricanes Katrina and Rita." Xcel believes the "financial component of the hedging strategy could have been extremely valuable to the ratepayers had wholesale market prices not fallen as a result of the extremely mild weather in January 2006." Xcel agreed "to report its financial hedging detail

---

trail than the competitive bidding process provides. For this reason and because the fixed price physical transactions have the same result and competitive price as combining indexed price gas and a financial swap instrument, Minnesota Gas elected to continue using fixed price physical transactions as its hedging tool." (CenterPoint, reply comments, p. 2) (fees, gains or loss on commodity and net gain or loss on hedging) in its future true-up reports as suggested by the Department." (Xcel, reply comments, p. 3)

The Department believes "Xcel Gas' response reasonably addresses the Department's request for complete information regarding the narrative of the events for the 2005-2006 heating season." (Department, response comments, pp. 15-16)

**4. Department - Summary Comment**

"The Department notes that, as in Minnesota, there is a nationwide quandary regarding hedging strategy and potential 'best practices' hedging approaches." The Department suggested that regulators and LDCs be aware of an NRRI research project that will "evaluate which particular utility hedging programs have been most effective in achieving their objective in mitigating price volatility to gas consumers."[20]

The Department also noted that the Federal Energy Regulatory Commission (FERC) is beginning to use its "authority to police energy financial derivative trading that affects the physical (as opposed to financial) and power markets." See, for example, FERC's Amaranth Market Manipulation Show Cause Order, in FERC Docket No. IN07-26-000.

(Department, Review, pp. 73-74)

**5. PUC Staff Comment**

In 2005-2006, Aquila's customers benefitted from Aquila's financial hedging activity. This is a change from the prior year, and, Aquila should be commended for its performance. Xcel's and CenterPoint's programs do not appear to have provided tangible, direct benefits to their customers. Staff finds it difficult to understand why Xcel's, and perhaps CenterPoint's, strategies failed to provide benefits when gas prices were as high and volatile as they were after hurricanes Katrina and Rita.

Staff recognizes that under certain circumstances Xcel's, and perhaps CenterPoint's, customers may be tangibly better off because of these hedging programs. However, staff does not understand how much more extreme prices would have to be, or how much more volatile the markets would have to be, than they were in the aftermath of hurricanes Katrina and Rita, for these programs to directly benefit consumers. Staff recognizes that these hedging strategies may provide consumers (or gas company management) with some peace-of-mind because these programs may provide some insurance against catastrophic price increases, even if the insurance is never used. In reality, however, it may be more economic for these customers to self-insure against catastrophic high prices than to have the companies engage in these hedging strategies.

Staff believes it is appropriate for the Department to continue evaluating and comparing the performance of these programs to ensure that the LDCs are maximizing whatever potential

---

[20] PUC Staff's understanding is that this project is authorized but has not been started because of competing demands on the time of NRRI's research staff.

benefits these programs may have to offer. In addition to evaluating the effectiveness and performance of these strategies, staff believes it is important to develop more consistent ways of measuring performance and making comparisons between LDCs. Staff believes the Commission may also want to consider whether it believes these programs have positive long-term value (tangible or otherwise) to ratepayers. If not, the Commission may want to consider discontinuing or modifying these programs.

Staff would also note that given what has been learned recently about how the price of natural gas financial instruments can be manipulated, and how these prices impact the formation of prices in the physical market for natural gas, the Minnesota Commission should not maintain unrealistic expectations about the potential for consumer benefits from these programs.

## LDC Treatment of Demand Costs

In its deliberations on the 2005 AAA reports, the Commission indicated some interest in mitigating the cost of gas for firm sales customers by requiring LDCs to allocate a share of their demand costs to interruptible sales customers. To do this, however, would require the Commission to recognize that interruptible sales customers benefit from an LDCs access to and use of transportation and storage services on the interstate pipelines. (Currently, most LDCs allocate all of their demand costs to firm customers. However, Interstate and MERC allocate a relatively small amount of demand costs to their interruptible customers in a way that is consistent with their Iowa affiliates.)

Based on its investigations of the LDCs' demand entitlement filings, and its review of the 2005-2006 AAA reports in this docket, the Department concluded that several of the LDCs should respond to questions about how they allocate demand costs in their PGAs. The Department invited all gas utilities to discuss this demand cost allocation issue in their reply comments. (Department, Review, pp. 74-82)

### 1. Greater Minnesota Gas

In its 2006 general rate case in Docket No. G-022/GR-06-1148, Greater Minnesota proposed, and received Commission authorization to eliminate the demand-cost component from the PGA gas cost recovery rates charged to interruptible customers. The Department did not oppose Greater Minnesota Gas' request in that docket. The Department reminded Greater Minnesota Gas that the assignment of demand costs may change due to Commission action in another docket. (Department, Review, p. 75, and response comments, p. 17)

Greater Minnesota Gas did not submit reply comments in this docket.

Greater Minnesota Gas' demand entitlement filing for the 2006-2007 heating season, in Docket No. G-022/M-07-1142, is pending. The allocation of demand costs does not appear to be an issue in that docket.

### 2. Great Plains

In response to discovery from the Department in its 2006-2007 demand entitlement filing, in Docket No. G-004/M-06-1526, Great Plains stated that while it does not allocate any demand costs to its interruptible sales customers in Minnesota, it might be appropriate because interruptible sales customers do use pipeline capacity. Great Plains indicated that in some of the jurisdictions in which it operates, i.e. Montana, North Dakota, South Dakota, and Wyoming, the Company designs its rates to recover all demand costs from firm customers but also charges interruptible customers a lower demand rate (based on an assumed 100 percent load factor). To the extent interruptible customers actually use Great Plains' system gas, the demand-related revenue from these customers is credited to firm customers. (Please see Department, Review, Attachment G21 for a copy.)

In its March 8, 2007 informal order, in Docket No. G-004/M-06-1526, the Commission stated that it would defer making a decision on Great Plains' possible allocation of demand costs to interruptible customers based on the Montana-Dakota demand cost allocation method to Docket No. E,G-999/AA-06-1208."

In this docket, the Department recommended that Great Plains explain the assumptions behind the design of the interruptible PGA rate it uses in other jurisdictions, and provide a rate impact analysis. (Department, Review, pp. 75-77)

In its reply comments, Great Plains stated that "The Department ... mistakenly concludes that the Company has proposed such an allocation in this Docket. Great Plains has not proposed such an allocation and takes this opportunity to alleviate any confusion." ... "While Great Plains does believe that it may be appropriate to allocate demand costs to the interruptible classes, it has not yet determined what method would be appropriate for Great Plains' customers. If, and when, Great Plains submits a proposal to change the allocation of demand costs to customers, it will provide a full analysts to support its proposal as suggested by the Department." (Great Plains, reply comments, p. 5; and Department, response comments, pp. 17-18)

### 3. Interstate Gas

The Department referred to IPL's response to an information request in IPL's 2006-2007 demand entitlement filing in which IPL stated that its position is that "costs should be allocated to the customers who benefit or use those services. ... The only demand costs that IPL allocates to interruptible customers are those costs referred to as Allocated Demand charges [because] these charges benefit interruptible as well as firm gas customers." "Allocated Demand charges are based on third-party reservation fees such as SMS, and other storage charges, and are charged to firm and interruptible customers on a per unit basis."[21] Interstate already allocates certain demand costs to interruptible customers, and does not propose to change its current demand cost allocation method. (Department, Review, p. 77)

[21] Commission, informal order, attachment 4, Docket No. G-001/M-06-1525, February 20, 2007

In its response comments, the Department noted that in Docket No. G-001/M-93-1219, the Commission approved [as reasonable] IPL Gas' request "to designate SMS, SBA, FDD and Canadian charges[22] as commodity capacity charges" which resulted in the assignment of these costs to firm and interruptible sales customers. (Department, response comments, p. 18)

Interstate Gas did not address this issue in its May 31 reply comments. However, in its November 9 reply comments, Interstate Gas stated that

> "IPL previously filed the 2007 Demand Entitlement filing, so IPL will respond to the Department's recommendations in these Reply Comments. IPL feels that it is reasonable to classify Producer Demand and Storage costs as commodity costs because these charges relate to the procurement and balancing services for the gas commodity costs for both firm and interruptible customers. IPL believes that those customers who benefit from these services should be the ones who pay for them."
>
> "In IPL's most recent AAA filing in Docket No. E,G999/AA-07-1130, IPL classified $180,973.92 as Producer Demand and Storage costs (see Exhibit L Page 1 of 2). IPL allocated $50,048.73 of these costs to interruptible customers. This represents about 1.5% of the total gas costs charged to interruptible customers. The remaining Producer Demand and Storage costs were allocated to firm customers, and represent about 1.3% of their total gas costs. If the Producer Demand and Storage costs which were allocated to interruptible customers were instead charged to firm customers, it would have increased their total gas costs by another 0.5%." (Interstate Gas, reply comments, p. 3)

**4. Aquila Networks-NMU & Aquila Networks-PNG**

In its Review, the Department noted that Aquila Networks-NMU & Aquila Networks-PNG already allocate certain demand costs to interruptible customers. The Department suggested that Aquila Networks-NMU & Aquila Networks-PNG should discuss an alternative method of allocating demand costs, including a rate impact analysis, in their reply comments. (Department,

[22] SMS, SBA, FDD, and Canadian charges are Northern Natural Gas Company's (Northern) "new services" implemented in 1993 as phase in services prior to FERC Order 636 which separated interstate pipelines' merchant and transportation functions. The services are defined as follows: (1) SBA (System Balancing Agreements) were agreements under 'new services' between Northern and shippers on its system who agreed to use their facilities and supplies at the demand of Northern to maintain system integrity when receipts and deliveries on the system were not in balance. Costs to Northern for such services were recovered through a surcharge to shippers. (2) SMS (System Management Service) was Northern's no-notice service under "new services" that provided additional tolerances for shippers, above the allowed 5 percent tolerance. (3) FDD (Firm Deferred Delivery Storage) is the storage service offer by Northern which the utilities typically use as reserved storage space to place natural gas purchased in the summer for later use during the winter. (4) 'Canadian capacity' costs were for Canadian natural gas supplies previously purchased by Northern for its merchant function which were considered stranded costs under Order 636, but used to maintain system pipeline pressure under 'new services'." (Department, response comments, footnote 41, p. 18)

Review, p. 78)

Aquila stated that "because this request relates to future actions by MERC-PNG and MERC-NMU, MERC is expected to respond to these requests." (Aquila, reply comments, p. 9)

MERC, stated that it "understands this question to refer to the allocation of demand costs to system interruptible customers. MERC currently does not allocate demand costs to interruptible customers and does not currently have an alternative method of allocating demand costs to interruptible customers. MERC does support the allocation of demand costs to interruptible customers, to the degree that interruptible customers benefit from the pipeline capacity held by the Company. When MERC has fully developed a methodology for allocating demand costs to interruptible customers it will present its proposal to the Commission and DOC for approval." (MERC, reply comments, p. 3)

In its response comments, the Department stated that "MERC's predecessor, Aquila, Inc., received Commission approval to recover five Northern Natural Gas Company (Northern) demand charges[23] plus its supplier Producer Demand payments,[24] as commodity. This approval resulted in the assignment of these costs to interruptible sales customers as well as firm customers. In Docket No. G-011/M-93-1092, the Commission found that 'Peoples had articulated a reasonable viewpoint of these charges.' Similar to the Commission's Order in Docket G-001/M-93-1219 discussed above, the Commission noted that 'another utility may reasonable designate these costs as demand.' In concluding its position on this matter, the Commission stated that it 'will carefully examine each utility's cost recovery mechanism and

[23] "The five Northern charges which Peoples proposed to classify and bill as commodity costs were as follows: (1) 'Canadian capacity' costs were for Canadian natural gas supplies previously purchased by Northern for its merchant function which were considered stranded costs under Order 636, but used to maintain system pipeline pressure under 'new services.' (2) CD-Merchant function reservation charges were fees for the contracted, per-unit fees paid to reserve third-party supplies. (3)'Account 191 Balance Costs' were unrecovered gas costs or credits remaining in the purchase gas adjustment (PGA) Account 191 when the pipeline adopted market-based pricing for its gas sales and terminated its PGA mechanisms. (4) GSR (Gas Supply Realignment) costs were the expenses of the pipeline to buyout, buy down, and recognize price differentials of gas supply contracts beginning on November 1, 1993 as a result of the restructuring of the pipeline and the elimination of the merchant function. And (5) ANGTS (Alaskan Natural Gas Transmission System) was the combination of pipelines (primarily Northern Border) who were provided specific allowances by the United States government to provide additional supplies from north of the contiguous lower 48 states. Northern maintained a deferred accounting procedure to prevent over or under collection of the costs assessed to it. With restructuring, Northern was required to relinquish such operations to its shippers. ANGTS costs allowed Northern to recover any remaining balance of costs in excess of revenues for the period ending October 31, 1993." (Department, response comments, footnote 44, p. 19)

[24] Producer Demand costs are the contracted, per-unit fees paid by the utility to reserve third-party supplies to guarantee (reserve) gas supplies at either a fixed-rate or an index-rate. (Department, response comments, footnote 45, p. 19)

decide upon its merit in light of the utility's unique set of facts.'"[25]

PUC Staff Note: In its 2006-2007 demand entitlement filings, MERC proposed to change the way it allocates financial hedging costs, and requested permission to "include its hedging costs in its demand costs. Historically, Aquila included its hedging costs with commodity costs." The Department believes "financial hedging costs should be included with the commodity costs so that all firm and interruptible classes pay for the full cost or benefit from the net gain on the related commodity. The Department recommended against this proposed change, and MERC, in docket 06-1535, accepted the Department's recommendation. MERC's 2006-2007 demand entitlement filings are pending in Docket Nos. G-007/M-06-1535 (MERC-NMU), G-011/M-06-1536 (MERC-PNG-NNG), G-011/M-06-1537 (MERC-PNG-GLT), and G-011/M-06-1538 (MERC-PNG-VGT). (The allocation of hedging costs does not appear to be discussed directly in docket 06-1536.) Apart from this issue, the allocation of demand costs to interruptible customers was not discussed in these dockets.

### 5. CenterPoint Energy

CenterPoint Energy currently does not allocate any demand costs to its dual-fuel interruptible customers, and is opposed to allocating demand costs to interruptible customers in the future. The Department noted that CenterPoint Energy, in response to the Department recommendation and Commission order in its 2005-2006 demand entitlement filing, has stated that its current allocation of demand costs is appropriate, and that customers are charged correctly for the capacity requirements they impose on CenterPoint's system. CenterPoint Energy identified three reasons for continuing its current allocation of demand costs:

- CenterPoint Energy does not purchase interstate pipeline capacity for dual-fuel customers (Interstate pipeline capacity is designed and purchased to deliver on-peak supply requirements to firm customers only. Dual Fuel customers are expected to discontinue their natural gas use on-peak, and therefore they do not require "room" on the pipeline for their requirements.);
- dual-fuel customers pay for the costs they incur on the distribution system including an assigned portion of CenterPoint's current storage contract; and
- pricing changes could lead to increased costs for firm customers. (Shifting costs to dual fuel customers may lead to these customers to (1) reduce their energy consumption which would reduce the benefit these customers contribute to CenterPoint's system, (2) switch to firm service which could increase firm gas costs for all firm customers, or (3) bypass CenterPoint's system completely.)[26]

"Nevertheless, CenterPoint Energy stated that it could be argued that [its] current storage contract with NGPL is used to serve [all of its system customers'] natural-gas requirements

---

[25] Commission, Order, September 12, 1994, pp. 6-7, paragraph D, in Docket No. G011/M-93-1092.

[26] See pp. 2-4, and exhibit D of CenterPoint Energy's 2006-2007 Request for Change in Demand Units, Docket No. G-008/M-06-1533, filed November 1, 2006. This docket is pending.

before curtailing, and that [a small, additional portion of the cost of] this storage might appropriately be charged to small-volume dual-fuel customers, since these customers are not frequently curtailed. CenterPoint Energy also stated that the demand portion of this storage contract would be spread over the projected firm and small-volume dual-fuel volumes. CenterPoint Energy noted that the net results would be a decrease in demand costs for residential customer of approximately $1.80 per year, and an increase to small-volume dual-fuel customers of approximately $0.01 per dekatherm."[27] (Department, Review, pp. 78, and 82)

CenterPoint Energy indicated that it has already provided information on its current allocation of demand costs and potential alternatives, and continues to believe that its current demand cost allocation is appropriate. (CenterPoint Energy, 1st reply comments, p. 2; and Department, response comments, p. 19)

In its October 30, 2007 reply comments, CenterPoint Energy stated that it filed its 2007-2008 demand entitlement petition on May 1, 2007, in Docket No. G-008/M-07-561, and recommended that its method of allocating producer demand and storage cost not change. CenterPoint stated that it "currently allocates a portion of its storage costs to all throughput. Producer demand (or seasonal reservation, as CenterPoint refers to these types of costs) are assigned in demand costs to firm customers for the contracts expected to serve their swing loads. Reservation fees contracted to serve Dual Fuel load, also referred to as Peaking Gas, are assigned to the dual fuel commodity costs based on load." CenterPoint states that it is "willing to analyze alternative allocations further in its next demand entitlement filing." (CenterPoint Energy, 2nd reply comments, pp. 1-2)

PUC Staff Note: "In Docket No. G-008/AA-05-1736, the Commission required CenterPoint Energy to include in its current demand entitlement filing, a proposal to assign demand costs to interruptible customers. CenterPoint Energy included the required information in its November 1 filing under Additional Requirements. The Department will report on this issue in its Review of the 2005-06 Annual Automatic Adjustment Reports, Docket No. E,G-999/A-06-1208." (Department, Comments, p. 7, Docket No. G-008/M-06-1533)

### 6. Xcel Gas

In its Review the Department described Xcel's position as follows: "In its 2006-2007 demand entitlement filing, in Docket No. G-002/M-06-1454, Xcel Energy stated that pipeline transportation demand charges or supply demand charges should not be assigned to interruptible customers. However, Xcel Energy states that interruptible customers are receiving the benefits of both storage and pipeline balancing service on non-design days, and that a portion of these costs could be recovered from interruptible customers on a prospective basis. Specifically, Xcel Energy proposes to assign the following demand costs to interruptible customers:

- underground storage capacity charges, which are placed on the entire cycle quantity of gas that can be stored (rather than deliverability demand charges, which determine the amount of peak day deliverability that can be withdrawn in the winter); and

[27] Ibid.

•pipeline balancing demand costs, which are incurred since Xcel Energy balances both firm and interruptible requirements on a daily basis on both Northern and Viking."

"With respect to its proposal for allocating underground storage capacity charges, Xcel Energy proposes to take the annual cost of storage-capacity demand charges for all storage facilities, including Northern's FDD, ANR Storage Company, and ANR Pipeline Company storage, divided by budgeted heating-season sales to determine a per-dekatherm cost to be paid for all gas commodity firm and interruptible sales during the five winter months of November through March. Xcel Energy states that under its proposal, approximately $691,000 or 14 percent of the total $4.865 million in storage capacity demand charges will be charged to the interruptible customers."

"With respect to its proposal for allocating pipeline balancing demand costs, Xcel Energy proposes to take the annual cost of pipeline balancing services divided by annual budgeted sales to determine a per-dekatherm cost to be paid for all gas-commodity firm and interruptible sales on an annual basis. Xcel Energy states that under its proposal, approximately $173,000 or 20 percent of the total $886,000 in pipeline balancing demand charges will be charged to the interruptible customers."[28] (Department, Review, pp. 78-80, and 82)

In its May 25 reply comments, Xcel described the proposal in its 2006-2007 demand entitlement filing as follows: "The proposal was to allocate the storage and pipeline balancing fees as if they were commodity costs instead of demand costs. ... Residential customers could see a 0.23% reduction on a typical annual bill (assuming consumption of 851 therms). Medium Interruptible customers could see a 0.83% increase on a typical annual bill (assuming consumption of 607,199 therms). Large Demand Billed customers could see a 0.001% decrease on a typical annual bill (assuming a demand level of 20,805 therms and commodity consumption of 208,889 therms). "Demand Billed demand costs are lowered with this methodology, but the increase in commodity costs can exceed the demand savings for individual customers." (Xcel, May 25 reply comments, pp. 2-3; and Department, response comments, pp. 19-20)

In its November 9 reply comments, Xcel stated that

> in response to the Department's recommendation regarding the allocation of Producer Demand and Storage costs, we note that we included our cost allocation proposal, rationale and rate impact analysis in our 2007-08 contract demand entitlement filing currently pending before the Commission (Docket No. G002/M-07-1395). (Xcel Gas, November 9 reply comments, p.1)

<u>PUC Staff Note</u>: In Xcel's 2006 rate case, in Docket No. G-002/GR-06-1429, Xcel argued in its exception comments, that the Commission should take administrative notice of this docket in its deliberations in the rate case because of the potential rate impact this docket could have on Xcel's interruptible customers, and because it was very likely that the proposed increase in pipeline cost allocations to the Interruptible classes will occur. In the rate case, the Commission

---

[28] Please see Attachment 4 of Xcel Energy's 2006-2007 Petition for Approval of Changes in Contract Demand Entitlements, Docket No. G-002/M-06-1454, filed November 21, 2006.

did not take administrative notice of this matter, but did modify the class revenue apportionment recommended by the Department and the Administrative Law Judge.

### 7. Department's Discussion, Conclusions, and Recommendations on the LDCs Treatment of Demand Costs

"With the exceptions for Interstate Gas and Peoples discussed above, the costs associated with supplier Producer Demand[29] and Contract Storage Service (Storage)[30] have traditionally been recovered as demand costs from firm sales customers. Historically, these types of costs were primarily used as tools to maintain distribution system reliability for the utility's firm customers. As noted above, the Commission has reviewed the utilities' unique set of circumstances and found that it was reasonable to allocate such costs as demand costs and assign them to firm customers."

"However, Producer Demand and Storage costs have recently been identified as tools used to mitigate price. Minnesota natural gas utilities are currently using these tools in developing their general gas supply portfolio, which is designed to provide gas to all system customers. Given what appears to be the evolving use of these tools, and because the Commission's prior decisions were made in 1993 dockets, it may be appropriate for the Commission to revisit the issue of classification and billing for these charges as demand or commodity. If it is indeed the case that utilities use these tools such that they benefit all of a utility's sales customers (i.e., both firm and interruptible sales customers), the Commission may want to note this fact and consider whether it is reasonable to classify Producer Demand and Storage costs as demand charges and assign all related costs solely to firm customers."

"As noted above, the Commission previously stated its preference to examine each utility's cost recovery mechanism and to decide upon its merit in light of each utility's unique set of facts. Thus, rather than recommend a global change to the classification and allocation of certain producer demand and storage costs, the Department recommends that the Commission require each utility to provide, as requested by the Department, its unique set of facts in determining whether it is reasonable to classify Producer Demand and Storage costs as commodity costs or demand costs, and to clarify which customer classes are to be assigned the related costs. The Commission should also require each utility to provide a detailed explanation of its rationale for its proposal <u>at the time it files its 2007[-2008] demand entitlement filings</u>. If the Commission accepts this recommendation, the Department recommends that the Commission require each

---

[29] "Producer Demand costs are the contracted, per-unit fees paid by the utility to reserve third-party supplies to guarantee (reserve) gas supplies at either a fixed-rate or an index-rate." (Department, response comments, footnote 45, p. 19)

[30] "The American Gas Association defines a Contract Storage Service as: service provided by a pipeline, or other owner of storage facilities, whereby storage customers may lease a portion of the facilities for the purposes of storing customer-owned gas. Contract storage service generally involves the injection of customer-owned gas into the facility during the off-peak period, the holding of the accumulated inventory for the customer, and the withdrawal of gas during the peak heating season." (Department, response comments, footnote 52, p. 20)

gas utility to also provide a rate impact analysis for all affected customer classes based on the utility's currently approved method of classifying and billing Producer Demand and Storage costs, together with a similar comparison of classifying and billing Producer Demand and Storage costs as commodity costs. As part of the recommended utility rate impact analysis, each gas utility should provide a description of their analysis, including all calculations and underlying assumptions used in the analysis." (emphasis added, Department, response comments, pp. 20-21)

**8. PUC Staff Comment**

Staff agrees with the Department's recommendation. However, staff also believes the Commission should allow, but not require, each natural gas utility to provide an alternative proposal, for consideration without prejudice, for allocating a portion of their demand costs to interruptible customers.

The main arguments for allocating costs classified as demand only to firm customers is based on: (1) the promotion of economically efficient rates, and (2) equity. Staff believes these are the reasons the Department advocated shifting some demand costs to interruptible customers by reclassifying, and then billing, Producer Demand and Storage costs as commodity costs.

The alternative approach (described, but not necessarily advocated, by Great Plains, and perhaps MERC) recognizes that interruptible customers are receiving the benefits of both storage and pipeline services on non-design days, and that a portion of all demand costs should be recovered from interruptible customers. This approach is more explicit in recognizing the general benefit provided to interruptible customers by firm customers under normal (i.e. off-peak) operating conditions.

If the Commission decides to consider requiring the utilities to provide this information in their 2007-2008 demand entitlement dockets, it may also want to consider whether there will be objections to the Department's recommended procedure. Staff would note that the Department's approach allows for different outcomes for different utilities.

Notice of this meeting has been provided to all of the parties in all of the 2007-2008 demand entitlement filing dockets, and the order in this docket will be served on all of the parties in those dockets.

# Commission Decision Alternatives

Acceptance of the AAA reports

1. Accept all of the gas utilities' 2005-2006 annual reports as filed, and subsequently amended by the gas utilities, as being complete as to Minnesota Rules 7825.2390 through 7825.2920,

   **or**

2. Accept all of the gas utilities' except CenterPoint Energy's 2005-2006 annual reports as filed, and subsequently amended by the gas utilities, as being complete as to Minnesota Rules 7825.2390 through 7825.2920.

Acceptance of the annual true-up filings

3. Greater Minnesota Gas, Inc.

   a. accept Greater Minnesota Gas' true-up, in Docket No. G-022/AA-06-1224; and

   b. allow Greater Minnesota Gas to implement its true-up, as shown in Attachment G5 of the Department's April 16, 2007 Review.

4. Great Plains Natural Gas Company

   a. accept Great Plains' true-ups for its North District and its South District, in Docket No. G-004/AA-06-1314; and

   b. allow Great Plains to implement its North District true-up and its South District true-up, as shown in Attachment G6 of the Department's April 16, 2007 Review.

5. Interstate Power & Light-Gas

   a accept Interstate Gas' true-up, Docket No. G-001/AA-06-1270; and

   b. allow Interstate Gas to implement its true-up, as shown in Attachment G7 of the Department's April 16, 2007 Review.

6. Aquila Networks-NMU

   a accept NMU's true-up in Docket No. G-007/AA-06-1267; and

   b. allow NMU to implement its true-up, as shown in Attachment G9 of the Department's April 16, 2007 Review.

7. Aquila Networks-PNG

   a. accept Peoples' true-ups for the Northern, Great Lakes, and Viking parts of its system, in Docket No. G-011/AA-06-1266; and

b. allow Peoples to implement its true-ups, as shown in Attachment G8 of the Department's April 16, 2007 Review.

8. CenterPoint Energy

a. accept CenterPoint Energy's true-up, in Docket No. G-008/AA-06-1269; and

b. allow CenterPoint Energy to implement its true-up, as shown in Attachment G10 of the Department's April 16, 2007 Review.

**or**

9. Take no action on CenterPoint Energy's 2005-2006 true-up until all of the issues involving CenterPoint Energy's 2004-2005 annual report and true-up have been resolved.

10. Xcel Gas

a. accept Xcel Gas' true-up, in Docket No. G-002/AA-06-1268;

b. allow Xcel Gas to implement its true-up as shown in Attachment G11(A) of the Department's April 16, 2007 Review;

c. require Xcel Gas to report its hedging detail (fees, gains or loss on commodity and net gain or loss on hedging) in its future true-up reports; and

d. Authorize the termination of compliance reporting concerning the allocation pricing methodology used for Xcel Gas' Agency Services program, which was initially required in Docket Nos. E,G-999/AA-01-838, and G-002/AA-01-1360.

Commission directive in Docket No. E, G-999/AA-05-1403 relating to NYMEX futures and options transactions

11. Find that Great Plains has satisfied the Commission's directive in Docket No. E, G-999/AA-05-1403 relating to NYMEX futures and options transactions, or

12. Find that all of the gas utilities have satisfied the Commission's directive in Docket No. E, G-999/AA-05-1403 relating to NYMEX futures and options transactions, or

13. Take no action because this is a compliance issue that does not require a finding that all of the gas utilities have satisfied the Commission's directive in Docket No. E, G-999/AA-05-1403 relating to NYMEX futures and options transactions.

Interstate Gas' strategy for minimizing gas costs

14. Require Interstate to address gas cost mitigation during the Commission's Energy Agenda

discussion of the Department's Review of the 2005-2006 AAA Reports and true-ups, or

15. Require Interstate to address gas cost mitigation in writing, in this docket, or

16. Take no action in this docket, and defer consideration of this issue to the review of Interstate Gas' 2006-2007 AAA reports and annual true-up filing, in Docket Nos. E,G-999/AA-07-1130, and G-001/AA-07-07-1172.

Alternative methods for the classification and billing of demand costs

17. Require each natural gas utility to provide, within 30 days, (if it has not already done so), in a supplement to its 2007-2008 demand entitlement filing,[31] its unique set of facts in determining whether (and why) it is reasonable to classify Producer Demand and Storage costs as commodity costs or demand costs, together with a detailed explanation of the utility's rationale; and

18. Require each natural gas utility to provide, within 30 days, (if it has not already done so), in a supplement to its 2007-2008 demand entitlement filing,[32] a rate impact analysis for all affected customer classes based on the utility's currently approved method of classifying and billing Producer Demand and Storage costs, together with a similar comparison classifying and billing Producer Demand and Storage costs as commodity costs; and

19. Authorize each natural gas utility to provide an alternative proposal, within 30 days, (if it has

[31] In the Matter of the Request of CenterPoint Energy Resources, Inc. d/b/a CenterPoint Energy Minnesota Gas, for a Change in Demand Units, Docket No. G-008/M-07-561; In the Matter of the Petition of Northern States Power Company, a Minnesota Corporation and Wholly Owned Subsidiary of Xcel Energy Inc., for Approval of Changes in Contract Demand Entitlements, Docket No. G-002/M-07-1395; In the Matter of the Request of Interstate Power and Light Company, an Alliant Energy Company, to Change Its Demand Entitlements, Docket No. G-001/M-07-1397; In the Matter of the Petition of Greater Minnesota Gas, Inc., a Wholly-Owned Subsidiary of Greater Minnesota Synergy, Inc., for Approval of Changes in Contract Demand Entitlements, Docket No. G-022/M-07-1398; In the Matter of the Request of Great Plains Natural Gas Co., a Division of MDU Resources Group, Inc., to Change Its Demand Entitlements, Docket No. G-004/M-07-1401; In the Matter of the Petition of Minnesota Energy Resources Corporation-NMU for Approval of a Change in Demand Entitlements, Docket No. G-007/M-07-1402; In the Matter of the Petition of Minnesota Energy Resources Corporation-PNG for Approval of a Change in Demand Entitlements for its Viking Gas Transmission System, Docket No. G-011/M-07-1403; In the Matter of the Petition of Minnesota Energy Resources Corporation-PNG for Approval of a Change in Demand Entitlements for its Great Lakes Gas Transmission System, Docket No. G-011/M-07-1404; In the Matter of the Petition of Minnesota Energy Resources Corporation-PNG for Approval of a Change in Demand Entitlements for its Northern Natural Gas Transmission System, Docket No. G-011/M-07-1405

[32] Ibid.

not already done so), in a supplement to its 2007-2008 demand entitlement filing,[33] for consideration without prejudice, for allocating a portion of their demand costs to interruptible customers that includes the same information required in alternatives 17 and 18 for the classification and allocation of Producer Demand and Storage costs, and a bill impact analysis.[34, 35]

All utility decision alternatives

20. Require all gas utilities to provide a specific justification for each piece of information for which the designation of trade secret is claimed in their annual reports and true-up filings. All companies shall limit the designation of trade secret to words, numbers, or phrases that are actually trade secret and not designate entire paragraphs or pages which contain the trade secret words, numbers, or phrases.

21. Request the Department to include the same Commission-requested information in its fiscal year 2006-2007 Review as was included in its 2005-2006 Review

22. Request the Department to continue its investigation of the amount of pipeline capacity release revenue the gas utilities receive from the pipelines and the amount of revenue the gas utilities refund to their customers.

23. Request the Department to continue providing a comparative evaluation and report on the natural gas utilities' financial and physical hedging activities in its 2006-2007 Review.

## Staff Recommendation

Staff recommends alternatives 2, 3, 4, 5, 6, 7, 9, 10, 12, 14, 17, 18, 19, 20, 21, 22, and 23.

[33] Ibid..

[34] "While Great Plains does believe that it may be appropriate to allocate demand costs to the interruptible classes, it has not yet determined what method would be appropriate for Great Plains' customers. If, and when, Great Plains submits a proposal to change the allocation of demand costs to customers, it will provide a full analysts to support its proposal as suggested by the Department." (Great Plains, reply comments, p. 5)

[35] "When MERC has fully developed a methodology for allocating demand costs to interruptible customers it will present its proposal to the Commission and DOC for approval." (MERC, reply comments, p. 3)

## Summary of the Review Process for the Annual Automatic Adjustment (AAA) Reports

On or about September 1st of each year, electric and natural gas distribution utilities file annual reports covering their automatic adjustment of charges for the previous 12-month time period beginning July 1st and ending on June 30th. These annual reports are prepared in accordance with Minn. Rules, parts 7825.2900 through 7825.2920, and include the following:

• a summary by month, of the automatic rate adjustment mechanism used to recover fuel costs, pursuant to Minn. Rules, part 7825.2810,

• for natural gas distribution utilities only, an annual true-up filing is required to reconcile the utilities' monthly purchased gas rate adjustments with their actual cost of gas, pursuant to Minn. Rules, part 7825.2910, subpart 4, and 7825.2700, subpart 7,

• a report on fuel procurement policies, including a summary of actions taken to minimize cost, pursuant to Minn. Rules, part 7825.2800,

• an annual auditor's report, pursuant to Minn. Rules, part 7825.2820, and

• an annual estimate of future fuel costs, pursuant to Minn. Rules, part 7825.2830. (For electric companies, the requirement is for a five-year projection. For gas utilities, the requirement is for a one-year projection.)

In addition, these reports include compliance filings required by Commission order in previous AAA dockets and other miscellaneous dockets, as well as various other reports requested at various times by the Commission. Utilities are required to provide notice of the availability of these reports to the intervenors in their past two general rate cases, pursuant to Minn. Rules, part 7825.2840.

Each year, the Department prepares a comprehensive review and analysis of the utilities' annual reports and provides extensive comment on other topics that it believes are important. Utilities are generally allowed three weeks to respond to the Department's comments and recommendations. Typically, a second round of comments and replies is required to address all of the questions raised by the Department, in its review.[36]

Automatic adjustment of charges filed under these rules are provisionally approved and may be

[36] This process follows part 7829.1400 of the Commission's rules of practice and procedure for miscellaneous tariff filings with the exception that parties are allowed significantly more time than the rule suggests to file their comments and replies, and are generally allowed to file supplemental comments. The Commission's rules do not specifically address practice and procedures for filing comments on the annual automatic adjustment reports and annual true-up filings.

placed into effect without Commission action, pursuant to Minn. Rules, part 7825.2920. However, disputes over Department recommendations to deny recovery of fuel costs can take several years to resolve through contested case proceedings.

The Commission is required to conduct a separate meeting to review the automatic adjustment of charges reported in these annual filings, pursuant to Minn. Rules, part 7825.2850.