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Minnesota Department of Commerce

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February 2, 2012 **PUBLIC DOCUMENT**

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

RE: **PUBLIC Comments of the Minnesota Department of Commerce, Division of Energy Resources**
Docket No. G002/M-11-1076

Dear Dr. Haar:

Attached are the **PUBLIC** *Comments* of the Minnesota Department of Commerce, Division of Energy Resources (Department) in the following matter:

> Petition of Northern States Power Company, a Minnesota Corporation (Xcel or the Company), for Approval of Changes in Contract Demand Entitlements.

The petition was filed on November 1, 2011. The petitioner on behalf of Xcel is:

> Amy Lieberkowski
> Manager, Pricing and Planning
> Xcel Energy Services Inc.
> 414 Nicollet Mall--7th Floor
> Minneapolis, MN 55401
> 612-330-6613

The Department recommends that the Commission approve Xcel's demand entitlements and its proposal to recover costs associated with demand entitlements, pending resolution of any revisions in the implementation of changes in recovery of demand costs. The Department has requested further information from Xcel on implementation.

The Department is available to answer any questions the Commission may have.

Sincerely,

/s/ MARLON GRIFFING
Financial Analyst
651-297-3900

MG/ja
Attachment

BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

PUBLIC COMMENTS OF THE
MINNESOTA DEPARTMENT OF COMMERCE
DIVISION OF ENERGY RESOURCES

DOCKET NO. G002/M-11-1076

I. SUMMARY OF XCEL ENERGY'S REQUEST

Northern States Power Company, a Minnesota Corporation (Xcel or the Company), filed a demand-entitlement petition (Petition) on November 1 2011. Pursuant to Minnesota Statute §216B.16, subd. 7, Minnesota Rule 7825.2920, and Xcel's Purchased Gas Adjustment (PGA) tariff (Minnesota Gas Rate Book sheet number 5-40, revision 2; sheet number 5-41, revision 3; and sheet number 5-42, revision 2), the Company has provisionally placed the PGA changes into effect on November 1, 2011, subject to later Commission approval.

In its Petition, Xcel requested approval from the Minnesota Public Utilities Commission (Commission) to implement its proposed interstate pipeline transportation, storage entitlements, and other demand-related contracts for 2011-2012 effective November 1, 2011. The Company requested that the adjustments be made through the PGA to reflect changes in its firm pipeline demand entitlement levels[1] as follows:

- increase its Minnesota jurisdictional Design Day capacity by 1,312 dekatherms (Dth);
- change the capacity resources used to meet the Design Day requirement;
- decrease its reserve margin by 1,371 Dth (a decrease of 6.3 percent to 6.1 percent);

[1] The entitlement levels discussed in Xcel Energy's system filing for the total Minnesota Company are the combined entitlements for Xcel Energy's Minnesota and North Dakota jurisdictions. Minnesota's portion of the entitlements is the total combined entitlements times the Minnesota allocation factor discussed below. The Department has included Department Attachment 1, which shows the effect of the demand entitlement changes in the Minnesota jurisdiction.

- slightly change the Jurisdictional Allocations between Minnesota and North Dakota to reflect usage patterns; and
- change its recovery of Supply Reservation fees.

Specifically, Xcel requested the following changes in demand volumes for the total Minnesota Company as shown in Table 1.

Table 1

Type of Entitlement	**Proposed Dth Change**	**Rate**	**Months**	**Proposed Cost Change**
NNG TF12 (Jan - Dec)	(3,974)	$3.8152	12	($181,939.26)
NNG TF12 (Jan - Dec)	(3,974)	$3.8000	12	$181,214.40
NNG TFX (Nov - Mar)	4,359	$15.1530	5	$330,259.64
NNG TFX (Apr - Oct)	4,359	$5.6830	7	$173,405.38
NNG TFX Disc (Jan - Dec)	4,800	$8.6272	5	$207,052.80
NNG TFX Disc (Jan - Dec)	4,800	$4.0000	7	$134,400.00
NNG TFX Disc (Nov - Mar)	90	$3.8000	5	$1,710.00
NNG TFX Disc (Apr-Jun, Sep-Aug)	90	$3.8000	5	$1,710.00
NNG TFX Disc (Jan - Dec)	90	$3.8000	2	$684.00
VGT FTA (Jan – Dec)	(5,000)	$4.5871	12	($275,226.00)
VGT FTA (Jan – Dec)	(16,105)	$4.5871	5	($369,376.23)
ANR FTS (Jan - Dec)	7,500	$5.3626	12	$482,630.40
ANR FSS (Jan - Dec)	5	$4.1800	12	$250.80
ANR FSS (Jan - Dec)	32	$2.0400	12	$783.36
GLGT FT (Nov - Apr)	(15,195)	$2.9480	6	$268,769.16
Total for Change in Pipeline Entitlement				$418,790.13

As indicated in the table above, Xcel proposed a number of changes in its demand entitlements that increase costs from all source systems by approximately $419,000. This amount is for Minnesota and North Dakota customers. The Company is increasing its net supplies from Northern Natural Gas (NNG) and ANR Pipeline Company (ANR), while it is decreasing its supplies from Viking Gas Transmission Company (VGT) and Great Lakes Transmission Company (GLGT). The net change is an increase of 2,213 Dekatherms (Dth) for the total Minnesota Company and 1,312 Dkt for the Minnesota jurisdiction. Because Xcel proposes to allocate more of the new capacity to North Dakota, the effect is a decrease in the reserve margin for Minnesota of 1,371 Dkt, or a decrease from 6.3 percent to 6.1 percent. The Department discusses this issue further below.

Xcel also requested approval to recover certain Producer Demand and Storage costs from both firm and interruptible customers in the Company's monthly PGA, effective with the November 2, 2011 billings. The proposal is a carryover of a plan first presented in the Company's 2007-2008 demand-entitlement filing, Docket No. G002/M-07-1395 (2007-2008 Demand Entitlement) and again in Xcel's subsequent demand entitlement filings (Docket Nos. G002/M-08-1315, G002/M-09-1287, and G002/M-10-1163). While the Commission has not yet acted on these filings, the Minnesota Department of Commerce, Division of Energy Resources (then known as the Office of Energy Security) recommended approval of this proposal in the previous filings, since this allocation reasonably reflects that these demand-entitlement costs associated with transportation capacity and third-party supply reservation levels should be assigned to interruptible customers.

Xcel also has provided a summary of hedging transactions in place for the 2011-2012 heating season in response to reporting requirements established in the Commission's May 27, 2008 Order in Docket No. G002/M-08-46. The Company has also provided commodity- and demand-cost information that enables analysis of the effect of changes in these costs on the rates that customers face in the PGA for 2011-2012.

II. DEPARTMENT ANALYSIS OF XCEL'S REQUEST

The Department's analysis of the Company's request includes a description and an evaluation of the Company's demand-entitlement petition. The Department separately discusses each part of the Company's request below.

A. XCEL'S PROPOSED DESIGN-DAY LEVELS

1. Xcel's Customer Base

Xcel's service areas were unchanged from the 2010-2011 heating season to the 2011-2012 heating season. Xcel expects an increase of 2,461 firm customers in the Minnesota jurisdiction between these two periods (from 436,594 to 439,055).

2. Xcel Forecast

The Company applied two forecast methodologies to arrive at its estimate of its Design Day requirement forecast for 2009-2010. One is the Actual Peak Use per Customer Design Day (UPC DD), while the other is the Average Monthly Design Day (Avg. Monthly DD). The Company has employed these techniques since its 2004-2005 demand-entitlement filing. In the following analysis of Xcel's forecast methods, the Department assesses the foundations of the methodologies.

a. Actual Peak Use per Customer Design Day (UPC DD)

The UPC DD method employs a use-per-customer number of 1.57393 Dth to estimate the Design Day demand forecast, based on the actual use per customer on Thursday, January 29, 2004, the coldest day in recent years. The Department notes that Xcel has used this value in all demand-entitlement dockets subsequent to 2004, based on the experience of that year. Xcel multiplies the 1.57393 value by estimates of total firm customers in all of Xcel's service areas and adds the contracted billing demand for Small and Large Demand Billed customers to arrive at the total expected Design Day demand for the Xcel system. Thus, the way customers are distributed among service areas does not affect the aggregate forecasts produced by the UPC DD method because the total number of customers and the resulting total volume is unchanged no matter where the customers are assigned.

If either cold temperatures or differences with the Avg. Monthly DD method indicate that the 1.57393 Dth Design Day usage-per-customer volume is out of date, the Company stated that it will adjust the volume accordingly.

b. Average Monthly Design Day

The Avg. Monthly DD method is a statistical method that uses linear regression to estimate Design Day demand. Because Xcel has performed regression analyses on each demand area for both residential and commercial customers, the coefficients used to estimate use per customer vary from service area to service area. Consequently, the shifting of customers among demand areas can affect the aggregate forecasts produced by the Avg. Monthly DD method. Since the Company's service areas were unchanged from the 2010-2011 heating season to the 2011-2012 heating season, there is no such change to discuss.

c. Average Monthly Design Day Reliability

Xcel Energy has 60 months of data, or the five years covering January 2006-December 2010, available as inputs for the Avg. Monthly DD method. The Department notes that Xcel has been increasing the data points each year in its Demand Entitlement filings since the Company made structural revisions to the Company's demand-area regions in 2005 (described in its 2008-2009 Demand Entitlement filing). The 2011-2012 analysis is the first since the service-area restructuring where the Company had as many as 60 data points.

The Department recommended in its comments in Docket No. G002/M-10-1163 (2010-2011 Demand Entitlement Filing) that Xcel examine in its next demand filing whether the amount of demand resources needed to serve firm customers should be revised to reflect any measurable changes in the amounts firm customers use on peak days, based on its forecast using 70 data points and any other factors the Company considers to be reasonable. The Department notes that Xcel elected to use 60 data points instead of the 70 available in its analysis. The Department requests that Xcel explain why it used only 60 data points and state whether it has plans to increase the number of data points in subsequent years' demand entitlement filings.

In its response to this recommendation, the Company cited the R-squared values for customer groups within the various service areas as a way of evaluating the reliability of the forecasts. The Department will not repeat the general discussion of the R-squared value from previous comments (e.g. page 4 of the Department's comments in G002/M-09-1287), but notes that the results are similar to the results from 2010-2011, that 27 of the 42 R-squared values reported for the customer classes in Xcel's service areas were 95 percent or greater and that 23 of these 27 predictions are in Minnesota service areas. Of the 15 cases in the Xcel system where the R-squared values drop below the 95-percent threshold, 1 residential case and 1 small commercial case are in North Dakota, while 6 small commercial and 7 large commercial cases are in Minnesota.

In six of the Minnesota cases of an R-squared value less than 95 percent, the Minnesota service-area commercial customer counts are less than 116; in small samples, outliers in the populations can have large impacts on the regression analyses and their explanatory value. Meanwhile, the R-squared values for five other service areas in the Minnesota cases lie between 92.25 percent and 93.90 percent. In the two remaining cases of an R-squared value for a service area not meeting the 95-percent mark, the customer counts are 235 small commercial customers and 580 small commercial customers, not especially large numbers, but greater than in some service areas that did reach 90 percent or 95 percent. The R-squared values for the two service areas are better than 85 percent, indicating they are not poor predictions. The two R-squared values for North Dakota service areas that do not meet the 95 percent standard are 89.83 percent (and 137 customers) and 94.95 percent.

These scores suggest that the Avg. Monthly DD method produces acceptable forecasts, provided that other aspects of the regression analysis are acceptable. At times, random variations in demand factors, especially factors not recognized in the regression, in a given year can cause predictions and consumption to not line up. The Department's review of Xcel's forecast method indicates that the analysis is reasonably sound.

The Department notes that the results of Xcel's Peak-Day method generally resulted in higher forecasted requirements for design days than the Avg. Monthly DD method. This result could be due to various factors, such as the potential that the increase in natural gas use on very cold days may not be a linear response. In any case, the Department agrees with Xcel that the Company should continue to use the two methods to develop its Design Day estimate. The Department expects that Xcel will, as the Company stated it will, continue to examine whether the amount of demand resources needed to serve firm customers should be revised to reflect any measurable changes in the amounts firm customers use on peak days.

3. Xcel's Forecasts

Xcel projected that its system (Minnesota and North Dakota) Design Day requirement will increase by 3,668 Dth to 785,892 Dth in the 2011-2012 heating season, a percentage increase of 0.5. The Company's forecast of its Minnesota Design Day requirement increased by 2,683 Dth to 702,294 Dth, an increase of 0.4 percent. Meanwhile, the forecasted usage for North Dakota for 2011-2012 is 83,598 Dth, up 985 Dth, or 1.2 percent from 2010-2011.

Xcel's customer forecast shows the number of Minnesota customers increasing by 2,461 from 436,468 in the 2010-2011 forecast to 438,929 in the 2010-2011 forecast, a 0.6 percent increase.

The North Dakota customer count is forecasted to increase 1.4 percent to 47,754 in 2011-2012, up from 46,143 in 2010-2011.

The Department notes that the smaller rate of increase in forecasted Minnesota gas consumption volume indicates that the proportion of Design-Day responsibility on the Xcel system has shifted slightly from Minnesota to North Dakota. According to the petition, the consumption allocator for Minnesota for 2010-2011 is 89.36 percent, down from 89.44 percent the year before. Such small changes in apportionment in one year are not significant. However, to reflect the greater increase in recent peak use in North Dakota compared to Minnesota, Xcel proposed to allocate less than this amount, 59 percent, of the total proposed increase in peak capacity to Minnesota (1,312 Dkt/2,213 Dkt). The Department concludes that it is reasonable to allocate less capacity to Minnesota.

The percentage increases in forecasted usage and customers in 2011-2012 are similar in both Minnesota and North Dakota. It does not necessarily follow that the customer counts and usage will track so closely. For example, North Dakota's customer count was forecasted to increase in 2009-2010, while the gas usage forecast was for a decrease. The long-term trend in gas usage per residential customer has been downward, which the Department stated was consistent with the contrasting movements in the North Dakota forecasts. That trend continues in Minnesota, where the total forecasted Design Day usage by residential customers has fallen by 4,903 Dth (-1.1 percent), whereas the forecasted residential customer count in the state has increased from 403,194 to 405,372 (0.5 percent).

In any event, the Department concludes from the Company's descriptions of its forecasting techniques that all aspects of Xcel's forecasting of Design-Day levels are performed appropriately.

B. CHANGES IN XCEL ENERGY'S DESIGN-DAY RESOURCES

Xcel's filing reflected changes in the resources used to meet its Design Day customer requirements. Overall, the Company's system demand entitlements rose slightly, from 831,598 Dth/day to 833,811 Dth/day, or 0.3 percent.

1. Northern Natural Gas Company Entitlements

The majority of Xcel's firm pipeline transportation contracts are with Northern Natural Gas (Northern). Most of these contracts were put in place in 2007 and run through 2017. The Company stated that it has modified its Northern entitlement levels in three ways since filing its 2010-2011 Demand Entitlement Filing.

First, Xcel took part in a Northern Zone EF 2011-2012 Expansion Open Season to increase capacity to its Brainerd service area. The Company stated that the increase is necessary to ensure adequate capacity for its firm customers and maintain a Design Day 5-percent reserve margin in the service area. The additional capacity, which has an expiration date of October 31, 2024, will be phased in over the four years beginning November 1, 2011 as follows:

Nov 1, 2011 – Oct 31, 2012	4,359Dth/day
Nov 1, 2012 – Oct 31, 2013	4,603 Dth/day
Nov 1, 2013 – Oct 31, 2014	4,839 Dth/day
Nov 1, 2014 – Oct 31, 2024	5,075 Dth/day

Second, Xcel exercised its biennial option to increase capacity by up to 5 percent at its St. Cloud #1, Sartell #1, and Becker #1 town border stations (TBS) in its St. Cloud Area. The Company stated that increasing demand in the St. Cloud Area will cause the Company's Design Day demand to outgrow Xcel's daily firm entitlement from Northern. To ensure that the Company had adequate capacity to meet the demands of its firm customers in the St. Cloud Area, Xcel elected the following capacity increases from Northern effective November 1, 2011:

St. Cloud #1	1,916 Dth/day
Sartell #1	884 Dth/day
Becker #1	2,000 Dth/day

Xcel stated that the discount associated with electing these capacity additions of 4,800 Dth/day will save ratepayers $1.2 million over the term of the contract compared with the maximum tariff rates for the same volume. These additions expire on October 31, 2017.

The third modification that Xcel made to its Northern entitlements occurred in the Hugo Area TBS of Stacy #1. The Company has a biennial option to increase capacity up to 5 percent annually. Xcel stated that hourly flow analysis at Stacy #1 indicates that the Company's hourly firm customer demands at Design Day temperatures will outgrow Xcel's entitlement demands on Northern. To ensure that the Company can meet its commitments to firm customers, Xcel elected a 90 Dth/day capacity increase in the Hugo Area effective November 1, 2011. The discount savings for ratepayers over the term of the contract, which expires on October 31, 2017, are $37,000 compared with the maximum tariff rates.

2. ANR Entitlements

Xcel increased its ANR demand entitlements under the terms of a Precedent Agreement the Company executed with ANR on June 30, 2008. Under the agreement the Company receives additional entitlements from the Joliet Hub in Chicago delivered to Marshfield, Minnesota, where ANR and Viking interconnect. The entitlement under the agreement increased from

50,000 Dth/day to 57,500 Dth/day on November 1, 2011. An additional increase to a total of 66,500 Dth/day is scheduled for November 1, 2012. This additional capacity allowed the Company to effectuate a Northern Chisago realignment discount option, starting on November 1, 2010, and to have gas supplies for the increased capacity that the Fargo lateral project required.

These two projects were discussed in the 2010-2011 Demand Entitlement Filing. The Northern Chisago realignment discount saves Xcel ratepayers $1,875 million per year, while the Fargo lateral project addressed Design Day capacity shortfalls that the Company had identified in that part of its system.

3. Great Lakes Gas Transmissions (GLGT) Entitlements

A backhaul contract that Xcel had with GLGT expired on April 30, 2011. The contract included a discounted demand charge and allowed Xcel to transport gas from Deward, Michigan, the GLGT interconnect with ANR Storage in Michigan, to Carlton, Minnesota, which is the GLGT interconnect with Northern. Xcel did not renew the contract, stating that the Company chose two cheaper displacement contracts instead. The contracts, totaling 15,297 Dth/day, are equal to Xcel's ANR Storage withdrawal capability. Under the contracts, Xcel will provide a gas supplier from its ANR Storage account at Deward a volume equal to the volume the supplier provides at Carlton. The contracts are in effect from November 1, 2011, to March 31, 2012, which coincides with the ANR Storage withdrawal season.

4. Viking Gas Transmission (Viking) Entitlements

A backhaul contract that Xcel had with Viking expired on October 31, 2011. This max rate contract allowed Xcel to transport gas from Marshfield, Minnesota, to Xcel markets served by Viking. Xcel determined that it no longer needed this backhaul capacity because it acquired backhaul capacity as part of the Fargo lateral project described above. The capacity that expired was 21,104 Dth/day.

The Department has analyzed the above changes in Design Day entitlement resources. Xcel supported each change with a reasonable analysis, kept the focus of the transactions as narrow as the circumstances warrant, and identified discount savings for ratepayers that the Company was able to take advantage of due to the terms of the contracts that it has in place for options to expand capacity. The Department, therefore, concludes that the changes for 2011-2012 demand entitlements are reasonable.

C. CHANGE IN XCEL'S RESERVE MARGIN

Xcel proposed to decrease its projected Design Day reserve margin in Minnesota from to 6.3 percent in 2010-2011 to 6.1 percent in 2011-2012. See Department Attachment 1. Xcel stated that it bases its reserve margin on the firm resources necessary to meet projected firm customer demand plus the capability of either the largest pump at its Wescott facility used to vaporize liquefied natural gas (LNG) or either of its St. Paul metro propane-air peak-shaving plants. The capacity decision reflects Xcel's assessment of the most economical method of adding capacity to meet demand beyond the forecasted Design Day demand. The reserve margin balances protecting against the loss of a firm gas supply source and actual consumer demand under Design Day conditions with the likelihood of experiencing Design Day conditions. Xcel stated that its proposed reserve margin in Minnesota of 42,800 Dth/day is appropriate to meet its Design Day needs. The Company further stated that the most economical method of adding capacity often involves adding increments that do not precisely match expected changes in demand.

Xcel's proposed reserve margin is within the 5-7 percent range that serves as a rule of thumb in deciding whether a given margin is reasonable. The 6.1 percent reserve margin represents a small decrease from the 2010-2011 reserve margin. Xcel has achieved the reduction, even though the Company has increased its total Minnesota Company Design Day requirement by 2,683 Dth/day in 2011-2012, because the Company has increased its total Design Day capacity to the Minnesota jurisdiction by 1,312 Dth/day. By allocating less peak capacity to Minnesota, Xcel was able to decrease the reserve margin.

The Department notes that the 6.1 reserve margin continues the downward trend from 2009-2010 when the reserve margin was 7.7 percent. At that time, Xcel was adding the Fargo lateral, which caused its Design-Day Capacity to rise by a large volume when the Design-Day Requirement was not keeping pace. In its Reply Comments in G002/M-09-1287 the Company explained that its experience with pipeline companies indicated that these counterparties will rarely agree to 1-2 percent annual capacity additions. Thus, Xcel stated, it typically has to add capacity in increments that may temporarily exceed customer demand growth for a few years. The Company provided forecasts of its reserve margins from 2009-2010 to 2013-2014 that showed the reserve margin declining. The 2011-2012 predicted reserve margin was 5.0 percent. The reserve margin has not dropped enough in the past two years to match this level, but the decline is in keeping with the Company's prediction of where the reserve margin would move. The current year's changes in demand entitlements are consistent with the Company's statement that the most economical method of adding capacity often involves adding increments that do not precisely match expected changes in demand. The additions are targeted to service areas or even TBS, while the other changes involve shedding contracts and replacing them with options that have lower costs. The Department, therefore, concludes that the 2011-2012 reserve margin is reasonable.

D. CHANGES IN XCEL'S JURISDICTIONAL ALLOCATIONS

1. Change in Minnesota Jurisdiction Allocation Factor

The previously noted 0.4 percent increase in forecasted Minnesota usage and 1.2 percent forecasted increase in North Dakota usage is reflected in the new Minnesota Jurisdictional Allocation Factor and, as discussed above, in the allocations of new peak capacity in this petition to Minnesota and North Dakota. The allocation factor is calculated by dividing the Design Day forecasted demand for Minnesota (702,294 Dth/day) by the same demand for the Company's system (785,892 Dth/day). The Avg. Monthly DD results are used to update the allocation factor, which fell from 89.44 percent to 89.36 percent. Small annual changes in the allocation factor such as that identified are almost inevitable. A change in a handful of customers in one state or the other can change the total numbers upon which the allocation factor is based and change the allocation between the states, but not significantly. The small change identified in the above analysis falls into this category. In addition, the Department is aware that the increased economic activity in North Dakota is increasing use of natural gas. Therefore, the Department concludes that Xcel's proposal is reasonable.

2. Elimination of the Minnesota Grand Forks Area Jurisdiction Allocation Factor

Xcel proposes to eliminate the Minnesota Grand Forks Design Day allocation factor. This allocation factor was used to allocate the costs of the incremental capacity on Viking related to a looping project completed in this service area several years ago. The expiration of the Viking demand entitlement contract on October 31, 2011, means the costs no longer apply. Therefore, the Department concludes that Xcel's proposed elimination of the Grand Forks Design Day allocation factor is reasonable.

E. CHANGES IN XCEL'S SUPPLIER RESERVATION FEES

Xcel notes that its Supplier Reservation fees have changed. **[TRADE SECRET DATA HAS BEEN EXCISED]** The new expense level reflects updated prices of the firm gas supply reservations. Therefore, the Department concludes that Xcel's proposal is reasonable.

F. XCEL'S PLANNED USE OF HEATING-SEASON FINANCIAL INSTRUMENTS

In compliance with reporting requirements of the Commission's Order in Docket No. G002/M-08-46, Xcel included a table summarizing the Company's hedging transactions for the 2011-2012 heating season. See Xcel Attachment 3. The information in the table is not sufficient to determine the cost to the Company of each transaction because the transactions had not closed at the time of the filing. Therefore, the portion of the total dollars shown for each transaction that relate to the Company's $32 million cap on hedging costs cannot be determined. The Department concludes that the Company has met its reporting requirement, and requests that Xcel provide updated information when it is available.

G. XCEL'S PGA COST RECOVERY PROPOSAL

Xcel proposed to reflect the costs associated with the demand entitlements in the petition in the PGA effective with November 1, 2011 billing cycles. The Department concludes that this effective date is reasonable because it reflects when its various supply and demand contracts for the 2011-2012 Heating Season demand entitlement take effect.

H. XCEL ENERGY'S PROPOSAL TO ASSIGN DEMAND COSTS TO INTERRUPTIBLE CUSTOMERS

Xcel Energy states that interruptible sales customers are receiving the benefits of storage and balancing services on non-Design Days. Thus, a portion of these costs could justifiably be recovered from these customers. The Company, therefore, developed a proposal to make such an assignment of costs on a prospective basis and presented it in Comments in the Company's 2007-2008 Demand Entitlement filing. Commission action in that docket is pending, as it is in the Company's 2008-2009 through 2010-2011 Demand Entitlement filings, in which the Company repeated the proposal.

The Department concluded in Comments dated October 7, 2008 that Xcel's proposal represents a systematic approach to determining when interruptible customers benefit from the services associated with demand costs. Therefore, the Department concluded that the proposal is reasonable. The Department position on the matter is unchanged in the current docket.

I. PGA COST RECOVERY ANALYSIS

The demand entitlements in Xcel Attachment 2, Schedule 1, Page 1 of 2, represent the demand entitlements for which the Company's firm customers are currently paying. Department Attachment 2, using data provided by Xcel in response to an informal request, compares the October 2011 PGA costs to the November 2011 PGA costs for the several customer classes. The demand costs of gas shown in Department Attachment 2 are a blend of summer and winter rates for each class and are weighted for actual volumes consumed. The resulting per Dth cost changes for each class are added to the commodity cost of gas change, which is the same for each customer class, to arrive at total per Dth cost changes for the customer classes. The changes shown in Department Attachment 2 combine all of Xcel's proposed changes and results in the following annual rate effects:

- Annual demand cost increase of $0.0207/Dth, or approximately $1.80 annually per year, for the average Residential customer consuming 87 Dth annually;
- Annual demand cost increase of $0.0207/Dth, or approximately$5.88 annually , for the average Small Commercial customer consuming 284 Dth annually;
- Annual demand cost increase of $0,0206Dth, or approximately $30.14 annually, for the average Large Commercial customer consuming 1,463 Dth annually; and
- No change in annual demand costs for the average Small Interruptible, Medium Interruptible, and Large Interruptible customers consuming, respectively, 8,114 Dth, 60,971 Dth, and 839,818 Dth annually. These customer classes are not allocated demand costs under the current cost allocation plan.

The Company also compares the October 2011 PGA costs to the November 2011 PGA costs for the customer classes with some demand costs allocated to the Interruptible customer classes, as would be the case under Xcel's pending proposal. The hypothetical changes combining all of Xcel's proposed cost changes for the customer classes result in the following annual rate effects:

- Annual demand cost increase of $0.0056/Dth, or approximately$0.49 annually, for the average Residential customer consuming 87 Dth annually;
- Annual demand cost increase of $0.0057/Dth, or approximately$1.62 annually , for the average Small Commercial customer consuming 284 Dth annually;
- Annual demand cost increase of $0.0058/Dth, or approximately $8.48, for the average Large Commercial customer consuming 1,463 Dth annually;
- Annual demand cost increase of $0.0707/Dth, or approximately $573.65 annually for the average Small Interruptible customer consuming 8,114 Dth annually;
- Annual demand cost increase of $0.0547/Dth, or approximately $3,325.25 annually for the average Medium Interruptible customer consuming 60,971 Dth annually; and
- Annual demand cost increase of $0.0575/Dth, or approximately $48,289.52 annually for the average Large Interruptible customer consuming 839,818 Dth annually.

The Department notes that the Commission recently decided in CenterPoint Energy demand filing G008/M-07-561 to ease into the allocation of certain storage and demand costs to interruptible customers, due to concerns about rate shock. While the Department supports the goal of ensuring that interruptible customers pay their fair shares of these costs, the Department requests Xcel to indicate in reply comments whether Xcel has any concerns about rate shock for the affected interruptible customers. If not, then the Department recommends that this change in rate design fully take place effective November 1, 2011. If there is a concern about rate shock, then this change should be phased in over a few years. The Department invites Xcel to propose such a phase-in plan, if needed.

Based on its analysis, the Department recommends that the Commission approve the proposed recovery of Xcel's demand costs, allocated in part or in full according to the Company's pending proposal, effective November 1, 2011. The Department will provide its final recommendations on this issue after reviewing Xcel's reply comments.

III. THE DEPARTMENT'S INQUIRIES REGARDING DEMAND ENTITLEMENT FILINGS

The Department issued discovery to each regulated Minnesota gas utility requesting input regarding the annual demand entitlement filing timeline and the reasonableness of acquiring capacity contracts for the upcoming heating season in excess of the amount estimated by the design day analysis. Various utility responses to the Department's inquiry are discussed below.[2]

Based on the discovery responses by each utility, there is universal agreement that the demand entitlement filings could be filed in the summer rather than in the fall. In particular, the utilities stated that they could make their filings either on July 1st or August 1st of each year. The Department prefers the utilities' suggested earlier timeline because it would enable any reliability issues to be identified and possibly resolved prior to the start of the heating season. Minnesota Rule 7825.2910, subpart 2 states the following:

> Subp. 2. Filing upon change in demand.
> Gas utilities shall file for a change in demand to increase or decrease demand, to redistribute demand percentages among classes, or to exchange one form of demand for another. A filing must contain:
>
> A. a description of the factors contributing to the need for changing demand;
> B. the utility's design-day demand by customer class and the change in design-day demand, if any, necessitating the demand revision;
> C. a summary of the levels of winter versus summer usage for all customer classes; and
> D. a description of design-day gas supply from all sources under the new level, allocation, or form of demand.

Although Minnesota Rule 7825.2910, subpart 2 does not specify a timeline for making the demand entitlement filing, the Department recommends that the Commission request Xcel to file, on a going-forward basis, its annual demand entitlement filing by August 1.

[2] Xcel's response to DOC Information Request No. 1 is provided as Department Attachment 3.

The Department also requested that each utility provide a discussion regarding the level of capacity procurement as it relates to the demand entitlement filing. In particular, the Department requested that the utilities comment on the practice of acquiring capacity contracts in excess of the amount estimated by the design day analysis for the upcoming heating season. The utilities generally stated that the nature of the interstate pipeline business requires these pipelines to sell capacity in larger blocks so that they are able to fully recover capital costs.

The Department acknowledges this fact, but is concerned that local distribution companies do not, in general, provide design day analyses for future heating seasons when requesting cost recovery of additional entitlements above the amount estimated for the upcoming heating season. The Department suggests that, if utilities want to include additional capacity above an adequate reserve margin calculated for the upcoming heating season, the utilities should provide information substantiating that these additional volumes will be necessary in future heating seasons and provide justification for recovering the corresponding costs from ratepayers in the current heating season, prior to the time when such capacity is needed.

IV. CONCLUSIONS AND RECOMMENDATIONS

The Department concludes that Xcel has sufficiently supported its:

- Proposed Design Day levels of capacity, including the derivation of its forecasting methods;
- Changes in Design Day resources;
- Reduction in reserve margin;
- Changes in jurisdictional allocations;
- Changes in supplier reservation fees;
- Proposal to assign demand costs to interruptible customers, although it may be necessary to phase in the rate change; and
- Proposal to recover demand costs associated with demand entitlements effective November 1, 2011.

Moreover, the Department concludes that Xcel has met its reporting requirement for planned use of heating-season financial instruments.

Therefore, the Department recommends that the Commission:

- approve Xcel's demand entitlements; however, the Department will address the issue of the implementation of the change in demand entitlements subsequent to reviewing Xcel's reply comments; and
- request Xcel to file, on a going-forward basis, its annual demand entitlement filing by August 1.

The Department recommends that the Company explain in reply comments why it elected to use 60 data points instead of the 70 available for its Average Monthly Design Day forecasting method and to state whether it has plans to increase the number of data points in subsequent years' demand-entitlement filings.

/ja

Docket No. G002/M-11-1076
Demand Entitlement Analysis--Minnesota Jurisdiction*

Northern States Power Company d/b/a Xcel Energy

	Number of Firm Customers			**Design-Day Requirement**			**Total Entitlement Plus Peak Shaving**			**Reserve Margin**	
Heating Season	(1) Number of Customers	(2) Change from Previous Year	(3) % Change From Previous Year	(4) Design Day (Dth)	(5) Change from Previous Year	(6) % Change From Previous Year	(7) Total Design-Day Capacity (Dth)	(8) Change from Previous Year	(9) % Change From Previous Year	(10) Reserve Margin	(11) % of Reserve [(7)-(4)]/(4)
2011-2012**	439,055	2,461	0.56%	702,294	2,683	0.38%	745,094	1,313	0.18%	42,800	6.09%
2010-2011**	436,594	2,896	0.67%	699,611	5,124	0.74%	743,781	(4,486)	-0.60%	44,170	6.31%
2009-2010**	433,698	4,846	1.13%	694,487	9,482	1.38%	748,267	15,976	2.18%	53,780	7.74%
2008-2009**	428,852	(2,651)	-0.61%	685,005	1,288	0.19%	732,291	10,785	1.49%	47,286	6.90%
2007-2008**	431,503	7,088	1.67%	683,717	5,984	0.88%	721,506	25,249	3.63%	37,789	5.53%
2006-2007	424,415	2,845	0.67%	677,733	6,887	1.03%	696,257	4,568	0.66%	18,524	2.73%
2005-2006	421,570	10,584	2.58%	670,846	21,191	3.26%	691,689	16,569	2.45%	20,843	3.11%
2004-2005	410,986	9,353	2.33%	649,655	46,187	7.65%	675,120	31,805	4.94%	25,465	3.92%
2003-2004	401,633	5,826	1.47%	603,468	(4,388)	-0.72%	643,315	1,040	0.16%	39,847	6.60%
2002-2003	395,807			607,856			642,275			34,419	5.66%
Average:			1.16%			1.64%			1.68%		5.46%

	Firm Peak-Day Sendout						
Heating Season	(12) Firm Peak-Day Sendout (Dth)	(13) Change from Previous Year	(14) % Change From Previous Year	(15) Excess per Customer [(7) - (4)]/(1)	(16) Design Day per Customer (4)/(1)	(17) Entitlement per Customer (7)/(1)	(18) Peak-Day Send per Customer (12)/(1)
2011-2012**	NA			0.0975	1.5996	1.6970	NA
2010-2011	675,577	84,646	14.32%	0.1012	1.6024	1.7036	1.5474
2009-2010	590,931	(10,494)	-1.74%	0.1240	1.6013	1.7253	1.3625
2008-2009	601,425	15,551	2.65%	0.1103	1.5973	1.7076	1.4024
2007-2008	585,874	16,911	2.97%	0.0876	1.5845	1.6721	1.3578
2006-2007	568,963	31,303	5.82%	0.0436	1.5969	1.6405	1.3406
2005-2006	537,660	286	0.05%	0.0494	1.5913	1.6407	1.2754
2004-2005	537,374	(23,876)	-4.25%	0.0620	1.5807	1.6427	1.3075
2003-2004	561,250	26,865	5.03%	0.0992	1.5025	1.6017	1.3974
2002-2003	534,385			0.0870	1.5357	1.6227	1.3501
Average			2.05%	0.0770	1.5699	1.6297	1.3473

*-Some numbers may differ from Xcel Attachments due to rounding

**-Reflects the UPC DD method. 0.893626605

Attachment 1

Prepared by the Minnesota Department of Commerce, Division of Energy Resources

Docket No. G002/M-11-1076
Demand Entitlement--PGA Cost Recovery Analysis

Residential	Last Rate Case (G002/GR-09-1153)	Last Approved Demand Change (G002/M-06-1454)	Oct PGA (10/1/11)	Nov 2011 PGAs with Proposed Demand Entitlement Changes	Nov 2011 PGA with some Dmd costs moved to IR (originally proposed in 07-1395)	Change From Last Rate Case	Change From Last Approved Demand Change	Percent Change (%) From Oct. PGA	Change ($) From Oct. PGA
Commodity Cost of Gas (WACOG)	$5.5042	$7.0824	$3.9272	$4.1398	$4.1398	-24.79%	-41.55%	5.41%	$0.2126
Demand Cost of Gas (1)	$0.9008	$1.0716	$0.9110	$0.9317	$0.9166	3.43%	-13.06%	2.27%	$0.0207
Distribution Margin	$1.8591	$1.6263	$1.8591	$1.8591	$1.8591	0.00%	14.32%	0.00%	$0.0000
Total per Dth Cost	$8.2641	$9.7803	$6.6973	$6.9306	$6.9155	-16.14%	-29.14%	3.48%	$0.2333
Average Annual Usage (Dk)	87	87	87	87	87				
Average Annual Total Cost	$718.60	$850.43	$582.36	$602.64	$601.33	-16.14%	-29.14%	3.48%	$20.29
Average Annual Total Demand Cost of Gas	$78.33	$93.18	$79.21	$81.01	$79.70			**Current Allocation**	**$1.80**
								Demand Costs to Non-Firm	**$0.49**

Small Commercial	Last Rate Case (G002/GR-09-1153)	Last Approved Demand Change (G002/M-06-1454)	Oct PGA (10/1/11)	Nov 2011 PGAs with Proposed Demand Entitlement Changes	Nov 2011 PGA with some Dmd costs moved to IR (originally proposed in 07-1395)	Change From Last Rate Case	Change From Last Approved Demand Change	Percent Change (%) From Oct. PGA	Change ($) From Oct. PGA
Commodity Cost of Gas (WACOG)	$5.4871	$7.0824	$3.9272	$4.1398	$4.1398	-24.55%	-41.55%	5.41%	$0.2126
Demand Cost of Gas (1)	$0.8984	$1.0873	$0.9085	$0.9292	$0.9142	3.43%	-14.54%	2.28%	$0.0207
Distribution Margin	$1.2331	$1.1366	$1.2331	$1.2331	$1.2331	0.00%	8.49%	0.00%	$0.0000
Total per Dth Cost	$7.6186	$9.3063	$6.0688	$6.3021	$6.2871	-17.28%	-32.28%	3.84%	$0.2333
Average Annual Usage (Dk)	284	284	284	284	284				
Average Annual Total Cost	$2,163.87	$2,643.22	$1,723.69	$1,789.96	$1,785.69	-17.28%	-32.28%	3.84%	$66.26
Average Annual Total Demand Cost of Gas	$255.17	$308.82	$258.04	$263.92	$259.66			**Current Allocation**	**$5.88**
								Demand Costs to Non-Firm	**$1.62**

Large Commercial	Last Rate Case (G002/GR-09-1153)	Last Approved Demand Change (G002/M-06-1454)	Oct PGA (10/1/11)	Nov 2011 PGAs with Proposed Demand Entitlement Changes	Nov 2011 PGA with some Dmd costs moved to IR (originally proposed in 07-1395)	Change From Last Rate Case	Change From Last Approved Demand Change	Percent Change (%) From Oct. PGA	Change ($) From Oct. PGA
Commodity Cost of Gas (WACOG)	$5.4871	$7.0824	$3.9272	$4.1398	$4.1398	-24.55%	-41.55%	5.41%	$0.2126
Demand Cost of Gas (1)	$0.8917	$1.0569	$0.9018	$0.9224	$0.9076	3.44%	-12.73%	2.28%	$0.0206
Distribution Margin	$1.2315	$1.1324	$1.2315	$1.2315	$1.2315	0.00%	8.75%	0.00%	$0.0000
Total per Dth Cost	$7.6103	$9.2717	$6.0605	$6.2937	$6.2789	-17.30%	-32.12%	3.85%	$0.2332
Average Annual Usage (Dk)	1,463	1,463	1,463	1,463	1,463				
Average Annual Total Cost	$11,131.14	$13,561.15	$8,864.34	$9,205.43	$9,183.78	-17.30%	-32.12%	3.85%	$341.09
Average Annual Total Demand Cost of Gas	$1,304.24	$1,545.86	$1,319.01	$1,349.14	$1,327.49			**Current Allocation**	**$30.13**
								Demand Costs to Non-Firm	**$8.48**

Small Interruptible	Last Rate Case (G002/GR-09-1153)	Last Approved Demand Change (G002/M-06-1454)	Oct PGA (10/1/11)	Nov 2011 PGAs with Proposed Demand Entitlement Changes	Nov 2011 PGA with some Dmd costs moved to IR (originally proposed in 07-1395)	Change From Last Rate Case	Change From Last Approved Demand Change	Percent Change (%) From Oct. PGA	Change ($) From Oct. PGA
Commodity Cost of Gas (WACOG)	$5.4926	$7.0824	$3.9272	$4.1398	$4.1398	-24.63%	-41.55%	5.41%	$0.2126
Demand Cost of Gas (1)	$0.0000	$0.0000	$0.0000	$0.0000	$0.0707	NA	NA	NA	$0.0000
Distribution Margin	$0.9635	$0.8675	$0.9635	$0.9635	$0.9635	0.00%	11.07%	0.00%	$0.0000
Total per Dth Cost	$6.4561	$7.9499	$4.8907	$5.1033	$5.1033	-20.95%	-35.81%	4.35%	$0.2126
Average Annual Usage (Dk)	8,114	8,114	8,114	8,114	8,114				
Average Annual Total Cost	$52,384.66	$64,504.92	$39,683.11	$41,408.14	$41,408.14	-20.95%	-35.81%	4.35%	$1,725.02
Average Annual Total Demand Cost of Gas	$0.00	$0.00	$0.00	$0.00	$573.65			**Current Allocation**	**$0.00**
								Demand Costs to Non-Firm	**$573.65**

Medium Interruptible	Last Rate Case (G002/GR-09-1153)	Last Approved Demand Change (G002/M-06-1454)	Oct PGA (10/1/11)	Nov 2011 PGAs with Proposed Demand Entitlement Changes	Nov 2011 PGA with some Dmd costs moved to IR (originally proposed in 07-1395)	Change From Last Rate Case	Change From Last Approved Demand Change	Percent Change (%) From Oct. PGA	Change ($) From Oct. PGA
Commodity Cost of Gas (WACOG)	$5.4696	$7.0824	$3.9272	$4.1398	$4.1398	-24.31%	-41.55%	5.41%	$0.2126
Demand Cost of Gas (1)	$0.0000	$0.0000	$0.0000	$0.0000	$0.0547	NA	NA	NA	$0.0000
Distribution Margin	$0.4751	$0.3900	$0.4751	$0.4751	$0.4751	0.00%	21.83%	0.00%	$0.0000
Total per Dth Cost	$5.9447	$7.4724	$4.4023	$4.6149	$4.6696	-22.37%	-38.24%	4.83%	$0.2126
Average Annual Usage (Dk)	60,791	60,791	60,791	60,791	60,791				
Average Annual Total Cost	$361,383.73	$454,252.47	$267,620.14	$280,544.24	$283,869.50	-22.37%	-38.24%	4.83%	$12,924.10
Average Annual Total Demand Cost of Gas	$0.00	$0.00	$0.00	$0.00	$3,325.25			**Current Allocation**	**$0.00**
								Demand Costs to Non-Firm	**$3,325.25**

Large Interruptible	Last Rate Case (G002/GR-09-1153)	Last Approved Demand Change (G002/M-06-1454)	Oct PGA (10/1/11)	Nov 2011 PGAs with Proposed Demand Entitlement Changes	Nov 2011 PGA with some Dmd costs moved to IR (originally proposed in 07-1395)	Change From Last Rate Case	Change From Last Approved Demand Change	Percent Change (%) From Oct. PGA	Change ($) From Oct. PGA
Commodity Cost of Gas (WACOG)	$5.5501	$7.0824	$3.9272	$4.1398	$4.1398	-25.41%	-41.55%	5.41%	$0.2126
Demand Cost of Gas (1)	$0.0000	$0.0000	$0.0000	$0.0000	$0.0575	NA	NA	NA	$0.0000
Distribution Margin	$0.4346	$0.3565	$0.4346	$0.4346	$0.4346	0.00%	21.91%	0.00%	$0.0000
Total per Dth Cost	$5.9847	$7.4389	$4.3618	$4.5744	$4.6319	-23.56%	-38.51%	4.87%	$0.2126
Average Annual Usage (Dk)	839,818	839,818	839,818	839,818	839,818				
Average Annual Total Cost	$5,026,031.87	$6,247,319.98	$3,663,125.29	$3,841,670.54	$3,889,960.06	-23.56%	-38.51%	4.87%	$178,545.25
Average Annual Total Demand Cost of Gas	$0.00	$0.00	$0.00	$0.00	$48,289.52			**Current Allocation**	**$0.00**
								Demand Costs to Non-Firm	**$48,289.52**

(1) Does not include demand smoothing

Current Allocation Summary Change from most recent PGA Customer Class	Commodity Change ($/Dk)	Commodity Change (Percent)	Demand Change ($/Dk)	Demand Change (Percent)	Demand Annual Change ($/Dk)	Total Annual Change ($/Dk)	Total Annual Change (Percent)
Residential	$0.2126	5.41%	$0.0207	2.27%	$1.80	$20.29	3.48%
Small Commercial	$0.2126	5.41%	$0.0207	2.28%	$5.88	$66.26	3.84%
Large Commercial	$0.2126	5.41%	$0.0206	2.28%	$30.13	$341.09	3.85%
Small Interruptible	$0.2126	5.41%	$0.0000	NA	$0.00	$1,725.02	4.35%
Medium Interruptible	$0.2126	5.41%	$0.0000	NA	$0.00	$12,924.10	4.83%
Large Interruptible	$0.2126	5.41%	$0.0000	NA	$0.00	$178,545.25	4.87%

Demand Costs to Non-Firm Summary Change from most recent PGA Customer Class	Commodity Change ($/Dk)	Commodity Change (Percent)	Demand Change ($/Dk)	Demand Change (Percent)	Demand Annual Change ($/Dk)	Total Annual Change ($/Dk)	Total Annual Change (Percent)
Residential	$0.2126	5.41%	$0.0056	0.61%	$0.49	$18.97	3.26%
Small Commercial	$0.2126	5.41%	$0.0057	0.63%	$1.62	$62.00	3.60%
Large Commercial	$0.2126	5.41%	$0.0058	0.63%	$8.48	$319.44	3.60%
Small Interruptible	$0.2126	5.41%	$0.0707	NA	$573.65	$2,298.68	4.35%
Medium Interruptible	$0.2126	5.41%	$0.0547	NA	$3,325.25	$16,249.36	6.07%
Large Interruptible	$0.2126	5.41%	$0.0575	NA	$48,289.52	$226,834.76	6.19%

☐ **Non Public Document – Contains Trade Secret Data**
☐ **Public Document – Trade Secret Data Excised**
☒ **Public Document**

Xcel Energy
Docket No.: E002/M-11-1076
Response To: Department of Commerce Information Request No. 1
Requestor: Adam Heinen/Michelle St. Pierre/Hwikwon Ham/Sachin Shah
Date Received: November 22, 2011

Question:
Annual Demand Entitlement Filing
Reference: DOC November 15, 2011 Response Comments in Docket Nos. G007/M-10-1166, G011/M-10-1167, and G011/M-10-1168, Pages 9 through 11

In the above reference, the Department included a discussion related to the nature of the annual demand entitlement filings. As part of this discussion, the Department made several suggestions that it believes could improve the overall process regarding these filings. Based on this reference, please provide the following:

a full response to the Department's proposal that the demand entitlement filing date be changed and a detailed explanation of when, on average, during the year the utility conducts its design-day analysis and subsequently procures demand entitlements for the upcoming heating season;

a detailed discussion of how the utility determines whether additional capacity, beyond the amount calculated in the design-day analysis, is reasonable and should be recovered from firm customers during the current heating season; and

a detailed discussion of whether the utility believes there is an effective mechanism to alleviate the issue of excess capacity during a given heating season, and the recovery of costs associated with these volumes, and whether the utility has discussed with the various interstate pipeline methods through which procured volumes can be phased in when they are needed rather than in advance of when the volumes are needed.

Response:

1. Annually, we produce our sales forecast for the upcoming heating season and the subsequent four heating seasons by pipeline lateral by May 1. After the annual sales forecast is completed, the design day requirements by pipeline lateral are calculated for the next five heating seasons. Load curves are developed for the upcoming heating season to determine the volume and type of supplies that are necessary to meet the design day requirements of our firm

customers. Request for Proposals for supply contracts are issued and firm supply contracts are negotiated. On average, this entire process is completed by June 1 of each year.

Contracting for pipeline entitlements is not part of the annual process described above, as adding pipeline entitlement usually takes 18-24 months to complete. For example, in our most recently filed Demand Entitlement Filing G002/M-11-1076, we participated in an open season on Northern Natural Gas ("Northern") in April 2010 to add capacity to Brainerd, MN effective November 1, 2011. In addition, we have a biennial election in our long term contract with Northern to increase capacity at certain town border stations ("TBS") on May 1st of every even year with the additional volumes becoming available on November 1st of the subsequent odd year.

We could file our annual demand entitlement filing as early as August 1st of each year. We prefer not to have the filing due on September 1st as the same resources are needed to file the September 1st Annual Automatic Adjustment report for our natural gas operations..

2. As discussed above, annually we calculate design day requirements by pipeline lateral for the next five heating seasons and compare that design day to the level of pipeline entitlement we have under contract to serve those delivery points. In addition to meeting design day requirements, we also believe a reserve margin is needed for the protection of the system and to meet our customers' needs. In particular, having a reserve margin protects our firm customers from: (1) colder than expected temperatures on a design day; or (2) differences between actual usage or customer growth and forecasting models projections. We have determined a reserve margin of around 5% by pipeline lateral is appropriate as it provides the Company with enough flexibility to protect its firm customers.

   If we determine a deficiency exists between our design day requirements and contracted pipeline entitlement or if the reserve margin is less than 5%, then we work with the pipeline to resolve the deficiency. Resolving the deficiency at the delivery point could be accomplished in a variety of ways including:

   a. Realigning delivery point capacity away from a points that have a reserve margin in excess of 5% to the delivery points with the deficiencies, or
   b. Contracting for additional pipeline capacity through our biennial elections in our long term contract with Northern, or
   c. Participating in an open season on the pipeline which could involve constructing pipeline facilities, or

d. Siting additional peakshaving facilities, or
e. Making changes to our distribution system which would eliminate the deficiency.

Decisions to increase pipeline capacity to meet design day requirements or the 5% reserve margin typically require a minimum of 18-24 months advance planning. By the time the additional pipeline capacity comes into service, actual sales and design day calculations may be different than what was forecasted at the time the decision was made. Therefore, when actual customer counts differ from a forecast from two years prior, the actual reserve margin with the new capacity may be more or less than the 5% reserve margin.

Sometimes when purchasing incremental capacity that requires construction, pipeline counterparties will not accommodate 1-2 percent capacity additions every year to following increases in customer demand. Therefore, we must purchase capacity in larger increments that may temporarily exceed customer growth for several years. When an expansion project adds new capacity, the project is typically over-built in the first years of operation so the Company can grow into the capacity over a period of several years. This approach is generally desirable, as the Company does not need to participate in expansion projects annually and can benefit from the economies of scale stemming from the larger projects.

Recovery of costs related to the 5% reserve margin and our efforts to purchase incremental capacity, which may at times temporarily result in a reserve margin over 5% are warranted as these costs result from prudent decision making based upon the best facts and circumstances known at the time the decisions are made. Thus, the costs are legitimate, reasonable costs of providing gas service to our customers and are in the public interest. Moreover, the type of planning and cost incurrence undertaken by the Company to meet our customers' needs, both in the near and long-term, are typical of actions taken by other gas utilities in the industry and as discussed above, will not generally accommodate small increments of expansion.

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3. We do not believe there is an effective mechanism to allow a utility to procure an exact amount of capacity to precisely meet its reserve demand and design day requirements each heating season. However, any time construction can be avoided there is a better chance of having actual capacity equal firm design day requirements plus 5% reserve margin. When a construction project is necessary, we have effectively negotiated with interstate pipelines to phase in volumes. For example, in our most recently filed Demand Entitlement Filing G002/M-11-1076, we participated in an open season on Northern in April 2010 to add capacity to Brainerd, MN. Contract entitlements for this project were phased in over a four-year period beginning November 1, 2011. We

would be happy to work with the Department and other utilities to explore alternative ways to manage reserve margin.

Preparer:	Joni Zich
Title:	Manager, Gas Resource Planning
Department:	Gas Resource Planning
Telephone:	715.737.4692
Date:	December 14, 2011

CERTIFICATE OF SERVICE

I, Sharon Ferguson, hereby certify that I have this day, served copies of the following document on the attached list of persons by electronic filing, certified mail, e-mail, or by depositing a true and correct copy thereof properly enveloped with postage paid in the United States Mail at St. Paul, Minnesota.

Minnesota Department of Commerce
Public Comments

Docket No. G002/M-11-1076

Dated this **2nd of February, 2012**

/s/Sharon Ferguson

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Tamie A.	Aberle	tamie.aberle@mdu.com	Great Plains Natural Gas Co.	400 North Fourth Street Bismarck, ND 585014092	Paper Service	No	OFF_SL_11-1076_11-1076
Julia	Anderson	Julia.Anderson@ag.state.mn.us	Office of the Attorney General-DOC	1800 BRM Tower 445 Minnesota St St. Paul, MN 551012134	Electronic Service	Yes	OFF_SL_11-1076_11-1076
Christopher	Anderson	canderson@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022191	Electronic Service	No	OFF_SL_11-1076_11-1076
Gail	Baranko	gail.baranko@xcelenergy.com	Xcel Energy	414 Nicollet Mall7th Floor Minneapolis, MN 55401	Electronic Service	Yes	OFF_SL_11-1076_11-1076
James J.	Bertrand	james.bertrand@leonard.com	Leonard Street & Deinard	Suite 2300 150 South Fifth Street Minneapolis, MN 55402	Paper Service	No	OFF_SL_11-1076_11-1076
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Michael	Bradley	bradleym@moss-barnett.com	Moss & Barnett	4800 Wells Fargo Ctr 90 S 7th St Minneapolis, MN 55402-4129	Electronic Service	No	OFF_SL_11-1076_11-1076
Robert S.	Carney, Jr.			4232 Colfax Ave. S. Minneapolis, MN 55409	Paper Service	No	OFF_SL_11-1076_11-1076
Christopher	Clark	christopher.b.clark@xcelenergy.com	Xcel Energy	5th Floor 414 Nicollet Mall Minneapolis, MN 554011993	Paper Service	Yes	OFF_SL_11-1076_11-1076
George	Crocker	gwillc@nawo.org	North American Water Office	PO Box 174 Lake Elmo, MN 55042	Paper Service	No	OFF_SL_11-1076_11-1076

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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