

Direct Testimony and Schedules
Jeffrey C. Robinson

Before the North Dakota Public Service Commission
State of North Dakota

In the Matter of the Application of Northern States Power Company,
a Minnesota corporation and wholly owned subsidiary of Xcel Energy Inc.
For Authority to Increase Rates for
Natural Gas Service in North Dakota

Case No. PU-06-____
Exhibit____

**Overall Revenue Requirements
Rate Base
Income Statement**

December 15, 2006

Table of Contents

I.	Introduction and Qualifications	1
II.	Data Provided and Selection of Test Year	2
III.	Test Year Budget Development	5
IV.	Test Year Revenue Deficiency	9
V.	Jurisdictional Cost of Service Study	15
VI.	Utility and Jurisdictional Allocations	18
VII.	Rate Base Components	23
VIII.	Net Utility Plant	24
IX.	Construction Work in Progress	25
X.	Accumulated Deferred Income Taxes	26
XI.	Other Rate Base	27
XII.	Income Statement	31
XIII.	Operating and Maintenance Expenses	33
XIV.	Advertising Adjustment	34
XV.	Depreciation Expense	34
XVI.	Charitable Contributions	34
XVII.	Incentive Comp	35
XVIII.	Rate Case Expense	35
XIX.	Lobbying Expenses	36
XX.	Customer Deposits	36
XXI.	Association Dues	36
XXII.	Demand Side Management	37
XXIII.	Economic Development	37
XXIV.	Conclusion	37

I. INTRODUCTION AND QUALIFICATIONS

1
2
3 Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

4 A. My name is Jeffrey C. Robinson. My business address is 414 Nicollet Mall,
5 Minneapolis, Minnesota 55401.
6

7 Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT POSITION?

8 A. I am the Manager of Revenue Analysis for Xcel Energy Services Inc. (“XES”
9 or the “Service Company”). My resume is included as Exhibit____(JCR-1),
10 Schedule 1.
11

12 Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE.

13 A. I have over thirty-four years of employment experience with Northern States
14 Power Company, a Minnesota corporation and wholly owned subsidiary of
15 Xcel Energy Inc. (“Xcel Energy” or the “Company”). I have an extensive
16 background in matters that concern the capital invested in utility property. I
17 have held management positions in the areas of Depreciation Services,
18 Depreciation & Nuclear Fuel Accounting, Corporate Economics &
19 Depreciation, and Capital Asset Accounting. I have been in my present
20 Revenue Analysis management position since 1994. I am responsible for the
21 general administration of the Revenue Analysis area and for the preparation
22 and presentation of cost of service studies, revenue requirement
23 determinations and jurisdictional annual reports for electric and gas utility
24 operations filed with the North Dakota Public Service Commission
25 (“NDPSC” or the “Commission”), the Minnesota Public Utilities
26 Commission (“MPUC”), the South Dakota Public Utilities Commission, and
27 the Federal Energy Regulatory Commission (“FERC”).

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Q. FOR WHOM ARE YOU TESTIFYING?

A. I am testifying on behalf of Northern States Power Company, a Minnesota corporation and wholly owned subsidiary of Xcel Energy Inc., the utility operating company subsidiary providing natural gas and electric service in North Dakota (“Xcel Energy” or the “Company”).

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I will provide testimony supporting the Company’s financial data and its Notice of Change in Rates for Natural Gas Service (the “Notice”) for the State of North Dakota retail natural gas jurisdiction. My testimony addresses the North Dakota jurisdiction’s retail gas operations’ overall retail revenue requirement of \$95,845,000 and revenue deficiency of \$2,801,000, determined by the cost of service for the 2007 budget test year.

Q. WERE THE SCHEDULES PRESENTED WITH YOUR TESTIMONY PREPARED BY YOU OR UNDER YOUR SUPERVISION?

A. Yes they were.

II. DATA PROVIDED AND SELECTION OF TEST YEAR

Q. PLEASE DEFINE THE FISCAL PERIODS FOR WHICH FINANCIAL DATA IS PROVIDED IN THIS PROCEEDING.

A. Financial data is provided for the most recent fiscal year, that being calendar year 2005, and the test year selected, calendar year 2007.

1 Financial data for the most recent fiscal year and the test year are adjusted for
2 traditional regulatory adjustments (*e.g.* charitable donations, organizational
3 dues, etc.). The test year on which the Notice is based starts with financial
4 data included in the Company's 2007 projected fiscal year budget, and then
5 includes ratemaking adjustments deemed necessary along with refinements
6 and corrections to 2007 budgeted data made to assure the appropriateness for
7 purposes of developing a test year that provides a normalized level of rate
8 base and expenses to establish just and reasonable rates. Separate rate base
9 and income statement bridge schedules that identify test period adjustments
10 are provided with my testimony as Exhibit____(JCR-1), Schedule 5.
11

12 Q. HOW DID THE COMPANY SELECT THE PROPOSED TEST YEAR FOR THIS
13 PROCEEDING?

14 A. Calendar year 2007 was selected as the test year for this filing using Xcel
15 Energy's first-year budget data. The test year is based on the most recent
16 available budget information that is deemed appropriate for ratemaking
17 purposes.
18

19 Q. DOES THE 2007 PROJECTED TEST YEAR MEET THE COMMISSION'S
20 REQUIREMENTS?

21 A. Yes. The use of a projected test year is consistent with the intent of North
22 Dakota Century Code ("NDCC") § 49-04-04.1, subd. 2, requires the
23 Company to present:

- 24 (a) a comparison of forecast data to historical period data to demonstrate
25 the reliability and accuracy of the utility's forecast including a
26 comparison of the prior years' forecast or budgeted data to actual
27 data for those periods;

1 (b) a statement that the test year budget data is reasonable, reliable, and
2 made in good faith and all basic assumptions used in making or
3 supporting the forecast are reasonable, evaluated, identified, and
4 justified to allow the commission to test the appropriateness of the
5 forecast; and

6 (c) the accounting treatment applied to anticipated events and
7 transactions in the budget is the same as the accounting treatment to
8 be applied in recording the events once they have occurred.

9
10 I provide a comparison of past budgets to actual costs later in my testimony
11 in compliance with the first requirement of this rule. The 2007 Company
12 budget data, as adjusted for the known and measurable changes discussed
13 below, is a reasonable representation of the costs and rate case expense the
14 Company will incur to provide natural gas service in the State of North
15 Dakota, and complies with NDCC § 49-05-04.1, subd. 2. Thus, the 2007
16 test year data is reasonable and appropriate for setting rates in this
17 proceeding. In addition, the accounting treatment applied to anticipated
18 events and transactions in the budget is the same as the accounting
19 treatment applied in recording the events once they have occurred.

20
21 Q. NDCC § 49-05-04.1, Subd. 1(b) REQUIRES A UTILITY TO FILE “HISTORIC
22 PERIOD” DATA. HOW IS XCEL ENERGY COMPLYING WITH THIS
23 REQUIREMENT?

24 A. Schedule 2 to my testimony is the Company's 2005 actual jurisdictional
25 summary data underlying the financial statements in our May 1, 2006
26 jurisdictional annual report filed with the Commission.

27

1
2 **III. TEST YEAR BUDGET DEVELOPMENT**
3

4 Q. DESCRIBE THE TEST YEAR BUDGET PROCESS.

5 A. The budgeting process for the 2007 test year began in late April 2006 with the
6 issuing of Budget Guidelines and Instructions to the various business areas
7 about the 2007 budget preparation. The test year budget is assembled
8 separately by its various components: Sales Forecast (customers and
9 consumption), Retail and Other Revenues, Cost of Gas Supplied, Operating
10 and Maintenance (“O&M”) Expenses, Capital Invested, Other Rate Base
11 Investment and Capital Structure Components. The various budgets are
12 submitted to the Finance Council for review. All final O&M, labor and
13 capital expenditure budgets are submitted to the Board of Directors for
14 review and approval. Management will use the final budget, as approved, to
15 monitor and manage the Company’s operations and financial performance
16 during 2007.

17
18 Q. DESCRIBE HOW COSTS FOR THE NORTH DAKOTA JURISDICTIONAL GAS
19 OPERATIONS ARE DEVELOPED IN THE BUDGET PROCESS.

20 A. Costs from the Service Company are typically either directly assigned or
21 allocated to the particular Xcel Energy operating company (here “NSP”) and
22 then further assigned or allocated to specific utility operations and
23 jurisdiction.

24
25 Each business area is responsible for appropriate FERC designation of its
26 budgeted O&M dollars. Accounting codes in the J.D. Edwards (“JDE”)
27 accounting system determine the FERC account to which budgeted costs
28 apply. Each JDE business unit description contains the necessary

1 information to determine the appropriate FERC account classification. In
2 addition, the business areas are responsible for including a location code
3 where appropriate. This information helps facilitate appropriate utility and
4 jurisdictional cost assignment.

5
6 Q. YOU MENTIONED THAT YOU MADE ADJUSTMENTS TO THE 2007 BUDGET FOR
7 CERTAIN TRADITIONAL REGULATORY ADJUSTMENTS. PLEASE DESCRIBE
8 THESE ADJUSTMENTS.

9 A. I made the following adjustments to the 2007 Budget to comply with the
10 traditional regulatory adjustments made by the Commission. Those
11 adjustments are:

- 12 1) Charitable Contributions
- 13 2) Advertising Expenses
- 14 3) Organizational Dues
- 15 4) Tax Benefit Transfer Leases
- 16 5) Interest on Customer Deposits

17
18 Q. DID YOUR ANALYSIS OF THE REVENUES, O&M, LABOR AND CAPITAL
19 BUDGETS REQUIRE THAT ADDITIONAL ADJUSTMENTS BE MADE TO OBTAIN A
20 TEST YEAR BUDGET FOR RATE CASE PRESENTATION?

21 A. Yes. As part of the preparation of any rate case, an additional level of internal
22 review of budget data is undertaken. The underlying financial operation and
23 capital data was scrutinized for anomalies and errors. During the process of
24 evaluating the data, a minor coding error was discovered which resulted in the
25 misclassification of labor loading dollars from one business area (Nuclear
26 Management Corporation, Pension & Benefits). Dollar cost amounts that
27 should have been identified as electric utility costs were instead assigned to

1 the common utility. This resulted in an inappropriate allocation of these costs
2 to the Company's natural gas utility operations. To correct this error, \$13,000
3 was removed from test year administrative and general costs. In addition,
4 when reviewing other operating revenues, it was determined that the budgeted
5 revenue level for customer connect charges was overstated and in error. To
6 correct for this, a historic 5-year average was used to determine an
7 appropriate level, which resulted in an \$82,000 downward adjustment. A list
8 of the traditional regulatory adjustments and these data review adjustments is
9 included in Exhibit____(JCR-1), Schedule 3.

10
11 Q. ONCE YOU COMPLETED THESE INITIAL ADJUSTMENTS TO THE BUDGET BASE
12 DATA, DID YOU FURTHER ADJUST THE BASE DATA TO DEVELOP THE TEST
13 YEAR?

14 A. Yes. I made a number of test period adjustments that affected either the rate
15 base or the income statement. A list of these test period adjustments is
16 shown on Exhibit____(JCR-1), Schedule 4. I will also discuss each
17 adjustment later in my testimony. In addition, I have provided a bridge
18 schedule (Exhibit____(JCR-1), Schedule 5) that shows all adjustments
19 included in Exhibit____(JCR-1), Schedule 3 and Exhibit____(JCR-1), Schedule
20 4.

21
22 Q. PLEASE DESCRIBE WHETHER THE COMPANY'S BUDGETING PROCESS IS
23 CONSISTENT WITH PREVIOUS BUSINESS PRACTICES AND WHETHER THAT
24 PROCESS PROVIDES REASONABLE RESULTS?

25 A. The budgeting process is consistent with past business practice and has
26 provided accurate forecasts of actual costs and revenues in the past. Except
27 for the immediate post-merger period (2001-2002), over the past six years the

1 2002, these numbers varied somewhat from normal deviations due to
2 processes necessary to fully integrate post-merger information and systems.
3 The 2003 - 2005 information illustrates how the historical correlation between
4 budgeted and actual O&M expenses has been reinstated now that the merger
5 process has been completed.

6
7 Q. IS THE 2007 O&M EXPENSE BUDGET FOR THE GAS UTILITY OPERATIONS AN
8 ACCURATE AND RELIABLE PROJECTION?

9 A. Yes. With the adjustments I previously described, it is a reasonable projection
10 on which to base this request for rate relief.

11
12 Q. HAVE THERE BEEN ORGANIZATIONAL AND OTHER CHANGES THAT HAVE
13 AFFECTED THE JURISDICTIONAL ASSIGNMENTS AND ALLOCATIONS?

14 A. Yes, there has been one noticeable change related to the way in which
15 customer counts are determined for combined natural gas and electric
16 customers. This change affects how common costs are allocated to the gas
17 and electric utility operations. This change has the effect of allocating a larger
18 portion of common costs to the Company's gas utility operations (\$363,000)
19 with a corresponding reduction in the amount allocated to electric utility
20 operations. This change is discussed in greater detail later in my testimony.

21
22 There have also been some organizational changes since 2004 that change
23 which JDE accounts will incur gas utility operation costs. The wires and
24 pipes portion of Xcel Energy's Customer and Field Operations (C&FO)
25 business area, along with Government and Regulatory Affairs, is now
26 consolidated in the Company's Utility Group. Business Systems and the

1 Customer Care group of C&FO is now part of Customer Enterprise
2 Solutions.

3
4 **IV. TEST YEAR REVENUE DEFICIENCY**
5

6 Q. WHAT IS THE AMOUNT OF THE JURISDICTIONAL REVENUE REQUIREMENT FOR
7 NORTH DAKOTA?

8 A. The jurisdictional retail revenue requirement for North Dakota gas utility
9 operations is \$95,845,000 based on average rate base and projected net
10 operating income for the 2007 test year, the average capital structure, short-
11 term debt, long-term debt and 11.3 percent cost of equity capital, based on
12 the 11.32 percent return on equity recommended by Dr. Karl McDermott in
13 his Direct Testimony filed with this Notice.

14
15 Q. WHAT IS THE AMOUNT OF THE REVENUE DEFICIENCY FOR THE TEST YEAR?

16 A. The amount of the revenue deficiency for the test year is \$2,801,000. A
17 summary of the revenue deficiency is shown in Exhibit____(JCR-1), Schedule
18 7 as a comparison of the jurisdictional revenue requirement amount for the
19 test year with the forecasted revenues for the same period under present rates
20 previously approved by the Commission in Case No. PU-400-04-578. The
21 level of North Dakota retail natural gas rates must be increased by this
22 amount in order to earn an overall return on rate base of 9.24%.

23

1 Q. WHAT IS THE BASIS FOR THE COMPANY'S CAPITAL STRUCTURE AND WHAT ARE
2 THE VARIOUS COMPONENTS?

3 A. The capital structure employed in this case represents the Company's 2007
4 budgeted amounts. The costs and ratios associated with this capital structure
5 are as follows:

	<u>Rate</u>	<u>Ratio</u>	<u>Weighted Cost</u>
7 Long Term Debt	7.08%	46.41%	3.29%
8 Short Term Debt	5.81%	2.00%	0.12%
9 Common Equity	11.30%	51.59%	<u>5.83%</u>
10 Weighted Cost			9.24%

11

12 These capital structure ratios and the cost rates are based on the 2007 budget
13 for the Company's separate capital structure.

14

15 Q. IS THE COMPANY A SEPARATE CORPORATION WITH ITS OWN CAPITAL
16 STRUCTURE?

17 A. Yes. The Company is a legally separate corporation that is a wholly owned
18 subsidiary of Xcel Energy Inc. The Company is not simply a division of a
19 larger corporation. The Company has its own, separate capital structure that
20 consists of common equity, long term debt and short term debt. It has no
21 preferred stock in its capital structure.

22

23 Q. DOES THE COMPANY ISSUE ITS OWN DEBT TO THE PUBLIC?

24 A. Yes. The Company currently has approximately \$2.4 billion of separately
25 issued and publicly traded long term debt securities outstanding. The
26 Company also incurs its own short term debt.

27

1 Q. IS THE COMPANY'S SEPARATE CAPITAL STRUCTURE SIGNIFICANT TO ITS COST
2 OF DEBT?

3 A. Yes. The Company files annual and quarterly 10K and 10Q statements
4 with the Securities and Exchange Commission ("SEC"). These SEC filings
5 disclose and reflect the Company's actual capital structure. The Company's
6 actual capital structure is significant to its financial risk. Investors in the
7 Company's publicly traded debt securities and the credit rating agencies have
8 relied on the Company's actual capital structure, as reflected in these SEC
9 filings.

10

11 Q. HAS THE COMPANY ADJUSTED THE PROPOSED CAPITAL STRUCTURE FOR
12 PREFERRED STOCK?

13 A. No. The Company does not recommend including an adjustment to its
14 budgeted capital structure in determining its proposed revenue requirement.
15 However, the Company adjusted the capital structure used for *interim* rate
16 calculations consistent with the settlement reached in Case No. PU-400-00-
17 521.

18

19 Q. WHY HASN'T THE COMPANY INCLUDED THE PREFERRED STOCK
20 ADJUSTMENT IN DETERMINING THE REVENUE REQUIREMENT?

21 A. There has been no preferred stock in the Company's capital structure since
22 2000. The Company believes the cost of capital should be reflective of its
23 test year capital structure. Increasing debt and reducing common equity to
24 make the adjustment would lead to a mismatch to the cost of debt and
25 equity that is reflected in the Company's revenue requirement.

26

27 Q. WHY WOULD THAT LEAD TO A MISMATCH?

1 A. The cost of debt included in the Company's revenue requirement reflects
2 investors' evaluation of the Company's financial characteristics, including the
3 Company's actual capital structure. Adding \$105 million to long term debt
4 and subtracting the same amount from common equity overstates the debt
5 ratio and understates the common equity ratio, increasing financial leverage.
6 This increased financial leverage increases the financial risk of the Company.
7 Therefore, both the cost of debt and equity should be adjusted upwards to
8 reflect the increased financial risk. Not including an increase in both the cost
9 of debt and equity would be a mismatch to the adjustment to the capital
10 structure.

11

12 Q. WHAT IS THE PERCENTAGE INCREASE IN REVENUES PROPOSED IN THIS CASE?

13 A. The revenue deficiency amount represents a 3.0 percent overall increase in
14 retail revenues compared to projected retail revenues at present rates.

15

16 Q. DID YOU PREPARE A COST OF SERVICE STUDY THAT SUPPORTS THE REVENUE
17 REQUIREMENT AMOUNT AND REVENUE DEFICIENCY FOR THE TEST YEAR?

18 A. Yes, under my direction, a cost of service study was prepared.
19 Exhibit__(JCR-1), Schedule 8 contains a copy of the jurisdictional cost of
20 service study.

21

22 Q. WHAT ARE THE MAJOR CAUSES OF THE COMPANY'S NEED FOR RATE RELIEF?

23 A. A summary of the cost elements to which the revenue deficiency can be
24 attributed is provided in Exhibit__(JCR-1), Schedule 9. The major cost
25 elements driving the revenue deficiency are related to: 1) the capital recovery
26 requirements associated with the additional rate base investments made since
27 the Company's last general rate increase; 2) higher overall cost of capital; 3)

1 increases in operating and maintenance costs due to refined jurisdictional cost
2 assignments, inflation, wage increases, higher incidence of uncollectible bills;
3 and 4) new natural gas demand side management (“DSM”) (conservation)
4 program costs.

5
6 Q. WHAT ARE THE ELEMENTS OF CAPITAL RECOVERY?

7 A. The elements of capital recovery are depreciation, which is the ratable return
8 of investment over its estimated service life, return on investment and related
9 income taxes. Depreciation expense has increased by \$118,000 since the
10 Company's last natural gas rate case. This expense is driven by the increase in
11 utility plant investment, including information systems investment allocated to
12 the Company's gas utility operations. Since the last natural gas rate
13 proceeding, utility plant in-service investment in North Dakota has increased
14 by over \$8.9 million. Later in my testimony I will discuss the specifics related
15 to changes in the average rate base investment since the 2004 natural gas rate
16 case test year.

17
18 Q. ARE THERE OTHER COST ELEMENTS RELATED TO THE AMOUNT OF UTILITY
19 PLANT IN-SERVICE INVESTMENT?

20 A. Yes. Real estate and personal property taxes are directly related to utility plant
21 in-service investment. Increases in real estate and personal property taxes
22 result from additional investment in plant and facilities and from higher
23 assessment levels by taxing authorities. As a result, the revenue requirement
24 for real estate and property taxes has increased by \$155,000 since the last
25 natural gas rate case test year.

26

1 Q. PLEASE DISCUSS THE COMPONENTS OF THE CALCULATION OF “NET SALES
2 GROWTH” SHOWN ON EXHIBIT____(JCR-1), SCHEDULE 9, PAGE 1, LINE 9.

3 A. Simply defined, the line item shows the change in the gross operating income
4 from the 2004 test period to the 2007 test period. While the number of
5 commercial natural gas customers in North Dakota has increased by 243 since
6 the 2004 test year (or 3.8 percent), the underlying dekatherm use per
7 commercial customer has decreased slightly. Combined with Residential
8 margins (which are unaffected by usage declines), the net result is an increase
9 in gross operating income that only partially offsets the increasing costs of
10 operations.

11

12 Gross operating income is calculated by subtracting from total revenue the
13 cost of natural gas, city franchise fees and the Grand Forks Manufactured Gas
14 Plant (“MGP”) clean-up cost amortization included in the Cost of Gas
15 adjustment.

16

17 Q. PLEASE DISCUSS THE COST ELEMENTS OF THE REVENUE DEFICIENCY RELATED
18 TO OPERATING EXPENSES.

19 A. Exhibit____(JCR-1), Schedule 9, Page 2 of 2, shows a summary of the change
20 in operating expenses by functional class over the three-year span between the
21 2004 rate case test period in Case No. PU-400-04-578, and the 2007 test
22 period in this case. The schedule also shows a calculation of the average
23 annual percent of increase over the same period.

24

25 Q. ARE THE FUNCTIONAL CLASS CATEGORIES OF OPERATING EXPENSE
26 COMPARABLE BETWEEN THE 2007 TEST YEAR BUDGET AND THOSE
27 CONTAINED IN CASE NO. PU-400-04-578?

1 A. Yes. Budget accounts for both periods conform to the FERC Uniform
2 System of Accounts.

3

4 Q. DO YOU INCLUDE COMPARISONS OF THE CHANGE IN THE PURCHASED COST OF
5 GAS AS PART OF THE O&M EXPENSE ANALYSIS?

6 A. No. Although the cost of purchased gas is considered to be an operating
7 expense, recovery occurs through the cost of gas adjustment (“COG”)
8 mechanism and true-up process provided in the Company's tariffs. In my
9 analysis of the cost elements of the overall revenue deficiency, I use the cost
10 of gas in the calculation of the Net Sales Growth Offset.

11

12 Q. WHAT IS THE AMOUNT OF CHANGE IN O&M COSTS SINCE THE LAST NATURAL
13 GAS RATE CASE?

14 A. Excluding the cost of gas supply, total operating expenses have increased in
15 total by \$1,700,000 since the 2004 test year. Most of this change reflects
16 higher operating and maintenance costs associated with the natural gas
17 distribution system, increased costs associated with customer accounting and
18 customer services, cost of living wage increases, inflation, and refinements to
19 jurisdictional cost assignments. Another \$164,000 is due to increases in the
20 provision for uncollectables expense. The Company is also proposing to add
21 \$138,000 for its proposed natural gas DSM program intended to help
22 residential customers reduce their energy consumption.

23

24

V. JURISDICTIONAL COST OF SERVICE STUDY

25

26 Q. PLEASE DESCRIBE THE COMPONENTS OF THE JURISDICTIONAL COST OF
27 SERVICE STUDY FOR THE TEST YEAR.

1 A. The complete jurisdictional cost of service is included in my testimony at
2 Exhibit____(JCR-1), Schedule 8. The jurisdictional cost of service includes:
3 capital structure, cost of capital, income tax rates, rate base, income statement,
4 income tax calculations and a cash working capital computation.
5

6 Q. PLEASE DESCRIBE THE JURISDICTIONAL COST OF SERVICE SUMMARY
7 SCHEDULES.

8 A. The summary of the jurisdictional cost of service consists of Schedule 7 and
9 Schedule 8. In Schedule 8, the cover page identifies the North Dakota Retail
10 jurisdiction target, and shows the earned return on equity in North Dakota,
11 the revenue deficiency, the percent of increase that would result if rates were
12 increased to earn the authorized or requested return on equity (in this case
13 11.3 percent). The “Rate Base Summary” for total Company natural gas
14 operations and the North Dakota jurisdiction is shown on Schedule 8, Page 2.
15 On Schedule 8, Page 3 an “Income Statement Summary” for total Company
16 natural gas operations and the North Dakota jurisdiction is shown. The
17 income statement shows the determination of total operating income at
18 present authorized retail rates. The “Income Tax Summary” for total
19 Company natural gas operations and the North Dakota jurisdiction is shown
20 on Schedule 8, Page 4. The schedule shows adjustments to book income
21 necessary to determine state and federal taxable income. The federal and
22 state income tax calculations are carried back to the income statement on
23 Schedule 8, Page 3. The computation of cash working capital, Schedule 8,
24 Page 6, is carried back to the rate base on Schedule 8, Page 2. Schedule 8,
25 Page 5 shows the “Revenue Requirement and Return Summary” for total
26 Company natural gas operations and the North Dakota jurisdiction.
27 Specifically, the schedule shows the calculated earned overall rate of return on

1 rate base, calculated earned rate of return on common stock equity capital, the
2 revenue deficiency that needs to be recovered to enable the North Dakota
3 jurisdiction gas operations to earn the requested return on common equity
4 and finally, the total revenue requirements and the percent of increase that
5 would result by increasing retail billing rates by the amount of the revenue
6 deficiency.

7
8 Q. ARE THE REVENUE CONVERSION FACTOR CALCULATION AND THE COMPOSITE
9 INCOME TAX RATES INCLUDED IN THIS FILING?

10 A. Yes. The revenue conversion factor calculation is included in my exhibits at
11 Exhibit____(JCR-1), Schedule 10.

12
13 Q. PLEASE EXPLAIN HOW THE INTEREST DEDUCTION FOR DETERMINING
14 TAXABLE INCOME IS CALCULATED.

15 A. The interest deduction applicable to the income tax calculation is the result of
16 a calculation commonly referred to as interest synchronization. The amount
17 of interest deducted for income tax purposes is the weighted cost of debt
18 capital multiplied by the average rate base.

19
20 Q. DESCRIBE THE SCHEDULE IN YOUR EXHIBIT THAT IS RELATED TO THE INCOME
21 STATEMENT.

22 A. Exhibit____(JCR-1), Schedule 11 relates to the income statement.

23
24 Q. PLEASE IDENTIFY THE CONTENTS OF EXHIBIT____(JCR-1), SCHEDULE 11.

25 A. Exhibit____(JCR-1) Schedule 11, Page 1 of 2, is a comparative income
26 statement for the 2007 test year showing the income effect of present
27 authorized rates and proposed rates. This comparative income statement was

1 prepared from the results of the jurisdictional cost of service study and
2 includes the revenue deficiency in the North Dakota jurisdiction natural gas
3 utility operations. Schedule 11, Page 2 of 2, shows a gas utility comparative
4 income statement for the North Dakota jurisdiction and total company for
5 the 2007 test year before making test period adjustments. The operating
6 income statement after making the proposed test period adjustments is also
7 shown on Page 2 of 2.

8
9 **VI. UTILITY AND JURISDICTIONAL ALLOCATIONS**

10
11 Q. PLEASE DESCRIBE THE METHODS USED TO ALLOCATE COSTS TO THE
12 COMPANY'S GAS UTILITY OPERATIONS.

13 A. The test year includes both costs incurred directly by the Company's gas
14 operating business and costs directly assigned or allocated by the Service
15 Company for corporate functions (*e.g.*, accounting, human resources, law,
16 etc.). The XES cost allocation and billing process is subject to FERC
17 jurisdiction and authorization under a Utility Services Agreement between
18 NSP and XES. O&M cost assignments and allocations were the same as used
19 by the Company in the recent Minnesota gas rate case filed with the MPUC
20 (MPUC Docket No. G002/GR-06-1429). Non-O&M costs include such
21 items as book depreciation expense, deferred income taxes and property
22 taxes. All of the common investments and their related costs, be it software
23 or other common investments and expenses, are evaluated as to whether the
24 cost should be direct assigned to Electric or Gas, or allocated based on
25 appropriate allocators such as: Customers, Customer Bills, Transportation
26 Studies, or the Three Factor allocator (the average of Revenue Ratio,
27 Employee Ratio, and Asset Ratio) used to allocate O&M expenses to utility.

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Q. PLEASE DESCRIBE THE METHODS USED TO ALLOCATE COSTS FOR THE COMPANY'S NATURAL GAS UTILITY OPERATIONS IN NORTH DAKOTA.

A. O&M cost assignments and allocations are summarized on Exhibit____(JCR-1) Schedule 12.

The expense budgets relied upon to develop test year income statement items were generally prepared on a functional basis (*i.e.*, Production, Transmission, Distribution, Customer Accounts, Customer Information, Sales, Administrative and General). These functional amounts are directly assigned to North Dakota jurisdiction gas operations or allocated to the gas operations based on cost causation.

Q. PLEASE EXPLAIN THE PROCESS FOR ASSIGNING THE COMPANY'S INVESTMENT IN GAS PLANT TO THE NORTH DAKOTA JURISDICTION.

A. A summary and description of the allocation factors used to allocate expenses and capital items to the North Dakota jurisdictional gas operations income statement and rate base is contained in Exhibit____(JCR-1) Schedule 13. Plant investments are accounted for in the manner prescribed by the FERC Uniform System of Accounts. Detailed records are maintained on a functional basis (*i.e.* Production, Storage, Transmission, Distribution, etc.). The capital budgets, from which the projected plant balances in rate base were developed, are also prepared on a functional basis. These functional amounts are assigned to the appropriate jurisdiction directly, or allocated based on the use of such assets in providing gas service in a particular jurisdiction and the underlying elements of cost causation.

1 Q. PLEASE EXPLAIN THE NEED FOR JURISDICTIONALLY ALLOCATING THE
2 INVESTMENT IN PRODUCTION, STORAGE AND TRANSMISSION FACILITIES.

3 A. The Company's production (*e.g.*, liquefied natural gas or liquefied propane
4 gas), storage and transmission system is designed, built, and operated to
5 provide an integrated source of natural gas shared by the Company's gas
6 customers in Minnesota and North Dakota. To determine the level of
7 investment associated with the provision of gas service to North Dakota
8 retail customers, it is necessary to assign or allocate a portion of the total
9 production, storage, and transmission investment to each jurisdiction.
10

11 Q. HOW WERE THE COMPANY'S GAS PRODUCTION, STORAGE AND TRANSMISSION
12 SYSTEM INVESTMENT AMOUNTS ALLOCATED TO THE NORTH DAKOTA
13 JURISDICTION IN THIS CASE?

14 A. The North Dakota jurisdiction's share of the projected system design day
15 peak demands for the test year was used to allocate the capital investment
16 costs. It is reasonable to use design day demand as an allocator because these
17 facilities are designed to meet peak firm customer requirements. This is also
18 consistent with the methodology accepted in the last three North Dakota
19 natural gas rate cases (Case Nos. PU-400-95-559, PU-400-00-521, and PU-
20 400-04-578). The 2006-07 heating season design day demand factors used in
21 this jurisdictional allocation process are consistent with the Company's annual
22 gas supply planning process.
23

24 Q. WHAT IS THE DESIGN DAY?

25 A. The design day is the coldest average 24-hour period recorded for the total
26 company gas service area. The Company designs its natural gas distribution
27 systems and contracts for natural gas supplies, transportation, storage and

1 peak shaving to meet the supply needs of firm customers under design day
2 conditions. The design day allocation method uses the jurisdictional specific
3 design day demands to assigns costs to the jurisdictional customer group on a
4 basis of gas service needs that cause the need for these facilities and supplies.
5

6 Q. HOW WERE THE DISTRIBUTION INVESTMENT AMOUNTS ASSIGNED TO THE
7 NORTH DAKOTA JURISDICTION?

8 A. The Company's natural gas distribution plant investment amounts have been
9 directly assigned based upon the jurisdiction(s) served by each of the
10 individual distribution facilities.
11

12 Q. IS THE 2007 TEST YEAR RATE BASE FOR THE XCEL ENERGY – NORTH DAKOTA
13 JURISDICTION GAS OPERATIONS REASONABLE FOR PURPOSES OF
14 DETERMINING FINAL RATES IN THIS PROCEEDING?

15 A. Yes. The test year rate base was developed on sound ratemaking principles in
16 a manner similar to prior Company natural gas rate cases.
17

18 Q. ARE THERE ANY AREAS WHERE NSP CHANGED THE BASIS FOR ALLOCATIONS?

19 A. Yes. As I previously explained, we changed the basis for the customer
20 allocator. The NSP general ledger system allocates common customer O&M
21 costs using a customer bill ratio. In the Company's previous natural gas rate
22 case (PU-400-04-578), the data for the utility allocation factor used to allocate
23 common (to both electric and gas) customer related O&M costs (FERC 901
24 through 917) was 2004 actual customer bill counts provided by the CSS
25 customer billing system. In the CSS billing system, a customer that is both an
26 electric and gas customer was counted as 1/2 electric customer bill, and 1/2

1 gas customer bill. The resulting ratios used in the 2004 budget data, which
2 was the basis for our 2004 gas rate case, were 81.44% electric and 18.56% gas.

3
4 Starting in February of 2005, Xcel Energy implemented a new customer
5 billing system, the Customer Resource System (“CRS”). The new system
6 calculates customer bill counts differently than the previous CSS system. In
7 the new system a customer who is both an electric and gas customer, would
8 count as 1 electric customer bill and 1 gas customer bill. By making this
9 change in methodology, Xcel Energy is now counting customer bills
10 consistently across all of its jurisdictions. As a result, the new customer bill
11 utility ratios, developed from 2005 actual customer bill counts, have shifted.
12 The new customer bill utility allocation ratios are 76.07% electric and 23.93%
13 gas. This new utility allocator was used to allocate the 2006 actual O&M
14 expenses and in the development of the 2007 O&M budget. The new
15 allocation factor shifts \$3.5 million in certain Company Customer Accounting,
16 Customer Information, and Sales costs from the electric utility to the gas
17 utility. The impact to the North Dakota jurisdiction is that \$363,000 of costs
18 shift from electric to natural gas utility operations for the 2007 test year.

19
20 Q. WOULD YOU PLEASE DESCRIBE HOW THE IMPACT TO NORTH DAKOTA WAS
21 CALCULATED?

22 A. We first identified all common O&M expenses in FERC accounts between
23 901 and 917, (customer accounting, customer information and sales) that
24 were assigned to gas using the customer bill allocator. The total of these
25 costs were multiplied by the difference between the previous gas utility factor
26 (18.56%) and the new factor (23.93)%.

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VII. RATE BASE COMPONENTS

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- Q. PLEASE EXPLAIN WHAT RATE BASE REPRESENTS.
- A. Rate base primarily reflects the capital expenditures made by a utility to secure plant, equipment, materials, supplies and other assets necessary for the provision of utility service, reduced by amounts recovered from depreciation and non-investor sources of capital.
- Q. PLEASE IDENTIFY THE MAJOR COMPONENTS OF THE PROJECTED TEST YEAR RATE BASE.
- A. The test year rate base is generally comprised of the following major items which will be described in further detail later in my testimony:
- Net Utility Plant
 - Short-term Construction Work in Progress
 - Accumulated Deferred Income Taxes
 - Other Rate Base Items
- Q. PLEASE DESCRIBE THE SCHEDULES IN YOUR EXHIBIT THAT ARE RELATED TO THE TEST YEAR AVERAGE INVESTMENT IN RATE BASE.
- A. Exhibit____(JCR-1), Schedule 14, Page 1 of 2, shows a detailed statement of the Average Rate Base by component for the 2007 Test Year. Schedule 14, Page 2 of 2, is a comparative statement of the 2007 Test Year Average Rate Base for the North Dakota jurisdiction and total company, before and after making proposed test period adjustments. Exhibit____(JCR-1), Schedule 2, page 2 shows the Company's actual 2005 Average Rate Base as provided in the May 1, 2006 jurisdictional annual report to the Commission.

VIII. NET UTILITY PLANT

1

2

3 Q. WHAT DOES NET UTILITY PLANT REPRESENT?

4 A. Net utility plant represents the Company's investment in plant and equipment
5 that is used and useful in providing retail natural gas service to its customers,
6 net of accumulated depreciation and amortization.

7

8 Q. PLEASE EXPLAIN THE METHOD USED TO CALCULATE NET UTILITY PLANT
9 INVESTMENT IN THIS CASE.

10 A. The net utility plant is included in rate base at depreciated original cost
11 reflecting the simple average of projected net plant balances at the beginning
12 and end of the test year. Such treatment is consistent with the method
13 employed in the most recent North Dakota natural gas rate case, Case No.
14 PU-400-04-578.

15

16 Q. WHAT HISTORICAL BASE DID NSP RELY ON AS A STARTING POINT TO DEVELOP
17 THE PROJECTED NET PLANT BALANCES FOR THE BEGINNING OF THE TEST
18 YEAR?

19 A. The historical base used was Xcel Energy's actual net investment (Plant in
20 Service less Accumulated Depreciation) on the books and records of the
21 Company as of May 31, 2006.

22

23 Q. ON WHAT BASIS WERE NET PLANT BALANCES PROJECTED FOR THE END OF THE
24 TEST YEAR?

25 A. The ending net plant balances were determined by applying the data
26 contained in the 2007 capital budget to the above-described beginning test

1 year balances adjusted for retirements, depreciation, salvage and removal costs
2 projected to occur during the test year.

3
4 Q. WHAT WAS THE AVERAGE NET UTILITY PLANT INCLUDED IN THE TEST YEAR
5 RATE BASE?

6 A. The average net utility plant included in the test year rate base is \$45,457,000,
7 as shown on Exhibit____(JCR-1), Schedule 8, Page 2. This is comprised of an
8 average plant balance of \$83,952,000 as detailed on Exhibit____(JCR-1),
9 Schedule 14, Page 1, minus an average depreciation reserve of \$38,495,000,
10 also shown by component on Exhibit____(JCR-1), Schedule 14, Page 1.

11
12 **IX. CONSTRUCTION WORK IN PROGRESS**

13
14 Q. HAS CONSTRUCTION WORK IN PROGRESS ("CWIP") BEEN INCLUDED IN THE
15 TEST YEAR RATE BASE?

16 A. Yes. The only CWIP that is included in rate base are costs related to projects
17 of a short-duration that do not accrue Allowance for Funds Used During
18 Construction ("AFUDC"). Thus, there is no AFUDC offset added to
19 operating income. The rate base amount reflects a simple average of
20 projected CWIP beginning and ending test year balances. This is consistent
21 with the method employed in the most recent North Dakota natural gas rate
22 case (Case No. PU-400-04-578) and matches the use of an average rate base.

23
24 Q. HOW WERE THE TEST YEAR BEGINNING AND ENDING CWIP BALANCES
25 DETERMINED?

26 A. The beginning test year balance for CWIP was the May 31, 2006 historical
27 balance. The beginning test year CWIP balance was adjusted to reflect

1 projected construction expenditures, and transfers to Plant in Service during
2 the 2007 test year to obtain the ending test year CWIP balance. These
3 projections were developed from the Company's 2007 capital budget.

4
5 Q. WHAT WAS THE LEVEL OF SHORT-TERM CWIP INCLUDED IN THE TEST YEAR
6 RATE BASE?

7 A. As shown on Exhibit____(JCR-1), Schedule 8, Page 2, the average short-term
8 CWIP included in rate base was \$33,000.

9
10 **X. ACCUMULATED DEFERRED INCOME TAXES**

11
12 Q. PLEASE DESCRIBE ACCUMULATED DEFERRED INCOME TAXES ("ADIT").

13 A. Inter-period differences exist between the book and taxable income treatment
14 of certain accounting transactions. These differences typically originate in
15 one period and reverse in one or more subsequent periods. For utilities, the
16 largest such timing difference typically is the extent to which accelerated tax
17 depreciation generally exceeds book depreciation during the early years of an
18 asset's service life. ADIT represents the cumulative net deferred tax amounts
19 that have been allowed and recovered in rates in previous periods.

20
21 Q. WHY ARE ACCUMULATED DEFERRED INCOME TAXES DEDUCTED IN ARRIVING
22 AT TOTAL RATE BASE?

23 A. To the extent deferred income taxes have been allowed for recovery in rates,
24 they represent a non-investor source of funds. Accordingly, the average
25 projected ADIT balance is deducted in arriving at total rate base to recognize
26 such funds are available for corporate use between the time they are collected
27 in rates and ultimately remitted to the respective taxing authorities.

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Q. WHAT AMOUNT OF ADIT WAS DEDUCTED IN THE PROJECTED TEST YEAR RATE BASE?

A. As shown on Exhibit____(JCR-1), Schedule 8, Page 2, \$6,931,000 was deducted. This amount reflects a simple average of the beginning and projected ending test year ADIT balances.

XI. OTHER RATE BASE

Q. PLEASE SUMMARIZE THE ITEMS YOU HAVE INCLUDED IN OTHER RATE BASE.

A. Other Rate Base is comprised of primarily what is referred to as Working Capital. It also includes certain unamortized balances that are the result of specific ratemaking amortizations as discussed further in my testimony.

Q. PLEASE EXPLAIN WHAT WORKING CAPITAL REPRESENTS.

A. Working Capital is the average investment in excess of net utility plant provided by investors that is required to provide day-to-day utility service. It includes items such as materials and supplies, gas in storage, prepayments, and various non-plant assets and liabilities. The net cash requirements, also referred to as Cash Working Capital, is shown separately.

Q. HOW HAVE TEST YEAR MATERIALS AND SUPPLIES AND GAS IN STORAGE REQUIREMENTS BEEN CALCULATED?

A. The Materials and Supplies and Gas in Storage amounts shown on Exhibit____(JCR-1), Schedule 8, Page 2, are based on the thirteen-month average balances projected during the test year. Materials and Supplies

1 average balance included in the test year rate base equals \$168,000. The test
2 year average rate base amount for Gas in Storage is \$5,781,000.

3
4 Q. HOW HAVE THE TEST YEAR NON-PLANT ASSETS & LIABILITIES BEEN
5 DETERMINED?

6 A. These balances as shown on Exhibit____(JCR-1), Schedule 8, Page 2, represent
7 the 2007 calendar year estimate of these balances. Any book/tax timing
8 differences associated with these items has been reflected in the
9 determination of current and deferred income tax provision and accumulated
10 deferred tax balances previously discussed. This group is primarily comprised
11 of liabilities that reduce test year rate base by \$1,082,000.

12
13 Q. HOW HAVE THE TEST YEAR PREPAYMENTS AND OTHER WORKING CAPITAL
14 ITEMS BEEN DETERMINED?

15 A. Items of Prepayments and Other Working Capital such as customer advances
16 and deposits, are based on the actual thirteen-month average balances during
17 the period ended May 31, 2006, as a proxy for the test year. The unamortized
18 balances included in this section are based on the amortization schedules as
19 described later in my testimony on revenue requirements. The net impact of
20 these various items increase test year rate base by \$2,749,000 as shown on
21 Exhibit____(JCR-1), Schedule 8, Page 2.

22
23 Q. HAVE YOU INCLUDED THE UNAMORTIZED BALANCE FOR MANUFACTURED GAS
24 PLANT REMEDIATION COSTS?

25 A. Yes. We included the unamortized balance of the Manufactured Gas Plant
26 clean-up costs approved in our last natural gas rate case (Case No. PU-400-04-
27 528). See Exhibit____(JCR-1), Schedule 5, page 2 of 2.

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Q. HOW HAVE THE TEST YEAR CASH WORKING CAPITAL REQUIREMENTS BEEN DETERMINED?

A. Cash Working Capital requirements have been determined by applying the results of a comprehensive lead/lag study to the projected test year revenues and expenses.

Q. HAVE THE COMPONENTS OF THE TEST YEAR CASH WORKING CAPITAL BEEN CALCULATED CONSISTENT WITH METHODS USED IN THE MOST RECENTLY APPROVED NORTH DAKOTA GAS RATE CASE (CASE NO. PU-400-04-578)?

A. Yes.

Q. PLEASE BRIEFLY EXPLAIN HOW A LEAD/LAG STUDY MEASURES CASH WORKING CAPITAL.

A. A lead/lag study is a detailed analysis of the time periods involved in the utility's receipt and disbursement of funds. The study measures the difference in days between the date services to a customer are rendered and the revenues for that service are received, and the date the costs of rendering the services are incurred until the related disbursements are actually made. A positive net revenue lag means that, on average, Xcel Energy investors have provided cash working capital, and are entitled to a return thereon.

Q. HAS XCEL ENERGY'S LEAD/LAG STUDY BEEN UPDATED SINCE THE LAST NORTH DAKOTA GAS RATE CASE (CASE NO. PU-400-04-578)?

A. Yes. In the last natural gas rate case several of the components were updated to reflect then-current experience. A new lead/lag study was filed in the recently filed Minnesota 2006 natural gas rate case (MPUC Docket No.

1 G002/GR-06-1429). The results of the new lead/lag study were
2 incorporated into the North Dakota jurisdiction cash working capital
3 calculations as shown on Exhibit____(JCR-1), Schedule 8, Page 2 and 6.
4

5 Q. WHAT IS THE TEST YEAR CASH WORKING CAPITAL AMOUNT?

6 A. The amount included in the average rate base is a positive \$456,000. The
7 components of this amount are summarized in Exhibit____(JCR-1), Schedule
8 8, Page 6.
9

10 Q. WHAT IS INDICATED BY THE POSITIVE CASH WORKING CAPITAL AMOUNT?

11 A. Positive cash working capital indicates overall revenue collections lag the date
12 when the associated costs of service are paid. This means that, on average,
13 cash working capital is being provided by the Company's investors. In the
14 Company's circumstance, taxing authorities comprise the largest source of
15 cash working capital as offsets to working capital provided by the Company's
16 investors. Other sources of offsets may include customers, creditors and
17 employees. When a positive cash working capital exists, or is required, it is
18 added to rate base to compensate the Company's investors for funds provided
19 to meet cash working capital requirements.
20

21 Q. WHAT HAVE BEEN THE MAIN REASONS FOR GROWTH IN THE GAS UTILITY
22 OPERATION'S DISTRIBUTION PLANT INVESTMENT?

23 A. First, Xcel Energy has experienced customer growth in the North Dakota
24 communities in which it provides natural gas service. Second, a significant
25 driver of natural gas distribution plant investment has been related to
26 mandated reconstruction programs where Xcel Energy is required to rebuild
27 and/or relocate its gas system as municipal infrastructure (streets, sewer and

1 water systems) is upgraded. For example, in 2004, the Company spent about
2 \$1.5 million on a gas pipeline relocation project along Main Avenue in Fargo
3 as was required to accommodate a North Dakota Department of
4 Transportation upgrade of that major thoroughfare in the northwest section
5 of the city. This project was not included in the test year in Case No. PU-
6 400-04-578. Third, Xcel Energy has extended existing facilities and provided
7 services to customers in growth areas where natural gas service was not
8 previously available.

9
10 Q. HAS THERE BEEN A NEED FOR SIGNIFICANT CAPITAL INVESTMENTS IN THE
11 PRODUCTION, STORAGE AND TRANSMISSION FUNCTIONS?

12 A. In general, the production, storage and transmission functions have not
13 required major capital improvements.

14
15 **XII. INCOME STATEMENT**
16 **REVENUES**

17
18 Q. WAS THE IMPACT OF WEATHER ON PROJECTED SALES FOR THE TEST YEAR
19 CONSIDERED?

20 A. Yes. Test year retail sales levels assume normal weather. The test year sales
21 volumes are supported by the direct testimony of Ms. Jannell Marks and the
22 adjustment on Exhibit____(JCR-1), Schedule 5, page 2 of 2 is based on her
23 testimony.

24
25 Q. DO RETAIL OPERATING REVENUES REFLECT THE PROJECTED LEVEL OF
26 UNBILLED SALES VOLUMES IN THE TEST YEAR?

1 A. Yes. This adjustment is incorporated into retail sales forecast, the effect of
2 which is to project the level of revenues on a calendar-month basis.

3

4 Q. HAS THE COMPANY MADE SIMILAR ADJUSTMENTS IN PRIOR RATE CASES TO
5 RECOGNIZE THE NET CHANGE IN UNBILLED REVENUES DURING THE TEST
6 YEAR?

7 A. Yes. The adjustment is consistent with the methodology in the last three Xcel
8 Energy North Dakota gas rate cases (Case Nos. PU-400-95-559, PU-400-04-
9 578, and PU-400-00-521).

10

11 Q. WHAT IS THE PURPOSE OF MAKING AN UNBILLED REVENUE CALCULATION IN
12 THE TEST YEAR?

13 A. The unbilled revenue calculation is used to determine the total revenue
14 requirement for gas operations in the North Dakota jurisdiction. Including
15 unbilled revenues in the determination of revenue requirements reflects a
16 proper matching of revenues with expense on a calendar year basis.

17

18 Q. HAVE YOU CONSIDERED OTHER OPERATING REVENUES AS AN OFFSET TO THE
19 RETAIL REVENUE REQUIREMENT?

20 A. Yes. The test-year includes the net margins associated with a variety of
21 services such as Limited Firm Service propane sales, late payments,
22 connection charges and direct-connect propane storage, consistent with
23 previous treatment in the 2004 gas rate case. Revenues from curtailment
24 penalties charged to retail customers, capacity release sales and sales related to
25 natural gas underground storage optimization are returned to customers
26 through the Cost of Gas adjustment annual true-up mechanism consistent
27 with Commission precedent. The Company continues to receive revenues

1 from Northern States Power Company (Wisconsin) for the joint use for the
2 Company's Supervisory Control And Data Acquisition (SCADA) System.
3

4 **XIII. OPERATING AND MAINTENANCE EXPENSES**

5 **COST OF GAS BUDGET**

6

7 Q. HOW DOES XCEL ENERGY DEVELOP ITS TEST YEAR COG BUDGET?

8 A. Normal temperatures are used to develop the sales forecast that in turn serves
9 as the basis for budgeted wholesale natural gas supply purchases.
10

11 Q. IF THERE ARE DEVIATIONS FROM THE COG BUDGET, HOW ARE CUSTOMERS
12 AFFECTED?

13 A. The Company's COG tariff mechanism automatically flows through monthly
14 supply cost changes, as well as any impact from a change in contract demand
15 entitlements. The Company formulates its heating supply plan for its North
16 Dakota and Minnesota natural gas utility operations to be dispatched as a
17 single operated system. The Company's natural gas supply plan is subject to
18 extensive review by the MPUC and Minnesota Department of Commerce
19 pursuant to MPUC rules. Applying the COG tariff in the billing process
20 seldom results in the precise recovery of the COG because there will always
21 be some over or under collection of gas costs in each jurisdiction due to
22 abnormal weather. Consequently, there is also an annual COG true-up in
23 each jurisdiction. The annual COG true-up is also used to flow through to
24 firm rate classes revenues from any pipeline capacity release sales activities.
25

1 A. Yes. The Company is proposing to include fifty percent of charitable
2 contributions attributable to the State of North Dakota in the test year.
3 Contributions made by the Company during 2005 were used as a proxy for
4 the 2007 test year. An analysis was performed on contribution detail to insure
5 that only amounts contributed to charities and institutions that could be
6 associated with the gas service territory in the North Dakota jurisdiction were
7 included in the cost of service.

8
9 **XVII. INCENTIVE COMPENSATION**

10
11 Q. PLEASE SUMMARIZE ADJUSTMENTS MADE TO THE TEST YEAR COST OF SERVICE
12 TO EXCLUDE COSTS FOR PARTS OF THE COMPANY'S ANNUAL INCENTIVE
13 COMPENSATION PROGRAMS.

14 A. Consistent with the Commission's Order in the Company's previous rate
15 cases, the test year reflects the exclusion of the long-term part of the officer's
16 incentive compensation, to remove non-corporate incentive plan costs,
17 inclusion of the target level of compensation and removal of all incentive plan
18 costs above twenty-five percent of base pay that were included at the target
19 level. The Company has also removed the amount associated with the
20 Company's Supplemental Executive Retirement Plan (SERP) consistent with
21 prior Commission practice. The determination of the incentive compensation
22 expense is shown on Exhibit____(JCR-1), Schedule 4.

23
24 **XVIII. RATE CASE EXPENSE**

25
26 Q. PLEASE EXPLAIN THE AMORTIZATION OF RATE CASE EXPENSE IN THIS
27 PROCEEDING.

1 A. The amortization includes \$50,000 of projected direct expenses associated
2 with this notice of rate change docket. Consistent with the settlement of its
3 last North Dakota natural gas rate case (Case No. PU-400-04-578), the
4 Company has used a three-year amortization period for these expenses. An
5 amount based on a three-year amortization of projected costs of \$150,000 is
6 proposed for inclusion in the cost of service with no rate base treatment of
7 the unamortized balance. Three years is reasonable because the Company
8 expects to file its next gas rate case in approximately three years.

9
10 **XIX. LOBBYING EXPENSES**

11
12 Q. HOW ARE THE COSTS OF LOBBYING ACTIVITIES TREATED IN THIS
13 APPLICATION?

14 A. Lobbying costs are recorded as non-operating expenses below-the-line and
15 are not included in the cost of service.

16
17 **XX. CUSTOMER DEPOSITS**

18
19 Q. HOW ARE CUSTOMER DEPOSITS TREATED IN THIS APPLICATION?

20 A. Customer deposits are treated as customer supplied capital and thus it is
21 appropriate to pay ratepayers a return on that investment. This adjustment is
22 reflected on Exhibit____(JCR-1), Schedule 3 and Exhibit____(JCR-1), Schedule
23 5, page 2.

24
25 **XXI. ASSOCIATION DUES**

26
27 Q. PLEASE DESCRIBE THE ORGANIZATIONAL DUES ADJUSTMENT.

1 A. Consistent with prior regulatory treatment in North Dakota, the Company has
2 reduced administrative and general expenses for either social organizations or
3 organizations not associated with the state of North Dakota. These
4 adjustments are reflected on Exhibit____(JCR-1), Schedule 3 and
5 Exhibit____(JCR-1), Schedule 5, page 2.

6
7 **XXII. DEMAND SIDE MANAGEMENT**

8
9 Q. PLEASE DESCRIBE THE ADJUSTMENT FOR NATURAL GAS DEMAND SIDE
10 MANAGEMENT (“DSM”) PROGRAM COSTS.

11 A. The Company will implement four Residential natural gas conservation
12 programs as part of an overall natural gas DSM initiative it is proposing in this
13 case. These programs are described in Ms. Debra Sundin’s testimony. The
14 costs of the DSM program are reflected on Exhibit____(JCR-1), Schedule 4
15 and Exhibit____(JCR-1), Schedule 5, page 2.

16
17 **XXIII. ECONOMIC DEVELOPMENT**

18
19 Q. PLEASE DESCRIBE THE ADJUSTMENT FOR ECONOMIC DEVELOPMENT COSTS.

20 A. An adjustment is necessary to include economic development contributions
21 recorded as below-the-line dues and donations. This adjustment is reflected
22 on Exhibit____(JCR-1), Schedule 3 and Exhibit____(JCR-1), Schedule 5.

23
24 **XXIV. CONCLUSION**

25
26 Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

27 A. Yes, it does.

STATE OF NORTH DAKOTA
BEFORE THE
PUBLIC SERVICE COMMISSION

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In the Matter of the Application of Northern)
States Power Company, a Minnesota corporation) **Notice of Change in Rates**
and wholly owned Subsidiary of Xcel Energy Inc.)
for Authority to Increase Rates For Natural Gas) Case No. PU-06-____
Service in North Dakota)

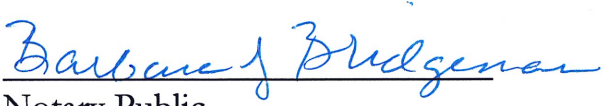
**AFFIDAVIT OF
Jeffrey C. Robinson**

I, the undersigned, being duly sworn, depose and say that the foregoing is the Direct Testimony of the undersigned, and that such Direct Testimony and the exhibits or schedules sponsored by me to the best of my knowledge, information and belief, are true, correct, accurate and complete, and I hereby adopt said testimony as if given by me in formal hearing, under oath.

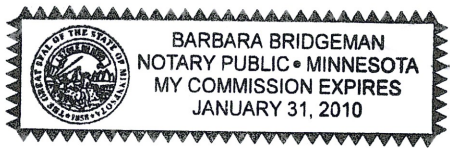


Jeffrey C. Robinson

Subscribed and sworn to before me, this 13 day of December, 2006.



Notary Public



Xcel Energy
Natural Gas Utility – State of North Dakota
Resume of Mr. Jeffrey C. Robinson

Manager
Revenue Analysis
September, 1972

Xcel Energy Services, Inc.
414 Nicollet Mall
Minneapolis, Minnesota 55401

Current Responsibilities

Since 1994, I have been the manager of Revenue Analysis. In this position I am responsible for the general administration of the Revenue Analysis area and for the preparation and presentation of cost of service studies, revenue requirement determinations and jurisdictional annual reports for electric and gas rates filed on behalf of Northern States Power Company, Minnesota, with the Minnesota Public Utilities Commission (MPUC), the North Dakota Public Service Commission, the South Dakota Public Utilities Commission and the Federal Energy Regulatory Commission (FERC).

Previous Employment (1972-1994)

Operations Analyst - NSP
Tax Depreciation Analyst - NSP
Manager, Depreciation Services - NSP
Manager, Depreciation & Nuclear Fuel Accounting - NSP
Manager, Corporate Economics and Depreciation - NSP
Manager, Capital Asset Accounting – NSP
Manager, Revenue Requirements - NSP

Education

University of Wisconsin, River Falls - Bachelor of Science
Major - Mathematics

Certifications

Certified Depreciation Professional (1997-2003)

Professional Associations and Registrations

Past Chair - Edison Electric Institute, Depreciation Accounting Committee (1984-1985)
Society of Depreciation Professionals

Articles or Papers Published or Presented

Jeffrey C. Robinson, "A Sinking Fund Approach to Nuclear Fuel Disposal Recovery," Iowa State University Regulatory Conference 1980 - Vol. 19. May 1980.

Jeffrey C. Robinson, "A Sinking Fund Approach to Nuclear Fuel Disposal Recovery," A.G.A. - EEI Depreciation Accounting Committee, Journal of Papers - Administration Year 1980 -1981, Vol. 2, June 1980.

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Jeffrey C. Robinson, "Revenue Requirements Related to Unit-Of-Production Depreciation," A.G.A. - EEI Depreciation Accounting Committee, Journal of Papers - Administrative Year 1981-1982, Vol. 3, February 1982.

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Minnesota, Nuclear Decommissioning, Docket No. E002/GR-87-670, 1987
Minnesota, Nuclear Decommissioning, Docket No. E002/GR-89-865, 1989
Minnesota, Nuclear Fuel Storage, Docket No. E002/CN-91-19, 1991
Minnesota, Depreciation and Nuclear Decommissioning, Docket No. E002/GR-92-1185, 1992
Minnesota, Pre-Merger Revenue Requirements, Merger Rate Plan, Savings Allocations, Docket No. E,G-002/PA-95-500, 1995
Minnesota, Rate Base, Docket No. G002/GR-97-1606, 1997
Minnesota, Overall Revenue Requirements, Rate Base, Income Statement, Docket No. G002/GR-04-1511, 2004
Minnesota, Overall Revenue Requirements, Rate Base, Income Statement, Docket No. E002/GR-05-1428, 2005
Minnesota, Overall Revenue Requirements, Rate Base, Income Statement, Docket No. G002/GR-06-1429, 2006

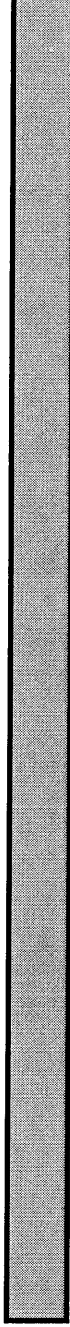
North Dakota, Depreciation, Docket No. 10,979, 1987
North Dakota, Overall Revenue Requirements, Rate Base, Income Statement, Case No. PU 400-04-578, 2004

South Dakota, Nuclear Decommissioning, Docket No. F-3764, 1988

ROE = 5.71%
Deficiency = \$1,919
% Increase = 2.24%
Required ROE = 11.50%

Xcel Energy
Natural Gas Utility - State of North Dakota
Jurisdictional Cost of Service Study
2005 Actual

Summary Reports



Xcel Energy
Natural Gas Utility - State of North Dakota
Jurisdictional Cost of Service Study
2005 Actual

(Dollars in Thousands)

Case No. PU-06-
 Exhibit (JCR-1)
 Schedule 2, Page 3 of 6

Income Statement Summary

	<u>Total Company Gas</u>	<u>North Dakota Retail Gas</u>	<u>All Other</u>
1			
Retail	809,358	85,660	723,698
2	0	0	0
Net Margin Weather Adjustment			
3	19,121	183	18,938
Interdepartmental & Transportation			
4	9,111	814	8,297
Other Operating			
5	0	0	0
Gross Earnings Tax			
6	837,590	86,657	750,933
Total Operating Revenues			
Expenses			
Operating Expenses:			
7	682,110	72,921	609,189
Purchased Gas			
8	3,672	769	2,903
Production			
9	723	78	645
Transmission			
10	23,158	1,953	21,206
Distribution			
11	13,566	1,398	12,168
Customer Accounting			
12	6,598	177	6,421
Customer Service & Information			
13	18,426	1,610	16,816
Administrative & General			
14	186	0	186
Amortizations			
15	164	35	129
Sales, Econ Dvlp & Other			
16	748,604	78,941	669,664
Total Operating Expenses			
17	30,782	2,818	27,964
Depreciation			
Taxes:			
18	12,316	1,066	11,250
Property			
19	0	0	0
Gross Earnings			
20	5,642	383	5,259
Deferred Income Tax & ITC			
21	7,021	625	6,396
State & Federal Income (see Page 3)			
22	2,112	187	1,926
Payroll & Other			
23	27,091	2,261	24,830
Total Taxes			
24	806,478	84,020	722,458
Total Expenses			
25	0	0	0
AFUDC			
26	31,112	2,637	28,475
Total Operating Income			

Xcel Energy
Natural Gas Utility - State of North Dakota
Jurisdictional Cost of Service Study
2005 Actual

(Dollars in Thousands)

Income Tax Summary

	<u>Total Company Gas</u>	<u>North Dakota Retail Gas</u>	<u>All Other</u>
1			
2	Total Operating Revenues	86,657	750,933
3	less: Total Operating Expenses	(78,941)	(669,664)
4	Book Depreciation	(2,818)	(27,964)
5	Taxes (Other Than Current Income)	(1,636)	(18,435)
	Total Before Tax Book Income	3,263	34,871
	<u>Tax Additions</u>		
6	Book Depreciation	2,818	27,964
9	Book Depreciation Cleared To Operating	0	0
10	Deferred Income Taxes & ITC	383	5,259
11	Book Amortizations	0	0
12	Connection Fees	0	0
13	Avoided Tax Interest	0	0
14	Tax Capitalized Leases	275	275
15	Meals & Entertainment	0	0
16	TBT Net Expense	58	53
17	Total Tax Additions	0	0
	36,757	3,206	33,551
	<u>Tax Deductions</u>		
18	Tax Depreciation & Removal Expense	3,135	33,198
19	Debt Interest Expense	1,496	14,669
20	Other Tax/Book Timing Differences	257	4,874
21	Net Preferred Stock Deduction	0	0
22	Total Tax Deductions	4,888	52,741
23	State Taxable Income	1,581	15,681
24	State Income Tax Rate	7.00%	N/A
25	Total State Income Taxes	111	1,396
26	Federal Taxable Income	1,470	14,285
27	Federal Income Tax Rate	35.00%	35.00%
28	Total Federal Income Taxes	515	5,000
29	Total Federal & State Income Taxes	7,021	6,396

(Dollars in Thousands)

Rate Base Detail - Cash Working Capital

Expenses	Total Company Gas		North Dakota Retail Gas		All Other	
	Dollars	Dollar x Days	Dollars	Dollar x Days	Dollars	Dollar x Days
Includable Expenses						
Purchased Gas						
1 Purchases	0.00	0	72,921	0	609,189	0
2 Subtotal Purchased Gas		0	72,921	0	609,189	0
Labor & Related Costs						
3 Regular Payroll	0.00	0	2,299	0	22,911	0
4 Incentive Compensation	0.00	0	99	0	987	0
5 Pension & Benefits	0.00	0	496	0	5,046	0
6 Subtotal Labor & Related		0	2,894	0	28,944	0
7 All Other Operating Expenses	0.00	0	3,126	0	31,344	0
8 Property Tax	0.00	0	1,066	0	11,250	0
9 Employer's Payroll Taxes	0.00	0	187	0	1,926	0
10 Gross Earnings Tax	0.00	0	0	0	0	0
11 Federal Income Tax	0.00	0	515	0	5,000	0
12 State Income Tax	0.00	0	111	0	1,396	0
13 State Sales Tax Customer Billings	0.00	0	1,111	0	12,557	0
14 Total Expenses	0.00	0	81,930	0	701,606	0
15 Net Annual Expense Amount		0		0		0
Revenues						
16 Computer Billing	0.00	0	85,660	0	723,698	0
17 Hand Billed	100.00%	0	0	0	0	0
18 Retail Revenue Adjustments	0.00%	0	0	0	0	0
19 Interdepartmental	0.00	0	5	0	15,684	0
20 Transportation	0.00	0	178	0	3,254	0
21 Late Payment	0.00	0	91	0	1,457	0
22 Non Curtailment Penalty	0.00	0	60	0	165	0
23 Connect Charge	0.00	0	4	0	448	0
24 Return Check Charge	0.00	0	4	0	73	0
25 Rents - Gas Property	0.00	0	0	0	0	0
26 CIP - Lost Sales Margin	0.00	0	0	0	0	0
27 Gas Agreement	0.00	0	42	0	344	0
28 Locating Services	0.00	4	0	0	4	0
29 Balancing Service	0.00	84	0	0	84	0
30 Standby Sales Res & Vols	0.00	0	0	0	0	0
31 Limited Firm Sales - Res & Vols	0.00	957	38	0	919	0
32 Sales to Other - MN LP	0.00	124	14	0	110	0
33 Off System End User	0.00	5,241	565	0	4,676	0
34 Opportunity Sales	0.00	0	0	0	0	0
35 CIAC Gross-Up	0.00	0	0	0	0	0
36 Agency Service	0.00	0	0	0	0	0
37 Other Gas Revenue	0.00	17	0	0	17	0
38 Total Revenues	0.00	837,590	86,657	0	750,933	0
39 Net Annual Amount		0		0		0
40 Expense / Revenue Factor		0.935464308		0.945447915		0
41 Allocated Revenue Amount		0		0		0
42 Net Cash Working Capital		0		0		0

	<u>Adjustment Description</u>	<u>Adjustment Target</u>	<u>Total Co.</u>	<u>ND Juris.</u>	<u>Allocation Method</u>	<u>Source of Data- All Volume 4 Tabs</u>
1	Charitable Contributions	Administrative & General	191	27	Direct/Customer	A1 Charitable Contributions
2	Advertising Expenses	Administrative & General	(504)	(92)	Direct/Customer	A2 Advertising
3	Professional Assn & Utility Assn Dues	Administrative & General	(3)	-	Customer	A3 Professional Assn & Utility Assn Dues
4	Economic Development Costs	Administrative & General	17	14	Direct/Customer	A4 Economic Development Costs
5	Tax Benefit Transfer Leases	Administrative & General	-	-	Customer	03 Adjustments
6	Interest on Customer Deposits	Administrative & General	9	1	Customer	A5 Interest on Customer Deposits
7	NMC Pension & Benefit Adjustment	Administrative & General	(141)	(13)	Customer	A9 NMC Pension & Benefit Adjustment
8	Total Administrative & General	Administrative & General	(431)	(63)		
9	CIP - Performance Incentive	Other Revenues	(976)	-	Direct	A6 CIP Adjustment
10	Connection Charge Adjustment	Other Revenues	(82)	(82)	Direct	A19 Connection Charge Adjustment
11	Total Other Revenues	Other Revenues	(1,058)	(82)		

Xcel Energy
Natural Gas Utility - State of North Dakota
SUMMARY OF TEST PERIOD ADJUSTMENTS
(\$000's)

	<u>Adjustment Description</u>	<u>Adjustment Target</u>	<u>Total Co.</u>	<u>ND Juris.</u>	<u>Allocation Method</u>	<u>Source of Data- All Volume 4 Tabs</u>
1	CIP Program Cost Adjustment	Retail Revenues	(2,618)	-	Direct	A12 CIP Program Cost Adjustment
2	CIAC 2004 Rate Case Adjustment	Other Revenues	287	-	Direct	A7 CIAC 2004 Rate Case Adjustment
3	Revised Sales Forecast	Retail Revenues	(2,481)	(2,481)	Direct	A18 Revised Sales Forecast
4	Total Revenues	Revenues	(4,812)	(2,481)		
Incentive Compensation						
5	Amounts in Excess of 25%	Administrative & General	(22)	(2)	Customer/Labor	A8 Incentive Compensation
6	Area Specific Plans	Administrative & General	(28)	-	Customer/Labor	A8 Incentive Compensation
7	Other Bonuses/Incentives	Administrative & General	(49)	(5)	Customer/Labor	A8 Incentive Compensation
8	Long Term Incentive Plans	Administrative & General	(470)	(47)	Customer/Labor	A8 Incentive Compensation
9	Adjust Base to 100% of Target	Administrative & General	881	54	Customer/Labor	A8 Incentive Compensation
10	Net Incentive Comp Adjustment	Administrative & General	313	-		
11	Rate Case Expense Adjustment	Administrative & General	(260)	-	Direct	A10 Rate Case Expenses
12	Total Administrative & General		53	-		
13	Customer Allocated FERC Accts	Customer Accounting	(2,945)	-	Direct	A11 Customer Allocated FERC Accts
14	Customer Allocated FERC Accts	Customer Serv & Info	(201)	-	Direct	A11 Customer Allocated FERC Accts
15	CIP Program Cost Adjustment	Customer Serv & Info	(2,618)	-	Direct	A12 CIP Program Cost Adjustment
16	Heating System Rebate	Customer Serv & Info	61	61	Direct	A14 Heating System Rebate
17	Water Heater Rebates	Customer Serv & Info	3	3	Direct	A15 Water Heater Rebates
18	Shower Heads	Customer Serv & Info	14	14	Direct	A16 Shower Heads
19	Home Energy Audits	Customer Serv & Info	60	60	Direct	A17 Home Energy Audits
20	Total Customer Information	Customer Serv & Info	(2,681)	138		
21	Customer Allocated FERC Accts	Customer Sales	(8)	-	Direct	A11 Customer Allocated FERC Accts
22	Rate Case Expense Amortization	Amortization	607	50	Direct	A10 Rate Case Expenses
23	Revised Sales Forecast	Purchased Gas	(2,207)	(2,207)	Direct	A18 Revised Sales Forecast
24	MPG Adjustment	Production	(12)	(12)	Direct	A13 MPG Adjustment
25	SERP/Deferred Compensation Adj	Production	(184)	(17)	Direct	A20 SERP/Deferred Compensation Adj
26	Total Expenses Schedule 3		(7,378)	(2,048)		

Xcel Energy
Natural Gas Utility - State of North Dakota
2007 Unadjusted Test Year versus 2007 Adjusted Test Year
(\$000's)

Case No. PU-06-____
Exhibit__(JCR-1)
Schedule 5, Page 1 of 2

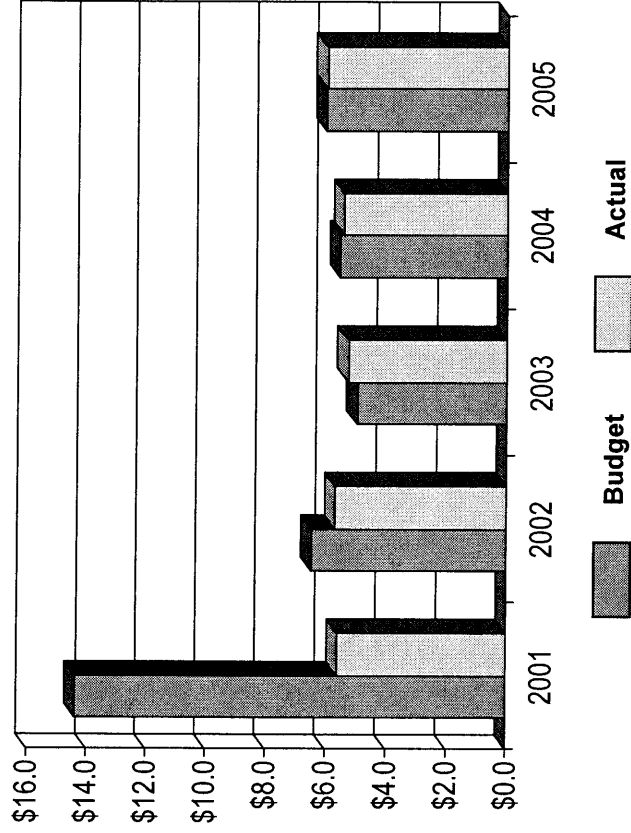
<u>Line No.</u>	<u>Description</u>	<u>Unadjusted (F)</u>	<u>Income Statement (1)</u>	<u>Adjusted</u>
	Gas Plant as Booked			
1	Production	\$1,607		\$1,607
2	Storage	\$3,539		\$3,539
3	Transmission	\$3,419		\$3,419
4	Distribution	\$67,876		\$67,876
5	General	\$1,533		\$1,533
6	Common	\$5,978		\$5,978
7	TBT Investment	\$0		\$0
8	TOTAL Utility Plant in Service	<u>\$83,952</u>		<u>\$83,952</u>
	Reserve for Depreciation			
9	Production	\$1,264		\$1,264
10	Storage	\$2,492		\$2,492
11	Transmission	\$1,444		\$1,444
12	Distribution	\$28,853		\$28,853
13	General	\$748		\$748
14	Common	\$3,694		\$3,694
15	TOTAL Reserve for Depreciation	<u>\$38,495</u>		<u>\$38,495</u>
	Net Utility Plant in Service			
16	Production	\$343		\$343
17	Storage	\$1,047		\$1,047
18	Transmission	\$1,975		\$1,975
19	Distribution	\$39,023		\$39,023
20	General	\$785		\$785
21	Common	\$2,284		\$2,284
22	TBT Investment	\$0		\$0
23	Net Utility Plant in Service	<u>\$45,457</u>		<u>\$45,457</u>
24	Utility Plant Held for Future Use	\$0		\$0
25	Construction Work in Progress	\$33		\$33
26	Less: Accumulated Deferred Income Taxes	\$6,931		\$6,931
27	Cash Working Capital	\$497	(\$41)	\$456
	Other Rate Base Items:			
28	Materials and Supplies	\$168		\$168
29	Gas In Storage	\$5,781		\$5,781
30	Non-Plant Assets & Liabilities	(\$1,082)		(\$1,082)
31	Prepayments	\$880		\$880
32	Customer Advances	(\$6)		(\$6)
33	Other Working Capital	<u>\$1,875</u>		<u>\$1,875</u>
34	Total Other Rate Base Items	\$7,616	\$0	\$7,616
35	Total Average Rate Base	<u>\$46,672</u>	<u>(\$41)</u>	<u>\$46,631</u>

Xcel Energy
Natural Gas Utility - State of North Dakota
2007 Unadjusted Test Year versus 2007 Adjusted Test Year
(\$000's)

Line No.	Description	2007 Unadjusted(1)	NMC Pension & Benefit Adj 1	Charitable Contributions/Deductions 2	Interest on Customer Deposits 3	Advertising 4	Economic Development 5	Incentive Compensation Adjustment 6	Rate Case Expense Amortization 7	Association Dues 8	MGP Adj 10	Gas DSM 11	Revised Sales Forec 12	Connection Charge Adj 13	SERP/Deferred Compensation Adj 14	2007 Adjusted(1)	
Operating Revenues																	
1	Retail	\$95,508															\$95,508
2	Weather Impact Net Margin Adjustment	0															\$0
3	Interdepartmental & Transportation	18															\$18
4	Other Operating	414															\$332
5	Gross Earnings Tax	0															\$0
6	Total Operating Revenues	\$95,940	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	(\$2,461)			\$0	\$93,376
Expenses																	
Operating Expenses:																	
7	Purchased Gas	\$81,097															\$78,890
8	Other Production	741															\$729
9	Transmission	132															\$132
10	Distribution	2,207															\$2,207
11	Customer Accounting	1,630															\$1,630
12	Customer Service & Information	243															\$381
13	Administrative & General	1,768	(13)	27	1	(92)	14	0	50	(0)		138			(17)	\$1,687	
14	Amortizations	0															\$0
15	Sales, Econ Dvlp & Other	0															\$0
16	Total Operating Expenses	\$88,018	(\$13)	\$27	\$1	(\$92)	\$14	\$0	\$50	(\$0)	(\$12)	\$138	(\$2,207)	\$0	(\$17)	\$0	\$85,907
17	Depreciation	\$2,816															\$2,816
Taxes:																	
18	Property	\$1,158															\$1,158
19	Gross Earnings	0															0
20	Deferred Income Tax & ITC	68															68
21	Federal & State Income Tax	773	5	(11)	(0)	36	(5)	(0)	(20)	0	5	(55)	(108)	(33)	7	595	
22	Payroll & Other	217															217
23	Total Taxes	\$2,216	\$5	(\$11)	(\$0)	\$36	(\$5)	(\$0)	(\$20)	\$0	\$5	(\$55)	(\$108)	(\$33)	\$7	\$2,038	
24	Total Expenses	\$93,050	(\$8)	\$16	\$1	(\$56)	\$8	\$0	\$30	(\$0)	(\$7)	\$83	(\$2,315)	(\$33)	(\$11)	\$0	\$90,761
25	Allowance for Funds Used During Construction	\$0															\$0
26	Total Operating Income	\$2,890	\$8	(\$16)	(\$1)	\$56	(\$8)	(\$0)	(\$30)	\$0	\$7	(\$83)	(\$166)	(\$50)	\$11	\$0	\$2,615

**Xcel Energy
Natural Gas Utility - State of North Dakota
Comparison of O&M Actuals to Budget**

O&M Expenses (ND Jurisdiction)



Xcel Energy
Natural Gas Utility - State of North Dakota
Revenue Deficiency Summary
(\$000's)

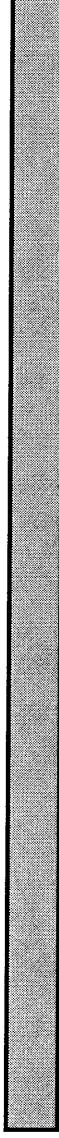
Case No. PU-06-____
 Exhibit____(JCR-1)
 Schedule 7, Page 1 of 1

<u>Line</u>	<u>Description</u>	<u>North Dakota Jurisdiction</u>
1	Average Rate Base	\$46,631
2	Operating Income (Before AFUDC)	\$2,615
3	Allowance for Funds Used During Construction	\$0
4	Total Available for Return (Line 2 + Line 3 + Rounding)	\$2,615
5	Overall Rate of Return (Line 4 / Line 1)	5.61%
6	Required Rate of Return	9.24%
7	Operating Income Requirement (Line 1 x Line 6)	\$4,309
8	Income Deficiency (Line 7 - Line 4)	\$1,693
9	Gross Revenue Conversion Factor	1.654260
10	Revenue Deficiency (Line 8 x Line 9)	\$2,801
11	Retail Related Revenue Under Present Rates	\$93,044
13	Percentage Increase Needed in Overall Revenue (Line 10 / Line 11)	3.01%

ROE = 4.26%
Deficiency = \$2,801
% Increase = 3.01%
Required ROE = 11.30%

Xcel Energy
Natural Gas Utility - State of North Dakota
Jurisdictional Cost of Service Study
2007 Test Year

Summary Reports



Xcel Energy
Natural Gas Utility - State of North Dakota
Jurisdictional Cost of Service Study
2007 Test Year

Case No. PU-06-
 Exhibit (JCR-1)
 Schedule 8, Page 2 of 6

(Dollars in Thousands)

Rate Base Summary

	Total Company Gas			North Dakota Retail Gas			All Other
	Beginning Balance	Ending Balance	Average Balance	Beginning Balance	Ending Balance	Average Balance	Beginning Balance
1 Plant Investment	912,771	961,463	937,117	81,813	86,090	83,952	830,958
2 Depreciation Reserve	(412,567)	(444,565)	(428,566)	(37,066)	(39,924)	(38,495)	(375,501)
3 Net Utility Plant	500,204	516,898	508,551	44,747	46,166	45,457	455,457
4 C.W.I.P.	611	864	738	30	35	33	581
5 Accumulated Deferred Taxes	(75,328)	(77,479)	(76,404)	(6,882)	(6,979)	(6,931)	(68,446)
Other Rate Base:							
6 Cash Working Capital (*)	(565)	(565)	(565)	456	456	456	(1,021)
7 Materials & Supplies	1,809	1,809	1,809	168	168	168	1,641
8 Gas In Storage	53,166	53,166	53,166	5,781	5,781	5,781	47,385
9 Non-Plant Assets & Liab	(18,646)	(19,475)	(19,061)	(1,034)	(1,129)	(1,082)	(17,612)
10 Prepaids & Other	6,415	6,055	6,235	2,929	2,569	2,749	3,486
11 Total Rate Base	467,666	481,274	474,469	46,195	47,068	46,631	421,471
							434,206
							427,838

(*) See Page 6.

Xcel Energy
Natural Gas Utility - State of North Dakota
Jurisdictional Cost of Service Study
2007 Test Year

Case No. PU-06-
 Exhibit (JCR-1)
 Schedule 8, Page 3 of 6

(Dollars in Thousands)

Income Statement Summary

	<u>Total Company Gas</u>	<u>North Dakota Retail Gas</u>	<u>All Other</u>
<u>Operating Revenues</u>			
1 Retail	842,047	93,026	749,021
2 Net Margin Weather Adjustment	0	0	0
3 Interdepartmental & Transportation	18,940	18	18,922
4 Other Operating	6,645	332	6,313
5 Gross Earnings Tax	0	0	0
6 Total Operating Revenues	867,632	93,376	774,256
<u>Expenses</u>			
Operating Expenses:			
7 Purchased Gas	709,671	78,890	630,781
8 Production	3,935	729	3,206
9 Transmission	1,199	132	1,066
10 Distribution	24,942	2,207	22,736
11 Customer Accounting	15,009	1,830	13,179
12 Customer Service & Information	5,839	381	5,457
13 Administrative & General	18,249	1,687	16,562
14 Amortizations	660	50	610
15 Sales, Econ Dvlp & Other	79	0	78
16 Total Operating Expenses	779,582	85,907	693,675
17 Depreciation	31,545	2,816	28,729
Taxes:			
18 Property	14,106	1,158	12,948
19 Gross Earnings	0	0	0
20 Deferred Income Tax & ITC	2,065	68	1,997
21 State & Federal Income (see Page 3)	7,333	595	6,738
22 Payroll & Other	2,373	217	2,156
23 Total Taxes	25,877	2,038	23,839
24 Total Expenses	837,004	90,761	746,243
25 AFUDC	0	0	0
26 Total Operating Income	30,628	2,615	28,013

Xcel Energy
Natural Gas Utility - State of North Dakota
Jurisdictional Cost of Service Study
2007 Test Year

(Dollars in Thousands)

Income Tax Summary

	<u>Total Company Gas</u>	<u>North Dakota Retail Gas</u>	<u>All Other</u>
Income Before Taxes			
1 Total Operating Revenues	867,632	93,376	774,256
2 less: Total Operating Expenses	(779,582)	(85,907)	(693,675)
3 Book Depreciation	(31,545)	(2,816)	(28,729)
4 Taxes (Other Than Current Income)	(18,544)	(1,443)	(17,101)
5 Total Before Tax Book Income	37,961	3,210	34,751
Tax Additions			
6 Book Depreciation	31,545	2,816	28,729
9 Book Depreciation Cleared To Operating	0	0	0
10 Deferred Income Taxes & ITC	2,065	68	1,997
11 Book Amortizations	0	0	0
12 Connection Fees	0	0	0
13 Avoided Tax Interest	1,099	37	1,062
14 Tax Capitalized Leases	0	0	0
15 Meals & Entertainment	0	0	0
16 TBT Net Expense	0	0	0
17 Total Tax Additions	34,709	2,921	31,788
Tax Deductions			
18 Tax Depreciation & Removal Expense	39,209	3,124	36,085
19 Debt Interest Expense	16,179	1,590	14,589
20 Other Tax/Book Timing Differences	(747)	(87)	(660)
21 Net Preferred Stock Deduction	0	0	0
22 Total Tax Deductions	54,641	4,627	50,014
23 State Taxable Income	18,029	1,504	16,525
24 State Income Tax Rate	8.73%	7.00%	N/A
25 Total State Income Taxes	1,574	105	1,468
26 Federal Taxable Income	16,455	1,399	15,057
27 Federal Income Tax Rate	35.00%	35.00%	35.00%
28 Total Federal Income Taxes	5,759	490	5,270
29 Total Federal & State Income Taxes	7,333	595	6,738

Revenue Requirement & Return Summary

		2007			
		Capital Structure	Rate	Ratio	Weighted Cost
1	Long Term Debt		7.0820%	46.4100%	3.2900%
2	Short Term Debt		5.8100%	2.0000%	0.1200%
3	Preferred Stock		0.0000%	0.0000%	0.0000%
4	Common Equity		11.3000%	51.5900%	5.8300%
5	Required Rate of Return				9.2400%
Composite Income Tax Rates					
	State of North Dakota Tax rate				7.00%
	Federal Statutory Tax rate				35.00%
	Federal Effective Tax Rate (1-State Rate * Fed Rate)				32.55%
	Total North Dakota Composite Tax Rate				39.55%
	Total Corporate Composite Tax Rate				40.67%
Rate of Return (ROR)					
6	Total Operating Income				2,615
7	Total Average Rate Base				427,838
8	ROR (Operating Income / Rate Base)				6.16%
Return on Equity (ROE)					
9	Total Operating Income				2,615
10	Debt Interest (Rate Base * Weighted Debt Cost)				(1,590)
11	Preferred Stock (Rate Base * Weighted Preferred Cost)				0
12	Earnings Available for Common				1,025
13	Equity Rate Base (Rate Base * Equity Ratio)				24,057
14	ROE (Earnings for Common / Equity Rate Base)				4.26%
Revenue Deficiency					
15	Require Operating Income (Rate Base * Required Return)				43,841
16	Operating Income				30,628
17	Operating Income Deficiency				13,213
18	Revenue Conversion Factor (1/(1-Composite Tax Rate))				1.68558
19	Revenue Deficiency (Income Deficiency * Conversion Factor)				22,272
Total Retail Revenue Requirements					
20	Retail Related Revenues				93,044
21	Revenue Deficiency				2,801
22	Total Retail Revenue Requirements				95,845
23	Percentage Increase (Decrease)				3.01%

North Dakota Retail Gas

		Total Company Gas	North Dakota Retail Gas	All Other
6	Total Operating Income	30,628	2,615	28,013
7	Total Average Rate Base	474,469	46,631	427,838
8	ROR (Operating Income / Rate Base)	6.46%	5.61%	6.55%
Return on Equity (ROE)				
9	Total Operating Income	30,628	2,615	28,013
10	Debt Interest (Rate Base * Weighted Debt Cost)	(16,179)	(1,590)	(14,589)
11	Preferred Stock (Rate Base * Weighted Preferred Cost)	0	0	0
12	Earnings Available for Common	14,449	1,025	13,424
13	Equity Rate Base (Rate Base * Equity Ratio)	244,779	24,057	220,722
14	ROE (Earnings for Common / Equity Rate Base)	5.90%	4.26%	6.08%
Revenue Deficiency				
15	Require Operating Income (Rate Base * Required Return)	43,841	4,309	39,532
16	Operating Income	30,628	2,615	28,013
17	Operating Income Deficiency	13,213	1,693	11,519
18	Revenue Conversion Factor (1/(1-Composite Tax Rate))	1.68558	1.65426	N/A
19	Revenue Deficiency (Income Deficiency * Conversion Factor)	22,272	2,801	19,471
Total Retail Revenue Requirements				
20	Retail Related Revenues	860,987	93,044	767,943
21	Revenue Deficiency	22,272	2,801	19,471
22	Total Retail Revenue Requirements	883,259	95,845	787,414
23	Percentage Increase (Decrease)	2.59%	3.01%	2.54%

(Dollars in Thousands)

Rate Base Detail - Cash Working Capital

Expenses	Total Company Gas			North Dakota Retail Gas			All Other		
	Lead Days	Dollars	Dollar x Days	Dollars	Dollar x Days	Dollars	Dollar x Days	Dollars	Dollar x Days
Includable Expenses									
Purchased Gas									
1 Purchases	40.25	709,671	28,564,239	78,890	3,175,323	630,781	25,388,916	630,781	25,388,916
2 Subtotal Purchased Gas		709,671	28,564,239	78,890	3,175,323	630,781	25,388,916	630,781	25,388,916
Labor & Related Costs									
3 Regular Payroll	13.79	28,859	397,970	2,741	37,794	26,119	360,176	26,119	360,176
4 Incentive Compensation	259.51	1,307	339,295	118	30,692	1,189	308,603	1,189	308,603
5 Pension & Benefits	29.79	5,162	153,778	494	14,701	4,669	139,076	4,669	139,076
6 Subtotal Labor & Related		35,329	891,042	3,352	83,187	31,976	807,855	31,976	807,855
7 All Other Operating Expenses	42.34	33,922	1,436,278	3,615	153,042	30,308	1,283,237	30,308	1,283,237
8 Property Tax	345.46	14,106	4,873,059	1,158	400,043	12,948	4,473,016	12,948	4,473,016
9 Employers Payroll Taxes	19.66	2,373	46,650	217	4,263	2,156	42,387	2,156	42,387
10 Gross Earnings Tax	68.75	12,819	881,306	1,873	128,769	10,946	752,538	10,946	752,538
11 Federal Income Tax	37.00	5,759	213,096	490	18,113	4,270	194,983	4,270	194,983
12 State Income Tax	29.25	1,574	46,028	105	3,079	1,468	42,949	1,468	42,949
13 State Sales Tax Customer Billings	51.86	18,312	949,660	1,626	84,324	16,686	865,336	16,686	865,336
14 Total Expenses	45.45	833,865	37,901,359	44.35	4,050,144	45.59	33,851,215	45.59	33,851,215
15 Net Annual Expense Amount			103,839		11,096		92,743		92,743
Revenues									
16 Computer Billing	46.20	842,047	38,902,571	93,026	4,297,801	749,021	34,604,770	749,021	34,604,770
17 Hand Billed	46.20	0	0	0	0	0	0	0	0
18 Retail Revenue Adjustments	46.20	0	0	0	0	0	0	0	0
19 Interdepartmental	0.00	17,849	0	18	0	17,831	0	17,831	0
20 Transportation	33.21	1,091	36,232	0	0	1,091	36,232	1,091	36,232
21 Late Payment	46.20	1,882	86,948	104	4,805	1,778	82,144	1,778	82,144
22 Non Curtailment Penalty	46.20	0	0	0	0	0	0	0	0
23 Connect Charge	46.20	1,286	59,413	58	2,680	1,228	56,734	1,228	56,734
24 Return Check Charge	46.20	90	4,158	5	231	85	3,927	85	3,927
25 Rents - Gas Property	35.21	0	0	0	0	0	0	0	0
26 CIP - Lost Sales Margin	0.00	401	14,119	41	1,444	360	12,676	360	12,676
27 Gas Agreement	35.21	0	0	0	0	0	0	0	0
28 Locating Services	35.21	0	0	0	0	0	0	0	0
29 Balancing Service	35.21	0	0	0	0	0	0	0	0
30 Standby Sales Res & Vols	35.21	0	0	0	0	0	0	0	0
31 Limited Firm Sales - Res & Vols	35.21	976	34,365	89	3,134	887	31,231	887	31,231
32 Sales to Other - MN LP	35.21	342	12,042	35	1,232	307	10,809	307	10,809
33 Off System End User	35.21	0	0	0	0	0	0	0	0
34 Opportunity Sales	35.21	0	0	0	0	0	0	0	0
35 CIAC 2004 Rate Case Adjustment	46.20	287	13,259	0	0	287	13,259	287	13,259
36 Agency Service	46.20	21	970	0	0	21	970	21	970
37 Other Gas Revenue	42.36	1,360	57,610	0	0	1,360	57,610	1,360	57,610
38 Total Revenues	45.21	867,632	39,221,688	46.17	4,311,326	45.09	34,910,362	45.09	34,910,362
39 Net Annual Amount			107,457		11,812		95,645		95,645
40 Expense / Revenue Factor			0.961080986		0.9780427				
41 Allocated Revenue Amount			103,275		11,552				
42 Net Cash Working Capital			(565)		456				(1,021)

Xcel Energy
Natural Gas Utility - State of North Dakota
Summary of Primary Elements of Revenue Deficiency
2007 Test Year vs. 2004 Test Year of Case No. PU=-400-04-578

Case No. PU-06-____
Exhibit____(JCR-1)
Schedule 9, Page 1 of 2

<u>Line</u>	<u>Item</u>	<u>Revenue Deficiency (millions)</u>
1	Capital Recovery for additional rate base investment (includes return requirement, change in cost of capital and depreciation)	\$1.24
	Operating Expenses:	
2	Production, Transmission and Distribution Operations	\$0.58
3	Customer Accounts	\$0.69
4	Customer Services, Sales and Administrative and General Expense	<u>\$0.43</u>
5	Total Operating Expenses	\$1.70
6	Taxes Other than Income Taxes - Payroll, Real Estate and Personal Property	\$0.21
7	Other - Rate Case Costs - Amortization	<u>\$0.03</u>
8	Subtotal	\$3.18
9	Less, Revenue Growth (Total Revenues Less Cost of Gas)	<u>(\$0.38)</u>
10	Net Revenue Deficiency	\$2.80

Summary of Test Year O & M Expense Changes
Since Case No. PU 400-04-578
Shown by Functional Grouping, Gross Dollar Change and
Item
(dollars in thousands)

<u>Line</u>	<u>Functional Class</u>	<u>Increase (Decrease)</u>	<u>Average Annual %</u>
1	Production, Storage, and Transmission Expense	\$41	3.0%
2	Distribution and Maintenance Expense	\$543	10.9%
3	Customer Accounting	\$688	20.1%
4	Customer Services and Sales Expenses	\$170	26.8%
5	Administrative and General Expenses	<u>\$258</u>	<u>6.0%</u>
6	Total Operating Expenses	\$1,700	11.5%

Xcel Energy
Natural Gas Utility - State of North Dakota
Gross Revenue Conversion Factor Calculation

Case No. PU-06-____
Exhibit____(JCR-1)
Schedule 10, Page 1 of 1

Definition: The incremental amount of gross revenue required to generate an additional dollar of operating income. Gross earnings fees included.

Let: GR = Gross Revenue Conversion Factor
T= Federal and North Dakota Income Tax

Formula for Gross Revenue Conversion Factor

$$GR = \frac{1}{1 - T}$$

Gross Revenue Conversion Factor:

$$GR = \frac{1}{1 - 0.3955}$$

$$GR = 1.65426$$

Xcel Energy
Natural Gas Utility - State of North Dakota
Operating Income with Present and Proposed Rates
(000's)

Case No. PU-06-____
Exhibit__(JCR-1)
Schedule 11, Page 1 of 2

Line No.	Description	Test Year Ending 12/31/07 Present Rates (A)	Final Increase (B)	Test Year Ending 12/31/07 Final Rates (C) = (B) + (A)
<u>Operating Revenues</u>				
1	Retail	\$93,026	\$2,801	\$95,827
2	Weather Impact Net Margin Adjustment	0		0
3	Interdepartmental & Transportation	18		18
4	Other Operating	332		332
5	Gross Earnings Tax	0		0
6	Total Operating Revenues	\$93,376	\$2,801	\$96,177
<u>Expenses</u>				
Operating Expenses:				
7	Purchased Gas	\$78,890		\$78,890
8	Other Production	729		729
9	Transmission	132		132
10	Distribution	2,207		2,207
11	Customer Accounting	1,830		1,830
12	Customer Service & Information	381		381
13	Administrative & General	1,687		1,687
14	Amortizations	50		50
15	Sales, Econ Dvlp & Other	0		0
16	Total Operating Expenses	\$85,907	\$0	\$85,907
17	Depreciation	\$2,816	\$0	\$2,816
Taxes:				
18	Property	\$1,158		\$1,158
19	Gross Earnings	0		0
20	Deferred Income Tax & ITC	68		68
21	Federal & State Income Tax	595	1,108	1,703
22	Payroll & Other	217		217
23	Total Taxes	\$2,038	\$1,108	\$3,146
24	Total Expenses	\$90,761	\$1,108	\$91,869
25	AFUDC	\$0	\$0	\$0
26	Total Operating Income	\$2,615	\$1,693	\$4,309

Note: Revenues reflect calendar month sales.

Xcel Energy
Natural Gas Utility - State of North Dakota
Statement of Operating Income
(000's)

Case No. PU-06-____
Exhibit____(JCR-1)
Schedule 11, Page 2 of 2

Line No.	Description	Proposed Test Year 2007			Proposed North Dakota Jurisdiction (H) (Col F + G)
		Unadjusted Total Utility (E)	Unadjusted North Dakota Jurisdiction (F)	Adjustments (G)	
Operating Revenues					
1	Retail	\$846,557	\$95,508	(\$2,482)	\$93,026
2	Weather Impact Net Margin Adjustment	\$0	\$0	0	0
3	Interdepartmental & Transportation	\$19,004	\$18	0	18
4	Other Operating	\$7,416	\$414	(82)	332
5	Gross Earnings Tax	\$0	\$0	0	0
6	Total Operating Revenues	\$872,976	\$95,940	(\$2,564)	\$93,376
Expenses					
Operating Expenses:					
7	Purchased Gas	\$711,877	\$81,097	(\$2,207)	\$78,890
8	Other Production	3,947	741	(12)	729
9	Transmission	1,200	132	0	132
10	Distribution	24,942	2,207	0	2,207
11	Customer Accounting	17,954	1,830	0	1,830
12	Customer Service & Information	8,519	243	138	381
13	Administrative & General	19,103	1,768	(81)	1,687
14	Amortizations	53	0	50	50
15	Sales, Econ Dvlp & Other	87	0	0	0
16	Total Operating Expenses	\$787,683	\$88,018	(\$2,112)	\$85,907
17	Depreciation	\$31,545	\$2,816	\$0	\$2,816
Taxes:					
18	Property	\$15,171	\$1,158	\$0	\$1,158
19	Gross Earnings	0	0	0	0
20	Deferred Income Tax & ITC	2,065	68	0	68
21	Federal & State Income Tax	5,740	773	(178)	595
22	Payroll & Other	2,373	217	0	217
23	Total Taxes	\$25,349	\$2,216	(\$178)	\$2,038
24	Total Expenses	\$844,577	\$93,050	(\$2,290)	\$90,761
25	Allowance for Funds Used During Constructi	\$1,483	\$0	0	\$0
26	Total Operating Income	\$29,883	\$2,890	(\$275)	\$2,615

Xcel Energy
Natural Gas Utility - State of North Dakota
Jurisdictional Allocation Factors

Case No. PU-06-____
Exhibit____(JCR-1)
Schedule 12, Page 1 of 2

Line	Description	Allocation Basis
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The allocation factors on this page were used to determine North Dakota jurisdictional income statement amounts for all of the years presented in these schedules. Accounts not on this page have been directly assigned to jurisdiction.

1	Production & Storage	Design Day Demand
2	Transmission	Load Dispatch
3	Distribution	Customers/Direct Assigned
4	Customer Accounting	Customers
5	Customer Service & Information	Customers
6	Sales, Econ Dvlp & Other	Customers
7	Administrative & General	Customers

Xcel Energy
Natural Gas Utility - State of North Dakota
Jurisdictional Allocation Factors

Case No. PU-06-____
 Exhibit____(JCR-1)
 Schedule 12, Page 2 of 2

Unadjusted Test Year 2007

<u>Line No.</u>	<u>Allocation Factor</u>	<u>Total Utility</u>	<u>North Dakota Jurisdiction</u>	<u>Allocation Factor</u>
1	Design Day Demand	695,300	71,802	10.3268%
2	Design Day Demand	695,300	71,802	5.1634%
	MCF	86,421,029	10,118,134	5.8540%
	Load Dispatch			<u>11.0174%</u>
3	Customers	475,275	44,220	9.3041%

- (1) Design Day Demand
- (2) Average of the Design Day Demand allocation and Total MCF Sales Percentage
- (3) Average number of Customers

Xcel Energy
Natural Gas Utility - State of North Dakota
Rate Base Jurisdictional Allocation Factors

Case No. PU-06-____
 Exhibit____(JCR-1)
 Schedule 13, Page 1 of 2

Line No.	Description	Allocation Basis
	The following allocation factors are used to compute North Dakota jurisdictional amounts for Plant-in-Service, Accumulated Depreciation, Accumulated Deferred Income Tax and Construction Work in Progress	
1	Production (LPG Production)	Design Day Demand
2	Storage (LNG Storage)	Design Day Demand
3	General Production Other	Design Day Demand Customers
4	Common Production Other	Design Day Demand Customers
	In addition, the following allocation factors are used to compute North Dakota Jurisdictional amounts.	
5	TBT Investment	Customers
6	Other Rate Base: Materials & Supplies Gas in Storage Gas in Storage-Underground Non-Plant Assets & Liabilities Prepayments - Insurance Prepayments - Gas Reserv. Fee Prepayments - Gas Imbalances Prepayments - Misc.	Customers Design Day Demand Load Dispatch Customers and Load Dispatch Customers Design Day Demand Load Dispatch Customers

Note:

The allocation factors on this page were used to determine North Dakota jurisdictional rate base amounts for all of the years presented in these schedules. Accounts not on this page have been directly assigned to jurisdictions.

Xcel Energy
Natural Gas Utility - State of North Dakota
Rate Base Jurisdictional Allocation Factors

Case No. PU-06-____
 Exhibit____(JCR-1)
 Schedule 13, Page 2 of 2

Unadjusted Test Year 2007

<u>Line No.</u>	<u>Allocation Factor</u>	<u>Total Utility</u>	<u>North Dakota Jurisdiction</u>	<u>Allocation Factor</u>
1	Design Day Demand	695,300	71,802	10.3268%
2	Design Day Demand	695,300	71,802	5.1634%
	MCF	86,421,029	10,118,134	5.8540%
	Load Dispatch			11.0174%
3	Customers	475,275	44,220	9.3041%

- (1) Design Day Demand
- (2) Average of the Design Day Demand allocation and Total MCF Sales Percentage
- (3) Average number of Customers

Xcel Energy
Natural Gas Utility - State of North Dakota
Average Rate Base
(\$000's)

Case No. PU-06-____
 Exhibit____(JCR-1)
 Schedule 14, Page 1 of 2

<u>Line</u>	<u>No. Description</u>	<u>Average Rate Base</u>
		<u>(A)</u>
	Gas Plant as Booked	
1	Production	\$1,607
2	Storage	3,539
3	Transmission	3,419
4	Distribution	67,876
5	General	1,533
6	Common	5,978
7	TBT Investment	0
8	TOTAL Utility Plant in Service	<u>\$83,952</u>
	Reserve for Depreciation	
9	Production	\$1,264
10	Storage	2,492
11	Transmission	1,444
12	Distribution	28,853
13	General	748
14	Common	3,694
15	TOTAL Reserve for Depreciation	<u>\$38,495</u>
	Net Utility Plant in Service	
16	Production	\$343
17	Storage	1,047
18	Transmission	1,975
19	Distribution	39,023
20	General	785
21	Common	2,284
22	TBT Investment	0
23	Net Utility Plant in Service	<u>\$45,457</u>
24	Utility Plant Held for Future Use	\$0
25	Construction Work in Progress	\$33
26	Less: Accumulated Deferred Income Taxes	\$6,931
27	Cash Working Capital	\$456
	Other Rate Base Items:	
28	Materials and Supplies	\$168
29	Gas In Storage	5,781
30	Non-Plant Assets & Liabilities	(1,082)
31	Prepayments	880
32	Customer Advances	(6)
33	Other Working Capital	<u>1,875</u>
34	Total Other Rate Base Items	\$7,616
35	Total Average Rate Base	<u><u>\$46,631</u></u>

Xcel Energy
Natural Gas Utility - State of North Dakota
Comparison of Detail Rate Base
(\$000's)

Case No. PU-06-____
 Exhibit____(JCR-1)
 Schedule 14, Page 2 of 2

		Proposed Test Year 2007					
Line		Total Utility			North Dakota Jurisdiction		
No.	Description	Unadjusted (A)	Adjustments (B)	Adjusted (C) (A) + (B)	Unadjusted (D)	Adjustments (E)	Adjusted (F) (D) + (E)
	Gas Plant as Booked						
1	Production	\$15,559	\$0	\$15,559	\$1,607	\$0	\$1,607
2	Storage	34,269	0	34,269	3,539	0	3,539
3	Transmission	52,228	0	52,228	3,419	0	3,419
4	Distribution	754,350	0	754,350	67,876	0	67,876
5	General	16,461	0	16,461	1,533	0	1,533
6	Common	64,250	0	64,250	5,978	0	5,978
7	TBT Investment	0	0	0	0	0	0
8	TOTAL Utility Plant in Service	<u>\$937,117</u>	<u>\$0</u>	<u>\$937,117</u>	<u>\$83,952</u>	<u>\$0</u>	<u>\$83,952</u>
	Reserve for Depreciation						
9	Production	\$12,237	\$0	\$12,237	\$1,264	\$0	\$1,264
10	Storage	24,135	0	24,135	2,492	0	2,492
11	Transmission	20,693	0	20,693	1,444	0	1,444
12	Distribution	323,774	0	323,774	28,853	0	28,853
13	General	8,031	0	8,031	748	0	748
14	Common	39,696	0	39,696	3,694	0	3,694
15	TOTAL Reserve for Depreciation	<u>\$428,566</u>	<u>\$0</u>	<u>\$428,566</u>	<u>\$38,495</u>	<u>\$0</u>	<u>\$38,495</u>
	Net Utility Plant in Service						
16	Production	\$3,322	\$0	\$3,322	\$343	\$0	\$343
17	Storage	10,134	0	10,134	1,047	0	1,047
18	Transmission	31,535	0	31,535	1,975	0	1,975
19	Distribution	430,576	0	430,576	39,023	0	39,023
20	General	8,430	0	8,430	785	0	785
21	Common	24,554	0	24,554	2,284	0	2,284
22	TBT Investment	0	0	0	0	0	0
23	Net Utility Plant in Service	<u>\$508,551</u>	<u>\$0</u>	<u>\$508,551</u>	<u>\$45,457</u>	<u>\$0</u>	<u>\$45,457</u>
24	Utility Plant Held for Future Use	\$0	\$0	\$0	\$0	\$0	\$0
25	Construction Work in Progress	\$738	\$0	\$738	\$33	\$0	\$33
26	Less: Accumulated Deferred Income	\$76,404	\$0	\$76,404	\$6,931	\$0	\$6,931
27	Cash Working Capital	(\$565)	\$52	(\$513)	\$497	(\$41)	\$456
	Other Rate Base Items:						
28	Materials and Supplies	\$1,809	\$0	\$1,809	\$168	\$0	\$168
29	Gas In Storage	53,166	0	53,166	5,781	0	5,781
30	Non-Plant Assets & Liabilities	(19,061)	0	(19,061)	(1,082)	0	(1,082)
31	Prepayments	8,611	0	8,611	880	0	880
32	Customer Advances	(1,416)	0	(1,416)	(6)	0	(6)
33	Other Working Capital	(960)	0	(960)	1,875	0	1,875
34	Total Other Rate Base Items	<u>\$42,149</u>	<u>\$0</u>	<u>\$42,149</u>	<u>\$7,616</u>	<u>\$0</u>	<u>\$7,616</u>
35	Total Average Rate Base	<u><u>\$474,469</u></u>	<u><u>\$52</u></u>	<u><u>\$474,521</u></u>	<u><u>\$46,672</u></u>	<u><u>(\$41)</u></u>	<u><u>\$46,631</u></u>