

**BEFORE THE NORTH DAKOTA PUBLIC SERVICE COMMISSION
STATE OF NORTH DAKOTA**

In the Matter of the Application of Northern Sates 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-06-525

**DIRECT TESTIMONY OF
MICHAEL J. MAJOROS, JR.**

May 1, 2007

Table of Contents

Introduction.....	1
Subject and Purpose of Testimony.....	2
Prior Experience	2
NSPC Case No. PU-400-00-521	3
Gas Price and Cost Trends.....	4
Summary of NSPC’s Filing	6
NSPC’s Rationalization for Increase.....	6
Rate Base Additions	8
Depreciation.....	8
New Information.....	11
Consolidated Taxes	26
Grand Forks MGP Clean Up.....	27
New DSM Program.....	28
Change to Jurisdictional Allocation Factors	29
Customer Sales Forecast – Back Billing.....	30
Summary of Snavelly King Adjustments.....	30

1 **Introduction**

2 **Q. State your name, position, and business address.**

3 A. My name is Michael J. Majoros, Jr. I am Vice President of Snavelly King
4 Majoros O'Connor & Lee, Inc. ("Snavelly King"), located at 1111 14TH Street,
5 N.W., Suite 300, Washington, D.C. 20005.

6 **Q. Describe Snavelly King.**

7 A. Snavelly King is an economic consulting firm founded in 1970 to conduct
8 research on a consulting basis into the rates, revenues, costs and economic
9 performance of regulated firms and industries. Snavelly King represents the
10 interests of government agencies, businesses, and individuals who are
11 consumers of telecom, public utility, and transportation services.

12 We have a professional staff of 11 economists, accountants, engineers
13 and cost analysts. Most of our work involves the development, preparation
14 and presentation of expert witness testimony before Federal and state
15 regulatory agencies. Over the course of our 36-year history, members of the
16 firm have participated in more than 1,000 proceedings before almost all of the
17 state commissions and all Federal commissions that regulate utilities or
18 transportation industries.

19 **Q. Have you prepared a summary of your qualifications and experience?**

20 A. Yes, Appendix A is a summary of my qualifications and experience. Appendix
21 B contains a tabulation of my appearances as an expert witness before state
22 and Federal regulatory agencies.

1 **Q. For whom are you appearing in this proceeding?**

2 A. I am appearing on behalf of the Staff of the North Dakota Public Service
3 Commission.

4 **Subject and Purpose of Testimony**

5 **Q. What is the subject of your testimony?**

6 A. This case involves a filing by Northern States Power Company ("NSPC") for
7 authority to increase its rates by \$2,801,000 or 3 percent.¹ My testimony
8 addresses the increase.

9 **Q. What is the purpose of your testimony?**

10 A. I have reviewed the Company's filing and based upon my findings, I am
11 recommending monetary adjustments to the Company's filed request. My
12 adjustments, which also incorporate Mr. King's rate of return
13 recommendations, reduces the increase from \$2,801,000 to \$1,213,000.

14 **Prior Experience**

15 **Q. Do you have any specific experience in the public utility field?**

16 A. Yes, I have been in the field of public utility regulation since the late 1970's.
17 My testimony has addressed numerous revenue requirement issues.
18 Furthermore, I and other members of my firm specialize in the field of public
19 utility depreciation. We have appeared as expert witnesses on this subject
20 before the regulatory commissions of almost every state in the country.

21 **Q. Have you ever testified in any proceedings involving NSPC or any of its**

¹ Larsen Direct, p.2.

1 **affiliates?**

2 A. Yes, recently I testified before the Colorado Public Utilities Commission in
3 Docket Nos. 06S-234EG and 06S-656G regarding Public Service Company of
4 Colorado's ("PSCo") electric and gas base rates. I also submitted testimony in
5 NSPC's North Dakota Case No. PU-400-00-521.

6 **NSPC Case No. PU-400-00-521**

7 **Q. Summarize your testimony and the outcome in Case No. PU-400-00-521.**

8 A. In that proceeding, NSPC originally proposed a \$1.4 million or 3.3 percent rate
9 increase based on a year 2000 test period. The Company subsequently
10 increased its request to \$1.6 million for additional costs of cleaning up the
11 manufactured gas plant site in Grand Forks.

12 My testimony in Case No. PU-400-00-521 recommended a \$247
13 thousand increase. My adjustments addressed:

- 14 (1) manufactured gas clean-up costs,
15 (2) the annual savings and cost of the Company's August, 2000
16 merger with New Century Energies, and
17 (3) the gas mains depreciation rate.

18 I also made an alternative proposal removing the amortization of the Grand
19 Forks clean up from base rates and including it in the PGA. The parties
20 settled Case PU-400-00-521 after the conclusion of evidentiary hearings.

21 **Q. Do any aspects of that settlement warrant discussion in this case?**

22 A. Yes, two aspects of the Case No. PU-400-00-521 settlement warrant

1 discussion. These two provisions are summarized below, and they will be
2 discussed in more detail later.

3 A. PU-400-00-521 Depreciation Rates. My testimony recommended a 55-
4 year life for gas mains, but the settlement retained the existing 45-year
5 service life. Paragraph 5 of the settlement specifically stated, "This
6 settlement Agreement does not in any way limit the Staff's authority to
7 advocate, or the Commission's authority to establish, revised
8 depreciation rates in future natural gas proceedings."²

9 B. PU-400-00-521 MGP Remediation Costs. The parties agreed that the
10 Company should amortize \$2.88 million of costs incurred by the
11 Company to remediate the former Grand Forks MGP site over eight (8)
12 years starting September 1, 2001. However, there was to be no rate
13 base treatment of the unamortized balance the of [sic] MGP
14 expenditures or related accumulated deferred income taxes. The
15 parties also agreed the MGP cost recovery shall occur through an
16 adjustment to the Company's annual Purchased Gas Adjustment
17 ("PGA").³

18 **Gas Price and Cost Trends**

19 **Q. Do you have any information concerning gas prices that provides a**
20 **backdrop for this revenue requirement testimony?**

² Northern States Power Company d/b/a Xcel Energy, Notice of Gas Rate Change, Case No. PU-400-00-521, Settlement Agreement paragraph 5. Also see, June 27, 2001 Findings of Fact, Conclusions of Law and Order, paragraph 14.

³ Id., paragraphs 5 and 15.

1 A. Yes, I do. Exhibit___ (MJM-1) consists of two charts of publicly available gas
2 price data for the last thirty years. Page 1 is Average U.S. Natural Gas
3 Wellhead Prices. Page 2 is Average U.S. Natural Gas Residential Price.

4 **Q. What do the charts demonstrate?**

5 A. They demonstrate a long-term rise in national gas prices with a rapid
6 acceleration beginning in 2000.

7 **Q. Do you have similar information for North Dakota?**

8 A. Yes, Exhibit___ (MJM-2) provides similar information for North Dakota. The
9 North Dakota tracks the national data.

10 **Q. What do you conclude from these charts?**

11 A. Natural gas prices are rising at a rapid rate and in my opinion will continue to
12 rise given the finite nature of natural gas. Local gas distribution companies
13 (“LDC”) are not able to control the market price of gas, and given that it is their
14 largest expense, regulation allows a pass through of these costs directly to
15 customers. NSPC’s PGA passes gas costs directly to its customers who are
16 in turn obviously aware of the direction and magnitude of such increases.

17 On the other hand, LDCs are able to control other aspects of their costs
18 and the items they include in rate case filings. Exhibits___ (MJM-1) and
19 (MJM-2) provide ample evidence in my opinion that LDCs should be careful to
20 include only credible costs in rate case filings and be prepared to fully support
21 those costs when challenged by public service commissions and other parties.

1 **Summary of NSPC's Filing**

2 **Q. Summarize the Company's filing in this case.**

3 A. NSPC's policy witness, Mr. Larsen, proposes a \$2,801,000 or 3 percent rate
4 increase in order to recover [the Company's] prudent costs of service and earn
5 a reasonable rate of return.⁴ The Company's revenue requirement witness,
6 Mr. Robinson elaborates that "the North Dakota retail rate jurisdiction's retail
7 gas operation' overall retail revenue requirement [is] \$95,845,000 and a
8 revenue deficiency of \$2,801,000 determined by the cost of service for the
9 2007 budget test year."⁵ The increase incorporates an 11.3 percent return on
10 equity.

11 **NSPC's Rationalization for Increase**

12 **Q. How does the Company rationalize the overall increase.**

13 A. According to Mr. Larsen "increases from customer and sales growth in [the
14 Company's] North Dakota service area is not sufficient to offset the increased
15 cost of installing new mains and services, operating and maintaining our
16 natural gas distribution system and providing the type of service our customers
17 have come to expect."⁶

18 Mr. Larsen bases the requested increase on several principal factors:

19 1. The rate base growth of the Company's natural gas investment in North

⁴ Id.

⁵ Robinson Direct, page 2.

⁶ Larsen Direct, page 2.

- 1 Dakota⁷
- 2 2. Depreciation expense increases associated with plant growth in North
- 3 Dakota⁸
- 4 3. \$3.9 million of new mains and services, and reconstruction in 2005 and
- 5 2006⁹
- 6 4. A \$1.5 million natural gas pipeline relocation project to accommodate a
- 7 North Dakota department of Transportation upgrade.¹⁰
- 8 5. A \$1.7 million increase to operation and maintenance expense since
- 9 the last rate case due to wage increase, inflation and changes to
- 10 jurisdictional assignment of costs to North Dakota¹¹
- 11 6. Higher incidences of uncollectible accounts¹²
- 12 7. A new demand side management program “which adds about \$138,000
- 13 of new costs to the 2007 test year.”¹³
- 14 8. Depressed commercial *firm service* sales relative to what was projected
- 15 in the 2004 test year in Case No. PU-400-04-578.¹⁴

16 **Q. Have you conducted an investigation of the Company’s rate request?**

17 A. Yes, my assistant and I read the Company’s filing and propounded numerous

18 data requests related to the Company’s rate request. As a result of this

⁷ Larsen, page 9.

⁸ Id.

⁹ Id.

¹⁰ Id.

¹¹ Id., page 10.

¹² Id.

¹³ Id.

1 investigation, I recommend that the Company's base rates be increased by
2 \$1.213 million as shown on Exhibit MJM-8, page 1 of 7.

3 **Rate Base Additions**

4 **Q. Are you challenging NSPC's \$3.9 million of new mains and services and**
5 **reconstruction, or its \$1.5 million natural gas pipeline relocation project?**

6 A. No, I am not challenging those rate base additions.

7 **Depreciation**

8 **Q. Is depreciation an important aspect of this case?**

9 A. Yes, it is. The depreciation expense relating to plant growth is Mr. Larsen's
10 second major reason for NSPC's proposed increase. In fact, Mr. Robinson's
11 Exhibit reveals that depreciation is NSPC's single largest expense after the
12 purchased gas cost. NSPC's depreciation expense exceeds \$30 million, all of
13 which is non-cash. In other words, depreciation is the largest expense in this
14 base rate case.

15 **Q. Is it reasonable to conclude that Staff might investigate depreciation in**
16 **this case?**

17 A. Yes, based on the fact that depreciation is NSPC's largest non-gas expense,
18 and based on the specific settlement provision in Case No. PU-400-00-521, it
19 is reasonable to assume that Staff might investigate depreciation in this case.

20 **Q. Did you attempt to investigate depreciation in this case?**

¹⁴ Id.

1 A. Yes, but I ran into a brick wall. Exhibit____(MJM-3) is a series of NSPC's
2 responses to staff data requests relating to depreciation. A consistent
3 response was as follows:

4 The Company declines to answer this question
5 because it requests information that is
6 irrelevant to determining the North Dakota
7 depreciation expense included in the test year
8 revenue requirement. The process for
9 establishing the depreciation is far too time
10 consuming and complicated to be conducted
11 effectively other than through a standalone
12 proceeding specific to that purpose. Instead,
13 the Commission has historically relied on the
14 depreciation expense established in the most
15 recent Minnesota proceeding for that
16 purpose.¹⁵
17

18 **Q. Were you able to analyze depreciation regardless of these responses?**

19 A. I was not able to analyze or challenge depreciation.

20 **Q. What do you conclude as a result of the responses?**

21 A. In my opinion, the credibility of NSPC's depreciation claim may be at stake.
22 Some might consider NSPC's responses as grounds for possible rejection of
23 its entire depreciation expense claim. As noted above, depreciation was
24 specifically identified as problematic in Case No. PU-400-00-521, it is the
25 single largest non-gas expense in NSPC's income statement and it is a
26 primary driver of this rate case.

27 **Q. Do you have any opinions concerning NSPC's depreciation expense as**
28 **filed?**

1 A. Yes, the life for mains is still too short, and new accounting information reveals
2 that NSPC has been over collecting for cost of removal by virtue of its
3 Minnesota depreciation rates.

4 **Q. Why do you say the mains life is still too short?**

5 A. The company's response to Staff 1-99 provides the company's most recent
6 Minnesota depreciation study. That study shows a 45-year life for mains.¹⁶ As
7 I stated in Case No. PU-400-00-521, based on my experience 45 years is too
8 short. I think the 45-year life may underlie NSPC's North Dakota depreciation,
9 but I am not certain. NSPC asserts that the depreciation rate in North Dakota
10 reflects the use of the Minnesota rates, but it was unable to provide the
11 schedules that would enable me to trace the rates through to the North Dakota
12 filing.¹⁷

13 **Q. Did you attempt to test the forty-five years?**

14 A. Yes, I requested the data necessary to conduct independent life studies, but
15 NSPC refused to provide that data.¹⁸ Consequently, my opinion from Case
16 No. PU-400-00-521 regarding the life of mains has not changed. I still believe
17 the 45-year life is too short, thus resulting in an excessive depreciation rate.

18 **Q. Explain how new accounting information reveals that NSPC has been**
19 **over collecting for cost of removal by virtue on its Minnesota**
20 **depreciation rates.**

¹⁵ NSPC responses to Staff Information Request Set 1, Nos. 114-125, 128-135, 143, 146-154 and 156-157.

¹⁶ Company response to Staff Information Request No. 1-99.

¹⁷ Company response to Staff Information Request No. 1-100.

1 A. NSPC's Minnesota depreciation rates include inflated future cost of removal
2 factors for costs they probably will not incur in their entirety. New information
3 revealed by recent accounting pronouncements has highlighted this fact.

4 **New Information**

5 **Q. Describe the new information revealed by recent accounting**
6 **pronouncements.**

7 A. Recent accounting pronouncements reveal that NSPC's prior recognition of
8 future cost of removal in Minnesota depreciation rates has resulted in
9 significant liabilities to ratepayers.

10 **Q. What is the genesis of this new information?**

11 A. The genesis of the new information is the Financial Accounting Standards
12 Board's ("FASB") 2002 Statement of Financial Accounting Standard No. 143
13 ("SFAS No. 143") which addresses AROs associated with long-lived plant.¹⁹

14 SFAS No. 143's focus is legal obligations to incur a cost when an asset
15 is retired – legal asset retirement obligations ("legal AROs"). SFAS No. 143
16 considers such obligations to be a component of the original cost of the asset.
17 It requires capitalization and depreciation of the discounted fair value of the
18 estimated asset retirement cost over the asset's life.

19 SFAS No. 143 also identified a significant regulatory liability resulting
20 from public utilities' past inclusion of excessive future cost of removal and
21 dismantlement factors in depreciation rates. FERC identified these amounts

¹⁸ Company response to Staff Information Request No. 1-114.

1 as “non-legal” asset retirement obligations, meaning that the utilities do not
2 have actual legal obligations and liabilities to incur these costs in the future.²⁰
3 SFAS No. 143 requires reporting of non-legal AROs as regulatory liabilities to
4 ratepayers - if the requirements of SFAS 71 are met.²¹

5 **Q. What conditions create a regulatory liability using GAAP?**

6 A. SFAS 71, ¶11, provides that a regulator’s rate actions impose a liability on the
7 utility to its customers (regulatory liability) if the regulator provides “current
8 rates intended to recover cost expected to be incurred in the future with the
9 understanding that if those costs are not incurred, future rates will be reduced
10 by corresponding amounts.”²² For Commission-regulated utilities, this
11 “understanding” has been implicit. Nevertheless, it is sufficiently clear to
12 NSPC’s parent to warrant creation of the regulatory liability for GAAP financial
13 reporting purposes. Now that SFAS No. 143 has identified the amounts, this
14 Commission should recognize them as the regulatory liabilities they are.

15 **Q. Does NSPC have any regulatory liabilities relating to non-legal AROs?**

16 A. Yes, Xcel’s SEC Form 10-K Reports show the following regulatory liabilities in
17 compliance with SFAS No. 143:

¹⁹ FERC Order No. 631 is that agency’s implementation of SFAS No. 143 for regulatory purposes for utility operations subject to that agency’s jurisdiction.

²⁰ FERC Order No. 631, para. 36.

²¹ SFAS No. 143, paragraph B.73.

²² SFAS No. 71, ¶11 and 11(b).

Xcel Energy, Inc.

Summary of New Information
Regulatory Liabilities Resulting from Non-Legal AROs
(\$millions)²³

<u>Year Ended</u>	<u>NSP-MN</u>	<u>NSP-WI</u>	<u>PSCo</u>	<u>SPS</u>	<u>Total Xcel</u>
2003	\$ 324	\$ 75	\$ 351	\$ 102	\$ 852
2004	323	81	383	104	891
2005	334	86	377	98	895
2006	355	91	389	85	920

This table clearly shows that the regulatory liability is continuing to grow. In fact, the largest growth from 2005 to 2006 belongs to NSP-Minnesota. North Dakota's portion would be included in that amount.

Q. What causes the increase to the regulatory liability each period?

A. The increase to the cost of removal liability each period is the estimated removal cost NSPC collected from ratepayers, over and above its actual removal cost expenditures for the period.

Q. Do you know the actual regulatory liability for cost of removal related to NSPC's North Dakota jurisdiction?

A. No, I do not. Information Request No. 1-152 asked for that data, but as shown in its response below, the Company "declined" to provide it.

Question:

Refer to page F-47 of Xcel Energy's December 31, 2006 Form 10K. Provide the accounting entries (debits and credits) used to implement SFAS No. 143

²³ Xcel Energy, Inc. December 31, 2004 10-K Report, page 126 and December 31, 2006 10-K Report, page F-47.

1 and FIN 47, along with all workpapers supporting
2 those entries, including the workpapers supporting the
3 calculation of the \$355 million (2006) and \$334 million
4 (2005) regulatory liabilities for asset cost of removal
5 for NSP-Minnesota. Please provide all these
6 workpapers and calculations in electronic format
7 (Excel) with all formulae intact. Indicate the amounts
8 applicable to North Dakota jurisdiction gas and
9 common plant.

10
11 Response:

12 The Company declines to answer this question
13 because it requests information that is irrelevant to
14 determining the North Dakota depreciation expense
15 included in the test year revenue requirement. The
16 process for establishing the depreciation is far too
17 time consuming and complicated to be conducted
18 effectively other than through a standalone
19 proceeding specific to that purpose. Instead, the
20 Commission has historically relied on the depreciation
21 expense established in the most recent Minnesota
22 proceeding conducted for that purpose.²⁴

23
24 **Q. Explain the new issues resulting from SFAS NO. 143 and FERC Order No.**
25 **631.**

26 A. There are several new issues. One important new issue is the need for the
27 Commission to **recognize** NSPC's non-legal ARO reserve as a regulatory
28 liability for regulatory and ratemaking purposes. Although Xcel has properly
29 recognized these amounts as regulatory liabilities in its 2003-2006 10-K
30 reports, NSPC has not done so for regulatory and ratemaking purposes.

31 **Q. Does Xcel disclose the amount of the cost of removal regulatory liability**
32 **in its 2005 FERC Form 1 report to the FERC?**

²⁴ Company response to Information Request No. 1-152.

1 A. Xcel did not include the regulatory liability for electric cost of removal in its
2 schedule of Other Regulatory Liabilities on page 278 of its NSP - Minnesota's
3 2005 FERC Form 1. Instead, it has the following statement in the Notes to
4 Financial Statements section.

5 Also, estimated removal costs for future removal
6 obligations are classified as accumulated depreciation
7 on the utility plant in the FERC presentation and
8 regulatory liabilities in the GAAP presentation.²⁵
9

10 **Q. What do you recommend?**

11 A. The Commission should require NSPC to file a stand alone North Dakota
12 Depreciation study. The Commission should also enforce the separate
13 identification and reporting requirements of FERC Order No. 631, and go one
14 step further and direct NSPC to transfer the amount to account 254—other
15 regulatory liabilities. Then, the Commission will need to address the issue of
16 what to do about the huge balance in this regulatory liability, and finally, in light
17 of the regulatory liability, the Commission must determine what to include in
18 depreciation on a going-forward basis.

19 **Q. Why is it necessary for the Commission to recognize a regulatory liability**
20 **for the non-legal cost of removal and dismantlement amounts?**

21 A. Although the FERC has recognized and isolated the amounts involved, FERC
22 does not require reporting them as regulatory liabilities. FERC deferred this
23 decision to the states which are the primary ratemaking bodies.
24 Consequently, while FERC Order No. 631 provides a new transparency by

1 requiring identification of the amounts and maintenance of separate subsidiary
2 records for regulatory analysis and rate setting purposes, it did not specifically
3 recognize a regulatory liability for non-legal AROs.

4 As a result, nothing holds NSPC specifically accountable for these
5 excess collections, even though the public accounting profession and the
6 Securities and Exchange Commission recognize that they are regulatory
7 liabilities and that the PSC implicitly holds NSPC accountable.

8 Regardless of the transparency provided by FERC's new requirements,
9 NSPC does not even identify or mention these requirements or the issue in its
10 rate case filing, and it refused to provide any relevant information. This is an
11 intolerable situation. The accountability must be explicit, and the Commission
12 must establish that accountability.

13 My experience shows that it is unlikely that all of the amounts collected
14 will be spent for future cost of removal. Nevertheless, even if it was highly
15 probable that NSPC might spend all this money for future cost of removal, it is
16 fair and reasonable for the Commission to recognize the ratepayers' claims on
17 these monies until actually spent on their intended purpose. Unless they are
18 explicitly identified as "subject to refund" there is an ongoing and wholly
19 unnecessary risk that they are merely hidden potential income to Xcel.

20 It is critical that the Commission require NSPC to explicitly identify and
21 report this regulatory liability and all related activity in all future reports, rate

²⁵ NSP-Minnesota, 2005 FERC Form 1 Report, page 123.1

1 cases and depreciation studies that it files with the Commission. The
2 Commission should require prominent disclosure of its explicit recognition of
3 this amount as an intrastate regulatory liability in Xcel's future FERC Form 1
4 and 2 reports to ensure sufficient recognition of and transparency concerning
5 these amounts.

6 Without a requirement for separate identification and reporting of these
7 amounts, they are hidden from the ratemaking process and regulatory scrutiny
8 in North Dakota. If it were not for my testimony, the issue would not have
9 come before the Commission in this proceeding even though Xcel's NSP-
10 Minnesota subsidiary has built a \$355 million cost of removal regulatory
11 liability with no explicit plan to either return the money or to spend the money
12 for cost of removal.

13 **Q. What is wrong with continuing to record the regulatory liability as**
14 **accumulated depreciation?**

15 A. Xcel and all utilities consider accumulated depreciation to represent the
16 measure of their capital that they have recovered from their ratepayers. As
17 simplistic as it sounds, *utilities consider any amount in accumulated*
18 *depreciation to be "their money" even if they collected it for a fictitious future*
19 *cost.*

20 **Q. Does NSPC agree that its collections for non-legal AROs result in a**
21 **regulatory liability?**

1 A. I do not know. As mentioned earlier, NSPC declined to respond to our
2 information request on this issue. However, as the Company explains in its
3 2006 10-K Report,

4 Our regulated utility subsidiaries account for certain
5 income and expense items in accordance with SFAS
6 No. 71 – “Accounting for the Effects of Certain Types
7 of Regulation.” Under SFAS No. 71:

- 8 • Certain costs, which would otherwise be
9 charged to expense, are deferred as regulatory
10 assets based on the expected ability to recover
11 them in future rates; and
- 12 • Certain credits, which would otherwise be
13 reflected as income, are deferred as regulatory
14 liabilities based on the expectation they will be
15 returned to customers in future rates.

16 Estimates of recovering deferred costs and returning
17 deferred credits are based on specific ratemaking
18 decisions or precedent for each item. Regulatory
19 assets and liabilities are amortized consistent with the
20 period of expected regulatory treatment.

21 If restructuring or other changes in the regulatory
22 environment occur, our regulated utility subsidiaries
23 may no longer be eligible to apply this accounting
24 treatment, and may be required to eliminate such
25 regulatory assets and liabilities from their balance
26 sheets. Such changes could have a material effect on
27 Xcel Energy’s results of operations in the period the
28 write-offs are recorded.²⁶

29 Xcel Energy’s regulated businesses prepare their
30 Consolidated Financial Statements in accordance with
31 the provisions of SFAS No. 71, as discussed in Note 1
32 to the Consolidated Financial Statements. Under
33 SFAS No. 71, regulatory assets and liabilities can be
34 created for amounts that regulators may allow to be
35 collected, or may require to be paid back to customers
36 in future electric and natural gas rates. Any portion of

²⁶ Xcel Energy Inc., December 31, 2006 10-K Report, p. F-12.

1 Xcel Energy's business that is not rate regulated
2 cannot use SFAS No. 71 accounting. If changes in
3 the utility industry or the business of Xcel Energy no
4 longer allow for the application of SFAS No. 71 under
5 GAAP, Xcel Energy would be required to recognize
6 the write-off of regulatory assets and liabilities in its
7 statement of income.²⁷

8 Removal Costs – Xcel Energy accrues an
9 obligation for plant removal costs for other
10 generation, transmission and distribution facilities
11 of its utility subsidiaries. Generally, the accrual of
12 future non-ARO removal obligations is not required.
13 However, long-standing ratemaking practices
14 approved by applicable state and federal regulatory
15 commissions have allowed provisions for such
16 costs in historical depreciation rates. These
17 removal costs have accumulated over a number of
18 years based on varying rates as authorized by the
19 appropriate regulatory entities. Given the long
20 periods over which the amounts were accrued and
21 the changing of rates through time, the utility
22 subsidiaries have estimated the amount of removal
23 costs accumulated through historic depreciation
24 expense based on current factors used in the
25 existing depreciation rates.²⁸

26 Xcel reports a \$355 million regulatory liability for cost of removal for
27 NSP – Minnesota as of December 31, 2006.²⁹ Given that Xcel can only create
28 a regulatory liability consistent with the letter and spirit of SFAS No. 71, the
29 Company must have determined (at least for financial reporting purposes) that,
30 in its management's judgment, the amounts it has collected but not yet spent
31 for costs of removal are "probable" of being credited to ratepayers through the

²⁷ Xcel Energy Inc., December 31, 2006 10-K Report, p. F-55 (emphasis added).

²⁸ Xcel Energy Inc., December 31, 2006 10-K Report, p. F-47 (emphasis added).

²⁹ Id.

1 ratemaking process. SFAS No. 71 clarifies that the phrase “credited to
2 ratepayers” means “if those costs are not incurred, future rates will be reduced
3 by corresponding amounts.”³⁰

4 Xcel does agree that both GAAP and the SEC recognize this fact, and
5 in order to get a “clean” audit opinion, it must report the amount as a regulatory
6 liability as long as it remains regulated, and subject to cost-based rate
7 base/rate of return regulation.

8 **Q. Why did you emphasize the proviso “as long as it remains regulated and**
9 **subject to cost-based, rate base/rate of return regulation”?**

10 **A.** The Edison Electric Institute and several individual utilities fought hard to avoid
11 having either the FASB or FERC require the identification and reporting of the
12 regulatory liability that I have just described. In fact, notice the qualification and
13 warning built into Xcel’s 2006 10-K Report as quoted above.

14 I am concerned because if Xcel were to be deregulated, or if regulation
15 were to change from “cost-based” to some form of alternative “price-based”
16 regulation, history tells us the Company would have every interest in
17 immediately transferring its \$355 million regulatory liability into its GAAP
18 income. This amount could well disappear from the scene unless the
19 Commission protects it on behalf of ratepayers. Therefore, this amount must
20 be specifically designated as a regulatory liability for ratemaking purposes.

³⁰ SFAS No. 71, ¶11b.

1 **Q. Why do you believe that Xcel would transfer its \$355 million non-legal**
2 **regulatory liability into GAAP income?**

3 A. As Xcel warns in its 2006 10-K Report, it will transfer the regulatory liability into
4 GAAP income because that is what GAAP requires. If deregulated, or if
5 regulation changes significantly, the provisions of SFAS No. 71 will no longer
6 apply. The regulatory liability amount will flow immediately and explicitly to
7 GAAP income, because SFAS No. 143 requires it to flow to income if it is not
8 payable to ratepayers. This is what electric utilities did when their production
9 plants were deregulated, and this is what Xcel warns it will do in its 2006 10-K
10 Report.

11 **Q. Do you have any credible evidence of such treatment?**

12 A. Yes, American Electric Power had several of its production plants deregulated.
13 It immediately transferred \$473 million from accumulated depreciation into
14 income relating to those deregulated plants.³¹

15 In another example, Tucson Electric Power Company ("TEP") stated
16 that:

17 TEP had accrued \$113 million for final
18 decommissioning of its generating facilities. ... this
19 amount was reversed for 2002 and included as part of
20 the cumulative effect adjustment of accounting
21 adjustment when FAS 143 was adopted on January
22 1, 2003.³²

23 This means that TEP transferred non-legal AROs into income.

³¹ AEP 2003 Annual Report to Shareholders, page 69.

³² Tucson Electric Power Company December 31, 2004 10 K Report, page K-59.

1 For its regulated operations, which include the transmission and
2 distribution portions of its business, TEP continued to apply SFAS 71. As a
3 result, TEP recorded the cost of removal collected for regulated non-legal
4 AROs as a regulatory liability.

5 As of December 31, 2004, TEP had accrued \$67
6 million for the net cost of removal of the interim
7 retirements from its transmission, distribution and
8 general plant. As of December 31, 2003, TEP had
9 accrued \$60 million for these removal costs. The
10 amount is recorded as a regulatory liability.³³

11 However, TEP also reported:

12 If TEP stopped applying FAS 71 to its remaining
13 regulated operations, it would write off the related
14 balances of its regulatory assets as an expense and
15 its regulatory liabilities as income on its income
16 statement.³⁴

17 The term “write off” is a euphemism for transferring the money to income.

18 **Q. Is TEP aware that you have used the quotation above to make the point**
19 **that given the chance a utility will transfer the regulatory liability to**
20 **income?**

21 A. Yes, in November 2005, the Public Utilities Fortnightly published an article I
22 wrote concerning the issues at hand in this proceeding.³⁵ I have included the
23 article, and the resulting responses as Exhibit___(MJM-4) to my testimony.

24 The article included the quotation from TEP’s 2004 10-K Report.

³³ Id., page K-60.

³⁴ Id. (Emphasis added.)

³⁵ Exhibit ___ (MJM-4), pages 1-6. Public Utilities Fortnightly, “Rate Base Cleansings: Rolling Over Ratepayers”, November 2005, pages 58-62.

1 Subsequently, Karen G. Kissinger, TEP's Vice President, Controller & Chief
2 Compliance Officer responded to my article.³⁶ Ms. Kissinger leveled several
3 attacks against my logic, but her last sentence corroborated the risk to
4 ratepayers that I identified in the article. Ms. Kissinger finished her letter
5 saying: "Ratepayers are not entitled to a refund of costs recognized to provide
6 services they have already received."³⁷ That means that TEP believes that its
7 ratepayers should pay it money in advance for future costs of removal, with no
8 expectation of a refund or future rate decrease should TEP not use the funds
9 for their intended purpose – in that event, they belong to TEP. Xcel's
10 ratepayers are subject to the same risks.

11 **Q. Does Xcel make a similar statement regarding charging to income the**
12 **amounts recorded as regulatory liabilities should it no longer be able to**
13 **apply SFAS No. 71 to its operations?**

14 A. Yes, as quoted above, Xcel's 2006 10-K Report warns, "If changes in the utility
15 industry or the business of Xcel Energy no longer allow for the application of
16 SFAS No. 71 under GAAP, Xcel Energy would be required to recognize the
17 write-off of regulatory assets and liabilities in its statement of income."³⁸

18 **Q. Have any other industries transferred non-legal ARO amounts into**
19 **income?**

³⁶ Id., page 12. Public Utilities Fortnightly, Letters to the Editor, April 2006, page 10.

³⁷ Id.

³⁸ Xcel Energy Inc., December 31, 2006 10-K Report, p. F-55.

1 A. Yes, while still regulated, the telephone industry collected substantial amounts
2 of future cost of removal from its ratepayers through depreciation, just as Xcel
3 wants to continue doing. Upon deregulation and the adoption of SFAS No.
4 143, the major telephone companies transferred \$11.5 **billion** from
5 accumulated depreciation into their net income.³⁹

6 **Q. What should the Commission do with Xcel's regulatory liability on a**
7 **going-forward basis?**

8 A. There are a number of alternatives to the treatment of the regulatory liability on
9 a going-forward basis. The Commission could require continued maintenance
10 as a permanent rate base offset representing customer-provided capital, or
11 amortization back to ratepayers over some specified amortization period. I
12 prefer an amortization, because I do not believe Xcel will ever spend all of this
13 money on future cost of removal, and as long as the money remains in Xcel's
14 hands, it will do whatever it can to convert the regulatory liability to income. An
15 amortization would reduce annual depreciation expense over the amortization
16 period. At a time of ever-increasing energy prices, this would be welcome
17 relief to Xcel's customers, as well as a means to eliminate the regulatory
18 liability.

19 **Q. Are you recommending an amortization of the cost of removal regulatory**
20 **liability in this case?**

³⁹ Pre-tax gains of SBC (\$5.9 billion), Verizon (\$3.5 billion), Qwest (\$0.4 billion), BellSouth (\$1.3 billion) and Sprint (\$0.4 billion). See SBC, Verizon, Qwest, BellSouth and Sprint's 2003 10K Reports and 2003 Annual Reports to Shareholders.

1 A. Ordinarily I would make this recommendation. However, in this case the
2 Company has declined to provide the data necessary to identify the regulatory
3 liability related to North Dakota operations.

4 **Q. How much non-legal ARO cost is included in the annual depreciation**
5 **expense under NSPC's current depreciation rates?**

6 A. I do not know. Although the Company has provided the depreciation studies
7 and orders underlying the current rates, it has not provided sufficient
8 information to calculate the amount of cost of removal included in its test
9 period.

10 **Q. What do you recommend?**

11 A. The solution is recognition of the non-legal ARO regulatory liability and a stand
12 alone North Dakota specific depreciation study. It is no longer appropriate to
13 rely on Minnesota regulators to protect North Dakota ratepayers. As quoted
14 from Xcel's responses to many of my depreciation related Information
15 Requests, "The process for establishing the depreciation is far too time
16 consuming and complicated to be conducted effectively other than through a
17 standalone proceeding specific to that purpose." Because the Company has
18 "declined" to provide Staff the data and information necessary to perform a
19 satisfactory review of its depreciation rates, I recommend that the Commission
20 implement a "standalone proceeding specific to that purpose" and require
21 NSPC to produce a standalone study for North Dakota in which lives, net
22 salvage, methods, procedures and techniques are subject to change and

1 challenge. As part of this proceeding I also recommend the Commission
2 review the regulatory liability for cost of removal related to North Dakota,
3 recognize it as a regulatory liability for North Dakota ratemaking, and consider
4 amortizing the amount back to North Dakota ratepayers.

5 **Consolidated Taxes**

6 **Q. Do you have any other examples of Xcel refusing to provide information**
7 **that might be relevant to a revenue requirement finding in this**
8 **proceeding?**

9 A. Yes, I do. Xcel is a participant in a consolidated federal income tax return.
10 These arrangements can result in the ratepayers of regulated entities
11 subsidizing losses of unregulated affiliates. In other public utility cases I have
12 read tax allocation agreements between the parties to consolidated tax
13 returns. On more than one occasion, I have see words requiring that taxes
14 collected from a regulated entity be passed through the parent to the loss
15 affiliates.

16 In this case, we submitted several data requests in this regard, only to
17 have the NSPC decline to respond. For example, in response to Staff 1-78,
18 NSPC responded as follows:

19 The Company objects to the [consolidated tax]
20 question on the grounds that the North Dakota
21 Public Service Commission uses the stand-
22 alone method to determine taxes for
23 ratemaking, which makes the question
24 irrelevant and unreasonably burdensome, The
25 stand-alone method bases the computation of
26 current and deferred tax expense on the

1 Company's jurisdictional utility income alone,
2 excluding both income and losses from
3 regulated activities in other jurisdictions and
4 non-regulated activities of the Company, its
5 affiliates, and its parent Xcel Energy, Inc.⁴⁰
6

7 **Q. Did the Company indicate it would make these materials available upon**
8 **signing a proprietary agreement?**

9 A. Yes, it did.

10 **Q. Has the Commission employed the stand-alone approach in the past?**

11 A. Yes, it has. However, given the experience with gas cost increases, I
12 recommend that the Commission revisit the issue. In a period of dwindling
13 resources and corresponding upward price spirals, the Commission should at
14 least know the magnitude of the consolidated tax subsidy and reconsider
15 whether captive ratepayers should be required to pay anymore than actual
16 taxes. The Commission should place NSPC on alert in this proceeding that it
17 intends to revisit the consolidated tax issue in the next rate case.

18 **Grand Forks MGP Clean Up**

19 **Q. Does NSPC's filing comply with the PU-400-00-521 settlement**
20 **concerning its Grand Forks MGP clean-up costs?**

21 A. No, NSPC's filing is at odds with the settlement. Above I quoted the specific
22 language precluding rate base treatment of the unamortized costs. Yet, Mr.
23 Robinson states, "We [Xcel] included the unamortized balance of the
24 Manufactured Gas Plant clean-up costs approved in our last natural gas case

⁴⁰ Response to Staff IR No. 1-78.

1 (Case No. PU-400-04-528).”⁴¹

2 **Q. Were you a witness in Case No. PU-400-04-528?**

3 A. I was not a witness in that case, and I am not familiar with its terms. I
4 understand, however, there was a black box settlement in that proceeding.
5 The Company’s attempt to gain rate base treatment in this case is yet another
6 indication of the credibility of its filing.

7 Nevertheless, the settlement in Case No. PU-400-00-521 specifically
8 precluded rate base treatment. As such, I am removing the unamortized
9 balance of the MGP clean-up costs including the associated deferred taxes
10 from the rate base in this filing. Exhibit___(MJM-5) contains the pages from
11 NSPC’s workpapers that deal with this issue. The net reduction to rate base is
12 \$320 thousand.

13 **New DSM Program**

14 **Q. Explain NSPC’s proposal regarding its new DSM program.**

15 A. NSPC proposes to increase its expenses in order to market and provide home
16 energy audits, furnace and boiler rebates, water heater rebates, and energy-
17 efficient “low-flow” showerheads.⁴² NSPC expects to spend \$138,000 annually
18 on these initiatives.⁴³ Consequently, it proposes to increase 2007 expenses
19 by \$138,000.

20 **Q. What do you recommend?**

⁴¹ Robinson Direct, page 28.

⁴² Sundin Direct, page 3.

⁴³ Id.

1 A. I recommend disallowance the cost. Ms. Sundin's concern for the hardships
2 caused by "the volatility in natural gas bills over the last several years" is
3 laudable.⁴⁴ However, as shown in my Exhibits MJM-1 and MJM-2, the overall
4 trend of vastly increased gas costs, especially since 2000, incorporates this
5 volatility.

6 Additional increases to provide offsetting rebates is not the answer.
7 The Federal Energy Policy Act of 2005 already provides \$billions of tax
8 incentives, some of which are geared towards individuals and small
9 businesses. It is my understanding that many of these tax breaks apply to the
10 same types of products that Xcel wants to subsidize with this additional
11 expense. Based on these considerations, I recommend disallowance of Xcel's
12 new DSM cost.

13 **Change to Jurisdictional Allocation Factors**

14 **Q. Explain NSPC's proposal regarding its change to allocations factors.**

15 A. NSPC changed the way it counts electric versus gas customers. As a result, it
16 proposes to increase it operating expenses by \$363,182.⁴⁵

17 **Q. What is your opinion regarding this proposal?**

18 A. Mr. King addresses this adjustment in his testimony. He recommends
19 rejection and I concur. Even if the allocation change was correct, NSPC did
20 not receive approval from this Commission to make the change in the first
21 place. As a result, I am removing \$363,182 from operating expenses.

⁴⁴ Id., page 2.

1 **Customer Sales Forecast – Back Billing**

2 **Q. Explain the back billing issue.**

3 A. When Xcel merged with New Century Energy both companies apparently
4 abandoned their customer information systems in favor of a new system. The
5 cost, which was substantial, was included in revenue requirements. However,
6 the new system resulted in a failure to bill 1,898 customers. The Company
7 identified the problem and began back billing those customers. The back
8 billing in turn created several complaints to the Commission. Exhibit____
9 (MJM-6) is a copy of certain emails concerning this issue.

10 We sent Information Request 4-1 to NSPC concerning the back billing
11 issue. Exhibit____(MJM-7) is a copy of the request and response. NSPC
12 anticipates \$148,445 of additional gas revenues in 2007 because of its back
13 billing program but none of those revenues are included in its 2007 test period.
14 I have included the \$148,445 as an addition to 2007 test year revenues.

15 **Summary of Snavely King Adjustments**

16 **Q. Do you have a summary of your individual adjustments to the**
17 **Company's filed revenue requirement?**

18 A. Yes, Exhibit____(MJM-8) summarizes the adjustments. It also incorporates Mr.
19 King's recommended 8.08 percent rate of return. As you can see, my adjusted
20 revenue requirement is \$1.439 million less than NSPC's. This reduces the
21 overall increase to \$1.213 million.

⁴⁵ Response to Staff Information Request Nos. 2-26 and 2-27.

1 Q. Does this conclude your testimony?

2 A. Yes, it does.