

DIVIDER

STATE OF NORTH DAKOTA

□ INFORMATION TECHNOLOGY DEPARTMENT

SFN 2053 (4-2002)

PU-400-00-195

**Northern States Power Company
Performance Based Regulation**

Application

Filed 4/24/2000

Closed 4/17/2006

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STATE OF NORTH DAKOTA
PUBLIC SERVICE COMMISSION

**Northern States Power Company
Performance Based Regulation
Application**

Case No. PU-400-00-195

AFFIDAVIT OF SERVICE BY CERTIFIED MAIL

STATE OF NORTH DAKOTA
COUNTY OF BURLEIGH

Sharon Helbling deposes and says that:

she is over the age of 18 years and not a party to this action and, on the **15th day of August, 2005**, she deposited in the United States Mail, Bismarck, North Dakota, **three** envelopes with certified postage, return receipt requested, fully prepaid, securely sealed and each containing a photocopy of:

Order Denying Request for Extension

The envelopes were addressed as follows:

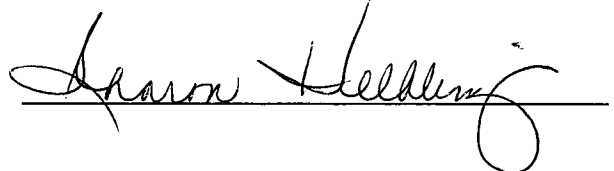
Kent Larson
Northern States Power Company
2302 Great Northern Dr
Fargo ND 58102
Cert. No. 7004 2510 0004 8815 5521

Dave Sederquist
Northern States Power Company
2302 Great Northern Dr
Fargo ND 58102
Cert. No. 7004 2510 0004 8815 5538

Bernadeen Brutlag
Otter Tail Corporation
215 S Cascade St
Fergus Falls MN 56538-0496
Cert. No. 7004 2510 0004 8815 5545

Each address shown is the respective addressee's last reasonably ascertainable post office address.

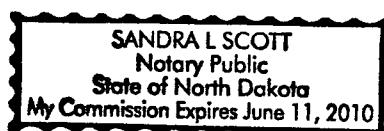
Subscribed and sworn to before me
this **15th day of August, 2005**.





Notary Public

SEAL



STATE OF NORTH DAKOTA
PUBLIC SERVICE COMMISSION

**Northern States Power Company
Performance Based Regulation
Application**

Case No. PU-400-00-195

AFFIDAVIT OF SERVICE BY ORDINARY MAIL OR E-MAIL

STATE OF NORTH DAKOTA
COUNTY OF BURLEIGH

Sharon Helbling deposes and says that:

she is over the age of 18 years and not a party to this action and, on the **15th day of August, 2005**, she deposited in the United States Mail, Bismarck, North Dakota, envelopes by first class mail, fully prepaid, securely sealed, each containing a photocopy of:

Order Denying Request for Extension

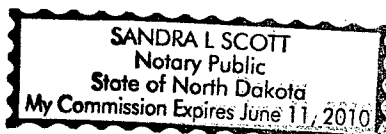
The envelopes were addressed as follows:

See Attached List

Each address shown is the respective addressee's last reasonably ascertainable post office address.

Subscribed and sworn to before me
this **15th day of August, 2005**.

SEAL



A handwritten signature in cursive script, reading "Sharon Helbling", written over a horizontal line.

A handwritten signature in cursive script, reading "Sandra L. Scott", written over a horizontal line.

Notary Public

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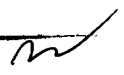
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Valley City ND 58072

Paul Lehman
Xcel Energy
512 Nicollet Mall
Minneapolis MN 55402

MOTION

APPROVED
DATE 8-10-05 

August 10, 2005

**Northern States Power Company
Performance Based Regulation
Application**

Case No. PU-400-00-195

I move the Commission adopt the Order Denying Northern States Power
Company's request for an extension of its Performance Based Regulation plan in Case
No. PU-400-00-195.

MRD/sdh

**STATE OF NORTH DAKOTA
PUBLIC SERVICE COMMISSION**

**Northern States Power Company
Performance Based Regulation
Application**

Case No. PU-400-00-195

ORDER DENYING REQUEST FOR EXTENSION

August 10, 2005

Preliminary Statement

On December 29, 2000, the Commission issued its Findings of Fact, Conclusions of Law and Order approving a performance-based rate (PBR) plan for Northern States Power Company d/b/a Xcel Energy. The order implemented a plan term of 5 years ending December 31, 2005.

On July 1, 2005, Xcel Energy requested to extend its plan one year ending December 31, 2006.

Discussion

In its filing, Xcel states that "the Company anticipates filing a general rate case in the fall of 2006 primarily to recover investments made to renew and/or supplement its fleet of electric generation facilities and new transmission infrastructure" and that it "will be imperative for Xcel Energy to—through a general rate application—'recalibrate' its base electric rates to correspond with the significant plant investments that will go into service during the 2007 to 2009 timeframe."

The Company argues that if an extension is granted it would forgo any "triggered rate relief that would be implemented in 2006 as a result of 2005 earnings and performance." The filing also states that "given that the Company would forgo any plan benefit in the event of a rate case, this modification provides greater flexibility in determining whether a 2005 rate case filing can be avoided."

On July 26, 2005, staff filed a recommendation to deny Xcel Energy's request. Staff argued that the request provides Xcel Energy with more flexibility in pursuing a rate increase but offered little by way of offsetting benefits to ratepayers. Staff argued that to ensure the greatest opportunity for fairness, the Commission should allow the existing plan to expire on December 31, 2005. Such an approach will provide the Commission with an opportunity to review and order on the costs and types of investment supported in Xcel Energy's next rate increase application. A rate increase

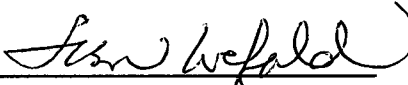
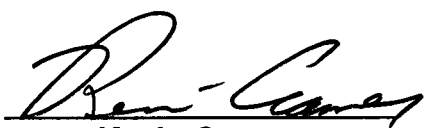
application will mean access to investigative and litigation funds for staff and resulting rates that are established on the facts established in an evidentiary hearing.

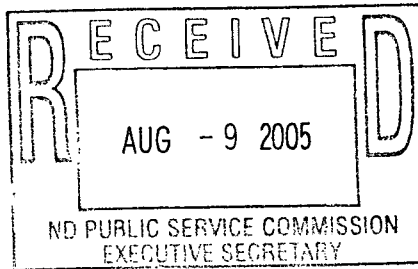
Order

The Commission orders:

Xcel Energy's request for an extension of its performance-based regulation plan denied.

PUBLIC SERVICE COMMISSION

		
Susan Wefald Commissioner	Tony Clark Commissioner	Kevin Cramer Commissioner



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(701) 241-8632
dave.sederquist@xcelenergy.com

August 9, 2005

Mike Diller, Director of Accounting
North Dakota Public Service Commission
State Capitol Building, Dept. 408
600 East Boulevard
Bismarck, ND 58505-0480

RE: PLUS PLAN SURCHARGE
CASE NOS. PU-400-00-195 (PLUS PLAN), PU-400-04-216 (2003 EARNINGS)

Dear Mike:

You requested information from Northern States Power Company d/b/a Xcel Energy regarding the costs versus benefits of using a line item surcharge versus recovery through the Fuel Clause Adjustment (FCA) to recover the PLUS Plan surcharge amount of \$954,000, or approximately \$5 for a typical residential electric service customer.

Although the Company's letter dated June 29, 2005, indicated the Company could use either a line item surcharge or recovery through the FCA, the letter also indicated there are cost savings and other benefits of using the FCA. Placing a line item credit or charge on customer bills involves a significant amount of effort to program, test, and verify customer records to ensure accurate and timely implementation. This process is now more challenging because Xcel Energy has recently installed a new billing system, and a one-time refund/surcharge has not yet been performed. Because of the complexity, Xcel Energy prefers to use this method only when passing along significant and easily communicated savings or costs to customers.

I spoke with Pat McDonough from our information technology group and he informed me that a one time surcharge would require from 240 to over 400 man-hours of additional work at a cost of approximately \$85 per hour. While these costs may not be entirely incremental, they represent resources that would need to be reassigned away from improving the generally functionality and services of the billing system.

By comparison, using the FCA:

1. requires no additional programming or interfacing with the Xcel Energy customer database, since the methodology for passing along and tracking costs and refunds has already been established;

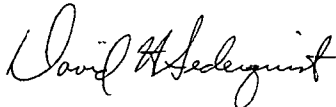
2. moderates the impact of the surcharge since the FCA spreads all costs out over a four month period, thereby minimizing the monthly impact to customers;
3. provides for accurate recovery since the FCA recovery can be adjusted or “trued-up” to avoid over (or under) recovery.

There may be concerns whether this “non-fuel” cost should be recovered through the FCA. However, the Company’s letter specifically requested a waiver from the Commission’s FCA rules, if necessary. Moreover, when appropriate, state Commissions in the NSP and NSP (Wisconsin) service territories have utilized the adjustment clauses used to recover either fuel/purchased energy or gas costs to efficiently pass through other types of “non fuel” refunds or costs in the past. These include:

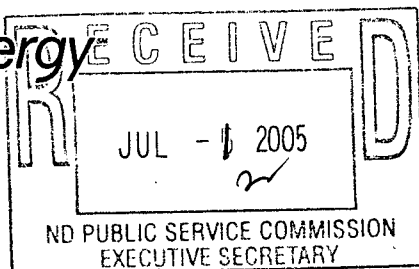
1. 1986 tax law change rate credits (North Dakota)
2. Gas transportation margin credits (North Dakota)
3. Coal option payments (North Dakota & Minnesota)
4. Financial instruments costs (North Dakota, Minnesota, and Wisconsin)
5. Distribution system expansion to WBI pipeline (North Dakota)
6. Manufactured gas cleanup costs (North Dakota)
7. Conservation program costs (Minnesota)
8. Hydrogen research and development (Minnesota)
9. Renewable development fund grants (Minnesota)
10. Wind energy transmission line expansion (Minnesota)

The Company recognizes that during the Commission’s administrative hearing on July 28, 2005, Mr. Jim Johnson indicated that Xcel Energy could and would recover the dollars through either a surcharge or through the FCA, depending on the decision of the Commission. That remains the case. However, I hope that Commission carefully considers the relative small size of this charge, and approves a methodology that it believes is best suited for the nature and magnitude of the surcharge being collected.

Sincerely



DAVID H. SEDERQUIST
SR. CONSULTANT, REGULATION & FINANCE
NORTHERN STATES POWER CO. D/B/A XCEL ENERGY



2302 Great Northern Drive
P O Box 2747
Fargo, ND 58108-2747
Telephone (701) 241-8632

July 1, 2005

Illona A. Jeffcoat-Sacco, Executive Secretary
North Dakota Public Service Commission
State Capitol Building, Dept. 408
600 East Boulevard
Bismarck, ND 58505

Re: Northern States Power Company d/b/a Xcel Energy
Proposed Extension of PLUS Plan through 2006 (Case No. PU-400-00-195)

Dear Ms. Jeffcoat-Sacco:

As required under the rules of the PLUS performance-based regulation plan ("Plan") approved by the Commission in Case No. PU-400-00-195 (order dated December 29, 2000), Northern States Power Company d/b/a Xcel Energy ("Xcel Energy" or "the Company") hereby indicates its desire to extend the PLUS Plan another year beyond the original five year term. The original Plan term was from January 1, 2001 to December 31, 2005. The Company would like to renew the Plan, subject to the currently effective terms, through December 31, 2006.

Xcel Energy is pleased with how the PLUS Plan has positively impacted its operational and customer service efforts and helped to avoid costly rate filings and earnings audits during the past five years. Since inception of the PLUS Plan four years ago, Xcel Energy's residential rates have either been the lowest (3 years) or next to lowest in the upper Midwest, the Company has exceeded various Plan performance standards 13 times, and returns on equity ("ROE") have averaged a fair and reasonable 11.3%. However, the Company anticipates filing a general rate case in the fall of 2006 primarily to recover investments made to renew and/or supplement its fleet of electric generation facilities and new transmission infrastructure needed to preserve or improve reliability. It will be imperative for Xcel Energy to – through a general rate application – "recalibrate" its base electric rates to correspond with the significant plant investments that will go into service during the 2007 to 2009 timeframe¹.

The PLUS plan approved by the Commission allows the Company to propose modifications to the existing PLUS plan or an extension of the existing plan prior to expiration of the initial five year term. Rather than burden the Commission and Staff with a potentially

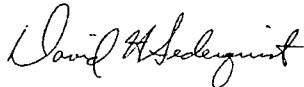
¹ A 2006 general rate case filing may also include another performance-based ratemaking plan proposal.

complicated or lengthy proceeding to establish a revised PLUS plan that might be in effect for only one year, the Company respectfully requests that the Commission approve extension of the existing PLUS Plan for the 2006 calendar year. Alternatively, if necessary, we request that the Commission provide direction to the Company and Staff to make the modifications necessary to gain Commission approval prior to January 1, 2006.

Lastly, Xcel Energy has also been contemplating filing a rate increase in late 2005, but a final decision will not be made until this fall. Should the Commission approve an extension of the current plan into 2006, the Company is willing to forgo any PLUS Plan triggered rate relief that would be implemented in 2006 as a result of 2005 earnings and performance. Xcel Energy recognizes that allowing the option to file a rate case during the term of the plan is a slight modification to the plan itself. However, given that the Company would forgo any plan benefit in the event of a rate case, this modification provides greater flexibility in determining whether a 2005 rate case filing can be avoided. The request for a one-year continuance is contingent upon acceptance of our ability to file a rate case in late 2005.

Please contact me (701-241-8632) if the Commission and/or Staff have any questions regarding this extension application.

Sincerely

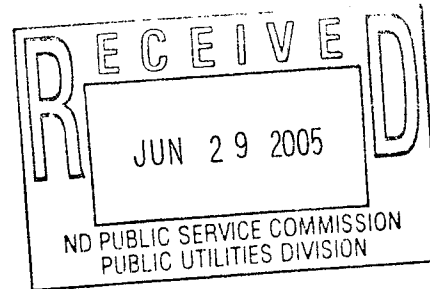


David H. Sederquist
Sr. Regulatory/Financial Consultant
Northern States Power Co. d/b/a Xcel Energy

cc: Kent Larson, Vice-President, Jurisdictional Relations
James P. Johnson, Assistant General Counsel



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Telephone (701) 241-8632



June 29, 2005

Illona A. Jeffcoat-Sacco, Executive Secretary
North Dakota Public Service Commission
State Capitol Building, Dept. 408
600 East Boulevard
Bismarck, ND 58505

Re: Northern States Power Company d/b/a Xcel Energy
Case Nos. PU-400-00-195 (PLUS Plan); PU-400-04-216 (2003 Electric Earnings)
PLUS Plan Surcharge to Recover 2003 Deficiency

Dear Ms. Jeffcoat-Sacco:

Northern States Power Company d/b/a Xcel Energy ("Xcel Energy" or "the Company") is preparing to implement an electric rate surcharge this fall to recover 50% of its 2003 North Dakota jurisdictional electric earnings deficiency, in accordance with the PLUS performance-based regulation plan ("Plan") approved by the Commission (Case No. PU-400-00-195, order dated December 29, 2000). This letter explains to the Commission and Staff how the PLUS Plan addresses earnings outside of the authorized return on equity (ROE) range through surcharges and/or refunds, and proposes two options for recovery of the 2003 deficiency later in 2005.

Background

In its 2003 earnings report, the Company calculated an unadjusted regulated ROE for its North Dakota retail electric utility operations of 9.53% (before calculation of the Plan's 50/50 earnings sharing). This ROE represented a \$1,908,000 revenue shortfall from the level needed to achieve the lower limit of the authorized ROE range allowed under the Plan. You will recall that the authorized ROE range is determined annually based on the Company's operational and customer service performance as measured by seven key indicators. In 2003, the authorized ROE range was 11.00% to 13.75%.

The PLUS Plan calls for a 50/50 sharing of any earnings deficiency or surplus relative to the authorized range.¹ After adjusting for the 2003 earnings deficiency sharing (an additional

¹ In addition to the earnings sharing mechanism, the PLUS Plan also allows for base rate changes under certain specific conditions. The consideration of Xcel Energy's low reported 2003 earnings in North Dakota, its good operational and service performance, and its low residential rates qualified the Company for a limited base rate increase of \$1.6 million effective August 1, 2004. The increase

\$954,000 of revenue), as specified in the Plan, Xcel Energy reported a final 2003 electric utility ROE in North Dakota of 10.26%. While recognizing the additional surcharge revenues in its reported 2003 earnings report to the Commission, the Company indicated the actual cash recovery from customers through a rate surcharge would not occur until 2005, and only then if the amount was not fully offset by higher than allowed earnings in 2004, as provided by the Plan terms.

As the Commission is aware, the Company's reported 2004 electric utility earnings of 10.80% were also below the authorized range minimum of 11.00%. As a result, the PLUS Plan provides for the Company to recover half of the 2003 deficiency, or \$954,000. The Company proposes to recover this amount through a surcharge to be effective no earlier than September 1, 2005, which is more than sixty (60) days after this notice. The other 50% of the 2003 deficiency will remain unrecovered, as provided by the Plan.

Recovery Plan

To effectuate the recovery authorized by the Plan, the Company proposes to do one of two things:

1. Implement a one-time electric rate surcharge, using a separate line on the bill, to collect the amount needed. The recoverable amount (\$954,000) will be allocated to customers of record on August 1, 2005 based on their consumption during the prior 12 months. The Company would recommend under this approach that the surcharge be effective during a "shoulder" month such as October 2005, which falls outside of the both the summer cooling or winter heating seasons. Attachment A provides a summary of the estimated allocation of the \$954,000 costs by customer class and bill impact of the one time surcharge for a typical residential customer. Or,
2. Include the \$954,000 surcharge amount in the Company's Fuel Clause Adjustment (FCA) calculation, which is applied to actual sales. Under this approach, the Company recommends that the amount be recorded as a July 2005 unrecovered cost, which would then be more gradually recovered in rates through the FCA in effect for the months of September, October, November, and December 2005. Attachment A shows an estimate of the bill impact of the FCA surcharge for a typical residential customer over a four month period.

If required, the Company respectfully requests waiver of the Company's FCA tariff and the Commission's rules regarding Automatic Adjustment Clauses (69-09-02-39) to provide recovery through the FCA mechanism.

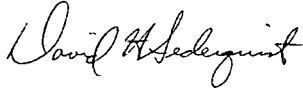
was capped at 60% of inflation, or 1.4%. This was well below the 2.45% average rate change among the Plan's regional utility comparison group (see Page 9 of the 2003 Regulatory Report of Electric Utility Operations filed by Xcel Energy on May 4, 2004).

The Company would defer to the Commission's preference as to how to effectuate the proposed Plan surcharge. However, the Company believes utilizing the FCA would be less burdensome to administer, and have the benefit of moderating the bill impact by spreading it over multiple months. In addition, the FCA has a self-regulating true-up mechanism that ensures the appropriate costs are recovered regardless of changes in sales.

The Company respectfully requests that the Commission issue an order regarding this filing within sixty (60) days to allow the Plan recovery mechanism to be effective with the September 2005 FCA billing rates (if the FCA recovery method is selected) or to allow the Company sufficient time to program its billing system to implement the one time surcharge method for October 2005 billings (if the surcharge method is selected).

Please contact me (701-241-8632) if the Commission and/or Staff have any questions regarding the proposed PLUS Plan deficiency recovery.

Sincerely

A handwritten signature in cursive script, appearing to read "David H. Sederquist".

David H. Sederquist
Sr. Regulatory/Financial Consultant
Northern States Power Co. d/b/a Xcel Energy

cc: Kent Larson, Vice-President, Jurisdictional Relations
James P. Johnson, Assistant General Counsel

Northern States Power Co. d/b/a Xcel Energy
Electric Utility - State of North Dakota
2003 PLUS Plan Revenue Sharing Surcharge

Estimated Surcharge by Customer Class

<u>Customer Class</u>	<u>2004 Revenues</u>	<u>% of Total Revenues</u>	<u>Surcharge by Class</u>	<u>% of Annual Revenue</u>
Residential	\$49,145,854	40%	\$378,703	0.8%
Small Commercial	\$56,597,565	46%	\$436,124	0.8%
Large Commercial	\$16,181,655	13%	\$124,691	0.8%
Public Str/Hiway	\$1,264,328	1%	\$9,743	0.8%
Public Authorities	\$615,099	0%	\$4,740	0.8%
Total Retail	\$123,804,500	100%	\$954,000	0.8%

Typical Bill Impacts

<u>Customer Class</u>	<u>Number of Customers</u>	<u>Est. One-time Bill Impact</u>	<u>Est. Mo. Amt over 4 mos.*</u>
Residential	73,562	\$5.15	\$1.29
Small Commercial	11,718	\$37.22	\$9.30
Large Commercial	27	\$4,693.81	\$1,173.45
Public Str/Hiway	89	\$109.36	\$27.34
Public Authorities	189	\$25.02	\$6.26
Total Retail	85,585	\$11.15	\$2.79

* Approximate impact of using Fuel Clause to implement recovery. Assumes an even pattern of recovery over 4 months. FCA automatically trues-up any differences in recovery due to sales volumes.

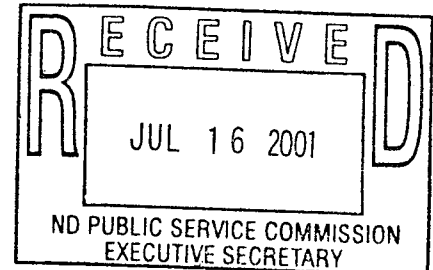


Northern States Power Company

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Telephone (701) 241-8632

July 13, 2001

Jon Mielke, Executive Secretary
North Dakota Public Service Commission
State Capitol Building, Dept. 408
600 East Boulevard
Bismarck, ND 58505



Re: Northern States Power Company d/b/a Xcel Energy
Case No. PU-400-00-195
Performance Based Regulation

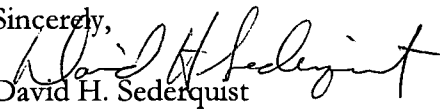
Dear Mr. Mielke:

As required by the North Dakota Public Service Commission on December 29, 2000, Northern States Power Company hereby submits an original and seven (7) copies of a comprehensive document which describes the Company's Performance Based Regulation Plan (the "PLUS" Plan) which went into effect on January 1, 2001.

The document incorporates the provisions of the original plan proposal along with the modifications encompassed in the final settlement. An electronic version of this document and the related attachments has also been forwarded to Staff for posting on the Commission website.

I would like to thank the Commission and Staff for allowing us additional time to assemble this document. Do not hesitate to direct questions to me at (701-241-8632).

Sincerely,


David H. Sederquist
Manager, ND Regulatory Affairs

cc: James P. Johnson, Assistant General Counsel

**NORTHERN STATES POWER COMPANY
PLUS PERFORMANCE-BASED REGULATION PLAN
EFFECTIVE JANUARY 1, 2001**

I. INTRODUCTION

On April 20, 2000, pursuant to N.D.C.C 49.02.02 and N.D.C.C. 49.02.03, Northern States Power Company (“NSP” or “the Company”) filed a performance-based regulation plan entitled *Performance Linking Utility Stakeholders* (“PLUS Plan” or “the Plan”) with the North Dakota Public Service Commission (“NDPSC” or “Commission”). The PLUS Plan would modify the method of Commission regulation of NSP’s retail electric rates and services in North Dakota consistent with the *Guidelines for Alternative Regulation Proposals* established by the NDPSC in Case No. PU-439-94-590 by order dated September 20, 1995.

After a hearing, the PLUS Plan, as modified by a Settlement Agreement between the Company and Commission Staff, was approved by the Commission by order dated December 29, 2000, as amended by supplemental order dated January 10, 2001. The orders required the Company to submit a PLUS Plan summary in compliance with the Settlement Agreement and orders.

II. DESCRIPTION OF THE PLUS PLAN

The key components of the approve PLUS Plan include 1) a dynamic “allowed ROE” range which can vary based on Company performance, 2) a revenue sharing mechanism, 3) establishment of service and operating performance standards, and 4) flexibility to adjust prices under specified circumstances, and 5) comprehensive annual

reporting of the Plan results to the Commission by May 1st following the end of each Plan year. The individual components, as established by the Settlement Agreement and approved by the Commission orders, are as follows:

A. DYNAMIC AUTHORIZED ROE BANDWIDTH

An authorized baseline return on equity (ROE) of 12.0% is established. A range of +/- 100 basis points around the baseline ROE will represent an “acceptable authorized range” or “deadband” of earnings performance. Actual Company reported ROE for the Company’s North Dakota electric operations which fall within this deadband are considered reasonably close to the baseline, and will not trigger any revenue sharing or rate adjustment (see Attachment A).

During the Plan term, the ROE deadband shall be subject to annual “basis point” adjustments depending on the Company’s performance under each Plan performance standard, as provided herein. If the net performance basis points are positive (award), the upper end of the allowable ROE deadband increases. If the net performance points are negative (penalty), the lower end of the ROE deadband is decreased. The baseline does not change.

B. REVENUE SHARING

As stated previously, if the Company’s reported actual earnings fall within the ROE deadband (as adjusted by the performance points) in a given Plan year, there will be no revenue sharing.

If the Company’s actual reported earnings for any given Plan year exceed the ROE deadband, the corresponding revenue ‘excess’ will be calculated, and 50% of this dollar amount will be refunded to customers during the July billing cycle following the Plan year. Customers of record on March 31 following the Plan year will be issued refunds by bill credit prorated on the basis of their electric usage for the twelve months ending March 31.

If actual Company earnings are below the deadband, 50% of the corresponding revenue deficiency is recovered through a surcharge on the Company’s electric rates effective no later than 24 months after the Plan year.

However, NSP will defer any reported fiscal year deficiency amount as a regulatory asset until the following Plan year revenue sharing amount -- if any -- is determined. If the prior year deficiency is fully offset by a current year reported revenue excess, the excess will be used to eliminate the regulatory asset, and no rate surcharge will be imposed. If the deficiency from the prior year is not fully offset, any remaining deficiency balance will be billed through a rate surcharge and collected over the remaining six-month period beginning July 1 of the year following the Plan fiscal reporting year, unless otherwise requested by either the Company or Commission Staff and approved by the Commission.

The customer share of any Plan refund or deficiency surcharge will be shown separately as a “performance-based dividend” or “performance-based surcharge”, respectively, on customer bills. Plan dividends paid to customers or surcharges received will be excluded from the Company’s regulated earnings statement for the Plan year in which the said dividends or surcharges are actually implemented.

Any deferred deficiency balance remaining at the end of the 5-year Plan term will first be considered as part of an on-going Plan, or alternatively, collected from customers through a surcharge.

Attachment B to this document provides an explanation of the dynamic ROE bandwidth and revenue sharing mechanisms provided in the PLUS Plan.

C. PERFORMANCE STANDARDS

The PLUS Plan takes a “comprehensive” approach to the utilization of performance measures and standards. NSP’s performance will be measured by seven high level indicators within the areas of electric reliability, customer satisfaction, price, and employee safety. In the Plan, ranges of ‘acceptable performance’ are established around each performance standard. Performance results which are outside of PLUS’s acceptable performance ranges will result in either an increase or decrease in the allowable ROE deadband. Each performance measure can adjust the ROE deadband by 25 basis points.

Three of the four performance areas have 2 indicators each, and hence have the ability to affect the baseline ROE and bandwidth up or down by 50 basis points, or 0.5% ROE. Safety has a single indicator with a total potential impact of 25 basis points, or 0.25%. The ROE impact of each measure is additive, meaning that it is possible for the combined effect on the baseline ROE of all seven measures to be anywhere from –1.75 % to +1.75 %, in increments of 0.25%.

The following tables summarize the performance standards to be used in PLUS. Additional information on each measure is found in Attachment C.

RELIABILITY

Measure	Award Threshold	Target	Penalty Threshold
CAIDI	< 75.6 minutes	89.0 minutes	> 102.4 minutes
SAIFI	< 0.77 outages/yr.	0.90 outages/yr.	> 1.04 outages/yr.

CUSTOMER SATISFACTION

Measure	Award Threshold	Target	Penalty Threshold
Relationship survey positive response %	> 84.0%	81.0%	< 78.0%
Transaction survey positive response %	> 66.0%	63.0%	< 60.0%

PRICE

Measure	Award Threshold	Target	Penalty Threshold
Competitive Res'l price position	< 85% of target	peer group avg. res'l price/kWh	> 115% of target
Annual change in Res'l avg. price	< (target-.05¢/kwh)	annual change in lowest priced utility avg. res'l price/kWh	> (target+.05¢/kwh)

SAFETY

Measure	Award Threshold	Target	Penalty Threshold
OSHA incident rate	< 3.70	4.32	> 5.00

D. CHANGES IN BASE RATES

The PLUS Plan incorporates both inflationary and ‘market price’ factors in the calculation of the allowable rate change parameter, or “Price Cap Factor”. The Plan thus

ensures the Company's retail electric rates will, adjusted for inflation, decrease over the term of the Plan.

1. Factors Which Regulate Base Rate Changes

The PLUS Plan allows for the implementation of annual rate adjustments, depending on the following four factors:

- The Company's recently reported earnings levels;
- The Company's price position in the region;
- Average % residential price changes of the 'market' comparison group (see Attachment D);
- Percentage changes in the Consumer Price Index (adjusted by an efficiency target factor).

These four factors work together each year to freeze rates, limit rate increases, or in certain circumstances, mandate rate decreases. Attachment E is a graphical flowchart showing how these factors operate to determine base rate changes in the PLUS Plan.

a. Earnings Levels

Under the PLUS Plan, if the Company's reported ROE for its electric operations in North Dakota is higher than the ROE deadband midpoint less 100 basis points (1.0%), no rate increase is allowed in the following year, even if the inflation and comparison group price data support one. Conversely, price reductions supported by the CPI /comparison group price cap cannot be imposed if the Company's ROE is lower than the ROE deadband midpoint plus 1.0%.

b. Competitive Rate Position

Rate increases will not be allowed if the Company’s average residential rate is higher than the comparison group average residential rate. Also, no decrease in rates will be required if the Company’s average residential rate is lower than the comparison group’s average residential rate.

c. Comparison Group Price Change

The annual percentage change in average residential rates for the seven state comparison group is calculated and used as the price cap factor for any rate change the Company may or must implement (unless inflation is even lower – see item # 4 below). Should the group average residential price decline, the Company is required to reduce its electric rates accordingly, unless reported actual ROE was deficient or the Company’s actual rates were already less than the comparison group average, as discussed in items #1 and #2 above.

d. Inflation and Efficiency Target

To assure the Company’s rates decline in real terms over the PLUS Plan period, the annual rate of inflation as measured by the Consumer Price Index (Urban) is also factored into the price cap formula. The CPI for the Plan reporting year is computed by averaging the annual CPIs reported at the end of each calendar quarter. The resulting average CPI rate is then multiplied by 60% (to reflect the Plan’s “efficiency factor”). If the result is lower than the average comparison group residential price change percentage, the adjusted CPI factor replaces the average group price change percentage as the price cap factor for any Company rate change percentage. The amount of the rate change is thus limited to the lower of 1) the change in residential rates for the seven state

mid-west market, or 2) 60% of the rate of inflation (CPI). See Attachment F for an example of this calculation.

2. Rate Change Procedure

Any proposed rate change allowed by the Plan would be reported to the Commission in the Company’s Annual Regulated Earnings report on May 1 following the Plan year. To implement any permissive rate increase or mandatory rate reduction under PLUS, the Company will file a notice of rate change and the accompanying tariffs pursuant to N.D.C.C. 49-05-05 not later than June 1.

The revised rates shall be effective on or after July 1 following the Plan year. Base rate changes will be across-the-board to all customer classes unless an alternative design is requested by the Company and approved by the Commission. The notice of rate change will not be suspended by the Commission under N.D.C.C. 49-05-06, but the revised rates shall be allowed to go into effect on the date proposed. If the Commission determines after investigation and hearing that the changed rates do not comply with the Plan terms as prescribed herein, the Commission may prospectively establish the rates it finds to be consistent with the Plan terms, and order a one-time billing true-up for the impact of the discrepancy since either the inception of the rate change or the previous 12 month period, whichever is less. Rates established consistent with the Plan are presumed just and reasonable, and non-discriminatory.

E. REGULATORY REPORTING AND REVIEW

1. Annual Report

On or before May 1 of the year following the fiscal period being reviewed, the Company will file with the Commission a report showing:

- The Company’s regulated electric earnings and return on equity (before and after any earnings sharing) in North Dakota for the fiscal year just completed;
- Summaries of operating revenue, expense, and regulated electric rate base;
- The Company’s regulated capital structure including debt and equity ratios, cost of capital, and return on rate base;
- Calculation of baseline ROE and the authorized earnings bandwidth for the Plan review year;
- Annual results, awards, and penalties related to the Company’s performance in the areas of reliability, price, customer satisfaction, and safety;
- Amount of revenues subject to sharing and the ‘customer dividend’ or surcharge;
- Comparison group average residential rates for the year in review;
- The calculation of the Price Cap Factor (CPI, comparison group rate changes);
- Proposed rate change percentages and typical bill impact for all customer classes.

2. Commission Review

Upon receipt of the PLUS earnings report in May, the Commission will perform its annual review, per existing Commission rules. A Staff report may be filed with the Commission. If none of the conditions for suspension of the Plan apply, any refunds,

charges, and/or proposed rate adjustments allowed by the Plan and properly filed by the Company will go into effect on July 1.

F. OTHER PLUS PLAN CONDITIONS

The following conditions of the PLUS Plan will also apply:

1. Plan Term

The PLUS Plan commences on January 1, 2001. Except as provided herein, the PLUS Plan will remain in effect for a five year term ending December 31, 2005. Prior to July 1, 2005, the Company may file for an extension and/or modification of the Plan if so desired. Absent such a filing and a further order of the Commission extending the Plan, the PLUS Plan will automatically terminate on December 31, 2005.

2. Commission Interim Review

After the first two years of the term have been completed, the Commission may conduct an informal review hearing after May 1, 2003, to assess the Plan's results and discuss potential improvements. It is anticipated that the Commission and the Company will continue to have open communication and constructive dialogue during the plan term and, when necessary, agree to make general modifications or refine certain elements of the Plan.

3. Fuel Clause Adjustment Mechanism

The Company's Fuel Clause Adjustment ("FCA") will remain in effect during the PLUS Plan term and operate as it does currently to adjust customer bills for changes in fuel and purchased energy costs. The comparative price performance standards discussed previously will be calculated using total Residential revenue per kWh including the FCA adjustments in effect during the Plan reporting year.

4. Demand Allocation Method

For purposes of calculating the Company's jurisdictional expenses for each PLUS Plan reporting year, 36 months of historical demand data will be used to establish the Demand Allocation factor (known as D10). The Demand Allocation factor is used to assign production and transmission related costs and investment to the Company's retail electric jurisdictions in North Dakota, South Dakota and Minnesota. The use of a 36 month demand allocator is for financial reporting purposes under the Plan only. Use of a 36 month historic allocator for the Plan shall have no precedential effect in future electric rate increase applications after the Plan term expires or if the Plan is suspended or terminated

G. CONDITIONS FOR SUSPENSION OR TERMINATION OF PLAN

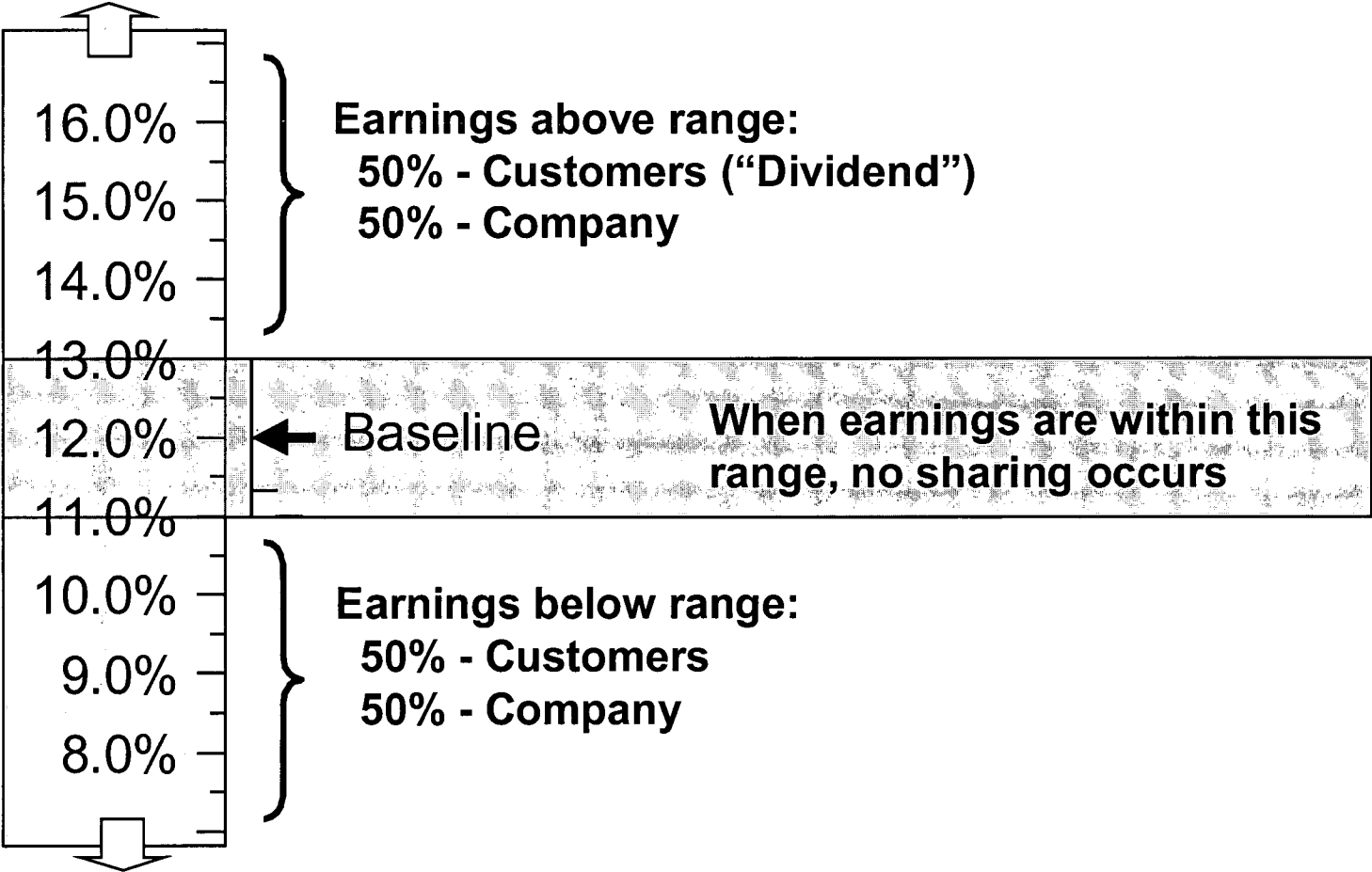
The Plan is intended to remain in effect for five years beginning January 1, 2001. However, the Company and Staff reserve the right to request adjustment, suspension, or termination of the Plan under the following events:

- Federal and/or state tax law changes;

- Passage of retail access legislation at either the federal or state level;
- Merger and acquisition events affecting the Company’s structure and operations;
- Natural disasters affecting the Company’s North Dakota electric operations (major storms, floods, etc.);
- Unusual events affecting the Company’s operations (major generating plant failure, damage to major transmission or distribution lines, etc.); or
- Material and sustained earnings extremes (defined as returns on equity +/- 5.0% from the ROE deadband, prior to sharing).

It is anticipated the Commission and Company will make reasonable efforts to resolve any condition that could otherwise trigger a Company application or Commission motion to suspend the Plan before any decision to terminate operation of the Plan during the Plan term.

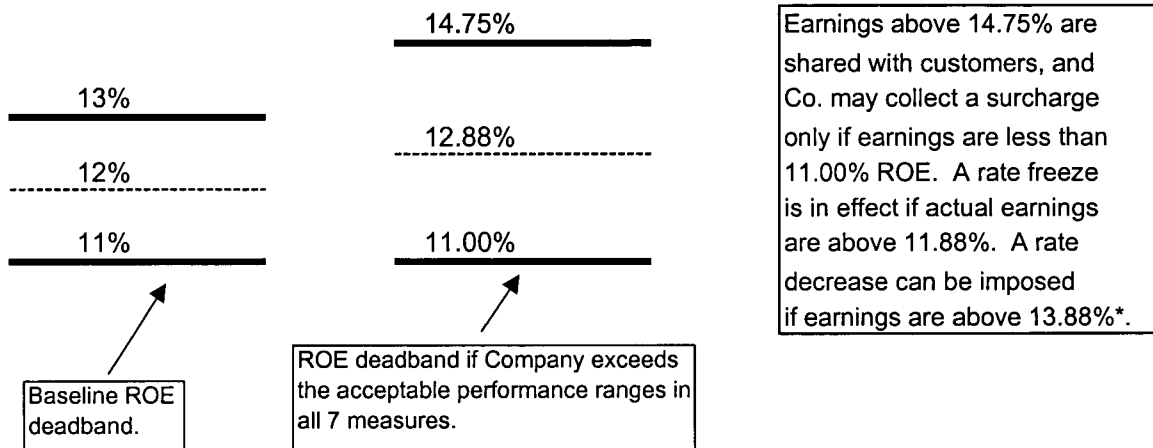
Revenue Sharing



PLUS Plan Revenue Sharing and Rate Change Criteria

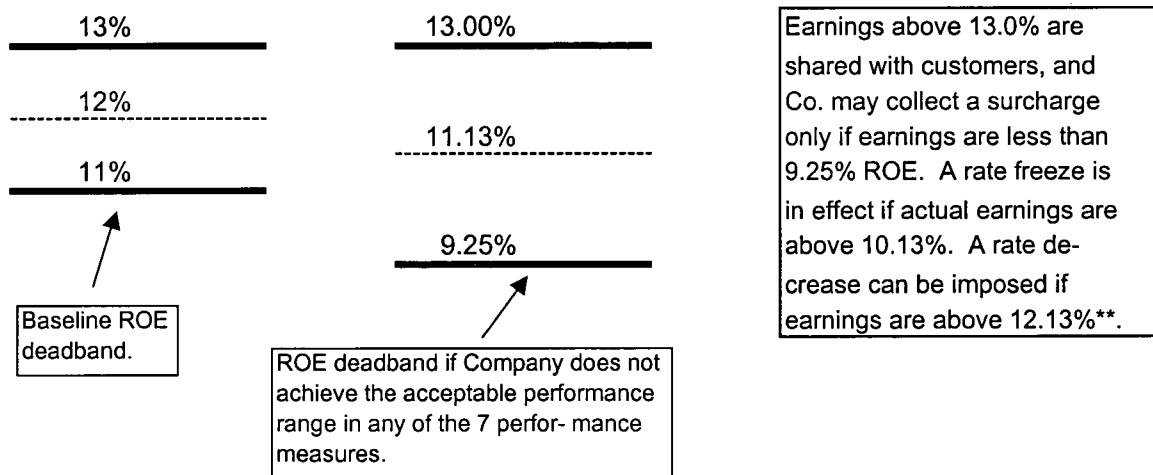
Scenario 1: All 7 performance standards are exceeded

Since net result of performance points is positive, only the *upper limit* of the ROE deadband increases. 7 X 25 points = 125 basis point adjustment.



Scenario 2: None of the 7 performance standards are met.

Since net result of performance points is negative, only the *lower limit* of the ROE deadband decreases. 7 X 25 points = 125 basis point adjustment.



* The rate freeze threshold is equal to the baseline (12.88% in this example) minus 1.00%, or 11.88%. Decreases can be imposed at 12.88%+1.0%, or 13.88%.

** The rate freeze threshold is equal to the baseline (11.13% in this example) minus 1.00%, or 10.13%. Decreases can be imposed at 11.13%+1.0%, or 12.13%.

Northern States Power Company
"PLUS" Plan Performance Section
Reliability Standards

Macro Measures:

Outage Restoration Time (CAIDI)

This is the amount of time that a typical customer experiencing a sustained outage¹ was out of power.

Restoration time = # of customer-minutes interrupted / number of customers interrupted

"CAIDI" stands for "Customer Average Interruption Duration Index"

Outage Frequency (SAIFI)

This is the average number of sustained outages that a typical customer experienced during the year.

Outage frequency = # of customer interruptions / number of customers served

"SAIFI" stands for "System Average Interruption Frequency Index"

The Performance Standards

Benchmark reliability standards will be developed using NSP(MN Co.) and NSP-ND average annual results for the five year period (1995-1999). While CAIDI and SAIFI are industry standard reliability measures, there are variations among utilities as to what constitutes an outage, how long an outage must last to be counted, and the process of normalizing outage data for weather. In addition, outage information is not readily accessible nor openly shared across the industry. Ranges of acceptable performance will be constructed by determining boundaries which are +/- 15% of the benchmark. Outages included are those lasting more than 5 minutes.

NSP (MN Co.) Results

Storm-Normalized			
	SAIFI (Outages)	CAIDI (Minutes)	SAIDI (Minutes)
1995	1.0000	100.8	100.8
1996	0.9700	115.8	112.3
1997	0.8800	115.2	101.4
1998	0.8600	121.8	104.7
1999	1.0300	112.2	115.6
Average	0.9480	113.2	107.3
Adj. Ave. ²	0.9500	114.4	108.7
Median	0.9700	115.2	111.7
Ave. of Co.& ND Standards			
Penalty >	1.04	105.3	97.0
Target	0.90	91.6	84.0
Award <	0.77	77.9	71.0

NSP-North Dakota Results

Storm-Normalized			
	SAIFI (Outages)	CAIDI (Minutes)	SAIDI (Minutes)
1995	0.7300	63.6	46.4
1996	0.8200	60.6	49.7
1997	0.9800	75.6	74.1
1998	0.7500	73.2	54.9
1999	1.0600	69.6	73.8
Average	0.8680	68.5	59.5
Adj. Ave. ²	0.8500	68.8	58.5
Median	0.8200	69.6	57.1
Stipulated Targets			
Penalty >	1.04	102.4	92.0
Target	0.90	89.0	80.0
Award <	0.77	75.7	68.0

Note: CAIDI X SAIFI = SAIDI

The proposed standards are consistent
with Otter Tail Power's SAIDI standard.

¹ > 5 minutes long

² Has both extreme upper and lower years removed.

**Northern States Power Company
"PLUS" Plan Performance Section
Customer Satisfaction Standards**

Macro Measures:

Relationship Survey Response %

This is the average % of North Dakota customers randomly surveyed who responded very favorably (either of the top two answers) to the survey question: "I'd like you to think of your overall relationship with Xcel Energy. Considering everything, would you say the overall quality of products, services, and support you receive from Xcel Energy is excellent, very good, good, fair, or poor?" The final Relationship Survey score will be the average of the residential, small commercial, and large commercial and industrial surveys.

Transaction Survey Response %

Transaction surveys focus on North Dakota customers who have recently made a call to Xcel Energy's customer Care Center regarding a billing issue or start/stop service request, or had contact with Company crews responding to an outage call. The overall question is, "Thinking of this entire interaction with Xcel Energy, from the time you first contacted Xcel Energy until your issue was resolved, how would you rate the quality of service provided by Xcel Energy?" The Transaction Survey score will be the average top two response % for both surveys.

The Performance Standards

A benchmark customer satisfaction survey standard will be developed through consideration of the previous three years of results on an NSP Company-wide basis. The target will be further developed by including North Dakota only scores in the historical average beginning in year three of the plan term.

Relationship Results

	Res'l	Small C&I	Large C&I	Average		Customer Care	Electric Service	Average
1998	81.0%	70.0%	86.0%	79.0%	1998	62.0%	57.0%	60.0%
1999	77.0%	77.0%	88.0%	81.0%	1999	72.0%	53.0%	63.0%
1999	80.0%	79.0%	94.0%	84.0%	1999	72.0%	58.0%	65.0%

Penalty <	78.0%
Target	81.0%
Award >	84.0%

Penalty <	60.0%
Target	63.0%
Award >	66.0%

**Northern States Power Company
"PLUS" Plan Performance Section
Employee Safety Standard**

Macro Measure:

OSHA Incident Rate

This is the average number of OSHA incidences occurring per 100 electric employees.

OSHA incidences include medical treatment cases, restricted work day injuries, lost workday injuries, and fatalities. Only NSP-ND results will be counted.

$$\text{OSHA} = \# \text{ of incidences} \times 200,000 \text{ hours} / \text{number of labor hours worked}$$

The Performance Standard

The OSHA rate target was developed using the average annual OSHA results for large utilities (> 7,000 employees) participating in the 1997 EEI safety survey, and includes a consideration of NSP's North Dakota OSHA results from 1995-1999. This revised target is more stringent than that derived from NCEA historical results and and proposed by the Company in its PLUS Plan application.

EEI OSHA Results

	OSHA Index
1994	4.83
1995	4.45
1996	4.20
1997	3.79
Average	4.32
Adj. Ave. ¹	4.33
Median	4.33

Penalty >	5.00
Target	4.32
Award <	3.70

¹ Excludes years with maximum and minimum results.

Northern States Power Company
"PLUS" Plan Performance Section
Price Standards

Macro Measures:

Average Residential Rate Compared to an External Utility Group

Avg. Price = Total NSP-ND residential revenues / total residential kWh sales

NSP's average price is compared to the average residential rate of the external utility comparison group.

Annual Change in the Average Residential Rate

The change in NSP's average residential price from the prior year is compared to the change in the average residential rate for the previous year's lowest priced utility within the external comparison group of investor-owned utilities.

The Performance Standards

The standard for the residential price position measure is the average residential price for a 7 state, multiple jurisdiction mid-west comparison group of investor-owned utilities.

The average rates for each utility jurisdiction is published by EEI twice each year¹ so the standard is restated each year. For the annual price change measure, NSP's annual change in rates is compared to the nominal change of the lowest priced utility from the previous year. A performance standard range is constructed for the position measure using a +/- 15% adjustment. The annual change measure range is developed by adjusting the change in the lowest priced utility's average residential rate by +/- 0.05¢/kWh.

EEI Comparison Group Results

Historical Results (NSP-North Dakota)

	Hi-Perf. <u>Level</u>	Average <u>¢/kWh</u>	Lo-Perf. <u>Level</u>		Residential <u>Revenues</u>	Residential <u>mwh Sales</u>	Average <u>¢/kWh</u>
1994	5.98	7.03	8.08	1994	\$40,514,344	679,678	5.96
1995	5.95	7.00	8.05	1995	\$41,569,815	716,554	5.80
1996	5.97	7.02	8.07	1996	\$43,013,673	748,504	5.75
1997	6.05	7.12	8.19	1997	\$40,572,694	691,882	5.86
1998	6.21	7.31	8.41	1998	\$40,873,907	673,777	6.07
1999	6.25	7.35	8.45	1999	\$40,987,401	670,796	6.11

¹ Source: Typical Residential, Commercial, and Industrial Bills, Edison Electric Institute.

Northern States Power Company
"PLUS" Plan Performance Section
Price Comparison Group Utilities by State

Minnesota

Minnesota Power
 Interstate Power
 Otter Tail Power
 Northern States Power

Wisconsin

Wisconsin Energy
 NW Wisconsin Electric
 Wisconsin Power & Light
 Wisconsin Public Service
 Northern States Power
 Madison Gas & Electric

Montana

Black Hills Power & Light
 Montana-Dakota Utilities
 Montana Power

Iowa

MidAmerica Energy
 IES Utilities
 Interstate Power

Wyoming

PacifiCorp
 PacifiCorp-Wyoming West
 Montana-Dakota Utilities
 Black Hills Power & Light
 Cheyenne Light, Fuel, & Power

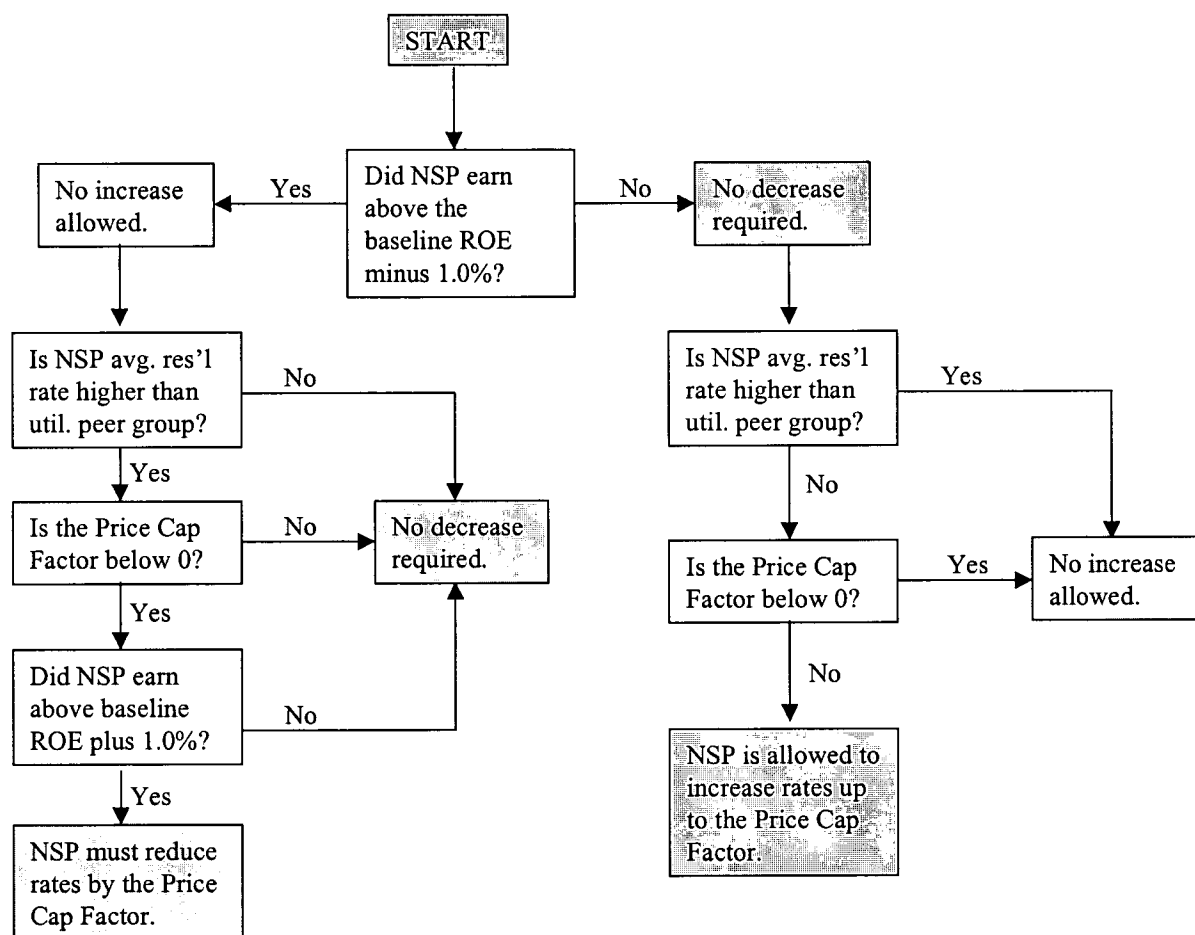
North Dakota

Montana-Dakota Utilities
 Otter Tail Power
 Northern States Power

South Dakota

Montana-Dakota Utilities
 Otter Tail Power
 Northern States Power
 Northwest Public Service
 Black Hills Power & Light
 MidAmerica Energy

Decision Model for PLUS PBR Price Cap Mechanism



Price Cap Factor = lower of 1) the utility peer group average annual residential price change, and 2) CPI X 60%

Price Cap Index

Sample Calculation of Rate Index

Line Item

1 Comparison group annual change in res'l ¢/kwh: 0.89%

	Inflation (CPI)	1996	1997	Change
2	March	155.7	160.0	2.76%
3	June	156.7	160.3	2.30%
4	September	157.8	161.2	2.15%
5	December	158.6	161.3	1.70%
6	Average:			2.23%

7 Inflation with 40% efficiency commitment adj. (60% X CPI): 1.34%

8 Maximum rate increase allowed* 0.00%

* Data is from 1997. In spite of the fact that the price cap factor was 0.89%, no rate increase would have been allowed in this year because NSP's earnings were above the ROE deadband less 1%

PU-400-00-195 PU-04-216

SENDER: COMPLETE THIS SECTION	COMPLETE THIS SECTION ON DELIVERY
■ Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired. ■ Print your name and address on the reverse so that we can return the card to you. ■ Attach this card to the back of the mailpiece, or on the front if space permits.	A. Signature X <i>[Signature]</i> ☐ Agent ☐ Addressee B. Received by (Printed Name) C. Date of Delivery <i>Peter Mon...</i> AUG 17 2005 D. Is delivery address different from item 1? ☐ Yes If YES, enter delivery address below: ☐ No
1. Article Addressed to: <i>Dave Sederquist</i> <i>Northern States Power Company</i> <i>2302 Great Northern Dr</i> <i>Fargo ND 58102</i>	3. Service Type ☒ Certified Mail ☐ Express Mail ☐ Registered ☐ Return Receipt for Merchandise ☐ Insured Mail ☐ C.O.D. 4. Restricted Delivery? (Extra Fee) ☐ Yes
2. Article Number (Transfer from service label) 7004 2510 0004 8815 5538	
PS Form 3811, February 2004 Domestic Return Receipt 102595-02-M-1540	

PU-400-00-195

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1. Article Addressed to: <i>Bernadene Brutley</i> <i>Otter Tail Corporation</i> <i>215 S Cascade St</i> <i>Fergus Falls MN 56538-0496</i>	3. Service Type ☒ Certified Mail ☐ Express Mail ☐ Registered ☐ Return Receipt for Merchandise ☐ Insured Mail ☐ C.O.D. 4. Restricted Delivery? (Extra Fee) ☐ Yes
2. Article Number (Transfer from service label) 7004 2510 0004 8815 5545	
PS Form 3811, February 2004 Domestic Return Receipt 102595-02-M-1540	

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SENDER: COMPLETE THIS SECTION	COMPLETE THIS SECTION ON DELIVERY
■ Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired. ■ Print your name and address on the reverse so that we can return the card to you. ■ Attach this card to the back of the mailpiece, or on the front if space permits.	A. Signature X <i>[Signature]</i> ☐ Agent ☐ Addressee B. Received by (Printed Name) C. Date of Delivery <i>Peter Mon...</i> AUG 17 2005 D. Is delivery address different from item 1? ☐ Yes If YES, enter delivery address below: ☐ No
1. Article Addressed to: <i>Kent Larson</i> <i>Northern States Power Company</i> <i>2302 Great Northern Dr</i> <i>Fargo ND 58102</i>	3. Service Type ☒ Certified Mail ☐ Express Mail ☐ Registered ☐ Return Receipt for Merchandise ☐ Insured Mail ☐ C.O.D. 4. Restricted Delivery? (Extra Fee) ☐ Yes
2. Article Number (Transfer from service label) 7004 2510 0004 8815 5521	
S Form 3811, February 2004 Domestic Return Receipt 102595-02-M-1540	

APPROVED

MOTION

DATE: 3-28-01
KMF

March 28, 2001

**Northern States Power Company
Performance Based Regulation
Application**

Case No. PU-400-00-195

I move the Commission allow Northern States Power Company until April 30, 2001 to make its compliance filing in its Performance Based Regulation Application, Case No. PU-400-00-195.

sdh



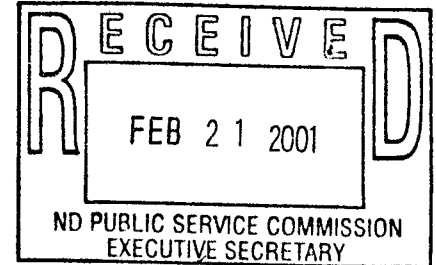
Northern States Power Company

2302 Great Northern Drive
P O Box 2747
Fargo, ND 58108-2747
Telephone (701) 241-8632

February 21, 2001

Jon Mielke, Executive Secretary
North Dakota Public Service Commission
State Capitol Building, Dept. 408
600 East Boulevard
Bismarck, ND 58505

Re: Northern States Power Company d/b/a Xcel Energy
Case No. PU-400-00-195
Performance Based Regulation



Dear Mr. Mielke:

Pursuant to the North Dakota Public Service Commission's January 10, 2001 order on Reconsideration ("Order") in Case No. PU-400-00-195, Xcel Energy was to provide the Commission with further documentation of its approved "PLUS" performance-based regulation plan by February 12.

With this letter, Xcel Energy respectfully requests to extend the deadline for filing of this compliance document to March 31, 2001. Other items, particularly wholesale gas price/PGA issues and the Company's gas rate case, have hindered the completion of the document, and the Company would like more time to ensure that the PLUS "instruction manual" it develops and files with the Commission will be comprehensive and well-designed.

I have discussed this matter with Mike Diller, and he has indicated that he can accept the revised timeline. There does not appear to be any negative impact of delaying submission of this document until the end of March.

Thank you for your consideration of this matter. Please call me if you have any questions (241-8632).

Sincerely,

David H. Sederquist
Manager, ND Regulatory Affairs

cc: Jim Johnson

STATE OF NORTH DAKOTA
PUBLIC SERVICE COMMISSION

Northern States Power Company
Performance Based Regulation
Application

Case No. PU-400-00-195

AFFIDAVIT OF SERVICE BY CERTIFIED MAIL

STATE OF NORTH DAKOTA
COUNTY OF BURLEIGH

Sharon Helbling deposes and says that:

she is over the age of 18 years and not a party to this action and, on the **11th day of January, 2001**, she deposited in the United States Mail, Bismarck, North Dakota, **three** envelopes with certified postage, return receipt requested, fully prepaid, securely sealed and each containing a photocopy of:

Order

The envelopes were addressed as follows:

Kent Larson
Northern States Power Company
2302 Great Northern Dr
Fargo ND 58102
Cert. No. 7000 0520 0022 8654 0070

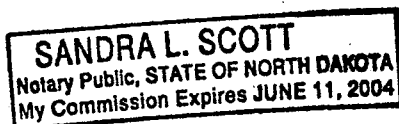
Dave Sederquist
Northern States Power Company
2302 Great Northern Dr
Fargo ND 58102
Cert. No. 7000 0520 0022 8654 0087

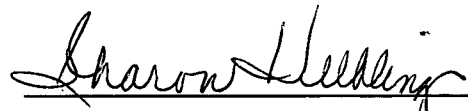
Bernadeen Brutlag
Otter Tail Power Company
215 S Cascade St
Fergus Falls MN 56538-0496
Cert. No. 7000 0520 0022 8654 0094

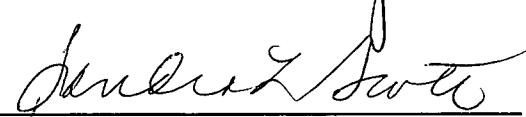
Each address shown is the respective addressee's last reasonably ascertainable post office address.

Subscribed and sworn to before me
this **11th day of January, 2001**.

SEAL







Notary Public

STATE OF NORTH DAKOTA
PUBLIC SERVICE COMMISSION

Northern States Power Company
Performance Based Regulation
Application

Case No. PU-400-00-195

AFFIDAVIT OF SERVICE BY ORDINARY MAIL OR E-MAIL

STATE OF NORTH DAKOTA
COUNTY OF BURLEIGH

Sharon Helbling deposes and says that:

she is over the age of 18 years and not a party to this action and, on the **11th day of January, 2001**, she deposited in the United States Mail, Bismarck, North Dakota, envelopes by first class mail, fully prepaid, securely sealed, each containing a photocopy of:

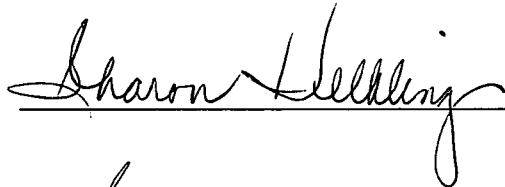
Order

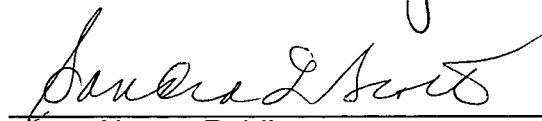
The envelopes were addressed as follows:

See Attached List

Each address shown is the respective addressee's last reasonably ascertainable post office address.

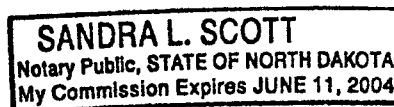
Subscribed and sworn to before me
this **11th day of January, 2001**.





Notary Public

SEAL



PU-400-00-195

Copies To:

State Library (8 copies)

Historical Society

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St Anthony ND 58566-9640

Myer Shark
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Bismarck ND 58501

Will Kaul
Cooperative Power Association
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Elk River MN 55330-0800

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Denver CO 80201-0239

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Chicago IL 60603
Tom Reynolds
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Washington DC 20044-7167

Mark Frederiksen
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Washington Grove MD 20880

Jay Casler
INDEPTH DATA INC
211 N Robinson Ave Ste S-1500
Oklahoma City OK 73102-7101

Jerry Tuchscherer
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Minot ND 58702-1686

Rick Jensen
KHND Radio
PO Box 6
Harvey ND 58341-0006

Jan Copeland
KN Energy Inc
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Lakewood CO 80228-8304

KTHI-TV
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Grand Forks ND 58208-2427

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Golden CO 80401

Everett Morris
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Kim Christianson
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Scott Speaker
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Paul Lehman
Northern States Power Company
512 Nicollet Mall
Minneapolis MN 55402

Public Utilities Reports Inc
Law Dept
8229 Boone Blvd Ste 401
Vienna VA 22182
LeRoy Neubauer
Valley City Public Works
254 2nd Ave NE
Valley City ND 58072

MOTION

DATE: 1-10-01
KME

January 10, 2001

**Northern States Power Company
Performance Based Regulation
Application**

Case No. PU-400-00-195

I move the Commission adopt the Order Granting Reconsideration and Findings of Fact, Conclusions of Law and Order on Reconsideration in Case No. PU-400-00-195, Northern States Power Company's Performance Based Regulation Application.

sdh

000195-75.doc

**STATE OF NORTH DAKOTA
PUBLIC SERVICE COMMISSION**

**Northern States Power Company
Performance Based Regulation
Application**

Case No. PU-400-00-195

**ORDER GRANTING RECONSIDERSTION and
FINDINGS OF FACT, CONCLUSIONS OF LAW AND ORDER on
RECONSIDERATION**

January 10, 2001

Preliminary Statement

On December 29, 2000, the Commission issued its Findings of Fact, Conclusions of Law and Order approving a performance based rate making settlement agreement between the Northern States Power Company (NSP) and the Public Service Commission Staff, with one modification.

On January 5, 2001, NSP submitted a Petition for Reconsideration, and a revised section 4.D to the previously filed final settlement agreement, concerning the portion of the settlement agreement that was modified in the Commission's December 29, 2000 order.

Discussion

In the December 29, 2000 order, specifically in Findings of Fact Nos. 18, 19, and 20, the Commission stated:

18. The proposed rate change procedure described in the revised settlement agreement is reasonable and consistent with state law. To implement any permissive rate change or mandatory rate reduction, NSP must file a notice of rate change and accompanying tariffs under N.D.C.C. § 49-05-05 after submission of the plan year performance report on May 1 but at least 30 days before the effective date of the proposed rates (July 1).

19. The revised settlement agreement contemplates that any notice of rate change filed under the plan will not be suspended by the Commission under N.D.C.C. § 49-05-06, but the revised rates would be allowed to go into effect on the date proposed. The plan allows the Commission to order a one-time billing "true up" if the Commission determines, after

hearing, that the notice of rate change filed by NSP was not reflective of the plan results or requirements.

20. The Commission agrees that rates established consistent with the plan are presumed just and reasonable, and non-discriminatory. The Commission also appreciates that the revised settlement agreement provides an ability to require billing true-ups as an alternative to suspending rate changes. However, the Commission's statutory authority and responsibility to suspend rate filings when it is necessary and appropriate to do so cannot be contracted away. Further, this Commission cannot act to bind a future Commission. Therefore, the Commission does not approve the Section 4.D. Rate Change Procedure of the revised settlement agreement to the extent that section is inconsistent with this finding.

In Ordering Paragraph No. 1 in the Commission's December 29, 2000 decision, the Commission stated:

1. The attached revised settlement agreement is approved, except as specified in Findings of Fact paragraph 20.

In its petition for Reconsideration, NSP stated its general support for the Commission's decision, but noted an objection to Finding of Fact No. 20 and Ordering Paragraph No. 1. These provisions of the Order require NSP to modify portions of Section 4.D of the settlement agreement, which describes the procedures applicable to filing, notice and implementation of rate changes under the Plan.

NSP asserts Section 4.D is a critical component of the comprehensive settlement agreement, and Section 5.D allows NSP to declare the settlement agreement void and withdraw the Plan due to Commission modification of the settlement agreement. However, NSP also states that it desires a solution which responds to the Commission's concern in Finding of Fact No. 20 while also preserving the expected economic effects of the Plan for NSP under Section 4.D of the settlement agreement.

Consequently, NSP filed Attachment A to its Petition for Reconsideration. Attachment A includes a proposed revision to Section 4.D of the settlement agreement which is acceptable to the Commission Staff. The revised procedure still contemplates that NSP file notice of its rate changes under N.D.C.C. section 49-05-05 not later than June 1 following completion of a plan year, for a July 1 effective date. However, the revised procedure includes a commitment by staff that if the filed rates are calculated consistent with the Plan, the Staff will not recommend suspension of the filing. The revised procedure further contemplates that if the Commission suspends the filing but later determines that the filing complies with the Plan, NSP is entitled to recover the full annual amount over the remaining months of the billing year.

The Commission appreciates NSP's concerns and the efforts of both NSP and staff to reach settlement provisions that are agreeable to the parties and consistent with the Commission's statutory responsibilities. The Commission finds it appropriate to grant reconsideration for the purpose of admitting the most recent settlement revisions into the record, and finds the revisions to section 4.D to be a reasonable resolution of the matter. Consequently, the Commission supplements the Findings of Fact in the December 29, 2000 order with the following:

Findings of Fact

1. The most recently revised settlement (filed as Attachment A to the Petition for Reconsideration) contemplates that any notice of rate change filed under the plan will be investigated by Commission Staff, who will not recommend suspension if the Staff finds the revised rates were calculated consistent with the Plan. The most recently revised section 4.D also contemplates that if a rate change filing is suspended by the Commission under N.D.C.C. § 49-05-06 and later found to be appropriate and consistent with the Plan, NSP would be allowed to recover the full annual increase over the remaining months of the Plan billing year.
2. The Commission agrees that rates established consistent with the plan are presumed just and reasonable, and non-discriminatory. The Commission also appreciates that the January 2001 revised settlement agreement provides a commitment by staff not to recommend suspension in appropriate circumstances, and an ability for NSP to later recover suspended but appropriately calculated and filed annual revenue increases (essentially billing true-ups) as an alternative to prohibiting Commission suspension of rate changes. We agree that these new provisions are more reasonable than the previous provisions in section 4.D, and better reflect the Commission's statutory responsibilities to protect the public interest. While the January 2001 revised section 4.D does not specifically address the symmetrical problem of filed but suspended rate decreases, we believe that the procedure outlined in section 4.D should also apply to any such rate decreases and we do not see any reason to treat decreases differently. We ask NSP to incorporate decreases into section 4.D in NSP's final comprehensive compliance filing.

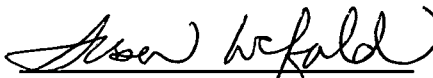
Order

The Commission orders:

1. NSP's Petition for Reconsideration is GRANTED.

2. Section 4.D of the settlement agreement, as modified and provided in Attachment A to the Petition for Reconsideration, is APPROVED, and a copy is attached to this Order.
3. The Final Settlement Agreement filed December 28, 2000, as modified to reflect the revised Section 4.D filed as Attachment A to the Petition for Reconsideration filed January 8, 2001, is APPROVED.
4. NSP shall reflect the revised Section 4.D of the settlement agreement and this decision in its comprehensive compliance filing, which is now due February 12, 2001.
5. The Commission's December 29, 2000 Findings of Fact, Conclusions of Law and Order are supplemented by this decision.

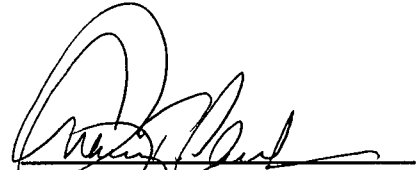
PUBLIC SERVICE COMMISSION



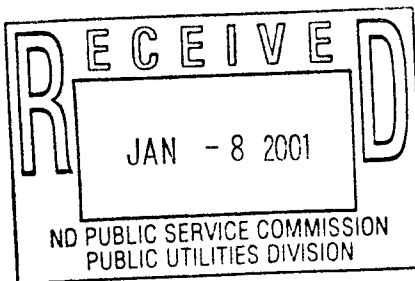
Susan Wefald
Commissioner



Leo M. Reinbold
Commissioner



Anthony T. Clark
Commissioner



James P. Johnson
Assistant General Counsel

800 Nicollet Mall, Suite 2900
Minneapolis, Minnesota 55402
Phone: 612.215.4592
Fax: 612.215.4544

January 5, 2000

Mr. Jon Mielke
Executive Secretary
North Dakota Public Service Commission
600 East Boulevard
Bismarck, ND 58505

Honorable Allen Hoberg
Administrative Law Judge
Office of Administrative Hearings
1701 North 9th Street
Bismarck, ND 58501-1882

Re: Application of Northern States Power Company d/b/a Xcel Energy for
Authority to Operate Under Performance Based Regulation In North Dakota
Case No. PU-400-00-195
Petition for Reconsideration and Remand of Final Settlement Agreement

Dear Mr. Mielke and Judge Hoberg:

Enclosed please find an original and seven copies of the "Petition for Reconsideration, Suspension of Order and Remand of Settlement Agreement" of Northern States Power Company d/b/a Xcel Energy ("NSP") in the above-captioned docket. As described below and in more detail in the petition, NSP is making this filing to allow an opportunity to promptly resolve a concern and proceed with implementation of the NSP PLUS performance-based electric service and rate regulation plan effective January 1, 2001.

On December 29, 2000, the Commission issued its *Findings of Fact, Conclusions of Law and Order* ("Order") in this proceeding approving implementation of NSP's performance-based ratemaking plan effective January 1, 2001. The Order approved, with one important modification, the Final Settlement Agreement dated December 28, 2000 between NSP and the Commission Advocacy Staff ("Staff") regarding the PBR plan. The Order found one aspect of the settlement provisions regarding Rate Change Procedures – specifically the provisions related to Commission authority to suspend electric rate changes which might be filed by NSP pursuant to the PBR plan – to be inappropriate. Finding of Fact #20 and Ordering Paragraph #1 rejected this provision and approved the Final Settlement Agreement subject to modification of this provision.

As the Commission knows, the Final Settlement Agreement was a comprehensive agreement intended to resolve all issues raised in the hearing and working sessions in this proceeding. Under Section 5.D of the Final Settlement Agreement, NSP can terminate the agreement and withdraw the PLUS Plan by notice to the Commission submitted by January 5, 2001, if the Order modifies the Final Settlement Agreement in any manner. Because the Rate Change Procedure section was a key component of the Final Settlement Agreement and PLUS Plan for NSP, the Company believes the modification in Finding #20 and Ordering Paragraph #1 constitutes a modification allowing NSP to submit a notice of withdrawal.

Mr. Jon Mielke
January 5, 2001
Page 2

However, NSP is committed to implementation of PBR in North Dakota. Now that we understand there is a concern with the settlement procedures for rate change filings under the plan, the Company believes the appropriate procedural solution is to reconsider the Order and either amend the Order or issue a supplemental order approving a revision to Section 4.D of the Final Settlement Agreement recently agreed to by NSP and Staff to cure both concerns.

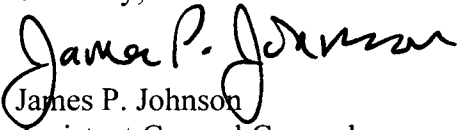
Approval of the revised Section 4.D is Option 1 described in the Petition. Attachment 1 to the Petition provides the proposed revision to the Final Settlement Agreement. For the convenience of the Commission and Advisory Staff, Attachment 2 provides a draft supplemental order approving the revision.

Alternatively, Option 2 requests the Commission reconsider and revise Finding #20 and Ordering Paragraph #1 and approve the Final Settlement Agreement in its entirety, without modification.

NSP appreciates the Commission's prompt action regarding this Petition. The Company will serve two copies of this filing on the Office of Administrative Hearings for the case record and two courtesy copies on Otter Tail Power Company.

Please contact the undersigned (612-215-4592) or Dave Sederquist (701-241-8632) with any questions.

Sincerely,


James P. Johnson
Assistant General Counsel

cc: Mr. Dave Sederquist

Enclosures

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

**Northern States Power Company
Performance Based Regulation
Application**

Case No. PU-400-00-195

**PETITION FOR RECONSIDERATION OF
NORTHERN STATES POWER COMPANY**

Pursuant to North Dakota Cent. Code § 28-32-14 and North Dakota Admin. Code § 69-02-06-02, Northern States Power Company d/b/a Xcel Energy ("NSP" or "the Company") hereby respectfully submits this Petition for Reconsideration ("Petition") of the Commission's *Findings of Fact, Conclusions of Law and Order* ("Order") dated December 29, 2000 in the above-captioned proceeding.

The Order generally approved the Company's proposal to implement the PLUS performance-based regulation plan ("PBR Plan") to regulate the Company's retail electric operations in North Dakota effective January 1, 2001, as revised by the Final Settlement Agreement dated December 28, 2000 between the Company and Commission Advocacy Staff ("Staff"). However, Finding of Fact #20 finds one aspect of the Final Settlement Agreement regarding Rate Change Procedures – the provisions in Section 4.D related to Commission authority to suspend electric rate changes which might be filed by NSP pursuant to the PBR Plan – to be inappropriate. Ordering Paragraph #1 then rejects this provision and approves the Final Settlement Agreement subject to this modification.

NSP is submitting this Petition to allow an opportunity to resolve the concern expressed in the Order while allowing NSP to proceed with implementation of the PLUS Plan.

SUMMARY OF PETITION

As the Commission knows, the Final Settlement Agreement was a comprehensive agreement intended to resolve all issues raised in the hearing and working sessions in this proceeding. Under Section 5.D of the Final Settlement Agreement, NSP can declare the agreement void and withdraw the PLUS Plan by notice to the Commission submitted by January 5, 2001, if the Order modifies the Final Settlement Agreement in any manner.

As described in Section A below, the Rate Change Procedure section was a key component of the Final Settlement Agreement and PLUS Plan for NSP. The Company thus believes the modification contained in Finding #20 and Ordering Paragraph #1 constitutes a modification allowing NSP to submit a notice of withdrawal. However, NSP is committed to resolving the issue so implementation of PBR in North Dakota can proceed. The Company proposes two options:

As described in Section B below, the Company believes the most expeditious solution to resolve the concern with Section 4.D of the Final Settlement Agreement is to promptly reconsider the Order and issue a further order approving the PLUS Plan and Final Settlement Agreement with the modifications to Section 4.D contained in Attachment A to this Petition. The Company is authorized to state the Advocacy Staff supports this method of resolving the Company's concern.

Alternatively, for the reasons discussed in Section C below, NSP requests the Commission grant reconsideration and issue an amended order on reconsideration approving the Final Settlement Agreement and revised PLUS plan without modification.

In support of this Petition, the Company states as follows:

A. STATEMENT OF GROUNDS UPON WHICH RELIEF IS REQUESTED

1. Procedural History and Section 4.D of the Final Settlement Agreement

As noted by the concurring opinion of Commissioner Wefald, the PLUS Plan and Final Settlement Agreement were “the result of months of study and work by the Commission, Commission Staff, and utility representatives.” Like the Commission, the Company believes the process was thorough and appropriate.

- The NSP PLUS Plan included in the April 20, 2000 application was an outgrowth of the Commission’s *Guidelines for Filing Alternative Regulation Proposals* issued September 20, 1995 in Case No. PU-439-94-590, which invited public utilities serving North Dakota to submit PBR plans consistent with the Guidelines.
- The Commission held a public input session to receive public comments on the NSP Plan and the similar PBR plan filed by Otter Tail Power Company (“Otter Tail”) in Case No. PU-401-00-36. As encouraged by the Guidelines, NSP electric customers were given the opportunity to comment on the proposed use of PBR to regulate NSP’s electric operations in North Dakota. No member of the public submitted comments opposing the change.
- Detailed testimony supporting the Plan was submitted by four witnesses for the Company (Mr. McDermott, Mr. Sederquist, Ms. Bagley and Ms. Schander). The Commission held a two day evidentiary hearing where the various Company, Otter Tail and Staff witnesses were subject to both cross examination by counsel and questions and comments by the Commission and its Advisory Staff.
- At the conclusion of that hearing, the Commission urged the Company and Staff to engage in settlement discussions to resolve the areas of disagreement regarding the

specific Plan components and measures. The Company and Staff then engaged in numerous face to face and telephone discussions in good faith to reach a comprehensive settlement, and submitted a Settlement Agreement on November 30, 2000.

- On December 1, 2000, the Company submitted “Proposed Findings of Fact, Conclusions of Law and Order” which provided an analysis of the Commission’s statutory authority to approve the PBR Plan as modified by the Settlement Agreement, including the Rate Change Procedures in Section 4.D of the Settlement Agreement.
- After the hearing and submission of the Settlement Agreement, the Commission conducted four working sessions (on November 20, 2000; December 1, 2000; December 11, 2000; and December 15, 2000) to discuss the NSP and Otter Tail PBR plans, the Proposed Findings and the Settlement Agreement. During the December 1 and 11, 2000 working sessions, the Commission and Advisory Staff raised issues regarding the PLUS Plan revisions agreed to in the Settlement Agreement. The Company agreed to further Plan clarifications and modifications, which were included in a “Amendment and Clarification to November 30, 2000 Settlement Agreement” filed on December 14, 2000. The Commission conducted a final working session on December 15, 2000, during which final Plan clarifications/ revisions were discussed and agreed to by the Company and Staff, and the Company and Staff agreed to submit the Final Settlement Agreement documenting the Plan (as revised) in detail. The Final Settlement Agreement was submitted on December 28, 2000, and the Commission issued the Order on December 29, 2000.

2. Section 4.D is a Critical Component of the Final Settlement Agreement

In considering this Petition, it is important to understand NSP considers the Rate Change Procedure provisions in Section 4.D of the Final Settlement Agreement to be a critical and necessary component of the PLUS Plan. As noted by Dr. McDermott in both his pre-filed an oral testimony, a key component of any PBR plan is symmetrical obligations and benefits. See Joint Exhibit 1, p. 17. The PLUS Plan procedures incorporated in the Final Settlement Agreement provide such symmetry:

- The process for a rate reduction or rate increase filing under the Plan is identical: the Company would file a notice of rate change under N.D.C.C. 49-05-05 no later than June 1 of a Plan year with revised tariff sheets to be placed into effect on July 1 of that year. Neither a rate decrease nor a rate increase would be subject to suspension, but both types of filings would be subject to potential Commission investigation and retroactive rate refunds if the rate filing is found inconsistent with the Plan.
- Under the Plan, however, the Company's "traditional" authority to file electric rate increases to recover 100 percent of its cost of service is constrained: the Company may only file rate increases within the confines of the Price Cap Factor, which limits increases to the *lower of* the increase in Residential electric rates among a comparable group of Midwest utilities or the 60% of the overall rate of inflation as measured by the Consumer Price Index ("CPI"). As such, if electric industry costs increase faster than the general CPI, and NSP experiences cost increases similar to the utility comparison group, NSP will not be able to recover this full increase under the PLUS Plan Price Cap Factor during the Plan term.

- The *quid pro quo* for this limitation on the Company's statutory right to file an electric rate increase is the recognition in the Plan that the Commission will not exercise its "traditional" earnings investigation authority during the Plan term. Instead, Company earnings above the Plan dynamic ROE bandwidth are subject to an *automatic* revenue sharing mechanism under the Plan, which avoids the costs and regulatory lag inherent in traditional earnings investigations.¹

By approving implementation of the five year PBR plans, the Commission has effectively and voluntarily adopted a new "regulatory compact" with NSP and Otter Tail through 2005. In NSP's view, Finding #20 and Ordering Paragraph #1 upset the symmetry of the Final Settlement Agreement.

3. The Order Could Result in Plan Withdrawal by NSP

For the first time in the proceeding, Finding #20 expresses a concern with Section 4.D of the Final Settlement Agreement. This section would allow the Company to file a Notice of Rate Change under N.D.C.C. § 49-05-05 to change (increase or reduce) retail electric rates in North Dakota subject to the many restrictions (e.g., the Price Cap Factor) in the PLUS Plan. The Notice of Rate Change would not be suspended by the Commission. Instead, the Commission could investigate a rate increase and order a refund to customers if it finds the rate change was implemented inconsistent with the PLUS Plan.

¹ For example, the Staff investigation of the Company's 1997 electric earnings was resolved in the Settlement Agreement approved in Case Nos. PU-400-98-246 and PU-400-99-418 (order dated April 12, 2000) via an electric rate reduction effective January 1, 2001, three years after the end of the "test year" under investigation. Under the PLUS Plan, by contrast, if the Company were to earn above the ROE bandwidth in any year, 50% of the earnings "sufficiency" would be rebated to customers in the following year.

However, Finding #20 rejects this provision:

The Commission agrees that rates established consistent with the plan are presumed just and reasonable, and non-discriminatory. The Commission also appreciates that the revised settlement agreement provides an ability to require billing true-ups as an alternative to suspending rate changes. However, the Commission's statutory authority and responsibility to suspend rate filings when it is necessary and appropriate to do so cannot be contracted away. Further, this Commission cannot act to bind a future Commission. Therefore, the Commission does not approve the Section 4.D. Rate Change Procedure of the revised settlement agreement to the extent that section is inconsistent with this finding.

Ordering Paragraph #1 then requires modification of this provision of the Final Settlement Agreement.² Because of this modification, Section 5.D of the Final Settlement Agreement would allow the Company to declare the agreement void and withdraw the request for approval of the PLUS Plan. However, rather than withdraw, the Company prefers to resolve the concern and proceed to implement the Plan, if possible.

4. Reconsideration is Warranted

North Dakota Cent. Code § 28-32-14 and North Dakota Admin. Code § 69-02-06-02 allow NSP to seek reconsideration within 15 days of the Order date. However, Section 5.D of the Final Settlement Agreement requires NSP to provide notice to the Commission by January 5, 2001 if the Company objects to a modification of the agreement. This Petition is expressly intended to perform both functions.

Since reconsideration is appropriate, the Company proposes the following alternative forms of relief. If Option 1 described in Section B is adopted, the Commission need not act on the relief requested in Option 2 (Section C).

² If the procedural and legal concerns reflected in Finding #20 and Ordering Paragraph #1 had been raised in one of the working sessions, the Company and Staff would presumably have revised the Final Settlement Agreement to resolve the concern. Granting the relief requested by the Company would achieve the same resolution.

B. OPTION 1: GRANT RECONSIDERATION AND APPROVE A
MODIFICATION TO SECTION 4.D OF THE FINAL SETTLEMENT

Since the Order was issued, the Company has held discussions with the Advocacy Staff, which understands both the Commission concern expressed in Finding #20 and the Company's concern with the modification to the comprehensive Final Settlement Agreement. As a result, the Company and Staff have agreed to revise Section 4.D of the Final Settlement Agreement to resolve both concerns.

The proposed language is reflected in Attachment A. This language preserves the Commission's suspension authority under N.D.C.C. 49-05-06 while keeping the Company financially whole under the Plan in the event the Commission suspended a notice of rate change but later determined all (or a portion) of the rate increase proposed was consistent with the Plan requirements. The Company sincerely appreciates the Staff's efforts to resolve this issue so promptly.

If the Commission approves Option 1, the Company believes the Commission can issue a brief supplemental order stating its approval of the revised Section 4.D of the Final Settlement Agreement. For the convenience of the Commission, Attachment B provides a draft supplemental order which would provide such approval. As provided in the draft supplemental order, NSP would reflect the revised Section 4.D in the comprehensive Plan description required to be submitted no later than January 31, 2001 pursuant to Ordering paragraph 4.³

³ Alternatively, if the Commission believes the approach of revising/clarifying Section 4.D of the Final Settlement Agreement has merit, but the revised Section 4.D proposed herein is not acceptable (or raises new issues) for some reason, the Company would request the Commission (a) grant reconsideration and (b) issue an order holding the Order in abeyance and remanding the settlement agreement for further negotiations between the Company and Advocacy Staff.

C. OPTION 2: GRANT RECONSIDERATION AND AMEND THE ORDER

Alternatively, if the Commission does not approve Option 1, the Company believes the record would support granting reconsideration and issuing an Order on Reconsideration which modifies Finding #20 and Ordering Paragraph #1. As described below, the Commission can determine Finding #20 and Ordering Paragraph #1 are inconsistent with the record and the Commission's authority under N.D.C.C. 49-05-05.

1. The Rate Reduction Procedures Comply with the N.D.C.C.

As described in the Company's Proposed Findings filed on December 1, 2000, the apparent statutory concern regarding the suspension provisions in the Rate Change Procedure section of the Settlement Agreement is not warranted. The Company proposed the following finding of fact:

16. The proposed Rate Change Procedure described in the Settlement Agreement is reasonable and consistent with the N.D. Cent. Code. To implement any permissive rate change or mandatory rate reduction, it is appropriate that the Company file a notice of rate change and the accompanying tariffs pursuant to N.D.C.C. § 49-05-05 after submission of the Plan year performance report on May 1 but at least 30 days before the effective date of the proposed rates (July 1).

The Settlement Agreement contemplates such notice of rate change will not be suspended by the Commission under N.D.C.C. § 49-05-06, but the revised rates would be allowed to go into effect on the date proposed. Rates established consistent with the Plan are presumed just and reasonable, and non-discriminatory. However, the Plan appropriately retains the Commission's statutory authority to prospectively change the Company's rates after hearing, and also allows the Commission to order the Company to make a one-time billing "true up" if the Commission determines, after hearing, that the notice of rate change filed by the Company was not reflective of the Plan results or requirements.

Consistent with this proposed finding of fact, the Company then proposed the following Conclusion of Law:

4. This order approving the Company's alternative regulation Plan shall constitute an "order applicable to special or peculiar circumstances or conditions" under N.D. Cent. Code § 49-05-05.

Finally, the Company proposed the following ordering paragraph consistent with the proposed finding and conclusion of law:

3. Not more than annually, the Company may file a notice of rate change pursuant to N.D. Cent. Code 49-05-05 to change its rates, subject to all the requirements of the Plan, to be effective July 1 of such Plan year. Any such notice shall be filed at least 30 days prior to the effective date of the proposed rate change, and will not be suspended by the Commission. However, if the Commission determines after investigation and hearing that the changed rates do not comply with the Plan terms as prescribed by the Settlement Agreement and herein, the Commission may prospectively establish the rates it finds to be consistent with the Plan terms, and order a one-time billing true-up for the impact of the discrepancy since either the inception of the rate change or the previous 12 month period, whichever is less.

The Company's Proposed Findings set forth a reasonable evidentiary and legal basis for approval of Section 4.D of the Final Settlement Agreement. The Advocacy Staff did not submit proposed findings or contest the Company's Proposed Findings. At no time in the hearing or working sessions, to the Company's recollection, did any party express specific concerns with the suspension provisions in Section 4.D of the Final Settlement Agreement or with the Proposed Findings. Thus Finding #20 and Ordering Paragraph #1 are inconsistent with the record, arbitrary and capricious and an abuse of discretion. Allstate Ins. Co. v. Knutson, 278 N.W.2d 383 (N.D. 1979).

Indeed, contrary to Finding #20, N.D.C.C. 49-05-05 specifically contemplates the Commission may allow rate changes to be placed into effect without suspension "by a general order applicable to special or peculiar circumstances or conditions." Further, the suspension authority under N.D.C.C. 49-05-06 is discretionary: "the commission *may* suspend by motion...." [emphasis added]. As such, the Commission can reasonably

conclude in its amended order approving the PLUS Plan (as suggested by the NSP Proposed Findings) that (a) implementation of a PBR plan is a “special or peculiar circumstance” justifying a discretionary exception to “traditional” suspension procedures, and (b) N.D.C.C. 40-05-05 clearly allows the Commission to bind itself (and future commissions) to by order.

The discretionary nature of the Commission’s suspension authority is supported by the North Dakota Supreme Court decision in O’Connor v. Northern States Power Company, 308 N.W. 2d 365 (1981). In that decision the Court stated:

Under the statutes which it administers, the PSC was aware that by failing to suspend the rate filed ... it would become effective 30 days later....The PSC did not nor was it required by statute to take such action and, under the statutory scheme governing rate increases, NSP was authorized to begin charging its new rate on June 11, 1977.

308 N.W. 2d at p. 370 [emphasis added].

The purpose of the Final Settlement Agreement provisions regarding Rate Change Procedures is to secure the symmetrical limitations on the authority of the Company and the Commission during the Plan term consistent with the provisions of N.D.C.C. 49-05-05 and 49-05-06 and the Guidelines. In addition, an express purpose of the PLUS Plan is to allow revenue sharing and electric rate changes (both increases and reductions) without the litigation costs or delays inherent in traditional rate cases or rate investigations. See Joint Exhibit 1, p. 7; see also Final Settlement Agreement, p. 3.

Finding of Fact #20 and Ordering Paragraph #1 impacts the balance negotiated in the Final Settlement Agreement by placing additional constraints on the Company. Specifically, while sharing of reported revenues contributing to earnings above the ROE bandwidth would be automatic, NSP’s ability to collect revenue deficiencies through the

sharing mechanism could effectively be moot. The rate surcharges filed on or before June 1 and applicable to bills issued during the subsequent July to December period could potentially be suspended beyond the December termination date. The revenue deficiency (which the Company already deferred) would then effectively be unrecoverable.

Similarly, a notice of rate change necessitated by cost increases to the Company and filed subject to all the Price Cap Factor and other PLUS Plan limitations could be suspended for up to seven months, delaying recovery of legitimate cost increases for almost two-thirds of a Plan year and negatively impacting Company earnings in the process. However, a notice of rate change reducing rates would almost certainly not be suspended. Again, the symmetry which Dr. McDermott testified is essential to any PBR plan would be lost.

Finally, as recognized in Finding #20, the Final Settlement Agreement does not leave the Commission without a remedy. By settlement, NSP would effectively waive the normal statutory prohibition (discussed in the O'Connor case) on refunds of rates not suspended by the Commission. While NSP assumes such “true-up” refunds would be unlikely – since NSP intends to administer the PLUS Plan and calculate any rate increases correctly – the Company recognizes it is appropriate for the Commission to have such a corrective remedy within the context of a comprehensive PBR plan which allows a notice of rate change to go into effect without suspension and prior to a Commission investigation. Given this alternative procedure to protect North Dakota electric customers from unreasonable rates, Finding #20 and Ordering Paragraph #1 are arbitrary and capricious and not supported by the record and should be revised on reconsideration.

The Company thus alternatively requests the Commission grant reconsideration and issue an amended order which replaces Finding #20 and Ordering Paragraph #1 with the Company's proposed finding of fact, conclusion of law and ordering paragraph discussed above. Granting this alternative relief would approve the Final Settlement Agreement and revised PLUS Plan in their entirety without modification.

However, as noted above, if Option 1 is adopted, the Commission need not act on this alternative request for relief.

CONCLUSION

For the reasons stated in Section B above, the Commission should promptly reconsider the Order and issue a brief supplemental order (in the form provided in Attachment B) approving the modification to Section 4.D of the Final Settlement Agreement (provided in Attachment A).

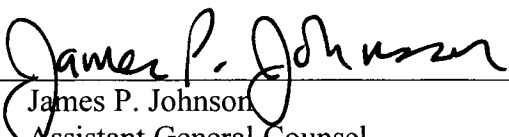
Alternatively, for the reasons stated in Section C above, the Company respectfully requests the Commission grant reconsideration and issue an amended order which replaces Finding #20 and Ordering Paragraph #1 with the Company's proposed finding of fact, conclusion of law and ordering paragraph discussed above. Granting this alternative relief would approve the Final Settlement Agreement and revised PLUS Plan in their entirety without modification.

Finally, if the Commission does not grant reconsideration and approve either Option 1 or Option 2, the Company hereby provides notice pursuant to Section 5.D of the Final Settlement Agreement that the Company reserves the right to declare the Final Settlement Agreement null and void and withdraw the April 20, 2000 application to

operate pursuant to the PLUS Plan effective January 1, 2001. However, like the Commission, the Company is committed to the operational success of the Plan and certainly prefers resolving the concerns through Option 1, which would be consistent with the conduct of the proceedings to date.

Respectfully submitted,

NORTHERN STATES POWER COMPANY

By: 
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Assistant General Counsel
Xcel Energy Services Inc.
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Minneapolis, MN 55402
Phone: (612) 215-4592
Fax: (612) 215-4544

Attorney for Northern States Power Company

Date: January 5, 2001

Revised Section 4.D to Final Settlement Agreement

D. Rate Change Procedure

To implement any permissive rate change pursuant to Section B or mandatory rate reduction pursuant to Section C, the Company shall file a notice of rate change and the accompanying tariffs pursuant to N.D.C.C. 49-05-05 not later than June 1, following completion of the Plan year and submission of the Plan performance report on May 1. The revised rates shall be effective on or after July 1 following the Plan year. Base rate changes will be across-the-board to all customer classes unless otherwise requested by the Company and approved by the Commission.

If the Staff investigation of the May 1 Plan performance report and the notice of rate change indicates the proposed rates are calculated consistent with the Plan, the Staff agrees it will not recommend the Commission suspend the notice of rate change. If a notice of rate change which would result in a rate increase is nonetheless suspended beyond July 1 by the Commission pursuant to N.D.C.C. 49-05-06, and the Commission determines after investigation a rate increase is consistent with the Plan terms, the Company may at the conclusion of the suspension period establish the rates necessary to recover the full annual increase over the remaining months of the Plan billing year.¹

¹ For example, assume the Company files a notice of rate change on June 1 proposing a \$1 million annual rate increase effective July 1, but the Commission suspends the rate increase until October 1. Assume the rate increase is 0.2 cents per kWh for all customer classes. If the Commission determines after investigation that the Plan would allow the Company to increase revenues by \$1 million annually, the Company may establish compliance rates effective October 1 (consisting of the filed increase of 0.2 cents/kWh plus a temporary surcharge to recover the increased revenues not recovered in rates from July through September) which would allow recovery of the \$1 million on its forecasted electric sales for the period October 1 through June 30.

Rates established consistent with the Plan are presumed just and reasonable,
and non-discriminatory.

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

Northern States Power Company d/b/a
Xcel Energy
Performance-Based Regulation Proposal

Case No. PU-400-00-195

SUPPLEMENTAL ORDER

January __, 2000

Procedural History

This matter came before the Commission on an application filed on April 20, 2000, by Northern States Power Company d/b/a Xcel Energy ("NSP" or "the Company") for approval of a "Proposal for a Performance-Based Regulation Plan." NSP asked the Commission to approve the Company's proposed performance-based regulation ("PBR") plan for purposes of regulating NSP's retail electric operations in North Dakota. The Company proposed the Plan be in effect for a five year term from January 1, 2001 to December 31, 2005. If approved, the Plan would create an alternative form of regulation for the Company's electric operations in North Dakota.

On December 29, 2000, the Commission issued its "Findings of Fact, Conclusions of Law and Order" ("Order") which, *inter alia*, approved the settlement agreement between the Company and the Advocacy Staff, with one modification. The settlement agreement recommended the Plan be allowed to go into effect January 1, 2001, but reflected various revisions to the Plan which the Company and Staff accepted after the hearing and working sessions conducted in this proceeding.

On January 5, 2001, the Company submitted a Petition for Reconsideration ("Petition") pursuant to North Dakota Cent. Code § 28-32-14 and North Dakota Admin. Code § 69-02-06-02 and Section 5.D of the settlement agreement. In the Petition, the Company states its general support for the Order but objects to Finding of Fact #20 and Ordering Paragraph #1. These provisions of the Order require modifications to portions of Section 4.D of the settlement agreement, which describes the procedures applicable to any notice of rate change filed by the Company pursuant to the Plan.

The Company asserts Section 4.D is a critical component of the comprehensive settlement agreement, and Section 5.D allows the Company to declare the settlement agreement void and withdraw the Plan because the Order modified the settlement agreement. However, the Company states it desires a solution which responds to the Commission's concern in Finding #20 regarding its legal authority pursuant to N.D.C.C.

49-05-06 while also preserving the expected economic effects of the Plan for the Company under Section 4.D of the settlement agreement.

Attachment A to the Petition includes a proposed revision to Section 4.D of the settlement agreement which is acceptable to the Advocacy Staff.¹

On January __, 2001, the Commission met to consider the Company's Petition for Reconsideration.

ORDER

The Commission grants the Company's Petition for Reconsideration and further orders:

1. Section 4.D of the settlement agreement, as modified and provided in Attachment A to the Petition, is approved. The Final Settlement Agreement filed December 28, 2000 is modified to reflect the revised Section 4.D, and as so modified the Final Settlement Agreement is APPROVED without modification.
2. Ordering paragraph 4 of the Order states that "NSP shall submit a single comprehensive stand-alone document describing the Plan as modified by the approved portion of the attached revised settlement agreement by January 31, 2001." The commission further orders NSP to reflect the revised Section 4.D of the settlement agreement in this comprehensive compliance filing.

PUBLIC SERVICE COMMISSION

Anthony T. Clark
Commissioner

Susan E. Wefald
Commissioner

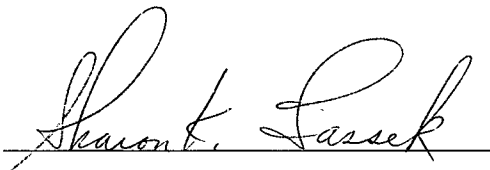
Leo M. Reinbold
Commissioner

¹ The Petition alternatively requests the Commission to grant reconsideration and issue an amended order revising the contested Finding #20 and Ordering Paragraph #1 and approving the settlement agreement without modification. However, since the Commission is granting the Company's preferred procedural option of a supplemental order approving the revised Section 4.D, the Petition indicates the alternative statement of specific grounds and relief requested requires no Commission action.

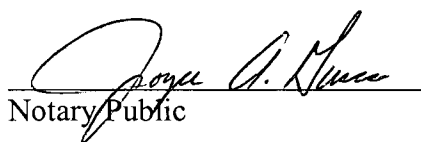
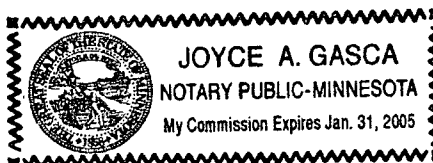
AFFIDAVIT OF SERVICE

I, Sharon K. Lassek, hereby certify that I have this day served the Petition for Reconsideration and Remand of Final Settlement Agreement on the parties listed below by placing in the U.S. mail at Minneapolis, Minnesota or by sending via Federal Express.

Dated this 5th day of January, 2001.



Subscribed and sworn to before
me this 5th day of January, 2001.


Notary Public

Jon Mielke
Executive Secretary
North Dakota Public Service Commission
600 East Boulevard
Bismarck, ND 58501

Honorable Allen Hoberg
Administrative Law Judge
Office of Administrative Hearings
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STATE OF NORTH DAKOTA
PUBLIC SERVICE COMMISSION

Otter Tail Power Company
Performance Based Regulation
Application

Case No. PU-401-00-36

Northern States Power Company
Performance Based Regulation
Application

Case No. PU-400-00-195

AFFIDAVIT OF SERVICE BY CERTIFIED MAIL

STATE OF NORTH DAKOTA
COUNTY OF BURLEIGH

Sharon Helbling deposes and says that:

she is over the age of 18 years and not a party to this action and, on the **2nd day of January, 2001**, she deposited in the United States Mail, Bismarck, North Dakota, **three** envelopes with certified postage, return receipt requested, fully prepaid, securely sealed and each containing a photocopy of:

Order

The envelopes were addressed as follows:

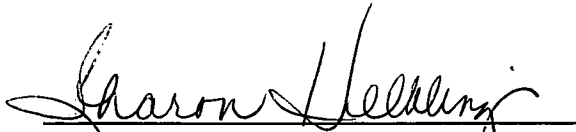
Kent Larson
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Each address shown is the respective addressee's last reasonably ascertainable post office address.

Subscribed and sworn to before me
this **2nd day of January, 2001**.




Notary Public

SEAL

SANDRA L. SCOTT
Notary Public, STATE OF NORTH DAKOTA
My Commission Expires JUNE 11, 2004

50

PU-400-00-195

Pages: 8

Affidavits of Service

by Public Service Commission

01/02/2001 CC: Comm Legal Illona, Pat, Jerry Mike

STATE OF NORTH DAKOTA
PUBLIC SERVICE COMMISSION

**Otter Tail Power Company
Performance Based Regulation
Application**

Case No. PU-401-00-36

**Northern States Power Company
Performance Based Regulation
Application**

Case No. PU-400-00-195

AFFIDAVIT OF SERVICE BY ORDINARY MAIL OR E-MAIL

STATE OF NORTH DAKOTA
COUNTY OF BURLEIGH

Sharon Helbling deposes and says that:

she is over the age of 18 years and not a party to this action and, on the **2nd day of January, 2001**, she deposited in the United States Mail, Bismarck, North Dakota, envelopes by first class mail, fully prepaid, securely sealed, each containing a photocopy of:

Order

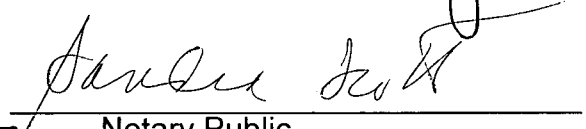
The envelopes were addressed as follows:

See Attached List

Each address shown is the respective addressee's last reasonably ascertainable post office address.

Subscribed and sworn to before me
this **2nd day of January, 2001**.





Notary Public

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PU-400-00-195

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MOTION

December 29, 2000

APPROVED:
DATE: 12-29-00
KME

**Northern States Power Company
Performance Based Regulation
Application**

Case No. PU-400-00-195

I move the Commission adopt the Findings of Fact, Conclusions of Law and Order approving a performance-based ratemaking plan for Northern States Power Company, Case No. PU-400-00-195.

JRL/sdh

**STATE OF NORTH DAKOTA
PUBLIC SERVICE COMMISSION**

**Northern States Power Company
Performance Based Regulation
Application**

Case No. PU-400-00-195

FINDINGS OF FACT, CONCLUSIONS OF LAW AND ORDER

December 29, 2000

Appearances

Commissioners Bruce Hagen, Leo M. Reinbold, Susan E. Wefald.

James P. Johnson, Assistant General Counsel, Xcel Energy Services Inc., 800 Nicollet Mall, Minneapolis, MN 55402, appearing on behalf of Northern States Power Company d/b/a Xcel Energy.

William W. Binek, Chief Counsel, Public Service Commission, State Capitol, 600 East Boulevard, Bismarck, ND 58505, appearing on behalf of the Public Service Commission Staff.

Allen C. Hoberg, Administrative Law Judge and Director, Office of Administrative Hearings, 1707 North 9th Street - Lower Level, Bismarck, ND 58501-1882, appearing as procedural Hearing Officer.

Preliminary Statement

On April 20, 2000 Northern States Power Company (NSP or Company) filed an application for approval of a Performance-Based Regulation (PBR) plan for purposes of regulating NSP's retail electric operations in North Dakota. NSP termed its plan the Performance Linking Utility Stakeholders (PLUS) plan. NSP proposes the plan be in effect for a five year term from January 1, 2001 to December 31, 2005. If approved, the plan would create an alternative form of regulation for NSP's electric operations in North Dakota. NSP asserts the proposed plan would comply with the Commission's Guidelines for Filing Alternative Regulation Proposals issued September 20, 1995 in Case No. PU-439-94-590.

On July 19, 2000, the Commission issued a "Notice of Hearing and Notice of Public Discussion Meeting" in the instant case and in Case No. PU-401-00-36, a case involving a similar PBR plan filed by Otter Tail Power Company (Otter Tail). The notice scheduled a public discussion meeting for September 6, 2000 and public hearings for October 23-24, 2000. The notice set forth the following issues to be considered:

1. Are the plans consistent with Commission guidelines?
2. Would the plans result in quality service and reasonable electric rates?
3. Would the plans support safe and reliable electric infrastructure and the financial viability of the utilities?
4. Would implementing the plans be in the public interest?

On September 6, 2000, the Commission conducted a public discussion meeting as scheduled, with public participation available through ten video conference sites at Belcourt, Bismarck, Bottineau, Devils Lake, Fargo, Fort Totten, Grand Forks, Jamestown, Minot and Wahpeton, North Dakota. Any written comments received from members of the public during the course of the proceeding were filed in the public input file in this case.

On October 23-24, 2000, the Commission conducted public hearings as scheduled. At the conclusion of the hearings, the Hearing Officer required the parties to submit briefs and proposed findings of fact and conclusions of law by December 1, 2000. Alternatively, in lieu of briefs, NSP and Staff were permitted to submit a settlement agreement resolving the disputed issues.

On November 20, 2000, the Commission held an informal working session to discuss NSP's proposal. On November 29, 2000, NSP and Staff submitted a settlement agreement. The Commission held a second informal working session to discuss the agreement on December 1, 2000. On December 8, 2000 NSP and Staff filed an amendment to the settlement agreement and the Commission held additional working sessions to discuss the amendment on December 11 and 15, 2000. Following those working sessions, NSP and Staff submitted a revised settlement agreement on December 28, 2000.

Discussion

On September 20, 1995, after numerous workshops with industry and other interested parties, the Commission issued "Guidelines for Filing Alternative Regulation Proposals" (Guidelines) in Case No. PU-439-94-590. The Guidelines indicated the Commission would consider proposals for alternative forms of regulation from traditional "cost-based rate of return" regulation. The Guidelines set forth both goals and criteria for alternative regulation proposals, which include:

- Goals: a plan should (1) promote utility efficiencies; (2) align customer and shareholder interests; (3) maintain/improve customer service; (4) allow utilities to be flexible; (5) minimize regulatory costs; and (6) improve public participation.
- Criteria: a plan should be (1) comprehensive; (2) administratively simple; (3) easily communicated; (4) balanced; and (5) flexible.

- The guidelines indicated that any proposal (1) must show the utility's base rates are just and reasonable at the start of the alternative mechanism; (2) should be for a limited period of time, and include a review date; (3) provide for a periodic review of the utility's profits pursuant to criteria in the plan; (4) enable the Commission to judge the success of the plan at its completion; and (5) must not violate the Territorial Integrity Act.

Findings of Fact

1. NSP is a Minnesota corporation providing electric and natural gas public utility service in North Dakota. NSP and its predecessor ("Old NSP") have continuously provided electric public utility service in North Dakota pursuant to authorizations provided by North Dakota law or issued by the Commission. NSP provides retail electric service under Commission jurisdiction in the communities of Fargo, Grand Forks, Minot, West Fargo, Berthold, Burlington, Buxton, Des Lacs, Hatton, Larimore, Mayville, Portland, Reynolds and Thompson, North Dakota, and certain surrounding areas.
2. NSP is a utility operating company subsidiary of Xcel Energy Inc., which was created by the merger of Old NSP and New Century Energies, Inc. on August 18, 2000. Xcel Energy Inc. is a registered holding Company subject to the jurisdiction of the U.S. Securities and Exchange Commission ("SEC") under the Public Utility Holding Company Act ("PUHCA").
3. NSP's application for approval of its PLUS plan was filed pursuant to a settlement agreement between NSP and Commission staff (Staff) in Case Nos. PU-400-99-418, an application requesting approval of NSP's merger with New Century Energies, Inc., and PU-400-98-246, a Staff investigation of NSP's electric earnings. This prior settlement agreement was approved by a May 10, 2000 Commission Order in those dockets.
4. The key components of NSP's PLUS plan include 1) a "dynamic allowed ROE" range which can vary based on Company performance, 2) a revenue sharing mechanism, 3) establishment of service performance standards, and 4) price capping flexibility to adjust prices under specified circumstances.
5. NSP proposes to implement its plan for the period January 1, 2001 to December 31, 2005. The Commission finds this term will allow sufficient time to evaluate operations under this alternative regulation plan.
6. The annual performance and financial reporting provisions of the plan, as modified by the revised settlement agreement, are reasonable. The interim review proposed for June 2003 is reasonable and consistent with the Guidelines.

7. Concurrently and independently with plan implementation, NSP will reduce non-fuel base retail electric rates to NSP's North Dakota electric service customers by \$261,000 annually (approximately 0.25%), pursuant to the Commission order dated May 10, 2000, in Case Nos. PU-400-99-418 (Merger with New Century Energies, Inc.) and PU-400-98-246 (Electric Rate Investigation). The Commission finds this rate adjustment results in just and reasonable initial rates at the time the plan is initiated.

8. The proposed baseline Return on Equity ("ROE") of 12.0%, the ROE deadband of +/- 1.0% around the baseline, and the annual dynamic ROE adjustments in terms of "basis points," subject to NSP's performance under each performance standard, are reasonable. The baseline ROE is comparable to the ROE used to resolve utility earnings investigations over the past few years, and the +/- 1% deadband is within a zone of reasonableness.

9. The proposed revenue sharing mechanism, as modified by the revised settlement agreement, is reasonable. This mechanism provides:

If NSP's reported actual earnings fall within the ROE deadband around the authorized ROE (as adjusted by the performance points) in a plan year, no revenue sharing will take place.

If NSP's actual reported earnings for any plan year exceed the deadband, the corresponding revenue 'sufficiency' will be calculated, and 50% of this dollar amount will be refunded to customers during the July billing cycle of the following year. Customers of record on March 31 following the Plan year will be issued refunds by bill credit prorated on the basis of their electric usage for the twelve months ending March 31.

If NSP's actual reported earnings for any plan year are below the deadband, 50% of the corresponding revenue "deficiency" may be recovered through a surcharge on NSP's electric rates effective no later than 24 months after the Plan year. However, NSP has agreed to defer recovery of a reported fiscal year deficiency by recording the amount as a regulatory asset until the following plan year revenue sharing amount, if any, is reported. If the prior year deficiency is fully offset by the current year reported revenue sufficiency, the sufficiency will be used to eliminate the regulatory asset, and no rate surcharge will be imposed. If the deficiency from the prior year is not fully offset, any remaining deficiency balance may be reflected in rates applicable to bills issued between the 18th and 24th month following the plan year when the deficiency occurred, subject to the Rate Change procedures described herein.

10. Treatment of NSP's economic development expenditures as a jurisdictional expense for financial reporting purposes is reasonable. This will provide greater consistency in treatment of this cost component between the NSP and Otter Tail plans.

11. The proposed reliability performance measures and standards, as modified by the revised settlement agreement, are reasonable. The Customer Average Interruption Duration Index (CAIDI) and System Average Interruption Frequency Index (SAIFI) are individual reliability measures widely used in the electric utility industry, the product of which is the System Average Interruption Duration Index (SAIDI) reliability measure originally proposed by NSP. By using both component standards, NSP will be measured on both the frequency of customer outages and the time it takes to restore power. Each measure will carry a potential reward or penalty of a 25 basis point adjustment to the authorized ROE deadband.

12. The proposed customer satisfaction performance measures, as modified by the revised settlement agreement, are reasonable. NSP will be measured based on both the relationship surveys for all three customer classes (Residential, Commercial, Large Industrial), and two transaction surveys relating to NSP's call center and electric service functions. The survey results will reflect the percentage of respondents who give NSP an 'excellent' or 'very good' rating. Each of the two survey standards will carry a potential reward or penalty of a 25 basis point adjustment to the authorized ROE deadband.

13. The proposed pricing measures and standards, as modified by the revised settlement agreement, are reasonable. NSP will be measured by 1) its average residential price per kWh compared to the 26 jurisdiction mid-western utility peer group; and 2) the annual change in average residential price relative to the change for the lowest priced utility in the peer group. The price measures will be calculated annually based on utility price data compiled in the Edison Electric Institute's "Typical Bills and Average Rate Report" for the 12 month period ending December 31st. Each of the two price measures will carry a potential reward or penalty of a 25 basis point adjustment to the authorized ROE deadband.

14. The proposed employee safety measure and standards, are reasonable. To be consistent with the other individual plan standards, it is appropriate that the employee safety measure carry a potential reward or penalty of a 25 basis point adjustment to the authorized ROE deadband.

15. The proposed price cap factor, as modified by the revised settlement agreement, is reasonable. The price cap factor will be the lower of 1) the annual percentage change in the utility peer group's average residential price per kWh for the reporting year, or 2) 60% of the change in the Consumer Price Index (CPI) for the reporting year.

16. The proposed rate change criteria, as modified by the revised settlement agreement, are reasonable. The plan imposes an electric rate freeze on NSP whenever: 1) its previous year reported ROE was higher than 100 basis points below the baseline ROE (as adjusted for performance), or 2) NSP's average residential rates were higher than the utility peer group average residential rate. If neither condition exists, then NSP may increase its electric rates by an overall percentage not to exceed the price cap factor, subject to the rate change procedures of the plan.

17. The proposed rate decrease criteria, as modified by the revised settlement agreement are reasonable. It is appropriate that NSP be required to reduce its retail electric rates under the plan if: 1) NSP's reported ROE for the plan reporting year was more than 100 basis points above the baseline ROE (as adjusted for performance), 2) NSP's average residential rates are higher than the PLUS utility peer group average residential rate, and 3) the price cap factor is negative.

18. The proposed rate change procedure described in the revised settlement agreement is reasonable and consistent with state law. To implement any permissive rate change or mandatory rate reduction, NSP must file a notice of rate change and accompanying tariffs under N.D.C.C. § 49-05-05 after submission of the plan year performance report on May 1 but at least 30 days before the effective date of the proposed rates (July 1).

19. The revised settlement agreement contemplates that any notice of rate change filed under the plan will not be suspended by the Commission under N.D.C.C. § 49-05-06, but the revised rates would be allowed to go into effect on the date proposed. The plan allows the Commission to order a one-time billing "true up" if the Commission determines, after hearing, that the notice of rate change filed by NSP was not reflective of the plan results or requirements.

20. The Commission agrees that rates established consistent with the plan are presumed just and reasonable, and non-discriminatory. The Commission also appreciates that the revised settlement agreement provides an ability to require billing true-ups as an alternative to suspending rate changes. However, the Commission's statutory authority and responsibility to suspend rate filings when it is necessary and appropriate to do so cannot be contracted away. Further, this Commission cannot act to bind a future Commission. Therefore, the Commission does not approve the Section 4.D. Rate Change Procedure of the revised settlement agreement to the extent that section is inconsistent with this finding.

21. Any increases or decreases in costs of electric service caused by governmentally imposed changes in taxes or accounting practices will be implemented within 60 days of the effective date of the change.

22. Use of 36 months of historic demand data for purposes of annual plan financial reporting is reasonable because it will mitigate volatility in the jurisdictional allocation factor. The use of a 36 month jurisdictional demand allocator is only for financial reporting purposes under the plan and has no precedential effect in future electric rate proceedings after the plan term expires or the plan is suspended or terminated.

23. The plan procedures for suspension or termination of the plan during the five year term are reasonable because they provide protections for both North Dakota electric customers and NSP. As provided by the revised settlement agreement, NSP

may request, or the Commission may on its own motion initiate a proceeding, to suspend or terminate the Plan prior to December 31, 2005 in the event of:

- Passage of retail access legislation at either the federal or state level;
- Merger and acquisition events affecting NSP's structure and operations;
- Natural disasters affecting NSP's North Dakota electric operations (major storms, floods, etc.);
- Unusual events affecting NSP's operations (major generating plant failure, damage to major transmission or distribution lines, etc.); or
- Material and sustained earnings extremes (defined as returns on equity +/- 5.0% from the ROE deadband, prior to sharing).

24. The plan is consistent with Commission guidelines.

25. The plan promotes quality service and reasonable electric rates.

26. The plan promotes safe and reliable electric infrastructure and the financial viability of the utility.

27. Implementing the plan is in the public interest.

From the foregoing Findings of Fact, the Commission makes its:

Conclusions Of Law

1. The Commission has jurisdiction over the parties and the subject matter of this proceeding.

2. For purposes of initial plan implementation, NSP's recently adjusted electric rates effective January 1, 2001 are just and reasonable and non-discriminatory.

3. Rates established consistent with the plan during the plan term are appropriately presumed just and reasonable and non-discriminatory.

4. The plan promotes quality service and reasonable electric rates.

5. The plan promotes safe and reliable electric infrastructure and the financial viability of the utility.

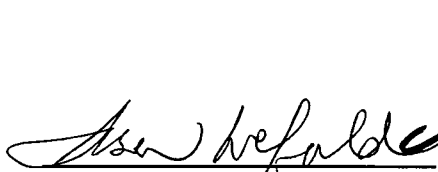
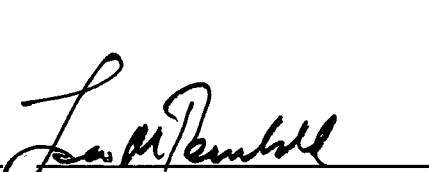
6. Implementing the plan is in the public interest.

Order

The Commission orders:

1. The attached revised settlement agreement is approved, except as specified in Findings of Fact paragraph 20.
2. NSP's PLUS plan, as modified by the approved portion of the attached revised settlement agreement, is approved.
3. NSP d/b/a Xcel Energy is authorized to implement the plan as modified by the revised settlement agreement for its electric utility operations in the State of North Dakota for the term January 1, 2001 to December 31, 2005.
4. NSP shall submit a single comprehensive stand-alone document describing the plan as modified by the approved portion of the attached revised settlement agreement by January 31, 2001.
5. NSP shall submit all annual performance and financial reports required by the plan (as modified) by May 1st of each plan year. The Commission may require interim reports during the plan term as necessary.
6. The plan is be subject to suspension or termination for good cause, as provided in the revised settlement agreement.
7. The Commission will review the operation and results of the plan upon receipt of reports for the 2002 plan year.

PUBLIC SERVICE COMMISSION

		
Susan E. Wefald Commissioner	Bruce Hagen President	Leo M. Reinbold Commissioner

STATE OF NORTH DAKOTA
PUBLIC SERVICE COMMISSION

**Otter Tail Power Company
Performance Based Regulation
Application**

Case No. PU-401-00-36

**Northern States Power Company
Performance Based Regulation
Application**

Case No. PU-400-00-195

**CONCURRING OPINION
COMMISSIONER SUSAN E. WEFALD**

December 29, 2000

Today the Commission is adopting Performance Based Regulation plans for purposes of regulating Northern States Power Company's and Ottetail's retail electric operations in North Dakota. This plan is the result of months of study and work by the Commission, Commission Staff, and utility representatives.

The plan promotes utility efficiencies, aligns customer and shareholder interests, works to maintain or improve customer service, allows utilities to be flexible, minimizes regulatory costs, and improves public participation. In other words, it is a win – win situation, good for consumers and good for NSP and Ottetail.

The companies will be measured on four areas of performance with this plan. These areas are reliability, customer satisfaction, price standards, and an employee safety standard.

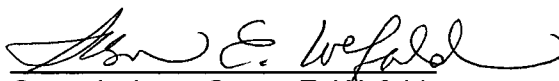
Customers should know that they play a role in determining the companies' performance each year. Each company will be doing several surveys of customers each year to determine the customers' satisfaction with their electric service.

Also, public input played a role in determining the provisions of the settlement. Ideas from letters received from the public were incorporated into the settlement.

The plan will be in place for 5 years and will be evaluated after 2 years.

These particular performance based regulation plans are unique to our state and our utilities. For anyone wishing to study the plans in more detail, the Commission order and the settlements will be available very soon on the Commission web site. The Commission and our staff will be happy to discuss the plans at any time.

I am proud of the work done by all parties on this project and am committed to the operational success of these plans.


Commissioner Susan E. Wefald

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

Northern States Power Company
Performance-Based Regulation Proposal

Case No. PU-400-00-195

FINAL SETTLEMENT AGREEMENT

This Final Settlement Agreement ("Final Agreement") is entered into this 27th day of December, 2000, by and between Northern States Power Company, a Minnesota corporation ("NSP" or "the Company") and the North Dakota Public Service Commission litigation staff ("Staff"). This Settlement Agreement resolves all outstanding issues in the above-captioned proceeding before the North Dakota Public Service Commission ("Commission") in a manner consistent with the public interest.

This Final Agreement consolidates and incorporates all relevant provisions from the "Settlement Agreement" dated November 30, 2000, and the "Amendment and Clarification to November 30, 2000 Settlement Agreement" previously executed and filed by the parties. This Final Agreement also consolidates and incorporates all revisions agreed to by the Company, Otter Tail Power Company and Staff reflecting their negotiations and the hearing and Commission working sessions held in this matter.

PRELIMINARY STATEMENT

1. Commission Alternative Regulation Guidelines, Case No. PU-439-94-590

On September 20, 1995, the Commission issued "Guidelines for Filing Alternative Regulation Proposals" ("Guidelines") in Case No. PU-439-94-590, after

conducting both a workshop and public input sessions to discuss different forms of regulation for electric utilities. The Guidelines indicated the Commission would consider proposals for alternative forms of regulation from traditional “cost-based rate of return” regulation. The Guidelines set forth both goals and criteria for alternative regulation proposals.

2. Summary of Record

On April 20, 2000, NSP filed a “Proposal for a Performance-Based Regulation Plan” (“Petition”) asking the Commission to approve the Company’s proposed performance based regulation (“PBR”) plan, called the “PLUS” plan (“Plan”), for purposes of regulating NSP’s retail electric operations in North Dakota. The key components of PLUS include 1) a “dynamic allowed ROE” range which can vary based on Company performance, 2) a revenue sharing mechanism, 3) establishment of service performance standards, and 4) price capping and flexibility to adjust prices under specified circumstances. If approved, the Plan would create an alternative form of regulation for the Company’s electric operations in North Dakota, as contemplated by the Guidelines. In its Petition, the Company asserted:

- The PLUS Plan meets the stated goals and criteria identified by the Commission Guidelines.
- The PLUS Plan is an appropriate regulatory model because it provides benefits to customers and to North Dakota’s economy which extend beyond traditional cost-based regulation, while at the same time ensuring that the Company’s North Dakota electric rates are just and reasonable and the Company’s operations have the opportunity to maintain financial strength.

- The PLUS Plan will work better than traditional cost-based regulation to promote a balanced emphasis on utility efficiency, service quality, and economic development in North Dakota, while maintaining the customer protections provided by traditional regulation.
- The PLUS Plan provides North Dakota regulation with an automatic, pre-defined mechanism to pass the benefits of a financially healthy utility on to its stakeholders. Unlike traditional, cost-based regulation, which can be a slow and adversarial, the PLUS Plan offers an efficient, win/win approach to utility regulation. PLUS places the regulatory focus more on results and less on process.
- As restructuring of the electric industry occurs, performance based regulation will play a role in facilitating the transition to a more competitive environment. The PLUS regulatory model better simulates a competitive market by creating meaningful incentives which promote high quality service and low cost.
- Since PLUS offers the Company the potential to achieve above-average returns on its North Dakota electric business if the Company's performance meets the thresholds set forth in the plan, PLUS will also create an additional incentive for NSP to invest its limited capital resources in North Dakota (other things being equal).

On July 19, 2000, the Commission issued a "Notice of Hearing and Notice of Public Discussion Meeting" in the instant docket and Case No. PU-401-00-36, a docket involving a similar PBR plan filed by Otter Tail Power Company ("Otter Tail").

On August 29, 2000, presiding Administrative Law Judge Allen C. Hoberg of the Office of Administrative Hearings issued a Pre-hearing Order which established procedural dates, hearing procedures, and other preliminary matters.

The Commission conducted a joint public hearing by video conference on September 6, 2000, with public participation available through ten video conference sites, including three in the Company's electric service area (Fargo, Grand Forks, Minot). No members of the public submitted oral comments opposing approval of the Plan at the public hearing.

Pursuant to the procedural schedule established by Judge Hoberg, NSP submitted pre-filed direct testimony in support of the PLUS Plan on September 29, 2000. On October 13, 2000, the Staff submitted pre-filed direct testimony recommending certain modifications to the PLUS Plan. On October 20, 2000, the Company submitted pre-filed rebuttal testimony responding to the Staff direct testimony.

On October 23 and 24, 2000, the Commission conducted a joint evidentiary hearing considering both NSP's PLUS Plan and Otter Tail's similar PBR plan in Case No. PU-401-00-36. Judge Hoberg presided over the hearing. The Petition and pre-filed testimony of both Companies and Staff were accepted into the record, and the witnesses were subject to cross examination by counsel and questions by the Commissioners and Advisory Staff.

At the conclusion of the evidentiary hearing, the Commission urged the parties to initiate discussions to resolve the areas of the Plans in which Staff and the Companies held differing views. The companies committed to a December 1 deadline for submitting to the Commission a settlement agreement.

Staff, NSP and Otter Tail held settlement discussions on November 2, 2000 in Jamestown, North Dakota, and held numerous telephone and electronic discussions since that date in an effort to reach a comprehensive settlement regarding implementation of performance based regulation in North Dakota.

On November 20, 2000, the Commission conducted a regularly scheduled and noticed working session with parties present in which the companies' PBR proposals and Staff's recommendations were discussed.

On November 30, 2000, NSP and Staff executed and filed a "Settlement Agreement" to resolve all outstanding issues in this proceeding.

On December 1, 2000, the Settlement Agreement was considered by the Commission at a regularly scheduled and noticed working session in order to allow the Commission and Advisory Staff to ask questions and develop a record supporting approval of the Settlement Agreement. Both the Company and Staff, the only parties to the proceeding, were present. The Commission expressed a desire to have more time to review the Agreements, and hold another working session.

On December 11, 2000, the Settlement Agreement was again considered at a regularly scheduled and noticed Commission working session, with both the Company and Staff again present. At this second working session, the Advisory Staff submitted two memos raising issues regarding the Plan as revised by the Settlement Agreement. The Commission indicated further clarifications and/or modifications to the Settlement Agreement and/or the Company's PLUS Plan were warranted prior to Commission approval of the Plan and Settlement Agreement.

Based on the Commission's request to clarify and amend the November 30 Settlement Agreement, the Company and Staff executed and filed an "Amendment and Clarification to November 30, 2000 Settlement Agreement" ("Amendment") on December 14, 2000. The Amendment included Plan changes or clarifications regarding 1) the ROE threshold for rate changes; 2) the "efficiency commitment" used in calculating the Price Cap Factor; 3) the procedures to be used in case of an exogenous event; 4) the process for extending the Plan term; and 5) the process for collection of surcharges from customers for unrecovered earnings deficiencies during a Plan year.

On December 15, 2000, the Amendment was considered at a third regularly scheduled and noticed Commission working session. Staff was present, and the Company participated by telephone. At this third working session, the Advisory Staff raised an issue regarding the revised Price Cap Factor "efficiency commitment" adjustment, which the Company and Staff modified in the Amendment to address concerns raised by Advisory Staff at the December 11, 2000 working session. The Company stated it would be willing to reinstate the Price Cap Factor efficiency commitment contained in the Settlement Agreement.

At this final working session, the Company and Staff also agreed to consolidate the terms of the November 30, 2000 Settlement Agreement, the December 14, 2000 Amendment, and the clarification regarding the "efficiency commitment", and submit a consolidated settlement document to the Commission no later than December 28, 2000. This Final Agreement provides the consolidated document.

3. The Plan and this Final Agreement Serve the Public Interest

Both the Company and Staff submitted pre-filed and oral testimony generally supporting implementation of performance-based regulation for the Company's electric utility operations in North Dakota. The Company and Staff differed, however, on the appropriate Plan performance standards and reward/penalty criteria. The record (the testimony of Dr. Karl McDermott) supports use of broad and balanced performance standards and symmetrical reward/penalty criteria, but the Company and Staff agree the record does not require approval of either the specific components of the Company's original Plan or the Staff recommendations without modification. In addition, Commissioner comments and questions at the evidentiary hearing and working sessions supported consideration of possible alternative performance standards. Dr. McDermott recommended the final Plan performance standards and reward/penalty criteria reflect the policy objectives of the Commission.

Based on the record in this matter, including the Petition, testimony, hearing, working sessions, Settlement Agreement and Amendment, the Company and Staff believe this Final Agreement is supported by the record, is consistent with the public interest, is consistent with the Commission's Guidelines on for Filing Alternative Regulation Proposals, will result in quality service and reasonable rates to North Dakota ratepayers, and supports the safe and reliable electric infrastructure and the financial viability of the Company. Other documentation in support of the Final Agreement is attached hereto.

As a result, implementation of the Company's PBR Plan, as revised, would serve the public interest. Accordingly, the Parties jointly recommend that the Commission

approve this Final Agreement. The Parties request the Commission issue an order approving this Final Agreement and modified PLUS Plan in their entirety, without conditions or modifications.

TERMS OF FINAL AGREEMENT

1. PLUS Plan Terms

A. Implementation/Term/Extension of Plan

As proposed by NSP and supported by Staff, the PLUS Plan will commence on January 1, 2001. Concurrently and independently, NSP will reduce non-fuel base retail electric rates to the Company's North Dakota electric service customers by \$261,000 annually (approximately 0.25%), pursuant to the Commission order dated May 10, 2000, in Case Nos. PU-400-99-418 (Merger with New Century Energies, Inc.) and PU-400-98-246 (Electric Rate Investigation). For purposes of initial Plan implementation, the Company's restated electric rates effective January 1, 2001 are deemed just and reasonable.

Except as provided herein, the PLUS Plan will remain in effect for a five year term ending December 31, 2005. Prior to July 1, 2005, the Company may file for an extension and/or modification of the Plan if so desired. Absent such a filing and a further order of the Commission extending the Plan, the PLUS Plan will automatically terminate on December 31, 2005.

B. Reporting/Review

Each year, on or before May 1, NSP will submit a comprehensive earnings and performance report for the previous calendar year fiscal period, as detailed in the Company's Petition.

The Commission will conduct an informal review hearing after May 1, 2003, but no later than June 30, 2003, to assess the Plan's results after two years.

2. ROE Deadband/Revenue Sharing

A. Baseline ROE and "Deadband"

The initial baseline Return on Equity ("ROE") for purposes of the Plan will be 12.0%. An ROE deadband of +/- 1.0% will be established around the baseline.

During the Plan term, the ROE deadband shall be subject to the annual dynamic ROE adjustments in terms of "basis points" depending on the Company's performance under each Plan performance standard, as provided herein. If the net performance basis points are positive (award), the upper end of the ROE deadband increases. If the net performance points are negative (penalty), the lower end of the ROE deadband is decreased. The baseline does not change.

Attachment 1 to this Final Agreement provides an example of the dynamic ROE bandwidth and revenue sharing mechanisms provided by this Final Agreement.

B. Revenue Sharing

If the Company's reported actual earnings fall within the ROE deadband around the authorized ROE (as adjusted by the performance points) in a given Plan year, no revenue sharing will take place. If the Company's actual reported earnings for any given Plan year exceed the deadband, the corresponding revenue 'sufficiency' will be calculated, and 50% of this dollar amount will be refunded to customers during the July billing cycle of the following year. Customers of record on March 31 following the Plan year will be issued refunds by bill credit prorated on the basis of their electric usage for the twelve months ending March 31.

The Petition proposed that 10 percent of any reported revenue sufficiency amount in any Plan year be used for economic development investments. The Staff indicated general support for economic development investments, but did not support the Plan's revenue sharing mechanism for this purpose. Pursuant to this Final Agreement, all sharing will be 50/50 between Customers and the Company. However, the Company may record economic development expenses incurred in a Plan year as a jurisdictional expense for purposes of annual financial reporting.

If earnings are below the deadband, 50% of the corresponding revenue deficiency may be recovered through a surcharge on the Company's electric rates effective no later than 24 months after the Plan year, as directed by the Financial Accounting Standards Board ("FASB"). However, NSP will defer a reported fiscal year deficiency amount as a regulatory asset until the following Plan year revenue sharing amount, if any, is reported. If the prior year deficiency is fully offset by a current year reported revenue sufficiency, the sufficiency will be used to eliminate the regulatory asset, and no rate surcharge will be imposed. If the deficiency from the prior year is not fully offset, any remaining deficiency balance will be billed through a rate surcharge and collected over the remaining six-month period beginning July 1 of the year following the Plan fiscal reporting year, unless otherwise requested by either the Company or Commission Staff and approved by the Commission.

The customer share of any Plan refund or deficiency surcharge will be shown separately as a "performance-based dividend" or "performance-based surcharge" on customer bills.

Any deferred deficiency balance remaining at the end of the 5-year Plan term will first be considered as part of an on-going Plan or alternatively, collected from customers through a surcharge.

Plan dividends paid or surcharges received will be excluded from the Company's return on equity calculation for the Plan year in which the said dividends or surcharges are actually implemented.

3. Performance Standards

A. Reliability

The Petition proposed a service reliability standard measurement using the weather normalized "System Average Interruption Duration Index" ("SAIDI") pursuant to the methodology established by the IEEE. Pursuant to this Final Agreement, two standards will be used in the PLUS Plan for purposes of measuring reliability: 1) customer average interruption duration index ("CAIDI"), and 2) system average interruption frequency index ("SAIFI").

CAIDI and SAIFI are individual reliability measures widely used in the electric utility industry, the product of which is the SAIDI result. By using both component standards, the Company will be measured on both the frequency of customer outages and the time it takes to restore power. Annual results for each measure will be weather-normalized to exclude storm day outages. Targets are based on achieving a SAIDI result of 80 minutes, which was developed using historical NSP outage results in North Dakota, and a consideration of the Otter Tail Plan target. Each measure will carry a potential reward and/or penalty of a 25 basis point adjustment to the authorized ROE deadband.

The following table defines the revised performance standards for reliability (see Attachment 1):

Measure	Award Threshold	Target	Penalty Threshold
CAIDI	< 75.6 minutes	89.0 minutes	> 102.4 minutes
SAIFI	< 0.77 outages/yr.	0.90 outages/yr.	> 1.04 outages/yr.

B. Customer Satisfaction

The Petition proposed a single customer satisfaction measure based on North Dakota customer responses to a single overall question contained in Company “relationship” surveys of all customer classes (Residential, Commercial and Large Industrial), based on the percentage of respondents providing a “top three box” rating (‘excellent’, ‘very good’, or ‘good’). Staff recommended use of a “transaction” survey, and also proposed using a “top two box” standard (i.e., customers who rate the Company’s performance ‘excellent’ or ‘very good’) for customer surveys.

Pursuant to this Final Agreement, the PLUS Plan will use two survey standards for purposes of measuring customer satisfaction: 1) an average satisfaction score from the relationship surveys for all three customer classes (Residential, Commercial, Large Industrial), and 2) an average satisfaction score from two transaction surveys relating to the Company’s call center and electric service functions. The survey scores will reflect the percentage of respondents who give NSP an ‘excellent’ or ‘very good’ rating. Targets are based on historic company-wide NSP survey results from the previous three years, and will be revised after two Plan years to reflect responses from North

Dakota customers only. Each of the two survey standards will carry a potential reward and/or penalty of a 25 basis point adjustment to the authorized ROE deadband.

The following table defines the Plan performance standards for customer service for at least the first two plan years:

Measure	Award Threshold	Target	Penalty Threshold
Relationship survey positive response %	> 84.0%	81.0%	< 78.0%
Transaction survey positive response %	> 66.0%	63.0%	< 60.0%

C. Price Standard

The Petition proposed a price standard comparing the Company's average Residential electric revenue per kWh for the Plan year to the average residential revenue/kWh for a comparison group of 26 mid-western utility jurisdictions. Staff proposed a price comparison measuring the change in the Company's residential electric revenue/kWh in the Plan year to the change for the ten lowest-priced utilities in the comparison group.

Pursuant to this Final Agreement, two price standards will be used in the PLUS Plan for purposes of measuring competitive price: 1) the Company's relative average residential price per kWh compared to the mid-western utility peer group; and 2) the annual change in average residential price relative to the change for the lowest priced utility in the peer group. The price targets are calculated annually based on utility price data compiled in an Edison Electric Institute publication entitled Typical Bills and Average Rate Report issued twice per year. For purposes of the PLUS Plan, the "winter" edition (reflecting the 12 month period ending December 31st) will be used.

Each of the two price measures will carry a potential reward and/or penalty of a 25 basis point adjustment to the authorized ROE deadband.

The following table defines the revised Plan performance standards for price:

Measure	Award Threshold	Target	Penalty Threshold
Competitive Res'l price position	< 85% of target	peer group avg. Residential price/kWh	> 115% of target
Annual change in Res'l avg. price	< (target-.05¢/kwh)	annual change in lowest priced utility Res'l avg. price	> (target+.05¢/kwh)

D. Employee Safety Standard

The Petition proposed an employee safety standard based on the Company's Occupational Safety and Health Administration ("OSHA") incident rate in the Plan year compared to historic performance of a number of regional utilities participating in a North Central Electric Association safety survey. The OSHA incident rate represents the number of safety-related incidents per 100 employees. The Petition proposed a reward and/or penalty of a 50 basis point adjustment to the baseline ROE.

Pursuant to this Final Agreement, the PLUS Plan will include an employee safety measurement based on the OSHA incident rate. The target is based primarily on historical results for Group 1 utilities (more than 7,000 employees) in the Edison Electric Institute survey, but also reflects consideration of what would provide an acceptable "stretch" for NSP's North Dakota operations. To be consistent with the other individual Plan standards, the employee safety measure will carry a potential reward and/or penalty of a 25 basis point adjustment to the authorized ROE deadband.

The following table defines the Plan performance standards for employee safety:

Measure	Award Threshold	Target	Penalty Threshold
OSHA incident rate	< 3.70	4.32	> 5.00

4. Changes in Base Rates

Attachment 1 to this Final Agreement provides a description the relationship of the Plan's dynamic ROE mechanism to the electric rate change criteria provided by this Final Agreement. Attachment 2 provides a flow chart of the price change criteria provided by this Final Agreement.

A. Price Cap Factor

Pursuant to this Final Agreement, the PLUS Plan will calculate a Price Cap Factor by determining the lower of 1) the annual percentage change in the utility peer group's average residential price per kWh for the reporting year, and 2) 60% of the change in the Consumer Price Index (CPI) for the reporting year.¹ The CPI for the Plan reporting year is computed by averaging the annual CPI reported at the end of each calendar quarter. The Price Cap Factor will determine the highest annual percentage rate increase allowed under the Plan, or the amount of a required rate decrease.

B. Rate Change Criteria

Pursuant to this Final Agreement, the PLUS Plan imposes an electric rate freeze on the Company whenever (i) its previous fiscal year ROE exceeds the baseline ROE,

¹ As such, the change to efficiency commitment factor provided in the Amendment (annual CPI – 0.8%) is replaced by the efficiency commitment in the Settlement Agreement (60% of annual CPI).

as adjusted pursuant to the performance points, minus 100 basis points (1.0%);² or (ii) the Company's average residential rates are higher than the utility peer group average residential rate. If neither condition exists, the Company may change rates by an overall percentage not to exceed the Price Cap Factor.

C. Required Rate Decrease Criteria

The Company shall reduce its retail electric rates pursuant to the PLUS Plan if (i) the Company's reported ROE for the Plan reporting year exceeded the baseline ROE, as adjusted pursuant to the performance points, plus 100 basis points (1.0%); (ii) the Company's average residential rates are higher than the PLUS utility peer group average residential rate; and (iii) the Price Cap Factor is negative.

D. Rate Change Procedure

To implement any permissive rate change pursuant to Section B or mandatory rate reduction pursuant to Section C, the Company shall file a notice of rate change and the accompanying tariffs pursuant to N.D.C.C. 49-05-05 not later than June 1, following completion of the Plan year and submission of the Plan performance report on May 1.

² As shown for illustrative purposes in Attachment 1, the lower ROE threshold could be 11.13% minus 100 basis points, or 10.13%, assuming the Company's performance would result in performance penalties in all seven Plan performance categories. In this example, a base electric rate freeze would be in effect if NSP's reported earnings in North Dakota for the prior Plan year were above 10.13%.

Similarly, the upper threshold could be 12.88% minus 100 basis points, or 11.88%, assuming the Company's performance would result in performance awards in all seven Plan performance categories. In this example, a base electric rate freeze would be in effect if the Company's reported earnings for the prior Plan year were above 11.88%.

If the Company's performance was within all of the Plan performance bandwidths, and no adjustment was made to the baseline ROE pursuant to the dynamic ROE mechanisms, a base electric rate freeze would be in effect if the Company's reported earnings in the prior Plan year exceeded 11.00%.

The revised rates shall be effective on or after July 1 following the Plan year. Base rate changes will be across-the-board to all customer classes unless otherwise requested by the Company and approved by the Commission.

Such rate change will not be suspended by the Commission under N.D.C.C. 49-05-06, but the revised rates shall be allowed to go into effect on the date proposed. If the Commission determines after investigation and hearing that the changed rates do not comply with the Plan terms as prescribed herein, the Commission may prospectively establish the rates it finds to be consistent with the Plan terms, and order a one-time billing true-up for the impact of the discrepancy since either the inception of the rate change or the previous 12 month period, whichever is less. Rates established consistent with the Plan are presumed just and reasonable, and non-discriminatory.

E. Exogenous Events.

Changes in base rates are subject to the price cap mechanisms included in this Final Agreement. However, any increases or decreases in costs of electric service caused by governmentally imposed changes in taxes and/or accounting practices shall be implemented within 60 days of the effective date of the change.

5. Other Terms and Conditions

A. Fuel Clause Adjustment

This Agreement and the Company's revised PBR Plan does not change the Company's existing fuel clause adjustment ("FCA") mechanism in its North Dakota Electric Rate Book tariff schedules. The comparative price standard provided above shall be calculated using total Residential revenue per kWh including the fuel clause adjustments in effect during the Plan reporting year.

B. Demand Allocator Factor

For purposes of calculating the Company's jurisdictional expenses for the PLUS Plan reporting year, 36 months of historical demand data will be used to establish the Demand Allocation factor (known as D10). The Demand Allocation factor is used to assign production and transmission related costs and investment to NSP's retail electric jurisdictions in North Dakota, South Dakota and Minnesota. The Petition demonstrated use of 36 months of demand data will mitigate volatility in this allocation factor. The use of a 36 month demand allocator is only for financial reporting purposes under the Plan. Use of a 36 month historic allocator for the Plan shall have no precedential effect in future electric rate increase applications after the Plan term expires or the Plan is suspended or terminated

C. Suspension/Termination of Plan

The PBR Plan will remain in effect for five years beginning January 1, 2001. However, the Company and Staff reserve the right to request adjustment, suspension, or termination of the Plan under the following events:

- Federal and/or state tax law changes;
- Passage of retail access legislation at either the federal or state level;
- Merger and acquisition events affecting the Company's structure and operations;
- Natural disasters affecting the Company's North Dakota electric operations (major storms, floods, etc.);
- Unusual events affecting the Company's operations (major generating plant failure, damage to major transmission or distribution lines, etc.); or

- Material and sustained earnings extremes (defined as returns on equity +/- 5.0% from the ROE deadband, prior to sharing).

It is anticipated the Commission and Company will make reasonable efforts to resolve any condition that could otherwise trigger a Company application or Commission motion to suspend the Plan before any decision to terminate operation of the Plan during the Plan term.

D. Applicability and Scope

Each of the provisions of this Final Agreement is in consideration for each and every other provision. This Final Agreement is subject to the approval of the Commission. If this Final Agreement and the PLUS Plan (as revised by this Final Agreement) are not approved in their entirety without modification by vote of the Commission by December 31, 2000, the Company, at its option, may submit written notice to the Commission that this Final Agreement is null and void and the Plan and Petition are withdrawn. Such notice shall be submitted no later than January 5, 2001.

This Final Agreement shall be binding on the parties hereto, and upon their successors, assigns, agents and representatives.

E. Effective Date

Except as provided herein, this Final Agreement shall be effective on the date of the final Commission order approving the Plan (as revised) and this Final Agreement without modification. This Final Agreement shall remain in full force and effect for the Plan term.

F. Effect of Settlement Negotiations

It is understood and agreed that all offers of settlement and discussions related thereto are privileged and may not be used in any manner in connection with proceedings in this case or otherwise, except as provided by law. In the event the Commission does not approve this Final Agreement, the Final Agreement shall not constitute part of the record in this proceeding and no part thereof may be used for any purpose in this proceeding or otherwise. This Final Agreement shall not in any respect constitute a determination by the parties hereto as to the merits of any specific allegations or contentions made by the parties in Case No. PU-400-00-195.

G. Counterparts

This Final Agreement may be executed in separate, identical counterparts.

H. Agreement Drafted Jointly

This Final Agreement shall be deemed to have been drafted jointly by Staff and NSP for purposes of construing or interpreting the meaning of any provision of this Final Agreement.

Northern States Power Company

By: James P. Johnson
James P. Johnson
Assistant General Counsel
Xcel Energy Services Inc., Agent for
Northern States Power Company

Date: December 28, 2000

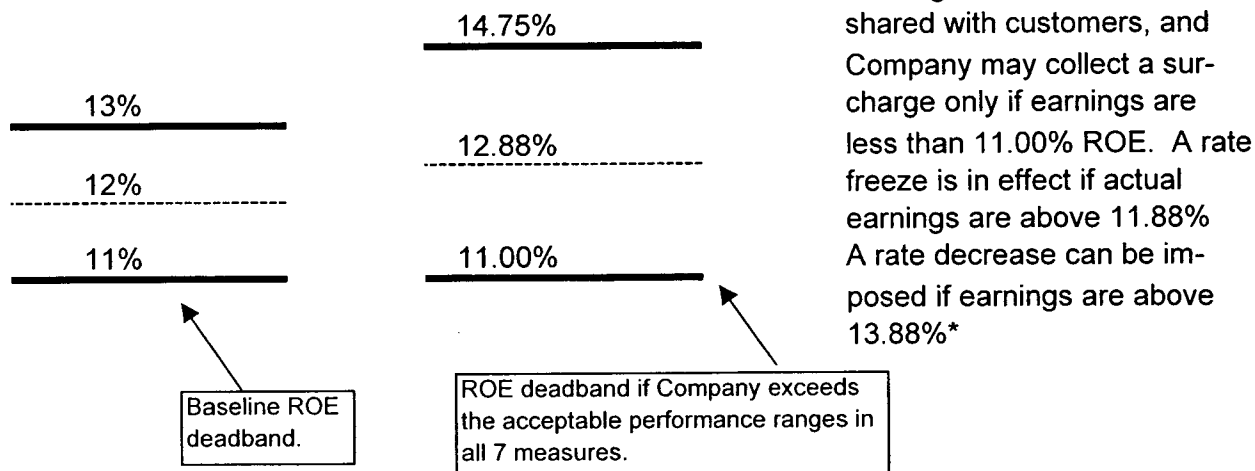
**North Dakota Public Service
Commission Staff**

By: William W. Binek
William W. Binek
Chief Counsel
North Dakota
Public Service Commission
December 28, 2000

Revenue Sharing and Price Change Mechanisms Amended Settlement Proposal

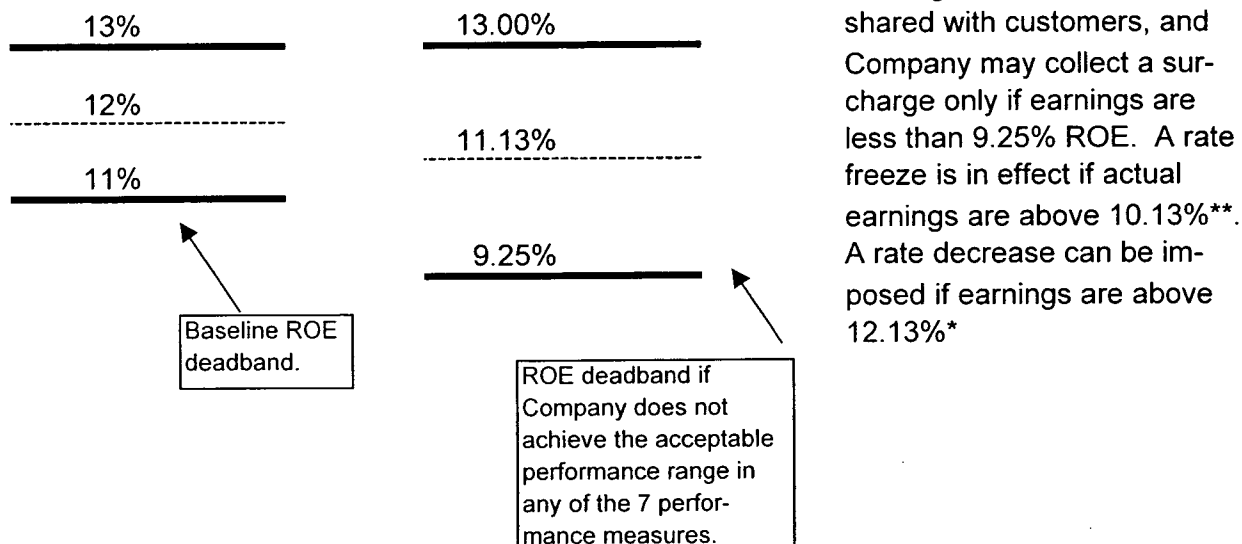
Assume all 7 performance measures are met, each worth 25 basis points

If net result of performance points is positive, only the *upper* limit of the ROE deadband increases.



Assume a penalty for all 7 performance measures, each worth 25 basis points

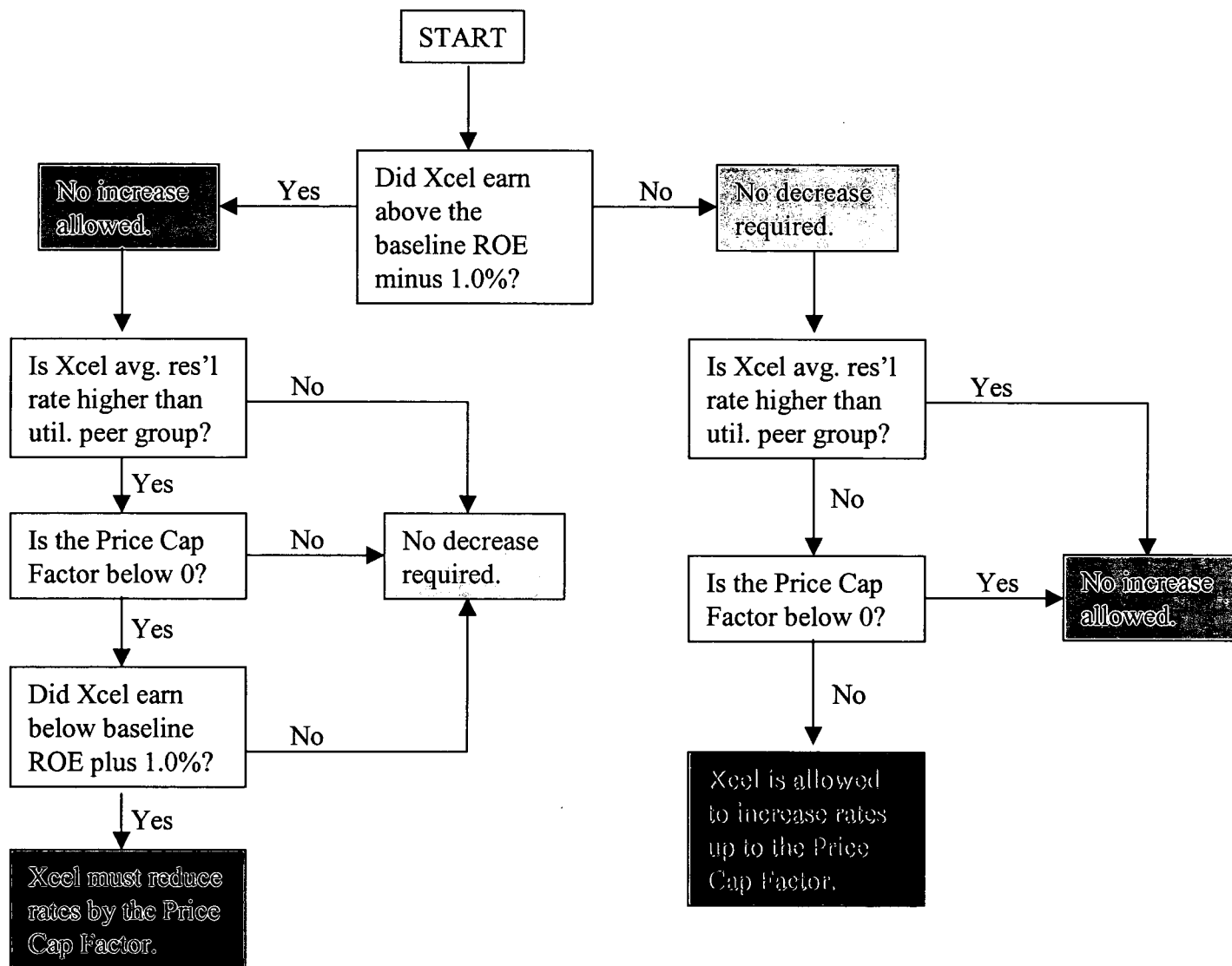
If net result of performance points is negative, only the *lower* limit of the ROE 'deadband' is reduced.



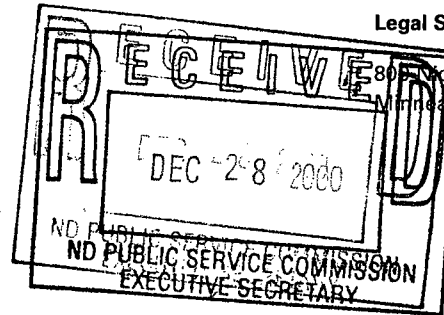
* The rate freeze threshold is equal to the baseline (12.88% in this example) minus 1.00%, or 11.88%. Decreases can be imposed at 12.88%+1.0%, or 13.88%.

** The rate freeze threshold is equal to the baseline (11.13% in this example) minus 1.00%, or 10.13%. Decreases can be imposed at 11.13%+1.0%, or 12.13%.

Decision Model for PLUS PBR Price Cap Mechanism



Price Cap Factor = lower of the utility peer group average annual price change or 60% of CPI



Legal Services

805 Wabasha St., Suite 2900
Minneapolis, Minnesota 55402

December 27, 2000

Mr. Mike Diller
North Dakota Public Service Commission
600 East Boulevard
Bismarck, ND 58505

Re: Application of Northern States Power Company d/b/a Xcel Energy for
Authority to Operate Under Performance Based Regulation In North Dakota
Case No. PU-400-00-195

Dear Mr. Diller:

Enclosed please find two original copies of the Final Agreement between Northern States Power Company d/b/a Xcel Energy and Commission Litigation Staff in the above-captioned docket. Please have Mr. Binek execute both copies, return one original to me, and submit the other original copy to the Commission along with the original transmittal letter (also enclosed for your convenience).

I assume the Staff will attach the certificate of service and serve an original and seven copies of the transmittal letter and Final Settlement on the Commission, plus two copies on Judge Hoberg at the Office of Administrative Hearings for the hearing record and one copy to Otter Tail Power Company.

Please contact me (612-215-4592) or Dave Sederquist (701-241-8632) with any questions.

Sincerely,

Jim Johnson
James P. Johnson
Assistant General Counsel

cc: Mr. Dave Sederquist

Enclosures

*Mike - as noted ^{12/27}
in my email today,
this needs
Attachment 2 to
be attached before
filing. The
See Attached ^m Mike*

47 PU-400-00-195

Pages: 1

Cover Letter for Final Settlement
Agreement
by Northern States Power Company

12/28/2000 CC: Comm Legal Illona, Pat, Jerry Mike

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

Northern States Power Company
Performance-Based Regulation Proposal

Case No. PU-400-00-195

FINAL SETTLEMENT AGREEMENT

This Final Settlement Agreement ("Final Agreement") is entered into this 27th day of December, 2000, by and between Northern States Power Company, a Minnesota corporation ("NSP" or "the Company") and the North Dakota Public Service Commission litigation staff ("Staff"). This Settlement Agreement resolves all outstanding issues in the above-captioned proceeding before the North Dakota Public Service Commission ("Commission") in a manner consistent with the public interest.

This Final Agreement consolidates and incorporates all relevant provisions from the "Settlement Agreement" dated November 30, 2000, and the "Amendment and Clarification to November 30, 2000 Settlement Agreement" previously executed and filed by the parties. This Final Agreement also consolidates and incorporates all revisions agreed to by the Company, Otter Tail Power Company and Staff reflecting their negotiations and the hearing and Commission working sessions held in this matter.

PRELIMINARY STATEMENT

1. Commission Alternative Regulation Guidelines, Case No. PU-439-94-590

On September 20, 1995, the Commission issued "Guidelines for Filing Alternative Regulation Proposals" ("Guidelines") in Case No. PU-439-94-590, after

conducting both a workshop and public input sessions to discuss different forms of regulation for electric utilities. The Guidelines indicated the Commission would consider proposals for alternative forms of regulation from traditional “cost-based rate of return” regulation. The Guidelines set forth both goals and criteria for alternative regulation proposals.

2. Summary of Record

On April 20, 2000, NSP filed a “Proposal for a Performance-Based Regulation Plan” (“Petition”) asking the Commission to approve the Company’s proposed performance based regulation (“PBR”) plan, called the “PLUS” plan (“Plan”), for purposes of regulating NSP’s retail electric operations in North Dakota. The key components of PLUS include 1) a “dynamic allowed ROE” range which can vary based on Company performance, 2) a revenue sharing mechanism, 3) establishment of service performance standards, and 4) price capping and flexibility to adjust prices under specified circumstances. If approved, the Plan would create an alternative form of regulation for the Company’s electric operations in North Dakota, as contemplated by the Guidelines. In its Petition, the Company asserted:

- The PLUS Plan meets the stated goals and criteria identified by the Commission Guidelines.
- The PLUS Plan is an appropriate regulatory model because it provides benefits to customers and to North Dakota’s economy which extend beyond traditional cost-based regulation, while at the same time ensuring that the Company’s North Dakota electric rates are just and reasonable and the Company’s operations have the opportunity to maintain financial strength.

- The PLUS Plan will work better than traditional cost-based regulation to promote a balanced emphasis on utility efficiency, service quality, and economic development in North Dakota, while maintaining the customer protections provided by traditional regulation.
- The PLUS Plan provides North Dakota regulation with an automatic, pre-defined mechanism to pass the benefits of a financially healthy utility on to its stakeholders. Unlike traditional, cost-based regulation, which can be a slow and adversarial, the PLUS Plan offers an efficient, win/win approach to utility regulation. PLUS places the regulatory focus more on results and less on process.
- As restructuring of the electric industry occurs, performance based regulation will play a role in facilitating the transition to a more competitive environment. The PLUS regulatory model better simulates a competitive market by creating meaningful incentives which promote high quality service and low cost.
- Since PLUS offers the Company the potential to achieve above-average returns on its North Dakota electric business if the Company's performance meets the thresholds set forth in the plan, PLUS will also create an additional incentive for NSP to invest its limited capital resources in North Dakota (other things being equal).

On July 19, 2000, the Commission issued a "Notice of Hearing and Notice of Public Discussion Meeting" in the instant docket and Case No. PU-401-00-36, a docket involving a similar PBR plan filed by Otter Tail Power Company ("Otter Tail").

On August 29, 2000, presiding Administrative Law Judge Allen C. Hoberg of the Office of Administrative Hearings issued a Pre-hearing Order which established procedural dates, hearing procedures, and other preliminary matters.

The Commission conducted a joint public hearing by video conference on September 6, 2000, with public participation available through ten video conference sites, including three in the Company's electric service area (Fargo, Grand Forks, Minot). No members of the public submitted oral comments opposing approval of the Plan at the public hearing.

Pursuant to the procedural schedule established by Judge Hoberg, NSP submitted pre-filed direct testimony in support of the PLUS Plan on September 29, 2000. On October 13, 2000, the Staff submitted pre-filed direct testimony recommending certain modifications to the PLUS Plan. On October 20, 2000, the Company submitted pre-filed rebuttal testimony responding to the Staff direct testimony.

On October 23 and 24, 2000, the Commission conducted a joint evidentiary hearing considering both NSP's PLUS Plan and Otter Tail's similar PBR plan in Case No. PU-401-00-36. Judge Hoberg presided over the hearing. The Petition and pre-filed testimony of both Companies and Staff were accepted into the record, and the witnesses were subject to cross examination by counsel and questions by the Commissioners and Advisory Staff.

At the conclusion of the evidentiary hearing, the Commission urged the parties to initiate discussions to resolve the areas of the Plans in which Staff and the Companies held differing views. The companies committed to a December 1 deadline for submitting to the Commission a settlement agreement.

Staff, NSP and Otter Tail held settlement discussions on November 2, 2000 in Jamestown, North Dakota, and held numerous telephone and electronic discussions since that date in an effort to reach a comprehensive settlement regarding implementation of performance based regulation in North Dakota.

On November 20, 2000, the Commission conducted a regularly scheduled and noticed working session with parties present in which the companies' PBR proposals and Staff's recommendations were discussed.

On November 30, 2000, NSP and Staff executed and filed a "Settlement Agreement" to resolve all outstanding issues in this proceeding.

On December 1, 2000, the Settlement Agreement was considered by the Commission at a regularly scheduled and noticed working session in order to allow the Commission and Advisory Staff to ask questions and develop a record supporting approval of the Settlement Agreement. Both the Company and Staff, the only parties to the proceeding, were present. The Commission expressed a desire to have more time to review the Agreements, and hold another working session.

On December 11, 2000, the Settlement Agreement was again considered at a regularly scheduled and noticed Commission working session, with both the Company and Staff again present. At this second working session, the Advisory Staff submitted two memos raising issues regarding the Plan as revised by the Settlement Agreement. The Commission indicated further clarifications and/or modifications to the Settlement Agreement and/or the Company's PLUS Plan were warranted prior to Commission approval of the Plan and Settlement Agreement.

Based on the Commission's request to clarify and amend the November 30 Settlement Agreement, the Company and Staff executed and filed an "Amendment and Clarification to November 30, 2000 Settlement Agreement" ("Amendment") on December 14, 2000. The Amendment included Plan changes or clarifications regarding 1) the ROE threshold for rate changes; 2) the "efficiency commitment" used in calculating the Price Cap Factor; 3) the procedures to be used in case of an exogenous event; 4) the process for extending the Plan term; and 5) the process for collection of surcharges from customers for unrecovered earnings deficiencies during a Plan year.

On December 15, 2000, the Amendment was considered at a third regularly scheduled and noticed Commission working session. Staff was present, and the Company participated by telephone. At this third working session, the Advisory Staff raised an issue regarding the revised Price Cap Factor "efficiency commitment" adjustment, which the Company and Staff modified in the Amendment to address concerns raised by Advisory Staff at the December 11, 2000 working session. The Company stated it would be willing to reinstate the Price Cap Factor efficiency commitment contained in the Settlement Agreement.

At this final working session, the Company and Staff also agreed to consolidate the terms of the November 30, 2000 Settlement Agreement, the December 14, 2000 Amendment, and the clarification regarding the "efficiency commitment", and submit a consolidated settlement document to the Commission no later than December 28, 2000. This Final Agreement provides the consolidated document.

3. The Plan and this Final Agreement Serve the Public Interest

Both the Company and Staff submitted pre-filed and oral testimony generally supporting implementation of performance-based regulation for the Company's electric utility operations in North Dakota. The Company and Staff differed, however, on the appropriate Plan performance standards and reward/penalty criteria. The record (the testimony of Dr. Karl McDermott) supports use of broad and balanced performance standards and symmetrical reward/penalty criteria, but the Company and Staff agree the record does not require approval of either the specific components of the Company's original Plan or the Staff recommendations without modification. In addition, Commissioner comments and questions at the evidentiary hearing and working sessions supported consideration of possible alternative performance standards. Dr. McDermott recommended the final Plan performance standards and reward/penalty criteria reflect the policy objectives of the Commission.

Based on the record in this matter, including the Petition, testimony, hearing, working sessions, Settlement Agreement and Amendment, the Company and Staff believe this Final Agreement is supported by the record, is consistent with the public interest, is consistent with the Commission's Guidelines on for Filing Alternative Regulation Proposals, will result in quality service and reasonable rates to North Dakota ratepayers, and supports the safe and reliable electric infrastructure and the financial viability of the Company. Other documentation in support of the Final Agreement is attached hereto.

As a result, implementation of the Company's PBR Plan, as revised, would serve the public interest. Accordingly, the Parties jointly recommend that the Commission

approve this Final Agreement. The Parties request the Commission issue an order approving this Final Agreement and modified PLUS Plan in their entirety, without conditions or modifications.

TERMS OF FINAL AGREEMENT

1. PLUS Plan Terms

A. Implementation/Term/Extension of Plan

As proposed by NSP and supported by Staff, the PLUS Plan will commence on January 1, 2001. Concurrently and independently, NSP will reduce non-fuel base retail electric rates to the Company's North Dakota electric service customers by \$261,000 annually (approximately 0.25%), pursuant to the Commission order dated May 10, 2000, in Case Nos. PU-400-99-418 (Merger with New Century Energies, Inc.) and PU-400-98-246 (Electric Rate Investigation). For purposes of initial Plan implementation, the Company's restated electric rates effective January 1, 2001 are deemed just and reasonable.

Except as provided herein, the PLUS Plan will remain in effect for a five year term ending December 31, 2005. Prior to July 1, 2005, the Company may file for an extension and/or modification of the Plan if so desired. Absent such a filing and a further order of the Commission extending the Plan, the PLUS Plan will automatically terminate on December 31, 2005.

B. Reporting/Review

Each year, on or before May 1, NSP will submit a comprehensive earnings and performance report for the previous calendar year fiscal period, as detailed in the Company's Petition.

The Commission will conduct an informal review hearing after May 1, 2003, but no later than June 30, 2003, to assess the Plan's results after two years.

2. ROE Deadband/Revenue Sharing

A. Baseline ROE and "Deadband"

The initial baseline Return on Equity ("ROE") for purposes of the Plan will be 12.0%. An ROE deadband of +/- 1.0% will be established around the baseline.

During the Plan term, the ROE deadband shall be subject to the annual dynamic ROE adjustments in terms of "basis points" depending on the Company's performance under each Plan performance standard, as provided herein. If the net performance basis points are positive (award), the upper end of the ROE deadband increases. If the net performance points are negative (penalty), the lower end of the ROE deadband is decreased. The baseline does not change.

Attachment 1 to this Final Agreement provides an example of the dynamic ROE bandwidth and revenue sharing mechanisms provided by this Final Agreement.

B. Revenue Sharing

If the Company's reported actual earnings fall within the ROE deadband around the authorized ROE (as adjusted by the performance points) in a given Plan year, no revenue sharing will take place. If the Company's actual reported earnings for any given Plan year exceed the deadband, the corresponding revenue 'sufficiency' will be calculated, and 50% of this dollar amount will be refunded to customers during the July billing cycle of the following year. Customers of record on March 31 following the Plan year will be issued refunds by bill credit prorated on the basis of their electric usage for the twelve months ending March 31.

The Petition proposed that 10 percent of any reported revenue sufficiency amount in any Plan year be used for economic development investments. The Staff indicated general support for economic development investments, but did not support the Plan's revenue sharing mechanism for this purpose. Pursuant to this Final Agreement, all sharing will be 50/50 between Customers and the Company. However, the Company may record economic development expenses incurred in a Plan year as a jurisdictional expense for purposes of annual financial reporting.

If earnings are below the deadband, 50% of the corresponding revenue deficiency may be recovered through a surcharge on the Company's electric rates effective no later than 24 months after the Plan year, as directed by the Financial Accounting Standards Board ("FASB"). However, NSP will defer a reported fiscal year deficiency amount as a regulatory asset until the following Plan year revenue sharing amount, if any, is reported. If the prior year deficiency is fully offset by a current year reported revenue sufficiency, the sufficiency will be used to eliminate the regulatory asset, and no rate surcharge will be imposed. If the deficiency from the prior year is not fully offset, any remaining deficiency balance will be billed through a rate surcharge and collected over the remaining six-month period beginning July 1 of the year following the Plan fiscal reporting year, unless otherwise requested by either the Company or Commission Staff and approved by the Commission.

The customer share of any Plan refund or deficiency surcharge will be shown separately as a "performance-based dividend" or "performance-based surcharge" on customer bills.

Any deferred deficiency balance remaining at the end of the 5-year Plan term will first be considered as part of an on-going Plan or alternatively, collected from customers through a surcharge.

Plan dividends paid or surcharges received will be excluded from the Company's return on equity calculation for the Plan year in which the said dividends or surcharges are actually implemented.

3. Performance Standards

A. Reliability

The Petition proposed a service reliability standard measurement using the weather normalized "System Average Interruption Duration Index" ("SAIDI") pursuant to the methodology established by the IEEE. Pursuant to this Final Agreement, two standards will be used in the PLUS Plan for purposes of measuring reliability: 1) customer average interruption duration index ("CAIDI"), and 2) system average interruption frequency index ("SAIFI").

CAIDI and SAIFI are individual reliability measures widely used in the electric utility industry, the product of which is the SAIDI result. By using both component standards, the Company will be measured on both the frequency of customer outages and the time it takes to restore power. Annual results for each measure will be weather-normalized to exclude storm day outages. Targets are based on achieving a SAIDI result of 80 minutes, which was developed using historical NSP outage results in North Dakota, and a consideration of the Otter Tail Plan target. Each measure will carry a potential reward and/or penalty of a 25 basis point adjustment to the authorized ROE deadband.

The following table defines the revised performance standards for reliability (see Attachment 1):

Measure	Award Threshold	Target	Penalty Threshold
CAIDI	< 75.6 minutes	89.0 minutes	> 102.4 minutes
SAIFI	< 0.77 outages/yr.	0.90 outages/yr.	> 1.04 outages/yr.

B. Customer Satisfaction

The Petition proposed a single customer satisfaction measure based on North Dakota customer responses to a single overall question contained in Company “relationship” surveys of all customer classes (Residential, Commercial and Large Industrial), based on the percentage of respondents providing a “top three box” rating (‘excellent’, ‘very good’, or ‘good’). Staff recommended use of a “transaction” survey, and also proposed using a “top two box” standard (i.e., customers who rate the Company’s performance ‘excellent’ or ‘very good’) for customer surveys.

Pursuant to this Final Agreement, the PLUS Plan will use two survey standards for purposes of measuring customer satisfaction: 1) an average satisfaction score from the relationship surveys for all three customer classes (Residential, Commercial, Large Industrial), and 2) an average satisfaction score from two transaction surveys relating to the Company’s call center and electric service functions. The survey scores will reflect the percentage of respondents who give NSP an ‘excellent’ or ‘very good’ rating. Targets are based on historic company-wide NSP survey results from the previous three years, and will be revised after two Plan years to reflect responses from North

Dakota customers only. Each of the two survey standards will carry a potential reward and/or penalty of a 25 basis point adjustment to the authorized ROE deadband.

The following table defines the Plan performance standards for customer service for at least the first two plan years:

Measure	Award Threshold	Target	Penalty Threshold
Relationship survey positive response %	> 84.0%	81.0%	< 78.0%
Transaction survey positive response %	> 66.0%	63.0%	< 60.0%

C. Price Standard

The Petition proposed a price standard comparing the Company's average Residential electric revenue per kWh for the Plan year to the average residential revenue/kWh for a comparison group of 26 mid-western utility jurisdictions. Staff proposed a price comparison measuring the change in the Company's residential electric revenue/kWh in the Plan year to the change for the ten lowest-priced utilities in the comparison group.

Pursuant to this Final Agreement, two price standards will be used in the PLUS Plan for purposes of measuring competitive price: 1) the Company's relative average residential price per kWh compared to the mid-western utility peer group; and 2) the annual change in average residential price relative to the change for the lowest priced utility in the peer group. The price targets are calculated annually based on utility price data compiled in an Edison Electric Institute publication entitled Typical Bills and Average Rate Report issued twice per year. For purposes of the PLUS Plan, the "winter" edition (reflecting the 12 month period ending December 31st) will be used.

Each of the two price measures will carry a potential reward and/or penalty of a 25 basis point adjustment to the authorized ROE deadband.

The following table defines the revised Plan performance standards for price:

Measure	Award Threshold	Target	Penalty Threshold
Competitive Res'l price position	< 85% of target	peer group avg. Residential price/kWh	> 115% of target
Annual change in Res'l avg. price	< (target-.05¢/kwh)	annual change in lowest priced utility Res'l avg. price	> (target+.05¢/kwh)

D. Employee Safety Standard

The Petition proposed an employee safety standard based on the Company's Occupational Safety and Health Administration ("OSHA") incident rate in the Plan year compared to historic performance of a number of regional utilities participating in a North Central Electric Association safety survey. The OSHA incident rate represents the number of safety-related incidents per 100 employees. The Petition proposed a reward and/or penalty of a 50 basis point adjustment to the baseline ROE.

Pursuant to this Final Agreement, the PLUS Plan will include an employee safety measurement based on the OSHA incident rate. The target is based primarily on historical results for Group 1 utilities (more than 7,000 employees) in the Edison Electric Institute survey, but also reflects consideration of what would provide an acceptable "stretch" for NSP's North Dakota operations. To be consistent with the other individual Plan standards, the employee safety measure will carry a potential reward and/or penalty of a 25 basis point adjustment to the authorized ROE deadband.

The following table defines the Plan performance standards for employee safety:

Measure	Award Threshold	Target	Penalty Threshold
OSHA incident rate	< 3.70	4.32	> 5.00

4. Changes in Base Rates

Attachment 1 to this Final Agreement provides a description the relationship of the Plan's dynamic ROE mechanism to the electric rate change criteria provided by this Final Agreement. Attachment 2 provides a flow chart of the price change criteria provided by this Final Agreement.

A. Price Cap Factor

Pursuant to this Final Agreement, the PLUS Plan will calculate a Price Cap Factor by determining the lower of 1) the annual percentage change in the utility peer group's average residential price per kWh for the reporting year, and 2) 60% of the change in the Consumer Price Index (CPI) for the reporting year.¹ The CPI for the Plan reporting year is computed by averaging the annual CPI reported at the end of each calendar quarter. The Price Cap Factor will determine the highest annual percentage rate increase allowed under the Plan, or the amount of a required rate decrease.

B. Rate Change Criteria

Pursuant to this Final Agreement, the PLUS Plan imposes an electric rate freeze on the Company whenever (i) its previous fiscal year ROE exceeds the baseline ROE,

¹ As such, the change to efficiency commitment factor provided in the Amendment (annual CPI – 0.8%) is replaced by the efficiency commitment in the Settlement Agreement (60% of annual CPI).

as adjusted pursuant to the performance points, minus 100 basis points (1.0%);² or (ii) the Company's average residential rates are higher than the utility peer group average residential rate. If neither condition exists, the Company may change rates by an overall percentage not to exceed the Price Cap Factor.

C. Required Rate Decrease Criteria

The Company shall reduce its retail electric rates pursuant to the PLUS Plan if (i) the Company's reported ROE for the Plan reporting year exceeded the baseline ROE, as adjusted pursuant to the performance points, plus 100 basis points (1.0%); (ii) the Company's average residential rates are higher than the PLUS utility peer group average residential rate; and (iii) the Price Cap Factor is negative.

D. Rate Change Procedure

To implement any permissive rate change pursuant to Section B or mandatory rate reduction pursuant to Section C, the Company shall file a notice of rate change and the accompanying tariffs pursuant to N.D.C.C. 49-05-05 not later than June 1, following completion of the Plan year and submission of the Plan performance report on May 1.

² As shown for illustrative purposes in Attachment 1, the lower ROE threshold could be 11.13% minus 100 basis points, or 10.13%, assuming the Company's performance would result in performance penalties in all seven Plan performance categories. In this example, a base electric rate freeze would be in effect if NSP's reported earnings in North Dakota for the prior Plan year were above 10.13%.

Similarly, the upper threshold could be 12.88% minus 100 basis points, or 11.88%, assuming the Company's performance would result in performance awards in all seven Plan performance categories. In this example, a base electric rate freeze would be in effect if the Company's reported earnings for the prior Plan year were above 11.88%.

If the Company's performance was within all of the Plan performance bandwidths, and no adjustment was made to the baseline ROE pursuant to the dynamic ROE mechanisms, a base electric rate freeze would be in effect if the Company's reported earnings in the prior Plan year exceeded 11.00%.

The revised rates shall be effective on or after July 1 following the Plan year. Base rate changes will be across-the-board to all customer classes unless otherwise requested by the Company and approved by the Commission.

Such rate change will not be suspended by the Commission under N.D.C.C. 49-05-06, but the revised rates shall be allowed to go into effect on the date proposed. If the Commission determines after investigation and hearing that the changed rates do not comply with the Plan terms as prescribed herein, the Commission may prospectively establish the rates it finds to be consistent with the Plan terms, and order a one-time billing true-up for the impact of the discrepancy since either the inception of the rate change or the previous 12 month period, whichever is less. Rates established consistent with the Plan are presumed just and reasonable, and non-discriminatory.

E. Exogenous Events.

Changes in base rates are subject to the price cap mechanisms included in this Final Agreement. However, any increases or decreases in costs of electric service caused by governmentally imposed changes in taxes and/or accounting practices shall be implemented within 60 days of the effective date of the change.

5. Other Terms and Conditions

A. Fuel Clause Adjustment

This Agreement and the Company's revised PBR Plan does not change the Company's existing fuel clause adjustment ("FCA") mechanism in its North Dakota Electric Rate Book tariff schedules. The comparative price standard provided above shall be calculated using total Residential revenue per kWh including the fuel clause adjustments in effect during the Plan reporting year.

B. Demand Allocator Factor

For purposes of calculating the Company's jurisdictional expenses for the PLUS Plan reporting year, 36 months of historical demand data will be used to establish the Demand Allocation factor (known as D10). The Demand Allocation factor is used to assign production and transmission related costs and investment to NSP's retail electric jurisdictions in North Dakota, South Dakota and Minnesota. The Petition demonstrated use of 36 months of demand data will mitigate volatility in this allocation factor. The use of a 36 month demand allocator is only for financial reporting purposes under the Plan. Use of a 36 month historic allocator for the Plan shall have no precedential effect in future electric rate increase applications after the Plan term expires or the Plan is suspended or terminated

C. Suspension/Termination of Plan

The PBR Plan will remain in effect for five years beginning January 1, 2001. However, the Company and Staff reserve the right to request adjustment, suspension, or termination of the Plan under the following events:

- Federal and/or state tax law changes;
- Passage of retail access legislation at either the federal or state level;
- Merger and acquisition events affecting the Company's structure and operations;
- Natural disasters affecting the Company's North Dakota electric operations (major storms, floods, etc.);
- Unusual events affecting the Company's operations (major generating plant failure, damage to major transmission or distribution lines, etc.); or

- Material and sustained earnings extremes (defined as returns on equity +/- 5.0% from the ROE deadband, prior to sharing).

It is anticipated the Commission and Company will make reasonable efforts to resolve any condition that could otherwise trigger a Company application or Commission motion to suspend the Plan before any decision to terminate operation of the Plan during the Plan term.

D. Applicability and Scope

Each of the provisions of this Final Agreement is in consideration for each and every other provision. This Final Agreement is subject to the approval of the Commission. If this Final Agreement and the PLUS Plan (as revised by this Final Agreement) are not approved in their entirety without modification by vote of the Commission by December 31, 2000, the Company, at its option, may submit written notice to the Commission that this Final Agreement is null and void and the Plan and Petition are withdrawn. Such notice shall be submitted no later than January 5, 2001.

This Final Agreement shall be binding on the parties hereto, and upon their successors, assigns, agents and representatives.

E. Effective Date

Except as provided herein, this Final Agreement shall be effective on the date of the final Commission order approving the Plan (as revised) and this Final Agreement without modification. This Final Agreement shall remain in full force and effect for the Plan term.

F. Effect of Settlement Negotiations

It is understood and agreed that all offers of settlement and discussions related thereto are privileged and may not be used in any manner in connection with proceedings in this case or otherwise, except as provided by law. In the event the Commission does not approve this Final Agreement, the Final Agreement shall not constitute part of the record in this proceeding and no part thereof may be used for any purpose in this proceeding or otherwise. This Final Agreement shall not in any respect constitute a determination by the parties hereto as to the merits of any specific allegations or contentions made by the parties in Case No. PU-400-00-195.

G. Counterparts

This Final Agreement may be executed in separate, identical counterparts.

H. Agreement Drafted Jointly

This Final Agreement shall be deemed to have been drafted jointly by Staff and NSP for purposes of construing or interpreting the meaning of any provision of this Final Agreement.

Northern States Power Company

By: James P. Johnson
James P. Johnson
Assistant General Counsel
Xcel Energy Services Inc., Agent for
Northern States Power Company

Date: December 28, 2000

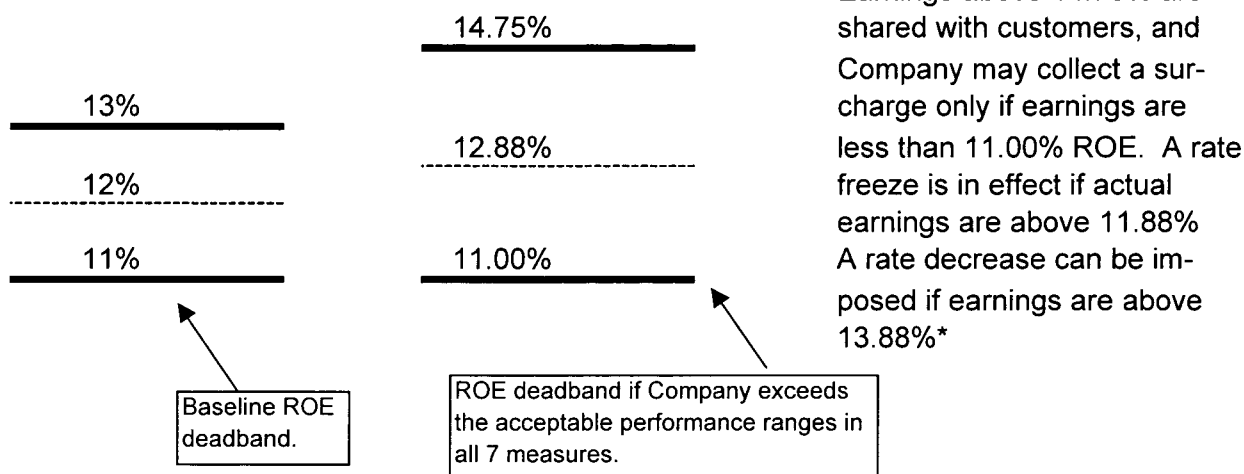
**North Dakota Public Service
Commission Staff**

By: William W. Binek
William W. Binek
Chief Counsel
North Dakota
Public Service Commission
December 28, 2000

Revenue Sharing and Price Change Mechanisms Amended Settlement Proposal

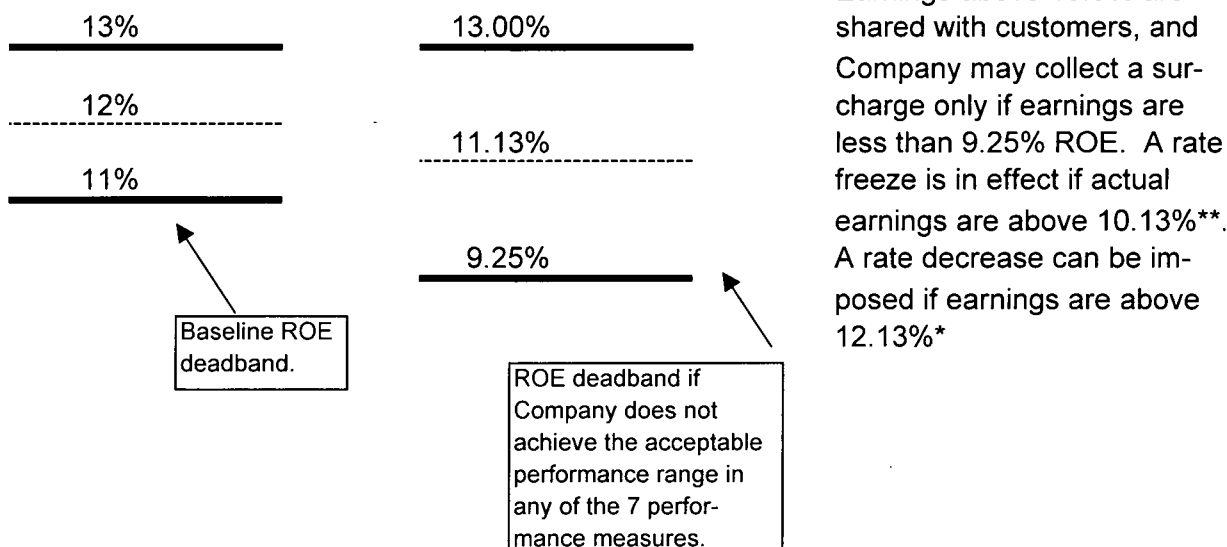
Assume all 7 performance measures are met, each worth 25 basis points

If net result of performance points is positive, only the *upper* limit of the ROE deadband increases.



Assume a penalty for all 7 performance measures, each worth 25 basis points

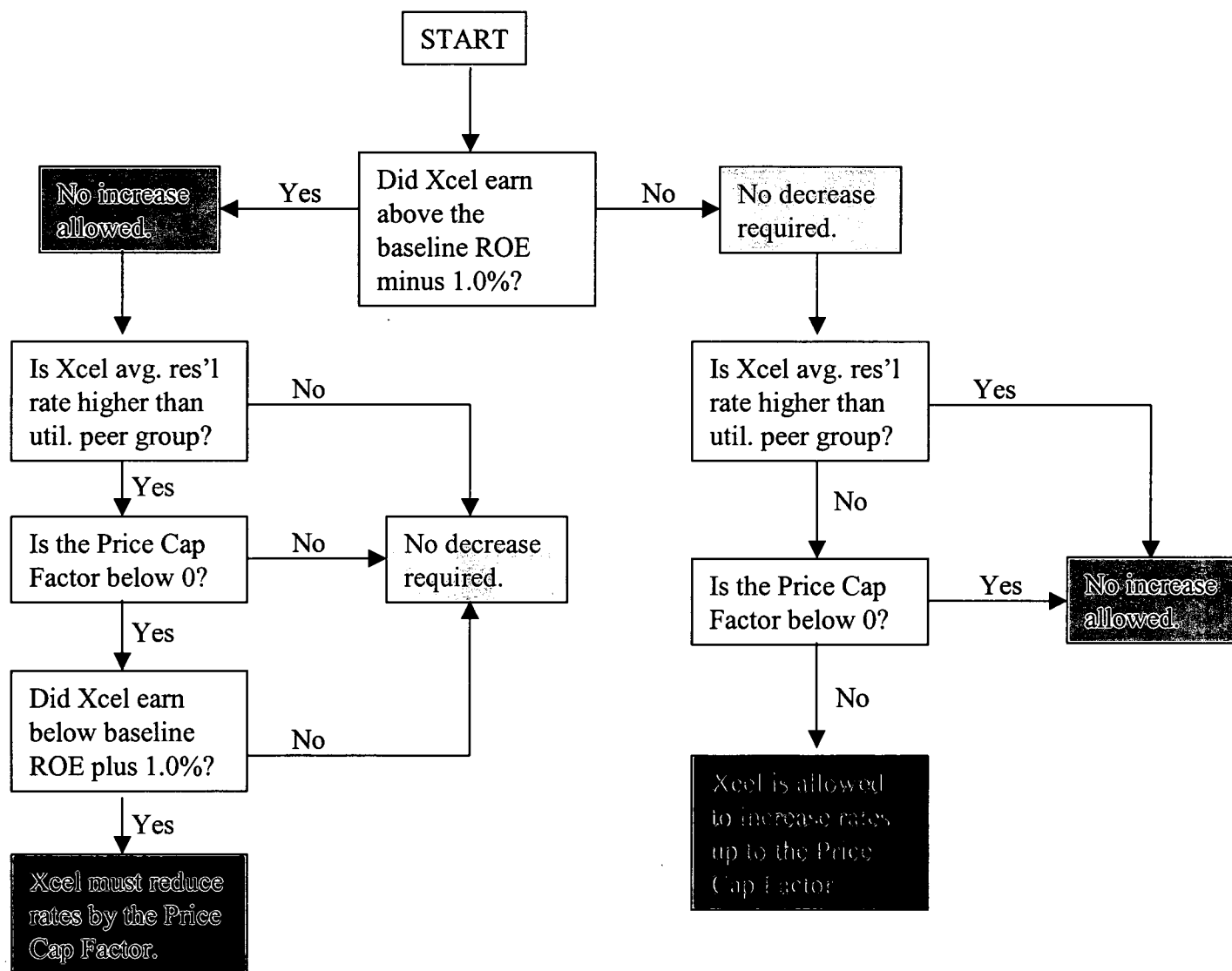
If net result of performance points is negative, only the *lower* limit of the ROE 'deadband' is reduced.



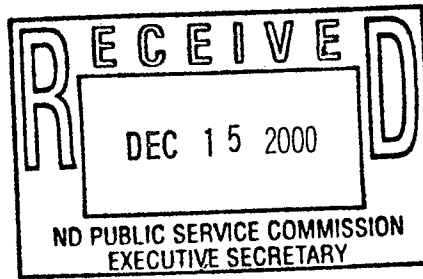
* The rate freeze threshold is equal to the baseline (12.88% in this example) minus 1.00%, or 11.88%. Decreases can be imposed at 12.88%+1.0%, or 13.88%.

** The rate freeze threshold is equal to the baseline (11.13% in this example) minus 1.00%, or 10.13%. Decreases can be imposed at 11.13%+1.0%, or 12.13%.

Decision Model for PLUS PBR Price Cap Mechanism



Price Cap Factor = lower of the utility peer group average annual price change or 60% of CPI



Legal Services

800 Nicollet Mall, Suite 2900
Minneapolis, Minnesota 55402

December 15, 2000

Mr. Jon Mielke
Executive Secretary
North Dakota Public Service Commission
600 East Boulevard
Bismarck, ND 58505

Honorable Allen Hoberg
Administrative Law Judge
Office of Administrative Hearings
1701 North 9th Street
Bismarck, ND 58501-1882

Re: Application of Northern States Power Company d/b/a Xcel Energy for
Authority to Operate Under Performance Based Regulation in North Dakota
Case No. PU-400-00-195

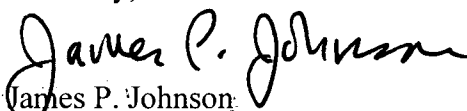
Dear Mr. Mielke and Judge Hoberg:

Enclosed please find an original and seven copies of the "Amendment and Clarifications to November 30, 2000 Settlement Agreement" ("Amendment") between Northern States Power Company d/b/a Xcel Energy and Commission Litigation Staff in the above-captioned docket. The Amendment responds to issues raised at the Commission working sessions in this proceeding on December 1 and December 11, 2000, in a manner consistent with the record. The Company and Staff respectfully request prompt approval of the PLUS Plan and the Settlement Agreement as revised and clarified by the Amendment.

The Company or Staff will serve two copies of this filing on the Office of Administrative Hearings for the hearing record and two courtesy copies on Otter Tail Power Company.

Please contact the undersigned (612-215-4592) or Dave Sederquist (701-241-8632) with any questions.

Sincerely,


James P. Johnson
Assistant General Counsel

cc: Mr. Dave Sederquist

Enclosures

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

In the Matter of Northern States Power Co.
Proposal to Implement
Performance-Based Regulation

Case No. PU-400-00-195

**AMENDMENT AND CLARIFICATION TO
NOVEMBER 30, 2000 SETTLEMENT AGREEMENT**

This Amendment and Clarification ("Amendment") to the November 30, 2000 Settlement Agreement ("Settlement Agreement") in the above captioned docket is entered into this 5th day of December 2000, by and between Northern States Power Company ("NSP" or the "Company") and the North Dakota Public Service Commission Litigation Staff ("Staff"). This Amendment amends and clarifies the Settlement Agreement.

This Amendment is supported by the administrative record in Case No. PU-400-00-195. Other documentation in support of the Amendment is contained herein or attached hereto. Accordingly, the Parties jointly recommend that the Commission approve the Settlement Agreement, as revised by this Amendment, in its entirety.

The Parties agree NSP's PLUS performance based ratemaking Plan ("Plan"), as further modified by the revisions and clarifications herein, is consistent with the public interest, and will result in just and reasonable rates. The Parties request the Commission issue an order approving the Settlement Agreement and Amendment and modified PLUS Plan in their entirety, without further conditions or modifications.

Background

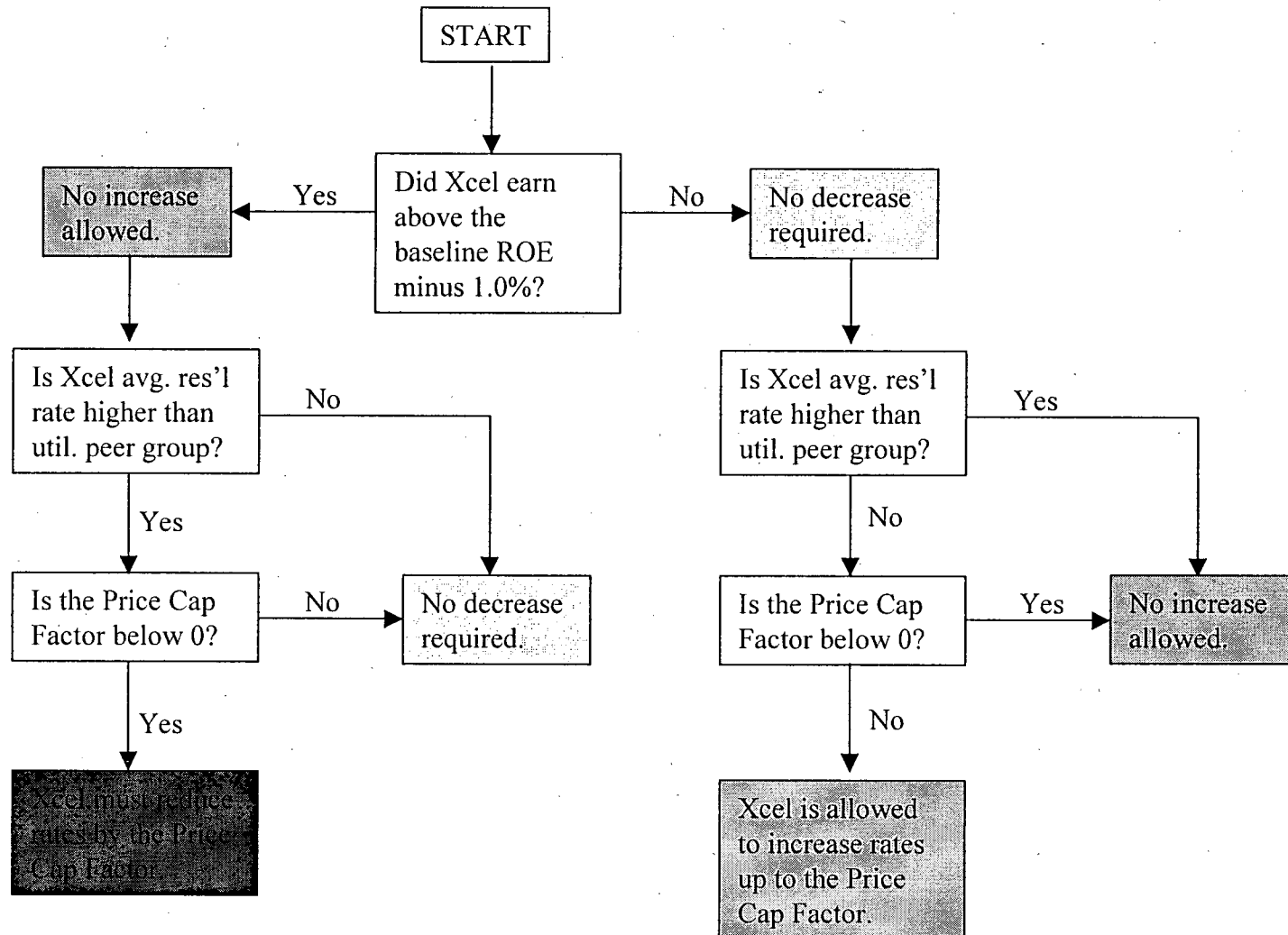
A. On November 30, 2000, NSP and Staff entered into a Settlement Agreement that NSP and Staff agreed resolved all outstanding issues in the above-captioned proceeding.

B. The Settlement Agreement was presented to the Commission on December 1, 2000 at a regularly scheduled and noticed working session to allow the Commission and Advisory Staff to ask questions and develop a record supporting approval of the Settlement Agreement. Both the Company and Staff, the only parties to the proceeding, were present.

C. On December 11, 2000, the Settlement Agreement was again the topic of discussion at a regularly scheduled and noticed Commission working session, with both the Company and Staff again present. At the second working session, the Advisory Staff submitted two memos raising issues regarding the Plan as revised by the Settlement Agreement. The Commission indicated further clarifications and/or modifications to the Settlement Agreement and/or the Company's PLUS Plan were warranted prior to Commission approval of the Plan and Settlement Agreement.

NOW, THEREFORE, in consideration of the foregoing, the parties agree on the following amendments and clarifications to the Settlement Agreement. The Parties agree these further amendments and clarifications to the Plan would serve the public interest.

Decision Model for PLUS PBR Price Cap Mechanism



Price Cap Factor = lower of the utility peer group avg. annual price change, or CPI - 0.8%

Amendments

1. ROE threshold for rate changes.

In the Settlement Agreement, the parties agreed the baseline Return on Equity ("ROE") threshold for determining whether electric rates can be increased or decreased could be anywhere between 11.13% and 12.88%, depending on the Company's performance and resulting adjustments to the initial baseline ROE (12.0%) pursuant to the dynamic ROE mechanism. This Amendment amends the threshold for rate changes to the baseline ROE (as adjusted) minus one percent.

As shown for illustrative purposes in Attachment A-1, the lower threshold could be 11.13% minus one hundred basis points, or 10.13%, assuming the Company's performance would result in performance penalties in all seven Plan performance categories. In this case, a base electric rate freeze would be in effect if NSP's reported earnings in North Dakota for the prior Plan year were above 10.13%.

Likewise, the upper threshold could be 12.88% minus one hundred basis points, or 11.88%, assuming the Company's performance would result in performance awards in all seven Plan performance categories. In this example, a base electric rate freeze would be in effect if the Company's reported earnings for the prior Plan year were above 11.88%.

If the Company's performance was within all of the Plan performance bandwidths, and no adjustment was made to the baseline ROE pursuant to the dynamic ROE mechanisms, a base electric rate freeze would be in effect if NSP's reported earnings in the prior Plan year exceeded 11.00%.

Attachment A-2 shows a flow chart which reflects the price changing criteria encompassed in the PLUS plan, as provided by this Amendment to the Settlement Agreement.

All other provisions of the price cap mechanism remain in effect, as set forth in the Company's PBR Plan as amended by the Settlement Agreement.

2. Productivity Factor.

The PLUS Plan uses a Price Cap Factor to limit electric rate increases to the lower of (a) the general rate of inflation based on the reported annual Consumer Price Index ("CPI") for the Plan year, or (b) the increase in electric rates for a comparable group of Midwest electric utilities. The filed Plan utilized a 75% multiplier of the annual CPI as a surrogate for a productivity factor offset in the Price Cap Factor. The Settlement Agreement reduced the CPI Price Cap Factor to 60% of the annual reported CPI.

In response to a concern expressed at the December 11, 2000 working session that the CPI component of the Price Cap Factor could result in a smaller electric rate reduction if CPI were negative, the parties agree to set a productivity factor at 0.8% to replace the percent of CPI mechanism. For example, if annual reported CPI for a Plan year were 2.0%, this component of the Price Cap Factor would be 2.0% - 0.8%, or 1.2%. If the annual reported CPI were 0.5%, this component of the Price Cap Factor would be 0.5% - 0.8%, or negative 0.3%.

Clarifications

3. Effect of exogenous events.

The parties agree that changes in the Company's base electric rates are subject to the price cap mechanism included in the proposed PLUS Plan, as amended by the Settlement Agreement and this Amendment. However, for purposes of clarification, the parties expressly recognize that any increases or decreases in costs of electric service caused by governmentally imposed changes in taxes and/or accounting practices shall be implemented within 60 days of the effective date of the change.

4. Extension of Plan Term.

As provided in the Settlement Agreement, the Plan will be in effect for five calendar years beginning January 1, 2001. Prior to July 1, 2005, the Company will file for extension and/or modification of the Plan if so desired. Absent such filing, the PLUS Plan will automatically terminate on December 31, 2005.

5. Unrecovered Revenue Deficiency Mechanism

At the December 11 working session, there was some question whether the Settlement Agreement adequately addressed the time period over which any uncollected deferred revenue deficiency would be collected from customers. To clarify, any such rate surcharge will be collected over the remaining six-month period beginning July 1 of the year following the Plan fiscal report year, unless otherwise requested by either the Company or Commission Staff and approved by the Commission.

6. Survival of Settlement Agreement

The Settlement Agreement, as amended by this Amendment, shall remain in full force and effect. for the Plan Term.

7. Amendment subject to Approval

This Amendment is subject to the approval of the North Dakota Public Service Commission.

8. Effect of Settlement Negotiations

It is understood and agreed that all offers of settlement and discussions related thereto are privileged and may not be used in any manner in connection with proceedings in this case or otherwise, except as provided by law. In the event the Commission does not approve this Amendment, the Amendment shall not constitute part of the record in this proceeding and no part thereof may be used for any purpose in this proceeding or otherwise. This Amendment shall not in any respect constitute a determination by the parties hereto as to the merits of any specific allegations or contentions made by the parties in Case No. PU-400-00-195.

9. Counterparts

This Amendment may be executed in separate, identical counterparts.

IN WITNESS WHEREOF, the parties hereto have executed this Amendment as of the date set forth in the first paragraph.

Northern States Power Company

By: James P. Johnson
James P. Johnson
Assistant General Counsel
Xcel Energy Services Inc., Agent for
Northern States Power Company

**North Dakota Public Service
Commission Staff**

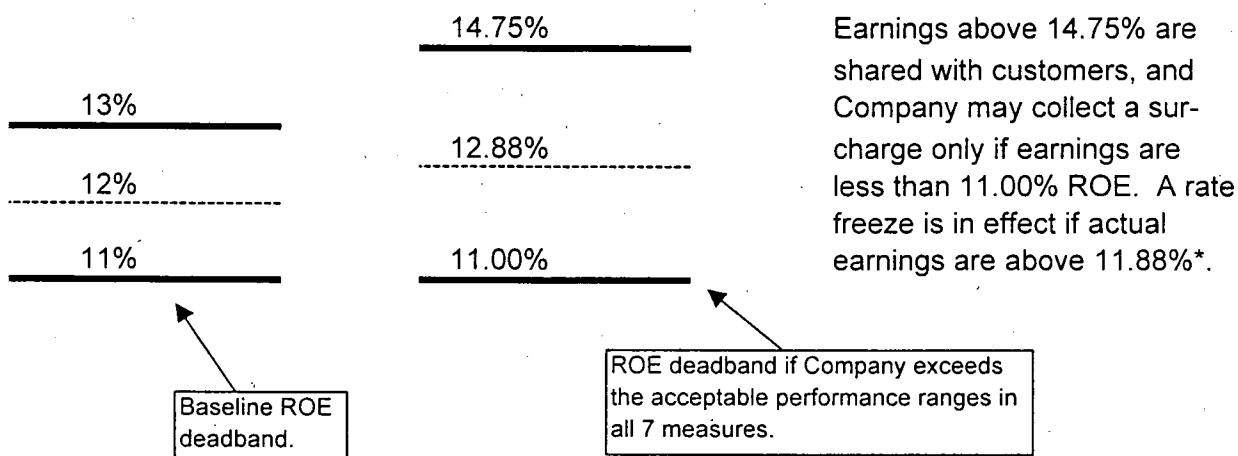
By: William W. Binek
William W. Binek
Chief Counsel
ND Public Service Commission
December 15, 2000

Date: December 14, 2000

Revenue Sharing and Price Change Mechanisms Amended Settlement Proposal

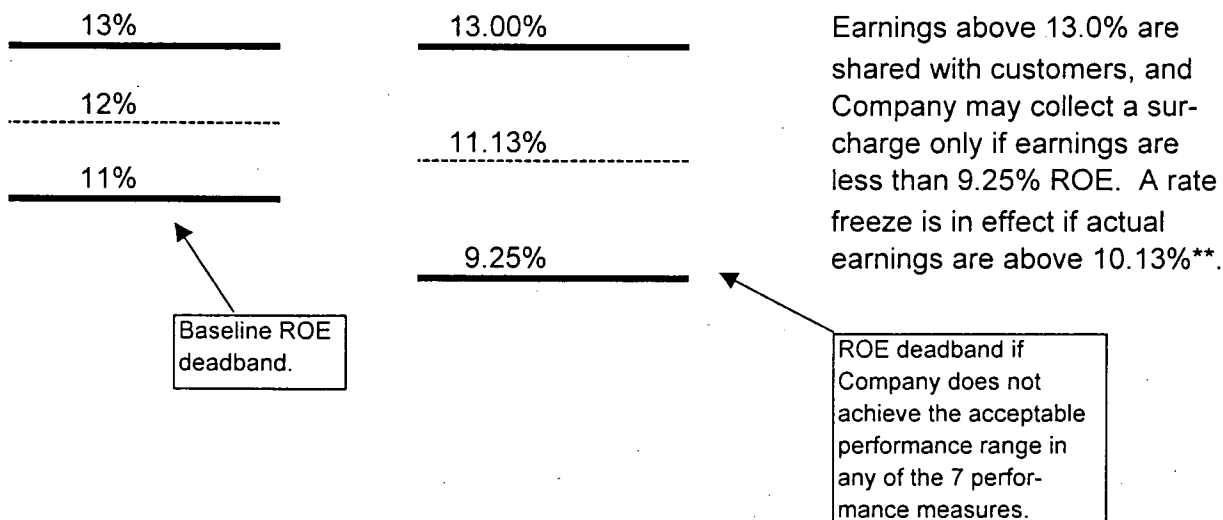
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Assume a penalty for all 7 performance measures, each worth 25 basis points

If net result of performance points is negative, only the *lower* limit of the ROE 'deadband' is reduced.



* The rate freeze threshold is equal to the baseline (12.88% in this example) minus 1.00%, or 11.88%

** The rate freeze threshold is equal to the baseline (11.13% in this example) minus 1.00%, or 10.13%

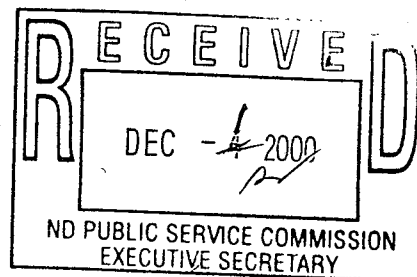


Legal Services

800 Nicollet Mall, Suite 2900
Minneapolis, Minnesota 55402

BY OVERNIGHT COURIER

December 1, 2000



Mr. Jon Mielke
Executive Secretary
North Dakota Public Service Commission
600 East Boulevard
Bismarck, ND 58505

Honorable Allen Hoberg
Administrative Law Judge
Office of Administrative Hearings
1701 North 9th Street
Bismarck, ND 58501-1882

Re: Application of Northern States Power Company d/b/a Xcel Energy for
Authority to Operate Under Performance Based Regulation In North Dakota
Case No. PU-400-00-195

Dear Mr. Mielke and Judge Hoberg:

Enclosed please find an original and seven copies of the Proposed Findings of Fact, Conclusions of Law and Order of Northern States Power Company d/b/a Xcel Energy in the above-captioned docket, pursuant to the schedule adopted by Administrative Law Judge Allen Hoberg at the conclusion of the hearing.

The Company will serve two copies of this filing on the Office of Administrative Hearings for the hearing record and two courtesy copies on Otter Tail Power Company.

Please contact the undersigned (612-215-4592) or Dave Sederquist (701-241-8632) with any questions.

Sincerely,

James P. Johnson
Assistant General Counsel

cc: Mr. Dave Sederquist
Mr. William Binek, Commission Staff Counsel
Mr. Mike Diller, Commission Staff

Enclosures

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

Northern States Power Company d/b/a
Xcel Energy
Performance-Based Regulation Proposal

Case No. PU-400-00-195

**FINDINGS OF FACT,
CONCLUSIONS OF LAW AND ORDER**

December __, 2000

Appearances

Commissioners: Bruce Hagen, Leo M. Reinbold, Susan E. Wefald.

James P. Johnson, Assistant General Counsel, Xcel Energy Services Inc.,
800 Nicollet Mall, Minneapolis, MN 55402, appearing for Northern States Power
Company d/b/a Xcel Energy.

William W. Binek, Chief Counsel, Public Service Commission, State Capitol,
600 East Boulevard, Bismarck, ND 58505, appearing for the Public Service Commission
Staff.

Allen C. Hoberg, Office of Administrative Hearings, 1707 North 9th Street -
Lower Level, Bismarck, ND 58501-1882, presiding Administrative Law Judge.

Preliminary Statement

Procedural History

This matter came before the Commission on an application ("Petition") filed on April 20, 2000, by Northern States Power Company d/b/a Xcel Energy ("NSP", "Xcel" or "the Company")¹ for approval of a "Proposal for a Performance-Based Regulation Plan." The Petition asks the Commission to approve the Company's proposed performance-based regulation ("PBR") plan, called the "PLUS" plan ("Plan"), for purposes of

¹ The Petition pre-dates the August 18, 2000 merger of Northern States Power Company ("Old NSP") and New Century Energies, Inc. to form Xcel Energy Inc., the registered holding company parent of NSP. Since the merger, the Company has been doing business under the trade name Xcel Energy.

regulating NSP's retail electric operations in North Dakota.² The Company proposes the Plan be in effect for a five year term from January 1, 2001 to December 31, 2005. If approved, the Plan would create an alternative form of regulation for the Company's electric operations in North Dakota. The Company asserts the proposed Plan would comply with the Commission's "Guidelines for Filing Alternative Regulation Proposals" ("Guidelines") issued in Case No. PU-439-94-590 (September 20, 1995).

The Petition was filed, *inter alia*, pursuant to the settlement agreement between the Company and Commission litigation staff ("Staff") in Case Nos. PU-400-99-418, requesting approval of the merger with New Century Energies, Inc., and PU-400-98-246, a Staff investigation of the Company's 1997 electric earnings. This prior settlement agreement was approved by a Commission order in those dockets. See "Findings of Fact, Conclusions of Law and Order," May 10, 2000.

On July 19, 2000, the Commission issued a "Notice of Hearing and Notice of Public Discussion Meeting" ("Notice") in the instant docket and Case No. PU-401-00-36, a docket involving a similar PBR plan filed by Otter Tail Power Company ("Otter Tail"). As provided in the Notice, the Commission conducted a joint public hearing by video conference from 11:00 a.m. to 1:00 p.m. on September 6, 2000, with public participation available through ten video conference sites, including three in the Company's electric service area (Fargo, Grand Forks, Minot). No members of the public submitted oral comments opposing approval of the Plan at the public hearing.

The Notice also set a joint evidentiary hearing on the proposed Plan and the similar Otter Tail PBR plan for October 23-24, 2000. The Notice set forth the following issues to be considered at the hearing:

- Are the PBR plans as submitted consistent with the Guidelines?
- Would the plans result in quality service and reasonable rates?
- Do the plans support safe and reliable electric infrastructure and the financial viability of the utilities?
- Is implementation of the plans in the public interest?

The hearing was assigned to the Office of Administrative Hearings. Administrative Law Judge Allen C. Hoberg was assigned to conduct the evidentiary hearing. No motions to intervene were filed.

On September 29, 2000, the Company and Otter Tail submitted joint pre-filed direct testimony of Dr. Karl McDermott of National Economic Research Associates ("NERA") (Joint Hearing Exhibit No. 1).³ Dr. McDermott provided a historic overview of

² "PLUS" is an acronym for "Performance Linking Utility Stakeholders."

³ Dr. McDermott is a former commissioner on the Illinois Commerce Commission ("ICC"), serving from 1992 to 1998.

performance based regulation, recommended certain criteria the Commission should apply in considering and approving a PBR plan, and provided an evaluation of the proposed Plan compared to those criteria and the Guidelines. Dr. McDermott also summarized the PBR plans approved by regulatory commissions in other states. The Company also submitted the pre-filed direct testimony of: (1) Mr. David H. Sederquist (NSP Hearing Exhibit 3), who described and supported the overall Plan and the proposed performance measures and standards; (2) Ms. Pamela L. Bagley (NSP Hearing Exhibit 6), who supported the proposed Reliability measure of System Average Interruption Duration Index ("SAIDI"); and (3) Ms. Heather A. Schander (NSP Hearing Exhibit 7), who supported the proposed Customer Service measure based on customer survey results.

On October 13, 2000, the Staff submitted the pre-filed direct testimony of Mr. Mike Diller. Mr. Diller discussed certain policy considerations for the Commission to weigh in approval of any PBR plan and recommending certain modifications to proposed PLUS Plan. Mr. Diller argued the filed Plan lacked symmetry in the price change provisions, and advocated changes to certain specific performance measures and standards.

On October 20, 2000, the Company and Otter Tail submitted the joint rebuttal testimony of Dr. McDermott (Joint Hearing Exhibit No. 2), and the Company submitted the rebuttal testimony of Mr. Sederquist (NSP Hearing Exhibit 4), which opposed certain Staff recommendations regarding changes to the standards and measures in the Plan.

On October 23-24, 2000, the Commission conducted a joint evidentiary hearing considering both NSP's PLUS Plan in the instant docket and Otter Tail's similar PBR plan in Case No. PU-401-00-36. Judge Hoberg presided over the hearing. The Petition and pre-filed testimony of the Company and Staff and other hearing exhibits were accepted into the record, and the witnesses were subject to cross examination by counsel and questions and comments by the Commissioners and Advisory Staff.

At the conclusion of the evidentiary hearing, the Presiding Judge required the Company and Staff to submit briefs and proposed findings of fact and conclusions of law by December 1, 2000. Alternatively, in lieu of briefs, the Company and Staff could submit a settlement agreement resolving the disputed issues.

On November 15 and 22, 2000, the Company filed its late-filed exhibits to the evidentiary hearing record, as prescribed by the Presiding Judge.

On November 21 and December 1, 2000, the Commission held additional working sessions to discuss the Company and Otter Tail PBR proposals. In the period after the evidentiary hearing, the Company, Staff and Otter Tail engaged in settlement discussions seeking to resolve the disputed issues.

On November 30, 2000, the Company and Staff submitted a Settlement Agreement which they assert would resolve all outstanding issues in the proceeding in a manner consistent with the public interest. The Company and Staff assert the Settlement Agreement is supported by the administrative record in Case No. PU-400-00-195 and other documentation attached to the Settlement Agreement, complies with the 1995 Commission Guidelines, and will result in rates which are just and reasonable and not discriminatory during the proposed Plan term. The Company and Staff requested prompt Commission approval of the Settlement Agreement without modification. The Staff also submitted a memorandum in support of the Settlement Agreement.

On December 1, 2000, the Company submitted Proposed Findings of Fact, Conclusions of Law and Order. On December __, 2000, the Commission considered this matter at its regular Formal Agenda meeting.

Summary of Petition and Hearing Record

The Petition and the Company's pre-filed testimony assert the key components of the original PLUS include 1) a "dynamic allowed ROE" range which can vary based on Company performance, 2) a revenue sharing mechanism, 3) establishment of service performance standards, and 4) price capping and flexibility to adjust prices under specified circumstances. In its Petition and pre-filed testimony, the Company asserts:

- The PLUS Plan meets the stated goals and criteria identified by the 1995 Commission Guidelines.
- The PLUS Plan is an appropriate regulatory model because it provides benefits to customers and to North Dakota's economy which extend beyond traditional cost-based regulation, while at the same time ensuring that the Company's North Dakota electric rates are just and reasonable and the Company's operations have the opportunity to maintain financial strength.
- The PLUS Plan will work better than traditional cost-based regulation to promote a balanced emphasis on utility efficiency and service quality in North Dakota, while maintaining the customer protections provided by traditional regulation.
- The PLUS Plan provides North Dakota regulation with an automatic, pre-defined mechanism to pass the benefits of a financially healthy utility on to its stakeholders. Unlike traditional, cost-based regulation, which can be a slow and adversarial, the PLUS Plan offers an efficient, win/win approach to utility regulation. PLUS places the regulatory focus more on results and less on process.
- As restructuring of the electric industry occurs, performance based regulation will play a role in facilitating the transition to a more competitive environment. The PLUS

regulatory model better simulates a competitive market by creating meaningful incentives which promote high quality service and low cost.

- Since PLUS offers the Company the potential to achieve above-average returns on its North Dakota electric business if the Company's performance meets the thresholds set forth in the plan, PLUS will also create an additional incentive for NSP to invest its limited capital resources in North Dakota (other things being equal).

The Company asserts the record, particularly the pre-filed and oral testimony of Dr. McDermott, supports use of broad and balanced performance standards and symmetrical reward/penalty criteria. The Company asserts the PLUS Plan complies with Dr. McDermott's recommendations. However, the Company agrees with Mr. McDermott that the performance measures and standards in any PBR plan approved by the Commission should be consistent with Commission policy, as expressed in the Guidelines.

The pre-filed and oral testimony of Staff witness Diller generally supported implementation of performance-based regulation for the Company's electric utility operations in North Dakota. However, Staff recommended various changes to the specific performance measures and standards proposed by the Company.

The rebuttal testimony of the Company opposed the Plan modifications proposed by Staff. At the hearing, however, the Company indicated its willingness to work with the Staff to attempt to resolve issues regarding the specific performance measures and standards in the Plan. In addition, Commissioner comments and questions at the evidentiary hearing and subsequent informal hearings suggested the parties consider alternative performance measures and standards. Specifically, the Commissioners and Advisory Staff noted the recommendations in Performance Based Regulation in a Restructured Electric Industry, Bruce Biewald *et al.* (prepared for the National Association of Regulatory Utility Commissioners by Synapse Energy Economics, 1997), and Performance-Based Ratemaking: Theory and Practice, Dr. Michael R. Schmidt (PUR Reports Inc., 2000) regarding suggested performance measures and criteria and procedures for design and administration of electric utility PBR plans.

Based on the evidentiary record, and the comments and questions of the Commission and Advisory Staff at the various hearings, the Company and Staff submitted a Settlement Agreement dated November 30, 2000, which would result in implementation of a modified PLUS Plan.

Legal Authority To Authorize and Regulate Alternative Regulation Plans

Any alternative regulation plan approved by the Commission must comply with the statutes setting forth the Commission's regulatory authority, and should comply with the "Guidelines for Filing Alternative Regulation Proposals" ("Guidelines") issued in Case No. PU-439-94-590 (1995). These may be summarized as follows:

1. Statutory Requirements

N.D. Cent. Code §§ 49-02-03, 49-02-04, 49-05-05 and 49-05-06 govern the Commission's jurisdiction over the proposed PBR Plan. N.D. Cent. Code § 49-02-03 provides, in relevant part:

The Commission shall supervise the rates of all public utilities. It shall have the power, after notice and hearing, to originate, establish, modify, adjust, promulgate, and enforce tariffs, rates, ...and charges of all public utilities.

N.D. Cent. Code § 49-02-04 provides, in relevant part:

The Commission shall prescribe, after hearing, rules and regulations for the performance of any service, or the furnishing of any commodity, of a character furnished or supplied by any public utility.

N.D. Cent. Code § 49-05-05 provides, in relevant part:

No change shall be made by any public utility in any tariffs, rates,... schedules,...or service which have been filed and published by any public utility, except after thirty days notice to the commission. The notice shall plainly state the changes proposed.... The commission for good cause shown, may allow changes upon less than the notice herein specified, either in particular instances or by a general order applicable to special or peculiar circumstances or conditions.

Finally, N.D. Cent. Code § 49-05-06 provides, in relevant part:

Whenever a notice or any schedule stating an individual or joint rate, classification, contract, practice, rule or regulation, increasing or decreasing, or resulting in an increase or decrease in any rate, shall be filed with the commission, the commission may suspend by motion such rate...All such rates...not so suspended, on the expiration of thirty days from the filing of the same with the commission,...shall go into effect and be the established and effective rates,...subject to the power of the commission, after a hearing had on its own motion or upon complaint, to alter or modify the same.

The Company and Staff assert the PBR Plan, as modified by the Settlement Agreement, satisfies these statutory requirements. The testimony of Dr. McDermott states the Commission can insure just and reasonable rates during the Plan term (a) if the rates and services of the Company are just and reasonable rates when the Plan is implemented, and (b) by prescribing an ongoing process to insure the Company's electric rates and services remain just and reasonable during the Plan term.

2. Commission Alternative Regulation Guidelines, Case No. PU-439-94-590

On September 20, 1995, the Commission issued the Guidelines after conducting both a workshop and public input sessions to discuss different forms of regulation for electric utilities. The Guidelines indicated the Commission would consider proposals for alternative forms of regulation from traditional “cost-based rate of return” regulation. The Guidelines set forth both goals and criteria for alternative regulation proposals, which include:

- Goals: a plan should: 1) promote utility efficiencies, 2) align customer and shareholder interests; 3) maintain/improve customer service; 4) allow utilities to be flexible; 5) minimize regulatory costs; and 6) improve public participation.
- Criteria: a plan should be: 1) comprehensive; 2) administratively simple; 3) easily communicated; 4) balanced; and 5) flexible.
- Other Considerations: the Guidelines state any alternative regulation proposal: 1) must show the utility’s base rates are just and reasonable at the start of the alternative mechanism; 2) should be for a limited period of time, and include a review date; 3) provide for a periodic review of the utility’s profits pursuant to criteria in the plan; 4) enable the Commission to judge the success of the plan at its completion; and 5) must not violate the Territorial Integrity Act.

As described above and in Appendix 1, the Company and Staff assert the PBR Plan, as modified by the Settlement Agreement, complies with the Guidelines.

The Commission, having reviewed the evidence in the record, including the Settlement Agreement, makes the following:

FINDINGS OF FACT

The Company

1. NSP is a Minnesota corporation providing electric and natural gas public utility service in North Dakota. NSP and its predecessor (“Old NSP”) have continuously provided electric public utility service in North Dakota pursuant to authorizations provided by North Dakota law or issued by the Commission. NSP provides retail electric service in the communities of Fargo, Grand Forks, Minot, West Fargo, Berthold, Burlington, Buxton, Des Lacs, Hatton, Larimore, Mayville, Portland, Reynolds and Thompson, North Dakota, and certain surrounding areas.

2. NSP is a utility operating company subsidiary of Xcel Energy Inc., which was created by the merger of Old NSP and New Century Energies, Inc. on August 18, 2000. Xcel Energy Inc. is a registered holding Company subject to the jurisdiction of the U.S.

Securities and Exchange Commission ("SEC") under the Public Utility Holding Company Act ("PUHCA"). NSP's rates, tariffs and services are subject to Commission jurisdiction under, *inter alia*, N.D. Cent. Code Chap 49-02 and 49-05,

The PLUS Plan, as Modified by the Settlement Agreement, is Reasonable

3. As proposed by the Company and supported by Staff, the Company should be allowed to implement its PLUS Plan for the period January 1, 2001 to December 31, 2005. The Commission finds the proposed five year term is appropriate. This term will allow sufficient time for the Commission and Company to evaluate operations under this alternative regulation plan, while retaining procedural protections (discussed below) in case factors outside the Company's control necessitate a suspension or termination of the Plan.

However, the record does not require the Commission to approval all of the specific components of the Company's original filed Plan or the modifications proposed by Staff. Instead, the Commission may apply its Guidelines, and its judgement and expertise based on the record, to approve a plan which serves the public interest. The Plan modifications pursuant to the Settlement Agreement would serve the public interest by providing implementation of a more balanced and symmetrical PBR plan.

4. Concurrently and independently with Plan implementation, the Company will reduce non-fuel base retail electric rates to the Company's North Dakota electric service customers by \$261,000 annually (approximately 0.25%), pursuant to the Commission order dated May 10, 2000, in Case Nos. PU-400-99-418 (Merger with New Century Energies, Inc.) and PU-400-98-246 (Electric Rate Investigation).⁴ The Commission finds this rate restatement will provide just and reasonable initial rates at the time the Plan is implemented, as required by the Guidelines.

5. The annual performance and financial reporting provisions of the Plan, as modified by the Settlement Agreement, are reasonable. The interim review hearing proposed for June 2003 is reasonable and consistent with the Guidelines, although the Commission will determine the specific date and procedures for hearing in its discretion based on the information available to it at the time.

6. The baseline Plan Return on Equity ("ROE") of 12.0%, the ROE deadband of +/- 1.0% around the baseline, and the annual dynamic ROE adjustments in terms of "basis points," subject to the Company's performance under each Plan performance standard,

⁴ The Company's compliance electric rate reduction effective January 1, 2001, is pending Commission action in Case No. PU-400-99-418. The Staff submitted a report dated November 16, 2000, stating the proposed rate reduction meets the requirements of the settlement agreement and order in Case Nos. PU-400-99-418 and PU-400-98-246, and recommending approval of the Company's revised rates.

are reasonable. The baseline ROE is comparable to the ROE used to resolve utility earnings investigations over the past few years, and the +/- 1% deadband is within the zone of reasonableness, as discussed by Dr. McDermott.

7. The proposed Revenue Sharing mechanism, as modified by the Settlement Agreement, is reasonable. This mechanism provides as follows:

If the Company's reported actual earnings fall within the ROE deadband around the authorized ROE (as adjusted by the performance points) in a Plan year, no revenue sharing will take place.

If the Company's actual reported earnings for any Plan year exceed the deadband, the corresponding revenue 'sufficiency' will be calculated, and 50% of this dollar amount will be refunded to customers during the July billing cycle of the following year. Customers of record on March 31 following the Plan year will be issued refunds by bill credit prorated on the basis of their electric usage for the twelve months ending March 31.

If the Company's actual reported earnings for any Plan year are below the deadband, 50% of the corresponding revenue "deficiency" may be recovered through a surcharge on the Company's electric rates effective no later than 24 months after the Plan year. However, NSP has agreed to defer recovery of a reported fiscal year deficiency by recording the amount as a regulatory asset until the following Plan year revenue sharing amount, if any, is reported. If the prior year deficiency is fully offset by the current year reported revenue sufficiency, the sufficiency will be used to eliminate the regulatory asset, and no rate surcharge will be imposed. If the deficiency from the prior year is not fully offset, any remaining deficiency balance may be reflected in rates applicable to bills issued between the 18th and 24th month following the Plan year when the deficiency occurred, subject to the Rate Change procedures described herein.

8. The Settlement Agreement treatment of the Company's economic development expenditures as a jurisdictional expense for financial reporting purposes is reasonable. This will provide greater consistency in treatment of this cost component between the Company and Otter Tail plans.

9. The proposed Reliability performance measures and standards, as modified by the Settlement Agreement, are reasonable. The Customer Average Interruption Duration Index ("CAIDI") and System Average Interruption Frequency Index ("SAIFI") are individual reliability measures widely used in the electric utility industry, the product of which is the SAIDI reliability measure originally proposed by the Company. By using both component standards, the Company will be measured on both the frequency of customer outages and the time it takes to restore power. Each measure will carry a potential reward and/or penalty of a 25 basis point adjustment to the authorized ROE deadband.

10. The proposed Customer Satisfaction performance measures, as modified by the Settlement Agreement, are reasonable. The Company will be measured based on the both the “relationship” surveys for all three customer classes (Residential, Commercial, Large Industrial), and two “transaction” surveys relating to the Company’s call center and electric service functions. The survey scores will reflect the percentage of respondents who give NSP an ‘excellent’ or ‘very good’ rating. Each of the two survey standards will carry a potential reward and/or penalty of a 25 basis point adjustment to the authorized ROE deadband.

11. The proposed Pricing measures and standards, as modified by the Settlement Agreement, are reasonable. The Company will be measured by 1) its average residential price per kWh compared to the 26 jurisdiction mid-western utility peer group; and 2) the annual change in average residential price relative to the change for the lowest priced utility in the peer group. The Price measures will be calculated annually based on utility price data compiled in the Edison Electric Institute *Typical Bills and Average Rate Report* for the 12 month period ending December 31st. Each of the two Price measures will carry a potential reward and/or penalty of a 25 basis point adjustment to the authorized ROE deadband. It is appropriate the comparative Price standard be calculated using the Company’s total Residential revenue per kWh, including the Fuel Clause Adjustments (FCA) in effect during the Plan reporting year.

12. The proposed Employee Safety measure and standards are reasonable. The Commission agrees with Dr. McDermott that inclusion of an employee safety measure is appropriate. To be consistent with the other individual Plan standards, it is reasonable that the Employee Safety measure carry a potential reward and/or penalty of a 25 basis point adjustment to the authorized ROE deadband.

13. The proposed Plan Price Cap Factor, as modified by the Settlement Agreement, is reasonable. Pursuant to the Settlement Agreement, the Price Cap Factor will be determined by the lower of 1) the annual percentage change in the utility peer group’s average residential price per kWh for the reporting year, or 2) 60% of the change in the Consumer Price Index (CPI) for the reporting year. It is appropriate that the Price Cap Factor determine the highest annual percentage rate increase allowed under the Plan, or the amount of a required rate decrease.

14. The proposed Plan Rate Change Criteria, as modified by the Settlement Agreement, are reasonable. It is appropriate that the Plan impose an electric rate freeze on the Company whenever: 1) its previous year reported ROE exceeds the baseline ROE (as adjusted pursuant to the performance points), or 2) the Company’s average residential rates were higher than the utility peer group average residential rate. If neither condition exists, however, it is appropriate that the Company be allowed to change its electric rates by an overall percentage not to exceed the Price Cap Factor, subject to the Rate Change Procedure in the Plan.

15. The proposed Required Rate Decrease Criteria established by the Settlement Agreement are reasonable. It is appropriate that the Company reduce its retail electric rates pursuant to the PLUS Plan if: 1) the Company's reported ROE for the Plan reporting year exceeded the baseline ROE (as adjusted pursuant to the performance points), 2) the Company's average residential rates are higher than the PLUS utility peer group average residential rate, and 3) the Price Cap Factor is negative.

16. The proposed Rate Change Procedure described in the Settlement Agreement is reasonable and consistent with the N.D. Cent. Code. To implement any permissive rate change or mandatory rate reduction, it is appropriate that the Company file a notice of rate change and the accompanying tariffs pursuant to N.D.C.C. § 49-05-05 after submission of the Plan year performance report on May 1 but at least 30 days before the effective date of the proposed rates (July 1).

The Settlement Agreement contemplates such notice of rate change will not be suspended by the Commission under N.D.C.C. § 49-05-06, but the revised rates would be allowed to go into effect on the date proposed. Rates established consistent with the Plan are presumed just and reasonable, and non-discriminatory. However, the Plan appropriately retains the Commission's statutory authority to prospectively change the Company's rates after hearing, and also allows the Commission to order the Company to make a one-time billing "true up" if the Commission determines, after hearing, that the notice of rate change filed by the Company was not reflective of the Plan results or requirements.

17. Use of 36 months of historic demand data for purposes of annual Plan financial reporting is reasonable. The record demonstrates use of 36 months of demand data will mitigate volatility in this allocation factor. Moreover, the use of a 36 month demand allocator is only for financial reporting purposes under the Plan. It is also appropriate that use of a 36 month historic allocator for the Plan have no precedential effect in future electric rate increase applications after the Plan term expires or the Plan is suspended or terminated.

18. The Plan procedures for suspension or termination of the Plan during the five year term are reasonable because they provide protections for both North Dakota electric ratepayers and the Company. As provided by the Settlement Agreement, the Company may request, or the Commission may on its own motion initiate a proceeding, to suspend or terminate the Plan prior to December 31, 2005 in the event of:

- Federal and/or state tax law changes;
- Passage of retail access legislation at either the federal or state level;
- Merger and acquisition events affecting the Company's structure and operations;
- Natural disasters affecting the Company's North Dakota electric operations (major storms, floods, etc.);
- Unusual events affecting the Company's operations (major generating plant failure, damage to major transmission or distribution lines, etc.); or

- Material and sustained earnings extremes (defined as returns on equity +/- 5.0% from the ROE deadband, prior to sharing).

However, the Commission agrees it would be appropriate for the Commission, Staff and Company to make reasonable efforts to resolve any condition that could otherwise trigger a Company application or Commission motion to suspend or terminate the Plan before issuance of any Commission order to suspend or terminate the Plan during the Plan term.

From the foregoing Findings of Fact, the Commission makes its:

CONCLUSIONS OF LAW

1. The Commission has jurisdiction over this matter, and jurisdiction over the retail electric rates and services of the Company in the State of North Dakota, pursuant to, *inter alia*, N.D. Cent. Code Chap. 49-02 and 49-05.
2. For purposes of initial Plan implementation, the Company's restated electric rates effective January 1, 2001 are deemed just and reasonable and non-discriminatory, as described herein.
3. The Plan, as modified by the Settlement Agreement, meets the legal standards for ongoing regulation of the Company's electric rates and services during the Plan term under N.D. Cent. Code Chap. 49-02 and 49-05, and complies with the "Guidelines for Filing Alternative Regulation Proposals" issued in Case No. PU-439-94-590 (September 1995). Rates established consistent with the Plan procedures during the Plan term are appropriately presumed just and reasonable and non-discriminatory.
4. This order approving the Company's alternative regulation Plan shall constitute an "order applicable to special or peculiar circumstances or conditions" under N.D. Cent. Code § 49-05-05.

ORDER

The Commission orders:

1. The Company's PLUS Plan (as modified) and Settlement Agreement are approved in their entirety, without conditions or modifications. Northern States Power Company d/b/a Xcel Energy is authorized to implement the Plan, as modified, for its electric utility operations in the State of North Dakota for the term January 1, 2001 to December 31, 2005.

2. The Company shall submit all annual performance and financial reports required by the Plan (as modified) by May 1st of each Plan year. The Commission will determine at a later date whether to request interim reports during the Plan term.

3. Not more than annually, the Company may file a notice of rate change pursuant to N.D. Cent. Code 49-05-05 to change its rates, subject to all the requirements of the Plan, to be effective July 1 of such Plan year. Any such notice shall be filed at least 30 days prior to the effective date of the proposed rate change, and will not be suspended by the Commission. However, if the Commission determines after investigation and hearing that the changed rates do not comply with the Plan terms as prescribed by the Settlement Agreement and herein, the Commission may prospectively establish the rates it finds to be consistent with the Plan terms, and order a one-time billing true-up for the impact of the discrepancy since either the inception of the rate change or the previous 12 month period, whichever is less.

4. The Plan shall be subject to suspension or termination for good cause, as provided in the Settlement Agreement and described herein.

5. The Commission Staff is directed to prepare an interim report regarding the results of the Plan during 2001 and 2002. The interim report should be submitted no later than June 1, 2003. The Commission will, if it deems necessary, conduct an informal or other hearing regarding the Plan results no later than June 30, 2003, or such other date the Commission deems appropriate.

PUBLIC SERVICE COMMISSION

Susan E. Wefald
Commissioner

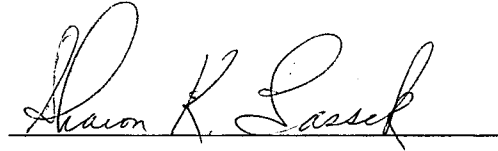
Bruce Hagen
President

Leo M. Reinbold
Commissioner

AFFIDAVIT OF SERVICE

I, Sharon K. Lassek, hereby certify that I have this day served the Proposed Findings of Fact, Conclusions of Law and Order on the parties listed below by placing in the U.S. mail at Minneapolis, Minnesota or by sending via Federal Express.

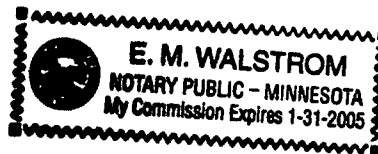
Dated this 1st day of December, 2000.



Subscribed and sworn to before
me this 1st day of December, 2000.



Notary Public



Jon Mielke
Executive Secretary
North Dakota Public Service Commission
600 East Boulevard
Bismarck, ND 58501

Honorable Allen Hoberg
Administrative Law Judge
Office of Administrative Hearings
1701 North 9th Street
Bismarck, ND 58501-1882

William Binek
North Dakota Public Service Commission
600 East Boulevard
Bismarck, ND 58501

Mike Diller
North Dakota Public Service Commission
600 East Boulevard
Bismarck, ND 58501

Todd Guerrero
Otter Tail Power Company
215 S. Cascade Street
Fergus Falls, MN 56538-0496

David Sederquist
Northern States Power Company
2302 Great Northern Drive
Fargo, ND 58102

STATE OF NORTH DAKOTA
PUBLIC SERVICE COMMISSION

**Otter Tail Power Company
Performance Based Regulation
Application**

Case No. PU-401-00-36

**Northern States Power Company
Performance Based Regulation
Application**

Case No. PU-400-00-195

AFFIDAVIT OF SERVICE

STATE OF NORTH DAKOTA
COUNTY OF BURLEIGH

Sandra L. Scott deposes and says that:

she is over the age of 18 years and not a party to this action and, on the **30th day of November, 2000**, she sent by regular mail:

1. **Settlement Agreement – Case No. PU-400-00-195**
2. **Settlement Agreement – Case No. PU-401-00-36**

To:

Dave Sederquist
Northern States Power Company
2302 Great Northern Dr
Fargo ND 58102

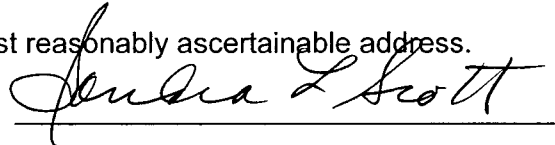
James P Johnson
Xcel Energy dba
Northern States Power Co.
800 Nicollet Mall Suite 2900
Minneapolis MN 55402

Bernadeen Brutlag
Otter Tail Power Company
215 S Cascade St
Fergus Falls MN 56538-0496

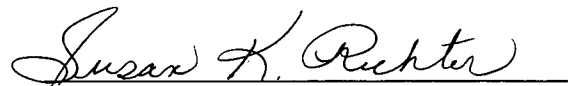
Todd Guerrero
Otter Tail Power Company
215 S Cascade St
Fergus Falls MN 56538-0496

Allen Hoberg
Office of Administrative Hearings
1701 North 9th Street
Bismarck ND 58501-1882

Each address shown is the respective addressee's last reasonably ascertainable address.



Subscribed and sworn to before me
this **30th day of November, 2000**.



Notary Public

SEAL

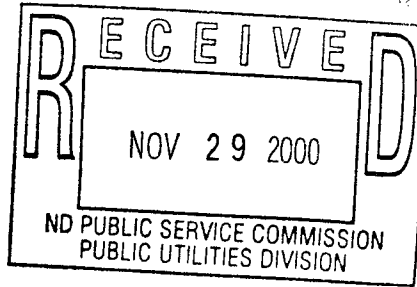


41 **PU-400-00-195**

Pages: 1

Affidavit of Service (serving Settlement
Agreement)
by Public Service Commission

11/30/2000 CC: Comm Legal Illona, Pat, Jerry Mike .



Legal Services

800 Nicollet Mall, Suite 2900
Minneapolis, Minnesota 55402

November 29, 2000

Mr. Jon Mielke
Executive Secretary
North Dakota Public Service Commission
600 East Boulevard
Bismarck, ND 58505

Honorable Allen Hoberg
Administrative Law Judge
Office of Administrative Hearings
1701 North 9th Street
Bismarck, ND 58501-1882

Re: Application of Northern States Power Company d/b/a Xcel Energy for
Authority to Operate Under Performance Based Regulation In North Dakota
Case No. PU-400-00-195

Dear Mr. Mielke and Judge Hoberg:

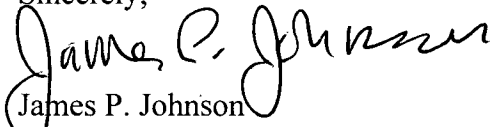
Enclosed please find an original and seven copies of the Settlement Agreement between Northern States Power Company d/b/a Xcel Energy and Commission Litigation Staff in the above-captioned docket. The Company and Staff respectfully request prompt approval of the Settlement Agreement.

Pursuant to the procedural rulings of Administrative Law Judge Hoberg at the conclusion of the evidentiary hearing, the Settlement Agreement is being submitted in lieu of briefs. The Settlement is being submitted before December 1, 2000, to allow the Commission to review the Settlement before the informal hearing scheduled for that date. The Company also intends to separately submit Proposed Findings of Fact, Conclusions of Law and Order no later than December 1, 2000.

The Company or Staff will serve two copies of this filing on the Office of Administrative Hearings for the hearing record and two courtesy copies on Otter Tail Power Company.

Please contact the undersigned (612-215-4592) or Dave Sederquist (701-241-8632) with any questions.

Sincerely,


James P. Johnson
Assistant General Counsel

cc: Mr. Dave Sederquist

Enclosures

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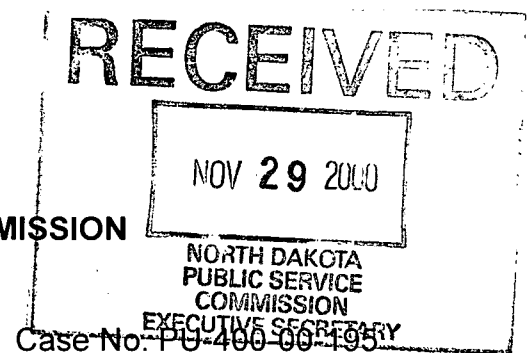
Pages: 1

Cover letter re filing of Settlement
Agreement
by Northern States Power Company

11/30/2000 CC: Comm Legal Illona, Pat, Jerry Mike

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

Northern States Power Company
Performance-Based Regulation Proposal



SETTLEMENT AGREEMENT

This Settlement Agreement is entered into this 29th day of November, 2000, by and between Northern States Power Company, a Minnesota corporation ("NSP" or "the Company") and the North Dakota Public Service Commission litigation staff ("Staff"). This Settlement Agreement resolves all outstanding issues in the above-captioned proceeding before the North Dakota Public Service Commission ("Commission") in a manner consistent with the public interest.

PRELIMINARY STATEMENT

1. Commission Alternative Regulation Guidelines, Case No. PU-439-94-590

On September 20, 1995, the Commission issued "Guidelines for Filing Alternative Regulation Proposals" ("Guidelines") in Case No. PU-439-94-590, after conducting both a workshop and public input sessions to discuss different forms of regulation for electric utilities. The Guidelines indicated the Commission would consider proposals for alternative forms of regulation from traditional "cost-based rate of return" regulation. The Guidelines set forth both goals and criteria for alternative regulation proposals.

2. Summary of Record

On April 20, 2000, NSP filed a “Proposal for a Performance-Based Regulation Plan” (“Petition”) asking the Commission to approve the Company’s proposed performance based regulation (“PBR”) plan, called the “PLUS” plan (“Plan”), for purposes of regulating NSP’s retail electric operations in North Dakota. The key components of PLUS include 1) a “dynamic allowed ROE” range which can vary based on Company performance, 2) a revenue sharing mechanism, 3) establishment of service performance standards, and 4) price capping and flexibility to adjust prices under specified circumstances. If approved, the Plan would create an alternative form of regulation for the Company’s electric operations in North Dakota, as contemplated by the Guidelines. In its Petition, the Company asserted:

- The PLUS Plan meets the stated goals and criteria identified by the Commission Guidelines.
- The PLUS Plan is an appropriate regulatory model because it provides benefits to customers and to North Dakota’s economy which extend beyond traditional cost-based regulation, while at the same time ensuring that the Company’s North Dakota electric rates are just and reasonable and the Company’s operations have the opportunity to maintain financial strength.
- The PLUS Plan will work better than traditional cost-based regulation to promote a balanced emphasis on utility efficiency, service quality, and economic development in North Dakota, while maintaining the customer protections provided by traditional regulation.

- The PLUS Plan provides North Dakota regulation with an automatic, pre-defined mechanism to pass the benefits of a financially healthy utility on to its stakeholders. Unlike traditional, cost-based regulation, which can be a slow and adversarial, the PLUS Plan offers an efficient, win/win approach to utility regulation. PLUS places the regulatory focus more on *results* and less on process.
- As restructuring of the electric industry occurs, performance based regulation will play a role in facilitating the transition to a more competitive environment. The PLUS regulatory model better simulates a competitive market by creating meaningful incentives which promote high quality service and low cost.
- Since PLUS offers the Company the potential to achieve above-average returns on its North Dakota electric business if the Company's performance meets the thresholds set forth in the plan, PLUS will also create an additional incentive for NSP to invest its limited capital resources in North Dakota (other things being equal).

On July 19, 2000, the Commission issued a "Notice of Hearing and Notice of Public Discussion Meeting" in the instant docket and Case No. PU-401-00-36, a docket involving a similar PBR plan filed by Otter Tail Power Company ("Otter Tail"). The Commission conducted a joint public hearing by video conference on September 6, 2000, with public participation available through ten video conference sites including three in the Company's electric service area (Fargo, Grand Forks, Minot). No members of the public submitted oral comments opposing approval of the Plan at the public hearing.

Pursuant to the procedural schedule established by presiding Administrative Law Judge Allen Hoberg of the Office of Administrative Hearings, NSP submitted pre-filed direct testimony in support of the PLUS Plan on September 29, 2000.

On October 13, 2000, the Staff submitted pre-filed direct testimony recommending certain modifications to PLUS Plan. On October 20, 2000, the Company submitted pre-filed rebuttal testimony responding to the Staff direct testimony.

On October 23 and 24, 2000, the Commission conducted a joint evidentiary hearing considering both NSP's PLUS Plan and Otter Tail's similar PBR plan in Case No. PU-401-00-36. Judge Hoberg presided over the hearing. The Petition and pre-filed testimony of both Companies and Staff were accepted into the record, and the witnesses were subject to cross examination and questions by the Commissioners.

At the conclusion of the evidentiary hearing, the Commission urged the parties to initiate discussions to resolve the areas of the Plans in which Staff and the Companies held differing views. The companies committed to a December 1 deadline for submitting to the Commission a settlement agreement.

3. This Settlement Agreement Serves the Public Interest

Both the Company and Staff submitted pre-filed and oral testimony generally supporting implementation of performance-based regulation for the Company's electric utility operations in North Dakota. The Company and Staff differed, however, on the appropriate Plan performance standards and reward/penalty criteria. The record (the testimony of Dr. Karl McDermott) supports use of broad and balanced performance standards and symmetrical reward/penalty criteria, but the Company and Staff agree

the record does not require approval of either the specific components of the Company Plan or the Staff recommendations without modification. In addition, Commissioner comments and questions at the evidentiary hearing supported consideration of possible alternative performance standards. Dr. McDermott recommended the final Plan performance standards and reward/penalty criteria reflect the policy objectives of the Commission.

Based on the record and information submitted by the parties in this case, informal settlement discussions were held between Staff, NSP, and Otter Tail representatives on November 2, 2000 in Jamestown, North Dakota. In addition, the parties conducted numerous telephone and electronic discussions.

On November 28, 2000, NSP and the Staff reached this Settlement Agreement which resolves the major issues discussed in the NSP Petition and testimony and Staff direct and oral testimony in this case.

This Settlement Agreement is supported by the administrative record in Case No. PU-400-00-195. Other documentation in support of the Settlement Agreement is contained herein or attached hereto. Accordingly, the Parties jointly recommend that the Commission approve this Settlement Agreement in its entirety.

The Parties agree NSP's PLUS PBR Plan, as modified by the conditions herein, is consistent with the public interest, and will result in just and reasonable rates. The Parties request the Commission issue an order approving this Settlement Agreement and modified PLUS Plan in its entirety, without conditions or modifications.

TERMS OF AGREEMENT

1. Revised PLUS Plan Terms

A. Implementation

As proposed by NSP and supported by Staff, the PLUS Plan will commence on January 1, 2001. Concurrently and independently, NSP will reduce non-fuel base retail electric rates to the Company's North Dakota electric service customers by \$261,000 annually (approximately 0.25%), pursuant to the Commission order dated May 10, 2000, in Case Nos. PU-400-99-418 (Merger with New Century Energies, Inc.) and PU-400-98-246 (Electric Rate Investigation). For purposes of initial Plan implementation, the Company's restated electric rates effective January 1, 2001 are deemed just and reasonable.

The PLUS Plan will remain in effect until December 31, 2005, unless it is renewed or extended further by order of the Commission, as provided herein.

B. Reporting/Review

Each year, on or before May 1, NSP will submit a comprehensive earnings and performance report for the previous calendar year fiscal period, as detailed in the Company's Petition.

The Commission will conduct an informal review hearing after May 1, 2003, but no later than June 30, 2003, to assess the Plan's results after two years.

2. ROE Deadband/Revenue Sharing

A. ROE

The baseline Return on Equity ("ROE") for purposes of the Plan will be 12.0%. An ROE deadband of +/- 1.0% will be initially established around the baseline.

During the Plan term, the ROE deadband shall be subject to the annual dynamic ROE adjustments in terms of "basis points" depending on the Company's performance under each Plan performance standard, as provided herein. If the net performance basis points are positive (award), the upper end of the ROE deadband increases. If the net performance points are negative (penalty), the lower end of the ROE deadband is decreased.

B. Revenue Sharing

If the Company's reported actual earnings fall within the ROE deadband around the authorized ROE (as adjusted by the performance points) in a given Plan year, no revenue sharing will take place. If the Company's actual reported earnings for any given Plan year exceed the deadband, the corresponding revenue 'sufficiency' will be calculated, and 50% of this dollar amount will be refunded to customers during the July billing cycle of the following year. Customers of record on March 31 following the Plan year will be issued refunds by bill credit prorated on the basis of their electric usage for the twelve months ending March 31.

The Petition proposed that 10 percent of any reported revenue sufficiency amount in any Plan year be used for economic development investments. The Staff indicated general support for economic development investments, but did not support this type of revenue sharing mechanism for this purpose. Pursuant to the Settlement,

all sharing will be 50/50 between Customers and the Company. However, the Company may record economic development expenses incurred in a Plan year as a jurisdictional expense for purposes of annual financial reporting.

If earnings are below the deadband, 50% of the corresponding revenue “deficiency” may be recovered through a surcharge on the Company’s electric rates effective no later than 24 months after the Plan year, as directed by the Financial Accounting Standards Board (“FASB”). However, NSP will defer a reported fiscal year deficiency amount as a regulatory asset until the following Plan year revenue sharing amount, if any, is reported. If the prior year deficiency is fully offset by a current year reported revenue sufficiency, the sufficiency will be used to eliminate the regulatory asset, and no rate surcharge will be imposed. If the deficiency from the prior year is not fully offset, any remaining deficiency balance will be billed through a rate surcharge applicable to bills issued between the 18th and 24th month following the Plan year when the deficiency occurred.

Exhibit 1 to this Settlement Agreement provides an examples of the Plan revenue sharing and dynamic ROE bandwidth mechanism as provided by this Settlement Agreement.

3. Revised Performance Standards

A. Reliability

The Petition proposed a service reliability standard measurement using the weather normalized “System Average Interruption Duration Index” (“SAIDI”) pursuant to the methodology established by the IEEE. Pursuant to this Settlement, two standards will be used in the PLUS Plan for purposes of measuring reliability: 1) customer

average interruption duration index (“CAIDI”), and 2) system average interruption frequency index (“SAIFI”).

CAIDI and SAIFI are individual reliability measures widely used in the electric utility industry, the product of which is the SAIDI result. By using both component standards, the Company will be measured on both the frequency of customer outages and the time it takes to restore power. Annual results for each measure will be weather-normalized to exclude storm day outages. Targets are based on achieving a SAIDI result of 80 minutes, which was developed using historical NSP outage results in North Dakota, and a consideration of Otter Tail Power Company’s Plan target. Each measure will carry a potential reward and/or penalty of a 25 basis point adjustment to the authorized ROE deadband.

The following table defines the revised performance standards for reliability (see Attachment 1):

Measure	Award Threshold	Target	Penalty Threshold
CAIDI	< 75.6 minutes	89.0 minutes	> 102.4 minutes
SAIFI	< 0.77 outages/yr.	0.90 outages/yr.	> 1.04 outages/yr.

Exhibit 2, Attachment 1, further describes the Plan reliability measures and standards as provided in this Settlement Agreement.

B. Customer Satisfaction

The Petition proposed a single customer satisfaction measure based on North Dakota customer responses to a single overall question contained in Company “relationship” surveys of all customer classes (Residential, Commercial and Large

Industrial), based on the percentage of respondents providing a “top three box” rating (‘excellent’, ‘very good’, or ‘good’). Staff recommended use of a “transaction” survey, and also proposed using a “top two box” (customers who rate the Company’s performance ‘excellent’ or ‘very good’) standard.

Pursuant to this Settlement, the PLUS Plan will use two survey standards for purposes of measuring customer satisfaction: 1) an average satisfaction score from the relationship surveys for all three customer classes (Residential, Commercial, Large Industrial), and 2) an average satisfaction score from two transaction surveys relating to the Company’s call center and electric service functions. The survey scores will reflect the percentage of respondents who give NSP an ‘excellent’ or ‘very good’ rating.

Targets are based on historical company-wide NSP survey results from the previous three years, and will be revised after two Plan years to reflect responses from North Dakota customers only. Each of the two survey standards will carry a potential reward and/or penalty of a 25 basis point adjustment to the authorized ROE deadband.

The following table defines the Plan performance standards for customer service for at least the first two plan years:

Measure	Award Threshold	Target	Penalty Threshold
Relationship positive response %	> 84.0%	81.0%	< 78.0%
Transaction positive response %	> 66.0%	63.0%	< 60.0%

Exhibit 2, Attachment 2, further describes the Plan customer satisfaction measures and standards as provided in this Settlement Agreement.

C. Price Standard

The Petition proposed a price standard comparing the Company's average Residential electric revenue per kWh for the Plan year to the average residential revenue/kWh for a comparison group of 26 mid-western utility jurisdictions. Staff proposed a price comparison measuring the change in the Company's residential electric revenue/kWh in the Plan year to the change for the ten lowest-priced utilities in the comparison group.

Pursuant to this Settlement, two price standards will be used in the PLUS Plan for purposes of measuring competitive price: 1) the Company's relative average residential price per kWh compared to the mid-western utility peer group; and 2) the annual change in average residential price relative to the change for the lowest priced utility in the peer group. The price targets are calculated annually based on utility price data compiled in an Edison Electric Institute publication entitled Typical Bills and Average Rate Report issued twice per year. For purposes of the PLUS Plan, the "winter" edition (reflecting the 12 month period ending December 31st) will be used. Each of the two price measures will carry a potential reward and/or penalty of a 25 basis point adjustment to the authorized ROE deadband.

The following table defines the revised Plan performance standards for price:

Measure	Award Threshold	Target	Penalty Threshold
Competitive res'l price position	< 85% of target	peer group avg. residential price/kWh	> 115% of target
Annual change in res'l avg. price	< (target-.05¢/kwh)	annual change in lowest priced utility	> (target+.05¢/kwh)

D. Employee Safety Standard

The Petition proposed an employee safety standard based on the Company's Occupational Safety and Health Administration ("OSHA") incident rate in the Plan year compared to historic performance of a number of regional utilities participating in a North Central Electric Association safety survey. The OSHA incident rate represents the number of safety-related incidents per 100 employees. The Petition proposed a reward and/or penalty of a 50 basis point adjustment to the baseline ROE.

Pursuant to this Settlement, the PLUS Plan will include an employee safety measurement based on the OSHA incident rate. The target is based primarily on historical results for Group 1 utilities (more than 7,000 employees) in the Edison Electric Institute survey, but also reflects consideration of what would provide an acceptable "stretch" for NSP's North Dakota operations. To be consistent with the other individual Plan standards, the measure will carry a potential reward and/or penalty of a 25 basis point adjustment to the authorized ROE deadband.

The following table defines the performance standards for employee safety (see Attachment 3):

Measure	Award Threshold	Target	Penalty Threshold
OSHA incident rate	< 3.70	4.32	> 5.00

Exhibit 2, Attachment 3, further describes the Plan employee safety measure and standards as provided in this Settlement Agreement.

4. Price Caps

A. Price Cap Factor

Pursuant to this Settlement, the PLUS Plan will calculate a Price Cap Factor by determining the lower of 1) the annual percentage change in the utility peer group's average residential price per kWh, and 2) 60% of the change in the Consumer Price Index (CPI) for the previous year (the CPI for the Plan year is computed by averaging the CPI at the end of each quarter). The Price Cap Factor will determine the highest annual percentage rate increase allowed under the Plan, or the amount of a required rate decrease.

B. Rate Change Criteria

Pursuant to this Settlement, the PLUS Plan imposes an electric rate freeze on the Company whenever (i) its previous fiscal year ROE exceeds the baseline ROE (as adjusted pursuant to the performance points), or (ii) the Company's average residential rates are higher than the utility peer group average residential rate. If neither condition exists, the Company may change rates by an overall percentage not to exceed the Price Cap Factor.

C. Required Rate Decrease Criteria

The Company shall reduce its retail electric rates pursuant to the PLUS Plan if (i) the Company's reported ROE for the Plan reporting year exceeded the baseline ROE (as adjusted pursuant to the performance points), (ii) the Company's average residential rates are higher than the PLUS utility peer group average residential rate, and (iii) the Price Cap Factor is negative.

D. Rate Change Procedure

To implement any permissive rate change pursuant to Section B or mandatory rate reduction pursuant to Section C, the Company shall file a notice of rate change and the accompanying tariffs pursuant to N.D.C.C. 49-05-05 not later than June 1, following completion of the Plan year and submission of the Plan performance report on May 1. The revised rates shall be effective on or after July 1 following the Plan year.

Such rate change will not be suspended by the Commission under N.D.C.C. 49-05-06, but the revised rates shall be allowed to go into effect on the date proposed. If the Commission determines after investigation and hearing that the changed rates do not comply with the Plan terms as prescribed herein, the Commission may prospectively establish the rates it finds to be consistent with the Plan terms, and order a one-time billing true-up for the impact of the discrepancy since either the inception of the rate change or the previous 12 month period, whichever is less. Rates established consistent with the Plan are presumed just and reasonable, and non-discriminatory.

5. Other Terms and Conditions

A. Fuel Clause Adjustment

This Settlement does not change the Company's existing fuel clause adjustment (FCA) mechanism in its North Dakota Electric Rate Book tariff schedules. The comparative price standard provided above shall be calculated using total Residential revenue per kWh including the FCA adjustments in effect during the Plan reporting year.

B. Demand Allocator Factor

For purposes of calculating the Company's jurisdictional expenses for the PLUS Plan reporting year, 36 months of historical demand data will be used to establish the

Demand Allocation factor (known as D10). The Demand Allocation factor is used to assign production and transmission related costs and investment to NSP's retail electric jurisdictions in North Dakota, South Dakota and Minnesota. The Petition demonstrated use of 36 months of demand data will mitigate volatility in this allocation factor. The use of a 36 month demand allocator is only for financial reporting purposes under the Plan. Use of a 36 month historic allocator for the Plan shall have no precedential effect in future electric rate increase applications after the Plan term expires or the Plan is suspended or terminated

C. Suspension of Plan

The PLUS Plan will remain in effect during the five year Plan Term unless the Company's earnings results or other events specified below enable either the Commission or the Company to formally request a suspension or termination of the Plan:

- Federal and/or state tax law changes;
- Passage of retail access legislation at either the federal or state level;
- Merger and acquisition events affecting the Company's structure and operations;
- Natural disasters affecting the Company's North Dakota electric operations (major storms, floods, etc.);
- Unusual events affecting the Company's operations (major generating plant failure, damage to major transmission or distribution lines, etc.); or
- Material and sustained earnings extremes (defined as returns on equity +/- 5.0% from the ROE deadband, prior to sharing).

It is anticipated the Commission and Company will make reasonable efforts to resolve any condition that could otherwise trigger a Company application or Commission motion to suspend the Plan before any decision to terminate operation of the Plan during the Plan term.

D. Applicability and Scope

Each of the provisions of this Settlement Agreement is in consideration for each and every other provision. If this Settlement Agreement is not accepted by the Commission in its entirety and without modification, at the option of NSP this Settlement Agreement shall be null and void.

This Settlement Agreement shall be binding on the parties hereto, and upon their successors, assigns, agents and representatives.

E. Effective Date

This Settlement Agreement shall be effective on the date of the final Commission order approving the Settlement Agreement. However, this Settlement Agreement shall be deemed terminated if NSP files a letter with the Commission prior to December 22, 2000 stating NSP no longer seeks to proceed with implementation of the PLUS plan.

F. Effect of Settlement Negotiations

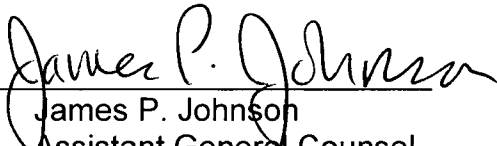
It is understood and agreed that all offers of settlement and discussions related thereto are privileged and may not be used in any manner in connection with proceedings in this case or otherwise, except as provided by law. In the event the Commission does not approve this Settlement Agreement, the Settlement Agreement shall not constitute part of the record in this proceeding and no part thereof may be used for any purpose in this proceeding or otherwise. This Settlement Agreement shall

not in any respect constitute a determination by the parties hereto as to the merits of any specific allegations or contentions made by the parties in Case No. PU-400-00-195.

G. Counterparts

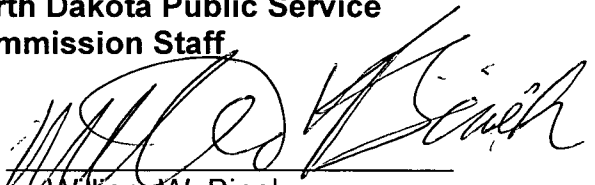
This Settlement Agreement may be executed in separate, identical counterparts.

Northern States Power Company

By: 
James P. Johnson
Assistant General Counsel
Xcel Energy Services Inc., Agent for
Northern States Power Company

Date: November 29, 2000

**North Dakota Public Service
Commission Staff**

By: 
William W. Binek
Chief Counsel
ND Public Service Commission

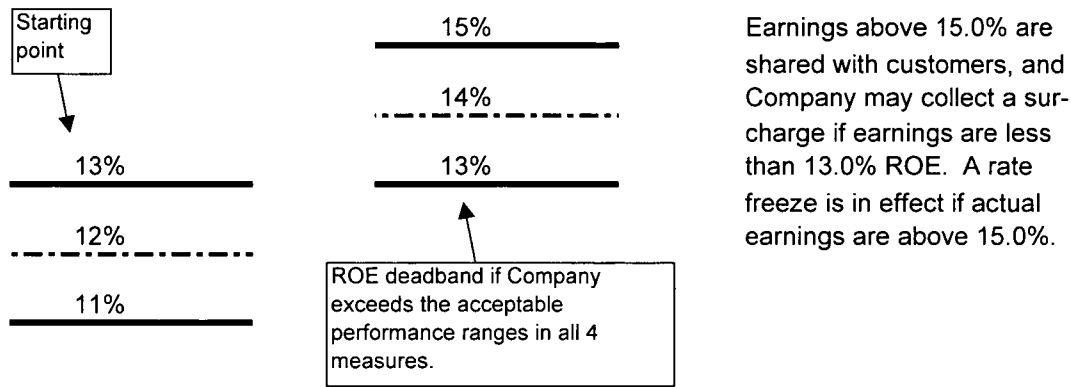
Dated: November 30, 2000

Exhibit 1

Example from Original PBR Proposal

4 performance measures, each worth 50 basis points.

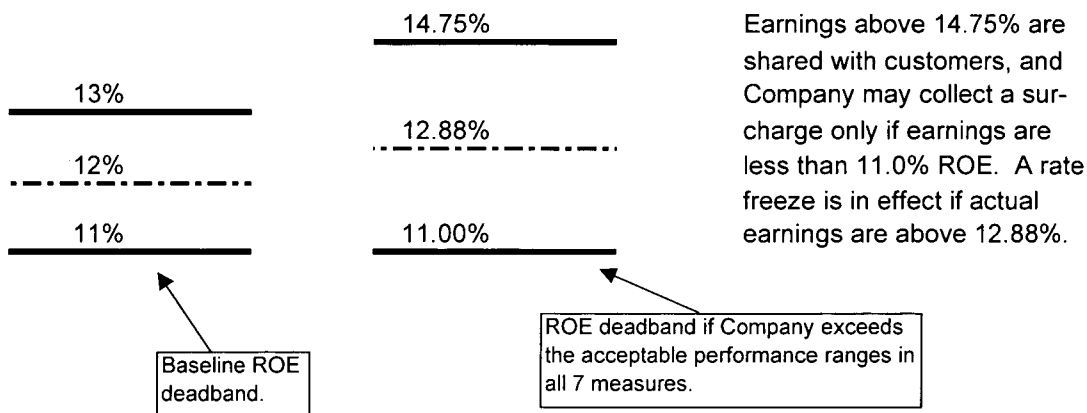
Based on the net result of performance points, the entire ROE deadband moves up or down.



Example using Settlement Proposal

7 performance measures, each worth 25 basis points

If net result of performance points is positive, only the *upper* limit of the ROE deadband increases.



If net result of performance points is negative, only the *lower* limit of the ROE 'deadband' is reduced.

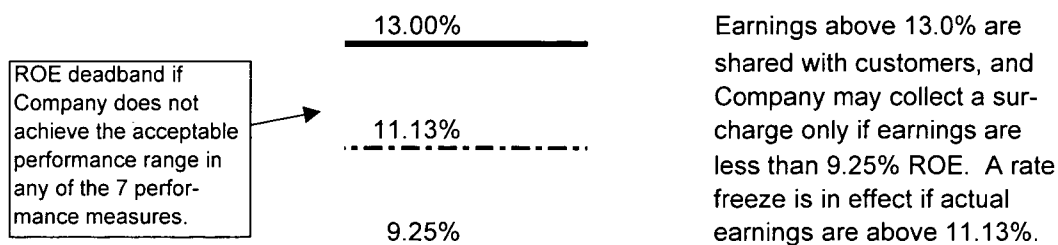


Exhibit 2

Northern States Power Company
"PLUS" Plan Performance Section
Reliability Standards (REVISED **)**

Macro Measures:

Outage Restoration Time (CAIDI)

This is the amount of time that a typical customer experiencing a sustained outage was out of power.

Restoration time = # of customer-minutes interrupted / number of customers interrupted

"CAIDI" stands for "Customer Average Interruption Duration Index"

Outage Frequency (SAIFI)

This is the average number of sustained outages that a typical customer experienced during the year.

Outage frequency = # of customer interruptions / number of customers served

"SAIFI" stands for "System Average Interruption Frequency Index"

Benchmark reliability standards will be developed using NSP(MN Co.) and NSP-ND average annual results for the five year period (1995-1999). While CAIDI and SAIFI are industry standard reliability measures, there are variations among utilities as to what constitutes an outage, how long an outage must last to be counted, and the process of normalizing outage data for weather. In addition, outage information is not readily accessible nor openly shared across the industry. Ranges of acceptable performance will be constructed by determining boundaries which are +/- 15% of the benchmark. Outages included are those lasting more than 5 minutes.

NSP (MN Co.) Results

Storm-Normalized			
	SAIFI	CAIDI	SAIDI
	(Outages)	(Minutes)	(Minutes)
1995	1.0000	100.8	100.8
1996	0.9700	115.8	112.3
1997	0.8800	115.2	101.4
1998	0.8600	121.8	104.7
1999	1.0300	112.2	115.6
Average	0.9480	113.2	107.3
Adj. Ave.*	0.9500	114.4	108.7
Median	0.9700	115.2	111.7
Ave. of Co. & ND Standards			
Penalty >	1.04	105.3	97.0
Target	0.90	91.6	84.0
Award <	0.77	77.9	71.0

NSP-North Dakota Results

Storm-Normalized			
	SAIFI	CAIDI	SAIDI
	(Outages)	(Minutes)	(Minutes)
1995	0.7300	63.6	46.4
1996	0.8200	60.6	49.7
1997	0.9800	75.6	74.1
1998	0.7500	73.2	54.9
1999	1.0600	69.6	73.8
Average	0.8680	68.5	59.5
Adj. Ave.*	0.8500	68.8	58.5
Median	0.8200	69.6	57.1
Stipulated Targets			
Penalty >	1.04	102.4	92.0
Target	0.90	89.0	80.0
Award <	0.77	75.7	68.0

* Has both extreme upper and lower years removed.

The proposed standards are consistent
with Otter Tail Power's SAIDI standard.

Note: CAIDI X SAIFI = SAIDI

Northern States Power Company
"PLUS" Plan Performance Section
Customer Satisfaction Standards (REVISED **)**

Macro Measures: "Excellent", "Very Good", or "Good" Response %

Relationship Survey Response %

This is the average % of North Dakota customers randomly surveyed who responded very favorably (either of the top two answers) to the survey question: "I'd like you to think of your overall relationship with Xcel Energy. Considering everything, would you say the overall quality of products, services, and support you receive from Xcel Energy is excellent, very good, good, fair, or poor?" Relationship survey scores will be the average of the residential, small commercial, and large commercial and industrial surveys.

Transaction Survey Response %

Transaction surveys focus on North Dakota customers who have recently made a call to Xcel Energy's customer Care Center regarding a billing issue or start/stop service request, or had contact with Company crews responding to an outage call. The overall question is, "Thinking of this entire interaction with Xcel Energy, from the time you first contacted Xcel Energy until your issue was resolved, how would you rate the quality of service provided by Xcel Energy?" The Transaction survey score will be the average top two response % for both surveys.

The Performance Standard

A benchmark customer satisfaction survey standard will be developed through consideration of the previous three years of results on an NSP Company-wide basis. The target will be further developed by including North Dakota only scores in the historical average beginning in year three of the plan term.

Relationship Results

Transaction Results

	<u>Res'l</u>	<u>Small C&I</u>	<u>Large C&I</u>	<u>Average</u>		<u>Customer Care</u>	<u>Electric Service</u>	<u>Average</u>
1998	81.0%	70.0%	86.0%	79.0%	1998	62.0%	57.0%	60.0%
1999	77.0%	77.0%	88.0%	81.0%	1999	72.0%	53.0%	63.0%
1999	80.0%	79.0%	94.0%	84.0%	1999	72.0%	58.0%	65.0%

Penalty <	78.0%
Target	81.0%
Award >	84.0%

Penalty <	60.0%
Target	63.0%
Award >	66.0%

Northern States Power Company
"PLUS" Plan Performance Section
Employee Safety Standard (REVISED **)**

Macro Measure:

OSHA Incident Rate

This is the average number of OSHA incidences occurring per 100 electric employees.

OSHA incidences include medical treatment cases, restricted work day injuries, lost workday injuries, and fatalities. Only NSP-ND results will be counted.

$$\text{OSHA} = \# \text{ of incidences} \times 200,000 \text{ hours} / \text{number of labor hours worked}$$

The Performance Standard

The OSHA rate target was developed using the average annual OSHA results for all of the utilities participating in the 1997 EEI safety survey, and includes a consideration of NSP's North Dakota OSHA results from 1995-1999. This revised target is more stringent than that derived from NCEA historical results and proposed by NSP in its PLUS Plan application.

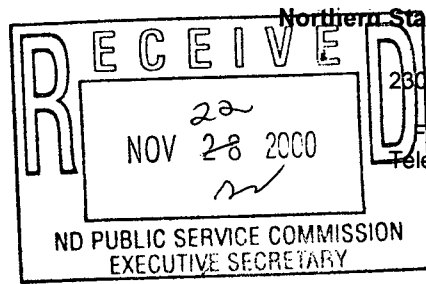
EEI OSHA Results

	OSHA Index
1994	4.83
1995	4.45
1996	4.20
1997	3.79
Average	4.32
Adj. Ave. ¹	4.33
Median	4.33

Penalty >	5.00
Target	4.32
Award <	3.70

¹ Excludes years with maximum and minimum results.

² Reflects an average of each of the simple average, adj. Average, and median.



Northern States Power Company

2302 Great Northern Drive
P O Box 2747
Fargo, ND 58108-2747
Telephone (701) 241-8632

November 22, 2000

Jon Mielke, Executive Secretary
North Dakota Public Service Commission
State Capitol Building, Dept. 408
600 East Boulevard
Bismarck, ND 58505

Judge Allen Hoberg
Administrative Law Judge
Office of Administrative Hearings
1701 North 9th Street
Bismarck, ND 58501-1882

Re: Northern States Power Company d/b/a Xcel Energy
Application to Operate Under Performance-Based Regulation in North Dakota
Case No. PU-400-00-195

Dear Mr. Mielke and Judge Hoberg:

Enclosed please find three additional pages that were inadvertently excluded from the late filed exhibits submitted by the Company in a mailing sent on November 15, 2000.

The additional pages show the average revenue per kWh by customer class for residential, commercial, and industrial customers.

The Company will serve an original and seven (7) copies of this information on the Commission and two copies on the Office of Administrative Hearings for the hearing record. The Company will also provide two courtesy copies to Otter Tail Power Company.

I apologize for any confusion this may have caused. Please contact me if you have any questions about the attached information. Thank you.

Sincerely,

David H. Sederquist
Manager, Regulatory Affairs
NSP-North Dakota

cc: Jim Johnson

38 PU-400-00-195

Pages: 4

Additional pages from the late filed
exhibits
by Northern States Power Company

11/22/2000 CC: Comm Legal Illona, Pat, Jerry Mike

Utility Comparison Group

Average Residential Revenue/Kwh

IOU's in North Dakota, South Dakota, Montana, Wyoming, Minnesota, Iowa, Wisconsin

1999 Rank	Utility	Jurisdiction	1999 ¢/kwh	1998 ¢/kwh	% Change
1	Pacificorp	Wyom	5.74	5.73	0.2%
2	<i>Otter Tail Power Co.</i>	<i>ND</i>	<i>6.03</i>	<i>6.09</i>	<i>-1.0%</i>
3	<i>NSP</i>	<i>ND</i>	<i>6.11</i>	<i>6.07</i>	<i>0.7%</i>
4	Cheyenne Light, Fuel, & Power	Wyom	6.20	5.66	9.5%
5	Otter Tail Power Co.	SD	6.25	6.30	-0.8%
6	Otter Tail Power Co.	MN	6.48	6.56	-1.2%
7	Wisc. Public Service	Wisc.	6.68	6.28	6.4%
8	Minnesota Power	MN	6.71	6.77	-0.9%
9	Wisconsin Power & Light (Alliant)	Wisc.	6.87	6.72	2.2%
10	Black Hills Power & Light	Mont	7.09	7.22	-1.8%
11	Montana-Dakota Utilities	ND	7.21	6.90	4.5%
12	NSP	Wisc.	7.33	7.10	3.2%
13	Montana-Dakota Utilities	Wyom	7.40	7.29	1.5%
14	Montana-Dakota Utilities	Mont	7.43	7.41	0.3%
15	NW Wisconsin Electric	Wisc.	7.59	7.62	-0.4%
16	Northwest Public Service	SD	7.79	7.45	4.6%
17	Black Hills Power & Light	Wyom	7.80	7.84	-0.5%
18	Wisconsin Energy Co.	Wisc.	7.81	7.79	0.3%
19	NSP	SD	7.85	7.66	2.5%
20	Interstate Power Co.	Iowa	7.86	8.55	-8.1%
21	NSP	MN	8.02	7.89	1.6%
22	Black Hills Power & Light	SD	8.29	8.28	0.1%
23	Interstate Power Co.(Alliant)	MN	8.30	8.62	-3.7%
24	Madison Gas & Elec	Wisc.	8.41	7.81	7.7%
25	IES Utilities (Alliant)	Iowa	8.57	8.73	-1.8%
26	Montana-Dakota Utilities	SD	9.17	8.96	2.3%
29	Average residential rate (¢/kwh):		7.35	7.28	0.89%

Source: Typical Residential, Commercial, and Industrial Bills, Edison Electric Institute.

Winter, 2000

Note: Montana Power (Montana) and MidAmerican Energy (Iowa) were dropped from the group in 1999 due to unavailable data.

Utility Comparison Group Average Commercial Revenue/Kwh

IOU's in North Dakota, South Dakota, Montana, Wyoming, Minnesota, Iowa, Wisconsin

1999			1999	1998	%
Rank	Utility	Jurisdiction	¢/kwh	¢/kwh	Change
1	Pacificorp	Wyom	4.75	4.81	-1.2%
2	Wisc. Public Service	Wisc.	4.81	4.69	2.6%
3	Cheyenne Light, Fuel, & Power	Wyom	4.83	4.83	0.0%
4	Montana-Dakota Utilities	Mont	5.39	5.66	-4.8%
5	Montana-Dakota Utilities	Wyom	5.52	5.48	0.7%
6	Madison Gas & Elec	Wisc.	5.82	5.56	4.7%
7	Minnesota Power	MN	5.88	5.97	-1.5%
8	IES Utilities (Alliant)	Iowa	5.92	7.41	-20.1%
9	Wisconsin Power & Light (Alliant)	Wisc.	5.96	5.80	2.8%
10	NSP	ND	6.03	5.91	2.0%
11	Northwest Public Service	SD	6.25	5.99	0.7%
12	Wisconsin Energy Co.	Wisc.	6.34	6.39	-0.8%
13	Montana-Dakota Utilities	ND	6.35	6.46	-1.7%
14	NSP	Wisc.	6.41	6.27	2.2%
15	NSP	SD	6.44	6.28	2.5%
16	Otter Tail Power Co.	SD	6.53	6.56	-0.5%
17	Otter Tail Power Co.	ND	6.56	6.70	-2.1%
18	NSP	MN	6.74	6.60	2.1%
19	Otter Tail Power Co.	MN	6.76	6.86	-1.5%
20	Interstate Power Co.(Alliant)	MN	6.80	7.09	-4.1%
21	Black Hills Power & Light	SD	7.51	7.54	-0.4%
22	Montana-Dakota Utilities	SD	7.62	7.65	-0.4%
23	Black Hills Power & Light	Wyom	7.63	7.60	0.4%
24	Interstate Power Co.	Iowa	8.15	8.44	-3.4%
25	NW Wisconsin Electric	Wisc.	8.28	8.27	0.1%
26	Black Hills Power & Light	Mont	8.90	8.92	-0.2%
29	Average commercial rate (¢/kwh):		6.47	6.53	-0.92%

Source: Typical Residential, Commercial, and Industrial Bills, Edison Electric Institute.

Winter, 2000

Note: Cheyenne P&L data for 1998 not available; 1999 rate used for 1998.

Utility Comparison Group

Average Industrial Revenue/Kwh

IOU's in North Dakota, South Dakota, Montana, Wyoming, Minnesota, Iowa, Wisconsin

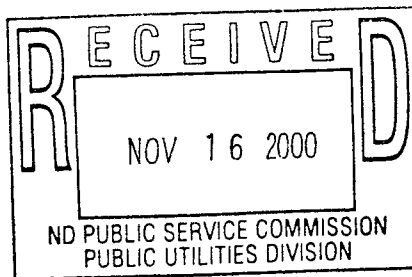
<u>1999</u> <u>Rank</u>	<u>Utility</u>	<u>Jurisdiction</u>	<u>1999</u> <u>¢/kwh</u>	<u>1998</u> <u>¢/kwh</u>	<u>%</u> <u>Change</u>
1	Pacificorp	Wyom	3.06	3.13	-2.2%
2	Wisc. Public Service	Wisc.	3.14	3.01	4.3%
3	Interstate Power Co.	Iowa	3.52	3.84	-8.3%
4	Minnesota Power	MN	3.57	3.61	-1.1%
5	Cheyenne Light, Fuel, & Power	Wyom	3.58	3.58	0.0%
6	Wisconsin Power & Light (Alliant)	Wisc.	3.72	3.62	2.8%
7	Madison Gas & Elec	Wisc.	3.87	3.76	2.9%
8	IES Utilities (Alliant)	Iowa	3.87	3.98	-2.8%
9	Wisconsin Energy Co.	Wisc.	4.25	4.27	-0.5%
10	Otter Tail Power Co.	MN	4.35	4.24	2.6%
11	Montana-Dakota Utilities	Mont	4.37	4.39	-0.5%
12	Otter Tail Power Co.	SD	4.40	4.70	-6.4%
13	NSP	ND	4.49	4.32	3.9%
14	Otter Tail Power Co.	ND	4.52	4.70	-3.8%
15	Black Hills Power & Light	Mont	4.59	4.96	-7.5%
16	NSP	Wisc.	4.61	4.47	3.1%
17	Black Hills Power & Light	SD	4.70	4.74	-0.8%
18	NSP	SD	4.81	4.64	3.7%
19	Interstate Power Co.(Alliant)	MN	4.96	5.27	-5.9%
20	NSP	MN	4.98	4.80	3.8%
21	Montana-Dakota Utilities	ND	5.09	5.09	0.0%
22	Black Hills Power & Light	Wyom	5.33	5.48	-2.7%
23	NW Wisconsin Electric	Wisc.	5.70	5.67	0.5%
24	Montana-Dakota Utilities	Wyom	6.07	5.39	12.6%
25	Montana-Dakota Utilities	SD	6.69	5.80	15.3%
26	Northwest Public Service	SD	na	na	#VALUE!

29	Average industrial rate (¢/kwh):	4.49	4.46	0.70%

Source: Typical Residential, Commercial, and Industrial Bills, Edison Electric Institute.

Winter, 2000

Note: MDU (ND juris.) rate for 1999 not available in EEI publication; 1998 rate used for 1999. NWPS (SD) data not in report either.



Legal Services

800 Nicollet Mall, Suite 2900
Minneapolis, Minnesota 55402

November 15, 2000

Mr. Jon Mielke
Executive Secretary
North Dakota Public Service Commission
600 East Boulevard
Bismarck, ND 58505

Honorable Allen Hoberg
Administrative Law Judge
Office of Administrative Hearings
1701 North 9th Street
Bismarck, ND 58501-1882

Re: Application of Northern States Power Company d/b/a Xcel Energy for
Authority to Operate Under Performance Based Regulation In North Dakota
Case No. PU-400-00-195

Dear Mr. Mielke and Judge Hoberg:

Enclosed please find the late-filed exhibits of Northern States Power Company d/b/a Xcel Energy following the evidentiary hearing in the above-captioned docket. They are:

NSP Exhibit 6A: Outage Weather Normalization/Standard Deviation
Witness: Pamela Bagley

NSP Exhibit 9: Average Revenue/kWH (all customer classes)
Witness: David Sederquist

The Company will serve an original and seven (7) copies of the late-filed exhibits on the Commission and two copies on the Office of Administrative Hearings for the hearing record. The Company will also provide two courtesy copies to Otter Tail Power Company.

The Company appreciates the opportunity to submit this information. If the Commission requires any further information, or has any questions regarding the late filed exhibits, please contact the undersigned (612-215-4592) or Dave Sederquist (701-241-8632).

Sincerely,


James P. Johnson
Assistant General Counsel

cc: Mr. Dave Sederquist
Ms. Pamela Bagley

Enclosures

37 PU-400-00-195

Pages: 1

Cover letter re late filed exhibits

by Northern States Power Company by James P Johnson
11/16/2000 CC: Comm Legal Illona, Pat, Jerry Mike

Xcel Energy Storm Normalization Method

Northern States Power Company d/b/a Xcel Energy ("Xcel") uses the outage data from the previous 3 years in determining the thresholds for storm normalization for each of our regions. The number of outages, both momentary and sustained, experienced each day in each of the regions is recorded. The average number of outages per day and the associated standard deviation¹ of the recorded outages per day is then calculated for each of the regions. This information is used in a formula which calculates the threshold number of outages. Any day that has the same or more outages than this threshold is considered a "storm day" for that region, and is excluded from the normalized SAIDI calculation.

The specific threshold formula is as follows:

A "storm day" is any day that experiences the average number of outages + 3 standard deviations.

Example of North Dakota Region (based on 1997, 1998, & 1999 data)

- Average number of outages per day for the region = 4
- Standard deviation of outages per day for the region = 8
- Storm day threshold = $4 + (3 \times 8) = 28$ outages

Storm days identified for North Dakota in previous 12 months (ending Sept 2000)

- 11/1/1999.....(45 outages)
- 6/19/2000.....(41 Outages)
- 6/20/2000.....(50 Outages)

For example, if the PLUS PBR plan had been in place for the 12 month period ending September 30, 2000, all outages in North Dakota with a duration of more than 5 minutes (the IEEE standard) would have been included in determining whether Xcel met the SAIDI performance standard, except the outages on November 1, 1999 and June 19 and 20, 2000.

¹ Standard Deviation is a primary indicator of the extent to which observations deviate from the mean (average). It is calculated by subtracting the mean of a set of numbers from each observation in the set, squaring each difference, adding up the sum of the squares, dividing this total by the number of observations, then taking the square root of this number. The calculation is easily done by a computer, given the raw data.

Utility Comparison Group

Average Revenue/Kwh (All Customers)

IOU's in North Dakota, South Dakota, Montana, Wyoming, Minnesota, Iowa, Wisconsin

1999 Rank	Utility	Jurisdiction	1999 ¢/kwh	1998 ¢/kwh	% Change
1	Pacificorp	Wyom	3.66	3.71	-1.3%
2	Minnesota Power	MN	4.21	4.20	0.2%
3	Interstate Power Co.	Iowa	4.62	5.13	-9.9%
4	Wisc. Public Service	Wisc.	4.70	4.47	5.1%
5	Cheyenne Light, Fuel, & Power	Wyom	4.71	4.71	0.0%
6	Black Hills Power & Light	Mont	4.78	5.14	-7.0%
7	Wisconsin Power & Light (Alliant)	Wisc.	5.20	5.06	2.8%
8	Otter Tail Power Co.	MN	5.32	5.17	2.9%
9	NSP	ND	5.43	5.31	2.3%
10	Otter Tail Power Co.	ND	5.49	5.59	-1.8%
11	Otter Tail Power Co.	SD	5.57	5.67	-1.8%
12	IES Utilities (Alliant)	Iowa	5.68	5.86	-3.1%
13	Montana-Dakota Utilities	Mont	5.70	5.79	-1.6%
14	Madison Gas & Elec	Wisc.	5.79	5.75	0.7%
15	NSP	Wisc.	5.83	5.66	3.0%
16	Black Hills Power & Light	Wyom	5.99	6.08	-1.5%
17	Wisconsin Energy Co.	Wisc.	6.04	6.06	-0.3%
18	NSP	MN	6.11	5.93	3.0%
19	NSP	SD	6.14	5.98	2.7%
20	Montana-Dakota Utilities	Wyom	6.38	6.32	0.9%
21	Interstate Power Co.(Alliant)	MN	6.60	6.82	-3.2%
22	Montana-Dakota Utilities	ND	6.62	6.45	2.6%
23	Northwest Public Service	SD	6.88	6.53	5.4%
24	Black Hills Power & Light	SD	6.88	6.89	-0.1%
25	NW Wisconsin Electric	Wisc.	7.08	7.09	-0.1%
26	Montana-Dakota Utilities	SD	8.30	8.10	2.5%

29	Average rate (¢/kwh):	5.76	5.75	0.16%

Source: Typical Residential, Commercial, and Industrial Bills, Edison Electric Institute.

Winter, 2000

Note: Cheyenne P&L data for 1998 not available; 1999 rate used for 1998.

AFFIDAVIT OF SERVICE

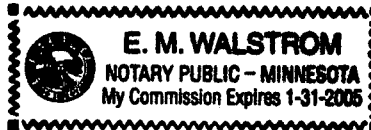
I, Sharon K. Lassek, hereby certify that I have this day served the late filed NSP Exhibit 6A and Exhibit 9 on the parties listed below by sending by Federal Express or by placing in the U.S. mail at Minneapolis, Minnesota.

Dated this 15th day of November, 2000.



Subscribed and sworn to before
me this 15th day of November, 2000.

E. M. Walstrom
Notary Public



Jon Mielke
Executive Secretary
North Dakota Public Service Commission
600 East Boulevard
Bismarck, ND 58501

Honorable Allen Hoberg
Administrative Law Judge
Office of Administrative Hearings
1701 North 9th Street
Bismarck, ND 58501-1882

William Binek
North Dakota Public Service Commission
600 East Boulevard
Bismarck, ND 58501

Mike Diller
North Dakota Public Service Commission
600 East Boulevard
Bismarck, ND 58501

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Otter Tail Power Company
215 S. Cascade Street
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James P. Johnson
Xcel Energy d/b/a/
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Minneapolis, MN 55402

Dave Sederquist
Northern States Power Company
2302 Great Northern Drive
Fargo, ND 58102

Pamela Bagley
Northern States Power Company
414 Nicollet Mall - 6th Floor
Minneapolis, MN 55401



OFFICE OF ADMINISTRATIVE HEARINGS

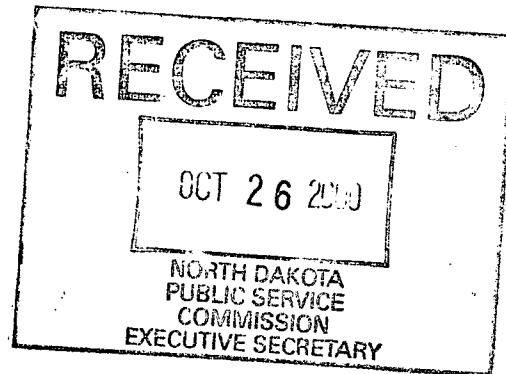
STATE OF NORTH DAKOTA
1707 North 9th Street
Bismarck, North Dakota 58501-1882

Allen C. Hoberg
Director

701-328-3260
FAX 701-328-3254

October 25, 2000

Mr. William W. Binek
Hearing Administrator
Public Service Commission
600 East Boulevard Avenue, Dept. 408
Bismarck, ND 58505-0480



Dear Mr. Binek:

On July 24, 2000, you requested the designation of an administrative law judge from the Office of Administrative Hearings to conduct a hearing in the matters of Otter Tail Power and Northern States Power (Performance Based Regulation Cases). I was designated as a procedural administrative law judge to conduct the combined hearing for these two matters, but not to make recommended findings of fact and conclusions of law, or issue recommended orders. The combined hearing on these two matters was held on October 23-24, 2000, and the hearing was closed. I understand that the agency will issue the appropriate orders, if necessary.

I am closing our files on these matters and returning that portion of the record from these matters and the hearing that I have in my possession to you for filing with the official agency record of these matters, as appropriate. Many of the documents are duplicates. I left the hearing tapes and the exhibits (except the late filed exhibits, to be filed by OTP and NSP) with Sandy, after the hearing. I am also enclosing an exhibit list, listing all of the exhibits from the hearing. If you have any questions about the record or the exhibit list, please contact me

Thank you for your attention to these matters.

Sincerely,

Allen C. Hoberg
Administrative Law Judge

ACH:klp
Enc.

32 PU-401-00-36

Pages: 1

Letter closing ALJ file

by Office of Administrative Hearings
10/26/2000 CC: Comm Legal Illona, Pat, Jerry Mike

33 PU-400-00-195

Pages: 1

Letter closing ALJ file

by Office of Administrative Hearings
10/26/2000 CC: Comm Legal Illona, Pat, Jerry Mike

RECEIVED

EXHIBIT LIST

OCT 26 2000

Matter Otter Tail Power and Northern States Power (Excel) - Combined Hearing
Case Nos. PU-401-00-36 and PU-400-00-195 - Public Service Commission

SOUTH DAKOTA
PUBLIC SERVICE
COMMISSION
EXECUTIVE SECRETARY

Hearing October 23-24, 2000

No.	Description	Mkd	Idd	Ofd	W/D	Adm	Note
1	Direct - Karl McDermott	Blue		X		X	Joint sponsor - OTP & NSP
2	Rebuttal - Karl McDermott	Blue		X		X	Joint sponsor - OTP & NSP
3	Direct - David Sederquist	Blue		X		X	NSP
4	Rebuttal - David Sederquist	Blue		X		X	NSP
5	NSP Cust. Satis. Stds. - correction to Application	Blue		X		X	NSP
6	Direct - Pamela Bagley	Blue		X		X	NSP
6A	Attachment to Bagley - data re SADIE - example	Blue		X		X	Late filed - NSP - Requested by Commission
7	Direct - Heather Schander	Blue		X		X	NSP
8	Correction exhibit 7, p.6, lines 3-5	Blue		X		X	NSP
1	Direct - Bernadeen Brutlag	Yellow		X		X	OTP
5	Rebuttal - Bernadeen Brutlag	Yellow		X		X	OTP
BCB-2	Attachment to BCB direct - similar to BCB-1 (but Com/Ind info)	Yellow		X		X	Late Filed - OTP - Requested by Commission
9	Document similar to BCB-1 for NSP (but Com/Ind info)	Blue		X		X	Late Filed - NSP - Requested by Commission
2	Direct - Brian Draxten	Yellow		X		X	OTP

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Pages: 2

Exhibit List from October 23-24, 2000
hearing
by Office of Administrative Hearings
10/26/2000 CC: Comm Legal PUD (3) Mike ALJ.

32 PU-400-00-195

Pages: 2

Exhibit List from October 23-24, 2000
hearing
by Office of Administrative Hearings
10/26/2000 CC: Comm Legal Illona, Pat, Jerry Mike.

3	Direct - Del Van Voorhis	Yellow		X		X	OTP
DVV-1	From DVV Direct, Page 5, Line 2 (attachment)	Yellow		X		X	Late filed - OTP - Requested by Commission
4	Direct - Steve Wevley	Yellow		X		X	OTP
PSC1	Mike Diller Testimony	Red		X		X	PSC Staff



**Northern States Power Company
"PLUS" Plan Performance Section
Customer Satisfaction Standard**

Macro Measure: "Excellent", "Very Good", or "Good" Response %

This is the average % of responses which were positive in nature (top 3 responses in a 5 option answer) from a survey question relating to NSP's overall quality of products, services, and support in the State of North Dakota. The "relationship" surveys are conducted twice annually for the residential, small commercial, and large commercial and industrial customer classes. The result for each class is averaged into one score.

The results used will be for the question: "I'd like you to think of your overall relationship with Xcel Energy. Considering everything, would you say the overall quality of products, services, and support you receive from Xcel Energy is excellent, very good, good, fair, or poor?"

The Performance Standard

A benchmark customer satisfaction survey standard will be developed by using the targets established for NSP's internal "Pay for Performance" compensation plan as the basis for the acceptable performance range. A score exceeding 96.5% will increase NSP's allowable earnings, while a score below 93.5% will reduce the level of allowed earnings.

Past Results

	<u>Res'l</u>	<u>Small C&I</u>	<u>Large C&I</u>	<u>Average</u>
1998	98.0%	97.0%	99.0%	98.0%
1999	96.0%	94.0%	98.0%	96.0%

Note: The survey question shown above was updated from the attachment on the original application, reflecting a minor wording revision.
Also, 1998 residential % was updated from 96% to 98% on 9/25/00.
The 96% was a typographical error.

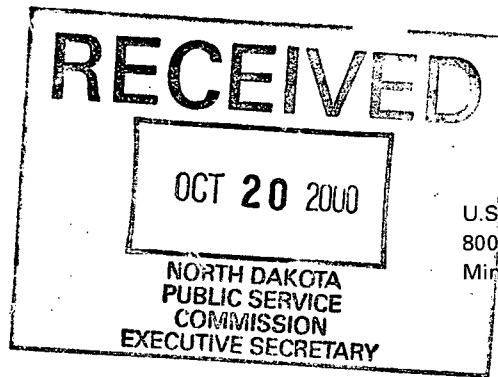
Overall Quality Question Wording

I'd like you to think of your overall relationship with Xcel Energy. Considering everything, would you say the overall quality of products, services and support you receive from Xcel Energy is excellent, very good, good, fair, or poor?





October 20, 2000



U.S. Bancorp Center
800 Nicollet Mall
Minneapolis, MN 55402-2023

Mr. Jon Mielke
Executive Secretary
North Dakota Public Service Commission
600 East Boulevard
Bismarck, ND 58505

Honorable Allen Hoberg
Administrative Law Judge
Office of Administrative Hearings
1701 North 9th Street
Bismarck, ND 58501-1882

Re: Application of Northern States Power Company d/b/a Xcel Energy for
Authority to Operate Under Performance Based Regulation In North Dakota
Case No. PU-400-00-195
Prepared Rebuttal Testimony of Xcel Energy

Dear Mr. Mielke and Judge Hoberg:

Enclosed please find an original and seven (7) copies of the prepared rebuttal testimony of Mr. David H. Sederquist in support of the April 20, 2000 petition of Northern States Power Company, now doing business in North Dakota as Xcel Energy ("Xcel Energy"), in the above captioned docket. This rebuttal testimony answers the direct testimony of Staff witness Mr. Mike Diller, filed on October 13, 2000.

In addition, enclosed please find an original and seven (7) copies of the prepared rebuttal testimony of Mr. Karl McDermott on behalf of both Xcel Energy in Case No. PU-400-00-195 and Otter Tail Power Company in Case No. PU-401-00-36. Mr. McDermott again addresses issues common to both PBR plans, responding to Staff.

Note: Xcel Energy is submitting this testimony electronically, as authorized by Judge Hoberg. We will serve the original and 7 copies on the Commission, plus two copies on Judge Hoberg, by hand early Monday morning, October 23, 2000, prior to the hearing.

Please direct any questions regarding this filing to the undersigned at (612) 215-4592 or to Mr. Dave Sederquist at (701) 241-8632.

Sincerely,

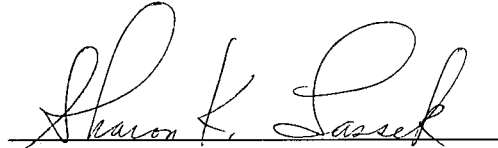

James P. Johnson
Assistant General Counsel

Enclosures

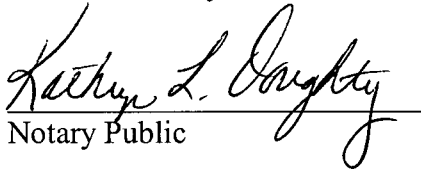
AFFIDAVIT OF SERVICE

I, Sharon K. Lassek, hereby certify that I have this day served the Rebuttal Testimony of David H. Sederquist and Karl McDermott on the parties listed below by placing in the U.S. mail at Minneapolis, Minnesota. Mr. Mielke and Judge Hoberg were served by hand.

Dated this 23rd day of October, 2000.



Subscribed and sworn to before
me this 23rd day of October, 2000.


Notary Public

Jon Mielke
Executive Secretary
North Dakota Public Service Commission
600 East Boulevard
Bismarck, ND 58501

Honorable Allen Hoberg
Administrative Law Judge
Office of Administrative Hearings
1701 North 9th Street
Bismarck, ND 58501-1882

William Binek
North Dakota Public Service Commission
600 East Boulevard
Bismarck, ND 58501

Mike Diller
North Dakota Public Service Commission
600 East Boulevard
Bismarck, ND 58501

Todd Guerrero
Otter Tail Power Company
215 S. Cascade Street
Fergus Falls, MN 56538-0496

James P. Johnson
Xcel Energy d/b/a/
Northern States Power Company
800 Nicollet Mall, Suite 2900
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Karl A. McDermott
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875 North Michigan Avenue, Suite 3650
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NATIONAL ECONOMIC
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875 NORTH MICHIGAN AVENUE, SUITE 3650
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nera
Consulting Economists

20

REBUTTAL TESTIMONY OF KARL MCDERMOTT

Vice-President

October 20, 2000



28 PU-400-00-195

Pages: 16

Rebuttal Testimony of Karl McDermott

by Northern States Power Company
Exhibit # Joint 2

10/20/2000 CC: Cornm Legal Illona, Pat, Jerry Mike

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1 **PREPARED REBUTTAL TESTIMONY**
2 **OF**
3 **KARL A. MCDERMOTT**

4 **I.**
5 **INTRODUCTION AND SUMMARY**

6 Q. Please state your name, current position and business address.

7 A. My name is Karl McDermott. I am a Vice President at National Economic Research
8 Associates, Inc. (NERA). My business address is 875 North Michigan Avenue, Suite 3650,
9 Chicago, IL 60611.

10 Q. Are you the same Karl McDermott that provided direct testimony in this proceeding?

11 A. Yes I am.

12 Q. What is the purpose of your rebuttal testimony?

13 A. I will comment on and respond to the rebuttal testimony of North Dakota Public Service
14 Commission (NDPSC) Staff member Mike Diller.

15 Q. What are you conclusions in this phase of the proceeding?

16 A. Mr. Diller's conclusion appears to generally supports the move to performance-based
17 regulation. I believe that movement toward PBR in this case will create a set of
18 comprehensive conditions that will enable benefits to be generated that would not
19 necessarily arise under more traditional forms of regulation. While I appreciate Mr. Diller's
20 good faith effort to suggest adjustments to the PBR proposal before the Commission, the
21 fundamental issue before the Commission is whether this plan has a reasonable chance of
22 providing customers with benefits in the future. As I noted in my direct testimony, the
23 Company's proposal while not perfect, has a lot to offer as a total package. Given that the
24 design takes these components and their interaction as a whole, caution must be exercised
25 in the consideration of making changes to certain segments of the plan. I would recommend
26 that if Staff is concerned with certain aspects of the plan that they work with both
27 Companies to reach an agreement on constructive changes that all parties can accept. I base
28 this recommendation on my observation of plans implemented across the country that have
29 in the majority of cases benefited the customers in those states.

II. STANDARD OF REVIEW

Q. Do you agree with Mr. Diller's characterization of why the Commission should consider moving to PBR found on page 2 of his testimony?

A. Mr. Diller seems to be cautioning the Commission that movement away from rate of return regulation (RORR) should not be an easy decision. I agree that a movement away from RORR is not an easy decision. In the case of adopting your first PBR plan, there is a sense that any change involves risk. The difference in this case is that a significant number of states have employed performance regulation to good effect in both the electric and natural gas industry. I would simply caution the Commission not to take Mr. Diller's warnings with any more emphasis than he has placed on them. I would urge a slightly different interpretation of Mr. Diller's conclusion.

First, I am not in complete agreement that RORR has "stood the test of time." Many of the high cost states that have been forced into restructuring operated under traditional regulation. The real issue for North Dakota is how to provide the appropriate incentive *going-forward* to bring the forces of competition to bear on these two North Dakota electric utilities. RORR or traditional regulation cannot keep up with the dynamic nature of the electric market today and therefore cannot stand the test of time moving forward.¹

Second, I would disagree slightly with Mr. Diller's characterization that a PBR plan should only be approved if "ratepayers will indeed benefit from the change." I caution the Commission against using such a strict standard, which I do not believe any reasonable plan could pass. My concern arises from the following: If we are to suggest that ratepayers *will benefit* from the change, how do we measure *a priori* whether customers *will indeed benefit* from the change? Moving to PBR entails costs and benefits, however so does staying with RORR. The appropriate standard the Commission should use should take into account the reasonable *expectation* that customers will benefit. This allows the Commission flexibility

¹ In addition, the regulation of public utilities in the past century has not been as critical as it is becoming in today's global marketplace. Attracting and retaining business is a function of the ability to obtain competitively supplied inputs more today than even 15 years ago. Electricity, and in particular, highly reliable electricity supply, is one of the key inputs into the so-called new economy businesses such as internet based companies.

1 in assigning *likely* outcomes to various scenarios and assessing the robustness of the plan
2 over time in meeting the variety of contingencies that develop. In addition, it sends the
3 signal that the “perfect will not be the enemy of the good.” The benefits of a reasonable
4 plan today out weigh, in my mind, the effort to create a perfect plan.

5 Q. On page 2 of his testimony Mr. Diller states “[P]roof that the PBR plan is not harmful to
6 ratepayers is not sufficient.” Do you agree with this assessment?

7 A. Not entirely. Again, while I don’t believe that Mr. Diller is attempting to use his policy
8 arguments to stop PBR from being implemented, I am concerned that such statements could
9 be interpreted as a reason to implement a standard that is much too stringent. The end result
10 of this standard, therefore would be to deny benefits to North Dakota of a reasonable plan.
11 Having said that, I believe that Mr. Diller is cautioning the Commission that the plan
12 should increase efficiency and not simply raise prices with no corresponding benefit.² I
13 think that this plan creates an opportunity to achieve that end.

14 Q. Did you conclude that the programs were appropriate and should be approved?

15 A. Yes. My direct testimony looked at the programs *as a whole*. In reviewing them in that light
16 I concluded that the public is likely to benefit from the programs and therefore they are in
17 the public interest. While it is true that I raised some questions that need reflection, as Mr.
18 Diller has in his testimony, the fact remains that as a whole the programs are in the public
19 interest. Even if a particular piece of the program might be improved upon, it is not at all
20 clear to me that the program as a whole is improved. I would caution against changing the
21 basic structure of the program. By changing the basic structure, the Commission runs the
22 risk of changing the parameters under which the Companies could accept the program.
23 Remember, in order to entice the Companies to move to PBR, there must be something in
24 the program that potentially benefits the stockholder as well as the customer. While I spoke
25 at great length about the program’s potential benefits to consumers in my direct testimony,
26 this street goes two ways. Adding additional risk to the program, without additional return

² Again, we need to be very careful in interpreting this standard. Price increases may result as a function of the plan, but if the *price path* is lower than under traditional regulation customers can still benefit from not being charged even higher prices that may be legitimately imposed under RORR.

1 could prompt utility management to reject the PBR program. As the plan is structured the
2 Commission has the opportunity to periodically review the plans effectiveness and with the
3 benefit of this experience recommend adjustments to the plan.

4 **III.**
5 **THE COMPANY'S PROPOSAL IS APPROPRIATE AT THIS TIME**

6 **A. Comprehensive Nature of the Benchmarks**

7 Q. At page 4 of his testimony, Mr. Diller notes that he was surprised that more comprehensive
8 plans are not in place around the country. Do you have any comments?

9 A. Of the 28 electric PBR plans I identified in the exhibits attached to my direct testimony, I
10 would consider 16 to be comprehensive. By comprehensive I mean any plan that forces the
11 company to manage its costs in their entirety. If Mr. Diller is tying the use of specific
12 benchmarks (e.g., service quality, price, reliability, etc.) to the term comprehensive, I would
13 agree that there are plans that employ price caps or rate freezes that do not have specific
14 benchmarks. However, that does not mean they are not comprehensive in nature.

15 Q. How does this relate to your discussion concerning the benchmarks?

16 A. If we are to take a comprehensive approach to PBR, which I have already noted is
17 appropriate, the benchmarks themselves should be comprehensive as well. The benchmarks
18 are in essence a control on certain variables the regulator deems important. They serve as a
19 constraint on the behavior of a firm, while allowing it to managing the overall performance
20 of costs. Generally benchmarks serve a method of ensuring that minimum standards of
21 service are maintained. Often the fear of moving to PBR is that the company will cut costs
22 in areas that will deteriorate quality and safety; by using benchmarks a target service level
23 can be maintained.

B. Equal Weighting of the Performance Standards is Appropriate

Q. Does Staff witness Diller agree that equal weighting is appropriate?

A. No. Mr. Diller suggests that equal weighting is “suspect” because this issue was addressed in my direct testimony.³

Q. Is this an appropriate interpretation of your testimony?

A. No. First, the simple fact that I addressed the issue should not be interpreted as a reason to question the validity of the equal weighting proposal. In fact, I addressed this issue to be responsive to Staff as they first brought up the issue in the list of questions provided to Northern States Power at an initial hearing in this proceeding. Second, my response to the question of the equal weighting issue stated the following:

While one could postulate that certain aspects of performance are more valuable to consumers than other aspects, the problem with attempting to perform some weighting analysis is two fold. First, weighting the standards obviously presents an incentive to the Company to meet those standards that have the highest weight. If one believes that these measures do measure overall performance, then equal weighting is appropriate as the Commission wants to send the signal that overall performance should be maintained and improved. Second, in practical terms, a weighting scheme would either be an estimate of the value placed on the standards by consumers or simply a judgement by the Commission. In the former case, such an estimate would be controversial to say the least and would take attention away from the real issues of designing a plan that best meets the public interest and is understandable. In the later case, any judgement would also be controversial. The best approach is the simplest in this case. By weighting each standard equally the Commission can send the signal that it expects the overall performance of the Companies to be maintained and improved. This is the appropriate signal to send.⁴

Mr. Diller’s conclusion that the customer satisfaction benchmark should not have equal weight with the other benchmarks⁵ suffers from the very problems that are identified in my response noted above.

³ Diller Rebuttal at 4.

⁴ McDermott Direct at 26-27.

⁵ Actually, Mr. Diller suggests that there should only be three benchmarks. I will address that issue later in this testimony.

1 Q. Why does Mr. Diller suggest that the customer satisfaction benchmark not be equally
2 weighted with the other benchmarks?

3 A. Mr. Diller suggests that 1) customers value the performance characteristics of the firm
4 differently; and 2) price and reliability are the main characteristics that customers value and
5 therefore satisfaction depends to a large degree on these factors.⁶

6 Q. How does Mr. Diller decide on the weighting factor applied to the customer satisfaction
7 benchmark?

8 A. Mr. Diller suggests that all customers are likely to value the different aspects of utility
9 service differently, but that “we should still be able to draw some broad conclusions as to
10 what is important to customers,” and that “[U]pon doing so, we should be able to assign a
11 value to each standard relative to its perceived value to customers.”⁷ He goes on to suggest
12 that because the price and reliability values are likely to be higher on a customer’s priority
13 list than the customer satisfaction value, it should receive only half the value.

14 Q. Is there a problem with this weighting allocation?

15 A. Mr. Diller’s proposal illustrates the issues I brought up in my direct testimony quoted
16 above. First, I agree with Mr. Diller that performance benchmarks create incentives, but
17 they also create constraints on the company. By weighting the benchmarks differently, the
18 Commission will be sending the signal that customer satisfaction is a lesser goal of the
19 program. I caution the Commission to consider the incentives such a weighting scheme
20 would send the Companies. Generally, customer service is a non-revenue expense. By that I
21 mean that the expenses associated with customer service do not necessarily have associated
22 revenues as higher reliability or better pricing might.⁸ Therefore, once the Companies are
23 taken off of RORR, the incentive to maintain customer service levels will be lessened
24 because any savings in customer service functions goes directly to the company either in

⁶ Diller Rebuttal at 6.

⁷ Id.

⁸ Reliability could also be a non-revenue expense and that is why it is important to maintain a reliability benchmark.

1 full or in part. Mr. Diller points out that in a competitive market, the market sets the
2 benchmark. This is true, however it is clear to me that one aspect of competitive markets is
3 that customer service is given an extremely high priority.⁹ As is noted below the customer
4 service aspect is extremely important in the utility industry as well.

5 Second, the weighting factor Mr. Diller uses is based on his *judgement*, not an estimate of
6 the *actual* value customers' place on satisfaction. This brings up a host of questions in my
7 mind. While I agree that price and reliability are clearly included in a customer's view of
8 their own satisfaction, it is unclear to me that customer satisfaction should be weighted as
9 only one-half as important. Why not one-quarter or one-eight or three-quarters? I am not at
10 all sure that customer satisfaction is a function of price and reliability only; in fact it is
11 highly likely that customer satisfaction, in and of itself, is a function of a variety of other
12 factors, some of which Mr. Diller notes in his testimony. The problem with attempting to
13 weight these factors differently should be apparent. Without complex and time-consuming
14 studies of customer willingness to pay for the various factors, the issue comes down to a
15 judgement call. Given the factors noted above, I caution the Commission in choosing an
16 uneven weighting scheme as such a scheme produces different incentives and without good
17 information on exactly what weight is correct, I believe the Commission would be taking an
18 unnecessary risk.

19 Q. What evidence do you have that customer satisfaction is likely as important as reliability or
20 price?

21 A. One of the main complaints people some time have with utilities is the lack of customer
22 service, beyond price and reliability. For example, recently SBC Communications has been
23 criticized in many of its Midwestern states (where it operates as Ameritech) for various
24 aspects of its service unrelated to price and reliability. An unprecedented regional
25 regulatory roundtable made up of seventeen Commissioners from the five Ameritech states
26 recently met in Chicago to discuss these problems with the CEO of SBC

⁹ Customer service becomes an even more important characteristic of a firm's product offering in markets where products have many substitutes.

1 Communications.¹⁰ Ameritech obviously realizes the importance of customer service as it
2 has set up a program to provide refunds to customers who have had to wait too long for
3 service calls.¹¹ I would hardly say that such items are of less concern to customers or
4 regulators than price or reliability.¹² In fact, often companies compete not on price or even
5 reliability, but on the customer service factors that make up the total package sold to a
6 customer.¹³

7 Further, items such as service transfer and bill clarity, as Mr. Diller points out, are not likely
8 to be caught by the other benchmarks. However, such items are only part of the story.
9 Customer service is a function of a variety of other issues such as:

- 10 • How does the utility respond when there is an outage?
- 11 • What is the backlog of non-emergency or non-reliability related repairs?
- 12 • How easy is it to talk to a live person when calling the company?
- 13 • How do company employees treat customers during service calls?
- 14 • Does the company make understanding service options easy?
- 15 • How does the company deal with metering reading, installation, etc.?
- 16 • How well does the company communicate with the public and public officials
- 17 during an emergency?
- 18

19 Last, customer service is clearly important for many companies. For example, United
20 Airlines has had well published customer service problems in the past year. This prompted
21 public apologies from the CEO of the parent company. According to a recent news release
22 from the airline, passenger traffic was down six percent in August of 2000 compared to
23 August of 1999.¹⁴ That same news release mentioned the “operational disruptions” as a

¹⁰ “Ameritech Woes Embarrassing SBC CEO Admits,” *Chicago Tribune*, Front Section, October 17, 2000.

¹¹ “Ameritech, SBC Vow Better Service,” *Chicago Sun-Times*, October 17, 2000.

¹² I can’t imagine the same type of regional conference of regulators being held concerning the prices Ameritech charges.

¹³ Many examples abound, computer and electronics stores, car dealers, banks and even telecommunications companies often advertise, not that their service is more reliable or is priced better than a competitor, but that there customer service is higher than a competitor.

¹⁴ “United Airline August Traffic Declines 6.0 Percent,” United Airlines Press release, September 6, 2000.

1 driving factor.¹⁵ Additionally, the airline has had to cut prices dramatically to entice
2 consumers back to the carrier. One can imagine how costly this has been to United Airlines
3 in terms of lost revenue and potentially lost customer base. While the market provides the
4 alternative for customers of airline carriers, customers of the utility cannot switch if
5 customer service declines and customer service declines tend to be the first problems that
6 show up when firms face more market-like signals.¹⁶ Therefore, the Commission should be
7 extremely careful in downplaying the role of customer service in the total package of
8 products and services provided to the customer.

9 C. Eliminating the Employee Safety Standard Sends the Wrong Signal

10 Q. Why does Mr. Diller believe that the worker safety benchmark should be removed from the
11 plan?

12 A. It appears that Mr. Diller has two main arguments. First he suggests that the competitive
13 market, for the most part, does not connect employee safety with earnings. Second, he
14 suggests that employee safety will be maintained, even under PBR, through a combination
15 of "moral" obligation and union and Federal government standards. Again I'd like to
16 emphasize that benchmarks establish constraints on firm behavior that reflect Commission
17 policy goals. In this case I believe safety is a reasonable goal.

18 Q. Do you agree with his assessment?

19 A. No. First, I believe there is a connection between employee safety and earnings in the
20 competitive market. Employee safety is simply another characteristic of a firm that an
21 employee will take into account when choosing a job. Companies with high ratings and
22 clear track records on employee safety tend to attract employees with higher productivity
23 levels. Therefore, higher worker safety, all else equal, helps attract the kind of employees
24 that a firm would like to attract. Second, while I agree that Companies have an obligation to

¹⁵ One might argue that these are "reliability" factors. There is clearly some of that involved in the disruptions. However, it is also clear that the customer service aspects of these disruptions played a major role in the problems faced by United this summer.

¹⁶ This has been true in the airline industry, telecommunications, electricity and other industries that begin to face greater competitive pressure.

1 comply with Federal safety standards, the incentive to maintain high worker safety
2 standards reinforces the Commission's commitment to worker safety as well as the
3 Companies'. Third, as Mr. Diller points out, these companies have met high standards for
4 safety. In the interest of maintaining the positive aspects of the current regulatory
5 paradigm, the Commission should carefully weigh the costs of potentially lower safety
6 records. However, this issue really boils down to a policy judgement. Does the Commission
7 want to send the signal to the Companies that worker safety is one of the areas where
8 aggressive cost cutting should be attempted? I believe, in the end, the prudent thing to do,
9 as other states have done, is to include worker safety as a benchmark. It aligns workers,
10 customer and management/shareholder interests better than leaving this benchmark out of
11 the plan.

12 Q. Doesn't eliminating the worker safety benchmark make the plan easier to understand and
13 administrate?

14 A. There is a trade-off between making a plan "too" simple and making it comprehensive
15 "enough." I believe that including the worker safety benchmark does not complicate the
16 plan all that much and preserves its comprehensiveness. The real question is this: Does the
17 plan gauge overall performance while maintaining understandability? I believe that one can
18 have four benchmarks, however weighted, and maintain understandability. Furthermore, the
19 Commission is making a policy statement that worker safety will not be compromised in
20 this new environment. Finally, the Commission has the opportunity to monitor this plan
21 over time and it has the ability to modify the benchmarks to assure that the goals of the plan
22 are being met.

23 **D. The Measure of Inflation**

24 Q. In your comments on inflation measures in your direct testimony did you raise any
25 significant issues with respect to the measure of inflation used by the Companies?

26 A. No, I don't believe that I did. Under the price change formula (referred to as Equation (A)
27 in my direct testimony) in the plan, the measure of inflation used is the Consumer Price
28 Index or the CPI. I suggested that often an estimate of total factor productivity (TFP) is

1 used to measure the so-called X factor and as such, an inflation measure that encompasses a
2 broader scope of goods and services (e.g., the GDPPI) is probably more appropriate.¹⁷
3 However, in this case, a much simpler, and probably just as effective, method (i.e.,
4 $0.75 \times \text{CPI}$) was used to measure productivity. This, to a great extent, alleviated much of my
5 concern with using a CPI versus a GDPPI or some other measure. In addition, the issue I
6 raised—that of using a broader scope of products and services to measure inflation—is
7 largely moot as it appears that the broader measures follow a path similar to the CPI.

8 Q. What is Mr. Diller's view of the inflation measure?

9 A. Mr. Diller suggests that the choice of the inflation measure is influenced by the objective or
10 the intended use of the measure.¹⁸ He suggests that the Producer Price Index (PPI) is a
11 better measure of inflation relative to the CPI, because it is a measure that relates more to
12 the price of electric service than the CPI.¹⁹

13 Q. Should the Commission accept Mr. Diller's proposal?

14 A. This is not as easy a question to answer as it might appear. Mr. Diller is correct that the PPI
15 does measure electric prices, but so does the CPI as energy is in the basket of goods
16 measured by the CPI. However, the PPI is not as broad of an index of inflation as the CPI
17 (or for that matter the GDPPI). For example, the PPI is used to measure changes in the
18 prices charged by manufacturing firms only. But the actual measurement of the "price" is
19 not as straightforward as using a comparison group. The measure of the price used by the
20 PPI is an estimate of the net revenues received by the seller, in the period observed, by
21 selling the product. This means that taxes, retail rebates and other impacts on revenues are
22 not included in the price of the product. If revenues go down, which might be a result of
23 costs going up, it would be reflected in a lower revenue per unit for the manufacturer and

¹⁷ See Equation (C) and the discussion surrounding it in my direct testimony.

¹⁸ Diller Rebuttal at 7.

¹⁹ Id. At 8.

1 hence the index would appear to be moving down, even though costs may moving up. In
2 the electric industry, this means that wholesale sales are also included in the PPI.²⁰

3 The price cap formula is used to limit the price increases based on a comparison of regional
4 utilities (i.e., competitive effects), whereas the price change formula is intended to send the
5 signal concerning overall inflation. By employing the peer group set the plan actually does
6 a better job of capturing the competitive issues that Mr. Diller seems to be concerned about.

7 Finally, in my review of price cap plans around the country, the PPI is used in the minority
8 of cases whereas the CPI or the GDPPI is used in the majority of cases. This illustrates the
9 usefulness of a broad measure of inflation in price cap plans.

10 Q. Why is the CPI useful in this case?

11 A. As I noted in my direct testimony, the CPI is not only used by other price cap plans, but it is
12 also probably the most understandable measure of inflation to the typical utility ratepayer.
13 For example, the CPI is used for everything from cost of living adjustments for state and
14 federal retirement benefits including Social Security, union collective bargaining
15 agreements, and to prevent so-called "bracket-creep" in the Federal income tax structure. In
16 addition, the CPI is clearly the most widely used measure of inflation in making economic
17 decisions over time. For example, when one suggests that energy prices have fallen in *real*
18 terms, one is generally referring to an index of energy prices that is *deflated* by the CPI.
19 Therefore, it is an understandable and relevant measure of inflation and if the Commission
20 used the CPI for the price change equation it would be perfectly consistent with other plans
21 adopted around the country.

22 Q. Is there any other reason why the CPI might be reasonable?

23 A. Yes. The price change formula is restrained by the price cap formula (referred to as
24 Equation (B) in my direct testimony). The concern that price inflation might be the wrong
25 tool to use to measure inflation is always tempered by the change in prices of the
26 comparison group of utilities.

²⁰ Some of the plans that use the PPI, use it to set rates for the largest customers (i.e., those customers whose load
(continued...)

E. Price Flexibility

Q. Mr. Diller has suggested that additional pricing flexibility is not necessary at this time. Do you agree?

A. As the Companies have not requested this additional flexibility, I would only add that I still support some form of flexibility as outlined in my direct testimony. I would note that while Mr. Diller is correct that the Companies have rates such as those to promote economic development and those that are "special" in nature to be approved by the Commission, such rates are generally used for a specific purpose such as avoiding uneconomic bypass. The flexibility that I was suggesting would not require the administrative costs of individually negotiating contracts with each customer, but would rather allow some flexibility in rate design. I would also add that under my proposal, the flexibility granted the Companies would still be severely limited.

F. Price Cap

Q. Does Mr. Diller support the price cap mechanism proposed by the Companies?

A. Not entirely. He suggests that due to the historic factors he reviewed the price change is unlikely to ever be negative (i.e., prices going down). He therefore suggests that a more "balanced" approach be taken that would start with the top end of the deadband, but drop the comparison group step and the productivity or stretch factor. Mr. Diller has provided a schematic of the two proposals attached to his testimony as Schedule MRD-6 and MRD-7.

Q. Do you concur with Mr. Diller's proposal?

A. No. The Companies proposed price cap and price change formulae incorporate a fairly conservative approach to setting up a price cap plan. There are safeguards for both the Companies and customers. For example, price increases can only occur if the Company does not exceed the upper end of its earnings band. While it is true that there are safeguards

(...continued)

shapes are more like a wholesale customer.)

1 for the Companies as well, such safeguards are important when experimenting with new
2 forms of regulation. Again, the Commission will have the opportunity to assess the
3 reasonableness of the price formulae over time.

4 **IV.**
5 **CONCLUSION**

6 Q. Do you have any final comments?

7 A. I would urge the Commission to make a decision based on the plan as a whole. The plan
8 fairly represents the interests of ratepayers, shareholders and workers and provides a good
9 starting point for moving to a new regulatory environment. Sometimes attempting to
10 address on particular part of a plan, while good intentioned, may cause other portions of the
11 plan to change in relative merit. In addition, the Commission will always have the
12 opportunity to review the program to determine its merits over time. If at some time in the
13 future, the Commission decides that the program should be modified, Staff should work
14 with the Companies and other interested parties to come to an agreement on which changes
15 would be beneficial to all.

16 Q. Does this conclude your rebuttal testimony?

17 A. Yes it does.

STATE OF NORTH DAKOTA
BEFORE THE
PUBLIC SERVICE COMMISSION

In the Matter of the Application of)
Northern States Power Company d/b/a)
Xcel Energy for Authority to Operate)
Under Performance-Based Regulation)
in North Dakota)

Case No. PU-400-00-195

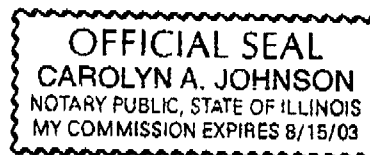
AFFIDAVIT OF
KARL A. MCDERMOTT

I, the undersigned, being duly sworn, depose and say that the foregoing is the testimony of the undersigned, and that such Rebuttal Testimony and the exhibits 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.

Karl A. McDermott
Karl A. McDermott

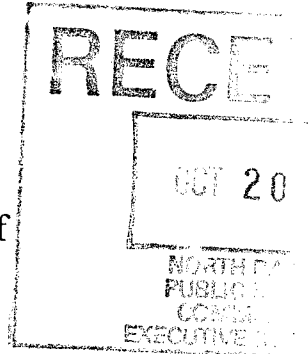
Subscribed and sworn to before me, this 20 day of October, 2000.

Carolyn A. Johnson
Notary Public



Rebuttal Testimony
Mr. David H. Sederquist
NSP Exhibit No. 6
Hearing Exhibit No. ____

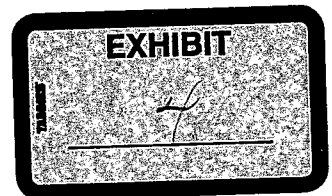
Before the Public Service Commission of
the State of North Dakota



In the Matter of the Application of
Northern States Power Company d/b/a Xcel Energy
for Authority to Operate under Performance-Based Regulation
in North Dakota

Case No. PU-400-00-195

October 20, 2000



29 PU-401-00-36 Pages: 16

Rebuttal Testimony of Karl McDermott

by Otter Tail Power Company

10/20/2000 CC: Comm Legal PUD (3) Mike ALJ.

27 PU-400-00-195 Pages: 18

Rebuttal Testimony of David Sederquist

by Northern States Power Company

Exhibit #4
10/20/2000 CC: Comm Legal Illona, Pat, Jerry Mike.

1 Q. Please state your name, position at Xcel Energy, and business address.

2 A. I am David H. Sederquist. I am Manager of North Dakota Regulatory
3 Affairs for Northern States Power Company d/b/a Xcel Energy ("Xcel
4 Energy" or "the Company"), the applicant in this proceeding.

5

6 Q. Have you provided testimony in this proceeding?

7 A. Yes, I submitted direct testimony on September 29 supporting approval of
8 Xcel Energy's proposed PLUS Performance-Based Regulation ("PBR")
9 plan for its electric utility operations in North Dakota.

10

11 Q. What is the purpose of your rebuttal testimony?

12 A. I will respond to a number of issues addressed by witness Mike Diller, on
13 behalf of Commission Staff, regarding the Xcel Energy PLUS plan.

14 Specifically, I will be responding to:

- 15 • the standard of review for approval of the PLUS plan;
- 16 • the weighting of performance standards in PLUS;
- 17 • the inclusion of a safety standard in PLUS;
- 18 • the PLUS price standard;
- 19 • the PLUS plan price cap and rate design.

1 Mr. McDermott is also providing rebuttal testimony on behalf of both Xcel
2 Energy and Otter Tail Power Company (“Otter Tail”) on certain policy
3 issues affecting both the Xcel Energy and Otter Tail PBR plans.
4

5 Q. Please summarize your rebuttal testimony.

6 A. The Company appreciates Mr. Diller’s analysis and comments on the PLUS
7 plan. Even though we do not agree with several of Staff’s specific
8 recommendations, this is a new form of regulatory oversight, so a good
9 discussion of the issues is important.
10

11 However, Xcel Energy would not support Commission approval of a PBR
12 plan for the Company which reflects the changes recommended by Staff.¹

13 As discussed in my direct testimony, the filed PLUS plan tried to reflect the
14 best components of PBR plans in other jurisdictions. It also reflected
15 suggestions received from the Commission in their 1995 *Guidelines for*

¹ The settlement between NSP and Staff approved by the Commission order in the Xcel Energy Inc. merger proceeding (Case Nos. PU-400-98-246 and PU-400-00-195) allows the Company to withdraw its PBR proposal and remain subject to cost of service regulation if the Commission imposes conditions on the PBR plan which the Company deems unacceptable.

1 *Filing Alternative Regulation Proposals* ("Guidelines") and in informal
2 discussions with Staff since issuance of the guidelines.

3
4 Specifically, the Company would object to Staff's proposed price
5 performance standard, removal of the safety standard, and revisions to the
6 price cap and rate change mechanisms. We also object to the use of the
7 Producer Price Index (PPI) instead of the Consumer Price Index (CPI) as the
8 inflationary factor for the price flexibility component, for the reasons
9 discussed by Mr. McDermott; and the proposed lower weighting of the
10 customer satisfaction performance standard. Finally, the proposed
11 economic development funding component should be retained.

12
13 Once the evidentiary hearing is completed and the issues and positions are
14 better defined, the Company believes it can work with Staff and hopefully
15 submit a consensus PLUS plan for Commission approval. This would allow
16 the PLUS plan to be put into effect January 1, 2001 as proposed.

1 **Standard of Review**

2 Q. Mr. Diller states that the Commission should approve PBR only if
3 ratepayers stand to benefit from the change. Please comment on that.

4 A. Mr. McDermott will respond to the issue of the appropriate standard of
5 review in more detail. However, the Commission Guidelines indicate a
6 regulatory framework like PBR which properly factors in utility
7 *performance* in the regulation of earnings and prices would be an
8 improvement over traditional regulation. The traditional model applies
9 minimum acceptable service standards, in the form of the Commission's
10 electric service rules in N.D. Admin. Code Chap. 69-09-02, and then entitles
11 the utility to recover the prudently incurred *costs* to provide this service. As
12 Mr. McDermott discussed in his direct testimony, regulatory commissions
13 across the country are recognizing a well designed PBR plan provides the
14 utility incentives to both improve performance and control costs. The
15 Commission must assume public utilities are rational entities and will
16 respond to incentives. This fundamental aspect of PBR provides customers
17 and the Commission assurance that, like the competitive market, PBR will
18 incent utilities to meet or exceed customer service and price standards
19 because doing so can improve its financial results.

1
2 On a more specific level, the Commission should note that the incentives in
3 PLUS promote performance by Xcel Energy that result in customer rebates,
4 better than "market" energy costs, excellent reliability and satisfied
5 customers, and a utility company with a strong emphasis on employee (and
6 presumably public) safety, innovation, and economic development. Since
7 1) Xcel Energy's electric rates will continue to be just and reasonable; 2) its
8 earnings will be within a bandwidth or subject to sharing; and 3) the
9 Company will be incented to make investments or improve its operations in
10 ways which and improve services to customers, the public interest is met.

11
12 Q. Who else can benefit from PBR?

13 A. A properly designed PBR plan, like PLUS, will provide the Commission
14 and Staff with a more streamlined and understandable method of regulating
15 utilities which allows more efficient application of limited regulatory
16 resources. The incentives in PLUS will also promote more economic
17 development, technological innovation, and investment in the North Dakota
18 communities served by Xcel Energy.

1 While there are no *guarantees* that PLUS will be successful, there are no
2 guarantees electric customers will receive anything more than bare-bones
3 minimum service under traditional cost of service regulation. Under PLUS,
4 the incentives are in place to ensure that the Company seeks to excel, and
5 North Dakota customers and regulatory administration will directly benefit
6 when they do.

7
8 **Response to Specific Proposed Modifications**

9 Q: Mr. Diller proposes to change from a “top three” to a “top two” customer
10 satisfaction measure, and expresses concerns about the 1.5% bandwidth.
11 Do you have any responsive comments?

12 A: Yes. As described by Ms. Schander’s direct testimony, the customer
13 satisfaction measure reflects all customers who rate the Company “good”,
14 “very good” or “excellent” in the annual surveys, and requires Xcel Energy
15 to have 95% of its North Dakota customers in the “top three boxes.” Staff
16 recommends using only the “very good” and “excellent” categories.

17
18 I question whether this change would improve the plan. As described by
19 Ms. Schander, the customer satisfaction standard is linked to the targets for
20 the 2000 Xcel Energy employee incentive compensation plan. Changing

1 the measure would also require reducing the standard from 95%. An
2 alternate standard has not been proposed by Staff, and Xcel Energy would
3 need to research this further. One concern about developing a standard
4 which focuses only upon the "delighted" segment of customers (top 2
5 responses) is that it could possibly lead to the Company being penalized
6 even if 100% of our customers in North Dakota are generally satisfied with
7 Xcel Energy's services and products.

8
9 Q. Please comment on Staff's proposal to reduce the weighting of the customer
10 satisfaction performance standard in PLUS.

11 A. I do not agree with Staff's proposal to reduce the level of importance that
12 overall customer satisfaction has in the plan. Customer satisfaction can be
13 impacted by many different functions performed in the delivery of electric
14 service which are not necessarily related directly to reliability or price.
15 Such activities would include meter reading, billing, phone service, credit,
16 complaint resolution, bill payment, tree trimming, and/or service
17 connections, to name a few. Customer satisfaction surveys provide a
18 general measurement of the Company's overall performance in these areas
19 as well as reliability and price. One could argue that, if anything, the survey
20 results should be weighted *higher* than any other single performance

1 category, since it reflects the perception by the Company's entire North
2 Dakota customer base of the overall value they are receiving from Xcel
3 Energy.

4
5 Furthermore, establishing varying weights for each major performance
6 category, as Staff proposes, may invite disproportionate management
7 attention to a certain area of operations. In other words, if the incentives for
8 improved customer-interactive functions (like phone center service, for
9 example) are less than those for delivery system reliability and price, then
10 efforts on the part of management and employees to elevate performance
11 levels will, quite rationally, be less in those areas, even if they significantly
12 affect overall customer satisfaction. The weighting proposed by the
13 Company encourages focus on all components of our service to customers.

14
15 Finally, I would also add that, in general, it would be difficult if not
16 impossible for the Commission to determine the optimum weighting of
17 utility performance categories. One approach might be for the Commission
18 to survey customers to find out what types of utility service or functions
19 they value most. Even then, priorities would likely vary among residential,
20 small business, and large industrial customers. Outside of a survey,

1 determining the proper weighting becomes a highly subjective exercise.

2 The Company applied its judgement and proposed equal weighting in the
3 PLUS plan, and Mr. McDermott supports this weighting.

4
5 Q. Should the safety measure be eliminated from the plan?

6 A. No, it shouldn't. While it is true the Company is subject to minimum
7 OSHA and other safety standards and rules, those standards do not (by
8 themselves) incent the Company to maintain or improve employee safety.

9
10 The Commission specifically included safety in its discussion of goals in
11 the 1995 Guidelines, and presumably this includes employee safety. Other
12 Commissions throughout the country have already recognized the value in
13 including a safety measure in their approved PBR plans.

14
15 The primary purpose for including safety metrics is to ensure that Company
16 efforts to minimize costs do not compromise employee safety. As required
17 by the Commission Guidelines, PLUS is designed to incorporate the most
18 critical aspects of providing electric service in North Dakota through broad
19 performance measures, and safety is too important to exclude from a
20 comprehensive performance-based regulation plan. It would send the

1 wrong signal if the Commission omitted safety from the performance
2 component of PLUS regulation, and it would be a departure from the
3 Commission’s own guidelines. If Xcel Energy is successful in achieving or
4 exceeding the PLUS employee safety targets, that is good for all of our
5 stakeholders, because a safety-conscious workforce will likely result in
6 better public safety, increase employee productivity, lower overall costs,
7 and improve service.

8
9 Q. Mr. Diller has suggested that the PLUS price standard be modified because
10 it is too easy to achieve. Do you agree with this assertion?

11 A. No. The PLUS price standard is based on a survey of 26 different electric
12 utility jurisdictions in seven very low-cost, Midwestern states. Because it
13 compares Xcel Energy’s average residential rate to those utilities in our
14 regional “market”, it is perhaps the most objective standard in the PLUS
15 plan, and certainly the best example of how the plan seeks to mimic the
16 competitive marketplace.

17
18 Staff contends that because Xcel Energy’s prices have been low enough in
19 past years to warrant an increase in the *authorized* Return on Equity
20 (“ROE”), the standard is too easily achieved. The problem with this

1 approach is that it completely ignores a fact that is of importance to
2 customers: Xcel Energy has the 3rd lowest price out of the 26 service
3 territories in the Midwest (based on 1999 data). In fact, only 4 of the 26
4 utilities in this low-cost region would be able to achieve this stringent
5 standard. If there is no recognition of Xcel Energy's current price position
6 in determining the proper level of allowed ROE, then an important
7 performance category has been ignored. In essence, Staff's position is that,
8 -- based on price performance -- Xcel Energy's *allowable* ROE should be
9 the same as the highest-priced utilities in the group, which is clearly
10 inconsistent with the entire concept of PBR. In fact, this approach could
11 result in a *lower* allowed ROE for Xcel Energy than for a higher-priced
12 utility elsewhere in the region.

13
14 Q. How could Staff's approach result in a lower ROE for a low-priced utility
15 like Xcel Energy than a high-priced utility?

16 A. Mr. Diller suggests adjustments to the allowed ROE be based only on the
17 Company's relative (i.e., compared to other Midwest utilities price changes)
18 *change* in its average rates from one year to the next, and not for the low
19 price that Xcel Energy currently offers North Dakota customers. While
20 price reductions are an important goal, price fluctuation is not the measure

1 by which customers make purchasing decisions in a competitive market,
2 and it is inconsistent with how the other PLUS performance award/penalty
3 mechanisms work for reliability, customer satisfaction, and safety.

4
5 It would be unfair to ignore the current price performance of Xcel Energy,
6 and rely only on relative, incremental percent changes in the determination
7 of the appropriate authorized ROE. As an example of this, suppose Xcel
8 Energy's residential rates went from 6.11¢/kwh to 6.21¢/kwh, while the
9 other top 10 companies in the region increased average rates from 6.43¢ to
10 6.47¢. Under Staff's proposal, Xcel Energy would be penalized by having
11 its allowed ROE reduced by 50 basis points. This in spite of the fact that
12 Xcel Energy would still have prices lower than 23 of the 26 utilities! This
13 approach is analogous to awarding the Olympic gold medal in the 100 meter
14 dash to the 5th place finisher because she improved her time the most from
15 the semifinal race to the final; or disqualifying the 1st place finisher because
16 her time was a little slower than her world record semifinal race. That is not
17 how competitive markets operate, or how PBR plans are to function under
18 the Commission guidelines.

19
20 Q. Do you have any other comments regarding the plan's price standard?

1 A. Yes, I do. Since the PLUS plan was designed to award utilities for having
2 low prices, the Commission should recognize that soon in the plan term
3 there may be a *calibration* of the allowed ROE with existing price
4 performance. In essence, the plan recognizes that if a utility is among the 3
5 or 4 lowest-priced utilities in the Midwest (which is by itself one of the
6 most competitively priced regions in the country), an authorized ROE
7 somewhat higher than the average utility is in order. This is consistent with
8 the economic outcomes that companies with competitively priced products
9 experience in a competitive market. The incentives to maintain or reduce
10 rates further are not eliminated just because Xcel Energy may be presently
11 in the award zone. On the contrary, Xcel Energy will be incented to retain
12 its price position so that its *allowed* ROE will not be reduced. Also, one
13 must keep in mind that PLUS only 'awards' very low prices with the
14 *opportunity* to earn a higher return; no direct financial benefit is created by
15 any of the four performance standards in this plan.

16
17 Q. Mr. Diller suggests eliminating the Economic Development revenue sharing
18 mechanism contained in PLUS. How would you respond to that?

19 A. The Company believes that including a revenue sharing mechanism which
20 reserves a portion of revenues for economic development support provides a

1 formalized and direct method of benefiting another Company stakeholder –
2 the communities we serve. The PLUS plan simply ensures that some funds
3 are earmarked for economic development when revenue sharing occurs. I
4 believe Mr. Diller, as well as the Commission, supports economic
5 development in North Dakota, and removing the mechanism does not
6 preclude Xcel Energy from directly supporting economic development in
7 the state.

8
9 Q. Please comment on Staff’s assertion that the price change criteria (decision
10 making model) needs to be modified to make price decreases more likely?

11 A. It is not clear to me why a PBR plan would be designed to inappropriately
12 increase the likelihood that rate decreases would be imposed on the 2nd and
13 3rd lowest priced utilities in the Midwest. The PLUS plan price change
14 criteria, as proposed, already requires Xcel Energy to maintain “below-
15 market” prices, and hold any rate increase below both the rate of inflation
16 and the average regional “market” price change. In addition, PLUS
17 prohibits Xcel Energy from increasing rates if its earnings are above the
18 authorized level. At the same time, PLUS provides Xcel Energy with at
19 least an opportunity to recover any increased costs of providing reliable
20 power and good service. Thus, the price change mechanism ensures that

1 increases in Xcel Energy rates (should they be allowed) for the purpose of
2 recovering increased costs will be competitive, below inflation, and
3 moderate.

4
5 Q. What would be the result of implementing the price cap criteria proposed by
6 Staff?

7 A. Staff's data (Schedule MRD-1) demonstrates the Producer Price Index
8 ("PPI") is an unpredictable and unstable index to use in changing rates .
9 Using the PPI in the rate cap calculation, and mandating rate decreases
10 (when the PPI is negative) -- even when Xcel Energy's current prices are
11 better than the market (Schedule MRD-7) -- would be punitive. There is
12 little justification for forcing a utility with prices among the lowest in the
13 region to reduce its rates even further. This is not how competitive markets
14 work either.

15
16 Furthermore, the comparison group price change is already incorporated
17 into the overall price cap formula to factor in regional industry costs, so it
18 would be duplicative to choose an inflationary measure that is also,
19 presumably, geared more toward industry costs than the Consumer Price
20 Index ("CPI"). The CPI reflects a more stable and familiar measure of

1 inflation, and one that has been used in other PBR plans across the country.

2 Mr. McDermott discusses other concerns with the PPI in his testimony.

3
4 I would also like to point out that customer price reductions are not the only
5 way that customer bills can be reduced under PLUS. If the Company is
6 successful in achieving earnings above the ROE deadband, the plans
7 revenue sharing mechanism kicks in to provide an automatic refund to
8 customers. This is a more responsible method of reducing customer bills
9 because it occurs at a time when the Company has adequately recovered its
10 costs of providing electric service.

11
12
13 Q. Does this conclude your testimony?

14 A. Yes, it does.

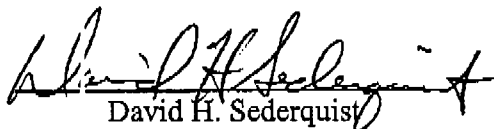
STATE OF NORTH DAKOTA
BEFORE THE
PUBLIC SERVICE COMMISSION

In the Matter of the Application of)
Northern States Power Company d/b/a)
Xcel Energy for Authority to Operate)
Under Performance-Based Regulation)
in North Dakota)

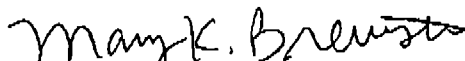
Case No. PU-400-00-195

AFFIDAVIT OF
DAVID H. SEDERQUIST

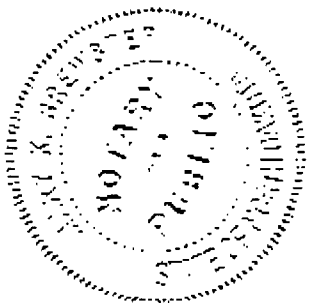
I, the undersigned, being duly sworn, depose and say that the foregoing is the testimony of the undersigned, and that such Rebuttal Testimony and the exhibits sponsored by me to the best of my knowledge, information and belief, are true, correct, accurate and complete, and I hereby adopt said testimony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


David H. Sederquist

Subscribed and sworn to before me, this 19th day of October, 2000.


Notary Public

MARY K. BREWSTER
Notary Public, STATE OF NORTH DAKOTA
My Commission Expires APRIL 26, 2001



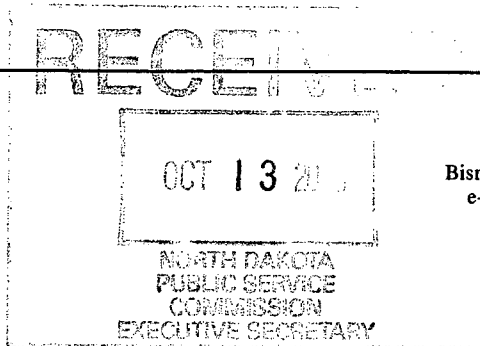


Public Service Commission

State of North Dakota

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Executive Secretary
Jon H. Mielke

October 13, 2000

Mr. Jon H. Mielke
Public Service Commission
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Bismarck, ND 58505-0480



RE: **Northern States Power Company and
Otter Tail Power Company
Application for Performance-Based Regulation Plan
Case No.'s. PU-400-00-195 & PU-401-00-36**

Dear Jon:

Enclosed for filing in the above referenced cases is the original and seven copies of the **Staff Analysis of Application and Rebuttal Testimony**.

Thank you.

Sincerely,

William W. Binek
Chief Counsel

WWBsls
Enclosure

C: Parties of Record

26 PU-401-00-36

Pages: 1

Cover letter re Rebuttal Testimony

by Public Service Commission

10/13/2000 CC: Comm Legal PUD (3) Mike ALJ

26 PU-400-00-195

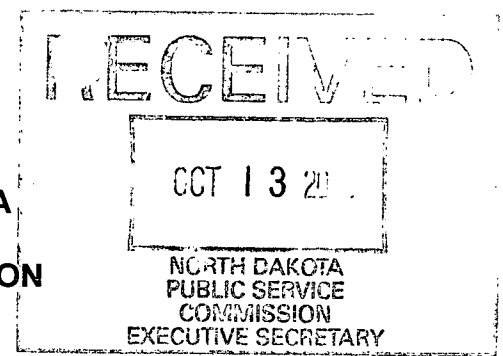
Pages: 1

Cover letter re Rebuttal Testimony

by Public Service Commission
Exhibit # PSC-1

10/13/2000 CC: Comm Legal Ilona, Pat, Jerry Mike

STATE OF NORTH DAKOTA
PUBLIC SERVICE COMMISSION



**Otter Tail Power Company
Performance Based Regulation
Application**

Case No. PU-401-00-36

**Northern States Power Company
Performance Based Regulation
Application**

Case No. PU-400-00-195

AFFIDAVIT OF SERVICE

STATE OF NORTH DAKOTA
COUNTY OF BURLEIGH

Sandra L. Scott deposes and says that:

she is over the age of 18 years and not a party to this action and, on the **13th day of October, 2000**, she sent by regular mail:

STAFF ANALYSIS OF APPLICATION AND REBUTTAL TESTIMONY

To:

Dave Sederquist
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James P Johnson
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Allen Hoberg
Office of Administrative Hearings
1701 North 9th Street
Bismarck ND 58501-1882

Each address shown is the respective addressee's last reasonably ascertainable address.

Sandra L. Scott

Subscribed and sworn to before me
this **13th day of October, 2000.**

Susan K. Richter

Notary Public

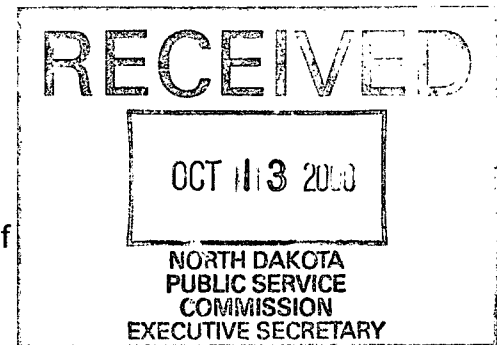
SEAL



Rebuttal Testimony

Mike Diller

Before the Public Service Commission of
the State of North Dakota



Northern States Power Company
and
Otter Tail Power Company

Application for Performance-Based Regulation
Case No.'s PU-400-00-195 & PU-401-00-36

Staff Analysis & Rebuttal

October 13, 2000

24 **PU-401-00-36** Pages: 27

Rebuttal Testimony of Mike Diller

by Public Service Commission

10/13/2000 CC: Comm Legal PUD (3) Mike ALJ

24 **PU-400-00-195** Pages: 13

Rebuttal Testimony of Mike Diller

by Public Service Commission

10/13/2000 CC: Comm Legal PUD (3) Mike ALJ

1 **Introduction**

2 Q: Provide your name and position with the Public Service Commission.

3 A: My name is Mike Diller and I am the Director of Accounting. I am
4 responsible for the Commission's accounting and data processing
5 operations and any assigned public utility matters.

6

7 Q: Provide a summary of your educational background and public utility
8 regulatory experience.

9 A: I have more than 17 years of public utility regulatory experience
10 including service for both the Oklahoma Corporation Commission and
11 the North Dakota Public Service Commission. I received a Bachelor
12 of Science Degree in Accounting from Oklahoma Christian College in
13 Edmond, Oklahoma in 1981. I am a Certified Public Accountant
14 licensed in the state of Oklahoma, and I am a member of the
15 American Institute of Certified Public Accountants.

16

17 Q: Have you provided testimony in North Dakota before?

18 A: Yes. I have testified before the Commission on telephone acquisition
19 proposals, rate cases, financial investigations and other issues.

20

21 Q: What is the purpose of your testimony?

22 A: I will provide an analysis of the performance-based regulation plans
23 as submitted by Northern States Power Company (NSP) and Otter
24 Tail Power Company (OTP). Because both plans are quite similar,
25 staff will address both plans together in this filing. The analysis will
26 take into consideration the applications and direct testimonies filed by
27 the applicants. I will provide suggestions and ideas for consideration.

28

1 Q: In your opinion, what events led to the filing of these plans?

2 A: First, it seems likely that the Commission's own activities of
3 developing guidelines for filing alternative regulation proposals and its
4 continued interest in alternative regulation has created a positive
5 environment for such filings. Several other events have occurred that
6 may have led to these filings including performance-based regulation
7 (PBR) activities in other states, profit motives of these two companies,
8 lack of progress by legislative bodies to restructure the electric
9 industry, a sense that PBR is coming sooner or later and perhaps
10 North Dakota provides an opportunity for a small-scale experiment.
11 The applicants have provided a number of reasons for this filing too.

12

13 **Why Performance-Based Regulation?**

14 Q: Why should the Commission consider moving away from rate of return
15 regulation in favor of another type of regulation?

16 A: Rate of return regulation has been used to regulate utilities for the last
17 100 years. It has stood the test of time and should not be abandoned
18 easily. Staff believes that the Commission should pursue PBR only if
19 it is convinced that ratepayers will indeed benefit from the change.
20 Proof that the PBR plan is not harmful to ratepayers is not sufficient.
21 Before a change is contemplated, the Commission should conclude
22 that ratepayers are indeed better off with PBR. Of secondary
23 importance, staff believes that if change in regulation is inevitable as
24 some suggest, it is better to be in the game rather than watching from
25 the sidelines.

26

27 **General Assessment of the Applications**

28 Q: Provide a general assessment of the applications.

1 A: Generally speaking, staff believes that the filings present a good
2 starting point for discussion. Like the applicants, staff believes that
3 any suitable PBR plan should be comprehensive yet relatively simple
4 to understand and administer. The plans include benchmarks and
5 clear means for measurement relative to price, reliability, customer
6 satisfaction and employee safety. These types of benchmarks are
7 commonly included in performance-based regulation plans.

8
9 **Highlights of Mr. McDermott's Testimony**

10 Q: What is your perception of Mr. McDermott's filed testimony?

11 A: I am glad that the applicants saw the need to hire him. He brings a lot
12 to the table of discussion and I look forward to meeting.

13
14 I appreciated his observation that "no plan is perfect" (page 3) and
15 that the Commission "needs to balance the pursuit of the perfect plan
16 with the realities of a regulatory proceeding" (page 19). Obviously,
17 rate of return regulation is not perfect and we should not expect that
18 PBR would be perfect either. A continued watch by the Commission
19 to ensure fair and reasonable rates is necessary under any plan until
20 such time that a competitive market exists.

21
22 Similarly, I appreciated his observation that "the trick to making
23 performance based regulation work is to design a set of incentives
24 such that the desired outcomes are likely to be realized." This is an
25 easy concept to understand but a difficult one for regulators to accept
26 and apply. Of course regulators want the companies to excel in the
27 areas of low prices, high reliability and good customer service.
28 However, those of us trained under rate of return regulation have

1 grown accustomed to holding companies to a specified rate of return
2 regardless of performance. The idea of a company having the
3 opportunity to retain higher levels of profits for higher levels of
4 performance will take some getting used to. Should PBR be approved
5 for use and the applicants are as successful as is hoped, higher
6 earnings levels may be achieved.

7

8 I also found his attachments helpful in trying to understand where the
9 rest of the country is in regard to PBR. I was quite surprised at the
10 small number of comprehensive plans currently in use. It appears that
11 these two cases are close to, if not on, the cutting edge of new
12 regulatory methods.

13

14 Q: You have highlighted some of the things you agree with, do you find
15 anything in Mr. McDermott's testimony that raises questions in your
16 mind?

17 A: Yes. I couldn't help but notice that towards the end of his testimony,
18 Mr. McDermott strays from what I will call "the company line." Mr.
19 McDermott (page 25) poses the question "Is it appropriate to weight
20 the standards equally?" The question itself and the response that
21 follows suggest to me that equal weighting is suspect. He supports
22 the equal weighting advocated by his clients but in my opinion leaves
23 the door open for additional consideration. Mr. McDermott (page 27)
24 also questions the use of the consumer price index (CPI) rather than a
25 broader economy wide price inflation factor. He further challenges the
26 pricing flexibility (page 28) supported by the applicants as well as the
27 price adjustment asymmetry (page 29) included in these plans. To

1 summarize, I believe Mr. McDermott raises some good questions that
2 need exploring.

- 3 ▪ Are the performance standards properly weighted?
- 4 ▪ Is CPI the best inflation index to use?
- 5 ▪ Should the applicants be given additional pricing flexibility?
- 6 ▪ Should price increase/decrease asymmetry be allowed?

7
8 **Equal Weighting of Performance Standards**

9 Q: What is your opinion regarding equal weighting for each of the
10 performance standards?

11 A: I agree with the applicants with respect to 50 basis points for the
12 rewards/penalties associated with the price and reliability standards. I
13 believe 25 basis points are in order for the customer satisfaction
14 standard and that no ROE baseline adjustment is necessary for
15 employee safety.

16
17 Performance benchmarks are used to create incentives for the
18 companies to perform at certain desirable levels. In a competitive
19 market, benchmarks are not necessary. If the prices charged relative
20 to the services rendered are too high, earnings suffer. If customer
21 service is shabby, earnings suffer. A competitive market place
22 actively links performance to profits without PBR.

23
24 Since a competitive market does not exist for electric service, a
25 surrogate for competition is necessary. An effective PBR plan
26 encourages companies to make market-like decisions to remain
27 competitive. That being the goal, it seems important to consider the
28 natural value of each performance measure to customers since the

1 market place makes similar judgments. It is doubtful that customers
2 value each equally as the 50 basis points for each performance
3 standard suggests. Every customer is different and therefore may
4 place a different value on each performance measure. Some would
5 place a greater value on reliability while others would be more
6 concerned about price. That being the case, we should still be able to
7 draw some broad conclusions as to what is important to customers.
8 Upon doing so, we should be able to assign a value to each standard
9 relative to its perceived value to customers. I believe that price and
10 reliability are the most important customer values and therefore place
11 a higher value on achieving those performance standards.

12
13 Customer satisfaction hinges directly and to a large degree on the
14 primary benchmarks of price and reliability and therefore warrants a
15 smaller incentive portion. Even though some overlapping occurs, it is
16 reasonable to think that sufficient other events and transactions occur
17 between utilities companies and customers to warrant its inclusion.
18 For example, bill clarity and readability would not influence the
19 outcome of the price or reliability standards yet are an important
20 monthly contact with consumers. While people may only move every
21 4 or 5 years, the experience related to the transfer of service or the
22 installation of new service is not quickly forgotten. Again, these types
23 of transactions are outside the measurable standards of price and
24 reliability, yet very important to customers. I believe transactional
25 surveys would be better and avoid some of the overlap that occurs in
26 the proposed relational surveys. However, my concerns are not great
27 and I understand the value of having relational survey history on hand
28 for implementing PBR.

1

2 **Eliminate Employee Safety Standard**

3 I am not convinced that an employee safety standard should be
4 included in the PBR plan. I am sympathetic to the desire to link
5 earnings with employee safety and the maintenance of a safe work
6 environment. However, including such a factor seems to step outside
7 the boundaries of trying to create a market-like environment. I believe
8 there are plenty of incentives to maintain worker safety without
9 building a profit motive into PBR. For the most part, such a
10 connection does not exist in a competitive market. Since we are
11 attempting to promote market conditions through the benchmarks, the
12 employee safety standard is not necessary. As the applicants'
13 testimony suggests, high safety standards are being maintained
14 without PBR. I believe similar results will be maintained under PBR
15 given management's moral obligations to their employees. If this is
16 not enough of an incentive, the federal government through the
17 Occupational Safety and Health Administration (OSHA), unions and
18 other watch dogs will inspire them. Further, lost productivity due to
19 injuries and accidents can negatively affect the three remaining
20 standards of price, reliability, and customer satisfaction.

21

22 **CPI or PPI**

23 Q: Is CPI the best inflation index to use for part of the price capping
24 mechanism?

25 A: I don't believe so. Deciding on which inflation index to use depends
26 on the objective or its intended use. The consumer price index
27 measures inflation experienced by consumers for day-to-day living
28 expenses. The types of costs driving the index include food and

1 beverages, housing, apparel, transportation, medical care, recreation,
2 education, communication and other goods and services. If the
3 purpose of using CPI is to limit potential price increases to a factor of
4 those experienced by urban consumers, then CPI is appropriate.

5
6 However, if the goal is to limit price increases to a broad index related
7 to electric prices, using an index like the producer price index (PPI)
8 would be more appropriate. The PPI is more of an industrial price
9 index rather than a consumer price index and includes specific
10 indexes for gas and electric utilities. The PPI is one of the oldest
11 indexing systems published by the Bureau of Labor and Statistics and
12 includes 10,000 indexes for specific products and product categories.
13 PPI maintains a countrywide index for electric power and natural gas
14 utilities, electric power, residential electric power, commercial electric
15 power, and industrial electric power. PPI indexes are also maintained
16 by region and by type of utility (investor owned or non-investor
17 owned). I have included Schedule MRD-1 to show a comparison of
18 PPI to CPI.

19
20 PPI is more representative of the changes in the prices of electric
21 power than is the CPI. Based on Schedule MRD-1, it makes little
22 difference in the long run whether the broader or more narrowly
23 defined PPI is used. According to the PPI, there has been little or no
24 inflation in providing electric service during the past 10 years. On the
25 other hand, consumer prices reflect a 2%-3% annual growth rate. Will
26 the near zero inflation of PPI continue? Probably not, but that is why
27 the use of an appropriate index factor is important. Inflation indexes

1 are not chosen to be punitive or to reward but to accurately reflect
2 price changes that are being experienced in the marketplace.

3
4 **Administering Price Changes**

5 Q: What is your understanding about how price increases/decreases will
6 be administered to the various customer classes?

7 A: Otter Tail does not address the issue in its filings. As I read NSP's
8 testimony on this matter (McDermott and Sederquist), there is very
9 little price flexibility in NSP's PBR plan. NSP's application states that
10 any price increases or decreases will be administered equally to all
11 customer classes unless the company requests something different.
12 Even then, according to Mr. Sederquist's testimony, the company is
13 restricted to asking for a rate design that assigns no more than the
14 overall percentage increase to each class. In other words, the
15 company may choose to forego part or all of an allowed price increase
16 to a particular customer class. According to Mr. Sederquist, price
17 decreases must be fully implemented across-the-board to all customer
18 classes unless the company would choose to lower rates even further
19 for a particular class of customers.

20
21 Q: Should NSP be given additional pricing flexibility, as Mr. McDermott
22 seems to suggest?

23 A: It is too early in the evolution of a competitive electric supply market to
24 give much on price flexing. I believe that the flexibility already granted
25 by the Commission through NSP's economic development tariff and
26 its ability to enter into Commission-approved contracts with individual
27 consumers provides enough freedom to pursue rates deemed
28 necessary by the company.

1

2 **Customer Satisfaction Standard**

3 Q: Do you have any comments regarding the customer satisfaction
4 performance standards advocated by the companies?

5 A: I think the companies have done a good job describing how customer
6 satisfaction will be measured and determined. There are some
7 differences between the two plans but I am primarily concerned with
8 the tightness of the band. Because the companies have traditionally
9 done a very good job at serving customers, including 3 out of the 5
10 answers as acceptable performance leaves little room for
11 improvement. Perhaps the plan should include the top 2 responses of
12 “very good” and “excellent” in developing the standard. After all, the
13 response “good” is really just average since it is in the middle of 5
14 possible answers. Shouldn’t the goal be higher than average?
15 Excluding the “good” responses from the benchmark would enable a
16 broader bandwidth and provide more room for improvement. For
17 example, assume 50% of customers currently rate a company “very
18 good” and “excellent.” Under this scenario, the company has 50% of
19 the customer base to work with as it tries to move perceived customer
20 service into the top two tiers. Changing the benchmark to only include
21 the top two responses also communicates to employees that the
22 company wants a higher level of service.

23

24 **Price Standard**

25 Q: Do you have any concerns about the price standard advanced by the
26 applicants?

27 A: Yes, I do. I believe the price standard will be too easily met. I
28 appreciate the view that ratepayers should be happy to have some of

1 the lowest rates in an already low cost region. However, our goal is to
2 promote a higher level of service, including price, beyond what we
3 already enjoy under rate of return regulation. While the price standard
4 is symmetrically structured, the possibility of incurring the penalty is
5 extremely remote while the chance of achieving the reward is very
6 good.

7
8 If the plan had been in effect during the past 6 years (1994 to 1999),
9 NSP would have claimed a reward of 50 basis points every year
10 except 1994 for exceeding the price standard. Even in 1994, NSP
11 would have missed the reward by only .04 cents per kWh. For
12 example, in 1994 the regional average less 15% was 5.92 cents per
13 kWh whereas NSP provided service for 5.96 cents per kWh. During
14 the past 5 years, NSP has on average exceeded the standard by .18
15 cents per kWh (see Schedule MRD-2 for details). By contrast, NSP
16 would have avoided the price penalty by an average of 2.33 cents
17 during the past 5 years. To put this in perspective, NSP recently
18 made a compliance filing because of a settlement reached in Case
19 Nos. PU-400-98-246 and PU-400-99-418 reducing electric rates by
20 \$261,000. The result of the compliance filing reduced residential
21 electric rates by .01 to .02 cents depending on the month service is
22 provided. Therefore, if it takes \$261,000 to move residential rates .02
23 cents, NSP North Dakota could raise its rates by \$30 million and still
24 receive a reward for exceeding the price standard. A similar analogy
25 could be made for OTP but the point is made.

26
27 A price standard could be developed to provide more of a market-like
28 stretch. For example, why not agree that no revenue sharing is

1 required for years in which a company achieves the lowest price per
2 kWh in the region. The only contingency necessary is that the
3 company must be within or above the bandwidth established for both
4 the customer satisfaction and reliability standards. I realize that both
5 applicants are within striking distance of meeting this objective but
6 only one can achieve it. Now that's market pressure!

7
8 In the mean time, it is necessary to tighten up the bandwidth so
9 meeting the price standard isn't quite so automatic. To this end, I
10 suggest we narrow the bandwidth by working off the average price
11 change of the previous year's top ten performers in the comparison
12 group. I recommend only the top ten because of the disparity
13 between prices within the region. Naturally, those companies with
14 high rates towards the bottom of the list have more of an opportunity
15 to reduce rates. Including only the top ten price performers will
16 present a fairer test of performance. For example, if the company
17 beats the average price change of the top 10 price performers by
18 more than .05 cents per kWh, 50 basis points are awarded. If on the
19 other hand, the limited comparison group beats the company by more
20 than .05 cents per kWh, 50 basis points are deducted. The bandwidth
21 then is arbitrarily set at .05 cents per kWh. For example, in 1999 the
22 limited comparison group averaged .12 cents per kWh increase over
23 1998. To participate in a reward, NSP would have had to provide
24 service for .07 cents less per kWh in 1999. To avoid a penalty of 50
25 basis points, NSP would have had to provide service for no more than
26 an additional .17 cents in 1999. Applying this type of system to the
27 last 6 years for both NSP and OTP, 50 basis points would have been
28 awarded to both companies 4 times, 50 basis points would have been

1 deducted in 1998 and no rewards would have been granted in 1994.

2 See Schedule MRD-3 for details.

3
4 Based on my historical application, it may seem unreasonable for the
5 applicants to benefit so regularly. However, it is hard to argue against
6 rewarding companies who are among the lowest in the region and still
7 beating the top price performers on a regular basis.

8
9 **12% ROE Baseline**

10 Q: Provide your thoughts on the suggested baseline return on equity.

11 A: Staff has been using a 12% return on equity in its investigations and
12 settlements for many years. The settlements were negotiated and
13 adopted by the Commission. Prior to the settlement era, the
14 Commission authorized similar returns. For instance, the Commission
15 last authorized an 11.5% return on equity for NSP's electric operations
16 in 1993. In 1991, the Commission authorized returns of 12% for both
17 MDU's and NSP's gas operations. Similar returns have been
18 authorized by the other jurisdictions regulating these applicants.
19 Further, a 12% return on equity is not unreasonable in comparison to
20 other rates being authorized throughout the country. Last, it is
21 important to remember that our goal is to achieve a fair end result.
22 The use of an 11% return on equity may be appropriate given certain
23 parameters. The use of a 13% return on equity may be appropriate
24 under different parameters. Based on the history of this Commission
25 and the returns authorized in other jurisdictions, staff believes that a
26 12% baseline return on equity is a reasonable starting point. For
27 specific returns authorized by various jurisdictions regulating NSP,
28 OTP and Montana-Dakota Utilities Co., see Schedule MRD-4.

1

2 **1% Deadband**

3 Q: Provide comments on using a 1% deadband around the return on
4 equity baseline.

5 A: I believe the proposed deadband is reasonable. In these applications
6 and without considering performance factors, a deadband of 1%
7 means that the companies would not share any earnings with
8 customers between a return on equity of 12% and 13%. Similarly, the
9 companies could not share any under-earnings with customers
10 between the baseline of 12% and 11%. To bring some perspective to
11 these numbers, a 1-percentage point change in equity equates to
12 about \$1.2 million in revenue requirements and 1% in total revenues
13 for the applicants. Therefore, revenues could vary as much as \$2.4
14 million from one year to the next and customers would be unaffected.

15

16 The deadband insures that customers are not affected by every factor
17 affecting the delivery of energy. Instead, the utilities are at risk for any
18 over or under-earnings within the band. In North Dakota, weather
19 extremes are a way of life and can greatly influence the earnings
20 capabilities of the electric companies. A deadband therefore puts the
21 utilities at risk for the swings in earnings caused by weather extremes.
22 Dead-bands provide a front line whereby the utilities are at risk for
23 both uncontrollable and controllable factors. Under PBR, a company
24 must affectively manage its embedded cost of debt and capital
25 structure to be successful. The company must manage its sales and
26 expenses to be successful. Some of the costs are controllable by the
27 company while others are more a matter of luck.

28

1 Under rate of return regulation, reported earnings on equity for OTP
2 have fluctuated between 10% and 14% during the past 5 years.
3 During the same period, reported earnings for NSP have fluctuated
4 between 11% and 17%. See Schedule MRD-5 for details of reported
5 earnings levels. At the close of each year, the Commission receives
6 annual reports from the utilities companies disclosing earnings levels.
7 Once received, the staff recommends to the Commission whether it
8 should open a financial investigation because of reported over-
9 earnings. Staff's investigations have typically focused on the use of a
10 12% return on equity. However, staff has not been inclined to suggest
11 opening an investigation unless reported earnings exceeded 13%
12 thereby recognizing a range of reasonableness similar to the dead
13 proposed by the applicants.

14
15 **Revenue Sharing**

16 Q: Otter Tail does not request an economic development component as
17 part of its revenue sharing plan. However, NSP suggests that 10% of
18 any revenue sharing be allocated to a dedicated economic
19 development fund. Comments?

20 A: I agree with the 50/50 sharing advocated by OTP. I don't believe it is
21 necessary to set up a specific mechanism to set aside economic
22 development funds. NSP can choose to participate or not participate
23 in economic development activities just like any other competitive
24 enterprise. However, each decision will impact the earnings of the
25 company. Under PBR, the company will pay for at least one-half of all
26 economic development activities. For earnings that would have fallen
27 within the bandwidth absent economic development expenditures,
28 NSP will pay 100% of the costs. For earnings that would have fallen

1 outside the bandwidth absent economic development expenditures,
2 NSP will pay for 50% of the costs. The fiduciary responsibility of
3 management to its stockholders will be strong and require thoughtful
4 consideration under PBR.

5
6 **Price Cap**

7 Q: What do you think about the price cap portion of the PBR plans?

8 A: Both companies support the same price cap calculation. Under the
9 plans, a price decrease is not likely to occur irrespective of earnings
10 levels achieved. On the other hand, the ability to raise prices under
11 PBR is likely to occur given the history of the determinants for a price
12 change, namely the applicants' rates in relation to those in the
13 comparison group, CPI, and the changes in the comparison group
14 prices. The last time the country saw a negative CPI for a December-
15 to-December comparison was in 1954. You might have to go back
16 just as far to find a period where applicants' North Dakota electric
17 rates were higher than the regional average. Therefore, two of the
18 three determinants strongly favor the applicants.

19
20 Q: What do you recommend?

21 A: I believe the decision making model should be adjusted to bring in a
22 more balanced approach. However, I agree with the starting point
23 that includes the top of the deadband. Under PBR, if the Commission
24 agrees that given certain parameters a particular company has earned
25 the right to earn a certain return on equity, before any sharing occurs,
26 then the price cap formula should begin at that point.

27

1 However, I suggest that the next decision level of whether rates are
2 higher or lower than the comparison group be dropped. Both NSP
3 and Otter Tail are more than a cent per kWh away from the
4 comparison group average providing little challenge or comparative
5 value. Inclusion of this standard in the price-flexing part of the plan
6 does little more than make price increases possible and price
7 decreases unlikely. See Schedule MRD-6 for applicants' decision-
8 making model.

9
10 I suggest that the CPI be replaced with an inflation index more closely
11 related to providing electricity. To this end, I suggest the use of the
12 broad PPI as discussed earlier. In consideration of the applicants'
13 already low rates, I don't believe a productivity offset or stretch factor
14 is necessary.

15
16 Last and in the interest of furthering symmetry and rate stability, I
17 suggest that the same negative and positive conclusion is made
18 possible. According to the companies' filings, when a rate decrease is
19 required the largest negative of the inflation index and the average
20 change in the comparison group prices must be used to adjust rates.
21 On the other hand, if a rate increase is allowed then the smallest
22 positive of the two indexes is used to adjust rates. I suggest that if a
23 price decrease is required, such a decrease be tempered to the
24 smaller of the two limiting indexes. Similarly, if a price increase is
25 allowed, such an increase is limited to the smaller of the two indexes.
26 See Schedule MRD-7 for staff's decision-making model.

27

1 In summary, staff advocates using the model developed by NSP with
2 a few adjustments. Staff's adjustments will add some symmetry to the
3 plan, eliminate a layer of the decision making model, and replace CPI
4 with a more relevant PPI index. These suggestions will limit price
5 increases and decreases to those experienced on average by both
6 the industry as a whole (PPI) and the companies in this particular
7 region (comparison group price change).

8
9 **Reliability Standard**

10 Q: Please comment on the reliability standard selected by the applicants.

11 A: I agree with the use of the system average interruption duration index
12 (SAIDI) for the reliability performance standard. There are other
13 indexes that could be considered or combined with the SAIDI but from
14 an overall perspective and for the sake of administrative ease, I
15 support the use of the SAIDI.

16
17 Q: What do you think about how the performance benchmark is
18 calculated?

19 A: Attachment D, Page 2 of the application provides the details of the
20 reliability standard advocated by NSP. Because consistent historical
21 information is not available for North Dakota prior to 1999, NSP's
22 proposal averages the averages of both North Dakota and Minnesota
23 indexes. I am leery about using Minnesota's index without any
24 support for its applicability to North Dakota. Instead, I suggest using
25 the North Dakota average of 1999 and 2000 (to be determined later)
26 plus or minus 15% for the initial bandwidth. For each year after that, I
27 suggest including last years index as part of the average. I'm not
28 entirely comfortable with either of these methods, but prefer a method

1 based on North Dakota results. That said, reliability is too important to
2 leave out of the PBR plan simply because good historical information
3 is not available. For 1999, NSP reported a North Dakota SAIDI index
4 of 74.

5
6 Otter Tail uses a straight 5-year system-wide average to develop its
7 standard of 83 minutes because of reporting difficulties on a state-by-
8 state basis. I would prefer a North Dakota basis but that type of
9 information is not available. Otter Tail is a much smaller company by
10 comparison to NSP and does much more of its business in North
11 Dakota. Therefore, staff is agreeable to using the system-wide
12 average supported by Otter Tail.

13
14 **Summary**

15 Q: Please summarize the PBR plan incorporating staff's suggested
16 revisions to NSP's plan.

17 A: Staff believes the 3 performance measures of price, reliability and
18 customer satisfaction are sufficient and recommends excluding the
19 employee safety standard. With regard to the performance measure
20 of price, staff recommends a bandwidth of plus or minus .05 cents
21 from the average of the prior year's top 10 price performers. Staff
22 agrees with the proposed reliability standard (SAIDI) but suggests that
23 NSP recalculate its index annually to reflect additional North Dakota
24 experience. Staff suggests that the companies consider including the
25 top two responses in the customer satisfaction standard rather than
26 the top three responses out of five. Staff believes that the proposed
27 return on equity baseline of 12% and a deadband of 1 percentage
28 point is a reasonable starting point. Rather than assigning 2

1 additional percentage points for meeting all four performance
2 standards, staff recommends an additional 1.25 percentage points for
3 meeting all three performance standards (.5 percentage points for
4 price and reliability and .25 percentage points for customer
5 satisfaction). With staff's revisions in place, the company has the
6 potential to earn 14.25% on equity before sharing any additional
7 profits with shareholders. However, to get there the company will
8 have to maintain its already low price status within the region, beat its
9 average system outages by 15% and serve customers very well. On
10 the flip side, if the company does not perform it has the potential to
11 earn as low as 9.75% return on equity before customers are expected
12 to share in its under earnings. Further, staff advocates no revenue
13 sharing if the company can secure the lowest price position in the
14 region and still maintain quality of service
15

16 Last and perhaps the most contentious are the price change schemes
17 advocated by staff and the companies. The companies recommend
18 plans that would make price decreases nearly impossible and price
19 increases quite possible--though limited to a factor of CPI or regional
20 price changes, whichever is smaller. On the other hand, staff argues
21 for a scheme that minimizes price changes of any kind.
22

23 Q: Does this conclude your testimony?

24 A: Yes, it does.
25

Comparison of CPI to PPI

Schedule MRD-1

Year	CPI		(1) Narrow PPI		(2) Broad PPI	
	Index	% Chg	Index	% Chg	Index	% Chg
1990	133.8	6.1%	100		100	
1991	137.9	3.1%	99.7	-0.3%	104.4	4.4%
1992	141.9	2.9%	100.1	0.4%	105.9	1.4%
1993	145.8	2.7%	99.9	-0.2%	107.1	1.1%
1994	149.7	2.7%	100	0.1%	109.1	1.9%
1995	153.5	2.5%	98.5	-1.5%	109.5	0.4%
1996	158.6	3.3%	99.2	0.7%	109.8	0.3%
1997	161.3	1.7%	99.9	0.7%	109.9	0.1%
1998	163.9	1.6%	100.4	0.5%	107.7	-2.0%
1999	168.3	2.7%	98.3	-2.1%	107.7	0.0%
Last 3 Yr Avg		2.0%		-0.3%		-0.6%
Last 9 Yr Avg		2.6%		-0.2%		0.8%

Source: The information pertaining to the CPI (Consumer Price Index) and the PPI (Producer Price Index) was taken from the U.S. Department of Labor's Bureau of Labor Statistics' website and includes the December index for each year.

(1) Includes the PPI for residential electric consumers in the West North Central Region. The West North Central Region includes the states of Iowa, Kansas, Minnesota, Missouri, Nebraska, North Dakota, and South Dakota.

(2) Includes the PPI for electric power nationwide.

Price Standard Analysis

<u>Year</u>	<u>NSP</u>	<u>Cent/kwh</u> <u>Change</u>	<u>%</u> <u>Change</u>	<u>Region</u> <u>Average</u>	<u>Cent/kwh</u> <u>Change</u>	<u>%</u> <u>Change</u>	<u>Region</u> <u>Average</u> <u>less 15%</u>	<u>Cent/kwh</u> <u>Reward</u> <u>Margin</u>	<u>%</u> <u>Reward</u> <u>Margin</u>	<u>Region</u> <u>Average</u> <u>plus 15%</u>	<u>Cent/kwh</u> <u>Penalty</u> <u>Margin</u>	<u>%</u> <u>Penalty</u> <u>Margin</u>
1993	5.91			7.05								
1994	5.96	0.05	0.85%	6.96	-0.09	-1.28%	5.92	-0.04	-0.74%	8.00	2.04	34.30%
1995	5.80	-0.16	-2.68%	7.00	0.04	0.57%	5.95	0.15	2.59%	8.05	2.25	38.79%
1996	5.75	-0.05	-0.86%	6.98	-0.02	-0.29%	5.93	0.18	3.18%	8.03	2.28	39.60%
1997	5.86	0.11	1.91%	7.21	0.23	3.30%	6.13	0.27	4.58%	8.29	2.43	41.49%
1998	6.07	0.21	3.58%	7.31	0.10	1.39%	6.21	0.14	2.36%	8.41	2.34	38.49%
1999	6.11	0.04	0.66%	7.35	0.04	0.55%	6.25	0.14	2.25%	8.45	2.34	38.34%
Average								0.14	2.37%		2.28	38.50%
Average of Last 5 Years								0.18			2.33	

<u>Year</u>	<u>OTP</u>	<u>Cent/kwh</u> <u>Change</u>	<u>%</u> <u>Change</u>	<u>Region</u> <u>Average</u>	<u>Cent/kwh</u> <u>Change</u>	<u>%</u> <u>Change</u>	<u>Region</u> <u>Average</u> <u>less 15%</u>	<u>Cent/kwh</u> <u>Reward</u> <u>Margin</u>	<u>%</u> <u>Reward</u> <u>Margin</u>	<u>Region</u> <u>Average</u> <u>plus 15%</u>	<u>Cent/kwh</u> <u>Penalty</u> <u>Margin</u>	<u>%</u> <u>Penalty</u> <u>Margin</u>
1993	6.04			7.05								
1994	6.08	0.04	0.66%	6.96	-0.09	-1.28%	5.92	-0.16	-2.70%	8.00	1.92	31.64%
1995	6.04	-0.04	-0.66%	7.00	0.04	0.57%	5.95	-0.09	-1.49%	8.05	2.01	33.28%
1996	5.91	-0.13	-2.15%	6.98	-0.02	-0.29%	5.93	0.02	0.39%	8.03	2.12	35.82%
1997	6.02	0.11	1.86%	7.21	0.23	3.30%	6.13	0.11	1.80%	8.29	2.27	37.73%
1998	6.09	0.07	1.16%	7.31	0.10	1.39%	6.21	0.12	2.03%	8.41	2.32	38.04%
1999	6.03	-0.06	-0.99%	7.35	0.04	0.55%	6.25	0.22	3.61%	8.45	2.42	40.17%
Average								0.04	0.61%		2.18	36.11%
Average of Last 5 Years								0.08			2.23	

Utility Comparison Group (Investor Owned Utilities)
Average Residential Revenue (Cents/Kwh)
North Dakota, South Dakota, Montana, Wyoming, Minnesota, Iowa, Wisconsin

<u>Utility Company by Jurisdiction</u>	<u>1999</u>	<u>Rank</u>	<u>1998</u>	<u>Rank</u>	<u>1997</u>	<u>Rank</u>	<u>1996</u>	<u>Rank</u>	<u>1995</u>	<u>Rank</u>	<u>1994</u>	<u>Rank</u>	<u>1993</u>	<u>Rank</u>
Pacificorp - Mont					5.03	1	5.01	1	5.03	1	5.07	1	4.78	1
Cheyenne Light, Fuel, & Power -Wyo	6.20	4	5.66	1	5.87	5	6.05	5	6.07	7	5.59	3	5.60	4
Pacificorp - Wyo	5.74	1	5.73	2	5.67	2	5.63	2	5.59	2	5.61	4	5.57	3
IES Utilities (IA Southern Util)					5.80	3								
NSP - ND	6.11	3	6.07	3	5.86	4	5.75	3	5.80	3	5.96	6	5.91	6
Ottertail Power Co. - ND	6.03	2	6.09	4	6.02	6	5.91	4	6.04	6	6.08	7	6.04	7
Superior Water & Light - Wisc.											6.16	9	6.56	11
Wisc. Public Service - Wis	6.68	7	6.28	5	6.39	8	6.61	11	6.62	11	6.80	12	7.07	
Ottertail Power Co. - SD	6.25	5	6.30	6	6.22	7	6.17	7	6.26	8	6.12	8	6.25	8
Ottertail Power Co. - Minn	6.48	6	6.56	7	6.42	9	6.35	9	6.39	10	6.46	11	6.43	9
Montana Power Co. - Mont			6.58	8	6.44	10	6.11	6	5.88	4	5.69	5	5.60	5
Wisconsin Power & Light (Alliant) - Wis	6.87	9	6.72	9	6.73	12	6.79	13	6.82	13	7.01		6.70	12
Minnesota Power - Minn	6.71	8	6.77	10	6.61	11	6.34	8	5.94	5	5.55	2	5.41	2
Montana-Dakota Utilities - ND	7.21	11	6.90	11	6.86	13	6.76	12	6.81	12	6.95	13	6.94	13
NSP - Wis	7.33	12	7.10	12	7.00		6.96	14	6.82	14	6.98	14	7.06	
Black Hills Power & Light - Mont	7.09	10	7.22	13	7.67		8.21		8.20		7.87		8.16	
Montana-Dakota Utilities - Wyo	7.40	13	7.29	14	7.16		6.35	10	6.34	9	6.39	10	6.43	10
Montana-Dakota Utilities - Mont	7.43	14	7.41	15	7.40		7.40		7.42		7.43		7.45	
Northwest Public Service - SD	7.79	16	7.45	16	7.35		7.35		7.43		7.57		7.60	
NW Wisconsin Electric - Wis	7.59	15	7.62	17	7.23		6.97	15	6.98	15	7.02		7.05	
NSP - SD	7.85	19	7.66	18	7.60		7.45		7.53		7.59		7.51	
Wisconsin Energy Co. - Wisc	7.81	18	7.79	19	7.08		7.04		7.19		7.25		7.16	
Madison Gas & Elec - Wisc	8.41	24	7.81	20	7.69		7.44		7.48		7.62		7.76	
Black Hills Power & Light - Wyo	7.80	17	7.84	21	7.81		7.76		7.39		7.28		6.96	15
NSP - Minn	8.02	21	7.89	22	7.87		7.70		7.69		7.49		7.37	
Black Hills Power & Light - SD	8.29	22	8.28	23	8.24		8.17		7.83		7.76		7.23	
Interstate Power Co. - Iowa	7.86	20	8.55	24	7.78		7.47		7.45		7.23		6.95	14
Interstate Power Co.(Alliant) - Minn	8.30	23	8.62	25	8.52		8.16		7.93		8.01		8.05	
IES Utilities (Alliant) - Iowa	8.57	25	8.73	26	9.70		8.08		8.15					
MidAmerican Energy - Iowa			8.88	27	8.83		8.85		9.17					
Montana-Dakota Utilities - SD	9.17	26	8.96	28	8.87		8.76		8.81		8.94		8.94	
Iowa Electric Light and Power - Iowa											8.05		9.64	
Midwest Power											8.48		9.32	
Iowa-III. Gas & Electric - Iowa											10.06		9.16	
Average Residential Rate	<u>7.35</u>		<u>7.31</u>		<u>7.12</u>		<u>7.02</u>		<u>7.00</u>		<u>7.03</u>		<u>7.05</u>	
Prior Years Top Ten Average Rate	6.43		6.31		6.13									
Comparison of Results														
Comparison Group Average Change	0.04		0.19		0.10		0.02		(0.03)		(0.02)			
Prior Years Top Ten Avg Rate Change	0.12		0.05		0.16		0.03		0.08		0.05			
NSP's Change	0.04		0.21		0.11		(0.05)		(0.16)		0.05			
OTP's Change	(0.06)		0.07		0.11		(0.13)		(0.04)		0.04			

Bandwidth of .05 Cents Around Top Ten Performers

Winners	Both			Both		Both		Both						
Losers		Both												
Draws											Both			

**Authorized Returns on Equity
Investor Owned Gas & Electric Companies of North Dakota
By Company and Jurisdiction**

Schedule MRD-4

<u>MDU Electric</u>	<u>Year</u>	<u>ROE</u>
Montana	1987	12.30
N. Dakota	1987	12.71
S. Dakota	1986	13.00
Wyoming	1993	11.35

<u>MDU Gas</u>		
Montana	1996	12.00
N. Dakota	1991	12.00
S. Dakota	1994	11.50
Wyoming	1993	11.35

<u>NSP Electric</u>		
Michigan	1999	11.90
Minnesota	1993	11.47
N. Dakota	1993	11.50
Wisconsin	1999	11.90

<u>NSP Gas</u>		
Michigan	1987	12.25
Minnesota	1998	11.40
N. Dakota	1991	12.00
Wisconsin	1999	11.90

<u>OTP</u>		
Minnesota	1986	12.00
N. Dakota	1984	14.84
S. Dakota	1986	11.75

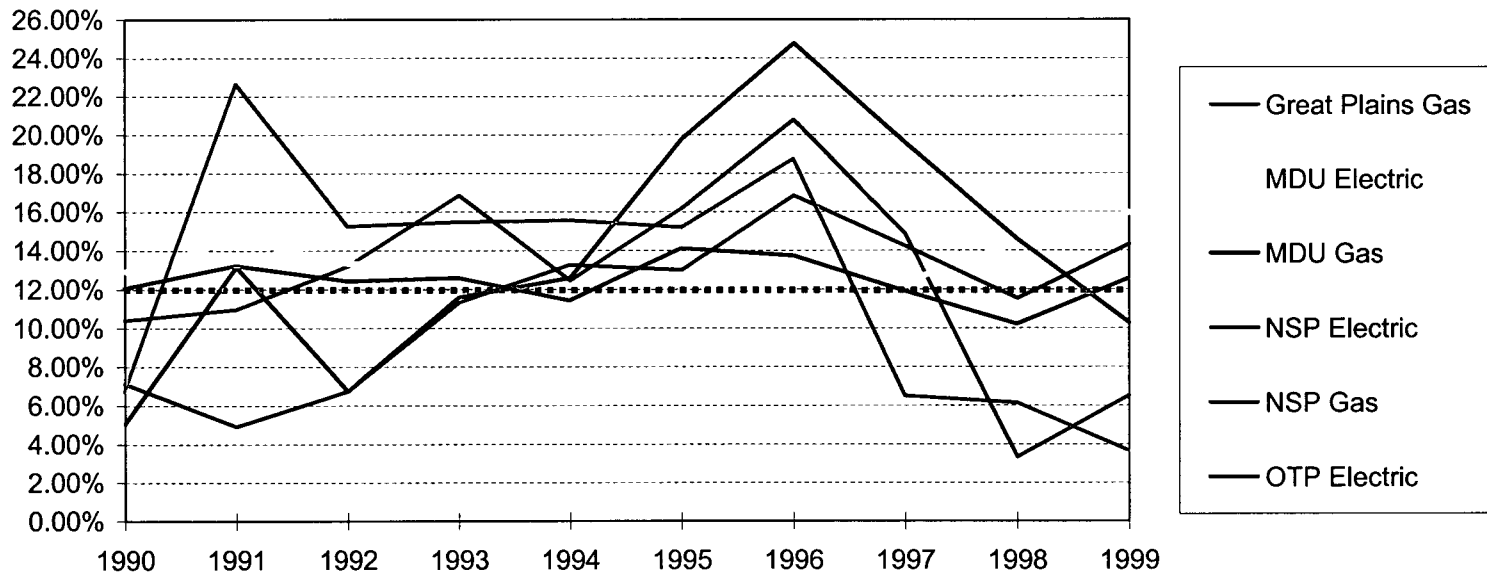
1995-2000 Average 11.82

1990-1994 Average 11.60

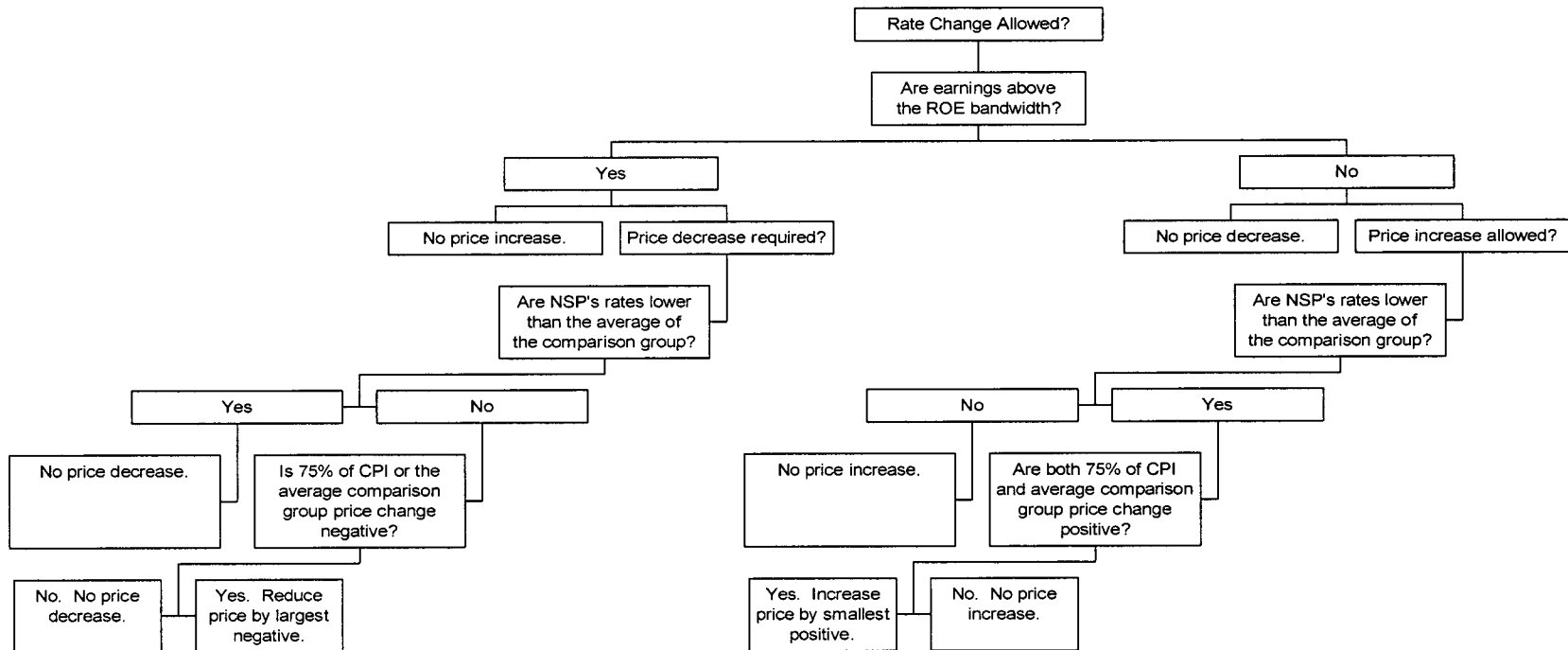
Average of All 12.06

**North Dakota
Investor Owned Gas & Electric Utilities
Reported Returns on Equity**

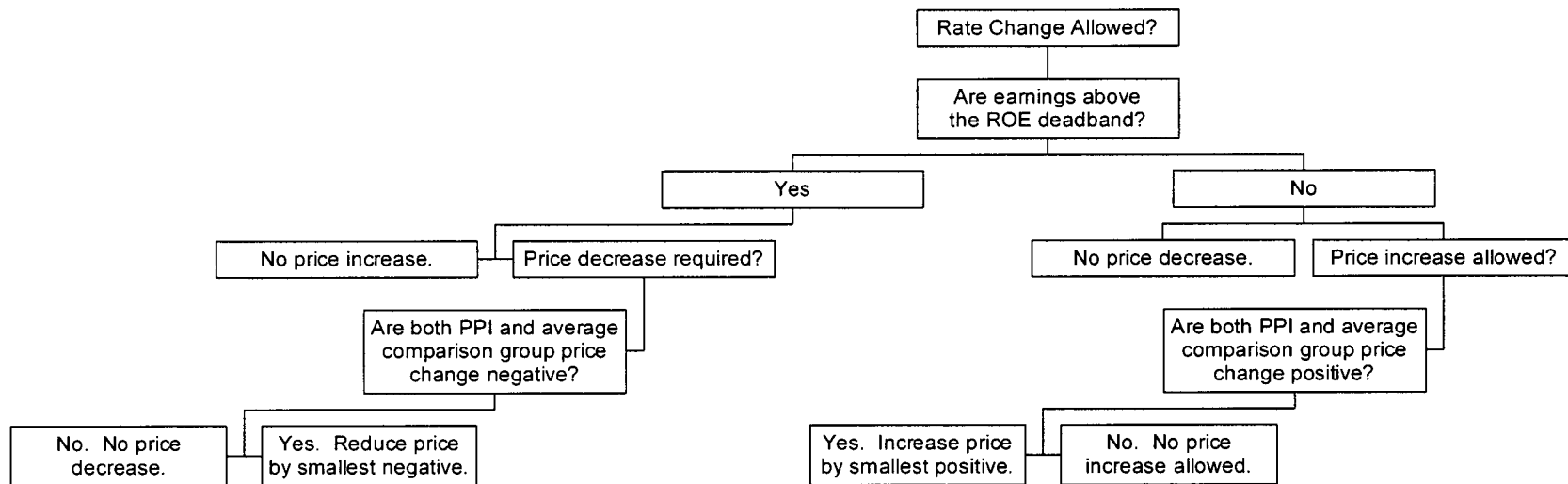
	<u>1990</u>	<u>1991</u>	<u>1992</u>	<u>1993</u>	<u>1994</u>	<u>1995</u>	<u>1996</u>	<u>1997</u>	<u>1998</u>	<u>1999</u>	Last 3 Year Average	10 Year Average
Great Plains Gas	10.40%	10.95%	13.17%	16.84%	12.44%	16.17%	20.77%	14.83%	3.31%	6.50%	8.21%	12.54%
MDU Electric	12.91%	14.56%	13.33%	13.04%	10.96%	11.72%	12.19%	12.35%	14.37%	15.94%	14.22%	13.14%
MDU Gas	5.04%	13.14%	6.71%	11.58%	12.59%	19.78%	24.75%	19.55%	14.55%	10.25%	14.78%	13.79%
NSP Electric	7.11%	4.90%	6.71%	11.31%	13.25%	12.98%	16.82%	14.20%	11.50%	14.30%	13.33%	11.31%
NSP Gas	6.72%	22.64%	15.24%	15.48%	15.55%	15.19%	18.73%	6.48%	6.12%	3.64%	5.41%	12.58%
OTP Electric	12.04%	13.21%	12.42%	12.59%	11.41%	14.11%	13.72%	11.88%	10.18%	12.53%	11.53%	12.41%
Average	9.04%	13.23%	11.26%	13.47%	12.70%	14.99%	17.83%	13.22%	10.01%	10.53%	11.25%	12.63%



Applicants' Price Cap Proposal



Staff's Price Cap Proposal

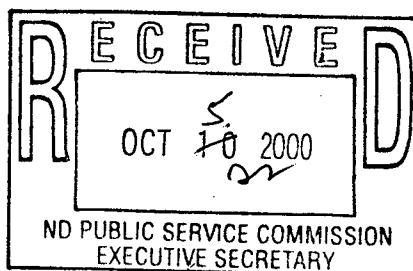




James P. Johnson
Assistant General Counsel

800 Nicollet Mall, Suite 2900
Minneapolis, Minnesota 55402
Phone: 612.215.4592
Fax: 612.215.4544

October 3, 2000



Mr. Jon Mielke
Executive Secretary
North Dakota Public Service Commission
600 East Boulevard
Bismarck, ND 58505

Re: Application of Northern States Power Company d/b/a Xcel Energy for
Authority to Operate Under Performance Based Regulation In North Dakota
Case No. PU-400-00-195

Dear Mr. Mielke:

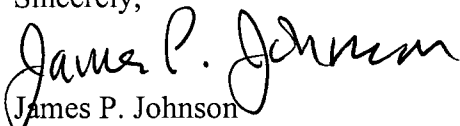
On September 29, 2000, Northern States Power Company d/b/a Xcel Energy ("Xcel Energy" or "the Company") submitted its prepared direct testimony in the above captioned docket via electronic mail. Hard copies were delivered on October 2, 2000.

As part of the filing, the Company included signed affidavits of the Xcel Energy witnesses. However, the Company provided a fax copy of the affidavit of David H. Sederquist because the original was in transit at the time the paper copies were prepared and submitted.

Enclosed is the original affidavit of Mr. Sederquist for attachment to the original copy of Mr. Sederquist's prepared direct testimony.

Please direct any questions regarding this filing to the undersigned at (612) 215-4592.

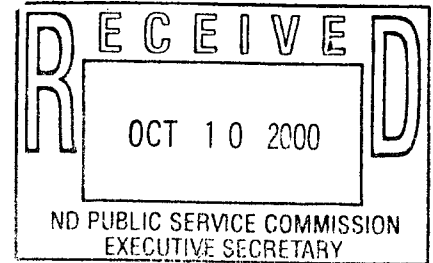
Sincerely,


James P. Johnson
Assistant General Counsel

cc: Honorable Allen Hoberg, Administrative Law Judge
Mr. Bill Binek, Commission Counsel

Enclosures

STATE OF NORTH DAKOTA
BEFORE THE
PUBLIC SERVICE COMMISSION

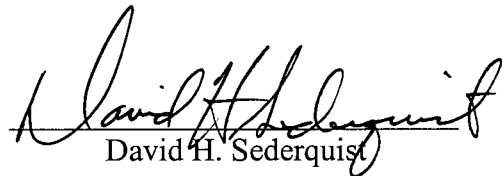


In the Matter of the Application of)
Northern States Power Company d/b/a)
Xcel Energy for Authority to Operate)
Under Performance-Based Regulation)
in North Dakota)

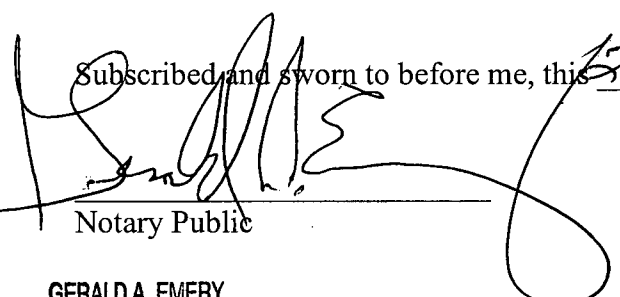
Case No. PU-400-00-195

**AFFIDAVIT OF
DAVID H. SEDERQUIST**

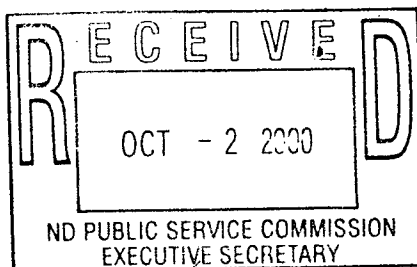
I, the undersigned, being duly sworn, depose and say that the foregoing is the testimony of the undersigned, and that such Direct Testimony and the exhibits sponsored by me to the best of my knowledge, information and belief, are true, correct, accurate and complete, and I hereby adopt said testimony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


David H. Sederquist

Subscribed and sworn to before me, this 28th day of September, 2000.


Notary Public

GERALD A. EMERY
Notary Public, STATE OF NORTH DAKOTA
My Commission Expires APRIL 25, 2002



Legal Services

800 Nicollet Mall, Suite 2900
Minneapolis, Minnesota 55402

September 29, 2000

Mr. Jon Mielke
Executive Secretary
North Dakota Public Service Commission
600 East Boulevard
Bismarck, ND 58505

Honorable Allen Hoberg
Administrative Law Judge
Office of Administrative Hearings
1701 North 9th Street
Bismarck, ND 58501-1882

Re: Application of Northern States Power Company d/b/a Xcel Energy for
Authority to Operate Under Performance Based Regulation In North Dakota
Case No. PU-400-00-195
Prepared Direct Testimony of Xcel Energy

Dear Mr. Mielke and Judge Hoberg:

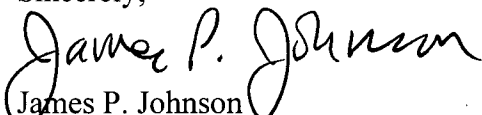
Enclosed please find an original and seven (7) copies of the prepared direct testimony of Mr. David H. Sederquist, Ms. Pamela L. Bagley and Ms. Heather A. Schander in support of the April 20, 2000 petition of Northern States Power Company, now doing business in North Dakota as Xcel Energy, in the above captioned docket.

In addition, enclosed please find an original and seven (7) copies of the prepared direct testimony and exhibits of Mr. Karl McDermott on behalf of both Xcel Energy in Case No. PU-400-00-195 and Otter Tail Power Company in Case No. PU-401-00-36. While the two cases have not been officially consolidated, the Xcel Energy and Otter Tail Power performance based regulation plans are similar and the cases will be subject to a joint evidentiary hearing scheduled for October 23-24, 2000.

Xcel Energy will also serve two copies of the prepared direct testimony on Judge Hoberg, and one copy on each party to the service list to Case No. PU-400-00-195. A certificate of service and service list is attached.

Please direct any questions regarding this filing to the undersigned at (612) 215-4592 or to Mr. Dave Sederquist at (701) 241-8632.

Sincerely,


James P. Johnson
Assistant General Counsel

Enclosures

21

PU-400-00-195

Pages: 2

Letter re filing and Affidavit of Service

by Northern States Power Company

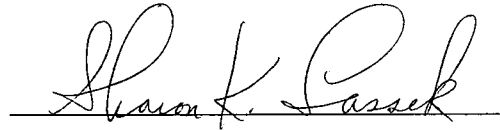
10/02/2000

CC: Comm Legal PUD (3) Mike ALJ

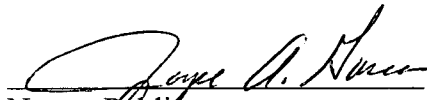
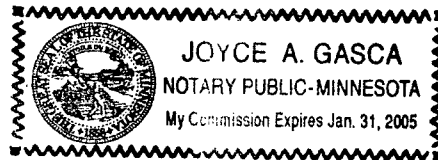
AFFIDAVIT OF SERVICE

I, Sharon K. Lassek, hereby certify that I have this day served the Direct Testimony of David H. Sederquist, Karl McDermott, Heather A. Schander and Pamela L. Bagley on the parties listed below by placing in the U.S. mail at Minneapolis, Minnesota.

Dated this 29th day of September, 2000.



Subscribed and sworn to before
me this 29th day of September, 2000.


Notary Public

Jon Mielke
Executive Secretary
North Dakota Public Service Commission
600 East Boulevard
Bismarck, ND 58501

Honorable Allen Hoberg
Administrative Law Judge
Office of Administrative Hearings
1701 North 9th Street
Bismarck, ND 58501-1882

William Binek
North Dakota Public Service Commission
600 East Boulevard
Bismarck, ND 58501

Mike Diller
North Dakota Public Service Commission
600 East Boulevard
Bismarck, ND 58501

Todd Guerrero
Otter Tail Power Company
215 S. Cascade Street
Fergus Falls, MN 56538-0496

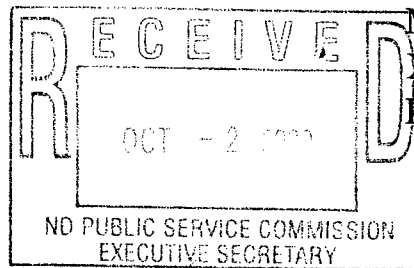
James P. Johnson
Xcel Energy d/b/a/
Northern States Power Company
800 Nicollet Mall, Suite 2900
Minneapolis, MN 55402

Direct Testimony

Ms. Heather A. Schander

Xcel Energy Exhibit 4

Hearing Exhibit ____



Before the Public Service Commission of
the State of North Dakota

In the Matter of the Application of
Northern States Power Company d/b/a Xcel Energy
for Authority to Operate under Performance-Based Regulation
in North Dakota

Case No. PU-400-00-195



September 29, 2000

20 PU-400-00-195

Pages: 10

Direct Testimony of Heather A Schander

by Northern States Power Company

Exhibit # 7

10/02/2000 CC: Comm Legal Ilona, Pat, Jerry Mike

1 Q. Please state your name, position and business address.

2 A. I am Heather A. Schander, Market Research Analyst for Xcel Energy
3 Services Inc., the service company subsidiary of Xcel Energy Inc. ("Xcel").
4 My business address is 512 Nicollet Mall, Minneapolis, Minnesota 55402.

5

6 Q. What are your responsibilities as Market Research Analyst?

7 A. My primary responsibilities include conducting primary and secondary
8 market research for the operating company subsidiaries of Xcel, including
9 Northern States Power Company d/b/a Xcel Energy ("Xcel Energy" or "the
10 Company"), which provides electric and natural gas service in North Dakota,
11 Minnesota and South Dakota.

12

13 Q. What is the purpose of your testimony?

14 A. As described by Mr. Sederquist, on April 20, 2000, the Company submitted
15 its PLUS performance based ratemaking ("PBR") plan. The purpose of my
16 testimony is to explain the PLUS plan customer satisfaction standard and
17 measure, how this measure will be derived, the survey process, and why this
18 process is a meaningful way of measuring our customers' perceptions of
19 customer service performance by Xcel Energy.

1 Q. Please explain the PLUS customer satisfaction standard and measure, and
2 how the measure will be derived.

3 A. The PLUS customer satisfaction standard is to have 95 percent of Xcel’s
4 residential, small commercial and industrial (C&I) and large commercial and
5 industrial (C&I) customers in North Dakota rate the Company’s performance
6 positively. The PLUS customer satisfaction measure will be derived from
7 the results of the satisfaction surveys of Xcel Energy's residential, small C&I
8 and large C&I customers in North Dakota.

9
10 Specifically, Xcel Energy will contract with an outside vendor to conduct
11 telephone surveys that measure the customer’s overall satisfaction with the
12 Company. The Company would conduct the large C&I and small C&I
13 surveys annually in the Fall, and the residential survey in two periods, once
14 in the Spring and once in the Fall. The 2001 results from these surveys will
15 be available no later than November 1, 2001, and would be reported to the
16 Commission in April 2002, as I understand. The measure for the PLUS plan
17 will be based exclusively on survey results from customers who reside in
18 Xcel Energy's North Dakota service territory.

1 Q. Why were customer satisfaction surveys selected to measure Xcel Energy's
2 customer service performance? Is this process a meaningful way of
3 measuring customer's perceptions of customer service performance?

4 A. The most effective way of truly measuring the Company's customer service
5 performance is to ask the customer directly. This technique is a
6 straightforward way of collecting direct feedback, which is a necessary input
7 for measuring the Company's performance in meeting customers' service
8 expectations. Our proposed, general measurement captures all aspects of the
9 customer's relationship from their perspective. As a result, it is the broadest
10 and best general measure of the Company's performance in providing
11 quality customer service.

12
13 Q. Can you please explain the survey process and how the results are compiled?

14 A. To ensure impartiality, Xcel Energy contracts with a third-party vendor to
15 conduct the survey. Xcel Energy personnel compile the lists of customers to
16 be used for the large C&I survey. The lists used for the residential and small
17 C&I surveys are extracted from Xcel Energy's customer databases. These
18 lists are forwarded to the third-party vendor, who then conducts the actual
19 telephone interviewing. The vendor randomly selects customers for

1 interviewing until typically one of two events has occurred 1) the desired
2 number of completed surveys (or quota) is met; or 2) all customers on the
3 lists have been attempted multiple times for interviewing. Quotas will be
4 based on meeting a confidence level of 95 percent and a confidence interval
5 of five percent (95% +/- 5%), which ensures the data collected is a true
6 representation of the population being surveyed (i.e., the Company can be
7 95% certain the true population would chose the same answers as the survey
8 group, give or take 5%). After the survey interviewing is complete, the
9 vendor tabulates the data and provides Xcel Energy a data file and a report.

10
11 Q. How will the PLUS customer satisfaction measure be calculated from the
12 results of the satisfaction studies?

13 A. The customer satisfaction measure for the PLUS plan will be derived from
14 the vendor-supplied report. The PLUS customer satisfaction measure will be
15 calculated by averaging the percentage of “positive responses” to one
16 question that is asked to each of the three survey groups (residential, small
17 C&I and large C&I).

1 Q. What is the question, and how is a "positive response" percent determined?

2 A. The question used for the PLUS plan customer satisfaction score reads:

3 "Thinking of your overall relationship with Xcel Energy, would you
4 rate the quality of products and services provided by Xcel Energy
5 as...?".

6 The participant is then given the options of "Excellent", "Very Good",
7 "Good", "Fair" or "Poor." The PLUS plan has an "acceptable" performance
8 standard based on the percent of customers who rate the Company positively
9 (i.e., "Excellent", "Very Good", or "Good") on this question. Again, the
10 PLUS plan score will be calculated by averaging the percent of positive
11 responses for residential, small C&I and large C&I customers surveyed who
12 reside in Xcel Energy's North Dakota service territory.

13

14 Q. How was the performance standard chosen for the PLUS plan?

15 A: As explained in earlier testimony, the PLUS plan has established an
16 acceptable performance standard of 95 percent positive. This target was
17 selected primarily because it is consistent with the customer satisfaction
18 performance target in the Company's 2000 "Pay for Performance" employee
19 compensation plan, which links customer satisfaction and annual goals. A

1 common target aids in the communication and understanding of the PLUS
2 plan objectives to employees, and insures the Company and its employees
3 are evaluated under a common standard. The selection of a +/- 1.5 percent
4 response range (between 93.5% and 96.5%) reflects a narrower band of
5 variability relative to the other three PLUS performance indicators, which
6 use a +/- 15 percent variability. The combination of the high initial standard
7 (95% favorable) plus the narrow bandwidth means the Company is
8 subjecting itself to a very stringent customer satisfaction measure in the
9 PLUS plan. For example, even if 90% of Xcel Energy's customers in North
10 Dakota were to give an overall positive rating in 2001, the Company would
11 not meet the minimum standard for PLUS.

12
13 Q. How well has Xcel Energy's North Dakota operations scored on this standard
14 in previous customer satisfaction surveys?

15 A. In 1998, the North Dakota operations had an average positive response rating
16 of 98.0%. In 1999, the North Dakota operations scored a 96.0% positive
17 rating, which would be within the PLUS plan's allowable performance
18 bandwidth. The 2000 satisfaction survey results are not yet complete.

1 Q. What safeguards are in place by Xcel Energy to ensure that the customer
2 satisfaction results compiled are legitimate and accurate?

3 A. As stated in earlier testimony, Xcel Energy hires a third-party vendor to
4 perform survey inquiries, collect the raw data, and tabulate the results. Also,
5 when the interviewing is conducted, the vendor randomly selects customers
6 for interviewing. The question is worded in a manner to be clear and
7 understandable to the respondent, and yet provide no hint of bias. Finally, a
8 confidence level and confidence interval of 95% +/- 5% is pursued to ensure
9 the results reflect the entire customer population in North Dakota. I am
10 confident the survey results accurately measure overall customer satisfaction
11 for our customers in North Dakota.

12

13 Q. Does this conclude your direct testimony?

14 A. Yes, it does.

HEATHER A. SCHANDER
Xcel Energy Services Inc.
512 Nicollet Mall, Minneapolis MN 55401

**WORK
EXPERIENCE**

Northern States Power Company, Minneapolis, MN (1996-present)

Position: 1998-present, Market Research Analyst

1996-1998, Marketing Research Assistant (Contractor)

Responsibilities: Represent "the voice of the customer" by communicating results from NSP's customer satisfaction studies to internal clients. Supervise and ensure successful implementation and maintenance of these studies, specifically survey development and administration, data analysis, and reporting of actionable results that can be utilized by NSP to improve customer satisfaction and retention. Also act as the liaison for NSP-North Dakota and South Dakota, making certain their market research needs are represented within NSP.

Snyders Family Restaurant, Maple Grove, MN (1995-1996)

Chinese Phoenix & Eddies Kitchen, St. Cloud, MN (1994-1995)

Position: Server/Supervisor

Jubilee Foods, Maple Grove, MN (1989-1994)

Position: Cashier/Customer Service Representative

Responsibilities: Worked in the customer service area, creating customer-focused solutions to problems.

EDUCATION

St. Cloud State University (AACSB), St. Cloud, MN

Bachelor of Science Degree

Major: Marketing Emphasis: Marketing Research

G.P.A.: 3.77 on a 4.0 scale

Graduation Date: November 1995 Summa Cum Laude

North Hennepin Community College, Brooklyn Park, MN

Associate of Arts Degree

G.P.A.: 3.8 on a 4.0 scale

Graduation Date: September 1993 with Honors

**COMPUTER
SKILLS**

SPSS, version 8.0

Microsoft Access

SAS

Microsoft Word

Microsoft Excel

Microsoft Powerpoint

**ACTIVITIES
&
ACHIEVEMENTS**

* Attended market research-focused seminars including: *Analyzing and Reporting Questionnaire Data, Developing Surveys and Questionnaires for Market Research, Using Secondary Market Research, Developing Business Strategies from Research.*

* Performed a market study for the **Small Business Institute (SBA)** in 1995.

STATE OF NORTH DAKOTA
BEFORE THE
PUBLIC SERVICE COMMISSION

In the Matter of the Application of)
Northern States Power Company d/b/a)
Xcel Energy for Authority to Operate)
Under Performance-Based Regulation)
in North Dakota)

Case No. PU-400-00-195

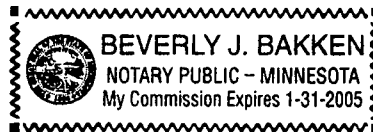
**AFFIDAVIT OF
HEATHER A. SCHANDER**

I, the undersigned, being duly sworn, depose and say that the foregoing is the testimony of the undersigned, and that such Direct Testimony and the exhibits 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.

Heather A. Schander
Heather A. Schander

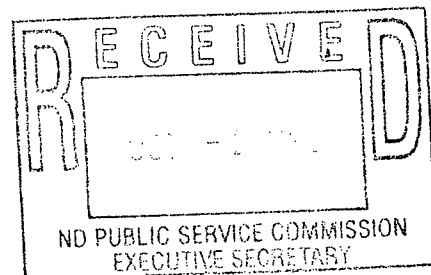
Subscribed and sworn to before me, this 28 day of September 2000.

Beverly J. Bakken
Notary Public



Direct Testimony
Mr. David H. Sederquist
NSP Exhibit No. 2
Hearing Exhibit No. ____

Before the Public Service Commission of
the State of North Dakota



In the Matter of the Application of
Northern States Power Company d/b/a Xcel Energy
for Authority to Operate under Performance-Based Regulation
in North Dakota

Case No. PU-400-00-195



September 29, 2000

19 **PU-400-00-195**

Pages: 38

Direct Testimony of David H Sederquist

by Northern States Power Company
Exhibit # 3
10/02/2000 CC: Comm Legal Illona, Pat, Jerry Mike .

1 Q. Please state your name, position at Xcel Energy, and business address.

2 A. I am David H. Sederquist. I am Manager of North Dakota Regulatory
3 Affairs for Northern States Power Company doing business as Xcel Energy
4 (“Xcel Energy” or “the Company”), a utility operating company subsidiary
5 of Xcel Energy Inc. My office is at 2302 Great Northern Drive in Fargo,
6 North Dakota 58102.

7

8 Q. What are your responsibilities as Manager of Regulatory Affairs?

9 A. My main responsibilities include serving as the primary liaison with North
10 Dakota regulatory agencies; monitoring, coordinating, and communicating
11 Xcel Energy’s positions, proposals; and compliance with North Dakota
12 regulation. I’m also involved in financial analysis, business planning, and
13 performance reporting for the Company’s North Dakota business unit.
14 Schedule 1 contains a resume of my professional and educational
15 background.

16

1 Q. What is the purpose of your testimony?

2 A. I will describe Xcel Energy’s filed “PLUS” performance-based regulation
3 (PBR) plan, and demonstrate why it is a preferable framework for future
4 regulation of Xcel Energy’s electric operations in North Dakota.

5
6 PLUS is an acronym for “Performance Linking Utility Stakeholders.” The
7 plan is designed to create and distribute benefits to *all* of Xcel Energy’s
8 stakeholders when the Company succeeds. The plan ensures that the
9 interests of customers, communities, regulators, employees, and shareholders
10 are aligned toward a common goal, and that all stakeholders benefit from the
11 overall success of the Company.

12
13 I was personally involved in development of the PLUS plan, and am the lead
14 Company witness testifying in support of our April 20, 2000 application and
15 most of the specific PLUS plan components. In addition to my direct
16 testimony, Ms. Pamela Bagley will support the PLUS plan reliability
17 performance measure, and Ms. Heather Schander will support the PLUS
18 customer satisfaction performance measure. Also, Mr. Karl McDermott is
19 submitting direct testimony on behalf of both Xcel Energy and Otter Tail

1 Power Company (“OTP”) which describes the benefits of performance-
2 based regulation in general, and provides an overview and evaluation of the
3 plans submitted by both companies.

4
5 Q. Please describe your experience with PBR.

6 A. Prior to the development of the PLUS plan, I participated on the
7 Commission’s 1995 Alternative Regulation task force, which led to its
8 “Guidelines for Filing Alternative Regulation Proposals” (“Guidelines”),
9 Case No. PU-439-94-590, order dated September 20, 1995 (see Attachment
10 A in the PLUS Application). Since that time I’ve reviewed various PBR
11 studies and industry literature on the subject and studied many of the
12 approved PBR plans across the country. I’ve also attended several
13 conferences on PBR-related topics, and have spoken personally with other
14 PBR designers across the country. After going through this education
15 process, I developed the specifics of the PLUS plan by choosing the best
16 components of successful PBR plans in place in other states, and applying
17 them uniquely to Xcel Energy’s electric operations in North Dakota.

1 Q. Has the PLUS plan been subject to “peer review”?

2 A. Yes. Early in the development of the plan, I presented and discussed the
3 proposal with officials from North Dakota’s other two investor-owned
4 electric utilities. In July 2000 I presented an overview of the PLUS plan to
5 industry and regulatory representatives at a Chicago, Illinois, PBR
6 conference sponsored by the Pacific Economics Group. I have also been in
7 contact with companies and other industry organizations requesting
8 information on the plan.

9
10 Xcel Energy and OTP have also jointly engaged Mr. Karl McDermott of
11 National Economics Research Associates (NERA) to review the plans and
12 give the Commission his expert opinion. As Mr. McDermott testifies, the
13 PLUS plan is, overall, a fair and reasonable approach to performance-based
14 regulation.

15
16 Q. Why did Xcel Energy file a PBR proposal?

17 A. Xcel Energy believes a PBR framework – specifically the PLUS plan – will
18 result in 1) superior customer service and efficiency, 2) a streamlined
19 regulatory process, and 3) more competitive rates, in the long-term, than

1 traditional cost-of-service regulation would produce. In addition, the
2 Company's commitment to file the proposal was an integral component of
3 the settlement agreement approved by the Commission in May 2000 to
4 resolve Case Nos. PU-400-99-418 and PU-400-98-246.

5
6 Q. When does Xcel Energy propose to began operating under PLUS, and how
7 long will it be in effect?

8 A. Xcel Energy proposes that PLUS take effect on January 1, 2001, concurrent
9 with our planned \$260,000 electric rate reduction.¹ The plan will be in place
10 for five years ending December 31, 2005. The proposal calls for the
11 Commission and the Company to review the plan after two years, and near
12 the end of the five-year term assess the success of the plan and whether it
13 should be modified and/or extended.

14
15
16

¹ Xcel Energy also agreed to this rate reduction as part of the approved settlement agreement in the recent merger between Northern States Power Company and New Century Energies, Inc., Case Nos. PU-400-99-418 and PU-400-98-246.

1 Q. Will Xcel Energy provide better customer service under PLUS?

2 A. Incentives for maintaining or improving customer service are clearly
3 established in PLUS. Unlike traditional cost-of-service regulation, PLUS
4 defines customer service and price performance as key factors in regulating
5 electric earnings and rates. The Commission recognized this potential in its
6 1995 Guidelines for filing PBR proposals, and Mr. McDermott discusses this
7 concept of PBR more fully in his testimony.

8
9 Q. Will Xcel Energy's electric rates increase under PLUS?

10 A. Again, under PLUS, the incentives are clearly in place for the Company to
11 control costs and hold down prices in both the short and long term. If the
12 Company is successful in achieving incremental efficiencies and realizing
13 better financial results, customers' electric bills should be lower under PLUS
14 through the revenue sharing mechanism. This sharing would not otherwise
15 occur without the PLUS plan. I will further address the PLUS plan's rate
16 changing provision later in my testimony.

17

18

19

1 Q. What are the main components of Xcel Energy’s PLUS plan?

2 A. The key components of PLUS include 1) customer service, employee safety,
3 and price performance standards, 2) a “dynamic” authorized rate of return on
4 common equity (“ROE”) range which can vary based on Company
5 performance, 3) a revenue-sharing mechanism, and 4) flexibility to adjust
6 prices under specified circumstances. I will now discuss each component in
7 more detail.

8
9 **Performance Standards**

10 Q. What performance measures is Xcel Energy proposing to use to gauge
11 customer service, price, and operational excellence?

12 A. The following table shows the four indicators that will be used to measure
13 performance within Xcel Energy’s North Dakota jurisdiction:

Performance	Indicator	Description
Reliability	SAIDI	Amount of time (minutes) a typical customer is without power in a year.
Customer Satisfaction	% positive survey response	% of respondents who rate Xcel Energy products and services as excellent, very good, or good.
Price	Avg. revenue per kilowatt	Residential revenues divided by residential sales
Employee Safety	OSHA incident rate	Number of annual safety incidents per 100 employees

1 Ms. Bagley discusses the basis for the SAIDI standard, and Ms. Schander
2 discusses the basis for the customer satisfaction standard.

3
4 Q. Why were these measures selected?

5 A. These measures were selected because they met the criteria outlined in the
6 Commission’s 1995 PBR guidelines. They are comprehensive, simple to
7 administer, understandable, and easily communicated.

8
9 In designing the PLUS plan, the Company made considerable effort to select
10 as few indicators as possible to measure the primary performance areas. In
11 my research I’ve observed that plans with numerous indicators often end up
12 being complex, difficult to monitor and verify, and contentious. In addition,
13 as described by Mr. McDermott, if the indicators are too narrowly focused,
14 there is a danger that management will direct disproportionate attention to
15 those areas, at the expense of overall operations.

16
17 The indicators chosen for PLUS each represent, in our view, the single most
18 comprehensive measure in each of four broad performance categories
19 important to customers. As such, they are less vulnerable to the problems

1 just mentioned. And since there are only four indicators, simplicity is
2 maintained. Finally, Xcel Energy has already been tracking these measures
3 internally for its customer service quality and employee incentive
4 compensation programs, so several years of performance data is readily
5 available. In addition, use of the same performance criteria in both PLUS
6 and the Company incentive program means the Company and its employees
7 are accountable to the same measures.

8
9 Q. Why is each PLUS indicator weighted equally in importance and impact on
10 the allowed earnings?

11 A. It is difficult if not impossible to arrive at an optimal weighting of the
12 various performance indicators, so equal weighting appeared to be the most
13 straightforward and reasonable approach, especially in light of the fact that
14 PLUS would be the first comprehensive electric PBR plan to be
15 implemented in North Dakota.

1 Q. What is the purpose of a bandwidth of acceptable performance for each
2 measure, and how is the bandwidth determined?

3 A. The performance standard bandwidth recognizes there is a range of
4 performance that can be considered ‘acceptable’ or close enough to the
5 standard to not warrant any penalties or rewards. Performance must be
6 either good enough or bad enough to warrant an adjustment in the allowed
7 ROE, and a performance bandwidth serves this purpose. Use of a range also
8 simplifies administration of the performance component of the plan.
9

10 ***Price***

11 Q. Please explain the price measure and standard included in PLUS.

12 A. The price standard is determined annually by taking the average residential
13 electric rate of the PLUS regional utility comparison group (see Attachment
14 D, page 5 of the Application). The group is comprised of 14 utilities with
15 operations in 7 Midwestern states. Use of a low-cost, Midwest regional
16 group ensures the price standard is appropriate and very competitive.
17

18 The acceptable price bandwidth is determined each year by taking 85% of
19 the annual average for the award level, and 115% of the average for the

1 penalty zone. In 1999, the price standard range would have been from
2 6.24¢/kWh to 8.45¢/kWh.

3
4 Q. Why does PLUS only focus on residential rates in North Dakota?

5 A. First of all, PLUS does not focus *only* on residential rates. The price caps in
6 PLUS ensure electric rates for *all* customers will remain competitive and
7 reasonable, including those in the commercial and industrial classes.

8
9 To ensure that rates are comparable among the various utility jurisdictions,
10 however, it is necessary to select one class for PLUS. This is because
11 average rates which include *all* customer classes can vary significantly due
12 solely to the utility’s mix of residential, small commercial and large
13 industrial customers. To ensure a more valid comparison, this “customer
14 mix” factor is removed from the average rate calculation.

15
16 Consequently, PLUS uses residential rates as a proxy for measuring Xcel
17 Energy’s overall North Dakota price competitiveness against other
18 Midwestern utility service areas. It makes sense to emphasize residential
19 prices in PLUS because 1) residential customers currently have fewer energy

1 purchasing options and hence are not able to benefit as readily from
2 competitive alternatives (such as interruptible rates or self-generation); 2)
3 different utility rates are less comparable if all types of customers are
4 combined into one average rate; 3) acquiring consistent pricing data from the
5 comparison group utilities is easier if one customer class is used; and 4)
6 residential consumers comprise the majority of Xcel Energy's North Dakota
7 customer base.

8
9 Q. How did Xcel Energy's North Dakota rate compare to the standard in 1999?

10 A. Xcel Energy's 1999 North Dakota residential average rate was 6.11¢ per
11 kilowatt-hour (kWh), which was slightly lower than the price standard award
12 threshold.

13
14 Q. Hasn't the price standard been designed to ensure Xcel Energy is awarded
15 immediately for its current price position?

16 A. No. The price standard is quite objective as it is developed every year using
17 external data compiled and published by Edison Electric Institute. It was
18 developed using electric rates from one of the lowest-priced regions in the

1 country. To reach the award level for 1999, Xcel Energy’s North Dakota
2 operations need to be one of the top 4 out of 26 jurisdictions listed.

3
4 The fact that Xcel Energy’s existing residential rates already exceed the
5 standard doesn’t imply that the standard is not stretching enough. Instead, it
6 demonstrates that Xcel Energy’s current prices in North Dakota are very
7 competitive. Moreover, the Company will need to maintain that relative
8 standing in 2001 and beyond to receive an increase in its allowed earnings
9 levels through PLUS.

10
11 ***Reliability***

12 Q. Please explain the PLUS reliability indicator and standard.

13 A. PLUS uses the “System Average Interruption Duration Index” (SAIDI) to
14 measure electric reliability within Xcel Energy’s North Dakota jurisdiction.
15 As described by Ms. Bagley, it measures the amount of time a typical
16 customer goes without power during the year. It is a function of the
17 frequency of outages and the time it takes Xcel Energy to restore power
18 when each outage has occurred.

1 The standard of 77 minutes was determined by averaging historical results
2 for both the entire Northern States Power (Minnesota Company) system
3 (serving Minnesota, North Dakota, and South Dakota) and the North Dakota
4 system only (see Attachment D, page 2 of the Application). The standard
5 bandwidth is determined by taking 85% of the average for the award level
6 (65 minutes), and 115% for the penalty zone (89 minutes). Ms. Pam Bagley
7 explains this in more detail in her testimony.

8
9 ***Customer Satisfaction***

10 Q. Please explain the PLUS customer service indicator and standard.

11 A. As described by Ms. Schander, PLUS uses three customer satisfaction
12 surveys to measure customer service performance. The indicator is the
13 percentage of North Dakota residential, small commercial, and large
14 industrial customers who give a favorable or “positive” response to a single
15 question asking them to rate the Company’s products and services (see
16 Attachment D, page 6 of the Application).

17
18 The standard is 95%, which is the Company’s target for its internal employee
19 incentive compensation plan. The standard bandwidth is 93.5% to 96.5%.

Ms. Schander discusses the reasonableness of the customer service indicator in greater detail in her testimony.

Employee Safety

Q. Please explain the PLUS safety measure and standard.

A. PLUS measures North Dakota worker safety performance with the Occupational Safety and Health Administration (OSHA) safety index. This index is a comprehensive measure of the frequency of safety-related incidents per 100 Xcel Energy employees (located in North Dakota) per year. A safety incident includes medical treatment cases, restricted workday cases, lost time workday cases, and fatalities. As I understand, the rate is determined as follows:

$$\frac{\text{\# of OSHA incidences multiplied by 200,000}}{\text{\# of labor hours worked}}$$

The standard of 5.74 was developed from historical OSHA Index results from several utilities participating in the North Central Electric Association safety survey (see Attachment D, page 7 of the Application). The standard bandwidth is determined by taking 85% of the average for the award level (4.90), and 115% for the penalty zone (6.60).

1 Q. Why is employee safety one of the key performance areas identified and
2 monitored in this plan?

3 A. Our employees are members of the North Dakota community. Including a
4 safety measure gives some assurance that incentives to reduce costs do not
5 adversely affect utility worker safety. Furthermore, a company that properly
6 emphasizes workforce safety will also likely be a strong promoter of public
7 safety. Finally, over time strong safety performance also translates into
8 increased productivity, lower costs (insurance, workers compensation, etc.),
9 and better service.

10
11 **Dynamic Authorized ROE**

12 Q. What does PLUS propose for an authorized Return on Equity (“ROE”)?

13 A. The PLUS plan proposes a 12.0% baseline ROE plus a “deadband” of +/-
14 1.0%. The Commission and Staff have used 12.0% or a similar ROE in a
15 number of rulings in previous years.² Mr. McDermott supports the use of a
16 deadband in his testimony.

² Case No. PU-399-93-582 (MDU- 12.0%); Case No. PU-401-93-520 (OTP- 12.23%) Case No. PU-399-94-297 (MDU- 12.0%); Case No. PU-400-95-559 (NSP- 12.0%); Case No. PU-399-96-325 (MDU- 12.5%); Case No. PU-401-97-503 (OTP- 12.5%).

1 Q. What is meant by “dynamic authorized ROE”?

2 A. While PLUS begins with a baseline authorized ROE of 12.0%, this baseline
3 is automatically adjusted up or down depending on the Company’s
4 performance in meeting reliability, customer satisfaction, price, and worker
5 safety standards. This moving, or dynamic, authorized ROE represents the
6 key link between the Company’s service performance and its financial
7 results.

8
9 Q. Please explain how performance impacts the authorized ROE.

10 A. A bandwidth of “acceptable performance” is defined for each of the four
11 performance standards in the PLUS. For each of the performance areas, if
12 Xcel Energy’s actual performance for a given year falls short of this
13 bandwidth, the ROE baseline is decreased 50 basis points (0.5% ROE). If
14 Company performance exceeds the bandwidth of acceptable performance,
15 the ROE baseline is increased 50 basis points. Given that there are four
16 different performance standards, the potential cumulative impact of
17 performance on the baseline ROE is +/- 200 basis points.

18

1 It is important to understand that while superior service performance can
2 increase the authorized ROE, this does not mean that the Company will in
3 fact experience increased earnings. Increasing the authorized ROE only
4 provides Xcel Energy with the opportunity to retain more of its earnings than
5 it would have otherwise. The Company must still achieve sufficient earnings
6 in order to benefit financially from good performance.

7
8 Q. Why should the authorized ROE be tied to service and price performance?

9 A. By linking the authorized earnings level to performance, PLUS ensures that
10 strong incentives are in place to ensure that Xcel Energy maintains or
11 improves its level of service and keeps its prices competitive. The linkage
12 provides Xcel Energy with the opportunity to retain more of its earnings
13 when it performs well. Conversely, if the Company does not perform to
14 standards, more of its earnings will be subject to refund to customers.

15
16 As discussed by Mr. McDermott, this is more consistent with the incentives
17 at work in competitive markets: when a company offers a superior product or
18 service at a low price, demand for the product will generate higher profits
19 than the “typical” company in the same industry. Companies with inferior

1 products at non-competitive prices will experience lower customer
2 satisfaction and profits.

3
4 Q. Please explain why the PLUS plan establishes an ROE “deadband” around
5 the authorized baseline ROE?

6 A. The deadband recognizes that there is actually a *range* of utility earnings that
7 can be considered fair and reasonable. Under traditional regulation, a utility
8 would typically not file a general rate increase in North Dakota to achieve a
9 1% increase in its ROE. Similarly, the Commission probably would not
10 initiate an earnings investigation if earnings were 1% above the authorized
11 level. The Commission has validated this approach in certain, previous
12 utility earnings reviews by determining that rate adjustments did not need to
13 be pursued even though reported earnings deviated from the authorized
14 level. The deadband provides a similar effect during the PLUS term.

15
16 Use of a deadband also reduces the administrative effort associated with
17 revenue sharing by ensuring that only material earnings variations are shared
18 between customer and company.

1 It should be noted that the deadband essentially assigns to shareholders the
2 responsibility for the relatively minor deviations in earnings around the
3 authorized baseline ROE, since no revenue sharing occurs when earnings fall
4 within the deadband. These types of earnings deviations are usually
5 attributed to expected variations in routine operations (i.e., moderate weather
6 impacts on sales, storm restoration expenses, plant maintenance, etc.).
7

8 Q. Is a +/- 1% deadband the appropriate range?

9 A. PLUS establishes a +/- 1% deadband because it approximates the range of
10 earnings deemed fair and reasonable by the Commission and Staff, based on
11 the Commission's most recent rate investigation rulings and informal
12 discussions with Staff. Also, the range appears to be a reasonable
13 approximation of the earnings variability due to routine operations. I have
14 observed that other PBR plans in place use larger deadbands, but given that
15 PLUS would represent the first comprehensive PBR plan in North Dakota,
16 the Company believed that a more conservative deadband would be
17 appropriate.
18
19

1 **Revenue Sharing**

2 Q. What is meant by “revenue sharing”?

3 A. Revenue sharing refers to the sharing of revenues – between Xcel Energy
4 and its customers – when the earned return varies from the authorized level.
5 Under revenue sharing in PLUS, if Xcel Energy earnings exceed the range of
6 acceptable ROE authorized by the Plan (i.e., above the deadband), part of the
7 revenues will be refunded to customers. Conversely, if earnings are below
8 the ROE deadband, part of the associated revenue deficiency could be
9 recovered from customers.

10
11 Q. Why is it important to have revenue sharing in the PLUS plan?

12 A. Revenue sharing is designed largely to protect both the customer and the
13 Company from the risks of over and under recovery, and/or from
14 components of a PBR plan that may not end up having the effect anticipated
15 at the onset of the plan. This “safety net” feature protects customers by
16 providing reasonable rates over a period of years. At the same time, revenue
17 sharing with a deadband still provides long-term financial incentives for the
18 Company to pursue operating efficiencies.

1 Q. How is the amount of revenue sharing determined?

2 A. After the authorized earnings deadband has been determined from Xcel
3 Energy’s reported performance results, the difference between actual
4 earnings for the year and the deadband is determined. If actual earnings
5 *exceed* the deadband, the difference is converted to a revenue sufficiency,
6 and 45% of this amount is refunded to customers in July of the following
7 year. 10% is allocated to a dedicated economic development balancing fund,
8 and the Company retains the remaining 45%.

9

10 Q. What if actual earnings are *below* the deadband?

11 A. The difference between actual earnings and the deadband is determined and
12 converted to a corresponding revenue *deficiency*. 50% of this amount is
13 recovered from customers in rates, and the Company absorbs the remaining
14 50%. However, the PLUS plan seeks to minimize or eliminate such charges
15 to the customer by holding the recovery due in a balancing account until the
16 *following* year’s results have been recorded. At that time, if the Company
17 experiences earnings above the authorized deadband, the resulting customer
18 dividend is used to fully or partially offset the amount in the balancing fund.

1 The purpose for this is to minimize or avoid, if possible, recovery from
2 customers of one-time earnings deficiencies.

3
4 Q. Why should customers share revenue deficiencies?

5 A. Under traditional regulation, when a utility is experiencing a revenue
6 shortfall it can file a general rate case application to recover all of the
7 deficiency from customers. Under PLUS, Xcel Energy essentially forgoes
8 this option (with very limited exceptions). Instead, PLUS provides limited
9 rate relief opportunities, including *partial* recovery of deficiencies through
10 the revenue sharing mechanism.

11
12 As described by Mr. McDermott, it is also important for any PBR plan to
13 have symmetry. The Commission’s PBR Guidelines also state this
14 objective. A plan that is symmetrical will treat customers and the Company
15 fairly because financial rewards and risks are shared equally, and Company
16 performance can be both rewarded and penalized at the same magnitude.
17 Sharing revenue deficiencies, should they occur, is the fair and reasonable
18 “flip-side” to sharing revenue sufficiencies. In the PLUS plan, the symmetry
19 of the revenue sharing component is actually pro-customer, because

customer dividends are issued immediately, while an earnings deficiency is not shared until it is determined that earnings from the next year are insufficient to offset it.

Rate Indexing

Q. Are rate changes allowed under PLUS?

A. Yes, provided a number of conditions are met. Even if these conditions are met, rate changes are limited by a “price cap” which is determined by taking the lower of 75% of inflation (as measured by the Consumers Price Index) or the annual change in the average rate of the utility comparison group. PLUS allows for both rate increases and rate reductions, so there is symmetry.

Q. Under what conditions would PLUS allow a rate increase?

A. The following conditions must be true in order for Xcel Energy to be allowed to increase North Dakota retail electric rates:

- 1) Xcel Energy earnings for the most recent year were within or below the ROE deadband (indicating a revenue deficiency);

- 1 2) Xcel Energy’s average residential rate for the most recent year is
2 lower than the comparison group average (indicating that rates are
3 competitive);
4 3) The price cap % is greater than 0 (indicating that inflation and the
5 comparison group rate change is positive).

6
7 If Xcel Energy is permitted a moderate price increase under PLUS, the
8 Company may still choose to implement a lower increase, or not implement
9 any increase because of the impact it might have on its future price
10 performance.

11
12 Q. Will all customers experience equal price changes under PLUS?

13 A. When the PLUS price cap and other criteria allow increases or requires rate
14 decreases, the default approach will be to implement the change on an
15 “across-the-board” basis. The PLUS plan would allow for exceptions to this,
16 however, if the Company requests a specific rate design in its annual
17 performance report filing. The rate adjustment “cap” calculated from the
18 Consumer Price Index (“CPI”) and utility rate data applies to each and every
19 customer class, so under no circumstances, for example, can a required 1.0%

1 rate reduction be implemented as a 2.0% reduction for one customer class
2 and a 0.5% reduction for another. Likewise, a 1.0% increase allowed by the
3 price cap does not mean one class can get a 2.0% increase while another
4 class sees no change in rates.

5
6 I should add that Mr. McDermott recommends in his testimony that, should
7 the Company wish to implement a rate design which changes rates uniquely
8 for each class, that it be allowed to do so without approval from the
9 Commission.

10
11 Q. Why would the Company want to implement a rate change that differs by
12 class?

13 A. A prime example would be if, for example, the PLUS plan allowed a small
14 increase but Xcel Energy felt that increasing its industrial rates would make
15 our rate noncompetitive with other fuels or technologies (e.g., self-
16 generation). Or perhaps the Company would decide not to raise residential
17 rates because doing so might cause the residential rate to become higher than
18 the standard, resulting in a lower authorized earnings level. These are some

1 of the factors that Xcel Energy must consider when implementing a price cap
2 increase.

3
4 Q. Can the PLUS plan ever *require* Xcel Energy to decrease electric rates?

5 A. Yes. If the following conditions occur, Xcel Energy would be mandated
6 under PLUS to reduce its rates:

7 1) Xcel Energy’s most recently reported ROE is above the
8 deadband;

9 2) Xcel Energy’s average residential rate is higher than the
10 comparison group average residential rate;

11 3) The price cap % is less than 0.
12

13 Q. How does the PLUS price cap mechanism promote rates that are
14 competitive, and prohibit unreasonable rate increases?

15 A. Xcel Energy’s electric rates in North Dakota are currently the third lowest in
16 the comparison group of 26 jurisdictions in 7 Midwest states. This position
17 should be maintained in PLUS, because even in years when rate increases
18 are allowed by the plan, they can never exceed the annual rate change for the
19 utility group’s average price. Furthermore, no rate increase can exceed 75%

1 of the rate of inflation (CPI) in any given year, even if the comparison group
2 annual change is larger. PLUS effectively ensures rates will decline in real
3 terms (inflation-adjusted) and will not increase more than the Midwest
4 comparison group “market.”

5
6 Q. Wouldn't the PLUS Plan be more effective if it did not allow for any
7 changes in rates?

8 A. No. The industry is undergoing significant change at this time and many
9 changes could occur over the next five years. It would not be appropriate for
10 the Company to be denied any recourse for rate relief. For example,
11 increasing consumer demand for electricity must be met by either purchasing
12 power or installing new generating capacity. If these prudent costs cannot be
13 offset by other cost reductions, or recovered through the fuel clause
14 adjustment, Xcel Energy's only recourse under PLUS is to get at least partial
15 recovery of the costs through the price cap mechanism.

16
17 Q. Why is the CPI used for the inflation factor?

18 A. CPI was selected simply because of its widespread use, familiarity among
19 consumers, and because it is easy to obtain updated CPI factors each quarter.

1 The use of an “efficiency commitment” factor to reduce the inflation factor
2 as well as a “peer price” index (i.e., the comparison group rate change) used
3 in tandem with the CPI cap in PLUS provides additional assurance that the
4 price cap is appropriately set.

5
6 Q. Please explain the “efficiency commitment” factor used to reduce the
7 inflationary price cap.

8 A. As stated in the PLUS application, the “efficiency commitment” (EC) is
9 similar to a productivity factor, which is essentially the anticipated efficiency
10 improvement a utility is expected to achieve. The EC is a variable
11 productivity factor, however, because it is 25% of the CPI inflation rate. In
12 the PLUS plan, the EC was designed to recognize that that some efficiencies
13 will likely be realized during the plan term. More importantly, it eliminates
14 the complex and potentially contentious process of determining a
15 productivity factor.

16
17 For example, Total Factor Productivity (TFP) is a common factor used for
18 this purpose in some other PBR plans, but it has several shortcomings,
19 including:

- 1 1) it fails to accurately measure productivity of a specific company;
- 2 2) it can't accurately forecast productivity using historical trends;
- 3 3) it fails to distinguish capital vs. labor productivity;
- 4 4) it can't accurately breakdown geographic productivity of a multi-
- 5 region company.

6

7 In my opinion, EC is a reasonable approach for taking into account likely

8 productivity gains so that the price cap mechanism, which should allow for

9 recovery of inflationary cost increases, is not overstated.

10

11 Q. Does the price cap apply to the bundled rate, or only the non-fuel portion?

12 A. Xcel Energy would have the discretion to adjust any one or all of the various

13 components of the rate, as long as the increase did not exceed the price cap.

14 In other words, if the price increase cap was 1.0%, Xcel Energy may choose

15 to increase the monthly customer charge, the non-fuel energy charge, the

16 demand charge, and even the fuel charge components of its base rates so

17 long as the total percentage increase is not more than 1.0%. This flexibility

18 is the beauty of the price cap mechanism because it provides the Company

1 with the ability to address competitive, economic, and customer service
2 forces in the most efficient manner, within the price cap constraints.

3
4 **PLUS Results Reporting**

5 Q. How will the Commission and/or public know how well the PLUS plan is
6 working?

7 A. Each April the Commission will receive an annual report from Xcel Energy
8 which will include the following:

- 9 ❖ regulated electric earnings and ROE for the previous fiscal year
- 10 ❖ electric operating revenues, expenses, and rate base
- 11 ❖ Xcel Energy’s regulated capital structure
- 12 ❖ the Company’s performance results (in reliability, customer
13 satisfaction, price, and employee safety) for the previous year, and
14 the impact on the baseline ROE
- 15 ❖ calculation of the revenue sharing amount
- 16 ❖ price cap calculation, including inflationary and comparison group
17 rate information
- 18 ❖ proposed electric rate changes (if any), and
- 19 ❖ other financial and operating statistics

1 If requested by the Commission, Xcel Energy could also provide the
2 Commission with a mid-year performance status report showing results
3 through June by August 15 of each fiscal year (with the possible exception of
4 survey data which will not be complete until later in the year).

5
6 The PLUS plan also provides for a mid-term hearing in 2003 to review and
7 discuss the plan's effectiveness. At this hearing potential refinements could
8 be suggested and perhaps implemented for the remaining years. Near the
9 end of the plan term, in mid-2005, Xcel Energy and the Commission will
10 need to make a decision regarding modifying and/or extending the plan.

11
12 Of course, regular communication between the Company, the Commission
13 and Staff will also help ensure that the plan is meeting expectations.

14
15 Q. What if the Commission or Xcel Energy wishes to modify the proposed plan
16 after it has been implemented?

17 A. Either party can initiate discussions with the other with respect to proposing
18 modifications to the plan. To fully realize the potential benefits of the plan,
19 however, it would be inappropriate to change the approved plan without the

1 agreement of both parties or full administrative due process. PBR will have
2 more success if all parties can be confident that the plan will operate
3 consistently over the term.
4

5 Q. Can the PLUS plan be suspended prior to the end of its 5 year term?

6 A. Yes. If circumstances change dramatically via changes in law, industry
7 restructuring, changes in the wholesale power market, acts of God, or other
8 material factors beyond the control of the Company. In addition, if there are
9 unusually extreme earnings deficiencies or excesses (as defined on page 23
10 in the Application), either the Commission or Company can request a
11 suspension or termination of the plan. These provisions protect the public
12 interest from unexpected and undesirable plan impacts created by significant
13 paradigm shifts.
14

15 Q. What else will be different under PLUS?

16 A. To minimize earnings swings in North Dakota due to changes in the demand
17 allocator for fixed production and transmission costs, a 36 month period will
18 be used to determine the demand cost allocator rather than a 12 month
19 period. This change will only impact reported actual returns during the

1 PLUS term, and will not preclude the Company from filing future rate
2 applications with a forecasted, 12 month demand allocator.
3

4 Q. How will the Fuel Clause Adjustment (FCA) be affected under PLUS?

5 A. There will be no proposed changes to the FCA as part of the PLUS plan.

6 The Company is not precluded from filing FCA modifications during the
7 plan term, however.
8

9 Q. In your professional opinion, will the PLUS plan meet the Commission's
10 Guidelines for PBR plans and provide a reasonable regulatory regime to
11 replace traditional cost-of-service regulation?

12 A. Yes. In my opinion, the PLUS plan defines a reasonable, streamlined
13 regulatory framework, and establishes incentives for the Company to provide
14 high quality service at competitive rates.
15

16 Q. Does this conclude your direct testimony?

17 A. Yes, it does.

David H. Sederquist
Manager, North Dakota Regulatory Affairs
Northern States Power Company d/b/a Xcel Energy Inc.
2302 Great Northern Drive, Fargo, North Dakota 58102

Current Responsibilities

Responsible for coordination of regulatory affairs within NSP's North Dakota jurisdiction, including communication of regulatory issues and events to ND management, preparation of ND filings, testifying at NDPSC hearings, participating in joint regulatory task forces, coordinating meetings/events involving ND PSC and Xcel Energy personnel, acting as liaison with corporate Regulatory Services staff, and other special regulatory projects. Also responsible for analyzing ND financial forecasts, assisting in economic analysis, coordinate business planning, and monitoring key performance indicators.

Previous Employment

Manager, ND Regulatory Affairs	September 2000 -
Regulatory/Financial Consultant, NSP-ND	May 1993 - August 2000
Senior Financial Analyst, NSP-ND	Mar. 1992 - Apr. 1993
Lead Financial Analyst, Financial Accting, Budgets, & Reports	Dec. 1990 - Feb. 1992
Senior Financial Analyst, NSP Electric Utility	May 1988 - Nov. 1990
Operations Analyst, Corporate Depreciation & Economics	Jun. 1984 - Apr. 1988

Education

Moorhead State University, Bachelor of Science (Mathematics)	1978-1983
North Dakota State University, MBA program	1998 -

Previous Testimony

NSP/NCE Merger	Case # PU-400-99-418
Natural Gas Rate Reduction	Case # PU-400-96-559
DSM Accounting Change	Case # PU-400-95-401
NSP/WEC Merger	Case # PU-400-95-340
Electric Demand Allocation	Case # PU-400-94-514
Manitoba Hydro Cost Recovery	Case # PU-400-93-731
Viking Acquisition Recovery	Case # PU-400-93-534

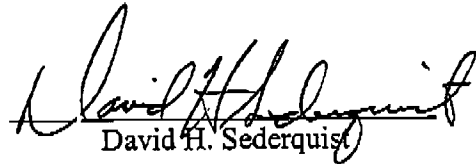
STATE OF NORTH DAKOTA
BEFORE THE
PUBLIC SERVICE COMMISSION

In the Matter of the Application of)
Northern States Power Company d/b/a)
Xcel Energy for Authority to Operate)
Under Performance-Based Regulation)
in North Dakota)

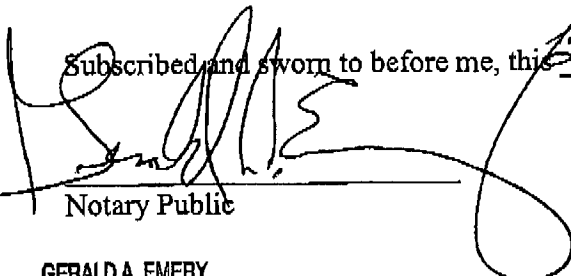
Case No. PU-400-00-195

**AFFIDAVIT OF
DAVID H. SEDERQUIST**

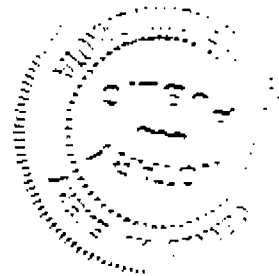
I, the undersigned, being duly sworn, depose and say that the foregoing is the testimony of the undersigned, and that such Direct Testimony and the exhibits sponsored by me to the best of my knowledge, information and belief, are true, correct, accurate and complete, and I hereby adopt said testimony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


David H. Sederquist

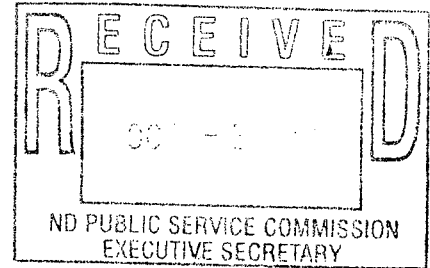
Subscribed and sworn to before me, this 28th day of September, 2000.


Notary Public

GERALD A. EMERY
Notary Public, STATE OF NORTH DAKOTA
My Commission Expires APRIL 25, 2002



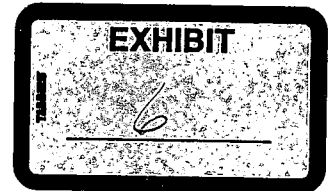
Direct Testimony
Ms. Pamela L. Bagley
Xcel Energy Exhibit 3
Hearing Exhibit No. _____



Before the Public Service Commission of
the State of North Dakota

In the Matter of the Application of
Northern States Power Company d/b/a Xcel Energy
for Authority to Operate under Performance-Based Regulation
in North Dakota

Case No. PU-400-00-195



September 29, 2000

18 PU-400-00-195

Pages: 14

Direct Testimony of Ms. Pamela L Bagley

by Northern States Power Company

Exhibit # 6
10/02/2000 CC: Comm Legal Illona, Pat, Jerry Mike .

1 Q. Please state your name, position and business address.

2 A. I am Pamela L. Bagley. I am Manager of Delivery System Reliability for
3 Northern States Power Company d/b/a Xcel Energy (“Xcel Energy” or “the
4 Company”), which provides electric and natural gas service in the states of
5 North Dakota, Minnesota and South Dakota. My business address is 414
6 Nicollet Mall, Minneapolis, Minnesota, 55401.

7

8 Q. What are your responsibilities as Manager of Delivery System Reliability?

9 A. My primary responsibilities are to provide performance analysis and
10 reliability planning for the electric transmission and distribution systems in
11 Xcel Energy's service territory, plus the electric service area of our utility
12 affiliate Northern States Power Company (Wisconsin) in Wisconsin and
13 Michigan. I am responsible for developing reliability measurements and
14 goals. I manage a team of engineers and an analyst responsible for
15 monitoring electric system performance and developing improvement plans.
16 I am also responsible for communicating reliability performance to executive
17 management and employees.

18

19

1 Q. What is the purpose of your testimony?

2 A. I will describe in detail and support the reliability measure and standard
3 contained in Xcel Energy's “PLUS” performance-based regulation (PBR)
4 plan. As I understand, the reliability measure would be one of four measures
5 used to evaluate Xcel Energy’s overall performance under the PLUS plan.

6
7 Q. Please define the PLUS reliability measure.

8 A. We propose to use the "system average interruption duration index," or
9 “SAIDI,” as the electric reliability performance measure for Xcel Energy's
10 PLUS plan in North Dakota. SAIDI is a standard electric utility industry
11 reliability indicator, defined in IEEE Standard 1366, “IEEE Trial-Use Guide
12 for Electric Power Distribution Reliability Indices.” SAIDI reflects the
13 average amount of time, measured in minutes, a customer is without electric
14 power in a given year. SAIDI is currently the most widely-used reliability
15 metric by both regulatory agencies and electric utilities.

16
17 For the PLUS plan, we propose to measure reliability with a SAIDI measure
18 of our North Dakota system, meaning the measure will reflect the average
19 amount of time a retail electric customer of Xcel Energy in North Dakota is

1 without power in a given year. The proposed benchmark is 77.0 outage
2 minutes per year. (There are 525,600 minutes in a 365 day year.)
3

4 Q. Why is SAIDI an appropriate measure of electric service reliability for use in
5 the PLUS plan?

6 A. As described by Mr. Sederquist, the purpose of the PLUS plan is to identify
7 and encourage good utility performance which satisfies customers. By
8 measuring the average amount of time customers are without power, SAIDI
9 is the best overall measure of system reliability from the customers'
10 perspective. Other measures of reliability are also available, but SAIDI is
11 the most comprehensive, and it measures our reliability performance in a
12 way that is directly related to the reliability performance perceived by our
13 retail customers.
14

15 Q. Does Xcel use SAIDI as a reliability measure in other jurisdictions?

16 A. Yes. As part of the service quality plan approved in conjunction with the
17 recent merger between NSP and New Century Energies, Inc. to form Xcel
18 Energy Inc., the Minnesota Public Utilities Commission adopted this same
19 reliability measure for Xcel Energy's retail electric operations in Minnesota.

1 In addition, SAIDI is the electric reliability measure Xcel Energy uses in its
2 2000 “Pay for Performance” employee incentive compensation plan. A
3 common measure aids in communication and understanding of the PLUS
4 plan objectives by employees, and insures the Company and its employees
5 are evaluated under a common standard.

6
7 Q. Which outages are included in the Xcel Energy SAIDI measurement?

8 A. Consistent with the IEEE standard, the PLUS plan SAIDI measurement will
9 include all outages with a duration of at least five minutes which occur as a
10 result of events on Xcel Energy’s North Dakota electric delivery system.

11
12 Q. Please define the term “electric delivery system.”

13 A. The electric delivery system is the portion of the power system between the
14 generating plants and the customer's meter. It includes both the electric
15 transmission system and the electric distribution system, including the
16 service line to an individual customer's facility.

1 A. What are the typical causes of outages on the Company’s electric delivery
2 system?

3 A. Outage events include: weather conditions such as lightning or high winds;
4 public damage by such actions as a vehicle hitting a pole; vandalism;
5 excavator damage to an underground cable; a failure or malfunction of
6 delivery system equipment; tree contact; employee error; animal contact;
7 overloaded equipment; fire; planned outages necessary for construction or
8 maintenance activity; and outages of unknown origin. Xcel Energy also has
9 an “other” classification that includes unusual or unique outage causes.

10
11 Q. Does your proposed SAIDI measure reflect the Company’s performance in
12 maintaining reliable electric service under these circumstances?

13 A. Yes. All outages stemming from these various causes will be reflected in
14 our SAIDI measure. The better job we do at avoiding outages from any of
15 these circumstances, the lower our SAIDI measure will be, reflecting our
16 performance. If the Company is able to reduce the SAIDI outage minutes,
17 customers in North Dakota benefit through more reliable service.

1 Q. Is anything excluded from the proposed SAIDI measurement?

2 A. Yes, two things. First, although Xcel Energy tracks some information on
3 outages caused by and whose impact is contained within an individual
4 customer’s own equipment (i.e., beyond the meter), the Company’s SAIDI
5 measurement for PLUS would not include these outages. Second, the
6 proposed standard reflects a performance level which is “normalized” for
7 extreme weather events. Although the outages due to most storms are
8 included in the SAIDI score for PLUS, the outages resulting from these
9 extreme weather events would be excluded. Each of these exclusions is
10 consistent with our intent to measure our performance and the results we can
11 directly influence, as opposed to those entirely outside of the Company’s
12 control, consistent with Mr. McDermott’s recommendations.

13

14 Q. I can understand why outages caused by customer equipment is out of your
15 control, but why is the standard normalized for extreme weather or very
16 unusual circumstances?

17 A. The intent of normalization is to remove the impacts of extreme events,
18 which are nearly always weather-related, which exceed reasonable design
19 limits of the delivery system. This allows Xcel Energy to analyze system

1 performance among different years to determine whether performance is
2 truly improving.

3
4 For example, the outages related to a major weather event like the 1997
5 flood in Grand Forks would not be included in the SAIDI calculation,
6 because it was such a massive and uncontrollable event. However, the
7 SAIDI standard would include localized outages caused by minor weather
8 events which could perhaps be mitigated by installation of relatively low cost
9 equipment. The performance standard provides the Company and
10 Commission with an ongoing measure of comparable annual performance
11 over time, and the PLUS plan provides an incentive for the Company to
12 make the investments or plan its work in a way that controls or reduces these
13 outages.

14
15 Q. Please describe the method used to normalize the SAIDI measure.

16 A. First, we calculate the 3-year average number of daily interruptions and the
17 associated standard deviation. An interruption is defined to be the loss of
18 service to one or more customers. Any day which has more than three times
19 the standard deviation of interruptions above the average is identified as a

1 "storm day." The outages associated with the storm day are not included in
2 the normalized performance metrics. Xcel Energy's current daily average
3 number of interruptions for North Dakota is three (3). A storm or event
4 which causes more than 16 interruptions in one day in North Dakota is
5 considered a major event and its impacts are not included in normalized
6 metrics.

7
8 Q. In general, how many days during the year are excluded by this method?

9 A. In 1997, 16 storm days were identified for North Dakota using this method.
10 This includes 11 days during April 1997 when Grand Forks experienced an
11 ice storm followed by massive flooding. In 1998, 6 days were identified as
12 storm days. In 1999, 13 days were identified, including 4 days in April 1999
13 related to an ice storm. 2000 data is not yet final.

14
15 Q. Does the Company also track reliability performance that includes the
16 impacts of all major storms and/or events?

17 A. Yes. This information is available, but we do not propose to include it as
18 part of our PLUS plan performance measures because these are not events
19 over which the Company can exercise meaningful control.

1 Q. How does a standard of 77.0 minutes compare with the performance of other
2 electric utilities?

3 A. Xcel Energy participates in benchmarking studies to determine how our
4 reliability performance compares with other utilities’ performance. The
5 2000 Electric Transmission and Distribution Benchmarking Program,
6 performed by Theodore Barry & Associates, compares the results of 46
7 utilities located in the United States and Canada. The mean value of SAIDI,
8 excluding major events and planned outages, was 112.88 minutes. The
9 PLUS standard of 77.0 minutes is significantly better than this average; e.g.,
10 our customers would experience roughly 30% fewer minutes of interruption
11 than the 46-company average under the proposed standard. In addition, as
12 noted above, the PLUS standard of 77.0 minutes includes the planned
13 outages necessary for Xcel Energy’s construction and maintenance activities
14 (which the Company controls).

15
16 Q. How does the proposed 77.0-minute standard compare with Xcel Energy’s
17 North Dakota performance in recent years?

18 A. The SAIDI standard in PLUS is not directly comparable to the historical
19 results for the North Dakota operations because the methodology for

1 recording outage statistics prior to 1999 is not consistent with the current
2 practice.

3
4 As a result, the PLUS plan measurement standard instead reflects a simple
5 average of the recent North Dakota operations SAIDI results, and the
6 system-wide SAIDI results for the entire Xcel Energy delivery system
7 (including North Dakota, Minnesota and South Dakota) –utilizing data
8 collected in a manner consistent with current Company methods. The
9 actual results in a PLUS plan year would then be compared to this standard.
10 See Attachment D, page 2, in the Company’s application for additional
11 information supporting the PLUS plan reliability standard.

12
13 Q: In your opinion, does the Company’s SAIDI reliability standard provide an
14 appropriate measure of reliability performance for a PBR plan like PLUS?

15 A: Yes. As described by Mr. Sederquist, the Commission’s guidelines for PBR
16 plans include a goal of maintaining or improving customer service. For the
17 reasons discussed above, in my opinion SAIDI is the best comprehensive
18 reliability measure available to the Commission for measuring utility
19 reliability performance.

1 Q. Does this conclude your direct testimony?

2 A. Yes, it does.

Pamela L. Bagley, P.E.
Northern States Power Company
414 Nicollet Mall, Minneapolis, MN 55401

EMPLOYMENT HISTORY

Northern States Power Company (NSP), 1/86 - Present

Minneapolis, MN

2/99-Present **Manager, Delivery System Reliability.** Manage engineers and analyst in team responsible for monitoring transmission and distribution system performance for 5-state territory. Develop reliability improvement measurements, goals, and plans. Develop delivery system maintenance plans and manage repair/replacement projects for failed major equipment. Benchmark system performance. Communicate goals, plans, and performance to executive management, state regulatory agencies, and employees.

8/95 - 2/99 **Senior Reliability/Operations Engineer.** Performed risk analysis, outage coordination, and security analysis for the operation of the electric delivery system. Provided dedicated operational and reliability engineering support for NSP's largest customer. Approved switching procedures for both transmission and distribution systems. Performed analysis and reporting for transmission- and distribution-level outage events. Established stock of substation emergency equipment. Developed substation maintenance plans.

7/91 - 7/95 **Substation Control Engineer.** Designed and implemented schemes for protective relaying, control, and communication systems on transmission and distribution circuits. Utilized a variety of electromechanical and microprocessor-based relays. Estimated and procured equipment for schemes. Performed short-circuit analysis and relay coordination. Provided technical support for construction and relay technicians. Developed and maintained protective relaying design standards.

12/87 - 7/91 **Substation Engineer.** Design engineer for substation construction projects. Job function included: detailed project scopes and cost estimates, schedules, major equipment specification and procurement, approval of construction drawings, and technical support for design and construction personnel. Managed project workload consisting of approximately 30 substation projects with a combined value of over \$10 million. Chaired and participated in equipment standards committees. Coordinated departmental technical training program.

1/86 - 12/87 **Intern/Student Engineer.** Assisted substation engineering staff with projects. Developed computer programs for mainframe and personal computer applications.

EDUCATION

University of Minnesota

Minneapolis, MN

1987 Bachelor of Electrical Engineering.
Member, Eta Kappa Nu.

2001 Master of Electrical Engineering anticipated. Emphasis in power system generation, operation, and control, with minor in applied economics.

ADDITIONAL

Registered Professional Engineer, state of Minnesota.

Member, IEEE Power Engineering Society, NSP Engineers' Association.

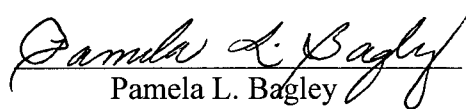
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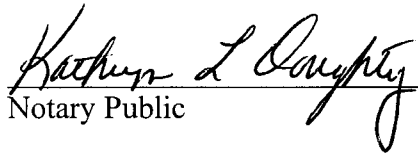
Case No. PU-400-00-195

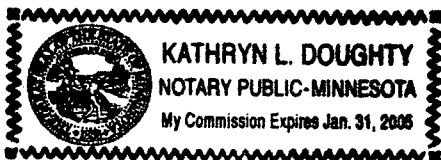
**AFFIDAVIT OF
PAMELA L. BAGLEY**

I, the undersigned, being duly sworn, depose and say that the foregoing is the testimony of the undersigned, and that such Direct Testimony and the exhibits 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.


Pamela L. Bagley

Subscribed and sworn to before me, this 28th day of Sept., 2000.


Notary Public



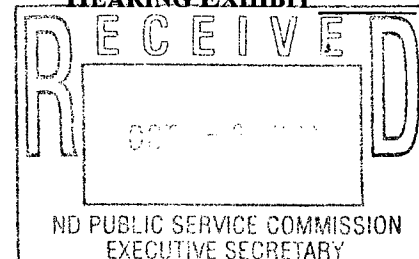
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ner/a
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**JOINT OTP/XCEL ENERGY
EXHIBIT No. 1**

HEARING EXHIBIT



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

In the Matter of the Application of)
Northern States Power Company d/b/a)
Xcel Energy for Authority to Operate)
Under Performance-Based Regulation)
in North Dakota)

Case No. PU-400-00-195

In the Matter of the Application of)
Otter Tail Power Company for)
Authority to Operate Under)
Performance Based Regulation)
in North Dakota)

Case No. PU-401-00-36

TESTIMONY OF KARL MCDERMOTT

Vice-President

September 29, 2000



18 PU-401-00-36

Pages: 57

Testimony of Karl McDermott

by Otter Tail Power Company

10/02/2000

CC: Comm Legal PUD (3) Mike ALJ .

/ Los Angeles, C.
/ A / Washington,
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17 PU-400-00-195

Pages: 57

Testimony of Karl McDermott

by Northern States Power Company
Exhibit # Joint 1

10/02/2000

CC: Comm Legal Ilona, Pat, Jerry Mike .

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1 **PREPARED DIRECT TESTIMONY**

2 **OF**

3 **KARL A. MCDERMOTT**

4 **I. INTRODUCTION AND SUMMARY**

5 Q. Please state your name, current position and business address.

6 A. My name is Karl McDermott. I am a Vice President at National Economic Research
7 Associates, Inc. (NERA). NERA is a firm of consulting economists with offices in the
8 United States, Europe and Australia. My business address is 875 North Michigan Avenue,
9 Suite 3650, Chicago, IL 60611.

10 Q. Please describe your qualifications.

11 A. I have been working in the field of public utility regulation for over twenty years. I received
12 a B.A. in economics from Indiana University of Pennsylvania, an M.A. in public utility
13 economics at the University of Wyoming and a Ph.D. in economics from the University of
14 Illinois at Urbana-Champaign. From April of 1992 until May of 1998, I served as a
15 Commissioner on the Illinois Commerce Commission. Prior to that, I was founder and
16 served as the President of the Center for Regulatory Studies (CRS), a not-for-profit
17 regulatory policy institute located on the campus of Illinois State University. CRS was
18 created to provide the Illinois regulatory environment with independent third-party research
19 and education on issues impacting the regulation of public utilities. Before founding the
20 CRS, I worked in numerous capacities including positions on the staff of the Illinois
21 Commerce Commission, the National Regulatory Research Institute (NRRI) and Argonne
22 National Laboratory. I have testified before state regulatory commissions in California,
23 Illinois, Indiana, Iowa, Kentucky, South Dakota and Wisconsin as well as before the
24 Federal Energy Regulatory Commission, the Federal Communications Commission and the
25 Iowa and Illinois General Assemblies. My current vita, detailing more fully my academic
26 and work experience, is attached as Appendix A.

1 Q. What is the purpose of your testimony?

2 A. I have been asked by Northern States Power Company d/b/a Xcel Energy (Xcel Energy)
3 and Otter Tail Power Company¹ (Otter Tail) to provide an overview of performance-based
4 regulation as it has been applied to public utilities and review and provide
5 recommendations on the overall design of their proposed performance-based regulation
6 plans.

7 Q. What is your experience with alternative regulation or performance-based regulation?

8 A. In the early 1980's I left NRRRI for a position on the Staff of the Illinois Commerce
9 Commission (ICC). One of the reasons I was hired by the ICC was to address issues related
10 to incentive-based regulation. While at the ICC, I authored three reports on the application
11 of alternatives to traditional cost of service regulation. In addition, I testified before the ICC
12 as to the potential use of incentive-based regulation to control costs of power plant
13 construction. Since that time I have authored several publications and reports on the
14 applicability of performance-based regulation (PBR) to both economic and environmental
15 regulation. My curriculum vita cites these reports and publications. Later in my career,
16 while a Commissioner at the ICC, I had the opportunity to evaluate and vote on several
17 incentive proposals brought before the Commission. These proposals ranged across the
18 regulated industries including incentive programs for gas commodity procurement, gas
19 storage capacity projects, electric PBR and a price cap plan for Illinois Bell Telephone
20 Company (Ameritech). In addition, I have lectured and advised governments, regulators
21 and utilities in a number of Eastern European states on the applicability, design and
22 implementation of performance-based regulation in the natural gas and electric industries.

23 Since leaving the ICC, I have been retained by MidAmerican Energy Company to evaluate
24 and provide expert testimony on its gas purchasing performance plan in South Dakota and
25 Iowa. I have also been retained by Wisconsin Electric Power Company to assist in the

¹ When referring to both Otter Tail and Xcel Energy I will use the term "Companies," otherwise I will explicitly name the company I am referring to.

design of its electric performance-based regulation plan and provide expert testimony in support of that plan.

Q. Please summarize your conclusions in this proceeding.

A. The move to alternative forms of regulation has gained substantial momentum in the past decade. Policymakers, regulators and utilities are beginning to recognize the benefits of altering the poor incentive structure inherent in traditional forms of economic regulation. The Companies have proposed a plan² that meets many of the criteria commonly used to evaluate these plans. The plan will provide better incentives for cost reduction, service performance and will reduce the costs to society of regulating the Companies. The plan also provides a reasonable process for price changes that will result in just and reasonable rates. This conclusion is based on a review of the plan as a whole. While no plan is perfect, this plan represents a reasonable regulatory framework that provides these Companies with the appropriate incentives. The Commission should approve the plan as presented.

II. PERFORMANCE-BASED REGULATION

A. Performance-based Regulation and Incentives

Q. Could you please explain what you mean by “performance-based regulation?”

A. Performance-based regulation generally refers to a regulatory structure that explicitly incorporates standards of performance that may not exist in the traditional cost of service methodology.³ One also hears references to “alternative” or “incentive” regulation as well.⁴ I will use the term performance-based regulation (PBR) to describe the Companies proposed plan as that term provides the correct emphasis on performance. There are many forms of performance-based regulation including price caps and revenue caps, and earnings

² The two plans are similar enough that I will refer to them as one, however some differences will be noted throughout my testimony.

³ In the remainder of this testimony any reference to “traditional regulation” will mean cost of service or rate of return regulation and the process and procedures generally associated with these regulatory mechanisms.

⁴ Alternative regulation is a catchall phrase used to denote nearly any type of plan that differs from traditional regulation. Incentive regulation is somewhat of a misnomer as all regulation is incentive regulation. However
(continued...)

1 sharing. The purpose of these plans is to provide positive incentives that counter the well-
2 known disincentives to efficient performance found in the traditional regulation.

3 Q. Could you briefly describe the history of performance-based regulation?

4 A. PBR plans are not new. Regulators have worried about the incentives created by cost-based
5 regulation for many years. In England, as far back as 1855, Sheffield Gas operated under a
6 type of "sliding-scale" plan. Under that plan, dividends were permitted to rise or fall
7 depending on the price of gas delivered to customers. In the United States, the Commission
8 in Washington, DC adopted a sliding-scale plan for Potomac Electric Power in 1925, and it
9 lasted until 1955.

10 Q. What do you mean by "incentives?"

11 A. An incentive is the structure of an economic system that provides rewards or penalties for
12 certain types of behavior. For example, the pricing system is an incentive system. As prices
13 rise people tend to consume less, as prices fall they tend to consume more. The incentive of
14 "higher prices" or "lower prices" guides the behavior of "consuming less" or "consuming
15 more." Another example is the legal system that establishes a set of rules identifying
16 behavior that will be punished in order to minimize its occurrence. There are many other
17 examples. Generally speaking we employ rewards and penalties to signal the firm or
18 individual the benefit or cost of particular actions. In this way we can encourage
19 modifications in behavior in order to achieve the goal that has been selected.

20 Q. What role do incentives play in improving the outcome of regulation?

21 A. First note that *all* regulation is "incentive" regulation in some form. Traditional cost of
22 service regulation sets up one type of incentive for the firm, whereas performance-based
23 regulation sets up an entirely different set of incentives. The role incentives play should be
24 clear from my discussion above. Altering the costs or benefits of certain types of behavior
25 will induce different behavior on the part of the firm. The trick to making performance-

(...continued)

the term is generally used to emphasize the use of specific incentive mechanism beyond those found in traditional regulation, as I will discuss below.

1 based regulation work is to design a set of incentives such that the desired outcomes are
2 likely to be realized.

3 Q. What is the purpose of performance-based regulation?

4 A. Performance-based regulation alters the incentives inherent in the regulatory system in an
5 attempt to alter the behavior of the regulated firm. By altering the firm's behavior
6 regulators can elicit benefits that can be shared by the firm and the customers.

7 Q. Are you suggesting that the behavior of the regulated firm under traditional regulation was
8 not appropriate?

9 A. No. What I am suggesting is that regulators cannot impose a desired level of effort or a
10 desired behavior on the part of a privately held (i.e., for profit) firm. Regulators can only
11 create an environment that is most likely to elicit the amount of effort deemed socially
12 acceptable. Traditionally, regulation used the "carrot" of restricted entry and an approved
13 return and the "stick" of prudence reviews and regulatory oversight to obtain a certain level
14 of effort from the firm. The firm behaved in a rational manner, given the incentives inherent
15 in the traditional system.

16 Q. What are the general categories of incentive plans used by regulators?

17 A. Incentive plans can be classified into two general types: specific and comprehensive.
18 Specific plans became popular with commissions in the United States in the late 1970's and
19 early 1980's. These plans were a response to the inflationary pressures affecting fuel costs
20 and the costs of building new power plants. A survey in 1986 identified 31 incentive
21 programs in 20 states.⁵ The majority of these plans involve targeting power plant
22 performance measures, such as plant capacity factors or availability factors, and tying
23 certain cost recovery treatment to achieving those targets. The emphasis was placed on the
24 tying of rewards or penalties to *performance* by linking rewards and penalties to specific
25 performance. By doing so, the state commission generated a clear logical connection
26 between the benefits of the project and the treatment of the utility.

1 Targeting continued to be the incentive mechanism of choice for state commissions into the
2 early 1990's. The emphasis of regulators shifted from traditional regulation to demand-side
3 management (DSM) and energy conservation programs. A NARUC report published in
4 1993 identified 28 states employing some form of incentive program for DSM and 6 states
5 in the process of approving a DSM incentive program.⁶

6 Q. Are there any problems with targeted incentives?

7 A. The problem with most specific or targeted incentives is that they can result in unintended
8 consequences for customers and companies. By singling out a specific activity to reward,
9 attention to and expenditures on other equally important activities may decrease. The result
10 could be, for example, that power plant availability rises by reducing maintenance outages.
11 At some point, equipment failures could impose significant costs on the customer and
12 company. Even if this adverse result occurs, the company may have satisfied the letter of
13 the incentive mechanism and be entitled to a reward for achieving the targeted result. This
14 type of perverse outcome is avoided by incentive mechanisms that adopt a more
15 comprehensive approach to cost control and performance.

16 Q. Could you please describe what you mean by the concept of a comprehensive mechanism?

17 A. Comprehensive plans enable a utility to examine the *overall* costs of providing service and
18 develop ways to reduce these costs and improve service. Comprehensive plans generally
19 identify a set of performance criteria and link the rewards or penalties to these criteria. The
20 difference between comprehensive and targeted incentives is that the performance criteria
21 are generally more "macro" oriented. That is, the criteria focus on price performance or
22 comparisons of system reliability or total cost control. Comprehensive mechanisms
23 typically take one or more of the following forms: earnings sharing, benchmarking, rate
24 freezes, and price caps.

(...continued)

⁵ See Paul Joskow and Richard Schmalensee, "Incentive Regulation for Electric Utilities," *Yale Journal on Regulation* Vol. 4, no 1, 1986

⁶ See *Incentives for Demand-side Management*, 2nd ed. March 1993 published by the National Association of Regulatory Utility Commissioners.

1 Comprehensive plans also streamline the regulatory process and reduce the cost to
2 customers of rate proceedings. An example of these savings is provided by Central Maine
3 Power, where the costs of rate proceedings were reduced from \$1.6 million to \$70,000. By
4 relying on formulae to determine the degree that prices will change and establishing an
5 automatic process for implementing these changes, the customer receives the benefits of
6 more timely downward adjustments in price and is protected from the full impact of price
7 increases by partial price adjustment formulas.

8 Q. Could you please describe the evolution of comprehensive incentive mechanisms?

9 A. Comprehensive incentive programs have followed a path that tracks more closely the
10 evolution of competition in each of the regulated industries. With the opening up of
11 telecommunications markets at the federal level after the 1984 divestiture of AT&T, the
12 Federal Communications Commission adopted a form of price cap regulation in 1989.⁷ The
13 proposals to deregulate natural gas and FERC's open access orders led to the FERC
14 commissioning a report on incentive regulation which was issued in November of 1989.⁸
15 As of March 1999, 24 states had adopted some form of incentive program for gas
16 commodity costs or base rates. In the electric industry to date, approximately 23
17 performance plans have been adopted; these plans include virtually the entire range of
18 comprehensive mechanisms identified above.

⁷ See Policy and Rules Concerning Rates for Dominant Carriers, Notice of Proposed Rulemaking, 2 FCC Red 5208(1987), Report and Order and Second Further Notice of Proposed Rulemaking 4 F.C.C.R. Rad.Reg.2d (P&F) (1989) and Second Report and Order, 5 F.C.C.R. Rad. Reg. 2d (P&F) (1990). For a complete survey of the evolution of the FCC price cap approach, see e.g., G. Vogt "Cap-Sized: How the Promise of Price Cap Voyage to Competition Was Lost in a Sea of Good Intentions" *Federal Communications Law Journal* Vol. 51, No. 2, March 1999. On the status of state programs, see D. Kridel, D Sappington and D Wiesman "The Effects of Incentive Regulation in the Telecommunications Industry: A Survey" *Journal of Regulatory Economics* Vol. 9 1996.

⁸ L. Brown, M. Einhorn and I. Vogelsang, *Incentive Regulation: A Research Report*, Office of Economic Policy Technical Report FERC 89-3, November 1989.

1 Q. Are there any other aspects of incentives that should be kept in mind when designing a
2 performance-based regulation plan?

3 A. Yes. First, we must remember that incentives only work when the outcomes are under
4 control of utility management. A plan that purports to provide incentives to management to
5 control costs and operate more efficiently but links the rewards to performance standards
6 that are largely out of the control of management is not likely to succeed. Second, we must
7 remember that the incentive structure should allow for the compensation for additional risk
8 born by the utility in moving away from traditional regulation. If the incremental cost of
9 taking on additional risk does not meet the incremental benefit it is highly unlikely that the
10 goals of the program will be achieved. Last, the incentive intensity⁹ is a function of the
11 ability of the utility to retain the incremental rewards from incremental effort.

12 Q. How does the customer benefit from performance-based regulation?

13 A. The customer will benefit from PBR in a number of ways depending on the design of the
14 mechanism. Incentives can be designed that incent the improvement in system reliability or
15 increase efficiency, or any number of other behaviors that are deemed appropriate by the
16 regulator. Practically any set of activities that a utility undertakes to provide service to
17 customers can be influenced in order to achieve benefits for ratepayers. As we will discuss
18 below there are advantages to designing incentive mechanisms that employ broader targets
19 such as total cost minimization as opposed to a single activity, such as demand side
20 management, because of the risks of distorting incentives that accompanies the use of
21 narrow measures.

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⁹ The term “high-powered incentives” is often used to describe an incentive system that results in the firm retaining all the benefits of the behavior change. The term “low-powered incentives” result from consumers retaining the benefits. A sharing of claims on the benefits would result in “intermediate-powered incentives.” See e.g., *A Theory of Incentives in Procurement and Regulation*, J.J. Laffont and J. Tirole, MIT Press, Cambridge, p. 11.

B. The Goals of Traditional Regulation are More Likely to be met under Alternative Regulation.

Q. What is the goal of traditional regulation?

A. While it is not often articulated or made explicit, the traditional goal of regulation has been to provide an environment in which the regulated firm operates as much like a competitive firm as possible. This was perhaps best stated by Professor Bonbright who noted:

Regulation it is said, is a substitute for competition. Hence its objectives should be to compel a regulated enterprise, despite its possession of complete or partial monopoly, to charge rates approximating those which it would charge if free from regulation but subject to the market forces of competition. In short regulation should be not only a substitute for competition, but a closely imitative substitute.¹⁰

Therefore, the goal of the regulatory process, at least theoretically, is to provide an environment in which the firm operates in the most efficient manner possible. Baumol and Sidak expand on the concept

...that the proper role of regulation is that of a substitute for competitive market forces where those forces are weak or absent. The regulator's task then becomes a two-part undertaking: first to determine the rules of behavior that a regulated firm could have been expected to follow if it had operated free of regulation in market with fully effective competitive forces; second, to constrain the regulated firm to behave as it would in such a competitive market and to circumscribe its behavior no less and no more than this.¹¹

The reason for this emulation of the competitive market is our belief that the system of incentives embodied in the competitive market process result in the least cost production of goods and services. If regulation could duplicate these results then the public interest would be well served.

Q. Has traditional regulation achieved this goal?

A. No. An increasing number of policymakers are coming to the conclusion that performance-based regulation can increase customer welfare compared to traditional cost of service regulation. The reason for this is quite simple—traditional cost of service regulation was,

¹⁰ James Bonbright, *Principles of Public Utility Rates*, Columbia University Press, New York, 1961, p. 93.

¹¹ W. Baumol and G. Sidak, *Toward Competition in Local Telephony*, MIT Press, Cambridge, 1994, p.5.

1 in part, designed to protect customers from the potential monopoly profits and
2 discriminatory pricing that could arise when an exclusive franchise was awarded to a
3 natural monopoly. In addition, the regulatory process attempted to balance the interests of
4 ratepayers and stockholders by reviewing the total costs incurred by the monopoly in
5 providing service. This was done to ensure that customers were not charged for imprudently
6 incurred costs while simultaneously providing the utility the opportunity to earn a fair rate
7 of return. Traditional regulation adopted a method of implementing these goals that relied
8 on a static model of the competitive process. This approach worked reasonably well as long
9 as the economy and the regulated industries remained generally stable. As the economy
10 becomes more subject to shocks, such as rapid and pronounced changes in input prices and
11 radical changes in technology, the traditional form of regulation begins to be a less effective
12 means of maximizing consumer welfare.

13 Q. Please elaborate.

14 A. The traditional regulatory process assumed a static “snapshot in time” in which total utility
15 costs were equal to total utility revenues. However, in a competitive market prices are
16 influenced by the existence of other firms that provides the incentive to minimize costs. But
17 the incentive to minimize costs extends beyond the current “state of technology.”¹² Firms in
18 competitive markets are constantly looking for methods that improve products (or create
19 new ones) and new techniques of production. Firms may experiment with new
20 organizations, new management styles, and may attempt to improvement both physical and
21 human capital all in a quest to become more “competitive.”¹³ The real business
22 environment is far more *dynamic* than traditional regulation assumed.

¹² The term “state of technology” simply refers to all of the aspects of production other than the physical inputs. This could refer to management styles, organization, knowledge about production, etc.

1 Q. Could you please elaborate on the incentives inherent in the static ratemaking process under
2 traditional regulation?

3 A. Traditionally, regulation has relied on the so-called regulatory lag to provide the incentive
4 for utilities to reduce costs. The regulatory lag exists because prices are generally rigid over
5 some period of time and the regulator is generally confined by administrative procedure
6 from retroactively reducing rates due to higher than allowed earning. This incentive is weak
7 for at least two reasons. First, the regulatory lag can be a short period of time (possibly as
8 few as 6-12 months) relative to the life of utility assets. Any long-term cost reduction by the
9 utility is generally going to be captured in full by ratepayers in the next rate case, thereby
10 muting the incentive to undertake actions that increase long-term efficiency.¹⁴ Second, most
11 utilities seek to avoid rate hearings as they are costly and create uncertainty for investors.
12 Theoretically, this implies sub-optimal cost minimization.

13 Q. What aspect of “competition” is likely to be better emulated by performance-based
14 regulation as opposed to traditional regulation?

15 A. The most important aspect of competition in reality, as opposed to the simple textbook
16 version, is that it is a highly dynamic process as noted above. The reliance of traditional
17 regulation on the static approach to regulation based on rigid prices and an equilibrium
18 concept of profit or return on invested capital clearly contradicts the dynamic nature of
19 competition. Performance-based regulation recognizes the *dynamic* nature of the
20 competitive process and harnesses those forces to achieve the goals of regulation in a more
21 efficient manner.

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(...continued)

¹³ By “more competitive” I simply mean that through these improvements in technology and products firms can better serve their customers and in the end remain viable as a commercial operation.

¹⁴ In economic terms, the consumer is the residual claimant to all cost savings.

1 Q. Specifically, what problematic aspects of the static regulatory approach (i.e., traditional
2 regulation) can be addressed by a performance-based regulation plan?

3 A. There are at least four.

4 First, the static approach attempts to justify a single return on equity (i.e., profit rate) based
5 on a snapshot in time. Competition, however, does not focus on a single return number, but
6 rather a range over which the market will reward a firm for operating efficiently (or being
7 lucky) or punish it for operating inefficiently (or being unlucky). Alternative regulation
8 that allows a *zone of reasonableness* better emulates the competitive market. Performance-
9 based regulatory plans often use a “deadband” of profit levels over which the company
10 cannot request a rate increase or, in the alternative, the regulator cannot order a rate
11 decrease (or revenue sharing).

12 Second, earning over the “allowed” rate of return may not indicate monopoly profits, but
13 rather may simply be compensation for additional risk taken on by the company. Standard
14 economic theory suggests that the so-called “normal” rate of profit¹⁵ is not a single number,
15 but rather is related to the risk undertaken by the firm. Alternative regulation allows the
16 firms to take more responsibility for recovering costs (i.e., allocates incremental risk to the
17 company) but also recognizes that such incremental risk must be compensated with
18 incremental return.

19 Third, regulatory lag is a weak incentive to lower costs over the long run. A dynamic
20 approach would recognize that costs factors, demand factors and revenue opportunities
21 fluctuate over time. Alternative regulation provides a mechanism that better mimics the ebb
22 and flow of competitive markets allowing the firm to optimize its cost structure.

23 Fourth, the static model implies price rigidity whereas dynamic models recognize the
24 consumer benefits of price flexibility. Alternative regulation generally allows for some

¹⁵ Generally the “normal” rate of profit in theory corresponds to the “allowed” rate of return in practice. However, as noted above, the allowed rate of return is rigid, whereas the normal profit level tends to fluctuate with the risk taken on by the company.

price flexibility by allowing the utility to begin to set prices, usually within certain pre-determined bounds, more in line with good business practice.

Q. Have other jurisdictions instituted performance-based regulation for public utilities?

A. Yes. I have attached to this testimony three exhibits entitled Exhibit KAM-1, Exhibit KAM-2 and Exhibit KAM-3. Exhibit KAM-1 provides a review of plans that are considered price or revenue cap plans and Exhibit KAM-2 provides an overview of plans that are not considered price or revenue cap plans. Exhibits KAM-1 and KAM-2 relate only to the electric industry. Exhibit KAM-3 provides a review of plans that incorporate deadbands for gas utilities. Note that about half of all states have or have had some form of a performance-based regulation plan for either gas or electric utilities.

C. Performance-based Regulation is Preferable to Traditional Regulation

Q. Generally speaking, what are the benefits from moving to performance-based regulation?

A. In general, PBR can produce multiple benefits. First, the firm has more of an incentive to operate like a competitive firm. Second, the direct cost of regulation is decreased through the automatic nature the plan. Third, the indirect cost of regulation, such as the cost associated with incomplete and asymmetric information, can be decreased. Fourth, the incentive to innovate is increased. Fifth, the incentive and ability to shift costs from unregulated services to regulated services is largely removed.

Q. What are the main constraints found in the typical regulatory environment?

A. The regulatory environment is characterized by three main constraints.

First, regulators often cannot obtain the appropriate level and detail of information needed to implement traditional regulation. Information concerning customer demand, utility costs and other pertinent information can be too complex to analyze in the time given, not available or too costly to obtain. In addition, as noted above this information changes over time and often is stale even by the end of a rate case. This is the *information constraint*.

1 Second, The regulatory environment imposes certain administrative costs that may or may
2 not be conducive to efficient operation of the business. This is the *administrative*
3 *constraint*.

4 Third, the regulatory compact that exists between the stakeholders cannot be completely
5 identified and specified. While certain parties may believe that certain actions are required
6 by other parties, there is always some ambiguity as to who has what responsibility. In
7 addition, one commission cannot generally commit future commissions to specific actions.
8 This constraint is referred to as the *transactional constraint*.

9 Q. Does traditional regulation generally deal well with these constraints?

10 A. Generally no. Clearly the information and administrative constraints are often not dealt with
11 effectively. Cost of service regulation requires detailed information concerning the firm's
12 costs and technology that is generally difficult for the regulatory body to obtain and verify.
13 But even if the regulatory body has perfect knowledge of the firm's cost structure, the
14 method by which traditional regulation sets prices—based on a test period—virtually
15 guarantees that prices will not reflect costs once the prices are set.¹⁶ The administrative
16 constraint can also hinder the ability of traditional regulation to produce efficient outcomes.
17 Administrative duties, formal filings and protracted rate cases can discourage the utility
18 from innovation and focuses management more on the regulatory function rather than the
19 provision of utility service. The transactional constraint can be problematic because the
20 regulator (or a legislature) generally cannot bind later incarnations of the commission or
21 legislation.

22 Q. How important is an understanding of the regulatory environment to designing
23 performance-based regulation?

24 A. It is extremely important. In order for a PBR plan to meet the public interest goals and be
25 an improvement over traditional regulation it must take into account and be consistent with
26 the ability of the firm and the regulatory agency to implement the plan. The plan must be

¹⁶ In addition, the fixed price methodology of traditional regulation also hinders its ability to produce efficient outcomes.

consistent with the information available to the firm and the regulator and use feasible instruments to implement it.

Q. How does PBR generally handle the regulatory constraints?

A. PBR can be designed to directly address all three of these constraints. First, PBR generally attempts to minimize the necessary information and attempts to use information that is easily verifiable. The on-going informational requirements tend to depend on publicly available data, such as the Consumer Price Index, or data that is determined in the rate case, such as a productivity index. In addition, prices can be allowed to be flexible within a certain range. This promotes economic efficiency without the regulatory body collecting and analyzing complex information concerning consumer demand. In this way one can avoid, to the greatest extent possible, the informational constraints while allowing the regulatory body the necessary control to set the initial starting point. Second, through the PBR plan the administrative constraint can also be minimized to only those administrative procedures that are necessary for the on-going regulation of the utility. The parameters of many alternative regulatory plans dictate minimal administration throughout the term of the plan. Last, while the transactional constraint remains as a conceptual difficulty in any type of regulation, PBR plans attempt to address the issue by making the parameters of the plan clear and codified through a regulatory order.

Q. In your opinion is PBR preferable to traditional regulation?

A. Based on a fundamental understanding of the constraints placed on traditional regulation, I am of the opinion that PBR makes better use of incentives, provides a better substitute for competition, institutes a more efficient regulatory environment and, when properly designed, represents a preferred regulatory mechanism relative to traditional regulation.

D. Performance-based Regulation Promotes the Public Interest

Q. Don't public utilities have the obligation under law to operate efficiently under traditional regulation?

A. Generally there is a legislative goal of providing utility services in the most efficient manner while providing the utility with the opportunity to recover its "cost of service."

1 However, as with all aspects of economic life, the firm will operate in a manner consistent
2 with the incentives inherent in the system. I have noted above that the incentives created by
3 traditional regulation have not been designed with full dynamic efficiency in mind. For
4 example, the administrative constraint placed on regulators does not have efficiency as a
5 goal, but rather has other goals such as openness, fairness, and due process that are
6 appropriate in an administrative environment, but may not be totally consistent with
7 economic efficiency. Therefore, one must temper ones interpretation of such legislative
8 mandates by realizing that a rational utility will operate as efficiently as it can given the
9 many constraints it faces.

10 Q. How is the public interest promoted by performance-based regulation?

11 A. There are five main ways that the public interest is promoted by PBR. First, unlike
12 traditional static approaches to regulation which are generally zero-sum games,¹⁷ alternative
13 regulation provides incentives for the utility to become more efficient and thereby creating
14 a non-zero sum game.¹⁸ This better aligns shareholder and ratepayer interests. Second, price
15 changes are more understandable under alternative regulation as they are linked to factors
16 that are more generally available and understandable to the public, such as the Consumer
17 Price Index. Traditional regulation relies on complex cost of service studies that the public
18 will not generally understand. Third, the direct and indirect cost of regulation is decreased.
19 Clearly direct costs such as the costs of regulatory hearings will be reduced. Indirect costs
20 such as those created by asymmetric and incomplete information, pricing errors, etc. can
21 also be reduced. Fourth, alternative regulation promotes innovation. As noted above,
22 traditional regulation tends to mute the incentive for innovation. As innovation is one of the
23 main drivers in creating a non-zero sum game, PBR that promotes innovation will also
24 promote the public interest. Fifth, rates remain just and reasonable. Generally PBR plans
25 use just and reasonable prices determined in a traditional rate case proceeding as a starting
26 point. Once the regulator has approved a PBR procedure as just and reasonable, the

¹⁷ A zero-sum game refers to a process by which one party gains directly at the expense of another party.

¹⁸ A non-zero sum game refers to a process by which one party gains but not at the expense of another party. This could also encompass a situation in which both parties gain.

1 resulting prices will also be just and reasonable. Additional protections such as earnings
2 sharing, plan monitoring and set plan periods also help assure that rates will remain just and
3 reasonable.

4 **III. ASSESSING THE XCEL ENERGY AND OTTER TAIL**
5 **PERFORMANCE-BASED REGULATION PLANS**

6 **A. Characteristics of an Appropriate Alternative Regulation Plan**

7 Q. Please describe the aspects of an appropriate PBR plan.

8 A. Briefly the characteristics that are most important in determining whether or not a PBR plan
9 is appropriate are as follows:

- 10 1. Simplicity and inexpensive to administer
- 11 2. Automatic operation
- 12 3. Symmetric
- 13 4. Employ identifiable and calculable benchmarks
- 14 5. Employ sufficient penalties and rewards
- 15 6. Operate for a sufficient length of time
- 16 7. Explicit recognition of exogenous events
- 17 8. Comprehensiveness
- 18 9. Flexibility

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21 Q. Please explain how you compiled this list.

22 A. These are characteristics of a plan that address the problems with traditional regulation
23 identified previously in my testimony. For example, I noted that traditional regulation
24 suffered from informational constraints by relying heavily on complex cost of service
25 calculation. To counter such tendencies simplicity should be substituted for complexity
26 where possible. A further counter to the information problem is to use benchmarks that are
27 sufficiently easy to calculate and verify. I also noted that administrative constraints exist
28 under traditional regulation. To counter these constraints a PBR plan should be automatic,
29 operate for a sufficient length of time and provide for flexibility. In addition to these
30 constraints, the transactional constraint can be countered by explicitly recognizing the
31 potential for exogenous events as well as allowing the plan to operate over a period of time.
32 Further, a plan that is comprehensive in scope and employs symmetry in penalties and

rewards tends to counter the disincentives to efficient operation found in traditional regulation.

Q. Has the North Dakota Public Service Commission (NDPSC or Commission) addressed the issues of assessing a PBR plan?

A. Yes it has. In Case No. PU-139-94-590, the NDPSC issued a document entitled "Guidelines for Filing Alternative Regulation Proposals" (the Guidelines).

Q. What are the goals set forth by the Guidelines for a PBR plan?

A. The Guidelines note the following goals:

- Promote Utility Efficiencies
- Align customer and shareholder interests
- Maintain/Improve customer service
- Allow utilities to be flexible
- Minimize regulatory costs
- Improve public participation

Q. Are these goals met by the plan proposed by the Companies?

A. The plan proposed by the Companies meets these goals as will be shown below. I would also note that each of these goals could be reconciled with the list of characteristics I noted above.

Q. What are the criteria the Commission has set forth and how do they relate to your discussion of performance-based regulation?

A. The Commission identified five criteria:

- Comprehensive
- Administratively Simple
- Easily Communicated
- Balanced
- Flexible

These criteria are also completely consistent with the characteristics of an appropriate plan that I noted above.

1 Q. How should the criteria be weighted in reviewing the Companies proposals?

2 A. As with both the Commission's criteria for judging the plan and my stated characteristics of
3 an appropriate plan, some of the factors are not entirely consistent with one another. For
4 example, while simplicity is a goal of the plan, the plan should still produce just and
5 reasonable rates. Therefore, the Commission will need to judge which factors are likely to
6 be most important to the overall performance of the plan. For example, the Commission
7 may wish to weight administrative ease higher than flexibility because saving state
8 resources in monitoring and reviewing the plan may benefit the stakeholders more than
9 flexibility. In addition, the Commission also needs to balance the pursuit of the "perfect"
10 plan with the realities of a regulatory proceeding. In other words, if the Commission is
11 convinced that these plans are in the public interest as outlined above, it should not allow
12 the "perfect to be the enemy of the good." In the end, if the Commission is convinced that
13 the plans meet a significant portion of the goals and criteria set forth, it can judge the plan
14 as meeting the public interest.

15 **B. Description of the Xcel Energy and Otter Tail PBR Plan**

16 Q. Please provide an overview of the Companies proposed plans.

17 A. The Companies propose a relatively simple plan that would allow the Companies a zone of
18 reasonableness on their ROE that could change if certain performance standards are met. In
19 addition, prices are set through a formula that is based on the rate of consumer price
20 inflation.¹⁹ Price increases are limited to years in which earnings do not exceed the zone of
21 reasonableness and price decreases are limited to years in which earnings do not exceed the
22 upper limit of the zone.

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¹⁹ This is true if the CPI formula results in a price increase that is lower than the changes in prices for the comparison group, otherwise the price change is capped at the comparison group change.

Q. Please provide an overview of the salient features of the plans proposed by Otter Tail and Xcel Energy.

A. The key aspects of the plan are as follows;

(1) *Dynamic Return on Equity (ROE) Bandwidth*

(2) *Earnings Sharing*

(3) *Performance Standards*

(4) *Limited Price Flexibility*

In addition, the Xcel Energy plan provides for economic development investment.

C. The Salient Features of the Companies' Plans are Appropriate

1. Dynamic Return on Equity Bandwidth

Q. Please explain the function and role of the dynamic ROE bandwidth?

A. As noted above, alternative regulatory plans often provide a range on the profits a utility can make before either prices can be increased or reduced. The Companies propose that the ROE be set at 12% with an initial range²⁰ of plus or minus 1%. The Companies also propose that the ROE be based on performance. That is, if the Companies meet certain performance standards the ROE will move up or down based on the achievement of the Companies. The purpose of allowing the ROE to float based on the performance of the Companies is to provide the Companies the incentive to meet the performance standards so that increases in efficiency can be retained by the Company. Note that the earnings sharing portion of the plan, discussed below, is provided to allow customers to also benefit from increased efficiencies that cause earnings to exceed the ROE in any given year.

²⁰ This range is referred to as the "bandwidth" or the "deadband."

1 Q. Why is it appropriate to have a deadband around earnings?

2 A. The deadband helps insulate both customers and the companies from small changes in
3 earnings due to the natural ebb and flow of general business conditions. In addition,
4 deadbands are very common in alternative regulation plans and serve an important role in
5 keeping the plan simple and easy to administer.

6 Q. Is the proposed deadband appropriate?

7 A. The proposed 100 basis point deadband is within a reasonable range based on my review of
8 other plans approved around the country. Exhibits KAM-1, KAM-2 illustrate this for the
9 electric industry and Exhibit KAM-3 provides an illustration for the gas industry.

10 Q. Is it appropriate for the deadband to be symmetric?

11 A. Yes it is. A symmetric deadband is one in which the allowed return is the same above the
12 target return as below it. As noted above, symmetry is one of the key aspects of an
13 appropriate alternative regulation plan. Without symmetry, either the company or the
14 ratepayer will be treated differently. This violates basic notions of fairness and sets up
15 incentives that may result in unintended circumstances. For example, if the deadband is
16 asymmetric in favor of the customers the Companies may simply refuse to implement the
17 plan if management believes its fiduciary responsibility to shareholders cannot be met. This
18 would deprive customers of benefits under the plan and re-institute the traditional
19 incentives under cost of service regulation.

20 Q. Is the proposed dynamic deadband an appropriate method of providing incentives for
21 efficiency?

22 A. Yes it is. In fact, such an approach is somewhat innovative in the realm of alternative
23 regulation as it bridges a gap between pure price cap plans and static earnings sharing plans.
24 The dynamic ROE bandwidth is appropriate for two main reasons. First, it sends the signal
25 to the Companies that superior performance will be rewarded. This alters the current
26 incentives inherent in the traditional regulatory paradigm toward providing superior service
27 Second, and most importantly, it provides high-powered incentives (i.e., the Companies
28 will be the residual claimant) to the Companies to reduce costs within the dynamic

1 deadband.²¹ This differs from many alternative regulatory plans that have earnings sharing
2 over a static deadband resulting in customers having some claim to refunds above those
3 ranges. The result of the Companies proposal will be two-fold. The Companies will strive
4 to meet the performance standards *and* will attempt to do so in a least-cost manner so it can
5 retain as much revenue as possible. This benefits customers through a more efficient utility
6 that provides service that meets customer expectations.

7 Q. Is the potential to adjust the ROE by 200 basis points appropriate?

8 A. Ideally, one would like to associate the adjustment in return to compensate for the increase
9 in risk the Companies are taking on by moving away from traditional regulation. However,
10 such a calculation would be difficult if not impossible to obtain objectively. Therefore, as
11 an alternative the Companies have proposed 200 basis points as a reasonable compensation.
12 The Commission must weigh the benefits of providing this additional incentive with its
13 costs. The benefits could be substantial, as noted above, while the costs relatively low. As
14 noted elsewhere in the plan, the price consumers pay will not rise as fast as inflation and
15 can only go up in certain relatively strict circumstances. In addition, the increases in
16 allowed ROE could only happen if the Companies meet the performance standards. Finally,
17 the Commission has the opportunity to review the operation of the program over time.
18 Given the safeguards in place and the relatively high level incentives provided by the
19 dynamic ROE, the 200 basis points (50 for each performance standard) is a reasonable
20 place to begin.

21 2. Earnings Sharing

22 Q. If the Companies retain all earnings in the dynamic bandwidth, how do ratepayers directly
23 benefit from the plan?

24 A. Beyond the benefits noted above within the dynamic deadband, ratepayers can directly
25 benefit from the second aspect of the plan and that is the earnings sharing. While the
26 Company has high-powered incentives within the dynamic ROE bandwidth, the incentives

²¹ It must be clear that the “dynamic” part of what I am calling the “dynamic deadband” is related to performance, i.e., the 50 basis points for each measure, whereas the deadband itself, i.e., the 100 basis points, remains static.

1 remain, although somewhat lessened, into the sharing range. Therefore, the Companies
2 have an incentive to reduce costs even if it results in rebating some money back to
3 customers because the Companies retain a portion of the earnings. As noted in the Xcel
4 Energy proposal, nearly \$700,000 could have been generated over the years 1994-1998 had
5 this plan been in place.²² These are real benefits that have been lost to consumers because
6 this plan was not in place.

7 Q. You noted that the incentives are lessened due to the earnings sharing. Is it appropriate to
8 have an earnings sharing mechanism (ESM) in the plan?

9 A. Yes it is. An ESM is important for three reasons. First, ESMs tends to mimic the
10 competitive market. Under a competitive regime, superior performing companies are
11 generally rewarded with superior returns. However, profit also invites entry by alternative
12 providers. Competition will eventually help drive prices down and consumers “share” in the
13 good fortune of the efficient firms through those price reductions. Second, even though the
14 plan is simple and can be implemented easily, mistakes can still be made. An ESM provides
15 a safeguard that mimics the regulatory review process. However, this mechanism is more
16 automatic, unlike an administrative rate case. Last, ESMs lends an air of fairness to the
17 program.²³ For example, companies may simply be the beneficiaries of “good luck.” If this
18 were to happen, customers would share in that good luck. In return, if the Companies
19 experience “bad luck” customers would not be hit with the full amount of the shortfall.

20 Q. Is it appropriate for the plans to provide for an equal sharing of earnings?

21 A. Yes it is. Sharing equally in the earnings meets our common notions of fairness and is
22 likely to be a result of a fairly determined game. For example, imagine a situation in which
23 two people have to decide how to allocate the last piece of cake between them. Further
24 assume that if given the opportunity each would take the full piece. One method of
25 allocation would be to allow one person to cut the cake, but allow the other to choose which

²² Northern States Power Company Petition at 3.

²³ The following example assumes that the Companies continue to meet the performance standards, but items beyond control of the managers alter the earnings either positively or negatively. Of course, this also assumes the earnings are outside of the deadband.

1 piece to take. The result will be a 50/50 sharing between the two people and each will feel
2 as if they were treated fairly. While one could make arguments for nearly any sharing
3 allocation, a 50/50 sharing meets the test of fairness better than any other allocation.

4 **3. Performance Standards**

5 Q. Please explain the function of the performance standards.

6 A. The Companies have proposed four performance standards that measure overall company
7 performance. The standards are: 1) Reliability; 2) Price; 3) Customer Satisfaction and 4)
8 Worker Safety. The performance standards function as surrogate for market-based service
9 standards. Firms in competitive markets not only have the incentive to minimize costs but
10 also to provide a level of service that meets the minimum standard set by the market. If a
11 firm cuts costs by lowering service below that standard, customers will switch suppliers or
12 new firms will enter to provide the level of service expected by consumers. As the utility
13 remains a monopoly, some surrogate for this mechanism must be designed. This allows the
14 Commission (through the plan) to reward the Companies if they maintain or improve
15 service while cutting costs, just as a competitive market would.

16 Q. Are the performance standards proposed by the Companies appropriate?

17 A. Yes they are. These standards are designed to measure performance in a very general way.
18 That is, the standards tend to measure overall company performance rather than attempting
19 to measure aspects that are too specific. This is appropriate because the Commission does
20 not want to provide an incentive for the Company to manage to specific targets; rather the
21 Commission should want the Companies to manage the overall business appropriately. In
22 addition, the standards are easily developed and monitored by the Commission. This adds
23 clarity to the regulatory process and avoids any misunderstanding as to what goals have
24 been set by the plan. Finally, these standards are linked to internal company goals also. This
25 sets up an appropriate incentive for employees to meet the internal standards that then
26 benefit customers through the maintenance and improvement of quality service.

1 Q. Is it appropriate to have deadbands around these standards?

2 A. Yes it is. As these standards measure performance on an ongoing basis one would expect
3 some random fluctuation in the performance of the Companies over time. Adding
4 deadbands around the performance standards recognizes that this is not an exact science,
5 but rather is an ongoing measure of company performance. By using the deadbands around
6 the performance measures the Commission can be reasonably assured that if a company
7 meets a target or misses a target it is because of actions on the part of the company and not
8 the random fluctuations that occur in the normal course of business.

9 Q. Are there additional measures that could be used?

10 A. One could always concoct different performance measures. However, unless the
11 Commission is sufficiently concerned with a specific area of performance that is not
12 measured by these indicators, it makes little sense to try and improve upon the performance
13 standards proposed by the Companies. This is so because these standards are general
14 enough to measure overall performance and any other measure would either simply
15 substitute for one of the proposed measures or inappropriately narrow the scope of the
16 measure such that the Companies could face perverse incentives to manage to that measure.
17 In the former case the plan is not improved but simply different; in the later case the plan
18 actually becomes less appropriate.

19 Q. Is it appropriate to weight the standards equally?

20 A. In this case I believe it is. While one could postulate that certain aspects of performance are
21 more valuable to consumers than other aspects, the problem with attempting to perform
22 some weighting analysis is two fold. First, weighting the standards obviously presents an
23 incentive to the Company to meet those standards that have the highest weight. If one
24 believes that these measures do measure overall performance, then equal weighting is
25 appropriate as the Commission wants to send the signal that overall performance should be
26 maintained and improved. Second, in practical terms, a weighting scheme would either be
27 an estimate of the value placed on the standards by consumers or simply a judgement by the
28 Commission. In the former case, such an estimate would be controversial to say the least
29 and would take attention away from the real issues of designing a plan that best meets the

public interest and is understandable. In the later case, any judgement would also be controversial. The best approach is the simplest in this case. By weighting each standard equally the Commission can send the signal that it expects the overall performance of the Companies to be maintained and improved. This is the appropriate signal to send.

4. Limited Price Flexibility

Q. Please describe the price flexibility aspect of the plan.

A. Under the proposed plan, prices are allowed to change according one of the following formulae:

$$P_{t+1} = P_t(1 + 0.75CPI) \quad (A)$$

$$P_{t+1} = P_t(1 + \Delta CGP) \quad (B)$$

Where P_{t+1} is the new price in the next year, P_t is the price in the current year, CPI is the Consumer Price Index and ΔCGP is the change in a comparison group price.²⁴ The actual price change is determined by the lower of ΔCGP or $0.75CPI$. That is, if $0.75CPI < \Delta CGP$ then equation (A) would be used, if $\Delta CGP < 0.75CPI$ then equation (B) would be used.

However, the new price is constrained by the following conditions:

- If price is higher than a comparison group²⁵ average, no price increase is allowed.
- If earnings exceed the ROE deadband then no price increase is allowed.
- If price is below the comparison group average, no price decrease is required.
- If earnings are in the deadband or below it no price decrease is required.

Any price changes are to be allocated across each rate class unless the Commission approves a Company proposed plan to change prices in a different manner.

²⁴ The comparison group is the average residential rate for a set of investor-owned utilities in a seven-state region in the Upper Midwest.

1 Q. Is the price change formula (i.e., equation (A)) reasonable?

2 A. Yes. Although as noted below, price cap plans tend to have formal productivity indexes
3 estimated, in this case such an exercise would likely be costly and not benefit the plan a
4 great deal. For example, under a price cap plan that had an explicit productivity number, the
5 price would change according to the following formula.

6
$$P_{t+1} = P_t(1 + INF - X) \quad (C)$$

7 where *INF* is the measure of inflation and *X* is a measure of productivity.²⁶ For example, if
8 inflation in a given time period was 2% and productivity 0.5%, the rate of change for the
9 price would be 1.5%. Under equation (A) if the CPI increases by 2%, the price change
10 would be 1.5% implying a productivity factor of 0.5%. The advantage to customers of
11 using (A) over (C) is that in high inflation years the implicit productivity levels increase,
12 unlike a set productivity number that would not increase with price inflation.

13 Q. Is it appropriate to use the consumer price index (CPI) rather than an alternative measure of
14 inflation such as the Gross Domestic Product Price Index (GDPPI)?

15 A. In a traditional price cap plan such as under equation (C), generally a measure of total
16 factor productivity (TFP) is used to estimate the productivity level and therefore a measure
17 of total economy wide price inflation, rather than only consumer prices, is more
18 theoretically sound. However, many analysts still argue for the CPI as it tends to be more
19 understandable to consumers. While I believe that a more general approach, such as the
20 GDPPI, is the more appropriate measure, the issue is somewhat minor, as there is no *a*
21 *priori* reason to believe that one measure would produce a higher inflation level than the
22 other. Since World War II, the CPI has grown at around 3.9% annually on average whereas
23 the GDPPI has grown at about 3.7% on average annually. However, in nearly half of those
24 years the GDPPI grew faster than the CPI. The Companies proposed use of the CPI to

(...continued)

²⁵ In this case the reference price is the average residential price.

²⁶ Often a Z factor will also be added in for exogenous factors.

1 measure inflation is a reasonable choice given that the price flexibility is limited and is not
2 based on a traditional price cap formulation.

3 Q. Is the price cap formula based on the utility rates (i.e., equation (B)) reasonable?

4 A. If the Commission is interested in restraining prices beyond the restraints contained in
5 equation (A), then equation (B) is a reasonable method to do so. Also note that one could
6 interpret equation (B) as emulating the marketplace in that prices are constrained by the
7 prices of other energy utilities.

8 Q. Is the construction of the comparison group reasonable?

9 A. Yes. The comparison group is reasonable as it simulates the “market” price for electricity in
10 service territories that are similar to North Dakota. This means that the weather patterns and
11 the composition of customers, i.e., urban/rural are similar. In addition, one could hardly
12 argue that this group represents the high-cost electric utilities. Therefore, the price cap is
13 based on prices that are already comparatively low. Such an index is reasonable to apply to
14 the Companies.

15 R. Is this limited price flexibility reasonable?

16 A. Yes. Generally price caps plans are set indexed to inflation and productivity as in equation
17 (A) above.²⁷ The price flexibility requested by the Companies in this case is much more
18 limited than a “standard” price cap plan. The added complexity of calculating comparison
19 group prices and setting price changes conditional on ROE calculations is not always
20 contained in a price cap plan. In addition, while the Companies have the opportunity to
21 request treatment of price changes in a manner other than across the board, the proposed
22 method requires additional regulatory scrutiny that adds complicating factors in attempting
23 to set prices in an appropriate manner. Many price cap plans allow the firm to set prices in
24 line with good business practice within a certain range.

²⁷ While equation (A) does not have a specific “X-factor” the 0.75 coefficient on the CPI works in the same way as a productivity factor in the standard price cap formula.

One issue that arises when setting price as proposed by the Companies, i.e., placing constraints on the price formulae, is that random factors could artificially increase or decrease earnings in any one year may and impact the ability to change price. Yet using a price cap formula, such as equation (A) or (C), also constrains price changes. Earnings can reasonably be treated separate from the actual price changes. However, the constraints proposed by the Companies work in favor of the customers while at the same time allowing the Commission to move incrementally toward a true formula method of setting prices. While generally one would like to allow the formula to control price changes, when experimenting with alternative forms of regulation, it could be reasonable to limit the ability of prices to change as is proposed by the Companies.

In addition, there seems to be some asymmetry in that price can go up within the earnings bandwidth but cannot go down. Allowing prices to change (both up and down) within the bandwidth could be a reasonable approach. However this relatively minor issue can be reviewed over time to see if any changes in the plan are justified.

Q. Would some flexibility on the allocation of price changes to the various customer classes be a reasonable approach in this case?

A. Although the Companies are not asking for this, I believe that allowing the Companies to change rates within a predetermined boundary in accordance with good business practice, without requesting regulatory approval, would be a reasonable approach. This is reasonable because most utilities have historically had subsidies built into the rates either through explicit regulatory action or possibly through mistakes made in the allocation of costs. Allowing some price freedom, within predetermined bounds, allows the utility to correct some of these pricing flaws without disrupting the consistency of rates too much. While clearly this adds a bit more complexity to customer understanding of the rate changes, if the flexibility given is within reason, customers should not see much difference between the current plan and this type of a mechanism.

Q. How could the Commission implement additional price flexibility into the plans?

A. One method the Commission could use is to allow the Companies to allocate price changes without regulatory approval that are "close" to the changes indicated by the formulae in

equations (A) and (B). For example, under equation (A) the Commission could allow the Companies to change prices such that no customer class sees a price change more than the rate of inflation while some customer classes see price changes less than the rate of inflation. For example, if the inflation rate were 2%, under the Companies proposal all classes would see an increase of 1.5%. Under this more flexible alternative, the Companies would be able to increase any customer class rates by as much as 2% as long as the total revenue from the price change remained the same as if all customer classes saw an increase of 1.5%.

If the price cap were to come into play, i.e., equation (B), either the original proposal could be implemented (i.e., across the board) or the Commission could set a deadband under which the Companies are allowed flexibility. For example, if the price indicated an increase of only 1% the Commission could allow the Companies to have a 0.5% deadband in which they could set rates as long as the expected revenue was no more than the price cap would allow. Of course, this approach could be used for changes under both equation (A) and (B).

Under this proposal, the Companies are not gaining any additional revenue from the price change, rather prices are allowed to float closer to what good business practice would dictate. The rates of all customers would not increase any faster than rate of inflation and the total rates recovered from customers would still rise at less than the rate of inflation. In addition, residential customers would remain protected by the price performance standard.

VI. THE PROPOSED PLAN IS IN THE PUBLIC INTEREST

Q. How are you defining the public interest?

A. The public has an interest in assuring that utilities operate efficiently and provide safe, reliable and adequate electric service. In this case, the public interest will be served if the plan can induce the utility to operate more efficiently, while maintaining or improving the service levels that consumers have grown accustomed to.

Q. Are the proposed plans in the public interest?

A. Yes they are.

1 Q. How did you arrive at that conclusion?

2 A. My conclusion is based on a review of the plans as a whole. The purpose of the plan is to
3 provide better incentives for efficient operation, these plans will do that. In addition the
4 plans allows for prices to change in a manner that is just and reasonable thereby creating
5 prices that are just and reasonable. Further, the plans also provide earnings sharing that will
6 benefit consumers while at the same time benefiting the utility shareholders. These aspects
7 of the plan indicate that it is in the public interest to approve it as filed.

8 Q. Do these plans send the right signal to the Company?

9 A. Yes they do. The Companies, under this plan, will have the incentive to provide reliable
10 service, maintain worker safety levels, maintain and improve customer service and continue
11 to provide a high quality energy value to consumers. Further this program sends the signal
12 that maintaining quality standards benefits shareholders as well as ratepayers and workers,
13 thus better aligning the interest of the these stakeholder groups.

14 Q. Does this plan send the right signal to consumers?

15 A. I think the signal this plan sends to consumers, as they get acquainted with it, is that their
16 service quality matters to the Companies. It matters because the plan explicitly includes
17 customers as a determining factor in utility profits. This is a good signal to send, not only to
18 the Companies, but also to customers. Consumers will generally see no change or an
19 increase in service quality and those price changes that do occur will be linked to variables
20 that are understandable to consumers. These are appropriate signals to be sending to
21 consumers.

22 Q. Does this conclude your direct testimony in this case?

23 A. Yes it does.

24

25

STATE OF NORTH DAKOTA
BEFORE THE
PUBLIC SERVICE COMMISSION

In the Matter of the Application of)
Northern States Power Company d/b/a)
Xcel Energy for Authority to Operate)
Under Performance-Based Regulation)
in North Dakota)

Case No. PU-400-00-195

In the Matter of the Application of)
Otter Tail Power Company for)
Authority to Operate Under)
Performance Based Regulation)
in North Dakota)

Case No. PU-401-00-36

AFFIDAVIT OF
KARL MCDERMOTT

I, the undersigned, being duly sworn, depose and say that the foregoing is the testimony of the undersigned, and that such Direct Testimony and the exhibits 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.


Karl McDermott

Subscribed and sworn to before me, this 28th day of September, 2000.


Notary Public



Price or Revenue Cap Plans in US

Name of State	Name of Utility	Type of Plan	Current Plan Begin Date	Current Plan End Date	Inflation Index	Authorized ROE	Productivity Offset (X)	Price Cap Formula	Earnings Sharing (Y/N)	Other Details
RI	Narragansett	Price Cap	1997	1998	CPI	11.00%	0.00%	$\Delta P = (CPI - X)$	Y	Companies can increase base rates by as much as CPI. Excess earnings b/w 0 and 1.5 percent above ROE are 50/50 shared; otherwise rate payers get 100 percent.
OR	Pacificorp	Price and Revenue Cap	1998	2000	GDP-PI	10.00%	0.30%	$\Delta P = (GDPPPI - X)$	Y	If earnings are 250 basis points above or below the benchmark rate then Pacificorp has to adjust rates and prices to bring earnings back into the 250 point band. Revenue cap applies to temperature-adjusted sales revenues for each customer class: they are compared to a pre-determined revenue allocation for that class. Excess revenues are collected in a balancing account, to be allocated the following year.
ME	Central Maine Power	Price Cap	1995	1999	GDP-PI	10.55%	See Formula	1997-99: $(1 - 0.375) * (\text{Inflation} - 1\%)$	Y	There is 50/50 sharing if earned ROE is 350 points below or above authorized level.
NY	Niagara Mohawk Power	Price Cap	1995	1999	Not Defined			1995-97: Frozen 1998-1999: Increase of no more than 1 pc	N	There is a "generation incentive" plan under which the company collects "incentives" equal to varying percentages of its proceeds from generation divestiture. Goal is to maximize divestiture proceeds. Incentive is collected as a surcharge in years 1998, 1999; the amount of the incentive is capped at "inflation less amounts authorized under the price caps filing and deferral recovery."
CA	San Diego Gas and Electric	Revenue Cap	1999	2002	Industry-specific escalation	10.60%	See Formula	$R[n] = (R[(n-1)] * (1 + \text{Esc} - X)) \pm Z$	Y	There is 75/25 sharing between customers/shareholders if ROE > 400 points above or below authorized levels.
CA	SCE	Revenue Cap	1997	2001	CPI	11.60%	1997: 1.2% 1998: 1.4% 1999: 1.6% 2000: 1.6% 2001: 1.6%	$\Delta P = (CPI - X)$	Y	Trigger Mechanism - return adjusted by 1/2 the change in bond index. No deadband, shareholder gets 100% up to $\pm 50bp$, 25-100% at 50-300bp, ratepayer gets 100% at >300bp. Plan review at 600bp.
WA	Puget Sound Light and Power	Price Cap	1997	2001			Series of fixed rate increases of between 1 and 1.5%		N	Plan was approved as part of Puget Sound merger with Washington Natural Gas.

States with a PBR plan in place other than price/revenue caps

State	Utility	Incentive Plan	Type of Incentive Plan	Details	Plan Duration
AL	Alabama Power	Y	Rate Stabilization and Equalization Plan	AL Power has a rate freeze in effect till 2001. In theory, the company's regulation plan allows for the adjustment of rates such that any returns on equity below 13 or exceeding 14.5 percent are re-adjusted to 13.75 percent. In practice, there is a rate freeze/rate cap in effect: the company's rates do not get adjusted upward, but might get adjusted downward in the event of over-earnings.	Until 2001
CO	Public Service of Colorado	Y	Benchmarking/Earnings Sharing/Rate Freeze	There is a rate freeze in effect till 2001. PS Colorado is planning to merge with Southwestern Public Service. In addition, PS Colorado has a quality-of-service program under which its performance on price, reliability and customer service (measured by telephone response times) is assessed; if the company misses its quality-of-service targets it will be penalized. There is a penalty for failure. The penalty payments are returned to ratepayers in the form of a bill credit. There is also an earnings sharing plan wherein PS Colorado keeps 35% of equity earnings between 11 and 12 percent, but a higher ratio at higher earnings levels: 65% of equity earnings between 14 and 15 percent. With the rate freeze in effect, higher equity earnings represent superior cost performance, so the plan maximizes incentives for good cost performance.	
CT	United Illuminating; Connecticut Power and Light	Y	Earnings Sharing/Benchmarking	Conn. Lgt and Power has a conservation-targeted incentive mechanism. It was allowed premium equity earnings on conservation and load-management providing it met the goals that regulators had set for it in this area. Performance goals were measured by the kWh savings from energy conservation and DSM type programs. United Illuminating has an alternative regulation plan (ARP) under which it was allowed to retain half of its equity earnings above 11.5 percent. Customers receive a bill credit for the remainder of the excess earnings.	United Illuminating: 1996-2001
DC	PEPCO	Y	Targeted Incentive/DSM	PEPCO must meet performance targets (unspecified) for its DSM programs. For achieved performance between 80 and 105 percent of established targets there is no reward. For performance exceeding 105 percent, PEPCO will receive 10 percent of the savings above 80 percent; for performance below 80 percent, a penalty will be imposed.	
DE	Delmarva Power and Light	N		Delmarva did have power-plant linked performance incentives: for nuclear plants, the capacity factor was measured and based on the (varying) targets, the company was either penalized or rewarded, with the penalty or reward capped at 2% of the company's jurisdictional equity investment. The penalty or reward was applied to rates. For fossil plants, a similar incentive was in place, but the equivalent availability factor was used in lieu of the capacity factor. However, these programs, in common with other incentive proposals are being phased out in favor of restructuring.	
FL	TECO; Florida Power and Light	Y	Targeted Incentive/DSM	Both TECO and FP&L have performance-adjusted plans. TECO, for example, keeps 20 percent of the profits from economy energy savings, with the remaining 80 percent being distributed to ratepayers in the form of bill credits.	
GA	Georgia Power	Y	Earnings Sharing	Georgia Power was allowed to retain 1/3rd of excess earnings, 2/3rds went to ratepayers. Large rate reductions required and amortization of regulatory assets required by the commission. Sharing to be applied through rate reductions on a going-forward basis.	1999-2001
HI	HECO	Y		There is no rate freeze or rate cap proposal. However, HECO's shareholders are permitted to retain 10 percent of after-tax savings from DSM programs. The commission calculates the present value of net savings from DSM and allows the company to recover 10 percent of this in the next year.	

States with a PBR plan in place other than price/revenue caps

State	Utility	Incentive Plan	Type of Incentive Plan	Details	Plan Duration
IA	Mid-American Energy	Y	Earnings Sharing	Mid-American Energy has an ROE sharing program; if the company's return on equity is between 12 and 14 percent, it will be allowed to retain 50 percent of the earnings between 12 and 14 percent. Only 17 percent of earnings in excess of a 14 percent return on equity may be retained. Sharing is flowed-through to ratepayers in the form of rate rebates.	1997-2001
IL	All Electrics	Y	Earnings Sharing	Rate reductions and freezes according to 1997 restructuring law. Utilities retain all earnings up to the average of the 30-year T-bond plus: 1998-1999: 4.0 % or 8% if utility's average residential rate is 90% or less of Midwest average and serves between 150,000 and 250,000 customers; 2000-2004: 7.0% for utilities that serve over 1 million customers or 9% if utility's average residential rate is 90% or less of Midwest average and serves between 150,000 and 250,000 customers or 11% if utility's average residential rate is less than 90% of the Midwest average and allows open access for 33% of customers in certain classes or 5% for all other utilities or 7% for utilities that do not ask for stranded cost recovery beyond the mandated transition period. Beyond that deadband earnings are shared 50/50. A rate increase can be requested if earnings in a two-year period fall below the average of the 30-yr T-bond. But no increase in rates can be requested until Jan 2000.	1997-2004
KY	LG&E/KUT	N		Merger savings are to be flowed-through to ratepayers in the form of a rate rebate. KUT and LG&E are in a merger: 53 percent of savings go to LG&E ratepayers, the remainder to KUT ratepayers.	
LA	Entergy Louisiana	Y	Earnings Sharing	A rate freeze is under consideration. Details of sharing: above 11.3 percent, all excess earnings credited to ratepayers; between 9.7 and 11.3 percent there is a 60/40 sharing in favor of shareholders. Below 9.7 percent, the company may institute a rate case, but there is no guarantee of rate increases.	1998-2003
MA	Boston Edison; Eastern Edison; Mass. Electric	Y	Earnings Sharing	Boston Edison, Mass. Electric have very similar sharing plans: Boston Edison shares equity earnings representing returns of between 11 and 12.5 percent in a 50/50 ratio with ratepayers. All earnings in excess of 12.5 percent are flowed through to ratepayers. All sharing with ratepayers takes place in the form of rate reductions (in the per kWh charges). Eastern Edison, Mass. Electric have identical plans. There is no rate freeze in Mass; however, should earnings fall below the 6 percent return on investment level, the electric's can start a new rate case and might be allowed to increase their rates.	1997-2001
MD	Delmarva Power and Light	Y	Targeted Incentive/DSM	Proposed settlement agreement calls for a 7.5 percent rate reduction in the unbundled wires charges effective in 2000. Following that, there is a rate freeze for the next five years until 2004. However, for now, the only programs in effect for Delmarva are DSM incentive programs that allow for (varying) proportions of DSM savings to be retained.	2000-2004
MD	Allegheny Power	Y	Earnings Sharing/Targeted Incentive/DSM	Allegheny is the only utility in MD with an explicit sharing mechanism: 50 percent of earnings above 11.4 percent are retained, while 50 percent are given to customers. The sharing happens in the form of credits, and not rate changes. In addition to this, Allegheny is also allowed to retain some of its DSM savings.	
MD	BGE	Y	Targeted Incentive/DSM	Proposed settlement agreement incorporating rate freezes and reductions, effective 2000. Until then, there are modest DSM programs identical to those for Delmarva.	

States with a PBR plan in place other than price/revenue caps

State	Utility	Incentive Plan	Type of Incentive Plan	Details	Plan Duration
MD	PEPCO	Y	Targeted Incentive/DSM	Proposed settlement agreement incorporating rate freezes and reductions, effective 2000. Until then, there are modest DSM programs identical to those for Delmarva.	
MN	Otter Tail Power	Y	Targeted Incentive/DSM	DSM related savings similar with those of NSP.	
MN	Northern States Power	Y	Targeted Incentive/DSM	Utilities allowed to retain 10 percent of DSM (varying performance goals set by the DPS). Penalties assessed if DSM savings less than 75 percent of set goal.	
MO	AmerenUE	Y	Earnings Sharings	For earnings between 12.61 and 14 percent there is a 50/50 share; all earnings over 14 percent are flowed-through to ratepayers	
MS	MS Power	Y	Benchmarking/Earnings Sharing	Miss. Power has a Performance Evaluation Plan that enables the company to earn a higher or lower Return on Equity depending on the utility's relative performance, as measured along the dimensions of price, reliability, and customer service. The commission determines their ROE as in normal rate-case setting, then it takes 10 percent of the performance index to calculate the final ROE for the company. The Commission also has a plan for earnings sharing: if the earned ROE is outside 50 basis points of the Performance-Based ROE then the company may retain varying proportions of the excess earnings depending on its CPR performance. No formal rate freeze in effect. Sharing is made through going-forward adjustments.	1994-1999
MS	Entergy Mississippi	Y	Benchmarking/Earnings Sharing	Formula rate plan is quite similar to MS Power. The company does have its ROE determined by its performance, and performance is measured similar to case of MS Power, but it shares its excess earnings in a fixed 50/50 ratio with ratepayers. Rate adjustments are also made on a going-forward basis. No rate freeze in effect.	1994-?
NC	Duke Power	Y	Targeted Incentive/DSM	Duke has a DSM account into which savings from DSMs are put; it can earn up to 15 percent return on this account. However, recently DSM contributions have been dropping very fast.	Annual
NC	North Carolina Power	Y	Targeted Incentive/DSM	Plan very similar to Duke; also seeing DSM contributions dropping fast.	Annual
NJ	GPU Energy; PSE&G	N		GPU and PSE&G have filed settlement agreements with the New Jersey Board of Public Utilities; the BPU has ordered several large rate reductions, to applied to the rates effective April 30, 1997. GPU was also ordered to pay an additional 5% rate refund effective for the period from August 1, 2002 through July 31, 2003. Rate reductions were also ordered as part of PSE&G's settlement.	

States with a PBR plan in place other than price/revenue caps

State	Utility	Incentive Plan	Type of Incentive Plan	Details	Plan Duration
NY	Con Edison	Y	Earnings Sharing	Con-Ed can retain 50 percent of earnings over 12.9 percent. 25 percent will be applied to rate reductions, 25 percent to accelerated depreciation. If forecast ROE falls below 8 percent, ConEd can file a rate case.	Five-year period ending March 31, 2002
NY	Rochester Gas and Electric	Y	Earnings Sharing	If RGE's ROE goes above 11.80 percent, as determined for the entire term of the settlement (five years), then the company must use 50 percent of the excess earnings to write down deferrals accumulated during the course of the settlement; part of the other fifty percent goes toward rate reductions, while the remaining part goes to recovery of all deferrals and sunk costs.	1997-2002
NY	Niagara Mohawk Power	Y	Targeted Incentive/Stranded Cost	NIMO has a price cap plan and also an incentive program targeted at Stranded Costs. Under this plan, NIMO gets to keep a higher proportion of the proceeds from generation divestiture, the more it divests. Plan aims at maximizing divestiture.	1997-2002
OH	Dayton Power and Light	Y	Targeted Incentive/DSM	The company can retain everything up to 14 percent; b/w 14 and 15 percent, one-half of earnings must go to a DSM deferral account. All earnings above a 15 percent equity return are credited to the DSM deferral account.	
TX	All Electrics	N		Statewide rate freeze in effect as of 9/1/99 to continue until January 1, 2002. Then, the affiliated Distribution companies formed from the incumbent Investor-owned Utilities will have their rates frozen within their own service territories for an additional 3 years for residential and small commercial customers.	1999-2005
VA	AEP-Virginia	Y	Earnings Sharing/Targeted Incentive/Stranded Cost/Rate Freeze	Earnings over 12.9 percent would a) be used to accelerate recovery of regulatory assets, and b) returned to ratepayers. AEP rates have been frozen till 2000.	1998-2000
VA	Virginia Power	Y	Earnings Sharing/Targeted Incentive/Stranded Cost/Rate Freeze	Earnings between 0 and 2.7 percent in excess of the 10.5 percent benchmark rate are to be split between shareholders and the recovery of regulatory assets. Above this earnings level, all excess earnings are allocated to regulatory asset recovery. Rates are frozen until 2002.	1998-2002

Performance Based Ratemaking Programs in the Natural Gas Industry

State	Company	Date Approved	Incentive	Benchmark	Tolerance Band	ROE Is Sharing Basis? (Y/N)	Sharing Mechanism (LDC / Customer)	Savings (LDC / Customer)	Program Term	Review Process	Other Issues
Alabama	Alabama Gas Corporation	1989	Rate Stabilization & Equalization Mechanism (RSE)	13.4% ROE "adjusting point"; LDC can file for rate increase annually if ROE falls below 13.15%, PSC can decrease rates quarterly if ROE goes above 13.65%	13.15% to 13.65% ROE	Y	n/a	n/a	Permanent	Quarterly	
Iowa	MidAmerican Energy	Pilot from 1995-1998	Performance based PGA, including commodity, transportation and storage; capacity release sharing; off-system sales incentive	PGA incentive: Weighted average of short-term spot index (BTU Daily) and long-term spot indices (Inside FERC and Natural Gas Intelligence) based on weighting in LDCs portfolio; transportation and storage costs at pipeline max-rates	First 0.5% of savings a deadband	N	Savings: first 0.5% 0/100, next 3% 50/50, above 0/100; Loss: first 2.5% 0/100, next 3% 50/50, above 0/100; 30/70 on capacity release, 50/50 off-system sales	Savings confidential	3-year pilot	Report on savings / loss filed every six months	
Indiana	Northern Indiana Public Service Company (NIPSCO)	Approved 10/8/97	Gas Cost Incentive Mechanism (GCIM)	For first of month purchases, average of Natural Gas Week spot bid-week index and Gas Daily Monthly Contract Index; for purchases not made on first of month, average of Gas Daily's Daily Price Survey and NGI's Daily Gas Price Index "Cash Market Prices"; all indices are for Chicago supply hub	First 0-3% of savings 100% to customer	N	Savings: 0-3% 0/100, 3-4% 30/70, 4-6% 50/50, above 6% 100/0; Loss: 0-2% 30/70, 2-4% 50/50, above 4% 70/30		Permanent	Quarterly	This program was filed after the Indiana Senate passed SB637 in 1995 that allowed LDCs to offer alternative rate plans
Kentucky	Columbia Gas, Louisville G&E, and Western Kentucky Gas	1997	Gas cost incentives	Relevant supply areas for each LDC, based on index of spot prices		N			2-year programs with sunset provisions	2-year review process	
Michigan	Consumers Energy	Approved 12/97, effective 4/98	GCR Factor suspended, gas costs frozen at \$2.8364/Mcf; base rates frozen from levels of last rate case	11.5% authorized return; in addition, quality standards established that Consumers must meet: 1) Safety: maintain top-quartile status in AGA safety rankings, 2) Leak response: average 30 minutes or less, 3) Cathodic protection: maintain compliance with current 10-year plan, 4) Estimated meter reads: less than 27.7% of total reads	50% of gas cost savings does not go into calculation of authorized return	Y	11.5% authorized return, up to 13.5% LDC keeps 100%, 13.5% to 17.5% split 50/50, above 17.5% 25/75	8 months from 4/98 to 12/98, Consumers after-tax commodity gain of \$16 million	3-year pilot	Michigan PSC tracks LDC gas cost savings due to freeze	The freezing of base rates and gas cost is part of a larger customer choice deal

Performance Based Ratemaking Programs in the Natural Gas Industry

State	Company	Date Approved	Incentive	Benchmark	Tolerance Band	ROE Is Sharing Basis? (Y/N)	Sharing Mechanism (LDC / Customer)	Savings (LDC / Customer)	Program Term	Review Process	Other Issues
	Michigan Consolidated	Effective 1/1/99	GCR Factor suspended, gas costs frozen at \$2.95/Mcf; base rates frozen from levels of last rate case	11.6% authorized return; in addition, quality standards established that Consumers must meet: 1) Safety: maintain top-quartile status in AGA safety rankings, 2) Leak response: average 30 minutes or less, 3) Customer calls must be answered in 35 seconds or less, 4) Estimated meter reads: less than 29.6% of total reads	50% of gas cost savings does not go into calculation of authorized return	Y	11.6% authorized return, up to 13.5% LDC keeps 100%, 13.5% to 17.5% split 50/50, above 17.5% 25/75	No savings information available yet	3-year pilot	Michigan PSC tracks LDC gas cost savings due to freeze	The freezing of base rates and gas cost is part of a larger customer choice deal
	Semco	Effective 1/1/99	GCR Factor suspended, gas costs frozen at \$2.99/Mcf; base rates frozen from levels of last rate case	10.75% authorized return; in addition, quality standards established that Consumers must meet: 1) Safety: maintain top-quartile status in AGA safety rankings, 2) Leak response: average 30 minutes or less, 3) Protection of underground facilities: 100% of staking and clearing must be completed within limit of 3 working days, 4) Actual meter reads: 90% or higher	50% of gas cost savings does not go into calculation of authorized return	Y	10.75% authorized return, up to 12.75% LDC keeps 100%, 12.75% to 16.75% split 50/50, above 16.75% 25/75	No savings information available yet	3-year pilot	Michigan PSC tracks LDC gas cost savings due to freeze	The freezing of base rates and gas cost is part of a larger customer choice deal
Minnesota	Minnegasco	7/96 - 6/98	Performance based PGA	Two-part benchmark, equally weighted: 1) Minnegasco WACOG vs WACOG of 3 next largest LDCs in state; 2a) Commodity: Minnegasco vs bid-week Inside FERC index price at Ventura, Iowa del. pt.; 2b) Demand: demand entitlement annual increase/decrease	99.5% to 100.5%	N	50/50 up to 2% of Minnegasco's total gas costs	Minnegasco \$10.5 million over 3 years / customers \$16.5 million over 3 years	3-year pilot	Annual review in conjunction with PGA review	At end of 3 year pilot, Minnegasco and consumer advocate couldn't agree on re-setting of banchmark
Mississippi	Mississippi Valley Gas, Entex, and Wilmut Gas	Mississippi Valley Gas 1992, Entex 1996, and Wilmut 1999	Earnings sharing mechanism	Benchmark is target ROE set for each LDC	Varies, generally 50 basis points	Y	Varies, generally progressive (LDC keeps higher percentage of ROE at higher levels)		Permanent	Annual review of ROE	
Missouri	Missouri Gas Energy (Division of Southern Union Company)	8/1/1996	Gas Cost Incentive Mechanism; regressive capacity release sharing	Weighted average Inside FERC Gas Market Report index of monthly spot market first of month prices for 2 LDC pipeline supplies (70% Williams Texas/Oklahoma/Kansas and 30% Panhandle Texas/Oklahoma), plus 4% adder (adder is the historical premium of Missouri Gas Energy gas costs above the index)	Losses: first 4% above benchmark LDC is not penalized	N	Savings: LDC shares 50/50 on gas costs between 94 and 100% of benchmark; Losses: LDC penalized 50/50 for gas costs between 104% and 110% of benchmark		3-year pilot, expires 6/30/99	Monthly comparison of gas cost to benchmark	

Performance Based Ratemaking Programs in the Natural Gas Industry

State	Company	Date Approved	Incentive	Benchmark	Tolerance Band	ROE Is Sharing Basis? (Y/N)	Sharing Mechanism (LDC / Customer)	Savings (LDC / Customer)	Program Term	Review Process	Other Issues
	LaClede Natural Gas Company	10/1/1996	Gas Supply Incentive Plan (GSIP); progressive capacity release sharing; off-system sales incentive; pipeline max-rate discount incentive	Weighted average Inside FERC Gas Market Report index of monthly spot market first of month prices for 2 LDC pipeline supplies (60% NORAM Gas Transmission-East and 40% Trunkline-Louisiana), plus 3.2% adder (adder is the historical premium of Missouri Gas Energy gas costs above the index)	Losses: first 4% above benchmark LDC is not penalized	N	Exact same gas cost sharing as Missouri Gas Energy; also, 30/70 off-system sales, and 20/80 of pipeline discounts from max-rate		3-year pilot, expires 9/30/99	Monthly comparison of gas cost to benchmark	
	Union Electric Company		Progressive capacity release sharing; off-system sales incentive; pipeline max-rate discount incentive	n/a		N	LDC gets 10% of capacity release up to \$250,000, 30% thereafter; 30% of off-system sales; and 10% of pipeline discounts from max-rate			Annual review of sharing revenues	
New York	Niagara Mohawk	12/96 rate settlement	Incentive on commodity cost of gas	97% of average of NYMEX and Inside FERC spot price indices	1% deadband	N	Within deadband (96% to 98% of indices) 0/100, outside of band 50/50; \$2.25 million maximum LDC exposure		Rate settlement ends 10/31/99	Annual filing	
Pennsylvania	National Fuel Gas Distribution Co, Equitable, Peoples Gas Co, PECO Gas, Columbia of PA, UGI Gas	Incentive mechanisms approved 3 to 5 years ago	All six have performance based PGA	Regional spot market indices	Some have deadbands between 0 to 2%	N	Usually accumulates progressively to LDC		Permanent	Most have annual review with gas costs	
South Dakota	MidAmerican Energy	Order approved 11/8/95; 3-year pilot expired 10/98	MidAmerican's gas cost incentive program in Iowa was approved with the same parameters in South Dakota	See Iowa for benchmarks	Year 3: 0.5% deadband on savings	N	Year 3: Savings: first 0.5% 0/100, next 3% 50/50, above 0/100; Losses: first 2.5% 0/100, next 3% 50/50, above 6.5% 0/100	Savings confidential	3-year pilot	Report on savings / loss filed every six months, recovery lagged 6 months	
Tennessee	United Cities Gas	Pilot 4/95, permanent 4/99	Performance based PGA	Indices Basket (NYMEX, Inside FERC, Natural Gas Intelligence)	97.7% - 102%	N	50/50 on gas purchasing, 10/90 on capacity release		Permanent	Annual Review of Incentive Plan Account (IPA)	

Performance Based Ratemaking Programs in the Natural Gas Industry

State	Company	Date Approved	Incentive	Benchmark	Tolerance Band	ROE Is Sharing Basis? (Y/N)	Sharing Mechanism (LDC / Customer)	Savings (LDC / Customer)	Program Term	Review Process	Other Issues
	Nashville Gas Co. (Division of Piedmont Natural Gas)	Permanent 8/98	Performance based PGA	Inside FERC	97.7% - 102%	N	50/50 on gas purchasing, 10/90 on capacity release		Permanent	Annual Review of Incentive Plan Account (IPA)	
Washington			Washington issued a policy statement in 1997 giving LDCs the option to file performance-based ratemaking plans; established 15 guiding principles for gas adjustment incentive mechanisms								
	Puget Sound Energy	Approved 6/98	Performance based PGA	Weighted index of monthly average spot prices for three supply hubs of LDC + summer or winter adder (adder level is confidential, created by looking at three year historical difference between spot index prices vs. actual gas costs for LDC - it represents the premium for firm gas supplies)	LDC savings cannot exceed 1% of rate of return	Y	\$0-\$500,000 0/100; \$501,000-\$27 million 40/60; above \$27 million 33/67		3-year pilot	Washington guiding principle #7 states the incentives should be reviewed when the pilot ends	Historical averages for off-system sales and capacity release revenues reduce the adder
Wisconsin	8 largest LDCs	12/96 order	By a 12/96 Wisconsin PSC order, the 8 largest LDCs are required to file a Gas Cost Recovery Mechanism (GCRM), which is a plan for recovery of gas costs that includes incentives for the LDCs to lower their gas costs								
	Wisconsin Gas	Effective 11/1/1997	GCRM	5 benchmarks: 1) commodity cost based on weighted average of indices for 7 regions, 2) supplier reliability premiums of 2.5%, 3) storage costs, 4) pipeline capacity costs (negotiated pipeline discounts, capacity release, off-system sales), 5) risk management	1.5% deadband above and below	N	0-1.5% to customers, 1.5% to 4.0% 50/50, above 4.0% to customers 100%	Just filed, no data available yet	3-years; began 11/1/97 and terminates 10/31/2000	Annual review of gas costs	RFP used to establish a benchmark for capacity release volumes,

APPENDIX A

CURRICULUM VITA OF KARL MCDERMOTT

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Dr. Karl McDermott is a Vice President with National Economic Research Associates, specializing in public utility regulation. He served as Commissioner (1992 - 1998) on the Illinois Commerce Commission during the negotiation of the Illinois restructuring law. He has also assisted the country of Poland since 1994 with their efforts to privatize and restructure their electric supply industry. As a Commissioner, Dr. McDermott also lectured extensively in Eastern Europe and South America on regulatory reform and restructuring.

During the six years that he served as Commissioner he has had an opportunity to evaluate alternative regulation proposals and the economic and social impacts of a number of new policies presented to the Commission. As a Commissioner, Dr. McDermott initiated the Commission's investigation into the alternative restructuring options and has made a number of presentations on restructuring issues.

Since leaving the Commission, Dr. McDermott has advised the members of the Southern Companies, Wisconsin Electric Power Company and Bell Atlantic on issues regarding restructuring. He is the author of "Is There a Rational Path to Implementing Competition?" which appeared in the January/February 1996 issue of *The Electricity Journal*.

Dr. McDermott received a B.A. in Economics from Indiana University of Pennsylvania, his M.A. in Public Utility Economics at the University of Wyoming, and his Ph.D. in Economics at the University of Illinois.

EDUCATION

Ph.D. 1990, Economics, University of Illinois
M.A. 1978, Public Utility Economics, University of Wyoming
B.A. 1976, Economics, Indiana University of Pennsylvania

Dissertation Topic: The Monetary Theory of Production of
John Maynard Keynes

Additional Education

Michigan State Public Utility Course; Michigan State University

Seminar on Austrian Economics at Marquette University, Milwaukee, Wisconsin,
conducted by the Institute of Humane Studies, Menlo Park, California

State of Illinois; Certificates in SPSS and advanced SPSS Computer Software Classes
and TSO Operations

Illinois Bell Telephone Seminars on Separations and Settlements, Embedded Direct
Analysis (EDA), Costs and Demand Analysis, and Engineering Characteristics of
Telecommunication System

EMPLOYMENT

1999- NATIONAL ECONOMIC RESEARCH ASSOCIATES, INC.
Vice President.

1998-1999 MCDERMOTT ASSOCIATES
President. Worked for various clients in the electric, and telephone industry
including the Edison Electric Institute, Georgia Power Co., Bell Atlantic, and L. E.
Burgess Consultants.

1992-1998 ILLINOIS COMMERCE COMMISSION
Commissioner.
Domestic:
Served as Chairman of both the Telecommunications Policy Committee and
Electricity and Resource Planning Policy Committee of the Illinois Commission.
Served on the National Association of Regulatory Utility Commissioners (NARUC)
Energy Resources and Environment Committee as the Chairman of its environmental
subcommittee. Made over one-hundred presentations and speeches on
telecommunications, electricity, and natural gas industry topics. Served on the
President's Global Climate Change Task Force, the Federal Energy Regulatory

Commission's Pipeline Competition Task Force, and as a member of the Harvard Electric Policy Group.

International:

In addition to regular Commission duties, served as part of the United States Energy Association and USAID educational effort in Eastern Europe. Lectured in Argentina, the Czech Republic, Latvia, Poland, Romania, Russia, and Slovakia. Participated in two joint USEA/USAID and World Bank seminars in Vienna providing advanced regulatory training. In addition, the Illinois Commission has hosted visits with the above-listed countries as well as Bulgaria, Lithuania, and Estonia.

PROFESSIONAL ACTIVITIES

1985-1998 *Chairman of the Board*, Center for Regulatory Studies, Inc.

1985-1992 *President*, Center for Regulatory Studies, Inc.
One of three cofounders of the Center. Involved in fundraising, organization, and program development. Focused on the development of statewide energy planning options for the State of Illinois, the introduction of competition into the natural gas market, environmental issues in Illinois, and competition in the Illinois telecommunications market. Conducted research on the use of competitive bidding and avoided-cost pricing mechanisms to acquire electricity supplies, the role of demand-side management in electricity supply planning, and the use of incentive mechanisms and the role of incentive regulation in our current regulatory environment.

1988-1992 *Research Scientist*, Argonne National Laboratory

Served as an economic advisor to the office of Fossil Energy at DOE. Investigated possible ways to promote development of innovative emission control technologies in the electric utility industry as part of the Presidential Task Force on Regulatory Relief directed by Vice President Bush. Involved in writing a chapter in the State of Science and Technology Report No. 25 of the National Acid Precipitation Assessment Program (NAPAP) concerning the use of tradable emission permits to control acid rain. Performed work on incentive mechanisms to promote clean coal technology and the trading of greenhouse gas emissions.

Performed research on the nature of individual's risk perception regarding nuclear waste deposits on behalf of the office of Radioactive Civilian Waste Management at the Department of Energy.

- 1988-1990 *President Elect and President, Illinois Economic Association*
Organized the 1989 Illinois Economic Association annual meeting and presided over the meetings.
- 1989- *Instructor, NARUC Introductory Regulatory Training Program*
Instructed new public utility commission employees from various state commissions on the basic economic issues confronting regulators.
- 1986-1992 *Lecturer in Economics, Department of Economics, Illinois State University*
Taught both graduate and undergraduate public utility courses, Money and Banking, as well as introductory courses.
- 1984-1991 *Instructor in Economics, Parkland Community College, Champaign, Illinois*
Taught both Principles of Economics I and II, with a typical course load of two sections of 35-40 students per class.
- 1984-1986 *Teaching Assistant, University of Illinois, Champaign, Illinois*
Taught both Principles of Economics and Introduction to Econometrics. In the spring semester of 1985, was the supervisory assistant in charge of coordinating the Economics 101 assistance for Professor Fred Gotthiel.
- 1982-1988 Graduate School, University of Illinois, Champaign, Illinois
Completed all coursework towards Ph.D. and defended dissertation on 6/12/88. Fields of specialization were: Monetary Theory and Policy, Macroeconomic Theory, and the History of Economic Thought.
- 1983-1985 *Consultant, Select Joint Subcommittee on Regulatory Reform, Illinois Legislature*
Investigated the effects of the AT&T divestiture and FCC decisions upon Illinois telephone utilities and assisted in identifying issues that require legislative action. Presentation of issue reports to the telecommunications subcommittee and served on the local exchange subgroup in developing recommendations for a new Illinois Public Utilities Act.
- 1980-1982 *Consultant, Governor's Sunset Task Force on Utility Regulatory Reform, Department of Energy and Natural Resources*
Delivered both written and oral reports on the issues of power plant certification, monitoring of construction costs, and allocation of power plant cancellation costs.
- 1980-1983 *Economic Analyst III, Policy Analysis and Research Division, Illinois Commerce Commission*

Conducted research investigating the development and use of incentive mechanisms in utility regulation. Prepared and presented testimony on the use of incentive mechanisms in power plant construction.

Conducted research and assisted in developing testimony on the cost of service for electric generation to meet PURPA requirements.

Assisted in the development of proposals for PURPA innovative rates projects on productivity and time-of-use pricing; cost-benefit analysis. Assisted in the managing of consultants conducting the TOD cost-benefit study. Prepared and presented testimony on the time-of-day pricing standards to meet the PURPA requirements.

Prepared and presented testimony regarding the use of q-ratios in determining rates-of-return for Illinois Bell Telephone Company and testimony regarding appropriate cost and pricing methodology and philosophy for Illinois Bell Telephone Company.

Assisted in the investigation of capacity expansion, lifeline rates, efficiency measurement, and impact of deregulation in electric generation, water rate design; and investigated the impact of investment tax credit changes on utilities.

1978-1979 *Senior Research Associate*, National Regulatory Research Institute
Ohio State University
Conducted research in the areas of telecommunication licensee contract fees and cost of service, the effects of budget billing plans on utilities and consumers, and methods of monitoring fuel adjustment clauses.

Assisted in research regarding marginal and average cost pricing, time-of-use pricing, power plant productivity, and the examination of cost and price differences of Ohio municipal gas rates.

Assisted in the management of consultant subcontractors as well as supervising the presentation of cost and load research seminars.

9/79-12/79 *Lecturer in Economics*, Department of Economics, Ohio State University
Taught Macro Economic Principles to a class of approximately 100 students.

1977-1978 *Cost Analyst*, Action Computing, Laramie, Wyoming
Developed cost data for competitive pricing of bids for the provision of computer services provided by Action Computing.

1976-1977 *Graduate Research Assistant*, University of Wyoming, Laramie, Wyoming
Assisted professors in conducting research and teaching of Principles of Economics, while completing a Masters degree in Economics with specialization in Public Utility Economics and Industrial Organization Theory.

AWARDS

1986 Alpha Lambda Delta Outstanding Teacher of Freshman Award
at the University of Illinois

- 1983 Thrift Prize at the University of Illinois for the paper entitled "*The Allocation of Savings: An Investigation of Portfolio Composition of Chicago Households*"

PROFESSIONAL SOCIETY ACTIVITIES

Alpha Lambda Delta Honorary Society
American Economic Association
Association for Social Economics
Canadian Economics Association
Econometric Society
Transportation Public Utilities Group of American Economic Association
Illinois Economic Association
History of Economics Society
Royal Economic Society

PUBLICATIONS

"Is There a Rational Path to Implementing Competition?" *The Electricity Journal*. Vol. 9:1 Jan-Feb 1996.

"Changing Regulatory Incentives" with G. Enholm and J. Robert Malko Eds., *Reinventing Electric Utility Regulation*. Public Utility Reports, Inc. Vienna, VA 1995.

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PUBLICATIONS: CONFERENCE PAPERS

The Use of Nontraditional Universal Service Programs in a Competitive Local Exchange Market with Cindi Schieber. Presented at the National Association of Regulatory Commissioners Biennial Conference (1996).

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Incentive Mechanisms as a Strategic Option in the Design of Regulatory Policies with D. W. South. Presented at National Association of Regulatory Utility Commissioners, Committee on Electricity, Subcommittee on Strategic Issues, San Francisco (July 1991).

Achieving Efficiency Through Emissions Trading: Paradoxes, Misconceptions and Market Performance with D. W. South. Presented at National Association of Regulatory Utility Commissioners, Committee on Electricity, Subcommittee on Environment and Efficiency, San Francisco (July 1991).

To Mitigate or Not To Mitigate: Regulatory Treatment of Emissions Trading Decisions and Its Effect on Marketplace Incentives with D. W. South. Presented at 84th Annual Meeting and Exhibition, Air and Waste Management Association, Vancouver, British Columbia (June 1991).

Regulatory Incentives: A Means to Accelerate Clean Coal Technology Adoption for Acid Rain Compliance with D. W. South. Presented at Compliance and Emissions Trading Strategies; Facing Acid Rain Tradeoffs, Center for Regulatory Studies, Chicago, IL (June 1991).

Implementing Emissions Trading: Regulatory and Compliance Planning Issues with D. W. South. Presented at the Workshop on Implementing the Electric Utility Provisions of the Clean Air Act Amendments of 1990: Midwestern State Public Utility Commission Issues, National Regulatory Research Institute, Chicago, IL (May 1991).

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The Future of Clean Coal Technology: An Evaluation of the Proposed Incentives in S. 1630 with D. W. South. Presented at the Seventh Annual International Pittsburgh Coal Conference, Pittsburgh, PA (September 1990).

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Avoided Cost Pricing: Theoretical Issues and Problems in Estimation. Prepared for the Illinois Department of Energy and Natural Resources (June 1990).

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The Economic Incentives Provided by Section 9-215 (Excess Capacity Rule) of Proposed Illinois Public Utility Act. A Memorandum to the Joint Committee (June 1985).

An Analysis of the Issue of Cross-Subsidization in the Local Telephone Market. Prepared for the Joint Committee on Public Utility Regulation (May 1985).

A Survey of State Regulatory Actions and Legislative Developments Resulting from the Divestiture of AT&T. Prepared for the Joint Committee on Public Utility Regulations, Illinois State Legislature (March 1985).

A Memorandum to the Telecommunications Policy Working Group on the Concepts of Competing, Competition and Market Structure (September 1984).

The Evolution of Competition in the Telephone Industry and the Critical Issues Facing the Illinois Legislature on the Deregulation of Telephone Service. Prepared for the Select Joint Subcommittee on Regulatory Reform (July 1984).

The Review of Existing Power Plant Certificates, Monitoring of Power Plant Costs and the Allocation of Power Plant Cancellation Costs. Presented to the Sunset Task Force on Utility Regulatory Reform (January 1984).

Utility Efficiency Report Subtask IX - Final Report in Incentive Mechanisms. Prepared for the Illinois Commerce Commission (May 1981).

Utility Efficiency Report Subtask IV - Evaluation and Choice of Incentive Mechanisms. Illinois Commerce Commission for the U.S. Department of Energy (July 1980).

Utility Efficiency Report Subtask II - Review of Existing Incentive Mechanisms. Illinois Commerce Commission for the U.S. Department of Energy (March 1980).

Estimating Fuel Prices, a Memorandum to the Virginia State Corporation Commission with K. Kelly, National Regulatory Research Institute (1979).

Summary of Regulatory Commission Activities on Power Plant Productivity. The National Regulatory Research Institute draft report for the U.S. Department of Energy (1979).

UNPUBLISHED PAPERS

The Reichbanks' Reaction Function During the Hyperinflation: An Alternative Test of the Causes of the Hyperinflation. (December 1987)

How Real Was The German Hyperinflation: A Reexamination of the Demand for Money Employing a Fully Specified Demand Function. (October 1987)

Bubbles During the Hyperinflation: An Empirical Test of the Interaction of the Double Bubble in Exchange Markets and Prices in Germany. (September 1987)

Evaluating the Causes of the Hyperinflation: A Reexamination of Monetary Policy and Theoretical Debates Concerning the Factors Affecting the German Money Supply from 1919 to 1923. (August 1987)

Decentralization vs. Coordination: An Examination of the Options for Deregulating the Electric Supply Industry. (June 1985)

Applied Fairness Theory: The Case of Allocating Canceled Power Plant Costs. (October 1983)

Is the Rational Expectations Equilibrium Business Cycle Theory a Neo-Austrian Theory? (October 1983)

An Examination of the Policy Alternatives for a Small Open Economy Experiencing a Trade Boom: The Case of Sterilization, Credit Rationing and Profit Taxation. (August 1983)

The Transmission of Monetary Shocks to Real Variables in the Business Cycle. (July 1983)

The Economics of Revolutions: A Club Theoretic Approach and a Case Study of England, 1642-1649. (Summer 1983)

Interest Rates, Market Efficiency and Expectations: The Effectiveness of Monetary Policy. (April 1983)

Towards Developing a Framework for Evaluating Incentive Mechanisms, Performance Measures and Institutional Choice in Deregulation. (August 1981)

A Critique of the Averch-Johnson Bias and a Test of Some Alternative Hypotheses. Master Thesis submitted to the Graduate School of the University of Wyoming. (July 1978)

An Overview of the Theories of Regulation and Pricing Policies for Regulated Industries. The National Regulatory Institute. (1979)

PRESENTATIONS

A Conflict of Paradigms; The Future Role of State Regulation of the Natural Gas Industry. Presented to the Midwest Gas Association (November 6, 1991).

Exit and Entry: Who Will Bear the Risk in a Competitive Natural Gas Industry. Presented at the conference "At the Crossroads: Restructuring the Natural Gas Industry," held by the Center for Regulatory Studies (October 1991).

"To Serve Man" - The Golden Rule or a Visit to the Twilight Zone: How to Reconcile the Obligation to Serve with Competitive Market Forces. Presented to the Gas Policy Committee of the Illinois Commerce Commission (April 16, 1991).

Regulatory Treatment of Emissions Trading Decisions and Their Effect on Marketplace Incentives with D. W. South Presented at the Notice of Inquiry Public Hearing, Illinois Commerce Commission (March 1991).

The National Energy Strategy: Impacts on the Farm Sector. Presented to the Illinois Farm Bureau Leadership Conference (February 1991).

Emissions Trading in the CAAA of 1990: Regulatory, Compliance Planning and Implementation Issues with D. W. South. Presented to the Illinois Commerce Commission (January 1991).

Obligations to Serve and Competition in the Natural Gas Industry. Luncheon presentation at the conference "Assessing the Competitiveness of the Natural Gas Industry," held by the Center for Regulatory Studies (October 1990).

Pricing in an Age of Opportunism: The Cost of Being a Provider of Last Resort. Presented at the conference "Natural Gas Supply Planning: The Implications for Planning Pricing and Competition," held by the Center for Regulatory Studies (March 1990).

Public Utility Issues: Long and Short-Term Impacts. Presented to the Illinois Farm Bureau Leadership Conference (February 1990).

Uncertainty in the Least-Cost Planning Process: The Case of Natural Gas. Presented at the conference "Issues in Least Cost Planning in the Natural Gas Industry," held by the Center for Regulatory Studies (December 21, 1989).

How Real was the German Hyperinflation: An Examination of the Factors Determining the German Money Supply, Demand and Prices Between 1920 and 1923 with M. J. Morey. Presented to the Economic History Workshop at the University of Illinois (December 1986).

While at the Illinois Commerce Commission, Dr. McDermott gave over one-hundred presentations on a variety of topics in the telecommunications, electricity and natural gas industries.

TESTIMONY

Federal Energy Regulatory Commission, Docket No. EL99-90-000, *City of Wichita, Kansas v. Western Resources, Inc.* Direct testimony on behalf of the City of Topeka, Kansas focusing on cost causation issues and rate parity, September, 2000.

Indiana Utility Regulatory Commission, Cause No. 41753, Direct testimony on behalf of Southern Energy regarding approval of certification of power plant under reduced regulation, August 18, 2000.

California Public Utilities Commission, Application A.00-06-032, Direct testimony on behalf of Southern California Gas Company regarding the appropriateness of peaking rate for gas services. August 10, 2000.

Illinois Commerce Commission, Docket No. 99-0013, Rebuttal testimony on behalf of Commonwealth Edison regarding appropriate treatment of unbundled rates for meter service, June 5, 2000.

Indiana Utility Regulatory Commission, Cause No. 41590, Rebuttal testimony on behalf of Southern Energy regarding approval of certification of power plant under reduced regulation, June 2, 2000.

Kentucky Public Service Commission, Case No. 2000-095, Testimony on behalf of LG&E Energy Corp. regarding approval of a merger, March 15, 2000.

Illinois Commerce Commission, Docket No. 98-0195, Testimony on behalf of GTE North Inc. and GTE South Inc. regarding investigation into certain payphone issues as directed in Docket 97-0225, December 21, 1999.

Public Service Commission of Wisconsin, Docket No. 6630-UR-111, Testimony on behalf of Wisconsin Electric Power Company regarding performance-based regulation, September 1999.

South Dakota Public Utilities Commission, Docket No. NG98-010, Testimony on behalf of MidAmerican Energy Company for continuation of its incentive gas supply procurement program, June 1999.

Iowa Utilities Board, Docket No. RPU-94-3, Request for Confidential Treatment on behalf of MidAmerican Energy Company, April 7, 1999.

Federal Communications Commission, CC Docket No. 99-24, Affidavit and Reply Affidavit of Karl McDermott and William E. Taylor on behalf of Bell Atlantic Telephone Companies for forbearance from regulation as dominant carriers in Delaware, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, Washington, DC, Vermont and Virginia, January 20, 1999 and April 8, 1999.

Testimony to Illinois General Assembly joint committee on electricity deregulation. Summer 1997.

Illinois Public Utilities Committee Telecommunications Subcommittee, Alternative Methods of Telecommunications Regulation, March 27, 1991.

Illinois Commerce Commission, Docket No. 80-0167, on the use of incentive mechanisms at Clinton Power Plant construction site.

Illinois Commerce Commission, Docket No. 80-0544, on the use of the variable return to CWIP incentive model in the Illinois Power rate case.

Illinois Commerce Commission, Docket No. 80-0167, rebuttal testimony to Dr. Pappas on the use of incentive mechanisms at the Clinton Power Plant site.

Illinois Commerce Commission, Docket No. 80-0367, on the treatment of the time of use pricing standards of the Public Utility Regulatory Policy Act (PURPA) for Iowa-Illinois Gas and Electric Company.

Illinois Commerce Commission, Docket No. 81-0478, on the use of q-ratios determining the appropriate rate of return for Illinois Bell Telephone Company.

Illinois Commerce Commission, Docket No. 81-0478, on the appropriate cost of service method for pricing telecommunication service under the transition to competition.

September, 2000

*Tape filed in Case
no PU-401-00-195*

17 PU-401-00-36

Pages: 0

Video tape of Public Discussion Meeting
held 9-6-00
by Public Service Commission

09/06/2000 CC: Comm Legal PUD (3) Mike ALJ .

16 PU-400-00-195

Pages: 0

Video tape of Public Discussion Meeting
held 9-6-00
by Public Service Commission

09/06/2000 CC: Comm Legal PUD (3) Mike ALJ .



OFFICE OF ADMINISTRATIVE HEARINGS

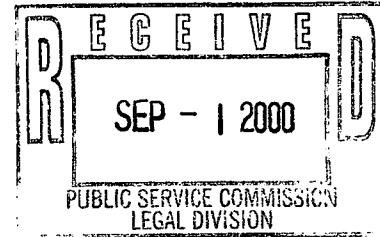
STATE OF NORTH DAKOTA
1707 North 9th Street
Bismarck, North Dakota 58501-1882

Allen C. Hoberg
Director

August 29, 2000

701-328-3260
FAX 701-328-3254

Mr. William W. Binek, Esq.
Hearing Administrator
Office of Public Service Commission
600 E. Boulevard Ave., Dept. 408
Bismarck, ND 58505-0480



RE: Prehearing Conference Summary - Otter Tail Power Company and Northern States
Power Company Performance Based Regulation Applications (case nos. PU-401-00-36
and PU-400-00-195)

Dear Mr. Binek:

On August 29, 2000, at 2:00 p.m., via telephone, a prehearing conference was held to discuss procedural dates, hearing procedure, and other preliminary matters. After discussion the following was agreed to by Otter Tail, NSP, and Commission Staff:

Procedural Dates:

1. Otter Tail and NSP will pre-file all of their anticipated witnesses direct testimony with the Commission, Commission Staff, and the ALJ (copying the other party) no later than September 29, 2000 (received by that date).
2. Commission Staff will pre-file rebuttal testimony (response to OT and NSP direct testimony) with the Commission, the ALJ, and the other two parties no later than October 13, 2000.
3. Otter Tail and NSP will pre-file response testimony (response to Commission Staff rebuttal) no later than October 20, 2000.
4. The hearing is scheduled to begin on October 23, 2000, at 1:30 p.m. and will continue into October 24 (beginning at 8:30 a.m.), if necessary, until completed.
5. Otter Tail, NSP, and Commission Staff (if desired) will each file a proposed decision, *i.e.* findings of fact, conclusions of law, and order, and a post-hearing brief no later than November 17, 2000.

16 PU-401-00-36

Pages: 2

Letter confirming procedural dates,
hearing procedur & perliminary matters
by Office of Administrative Hearings by Allen Hoberg, A
09/01/2000 CC: Comm Legal PUD (3) Mike ALJ .

15 PU-400-00-195

Pages: 2

Letter confirming procedural dates,
hearing procedure & perliminary matters
by Office of Administrative Hearings by Allen Hoberg, A
09/01/2000 CC: Comm Legal PUD (3) Mike ALJ .

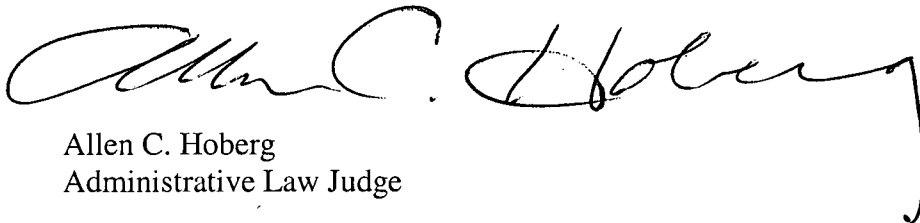
Mr. William W. Binek
Page Two
August 30, 2000

Hearing Procedure:

Although the Otter Tail and NSP filings are separate and have not been consolidated, the two matters are substantially similar and should be combined for hearing, for convenience sake. It was agreed by all the parties that the two matters should be heard contemporaneously as one overall case, but that they remain two separate matters with two separate orders being issued. Accordingly, the two matters will be combined into one hearing beginning October 23. Either, Otter Tail or NSP will proceed first (to be mutually agreed upon by the two companies, later). The first Company will present all of its direct witnesses (for brief direct, cross-examination, Commission questions, and further questioning). Then, the second Company will present all of its direct witnesses (direct-cross-Commission-further). Then, the Commission Staff will present its witness to respond to the two Companies (direct-cross-Commission -further). Then, the Companies will be allowed to present any necessary rebuttal witnesses not already called (first company - second company) and to recall any necessary rebuttal witnesses from those previously called. Finally, the hearing will close subject to the above post hearing filings.

If any party disagrees with any part of this prehearing conference summary, or wishes to add something significant that has been omitted, they must state their disagreement or addition in writing within seven days of receiving a copy of the summary.

Sincerely,



Allen C. Hoberg
Administrative Law Judge

AH/ljc

cc: Mr. Todd J. Guerrero, Otter Tail
Mr. Jim Johnson, NSP

INFORMAL HEARING

19 June 2000

Northern States Power Company
Application for PBR
PU-400-00-195

Otter Tail Power Company
Application for PBR
PU-401-00-36

PURPOSE

The purpose of holding an informal hearing on these cases at this time is to discuss and determine the appropriate procedure to use to process the cases, a suggested time frame for processing the case, and identify potential issues relevant to a decision.

PROCEDURE

These cases present substitutes for rate cases, and adoption will likely result in rate changes sooner or later. For this reason, we recommend holding a **formal hearing** and issuing a **formal notice of hearing**. At this time, an informal hearing alone would seem to be inappropriate, although it may be appropriate later depending on how the cases evolve.

Due to the potential impact of these cases on customers, we recommend the participants and the Commission discuss the merits of also holding **public input sessions**, and of **other forms of notice**, including bill stuffers.

As will be discussed below, there are many and varied issues to be discussed in considering these applications. Consequently, we recommend **requesting input prior to issuing a notice of hearing** to determine what issues to notice and to consider any other matters of which we are made aware.

We recommend the **filing of both direct and responsive testimony prior to the hearing**. A discussion of what supporting information might be useful or appropriate would be helpful, including supporting information justifying the suggested performance measures as well as the return on equity standards.

It would also be appropriate to discuss available **hearing dates** and the potential length of the hearing, and a **target date for Commission decisions** on the applications.

TIME FRAME

Request Comments

Receive Comments

Issue Notices

Intervention Deadlines, if any

Testimony Filing Date(s)

Hearings

Post-Hearing Filings, if any

Decisions

POTENTIAL ISSUES

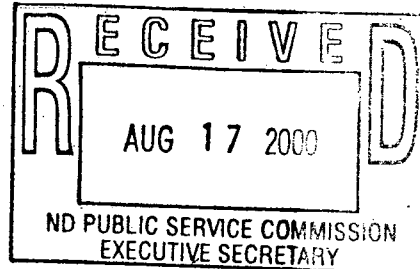
1. How is the public interest served by a move from rate of return regulation to performance based regulation?
2. Are the four performance indicators appropriate?
3. Do these four indicators measure overall company performance?
4. Are there other indicators that should be included?
5. If so, what are they and how are they to be measured?
6. Are the measurement standards for the indicators appropriate?
7. If not, what standards should be used (SAIFI, Momentary Outage Index)?
8. Should the indicators be weighted equally?
9. What is the appropriate starting return on equity?
10. Does the plan send the correct signals to the company?
11. Does the plan send the correct signals to the customer?
12. Should there be a Dead Band?
13. Is the proposed Dead Band correct?
14. Should the Dead Band be symmetric?
15. Is it appropriate to adjust the baseline ROE and Dead Band based on the indicators?
16. If yes, is 2% appropriate?
17. Is it appropriate for the company and customers to share liability for company under earning?
18. Should liability be deferred?
19. If so, what interest should accrue?
20. Is it appropriate for the company and customers to share in over earnings?
21. What is the appropriate Rate Design for surcharges/dividends?
22. How should special contracts be recognized?

23. What is the impact per kWh for selected surcharges/dividends?
24. Is it appropriate for part of the over earnings to be contributed to economic development programs?
25. Is the price comparison group appropriate?
26. What factors are relevant to selecting an appropriate price comparison group?
27. Are the proposed reporting requirements appropriate?
28. Are the proposed reporting processes appropriate?
29. Are the proposed PBR plans reasonable?
30. Will the proposed PBR plans result in just and reasonable rates?

Affidavit of Publication

State of North Dakota)

County of Burleigh)



Laurie Thiel

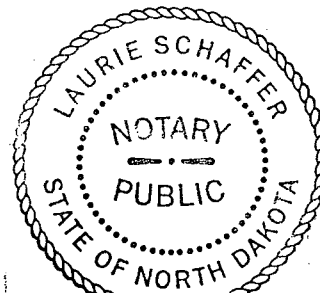
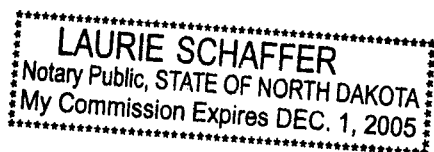
, being duly sworn, state as follows:

1. I am the designated agent, under the provisions and for the purposes of, Section 31-04-06, NDCC, for the newspapers listed on the attached exhibits.
2. The newspapers listed on the exhibits published the advertisement of:
Offer Tail / Northern State, 1 time(s)
as required by law or ordinance.
3. All of the listed newspapers are legal newspapers in the State of North Dakota and, under the provisions of Section 46-05-01, NDCC, are qualified to publish any public notice or any matter required by law or ordinance to be printed or published in a newspaper in North Dakota.

Signed: Laurie Thiel

Subscribed and sworn to before me this 15th day of August A.D. 2000

Laurie Schaffer



14 PU-401-00-36

Pages: 11

Affidavit of Publication

by North Dakota Advertising Service, Inc.

08/17/2000

CC: Comm Legal PUD (3) Mike ALJ.

13 PU-400-00-195

Pages: 11

Affidavit of Publication

by North Dakota Advertising Service, Inc.

08/17/2000

CC: Comm Legal PUD (3) Mike ALJ.



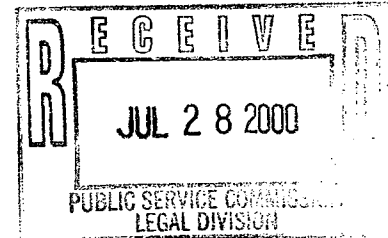
OFFICE OF ADMINISTRATIVE HEARINGS

STATE OF NORTH DAKOTA
1707 North 9th Street
Bismarck, North Dakota 58501-1882

Allen C. Hoberg
Director

701-328-3260
FAX 701-328-3254

July 27, 2000



Mr. William W. Binek
Hearing Administrator
Public Service Commission
600 East Boulevard Avenue, Dept. 408
Bismarck, ND 58505-0480

Dear Mr. Binek:

Thank you for your July 24, 2000, request of the designation of an administrative law judge from the Office of Administrative Hearings to conduct a hearing in the matters of Otter Tail Power Company (PU-401-00-36) and North States Power Company (PU-400-00-195). I hereby designate myself to be assigned as a administrative law judge to conduct the hearing in regard to this matter. Because the administrative law judge will not be making recommended findings of fact and conclusions of law, or issuing a recommended order, the person or persons who will actually be making the final administrative decision in regard to this matter (i.e., agency head, deputy, board, commission) must actually be in attendance at the hearing.

Please send all additional relevant documents in regard to this matter (correspondence, and other pleadings and documents) to the designated administrative law judge in care of the Office of Administrative Hearings, 1707 North 9th Street, Lower Level, Bismarck, North Dakota 58501-1882. I understand a combined hearing will be held on October 23, 2000, at 1:30 p.m., in the Commission Hearing Room, 12th Floor, State Capitol, 600 East Boulevard Avenue, Bismarck, North Dakota. Because the administrative law judge is requested to conduct the hearing only, the agency must give proper notice of the hearing.

Sincerely,

Allen C. Hoberg
Director

ACH:klp

c: Ms. Bernadeen Brutlag
Mr. Kent L. Larson
Mr. Dave Sederquist

12 PU-400-00-195

Pages: 1

07/28/2000

Office of Administrative Hearings

Allen Hoberg appointed Administrative Law
Judge

CC: Comm Legal PUD (3) Mike ALJ.

13 PU-401-00-36

Pages: 1

07/28/2000

Office of Administrative Hearings

Allen Hoberg appointed Administrative Law
Judge

CC: Comm Legal PUD (3) Mike ALJ.



Public Service Commission

State of North Dakota

COMMISSIONERS

Bruce Hagen
President
Susan E. Wefald
Leo M. Reinbold

600 E Boulevard Ave. Dept. 408
Bismarck, North Dakota 58505-0480
e-mail: sab@oracle.psc.state.nd.us
TDD 800-366-6888
Fax 701-328-2410
Phone 701-328-2400

Executive Secretary
Jon H. Mielke

July 25, 2000

Mr. Allen C. Hoberg
Office of Administrative Hearings
1707 North 9th Street, Lower Level
Bismarck, ND 58501

Re: Case No. PU-401-00-36	Case No. PU-400-00-195
Otter Tail Power Company	Northern States Power Company
Performance Based Regulation Application	Performance Based Regulation Application

Dear Mr. Hoberg:

Enclosed is a request for an administrative law judge in the above captioned cases. The Commission has scheduled a hearing for October 23, 2000, beginning at 1:30 p.m. in the Commission Hearing Room. The administrative law judge will serve as a procedural law judge, a court reporter will not be present and the hearing will be tape recorded. A copy of each case is enclosed.

Please provide the Commission with a copy of any correspondence issued by your office in this matter.

If you have any questions, please contact me at 328-4088. Thank you.

Sincerely,


William W. Binek
Hearing Administrator

WWBsls
Enclosure

Cc: Kent Larson/Dave Sederquist, NSP
Bernadeen Brutlag, OTP

12 PU-401-00-36 Pages: 2
07/25/2000
Public Service Commission
Request for Administrative Law Judge

CC: Comm Legal PUD (3) Mike ALJ .

11 PU-400-00-195 Pages: 2 ✓
07/25/2000
Public Service Commission
Request for Administrative Law Judge

CC: Comm Legal PUD (3) Mike ALJ .



REQUEST FOR ADMINISTRATIVE LAW JUDGE--APPEAL, APPLICATION, OR PETITION
NORTH DAKOTA OFFICE OF ADMINISTRATIVE HEARINGS
SFN 17819 (8-95)

Name of Agency, Board, or Commission
Public Service Commission

The above named agency, board, or commission requests designation of an administrative law judge from the Office of Administrative Hearings for the NSP Performance Based Regulation Application (Case No. PU-400-00-19)
and OTP Performance Based Regulation Application (Case No. PU-401-00-36)

(e.g., application of [name], appeal of [name], petition of [name]). Authority for the administrative action is found in NDCC Title 49 (North Dakota Century Code and/or North Dakota Administrative Code).

Please attach related documents and correspondence.

The administrative action is more fully described as follows:

It requests designation of an administrative law judge (please check one):

- ☐ To conduct the hearing and issue recommended findings of fact, conclusions of law, and order.
- ☒ To serve as a procedural administrative law judge only (no recommended decision). The agency head will be present at the hearing as required by NDCC 54-57-04(6).
- ☐ To conduct the hearing, issue findings of fact, conclusions of law, and a final order.

PLEASE MAKE A REQUEST FOR AN ADMINISTRATIVE LAW JUDGE AT LEAST ONE MONTH BEFORE THE HEARING.

Please list parties, including the agency if it is a Party, and Representation [attorney (or other)] if known, or Agency Contact: (Attach separate list if necessary.)

AGENCY	Address	Telephone Number
Representation	Address	Telephone Number
PARTY Northern States Power Co.	Address P. O. Box 2747, Fargo, ND 58108	Telephone Number 701-241-8607
Representation Kent L. Larson & Dave Sederquist	Address Same as above	Telephone Number
PARTY Otter Tail Power Co.	Address P. O. Box 496, Fergus Falls, MN	Telephone Number 218-739-8200
Representation Bernadeen Brutlag	Address Same as above	Telephone Number 56538-0496

Additional Comments

A combined hearing will be held October 23, 2000 at 1:30 PM in the Commission Hearing Room,
12th Floor, State Capitol, Bismarck, ND

(For agencies required to use OAH, notice of hearing will be issued by the administrative law judge, unless a procedural administrative law judge is requested. Other requesting agencies and agencies requesting a procedural administrative law judge should first contact OAH about scheduling a hearing. If notice has already been issued, attach a copy of notice.)

Typed or Printed Name and Title of Requesting Person <u>William W. Binek, Hearing Administrator</u>	Date <u>7-24-00</u>
Signature of Requesting Person <u>X [Signature]</u>	Telephone Number <u>328-4088</u>

STATE OF NORTH DAKOTA
PUBLIC SERVICE COMMISSION

Otter Tail Power Company
Performance Based Regulation
Application

Case No. PU-401-00-36

Northern States Power Company
Performance Based Regulation
Application

Case No. PU-400-00-195

AFFIDAVIT OF SERVICE BY CERTIFIED MAIL

STATE OF NORTH DAKOTA
COUNTY OF BURLEIGH

Sharon Helbling deposes and says that:

she is over the age of 18 years and not a party to this action and, on the **20th day of July, 2000**, she deposited in the United States Mail, Bismarck, North Dakota, **one** envelope with certified postage, return receipt requested, fully prepaid, securely sealed and each containing a photocopy of:

Notice of Hearing and Public Discussion Meeting

The envelope was addressed as follows:

Kent Larson
Northern States Power Company
2302 Great Northern Dr
Fargo ND 58102
Cert. No. 7099 3220 0002 8476 8333

Dave Sederquist
Northern States Power Company
2302 Great Northern Dr
Fargo ND 58102
Cert. No. 7099 3220 0002 8476 8340

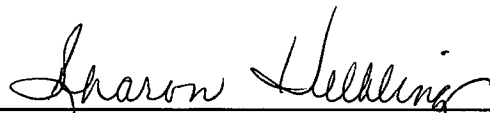
Bernadeen Brutlag
Otter Tail Power Company
215 S Cascade St
Fergus Falls MN 56538-0496
Cert. No. 7099 3220 0002 8476 8357

Each address shown is the respective addressee's last reasonably ascertainable post office address.

Subscribed and sworn to before me
this **20th day of July, 2000**.

SANDRA L. SCOTT
Notary Public, STATE OF NORTH DAKOTA
My Commission Expires JUNE 11, 2004

SEAL



Notary Public

10 PU-400-00-195

Pages: 1

07/20/2000

Public Service Commission

Affidavit of Service by Certified Mail

CC: Comm Legal Illona, Pat, Jerry Mike

STATE OF NORTH DAKOTA
PUBLIC SERVICE COMMISSION

Otter Tail Power Company
Performance Based Regulation
Application

Case No. PU-401-00-36

Northern States Power Company
Performance Based Regulation
Application

Case No. PU-400-00-195

AFFIDAVIT OF SERVICE BY ORDINARY MAIL OR E-MAIL

STATE OF NORTH DAKOTA
COUNTY OF BURLEIGH

Sharon Helbling deposes and says that:

she is over the age of 18 years and not a party to this action and, on the **20th day of July, 2000**, she deposited in the United States Mail, Bismarck, North Dakota, envelopes by first class mail, fully prepaid, securely sealed, each containing a photocopy of:

Notice of Hearing and Public Discussion Meeting

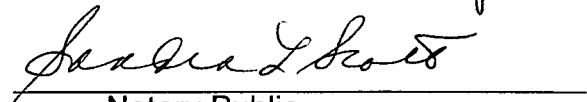
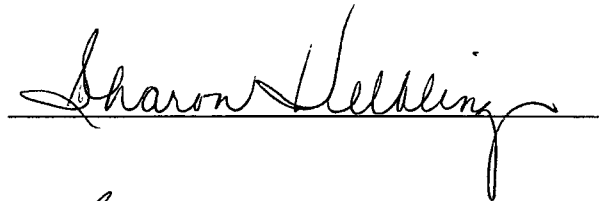
The envelopes were addressed as follows:

See Attached List

Each address shown is the respective addressee's last reasonably ascertainable post office address.

Subscribed and sworn to before me
this **20th day of July, 2000**.

SEAL



Notary Public



9 **PU-400-00-195**

Pages: 8

07/20/2000

Public Service Commission

Affidavit of Service by Ordinary Mail or E-mail

CC: Comm Legal Illona, Pat, Jerry Mike

akemp@tminc.com
Ann-Marie Kemp

wpp@pearce-ck.com
William Pearce
PO Box 400
Bismarck ND 58502-0400

Lubka@rrnet.com
Lewis Lubka
1723 6th St S
Fargo ND 58103

jason_gustafson@bobcat.com
Jason Gustafson
Melroe Company
P O Box 128
Gwinner ND 58040-0128

craig_scott@bobcat.com
Craig Scott
Melroe Company
P O Box 128
Gwinner ND 58040-0128

shandy@kwh.com
Scott Handy
Cass County Elec Coop Inc
4100 32nd Ave SW
Fargo ND 58104

Mark.Hanson@grandforks.af.mil
Mark Hanson
Grand Forks Air Force Base
319 ARW/JA
460 Steen Blvd Ste 201
Grand Forks ND 58205

itci@means.net
Bruce Reuber
Interstate Telcom Consulting Inc
130 Birch Ave W
Hector MN 55342-0668

kgrass@ipams.org
Karyn Grass
IPAMS
6620 Denver Club Bldg
518 17th ST
Denver CO 80202-4167

rmattern@badlands.nodak.edu
Rich Mattern
KDSU-FM Radio
PO Box 5347
Fargo ND 58105-5347

Michel.Murray@MCI.com
Michel Murray
MCI WorldCom Inc
707 17th St Ste 3600
Denver CO 80202

collinsk@mdu.mdures.com
Karen Collins
Montana-Dakota Utilities Co
400 N 4th St
Bismarck ND 58501

collinsk@mdu.mdures.com
Karen Collins
Montana-Dakota Utilities Co
400 N 4th St
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Grand Forks ND 58201-6703

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Oklahoma City OK 73102-7101

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Williston ND 58801

KBMR AM-KQDY FM
3500 E Rosser Ave
Bismarck ND 58501

KBMW-AM
PO Box 1115
Wahpeton ND 58074-1115

KCJB AM-FM & KXMC TV
PO Box 1686
Minot ND 58702-1686

KDAK AM
Box 50
Carrington ND 58421-0050

KDDR
Box 411
Oakes ND 58474-0411

Rod Kleinjan
KDIX Radio
119 2nd Ave W
Dickinson ND 58601-5115

KDLR AM-FM
Box 190
Devils Lake ND 58301-0190

KEYZ-AM
PO Box 2048
Williston ND 58802-2048

KFGO
Box 2966
Fargo ND 58102-2966

Jeff Alexander
KFYR-AM Radio
PO Box 1738
Bismarck ND 58502-1738

Rick Jensen
KHND Radio
PO Box 6
Harvey ND 58341-0006

KHRT AM
PO Box 1210
Minot ND 58702-1210

KKXL-AM/FM
PO Box 13598
Grand Forks ND 58208-3598

KLXX AM
4303 Memorial Hwy
Mandan ND 58554

KMAV-AM
PO Box 36
Mayville ND 58257-0036

KMOT TV
Box 1120
Minot ND 58702-1120

Jan Copeland
KN Energy Inc
PO Box 281304
Lakewood CO 80228-8304

KNDK-AM
HCR 5 Box 9
Langdon ND 58249

Terry Hildestad
Knife River Coal Mining Company
1915 N Kaveney Dr
Bismarck ND 58501

KNOX-AM & KRRK-FM
PO Box 13638
Grand Forks ND 58208-3638

KOVC-AM
PO Box 994
Valley City ND 58072-0994

KQDJ-AM
PO Box 1170
Jamestown ND 58402-1170

KQWB-AM/FM Radio
PO Box 9919
Fargo ND 58106-9919

KSJB-AM/KSJZ-FM
PO Box 1840
Jamestown ND 58402-1840

KTGO-AM
Box 457
Tioga ND 58852-0457

KTHI-TV
PO Box 1878
Fargo ND 58107-1878

KXJB-TV 4
PO Box 10399
Fargo ND 58106-0399

KXMB TV
Box 1617
Bismarck ND 58502-1617

KXMD-TV
PO Box 790
Williston ND 58802-0790

KZZJ-AM
PO Box 105
Rugby ND 58368-0105

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Nat'l Assoc Plumbing-Htng-Cooling
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Falls Church VA 22046-6808

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Natural Gas Week
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Washington DC 20005-2150

Everett Morris
NJ Public Service Electric & Gas
80 Park Pl
Newark NJ 07101

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215 S Cascade Street
Fergus Falls MN 56538-0496

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PO Box 1287
Williston ND 58802-1287

News Director
KXMA-TV
Drawer B
Dickinson ND 58602

KXMC TV
Box 1686
Minot ND 58701-1686

KXPO AM & FM Radio
856 W 12 St
Grafton ND 58237

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Harlan Fuglesten
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Fergus Falls MN 56538-0496

Patricia E. ...
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PO Box 970
Wahpeton ND 58074-0970

Public Utilities Reports Inc
Law Dept
8229 Boone Blvd Ste 401
Vienna VA 22182

Telecommunications Reports
1333 H St NW 11th Fl W Tower
Washington DC 20005

John Kapsner
The Vogel Law Firm
P O Box 2097
Bismarck ND 58502-2097

LeRoy Neubauer
Valley City Public Works
254 2nd Ave NE
Valley City ND 58072

WDAY AM-FM & TV
PO Box 2466
Fargo ND 58108-2466

WDAZ-TV
PO Box 12639
Grand Forks ND 58208-2639

PU-400-00-195

Copies To:

State Library (8 copies)

Historical Society

Associated Press

Helbling, Sharon D.

From: Helbling, Sharon D.
Sent: Thursday, July 20, 2000 11:13 AM
To: 'ndna'
Subject: Attached Notices

Please have the attached Notices published as legal publications in the ten North Dakota daily newspapers. Also run them as "News Item Only" articles.

Send the bill to the Public Service Commission, along with a tear sheet for billing purposes.

If you have any questions, give me a call at 328-4076.

Thank you.

Sharon Helbling
Public Utilities Division



8 **PU-400-00-195** Pages: 1
07/20/2000
Public Service Commission
Notice e-mailed to NDNA for publication

M O T I O N

July 19, 2000

**Otter Tail Power Company
Performance Based Regulation
Application**

Case No. PU-401-00-36

**Northern States Power Company
Performance Based Regulation
Application**

Case No. PU-400-00-195

I move the Commission issue a Notice of Hearing and Notice of Public Discussion Meeting in the applications of Otter Tail Power Company and Northern States Power Company for approval of a performance-based ratemaking plan, Case Nos. PU-401-00-36 and PU-400-00-195.

JRL/sdh

000195-3.doc

**STATE OF NORTH DAKOTA
PUBLIC SERVICE COMMISSION**

**Otter Tail Power Company
Performance Based Regulation
Application**

Case No. PU-401-00-36

**Northern States Power Company
Performance Based Regulation
Application**

Case No. PU-400-00-195

NOTICE OF HEARING AND NOTICE OF PUBLIC DISCUSSION MEETING

July 19, 2000

On January 31, 2000, in Case No. PU-401-00-36, Otter Tail Power Company filed an application for approval of a performance-based ratemaking plan. On April 24, 2000, in Case No. PU-400-00-195, Northern States Power Company (NSP) filed an application for approval of a similar performance-based ratemaking plan.

These plans propose an earnings range within which allowed utility earnings could vary annually based on utility performance. One-half of earnings greater than the allowed range would be credited to customers, except that NSP proposes to first donate 10% to economic development. If utility earnings were less than the allowed range, one half of the revenue shortfall would be billed to customers. The range of allowable utility earnings would be set annually by the Commission according to specified performance standards relating to price, reliability, customer service and safety.

A public hearing on these applications will be held beginning **October 23, 2000 at 1:30 p.m. (CDT)** in the Commission hearing room, State Capitol, 12th Floor, Bismarck, North Dakota 58505-0480. The issues to be considered are:

1. Are the plans consistent with Commission guidelines?
2. Would the plans result in quality service and reasonable electric rates?
3. Would the plans support safe and reliable electric infrastructure and the financial viability of the utilities?
4. Would implementing the plans be in the public interest?

A Public Discussion Meeting will be conducted via interactive television beginning at **12 noon (CDT) on September 6, 2000** at the following locations:

Bismarck State College (Host)
Vocational Technical Center
1200 College Drive, Rm 216
Bismarck, North Dakota

North Dakota State University
Walstar Hall, Rm 220
Albrecht Blvd. & 14th Ave. North
Fargo, North Dakota

Lake Region State College
Administration Bldg
1801 College Drive North, Rm 172
Devils Lake, North Dakota

Cankdeska Cikana Community College
(Little Hoop)
Higher Education Office
Fort Totten, ND

Minot State University
Administration Bldg, Rm 158
East Ctr. Campus, Next to Student Union
Minot, North Dakota

University of North Dakota
Gamble Hall, Room 130
Centennial Drive
Grand Forks, ND

North Dakota State College of Science
Allied Health Bldg, Rm 212
Wahpeton, North Dakota

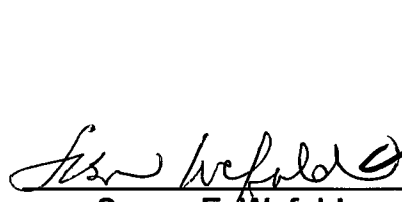
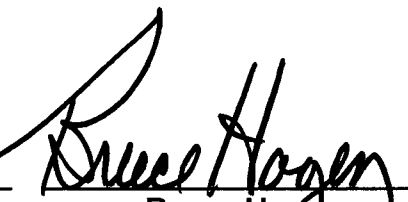
Jamestown State Hospital
Education (12 West) Building, 3rd Floor
Jamestown, ND

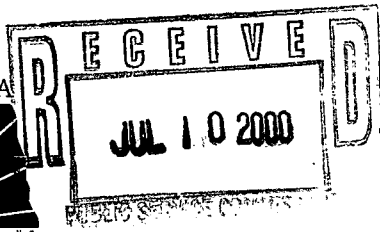
Minot State University – Bottineau
Student Union – Wold Room
Bottineau, North Dakota

Turtle Mountain Community College
Gailfus Building
Belcourt, ND

For more information contact the Public Service Commission, State Capitol, Bismarck, North Dakota 58505, 701-328-2400; or Relay North Dakota 1-800-366-6888 TTY. If you require any auxiliary aids or services, such as readers, signers, or Braille materials please notify Jon Mielke, Executive Secretary, at least 24 hours prior to the hearing.

PUBLIC SERVICE COMMISSION

		
Susan E. Wefald Commissioner	Bruce Hagen President	Leo M. Reinbold Commissioner



North Dakota University System
Distance Education
UND, PO Box 8384
Grand Forks, ND 58202-8384
701-777-6486
Fax: 701-777-6353

Videoconference Confirmation

This is not a bill

July 7, 2000

Public Service Commission
600 E. Boulevard Avenue
Bismarck, ND 58505-0480

The following event has been scheduled on the North Dakota Interactive Video Network (IVN):

Date: September 6, 2000 Time: 12:00-1:50 Event: 2441520

Event Title: Ottertail Public Hearing

Site(s) Scheduled: Host - BSC 216; LRSC 172; MiSU Admin; NDSCS Allied Health 212;
MiSU-Bottineau--Wold Rm; NDSU Walster; State Hospital;
UND Gamble Hall 130; Little Hoop Comm. College;
Turtle Mountain Community College

Telephone Line Charges:	\$80 x2 hrs	\$ 160.00
Technical Charge:	\$10 x 2 hrs x 10 site(s)	<u>200.00</u>

Total Due NDUS Distance Education \$360.00

Events cancelled less than 24 hours before event will be charged the administration and site fee. Sites dropped less than 24 hours before an event will be charged the technical support fee.

6 **PU-401-00-36** Pages: 12
07/10/2000
North Dakota Interactive Video Network
Videoconference Confirmation

KOTA

5 **PU-400-00-195** Pages: 12
07/10/2000
North Dakota Interactive Video Network
Videoconference Confirmation

IVN CLASSROOMS, PHONE/FAX NUMBERS

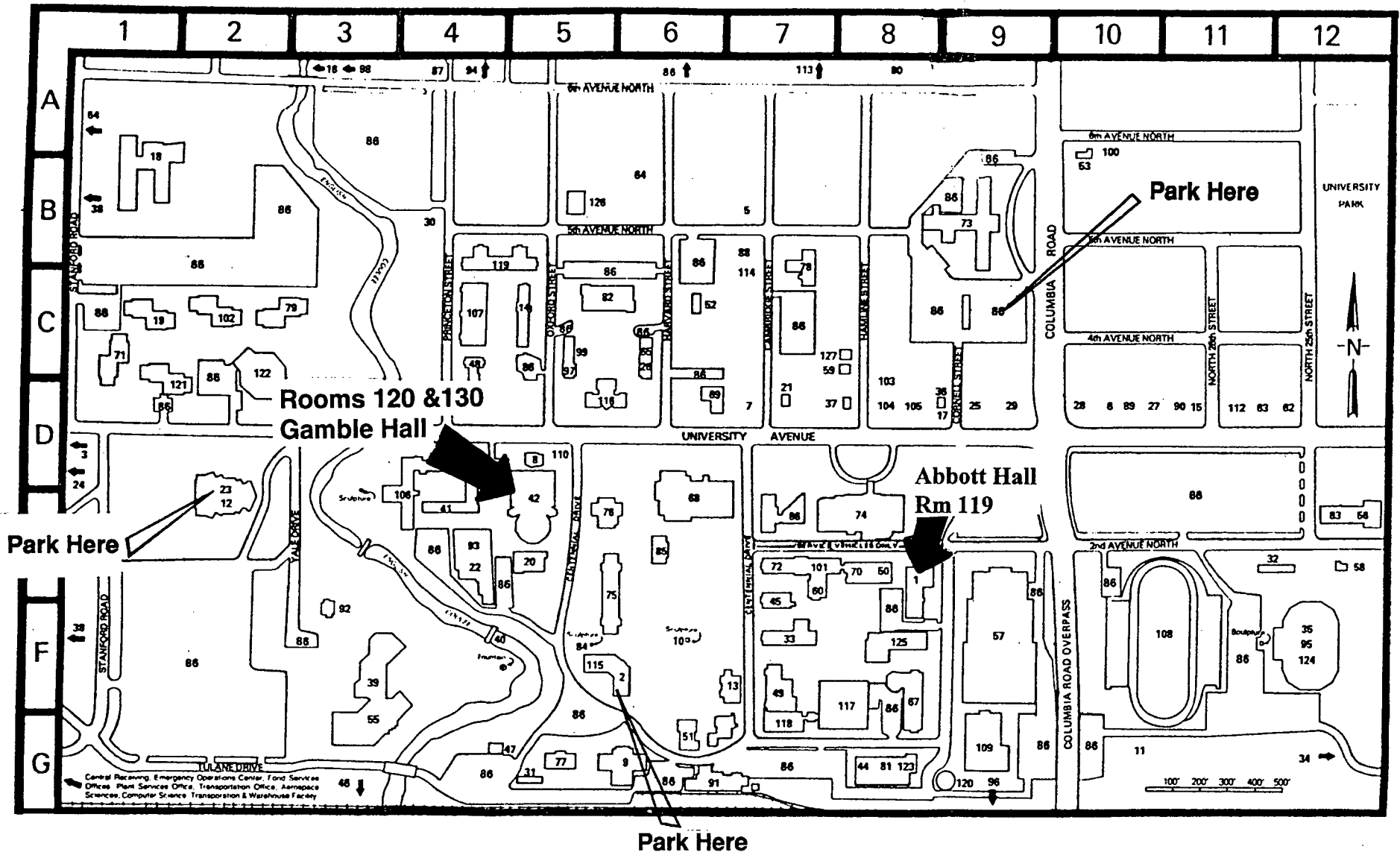
<u>Site</u>	<u>Address</u>	<u>VC Wizard Abbr.</u>	<u>CAP.</u>	<u>PHONE #</u>	<u>FAX #</u>
Belcourt-TMCC	Gailfus Bldg.	TMCC	20	477-7904	477-6088
Bismarck-BSC	Vocational Technical Center, 1200 College Drive				
	Rm 216	BSC 216	28	224-5508	224-5507
	Rm 228	BSC 228	28	224-5641	224-5507
Bismarck-State Capitol	Fort Lincoln Room West Wing, Ground Floor 600 E. Boulevard Ave.	State Capitol	10	328-3270	328-2961
Bismarck-UTTC	UTTC - Skills Center	UTTC	30	255-3285 x 324	530-0602
✓ Bottineau-MISU-B	Arntzen IVN Bldg., Rm 100 105 Sjmrrall Blvd.	MISU BOTT	24	228-5421	228-5428
✓✓✓ Devils Lake-LRSC	Student Union - World Room Administration Bldg. 1801 College Drive North			228-5476	228-5401
	Rm 171	LR 171	20	662-1588	662-1599
	Rm 172	LR 172	20	662-1595	662-1599
Dickinson-DSU	North Campus, Rm 104 1679 Sixth Ave. W.	DSU 104	27	483-2013	483-2028
	Klinefelter Hall, Rm 220 Corner of 2 nd St W & 10 th Ave W	DSU 220	27	483-2071	483-2160
✓ Fargo-NDSU	E. Morrow Lebedeff Bldg., Rm 183	NDSU EML	35	231-8523	231-6117
	Centennial Blvd.	NDSU Walster	30	231-1997	231-6116
	Walster Hall, Rm 220				
	Albrecht Blvd. & 14th Ave N.	NDSU IACC	40	231-9455	231-6115
	IACC, Rm 422				
✓ Fort Totten-CCCC	Higher Education Office	LHCC	30	766-4980	766-1350
Fort Yates-SBC	Sitting Bull College, Rm 5	SBC	15	854-2140	854-3403
✓ Grand Forks-UND	Gamble Hall, Centennial Drive				
	Rm 120	UND 120	30	777-4825	777-4750
	Rm 130	UND 130	50	777-4907	777-4750
	Abbott Hall, Rm 119	UND 119	25	777-2357	777-2358
	Corner of Campus Rd. & 2nd Ave N				
✓ Jamestown State Hospital	Education (12 West) Building 3rd Floor	State Hospital	28	253-3205	253-3204
Mayville-MaSU	Library, Rm 115 330 3rd Street NE	MaSU	20	786-4638	786-4749
✓ Minot-MISU	Administration Bldg., Rm 158	MISU Admin	24	858-3487	858-3239
	E. Ctr. of Campus, next to Student Union				
	Model Hall, Rm 113	MISU Model	30	858-3984	858-3582
	University Ave. & 8th St. NW				
New Town-FBCC	Fort Berthold Community College	FBCC	20	627-4738 x 271	627-3018
Valley City-VCSU	Vangstad Hall, Rm 115 101 College Street	VCSU	24	845-7207	845-7121
✓ Wahpeton-NDSCS	Mildred Johnson Library, Rm 117	NDSCS	24	671-2606	671-2151
	Allied Health Bldg.	Allied Health	25	671-2409	671-2193
Williston-WSC	Main Building, Rm 120 1410 University Ave.	WSC MAIN	30	774-4250	774-4287
	Crighton Building, Rm 109	WSC CRTN	24	774-4297	774-4284

Network Trouble Shooting Beeper number 328-2004

1. Leave message after the tone including your name, phone number and a short description of the problem.
2. Stay off the phone until network technician calls.

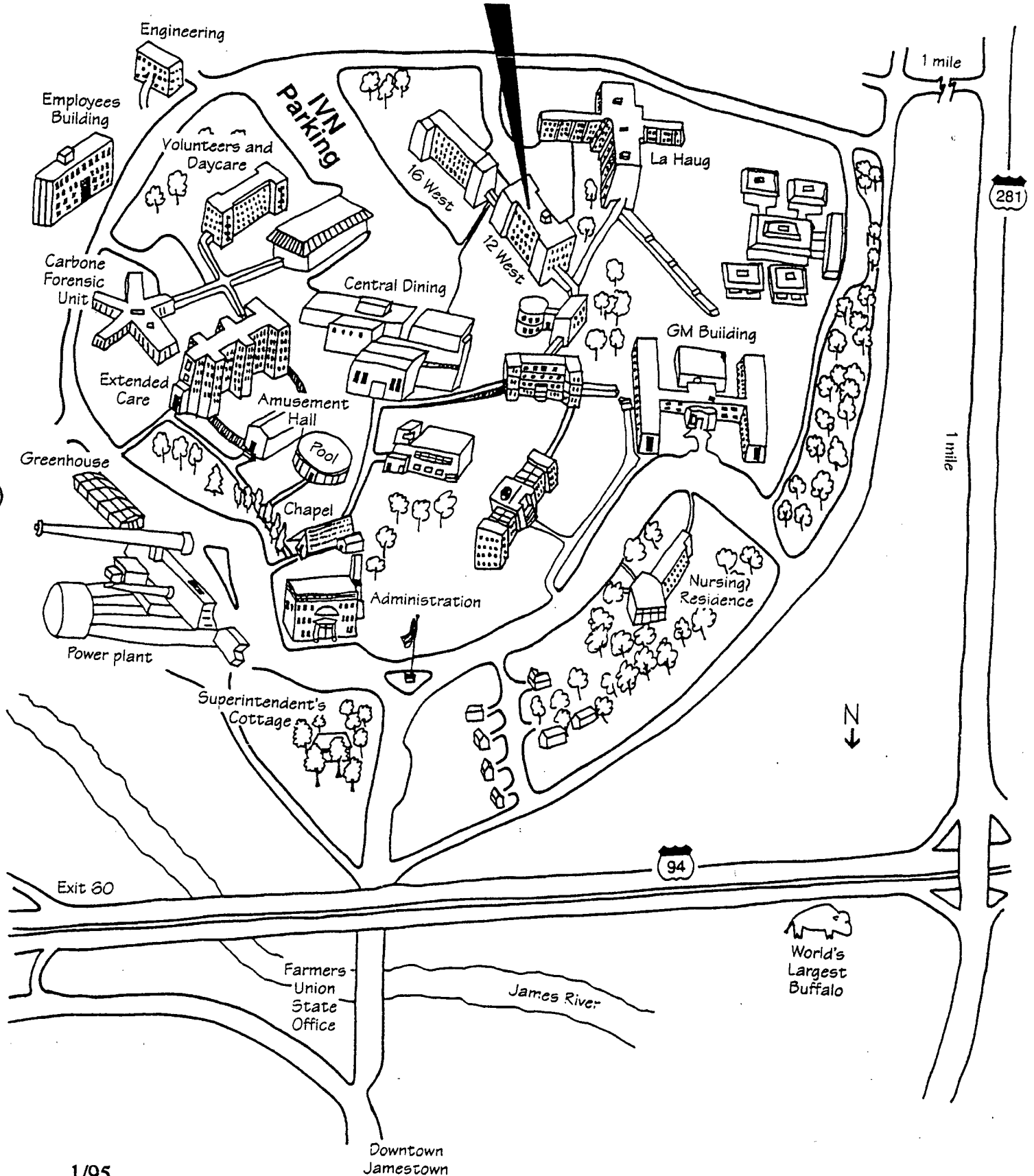
IVN Classroom Locations

UNIVERSITY OF NORTH DAKOTA - UND



IVN Classroom Location State Hospital, Jamestown, N.D.

IVN 3rd floor

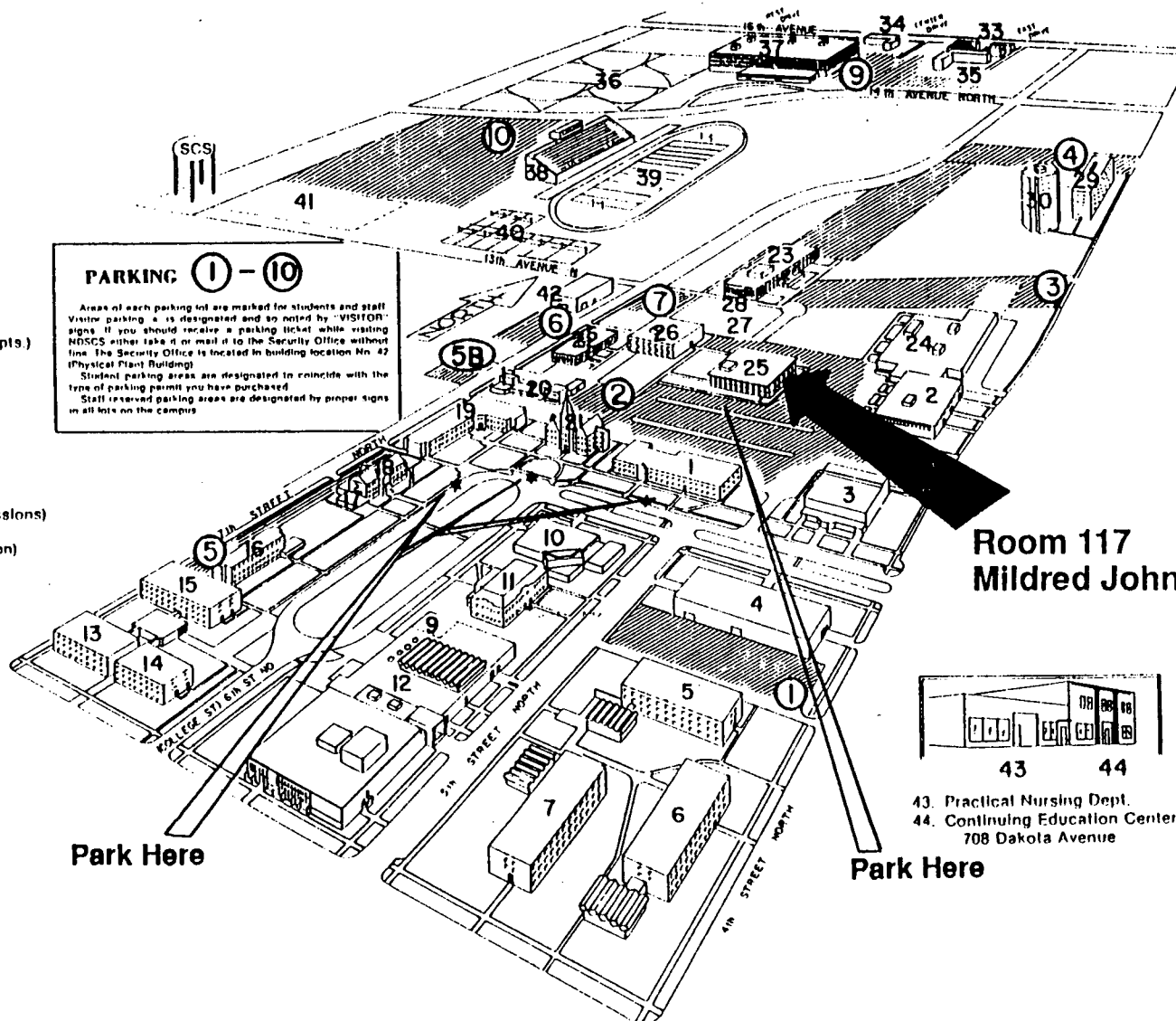


IVN Classroom Locations

NORTH DAKOTA STATE COLLEGE OF SCIENCE

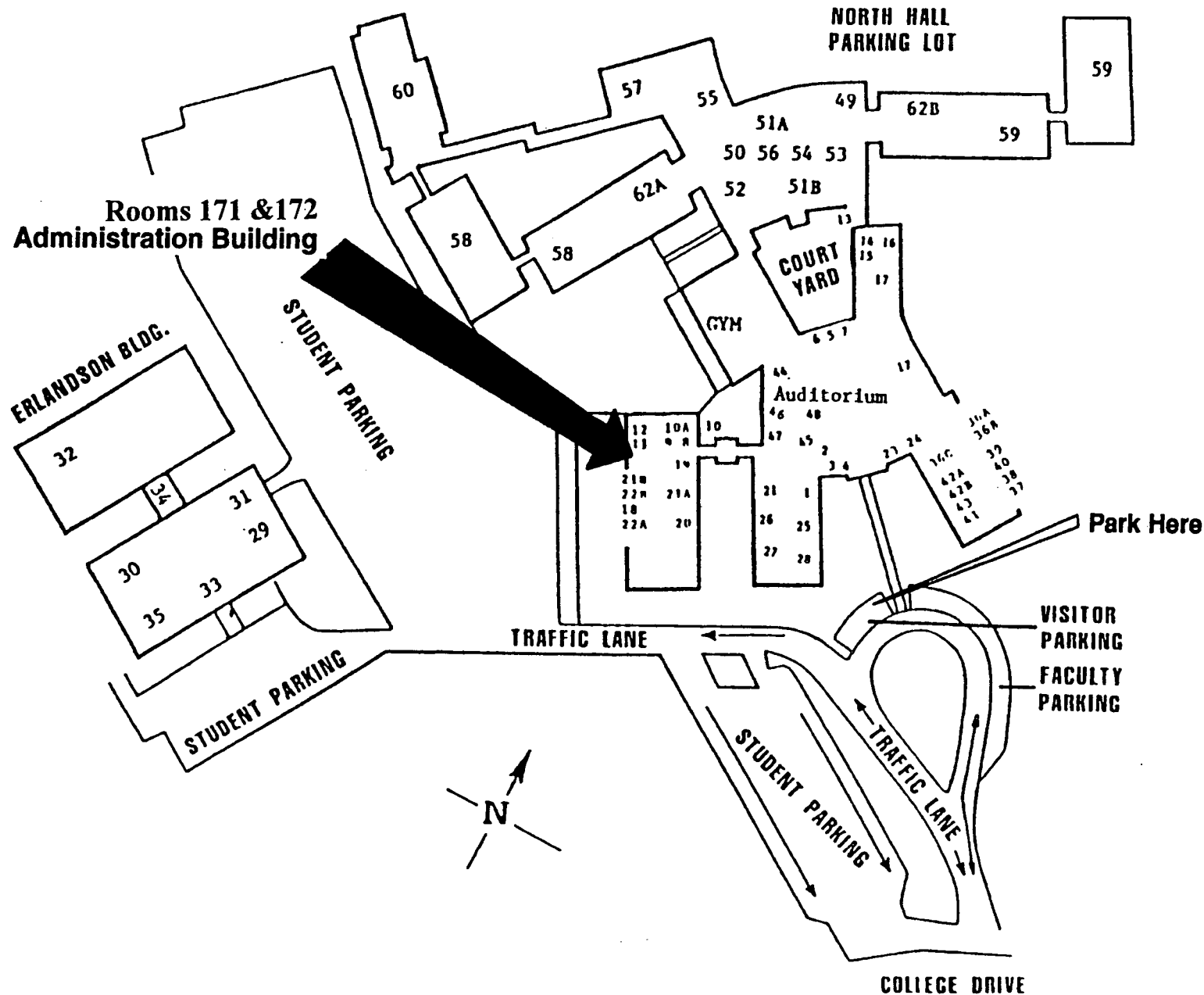
Legend

1. Horton Hall
(Trade-Technical No. 1)
2. Trade-Technical No. 2
(Machine Tooling/Welding)
3. Bute Gymnasium
4. Ballweber Hall
(Auto Collision Tech.)
5. Babcock Hall (Men)
6. Satterlee Hall (Men)
7. McMahon Hall (Men)
- ①-④ Parking Areas
9. Health Center
10. Auditorium/Cultural Center
11. Hekker Hall
(Dental Auxiliaries/OTA Depts.)
12. Student Center and
Food Service
13. Schulz Hall (Women)
14. Wallon Hall (Women)
15. Forkner Hall (Women)
16. Riley Hall (Women)
17. ATEA Nat'l Bldg.
18. Burch Hall (Men)
19. Haverly Hall
(Administration and Admissions)
20. Central Heating Plant
21. Old Main (Business Division)
22. Environmental Systems
(Plumbing, Sheet Metal,
Heating and Cooling)
23. Diesel Technology
24. Schuett Hall
(Auto Mechanics Tech.)
25. Mildred Johnson Library
26. Barnard Hall
(Electrical/Electronics/
Refrigeration)
- 27-28 (To be designated)
29. Robertson Hall (Men)
30. Nordgaard Hall (Men)
- 31-32 (To be designated)
33. College Complex
34. College Complex NW
35. College Complex SE
36. Activity Area
37. Activities Center
(Varsity/Intramural)
38. Alumni Stadium
39. Frank Verlin Field
40. Tennis Courts
41. Football Practice Field
42. Physical Plant/Storage/
Security Office
43. Practical Nursing Dept.
44. Continuing Education Center



IVN Classroom Locations Lake Region State College

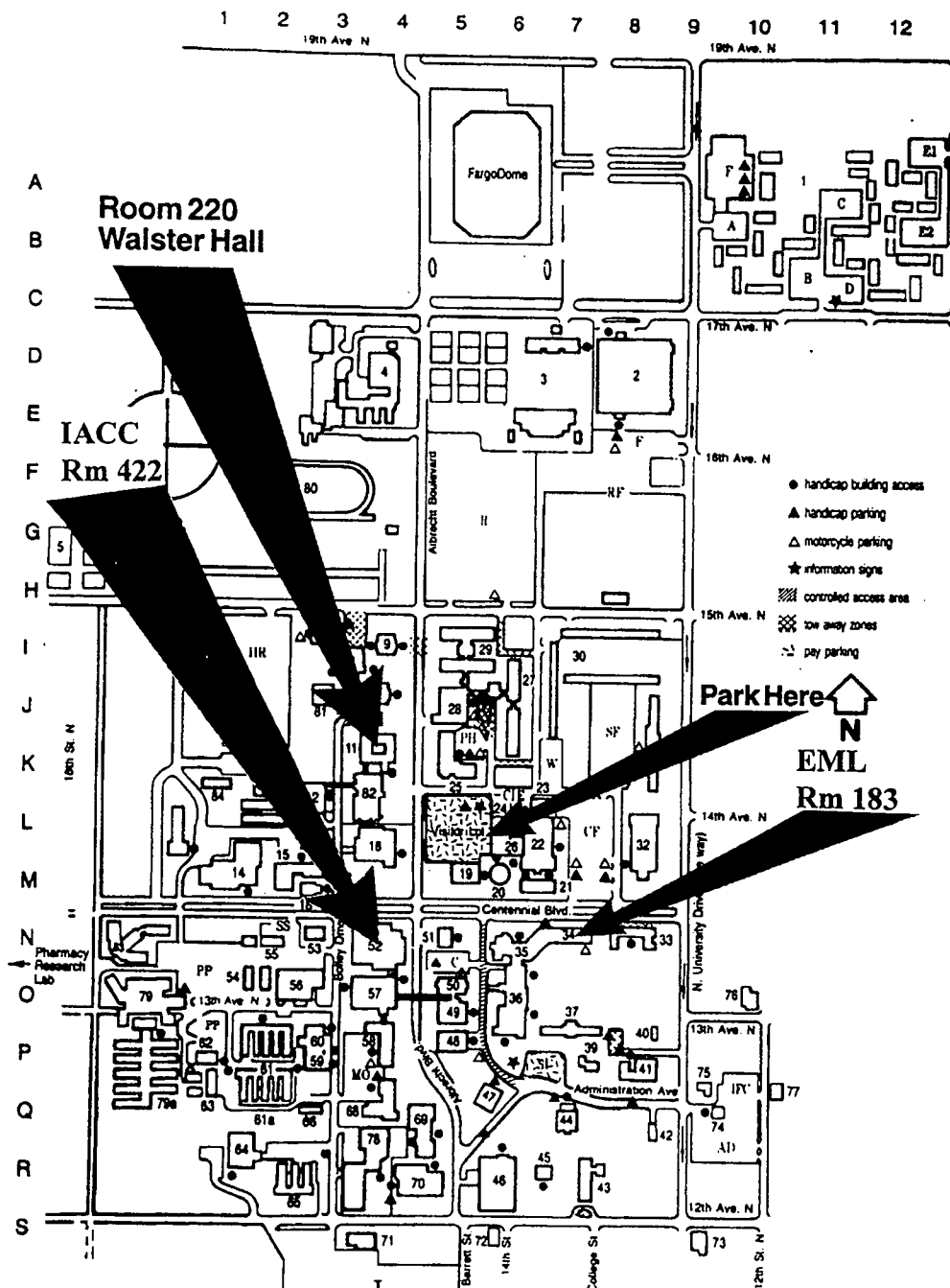
Devils Lake, ND



IVN Locations

NDSU

North Dakota State University,
Fargo, N.D.



NDSU Campus

- P5 48 Agricultural Engineering
- P2 61 Agronomy Greenhouse Plant Diagnostic Lab
- P8 40 Alba Bales House (Family Studies Institute)
- P9 75 Alumni, Development Center
- M6 21 Architecture & Landscape Architecture
- L6 23 Architecture Quonset
- R3 65 Art
- R4 70 Askane Hall (Little Country Theatre)
- Q2 64 Auxiliary Enterprises (Dining Services and Housing)
- E4 4 Biosciences Research Laboratory
- E8 2 Bison Sports Arena (Physical Education, Sports Information)
- Q3 66 Campus Laundry
- P8 41 Ceres Hall—(Admission, Financial Aid, Counseling, Career Services, Registrar, Student Academic Affairs)
- L6 24 Civil and Industrial Engineering
- L6 26 Construction Management
- S6 72 Credit Union (Northland Educators)
- P2 61 Crop and Weed Sciences Greenhouse
- E6 3 Dakota Field
- L6 22 Dolva Hall (Mechanical Engineering)
- O5 50 Dunbar Laboratories (Biochemistry, Polymers and Coatings)
- M5 19 Electrical Engineering
- M6 20 Engineering Administration
- N5 51 Engineering and Technology
- N6 35 Family Life, 4-H Center (Education)
- P3 60 Harris Hall (Cereal Science and Food Technology)
- N3 53 Hastings Hall
- P4 68 Heating Plant
- N7 34 Home Economics (Human Development and Education)
- K4 82 Horticulture Science (Lottsgard Hall)
- P2 61a Horticulture and Plant Pathology Greenhouse
- O4 57 Hultz Hall (Animal & Range Sciences, Entomology)
- N4 52 Industrial Agriculture and Communications Center (Computer Center, Computer Network, Computer Science, and Industrial Agriculture)
- N1 83 Johansen Hall (State Seed Dept., Seed Research)
- O5 49 Ladd Hall (Chemistry)
- R6 46 Library (Publications Services)
- K4 82 Lottsgard Hall (Horticulture)
- N2 55 Longwell Building
- P2 61 Lord & Burnham Greenhouses
- O10 76 Lutheran Student Center
- N2 54 Maintenance Buildings
- O6 36 Memorial Union (Varsity Mart)
- Q4 69 Minard Hall (Humanities and Social Sciences)
- P4 58 Morrill Hall (Agriculture, Ag. Econ., University Studies)
- R4 78 Music Education Building (Festival Concert Hall)
- P7 39 Nelson Health Center
- P3 59 Northern Crops Institute
- O1 79 Northern Crops Science Lab (sunflowers, sugar beets)
- S6 72 Northland Educators Federal Credit Union
- Q7 44 Old Main (Administration, Business Office, Student Affairs News and Media Services)
- L8 32 Physical Education Building (ROTC & Women's Athletics)
- P1 79a Plant Science Greenhouse
- Q9 74 Post Office
- P1 63 Potato Research-Pesticide Storage
- H1 5 Poultry Research Center
- O8 42 President's House
- R7 45 Putnam Hall (Business)
- R4 78 Reineke Fine Arts Center (Music)
- J5 28 Residence Dining Center
- L1 14a Robinson Hall (Veterinary Research)
- F2 80 Running Track Facility
- K1 84 Service Center, Pilot Plant
- L4 18 Shepperd Arena
- P5 47 South Engineering (Physics)
- M3 16 Stevens Auditorium
- M3 15 Stevens Hall (Natural Sciences)
- S9 73 St. Paul's Chapel (Newman Center)
- K5 25 Sudro Hall (Pharmacy, Nursing)
- P1 62 Sugar Beet Research
- S4 71 Thordarson Hall (Independent Study, State Film Library)
- O3 56 Thorson Maintenance Center (Physical Plant)
- P10 77 United Campus Ministry, YMCA of NDSU
- M2 14 Van Es (Vet Science, Microbiology)
- K3 12 Waldron Laboratory (Agriculture, Soil Testing Lab, Statistics)
- K4 11 Walster Hall (Agriculture)
- I3 8 West Dining Center
- L3 17 Widakas Lab (Crop & Weed Sciences, Corn Seed House)

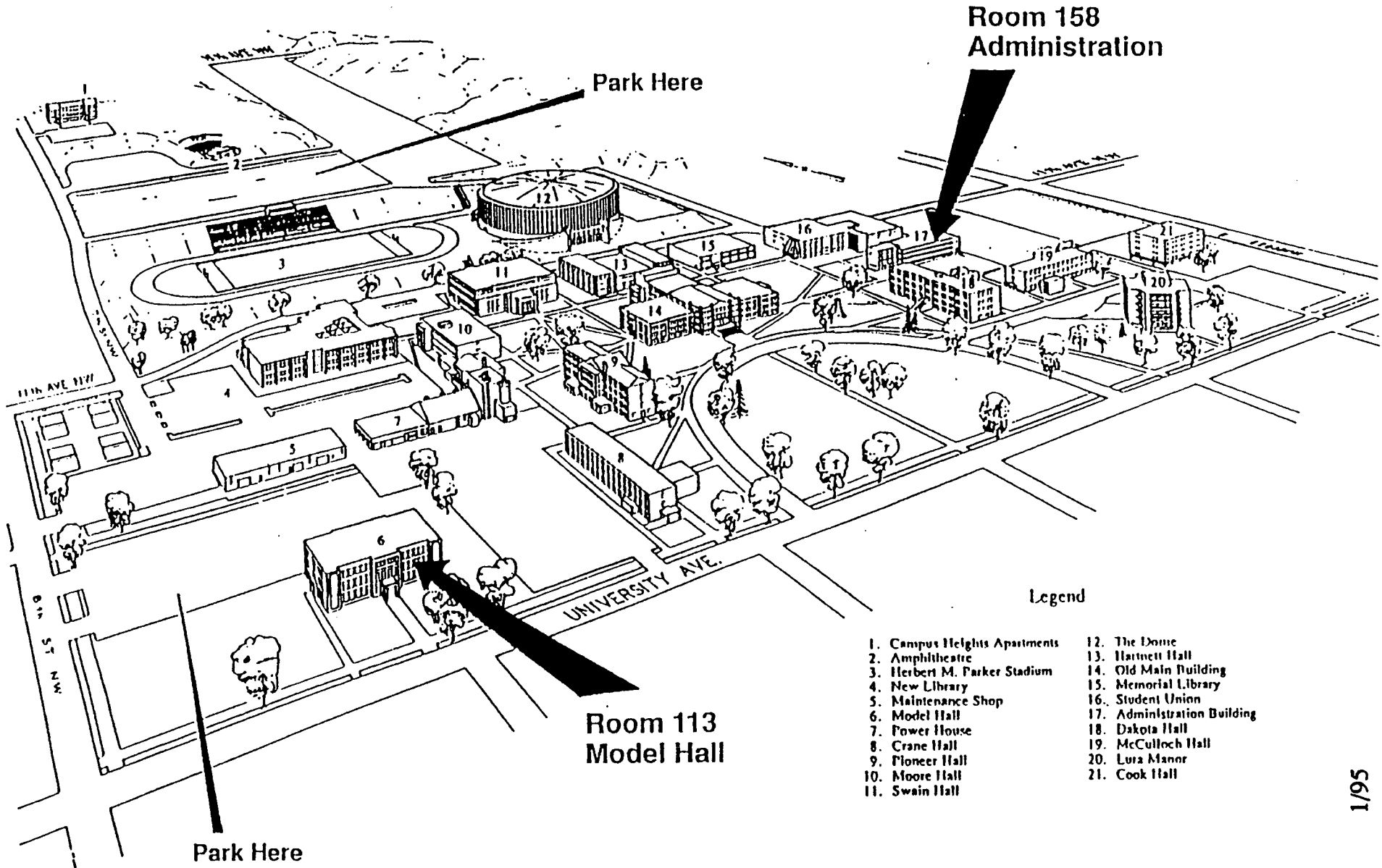
Housing Units

- I7 30 Bison Courts
- R7 43 Burgum Hall
- N8 33 Churchill Hall
- O7 37 Dinan Hall
- J3 81 Pavak Hall
- I5 29 Reed-Johnson Halls
- I3 7 Seim Hall
- I4 9 Sevrinson Hall
- K8 31 Stockbridge Hall
- J4 10 Thompson Hall
- C11 1 University Village
- J6 27 Weible Halls (North & South)
- H2 6 West Trailer Courts

Selected Offices

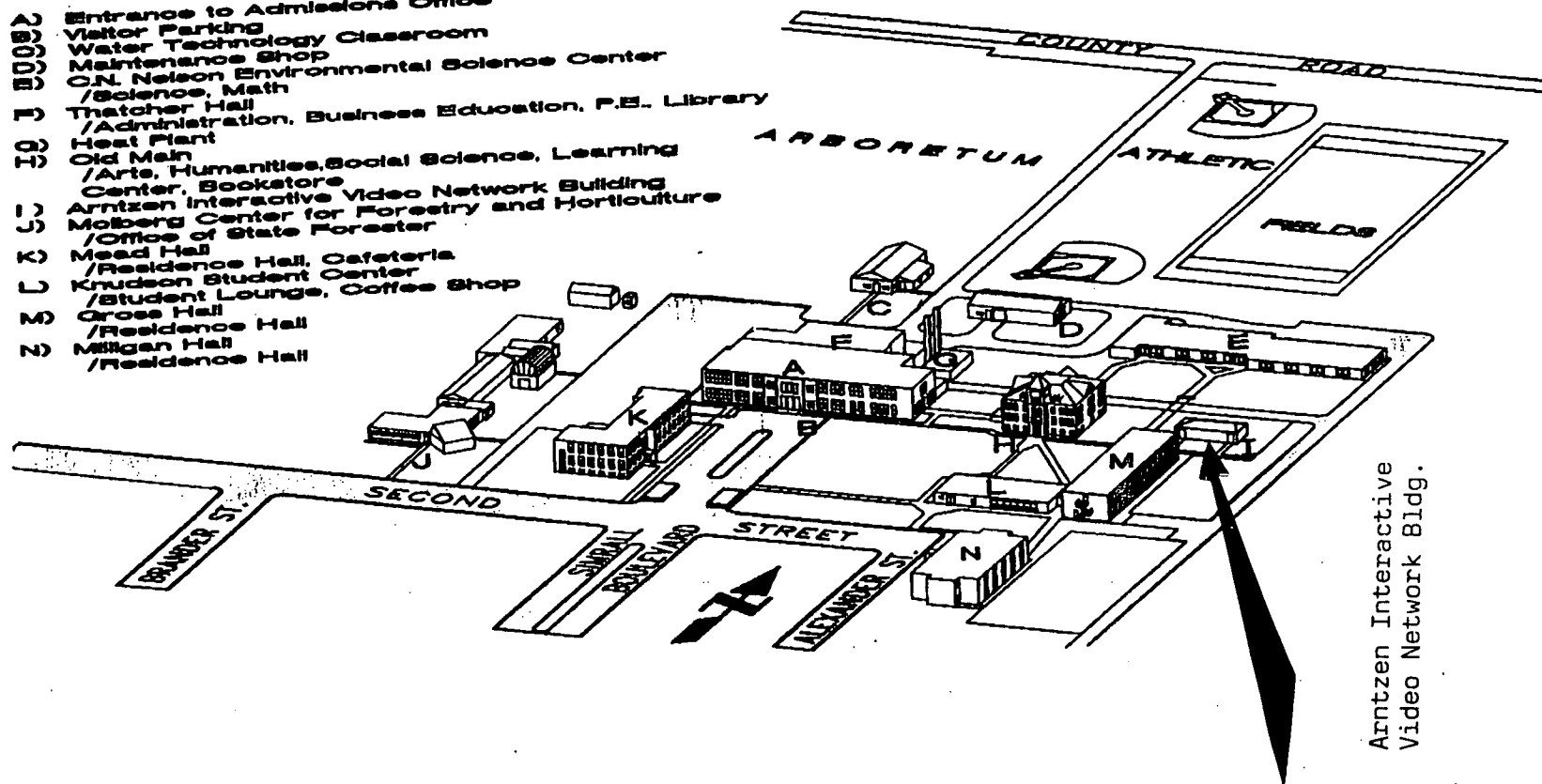
- P8 41 Admission (Ceres Hall)
- Q7 44 Business Office (Old Main)
- P8 41 Career Services (Ceres Hall)
- P8 41 Counseling (Ceres Hall)
- P8 41 Financial Aid (Ceres Hall)
- Q2 64 Housing (Aux. Ent.)
- Q7 44 Human Resources (Old Main)
- P8 41 Registrar, Student Academic Affairs (Ceres Hall)
- Q7 44 Student Affairs (Old Main)
- O3 56 Traffic (Thorson Maintenance Center)
- O6 36 Varsity Mart (Memorial Union)

IVN Classroom Locations MINOT STATE UNIVERSITY



M S U - BOTTINEAU CAMPUS MAP

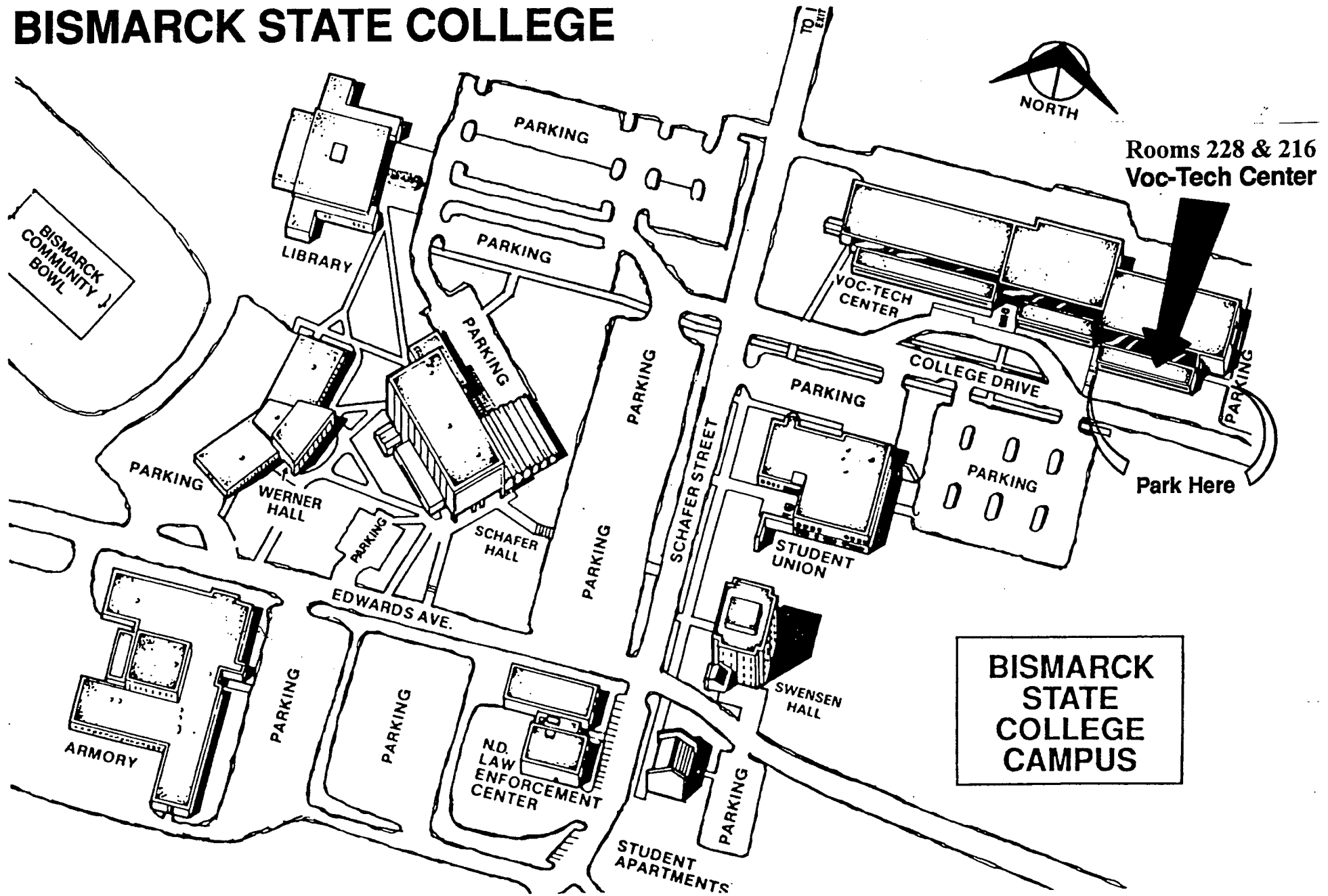
- A) Entrance to Admissions Office
- B) Visitor Parking
- C) Water Technology Classroom
- D) Maintenance Shop
- E) O.N. Nelson Environmental Science Center
/Science, Math
- F) Thatcher Hall
/Administration, Business Education, P.E., Library
- G) Heat Plant
- H) Old Man
/Arts, Humanities, Social Science, Learning
Center, Bookstore
- I) Arntzen Interactive Video Network Building
- J) Molberg Center for Forestry and Horticulture
/Office of State Forester
- K) Mead Hall
/Residence Hall, Cafeteria
- L) Knudson Student Center
/Student Lounge, Coffee Shop
- M) Gross Hall
/Residence Hall
- N) Miligan Hall
/Residence Hall



Arntzen Interactive
Video Network Bldg.

IVN Classroom Locations

BISMARCK STATE COLLEGE



Site and Technical Coordinators List to Post

			Phone	Fax
Belcourt--TMCC		PO Box 340; Belcourt, ND 58316		
Site:	Bill Gourneau	bgourneau@giizis.turtle-mountain.cc.nd.us	477-7825	477-7807
Tech:	Tony Poitra	tpoitra@giizis.turtle-mountain.cc.nd.us	477-7904	477-7807
Bismarck--BSC		PO Box 5587; Bismarck, ND 58506-5587		
Site:	Pat Gross	jagross@gwmail.nodak.edu	224-5484	224-5507
Tech:	Lloyd Hieb	lhieb@badlands.nodak.edu	224-5610	224-5507
Bismarck--State Capitol		ITD; 600 E. Boulevard Ave.; Bismarck, ND 58505		
Site/Tech:	Norma Schacher	nschache@state.nd.us	328-3054	328-3000
Bismarck--UTTC		3315 University Dr.; Skills Center; Bismarck, ND 58504		
Site/Tech:	Liz Miller	dyhuman@hotmail.com	255-3285 ext. 316	530-0602
Bottineau--MiSU-B		Arntzen Interactive Video Building; Bottineau, ND 58318		
Site/Tech:	Nancy Underwood	underwon@warp6.cs.misu.nodak.edu	228-5421	228-5428
Devils Lake--LRSC		1801 College Drive North; Devils Lake, ND 58301-1598		
Site/Tech:	Marlene Jonas	jonasm.@lrsc.nodak.edu	662-1601	662-1599
Dickinson--DSU		291 Campus Dr.; Dickinson, ND 58601		
Site:	Marty Odermann-Gardner	moderman@eagle.dsu.nodak.edu	483-2166	483-2028
Tech:	Kathy Obritsch	kobritsc@eagle.dsu.nodak.edu	483-2129	483-2028
Fargo--NDSU		IACC Bldg., Room 206; Fargo, ND 58105		
Site:	Tammy Cummings	tammy_cummings@ndsu.nodak.edu	231-1090	234-8541
Tech:	Joel Writer	joel_writer@ndsu.nodak.edu	231-6247	231-8541
		Emergency number - 793-3105		
Fort Totten--CCCC		Cankdeska Cikana Comm. College; Ft. Totten, ND 58335		
Site/Tech:	Scott Jones	sajones@hoopster.little-hoop.cc.nd.us	766-4980	766-1350
Fort Yates--SBC		HC 1, Box 4; Fort Yates, ND 58538		
Site/Tech:	Rick Pelishek	rickp@sbc.edu	854-2140	854-3403
Grand Forks--UND		PO Box 9021; Gustafson Hall; Grand Forks, ND 58202-9021		
Site:	CK Braun	ck_braun@mail.und.nodak.edu	777-3308	777-4282
Tech:	John Murphy	john_murphy@mail.und.nodak.edu	777-6452	777-4282
		Cell: 741-8488		
Great Western Network--GWN		Washburn High School; PO Box 280; Washburn, ND 58577		
Site/Tech:	Bill Strasser	strasser@sendit.nodak.edu	462-8260	462-3574
		Bismarck High School	221-3727	221-3730
Jamestown--State Hospital		PO Box 476; 1624 23rd St. SE; Jamestown, ND 58401		
Site/Tech:	Linda Bjone	bjonel@state.nd.us	253-3922	253-3204
Mayville--MaSU		330 3rd Street NE; Mayville, ND 58257		
Site:	Marjorie Fugleberg	marjorie_fugleberg@mail.masu.nodak.edu	786-4817	786-4846
Tech:	Jeanette Krogstad	jeanette_krogstad@mail.masu.nodak.edu	786-4817	786-4846

Minot--MiSU

Site: Bob Larson
Tech: Bob Feller
Dick Debertin

500 University Avenue West; Minot, ND 58701

larsonb@warp6.cs.misu.nodak.edu
feller@warp6.cs.misu.nodak.edu
rdebert@misu.nodak.edu

Cell: 720-0217

858-3186 858-3823
858-3210 839-6933
858-3984 858-3582

New Town--FBCC

Site: Roberta Holds-The-Enemy
Tech: Mariam Packineau

PO Box 490; New Town, ND 58763

roberta@fbcc.bia.edu
mpack@fbcc.bia.edu

627-4738 627-4677
ext. 228
627-4738 627-3609
ext. 225

Valley City--VCSU

Site: Bill Buck
Tech: Kathy Schlotman

101 College Street; Valley City, ND 58072

bill_buck@mail.vcsu.nodak.edu
kathy_schlotman@mail.vcsu.nodak.edu

845-7417 845-7418
845-4362 845-7245

Wahpeton--NDSCS

Site: Steve Krohn
Tech: Tom Hickman

800 North 6th Street; Wahpeton, ND 58067

krohn@plains.nodak.edu
thickman@badlands.nodak.edu

671-2626 671-2613
671-2354 671-2613

Williston--WSC

Site: Ken Quamme
Tech: Linda Clemes

1410 University Avenue; Williston, ND 58801

kquamme@mail.wsc.nodak.edu
lclemes@mail.wsc.nodak.edu

774-4207 774-4287
774-4276 774-4287

Network Trouble Line 701-328-2004. Leave a message after the tone including your name, phone number and a short description of the problem. Stay off the phone until the network technician returns your call.

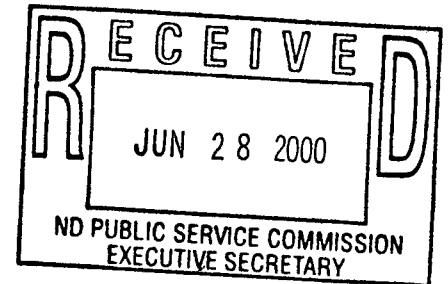


Northern States Power Company

2302 Great Northern Drive
Fargo, ND 58102
701-241-8632

June 23, 2000

Jon Mielke
Executive Secretary
North Dakota Public Service Commission
600 East Boulevard Ave. Dept. 408
Bismarck, ND 58505-0480



Re: Northern States Power Company, Case No. PU-400-00-195
Otter Tail Power Company, Case No. PU-401-00-36

Dear Mr. Mielke:

At the Monday, June 19 informal hearing regarding Performance-Based Regulation (PBR) proposals filed by both NSP and OTP, the utilities were asked to provide comments on what issues should be included in a Notice of Opportunity for Hearing. These comments were to be submitted by Friday, June 23.

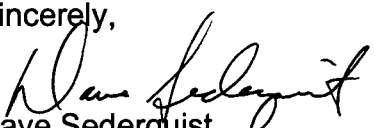
It is NSP's position that the following issues should be outlined in the notice:

- ☐ Are the performance-based regulation plans consistent with the 1995 Commission guidelines adopted for such plans?
- ☐ Will the PBR plans result in just and reasonable rates and maintain service quality for electric customers in North Dakota?
- ☐ Will the PBR plans support reliable and safe electric utility infrastructure and the financial health of utilities?

In our view, the lengthy list of potential topics presented by Staff at the informal hearing represent detailed questions which relate directly to the broader issues outlined above. They are topics which could be addressed in Staff litigation testimony, but need not be listed in the notice.

If you have any questions about the issues recommended in this submittal, please call me at 701-241-8632. Thank you.

Sincerely,


Dave Sederquist
Regulatory/Financial Consultant
NSP-North Dakota

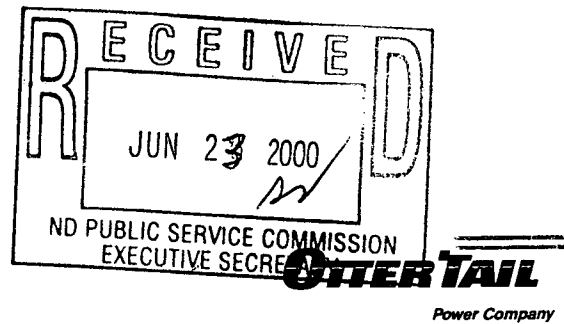
5 **PU-401-00-36** Pages: 1
06/28/2000
Northern States Power Company
Comments

CC: Comm Legal Illona, Pat, Jerry Mike

4 **PU-400-00-195** Pages: 1
06/28/2000
Northern States Power Company
Comments

CC: Comm Legal Illona, Pat, Jerry Mike

215 South Cascade Street
PO Box 496
Fergus Falls, Minnesota 56538-0496
218 739-8200
www.otpc.com (web site)



June 23, 2000

E-MAIL & POSTAL MAIL

Mr. Jon Mielke
Executive Secretary
North Dakota Public Service Commission
State Capitol - 600 East Boulevard
Bismarck, ND 58505-0480

RE: Otter Tail Power Company, Case No. PU-401-00-36
Northern States Power Company, Case No. PU-400-00-195

Dear Mr. Mielke:

On June 19 at the Informal Hearing on the above-captioned cases, the Commission asked both companies to provide comments, by June 23, on the issues that should be included in the Notice of Opportunity for Hearing.

Otter Tail Power suggests the following issues would be appropriate:

1. Is performance-based regulation (PBR) in the public interest?
2. Will the proposed PBR plans result in just and reasonable rates and maintain service quality?
3. Are the proposed PBR plans consistent with the guidelines adopted by the Commission?
4. Will the proposed PBR plans continue to support a safe and reliable electric infrastructure and the financial viability of the utilities?

The list of issues developed by staff will be extremely helpful in preparing testimony. However, I think the four items above encompass the items on that longer list.

If you have questions, don't hesitate to call me at (218) 739-8289 or e-mail me at bbrutlag@otpc.com.

Your very truly,

Bernadeen Brutlag, Manager
Regulatory Services

Cc: Illona Jeffcoat-Sacco
Dave Sederquist - NSP

4 **PU-401-00-36**
06/23/2000
Otter Tail Power Company
Comments

Pages: 1

CC: Comm Legal Illona, Pat, Jerry Mike

3 **PU-400-00-195**
06/23/2000
Otter Tail Power Company
Comments

Pages: 1

CC: Comm Legal Illona, Pat, Jerry Mike

MOTION

April 26, 2000

APPROVED:
DATE: 4-26-00
KMF

**Northern States Power Company
Performance Based Regulation
Application**

Case No. PU-400-00-195

I move the Commission appoint Mike Diller, Pat Fahn and Bill Binek as staff advisors, and Illona Jeffcoat-Sacco and Jerry Lein as Commission advisors in Case No. PU-400-00-195, Northern States Power Company's Performance Based Regulation application.

sdh

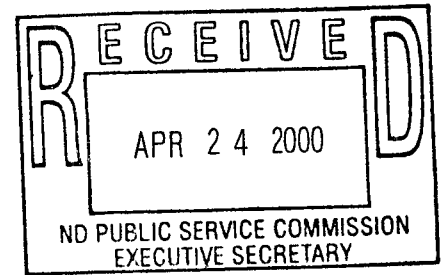
000195-1 doc



Northern States Power Company

PO Box 2747
Fargo, ND 58108-2747
701-241-8607

April 20, 2000



Mr. John Mielke
Executive Secretary
North Dakota Public Service Commission
State Capitol Building - 12th Floor
Bismarck, North Dakota 58505

Re: Northern States Power Company - North Dakota
Application for a Performance Based Regulation Plan

Dear Mr. Mielke:

Enclosed you will find an original and seven copies of Northern States Power Company's application for a Performance-Based Regulation Plan, which is referred to as the "PLUS" Plan.

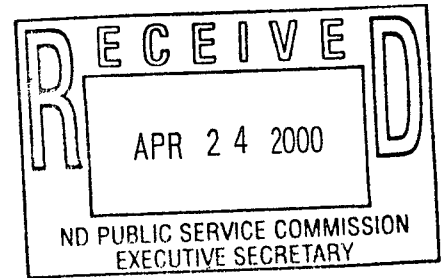
This application satisfies a requirement of the recently approved settlement involving Cases PU-400-98-246 and PU-400-99-418.

Please contact Dave Sederquist (701-241-8632) if you have any questions regarding this filing.

Sincerely,

Kent T. Larson
CEO & Managing Director, NSP-Dakotas

NORTH DAKOTA
PUBLIC SERVICE COMMISSION



Case No. PU-400-00-____

PROPOSAL OF
NORTHERN STATES POWER COMPANY
FOR A
PERFORMANCE-BASED REGULATION PLAN

I. INTRODUCTION

Pursuant to N.D.C.C 49.02.02 and N.D.C.C. 49.02.03, Northern States Power Company ("NSP" or "the Company") hereby petitions the North Dakota Public Service Commission ("NDPSC" or "Commission") to approve its performance-based regulation ("PBR") plan entitled *Performance Linking Utility Stakeholders* ("PLUS") for purposes of regulating NSP's electric operations in North Dakota ("NSP-ND"), subject to the jurisdiction of the Commission. The proposed PLUS Plan is an appropriate regulatory model for NSP because it provides benefits to customers and to North Dakota's economy which extend beyond traditional cost-based regulation, while at the same time ensuring that the Company's North Dakota electric operations have the opportunity to maintain financial strength.

The plan, as detailed below, sets a new course for North Dakota's regulatory environment by establishing a framework that provides appropriate economic signals for NSP to

pursue efficiency gains and improve customer service, and ensures that NSP's customers, communities, and shareholders share those gains over the long term.

The PLUS Plan as proposed satisfies the guidelines and other criteria established by the NDPSC and adopted on September 20, 1995, Case No. PU-439-94-590 (Attachment A).

II. PLAN SUMMARY

The NSP PLUS Plan will work better than traditional cost-based regulation to promote a balanced emphasis on utility efficiency, service quality, and economic development in North Dakota, while maintaining the customer protections provided by traditional regulation. As stated in a 1997 report entitled "Performance-Based Regulation in a Restructured Electric Industry" prepared on behalf of the National Association of Regulatory Utility Commissioners (NARUC), "PBR reshapes regulatory oversight of monopolies without eliminating the need for it." The PLUS Plan doesn't eliminate the need for regulatory oversight, but it offers a streamlined approach which emphasizes results, not processes.

KEY COMPONENTS

The key components of PLUS include 1) a dynamic "allowed ROE" range which can vary based on company performance, 2) a revenue sharing mechanism, 3) establishment of service performance standards, and 4) flexibility to adjust prices under specified circumstances. PLUS also promotes economic development by requiring a percentage of

shared revenues to be dedicated to economic development projects in the Company’s North Dakota service area.

CONSISTENT WITH RESTRUCTURING

As restructuring of the electric industry occurs, regulation will play a role in facilitating the transition to a more competitive environment. Regulation is intended to be a proxy for competition. For the utility services that will likely remain regulated, state regulation should, where possible, simulate the economic incentives found in competitive markets. In competitive industries, companies selling superior products and services at competitive prices generate and retain higher earnings. This motivates companies to improve their products and maximize efficiencies in order to increase shareholder value. In contrast, under traditional cost-based regulation, a utility that is innovative and aggressively managing costs can be subject to earnings investigations and rate reductions. This situation creates economic signals that are generally inconsistent with the competitive market model.

SHARING VALUE CREATION

The PLUS Plan recognizes that NSP’s North Dakota customers, the communities they live in, and the Company’s shareholders can all benefit from NSP’s success. PLUS aligns customer, community, employee and shareholder interests such that all share in the value created from superior company performance. If PLUS had been in place during that five year period from 1994 to 1998, NSP estimates that just over \$700,000 in net customer refunds would have been generated, and about \$300,000 would have been

available for North Dakota economic development. In addition, there would have been no need for the NDPSC to conduct the lengthy investigation of NSP’s 1997 earnings because PLUS would have provided revenue sharing automatically.

STREAMLINED REGULATION

As described in the NARUC report, a number of states have moved toward performance-based regulation over the last decade. The Commission policy statement encouraged the filing of such plans. The PLUS Plan would give North Dakota regulation a clear, pre-defined mechanism to pass the benefits of a financially healthy utility on to its stakeholders. Unlike traditional, cost-based regulation, which can be slow, litigious, and adversarial, the PLUS Plan offers an efficient, win/win approach to utility regulation. Moreover, this new regulatory model better simulates a competitive market by creating meaningful incentives which promote high quality service and low cost. As previously stated, PLUS places the regulatory focus more on *results* and less on process.

INVESTMENT IN NORTH DAKOTA

Since PLUS offers the Company the potential to achieve above-average returns on its North Dakota electric business, it will provide an additional incentive for investing more capital resources in North Dakota (other things being equal). NSP, like any for-profit business, seeks to achieve full potential on every investment dollar. The PLUS Plan creates additional reasons to invest limited company resources in North Dakota.

III. DESCRIPTION OF THE PLUS PLAN

The primary components of the PLUS Plan include:

- Dynamic authorized ROE bandwidth
- Revenue sharing
- Service performance standards
- Rate flexibility and caps
- Comprehensive regulatory reporting to allow monitoring

A brief description of each follows.

DYNAMIC AUTHORIZED ROE BANDWIDTH

In the PLUS Plan, NSP proposes an authorized baseline return on equity (ROE) of 12.0%, consistent with previous NDPSC rate settlements and the orders of certain other state jurisdictions. A range of plus or minus 1.0% around the baseline ROE is constructed to represent an “acceptable authorized range” or “deadband” of earnings performance. Actual returns which fall within this deadband would be considered reasonably close to the baseline, and would not trigger any revenue sharing or rate adjustments (see Attachment B).

The baseline ROE (and its corresponding deadband) are not static, but instead can be adjusted up or down by as much as 2.0% based upon NSP-ND’s service quality and employee safety performance (discussed later). For example, the baseline ROE could be decreased to as low as 10.0 % (with a corresponding deadband of 9.0% - 11.0%) or adjusted upward to a maximum of 14.0 % (with a corresponding deadband of 13.0% -

15.0%) depending on NSP’s ability to achieve certain levels of performance in four service quality measures.

The use of an ROE baseline and deadband (i.e., acceptable earnings range) serves two purposes. First, it is expected that a utility’s annual returns will fluctuate somewhat around the authorized ROE due to factors generally unrelated to company performance. Typically, minimal variances such as this do not prompt Commission rate investigations, and it would be burdensome and unnecessary to implement a customer refund or surcharge for every such fluctuation. The deadband eliminates immaterial and unnecessary rate adjustments when earnings are near authorized levels. Second, the moving authorized ROE baseline and deadband create a mechanism to link NSP’s *service performance to financial performance*.

In this manner, the achievement of high quality service and low prices would allow for (but not necessarily ensure) a higher level of authorized earnings. In other words, excellent performance would not guarantee higher earnings for NSP, but would increase the allowable return and thereby create the *opportunity* to retain more of the earnings that were achieved.

Conversely, poor quality electric service creates an economic disincentive as the company would be required to either compensate customers with a larger dividend (when earnings exceed the ROE deadband), or absorb a greater portion of an earnings deficiency, without the option of a future make-whole rate increase.

REVENUE SHARING

In the event that NSP-ND earnings exceed the ROE deadband, the associated revenues would be shared as follows:

- 45% is passed back to customers,
- 10% is dedicated to economic development in NSP-ND’s service area,
- 45% is retained by the Company.

Under PLUS, customers would receive their share in the form of an annual one-time credit (or, in the alternative, a ‘surcharge’) on their bill. The one-time credit would be issued in July of the year following the fiscal year under review, on a separate line on the bill entitled “Customer Dividend”. A notice in each customer’s monthly bill would alert them to refunds generated by the PLUS Plan. This would promote awareness among NSP’s customers of the Company’s performance as well as the goals of performance-based regulation in North Dakota.

To the extent NSP-ND earnings are below the allowed ROE deadband, the amount of the deficiency would be borne equally between the Company and its customers. In years requiring a surcharge, customers could be informed of factors (weather, storm costs, purchased power) which may have contributed to the Company’s lower than authorized earnings. As mentioned previously, recoveries to be collected from customers using a surcharge would be deferred one year to assess whether the surcharge could be offset or reduced with a dividend generated by the subsequent year’s performance. If the following year does not produce earnings and customer dividends sufficient to totally

offset the pending customer liability, only then will the remaining balance be charged to customers, during the second year following the fiscal earnings year.¹

Funds created through PLUS’s revenue sharing mechanism for promoting economic development in NSP’s North Dakota service area would be set aside by the company in a dedicated account, to be used for qualifying economic development programs and projects. By requiring that a portion of above-authorized earnings be set aside for cost-effective economic development projects in three of North Dakota’s four primary urban areas, the Commission can facilitate additional funding from NSP during periods of solid financial performance. Eligible economic development activities and the proposed rules for disseminating the funds are listed on Attachment C.

Should there remain a deferred surcharge balance at the conclusion of the PLUS Plan term, the amount will be recovered from customers within 24 months of the final PLUS plan year (unless the PLUS Plan is renewed for another term, in which case the balance will roll over into the renewal term).

SERVICE PERFORMANCE STANDARDS

The PLUS Plan takes a “comprehensive” approach to the utilization of performance measures and standards. In other words, under PLUS the focus will be primarily on maintaining or improving NSP’s *overall* performance in each of the areas of electric reliability, customer satisfaction, price, and promoting a safe work culture. By avoiding

¹ The Financial Accounting Standards Board (FASB) has issued an accounting order requiring utilities operating under a Performance Based Regulation plan to refund and/or recover from customers shared

the use of measures which are overly specific, the plan seeks to minimize management actions which are too narrowly focused.

The primary objectives of the performance component of the PLUS Plan are:

- 1) safeguard customers and employees from reduced service levels or working conditions which may result from the pursuit of short-term efficiency gains.
- 2) create a closer link between service performance and financial results; create rewards for superior performance and establish penalties for poor service, and
- 3) provide the Commission with the opportunity to authorize acceptable standards of performance, and establish a formal mechanism to monitor company performance relative to these standards.

In the PLUS Plan, NSP-ND's performance will be measured by four “macro measures” representing electric price, reliability, customer satisfaction and employee safety. These fundamental service areas are outlined specifically in Goal #3 of the NDPSC's Guidelines for Alternative Regulation Proposals (Attachment A, page 1). The macro-measures were designed to give a broad indication of the Company's performance in these categories, and contain the following attributes:

- The performance measures are understandable, used industry wide, and are representative of key factors defining value in the electric industry,
- The performance data is easily accessible and the related calculations objective, well-established, and easily audited,

revenues within 2 years of the fiscal period in which the revenues were originally recorded.

- The performance standards were derived using either industry data or recent NSP-ND performance results,
- The “macro-measures” can be supported/augmented by more specific, underlying measures and data.

In the PLUS Plan, ranges of ‘acceptable performance’ for each performance measure are established around a performance standard. The reason for this is analogous to the use of an allowed ROE deadband; the plan avoids over-reacting to expected but relatively insignificant variances from the established standard. Performance results which are outside of PLUS’s acceptable performance ranges will result in either an increase or decrease in the allowable ROE deadband.

Each of the four performance areas has the ability to slide the baseline ROE and bandwidth up or down by 50 basis points, or 0.5% ROE. The ROE impact of each measure is additive, meaning that it is possible for the combined effect on the baseline ROE of all four measures to be anywhere from –2.0 % to +2.0 %, in increments of 0.5%. A discussion of each performance measure follows.

Reliability The PLUS Plan measure for reliability is the average amount of time a typical NSP-ND customer is out of electric service during the entire year. The industry definition of this measure is the “System Average Interruption Duration Index”, or SAIDI. The average outage time is a product of both the frequency of outages on NSP’s

system, and the time it takes the Company to restore power when a customer outage has occurred.

Since it is difficult, if not impossible, to periodically compile consistent outage performance information from other electric utilities in a timely manner, the PLUS Plan reliability standard was developed using a five year (1994-1998) historical average of NSP’s company-wide distribution system outage results, averaged again with a five year (1994-1998) average of NSP-ND outage history². Using a combination of the mean, median, and adjusted 5 year average (i.e., excluding the extreme high and low years), a standard of 77.0 minutes was established (Attachment D, pages 1, 2). A bandwidth of acceptable performance was constructed around this standard by applying a +/- 15% factor to the standard, such that the award level is 65 minutes and the penalty threshold is 89 minutes. Achieving an average outage time for the year of less than 65 minutes per customer will generate a 0.5 % increase in the allowable ROE deadband. Conversely, an average outage time greater than 89 minutes per customer will generate a 0.5% *decrease* in the allowable ROE deadband (see Attachment D, pages 1, 2).

For purposes of this measure, an outage is defined as the inability to deliver power to a firm customer for a sustained period of time (> 5 minutes). Outages caused by storms or other statistically outlying factors beyond the company’s control are not included.³ This

² NSP-North Dakota historical outage data could not be used exclusively to establish the standard since not all NSP-ND outages were consistently recorded in the Company’s Distribution Dispatch System (“DDS”) computer files during the 1994-98 period. With the recent delivery process integration effort within NSP, outage tracking methods have been established in North Dakota are now consistent with those used in other company jurisdictions.

³ A “storm outage” is a mathematically determined event. When the number of outages recorded in a given day exceeds the daily average by 3 times the standard deviation, the day is considered a “storm day”, and

ensures that the measure is focused on outage causes that Company reliability efforts (or lack thereof) can have a meaningful impact on.

In 1999, NSP-ND’s annual average outage time per customer was 73.8 minutes, just under the proposed standard and within the acceptable performance bandwidth.

Price The PLUS Plan gauges NSP’s price performance by comparing NSP’s average North Dakota residential rate to a midwestern, seven state comparison group (see Attachment D, page 3). Residential rates are emphasized in this plan because residential consumers comprise the largest customer class, they generally have fewer competitive options, and comparisons of average commercial and industrial rates are sensitive to varying load profiles. By establishing a price standard for the residential group, the PLUS Plan promotes NSP-North Dakota rates that are more competitive than those offered by other utilities in our low-cost region. Unlike the other three performance measures, the price standard varies for each PLUS Plan year depending on changes in the regional electric “market” (comparison group). This ensures that NSP-ND’s residential rates must remain competitive over the term of the Plan.

The price measure is the average revenue per kWh sold for all residential customers, calculated by taking total annual revenues for the residential class and dividing by total residential kilowatt hours sold (Attachment D, page 4).

these outages are excluded. Currently, NSP’s daily average in ND is 3 outages. Any day with 16 or more outages is considered a storm day.

To determine the PLUS price standard for each year, the average revenue per kWh is compiled for each utility jurisdiction located within the states of North Dakota, South Dakota, Minnesota, Montana, Wisconsin, Iowa, and Wyoming. Then the average of all 28 jurisdictions is calculated. In 1998, the last calendar year data available, the comparison group average was 7.31¢ (see Attachment D, page 5). As with the reliability standard, a bandwidth of ‘acceptable performance’ is calculated by applying a +/- 15% factor to the standard. Exceeding this acceptable performance band would require rates among the lowest 4 or 5 service territories in the entire region. For 1998, the award level was 6.22¢ and the penalty threshold was 8.41¢. Hence, an average residential price of less than 6.22¢ would generate a 0.5 % increase in the allowable ROE deadband, and an average residential price greater than 8.41¢ would decrease the allowable ROE deadband 0.5% (using 1998 data).

In 1999 NSP’s average residential rate in North Dakota was 6.11¢, which is more competitive than the performance bandwidth established for 1998 (1999 data will be available shortly after this proposal has been filed).

Customer Satisfaction In 1998, NSP implemented random “relationship” surveys in all of its jurisdictions for residential, small business, and large commercial and industrial (C&I) customer classes to measure customer satisfaction relating to NSP’s energy prices, products and services. Three of the relationship surveys (as opposed to the Company’s “transaction” surveys, which query only those customers who have recently had direct contact with NSP employees in some form) conducted in North Dakota ask

customers to rate, among other things, the overall level of service they receive from NSP. Five response options are available to the survey participant: “Excellent”, “Very Good”, “Good”, “Fair”, or “Poor”. NSP tracks the percent of residential, small business, and large C&I respondents who submit a favorable score (i.e., the top three of the five choices). For purposes of obtaining a PLUS Plan customer satisfaction result, the three customer class survey scores are averaged together.

Because the survey has been conducted for all customer classes since only 1998, and there is little historical data to analyze, the PLUS Plan has established an ‘acceptable performance’ standard of 95.0% which is consistent with the target outlined in the Company’s “Pay for Performance” employee compensation plan (see Attachment D, page 6). A bandwidth of ‘acceptable performance’ is established (+/- 1.5% of the 95.0% standard) such that the award level would be a score higher than 96.5% and the penalty threshold is 93.5%. In other words, a positive response percentage higher than 96.5% would generate a 0.5 % increase in the allowable ROE deadband, while a result lower than 93.5% would generate a 0.5 % decrease in the allowable ROE deadband.

In 1999, customer responses were within the bandwidth, as the three survey scores averaged a 96.0% favorable response score.

Safety The fourth ‘macro-measure’ employed in the PLUS Plan performance component is the Occupational Safety and Health Administration (OSHA) Incident Rate. Employee safety has always been a high priority in the Company, as worker safety

impacts many operational, customer service, and financial results. Besides improving employees' quality of life, a safe work environment helps to improve productivity, enhance employee morale, improve public safety, and lower workers compensation and other costs. Including safety in the PLUS Plan performance component is consistent with Company priorities and helps ensure that employee safety continues to be valued objective of NSP and North Dakota regulation.

The OSHA Incident Rate, which is tracked and reported by all industries throughout the country, is essentially the number of medical incidences for every 100 employees which have occurred within an organization in a year. Medical incidences would include injuries requiring medical treatment (excludes basic first aid), restricted work day injuries, lost work day injuries, and fatalities.

To establish a safety standard for the PLUS Plan, data from the annual North Central Electric Association safety survey was used. Survey participation varies each year, but in general safety results for 7 to 10 member utilities in the upper Midwest are recorded. The average utility OSHA rate for the past five years was calculated (5.75) and established as the standard (see Attachment D, page 7). As with the reliability and price standards, an 'acceptable performance' bandwidth was created by applying a +/- 15% factor to the standard. The band of acceptable performance ranges from 4.90 to 6.60, meaning that the ROE baseline would be adjusted +0.5% for OSHA results lower than 4.90, or adjusted - 0.5% for OSHA results higher than 6.60.

In 1999, NSP-North Dakota electric employees achieved an unusually low 2.41 OSHA rate, which far exceeded the safety performance of other NCEA utilities used to establish the PLUS standard.

RATE FLEXIBILITY AND CAPS

The PLUS Plan guarantees that NSP’s electric rates will, adjusted for inflation, decrease over the term of the plan, and be more competitive than they were at the onset of the Plan. This is accomplished by incorporating both inflationary and ‘market price’ caps in the calculation of allowable rate change parameters. In addition, PLUS streamlines the regulatory process involved in changing rates.

Essentially, PLUS allows for the implementation of annual rate adjustments, subject to:

- 1) average % price changes of the ‘market’ comparison group,
- 2) % changes in the Consumer Price Index (adjusted by an efficiency target factor),
- 3) NSP-ND’s recently reported earnings levels, and
- 4) NSP-ND’s price position in the region.

These four factors work together each year to preclude or limit rate increases, or in certain circumstances, mandate rate *decreases*. Even when PLUS price cap factors allow NSP-ND to implement an increase, the Company needs to assess the impact of doing so, not only from the standpoint of how it affects customers but also with regards to the impact it has on the Company’s price performance standard. Increasing prices may,

eventually, result in an unfavorable financial signal from the PLUS Plan price performance component because the ROE bandwidth can be lowered.

Price Change Determinants The following four factors determine to what extent base rate changes can occur under the Plus Plan:

1. **Earnings Levels:** Under the PLUS Plan, if NSP’s final earnings in North Dakota exceed the ROE deadband, no rate increase is allowed in the following year, even if the inflation and comparison group price data support one. Conversely, under the PLUS Plan, price *reductions* called for by the CPI /comparison group price cap will not be imposed if NSP-ND’s earnings are within or below the allowed ROE deadband.
2. **Competitive Position:** Under the PLUS Plan, a rate increase will not be allowed if NSP’s average residential rate is higher than the comparison group average. Also, no decrease in rates will be required if NSP’s average rate is lower than the comparison group rate.
3. **Comparison Group Price Movement:** The annual change in average residential rates for the seven state comparison group is calculated and used as a cap on the increase that NSP-ND may implement (unless inflation is even lower – see item # 4). Should the group price decline, NSP-ND would be required to reduce its own rates accordingly (unless earnings were deficient or rates were already less than the comparison group average, as discussed in items #1, #2 above).
4. **Inflation and “Efficiency Target”:** To guarantee that NSP-ND rates decline in real terms over the PLUS Plan period, the annual rate of inflation as measured by the

Consumer Price Index (Urban) is factored into the price cap formula. The inflation rate is calculated for the given year and multiplied by 75% to reflect the company’s efficiency commitment⁴. If the result is lower than the average comparison group price change, it replaces the average group price change as the price cap (limiting factor) for any NSP-ND rate change (see Attachment F, page 9 for example with 1997 data).

In summary, any future NSP-ND rate increase is limited by the lower of 1) the change in residential rates for our seven state market, or 2) 75% of the rate of inflation (CPI).

Any proposed rate change implemented by NSP-ND would be reported to the NDPSC in the annual regulatory report on May 1 of the following year, and placed into effect beginning with July bills (i.e., at least 60 days after notice to the Commission). In addition, any rate change would default to an across-the-board adjustment to all customer classes, unless the Company requests and the Commission approves an alternative design by June 1 of the rate change year.

This type of rate flexibility avoids the burdensome process of developing, filing, and hearing a general rate case to obtain increases that may, in the final analysis, be in excess of what is allowed under PLUS’s price cap mechanism. With this approach, regulatory oversight shifts from litigation on whether costs are prudently incurred to an assurance

⁴ The “efficiency commitment” is similar to a productivity factor in that the price cap will always be less than inflation, ensuring that over time and adjusted for inflation, NSP-ND’s electric rates will decrease.

that rates are ‘competitive’, decreasing in real terms, recovering necessary costs of service, and representative of a ‘good energy value’.

IMPROVED REGULATORY REPORTING

The PLUS plan will improve regulatory reporting to the NDPSC through the addition of helpful information and the offering of an optional midyear performance report.

PLUS Plan Annual Reporting On or before May 1 of the year following the fiscal period being reviewed, NSP-ND shall file with the Commission a report showing:

1. NSP’s regulated electric earnings and return on equity (before and after any earnings sharing) in North Dakota for the fiscal year just completed;
2. Summaries of operating revenue, expense, and regulated electric rate base;
3. NSP’s regulated capital structure including debt and equity ratios, cost of capital, and return on rate base;
4. Calculation of baseline ROE and the authorized earnings bandwidth for the review year;
5. Annual results, awards, and penalties related to NSP-ND’s performance in reliability, price, customer satisfaction, and safety;
6. Amount of revenues subject to sharing, the ‘customer dividend’ or surcharge, and the economic development fund contribution;
7. Comparison group average residential rates for the year in review;
8. The calculation of the price-capping factors (CPI, comparison group rate changes);

9. Proposed rate change percentage and typical bill impact for all customer classes.

NSP's 1999 results were not available at the time of this filing. However, NSP will be able to develop a "mock" PLUS Plan report in May, 2000 for Commission review which will show its 1999 results as if PLUS had been in effect for the year. NSP-ND would submit these results by May 31, 2000.

Commission Review It is anticipated that upon receipt of the PLUS earnings report in May, the Commission would perform its annual review, per existing NDPSC rules. NDPSC Staff would examine the PLUS report for accuracy and, if necessary, submit information requests to NSP. A final report might be filed with the Commission as well. However, if none of the conditions for suspension of the plan apply, any refunds, charges, and/or proposed rate adjustments provided by the plan will go into effect on (and after) July 1.

The Commission or NSP-ND may pursue resolution of any questions or disputes concerning the calculations or data required by the plan. However, the Commission or NSP would not be allowed to change the accounting or allocation methodology in place at the onset of the PLUS Plan without agreement from the other party, nor could the Commission disallow any established expense or rate base items. Any new accounting or allocations proposed by NSP-ND or Commission Staff shall be subject to agreement by both parties and formal approval by the Commission.

Midyear Performance Reports If requested by NDPSC Staff, NSP-ND will file with the Commission by August 15 of each year a mid-year report showing the service performance results for the first six months of the current fiscal year. The purpose of this report would be to update the Commission and Staff of NSP-ND current performance and any emerging PLUS Plan issues prior to the yearend filing.

OTHER PLUS PLAN CONDITIONS

The following conditions of the PLUS Plan will also apply:

Plan Term The term of the Plan shall be for a period of 5 years, with calendar year 2001 results serving as the first full year of the Plan. After the first two years of the term have been completed, an informal hearing will be scheduled between the NDPSC, NSP, and any other interested parties to review the plan's performance and discuss potential improvements. It is anticipated that the NDPSC and the Company will continue to have open communication and constructive dialogue at all times during the plan term, and make general modifications or refine certain elements of the plan if necessary and mutually agreed upon.

Initial Rates Pursuant to the recent rate settlement approved by the Commission in Cases No. PU-400-98-246 and PU-400-99-418, NSP will implement a \$250,000 electric reduction on January 1, 2001, which is the effective start date of the proposed PLUS Plan.

A consideration of NSP’s projected cost increases indicates that any further adjustment to existing base rates is not necessary at this time. NSP-ND’s 1998 results were below the 12.0% benchmark, and additional investments the Company is making in North Dakota to install state-of-the-art metering equipment, combined with additional purchased capacity costs, increasing rate base investment and depreciation expense, and other O&M cost increases will result in even more demands on present revenues. In addition, NSP’s merger with NCE is not expected to yield savings in excess of the amortized costs to achieve for most of the Plan term.

NSP will need to work diligently to sustain a financially healthy North Dakota operation in 2001 and beyond. Under the PLUS Plan, if NSP-ND is successful in achieving earnings above authorized levels, dividends will be available for customers, communities, and the Company alike.

Fuel Clause Adjustment Mechanism NSP’s Fuel Clause Adjustment (“FCA”) will remain in effect during the PLUS term and operate as it does currently to adjust customer bills for fluctuations in fuel and purchased energy costs.

Demand Allocation Method For purposes of allocating production and transmission related revenues, costs, and investment, the PLUS Plan will continue to utilize average monthly electric peak demand data. However, NSP will use a historical 36 month period to compute the North Dakota jurisdictional allocator for annual regulatory reporting

purposes under PLUS⁵. This is consistent with methodology proposed by NDPSC Staff in its recent earnings audit report, and authorized by the FERC for allocations of generation and transmission costs shared between NSP and NSP(Wisconsin) under the Interchange Agreement. Use of a 36 month period would reduce the degree of annual fluctuations in allocated rate base, production and transmission expenses, and other revenues compared to using 12 months of peak demand data. In addition, this change will improve the Company’s ability to forecast its earnings in North Dakota, which is essential for accruing customer dividends in the proper fiscal year.

CONDITIONS FOR SUSPENSION/TERMINATION OF PLUS

The Commission or the Company may file a request at any time to temporarily suspend or terminate the PLUS Plan under any of the following conditions:

1. Actual ROE (before sharing adjustment) exceeds the ROE baseline by 500 basis points (5.0%) for two consecutive years;
2. Actual ROE (before sharing adjustment) is lower than the ROE deadband by 500 basis points (5.0%) for two consecutive years;
3. A material change in operations or earnings has occurred, or is anticipated to occur as a result of industry or corporate restructuring, significant changes in the wholesale power market, federal or state law change, FERC mandate, tax law changes, acts of God, or other material factors beyond the control of the Company.

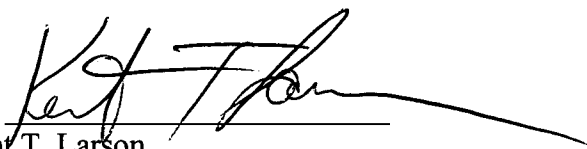
⁵ Implementation of a 36 month period for purposes of reporting earnings under PLUS does not establish a precedence for general ratemaking purposes. The NDPSC and NSP agree that a forecasted 12 month period will continue to be used to determine the Demand Allocator for NSP rate cases outside of the PLUS framework.

IV. CONCLUSION

For the foregoing reasons, NSP requests that the Commission find that the proposed PLUS Plan is in the public interest, and approve PLUS for purposes of regulating NSP's North Dakota electric operations for a five year period beginning January 1, 2001.

Respectfully Submitted,

NSP-North Dakota

By: 

Kent T. Larson

CEO and Managing Director, NSP-Dakotas

Dated: April 20, 2000

PUBLIC SERVICE COMMISSION

STATE OF NORTH DAKOTA

Public Service Commission
Incentive Regulation-Electric
Investigation

Case No. PU-439-94-590

GUIDELINES FOR FILING ALTERNATIVE REGULATION PROPOSALS

September 20, 1995

The Commission wants North Dakota consumers to receive reliable electric service at the lowest reasonable rates. To further that purpose, the Commission will consider proposals for alternative forms of regulation.

The Commission and interested parties have been meeting in workshop and public input settings to discuss different types of regulation for electric companies during the past several months. Based on those discussions, proposals should promote the following goals:

1. **Promote Utility Efficiencies:** Regulatory signals should encourage short and long term cost optimization, streamlined operating procedures, improved employee productivity, and increased pricing efficiency.
2. **Align Customer and Shareholder Interests:** Utilities and their customers should share in benefits obtained through improved efficiency and innovative techniques.
3. **Maintain/Improve Customer Service:** Safety, reliability, and customer service and satisfaction should be maintained or improved over current levels, and customers should experience lower, non-discriminatory rates than they would with the current regulatory framework.
4. **Allow Utilities to be Flexible:** Utilities must be able to respond to customers' specific needs.
5. **Minimize Regulatory Costs:** Regulation should focus more on results (overall performance) rather than processes and allow increased flexibility in management decisions. This will reduce the need for some filings, hearings, and other regulatory proceedings and enable utilities to respond more quickly and creatively to changing business conditions.

6. **Improve Public Participation:** Opportunities for public input should be enhanced.

Proposals should also meet the following criteria:

1. **Comprehensive:** Adopt plans that keep the focus on the overall economics of operating the utility and serving customers. The plans should also avoid potential for overemphasis on specific aspects of the utility operation.
2. **Administratively Simple:** Adopt plans that are straightforward, using easily measured data. Plans should include measurable and verifiable processes that avoid arguments by parties in assessing results to provide a basis for evaluating the success of the plan.
3. **Easily Communicated:** Adopt plans that utility employees understand so that actions to make improvements occur. The goal of alternative plans is to improve performance above the level that would have been achieved without the plan. It takes actions by utility employees to make this happen. Plans should also contain mechanisms that inform customers about plans and their benefits.
4. **Balanced:** Adopt plans that are symmetrical in terms of the rewards and penalties offered. In a competitive market, good performance is rewarded and poor performance is penalized.
5. **Flexible:** Adopt utility specific plans that provide flexibility both in terms of the ability to modify plans to improve effectiveness and in terms of the utility's ability to be responsive to customers in increasingly competitive situations.

The Commission would also like any proposals to reflect the following considerations:

1. That a utility should not assume that its existing rate base will be the base to which the alternative rate proposal will apply. The utility must show that the base rates--calculated on a cost-of-service basis--are just and reasonable at the start of the alternative mechanism.
2. That the proposal will be for a limited period of time and for an experimental purpose only. Each plan should include a review date and a rationale for that date. The Commission will consider the time period proposed in conjunction with the plan.
3. That during the period of the experiment, the plan will provide for a periodic review of the utility's profits by the Commission, which profits will be adjusted, if necessary, pursuant to criteria defined in the plan.

4. That the proposal will enable the Commission to judge the success of the experiment at its completion.
5. In adopting these guidelines, the Commission will not permit companies to violate the Territorial Integrity Act.

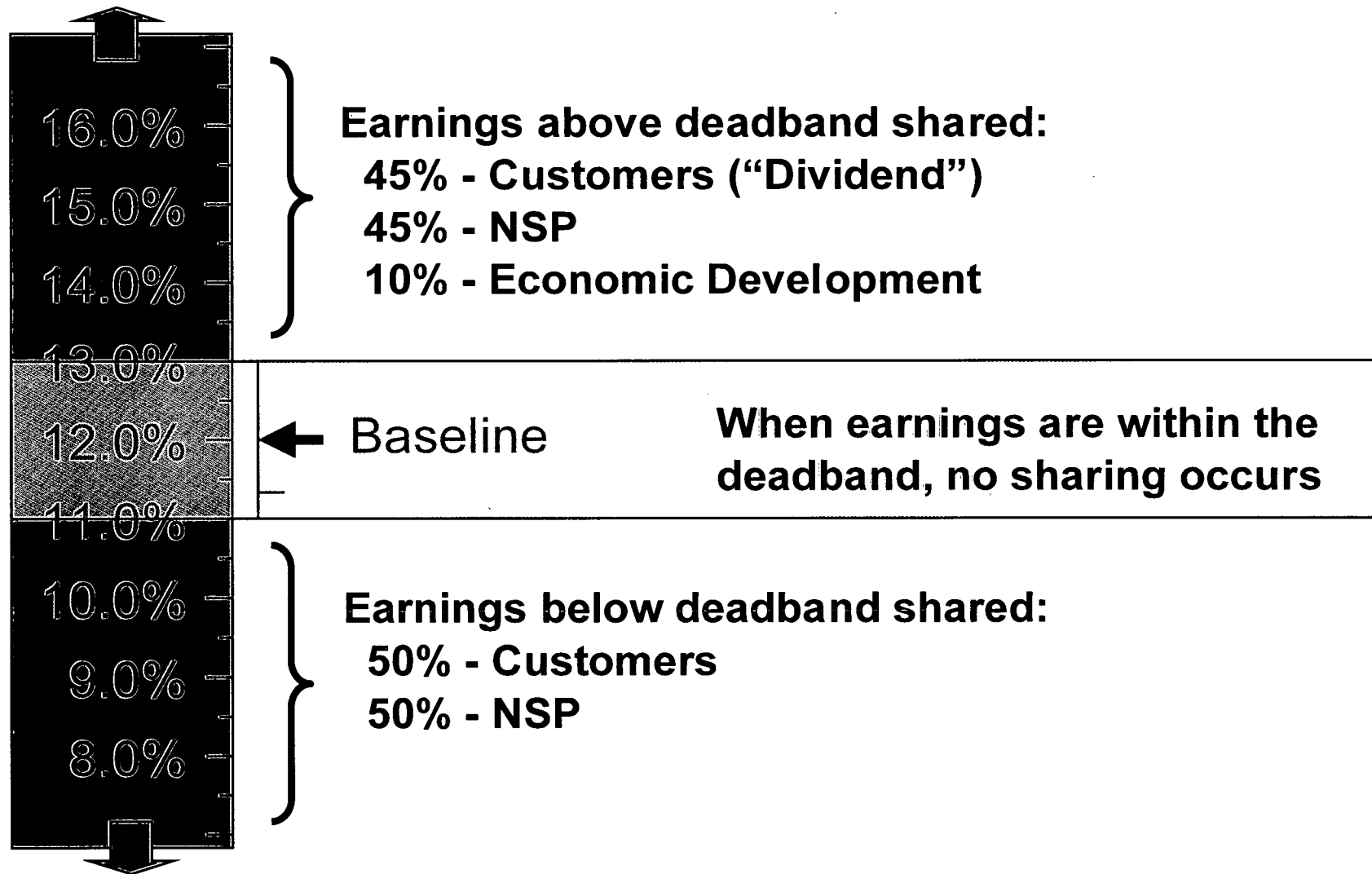
PUBLIC SERVICE COMMISSION

Bruce Hagen
Commissioner

Susan E. Wefald
President

Leo M. Reinbold
Commissioner

ROE Deadband



Northern States Power Co.
North Dakota Jurisdiction – Electric
PLUS Plan -- Economic Development Criteria

Economic Development

The following economic development programs/activities are examples of efforts which qualify for funds made available by earnings in excess of authorized levels under the PLUS Plan:

- Industrial park development (land purchases, infrastructure support, etc.)
- Technology parks (start-up funding, facilities support, etc.)
- Job development programs (promoting new businesses or expansions which create significant job growth)
- Marketing Assistance (trade shows, industry advertising, site location services)
- Renaissance Zone Corporation support
- Low interest loan pools
- Retention incentives and support (infrastructure, consulting services, higher education)
- Incubator buildings (house small business start-ups, entrepreneurial activities)
- Other items as mutually agreed to by NSP and the NDPSC

Criteria regarding use of funds:

1. Qualifying projects will be located within NSP electric territory, or will otherwise clearly benefit NSP customers through stable or lower rates.
2. Decisions regarding funded projects will be at the discretion of NSP management.
3. NSP's annual economic development expenditures will not be limited by amounts provided under the PLUS Plan funding mechanism.
4. An annual report to the North Dakota Public Service Commission will be filed showing expenditure amounts, recipients, purpose of expenditure, and estimated job creation and electric load impacts, where quantifiable.

**Northern States Power Company
North Dakota Jurisdiction - Electric
PLUS Plan Performance Standards**

Reliability

Measure: Average outage time per customer per year

Standard: Average of NSP(MN Co.) and NSP-ND's results from 1994 -1998,
or 77.0 minutes.

Acceptable range of performance: 65.0 minutes to 89.0 minutes (+/- 15%)

Price

Measure: Average residential electric rate per Kwh sold

Standard: Annual average of of midwest region utility comparison group,
which varies for each year of the plan term.

Acceptable range of performance: 115% to 85% of annual average (+/- 15%)

Customer Satisfaction

Measure: % of Customer survey responses that are favorable

Standard: NSP "Pay for Performance" employee compensation target, or 95.0%

Acceptable range of performance: 93.5% to 96.5% (+/- 1.5%)

Employee Safety

Measure: OSHA Incident Rate (annual safety incidents per 100 employees)

Standard: Average of NCEA utility group results from 1994 -1998, or 5..

Acceptable range of performance: 4.90 to 6.60 (+/- 15%)

**Northern States Power Company
"PLUS" Plan Performance Section
Reliability Standard**

Macro Measure: Outage time per customer

This is the amount of time that a typical customer was without power during the year.

This measure is commonly referred to as "SAIDI", or "System Average Interruption Duration Index". It is the product of two reliability indices (CAIDI, SAIFI) commonly monitored at NSP and throughout the utility industry.

$$\text{Outage time/customer} = \# \text{ of customer-hours interrupted} / \text{number of customers served}$$

The Performance Standard

A benchmark reliability standard will be developed using NSP(MN Co.) and NSP-ND average annual results for the five year period (1994-1998) just preceding the plan term. While SAIDI is an industry standard reliability measure, there are variations among utilities as to what constitutes an outage, how long an outage must last to be counted, and the process of normalizing outage data for weather. In addition, outage information is not readily accessible nor openly shared across the industry. A range of acceptable performance will be constructed by determining boundaries which are +/- 15% of the benchmark.

Historical Results (NSP MN Co.)

Storm-Normalized	
	SAIDI (Minutes)
1994	55.1
1995	100.8
1996	112.3
1997	101.4
1998	104.7
Average	94.9
Adjusted Average ²	102.3
Median	101.4
Lower Limit (85%)	85.0
Proposed Standard ³	100.0
Upper Limit (115%)	115.0

Historical Results (NSP-North Dakota)¹

Storm-Normalized	
	SAIDI (Minutes)
1994	49.7
1995	46.4
1996	49.7
1997	74.1
1998	54.9
Average	55.0
Adjusted Average ²	56.3
Median	49.7
Lower Limit	46.0
Proposed Standard ³	54.0
Upper Limit	62.0

Ave. of NSP Co. & ND Standards	
Lower Limit	65.0
Proposed Standard	77.0
Upper Limit	89.0

¹ ND outage tracking for 1994-98 not consistent with MN, Wisc., and SD jurisdictions; corrected in 1999.

² Excludes years with maximum and minimum results.

³ Reflects an average of each of the simple average, adj. Average, and median.

Northern States Power Company
"PLUS" Plan Performance Section
Price Comparison Utilities by State

Minnesota

Minnesota Power
Interstate Power
Otter Tail Power
Northern States Power

Wisconsin

Wisconsin Energy
NW Wisconsin Electric
Wisconsin Power & Light
Wisconsin Public Service
Northern States Power
Madison Gas & Electric

Montana

Black Hills Power & Light
Montana-Dakota Utilities
Montana Power

Wyoming

PacifiCorp
Montana-Dakota Utilities
Black Hills Power & Light
Cheyenne Light, Fuel, & Power

Iowa

MidAmerica Energy
IES Utilities
Interstate Power

South Dakota

Montana-Dakota Utilities
Otter Tail Power
Northern States Power
Northwest Public Service
Black Hills Power & Light

North Dakota

Montana-Dakota Utilities
Otter Tail Power
Northern States Power

**Northern States Power Company
"PLUS" Plan Performance Section
Price Standard**

Macro Measure: Average Residential Revenue per kWh

This measure determines an average price per kilowatt-hour of electricity

The measure focuses on residential rates since residential customers may likely have fewest competitive energy options.

Avg. Price = Total NSP-ND residential revenues / total residential kWh sales

The Performance Standard

A benchmark residential price standard will be developed using a 7 state, 28 jurisdiction comparison group of 18 investor-owned utilities. The average revenue per kWh will be computed for each utility in each state from data collected and published by EEI two times each year. The PLUS plan benchmark will be the average revenue/kWh for the entire group for each given year of the PLUS term. A range of acceptable price performance will be constructed by determining boundaries which are +/- 15% of the benchmark, or roughly the 2nd and 3rd quartile of the comparison group.

EEI Comparison Group Results

	Hi-Perf. <u>Level</u>	Average <u>¢/kWh</u>	Lo-Perf. <u>Level</u>
1994	5.98	7.03	8.08
1995	5.95	7.00	8.05
1996	5.97	7.02	8.07
1997	6.05	7.12	8.19
1998	6.22	7.31	8.41

* Has both extreme upper and lower years removed.

Utility Comparison Group Average Residential Revenue/Kwh

IOU's in North Dakota, South Dakota, Montana, Wyoming, Minnesota, Iowa, Wisconsin

<u>1998</u> <u>Rank</u>	<u>Utility</u>	<u>Jurisdiction</u>	<u>1998</u> <u>¢/kwh</u>	<u>1997</u> <u>¢/kwh</u>	<u>%</u> <u>Change</u>
1	Cheyenne Light, Fuel, & Power	Wyom	5.66	5.87	-3.6%
2	Pacificorp	Wyom	5.73	5.67	1.1%
3	NSP	ND	6.07	5.86	3.6%
4	Ottertail Power Co.	ND	6.09	6.02	1.2%
5	Wisc. Public Service	Wisc.	6.28	6.39	-1.7%
6	Ottertail Power Co.	SD	6.30	6.22	1.3%
7	Ottertail Power Co.	MN	6.56	6.42	2.2%
8	Montana Power Co.	Mont	6.58	6.44	2.2%
9	Wisconsin Power & Light (Alliant)	Wisc.	6.72	6.73	-0.1%
10	Minnesota Power	MN	6.77	6.61	2.4%
11	Montana-Dakota Utilities	ND	6.90	6.86	0.6%
12	NSP	Wisc.	7.10	7.00	1.4%
13	Black Hills Power & Light	Mont	7.22	7.67	-5.9%
14	Montana-Dakota Utilities	Wyom	7.29	7.16	1.8%
15	Montana-Dakota Utilities	Mont	7.41	7.40	0.1%
16	Northwest Public Service	SD	7.45	7.35	1.4%
17	NW Wisconsin Electric	Wisc.	7.62	7.23	5.4%
18	NSP	SD	7.66	7.60	0.8%
19	Wisconsin Energy Co.	Wisc.	7.79	7.08	10.0%
20	Madison Gas & Elec	Wisc.	7.81	7.69	1.6%
21	Black Hills Power & Light	Wyom	7.84	7.81	0.4%
22	NSP	MN	7.89	7.87	0.3%
23	Black Hills Power & Light	SD	8.28	8.24	0.5%
24	Interstate Power Co.	Iowa	8.55	7.78	9.9%
25	Interstate Power Co.(Alliant)	MN	8.62	8.52	1.2%
26	IES Utilities (Alliant) ¹	Iowa	8.73	8.73	0.0%
27	MidAmerican Energy	Iowa	8.88	8.83	0.6%
28	Montana-Dakota Utilities	SD	8.96	8.87	1.0%
29	Average residential rate (¢/kwh):		7.31	7.21	1.41%

Source: Typical Residential, Commercial, and Industrial Bills, Edison Electric Institute.

Winter, 1999

¹ Reflects consolidated IES rates in Iowa (IA Elec P&L, IA Southern Utilities); 1997 average for consolidated not available, so 1998 price used.

Northern States Power Company
"PLUS" Plan Performance Section
Customer Satisfaction Standard

Macro Measure: "Excellent", "Very Good", or "Good" Response %

This is the average % of responses which were positive in nature (top 3 responses in a 5 option answer) from a survey question relating to NSP's overall quality of products, services, and support in the State of North Dakota. The "relationship" surveys are conducted twice annually for the residential, small commercial, and large commercial and industrial customer classes. The result for each class is averaged into one score.

The results used will be for the question: "Thinking again of your entire relationship with NSP, would you rate the overall quality of products, services, and support you receive from NSP as 'excellent', 'very good', 'good', 'fair', or 'poor'?" (Q 8.2)

The Performance Standard

A benchmark customer satisfaction survey standard will be developed by using the targets established for NSP's internal "Pay for Performance" compensation plan as the basis for the acceptable performance range. A score exceeding 96.5% will increase NSP's allowable earnings, while a score below 93.5% will reduce the level of allowed earnings.

Past Results

	<u>Res'l</u>	<u>Small C&I</u>	<u>Large C&I</u>	<u>Average</u>
1998	96.0%	97.0%	99.0%	97.3%
1999	96.0%	94.0%	98.0%	96.0%

Northern States Power Company
"PLUS" Plan Performance Section
Safety Standard

Macro Measure: OSHA Incident Rate

This is the average number of OSHA incidences occurring per 100 electric employees.

OSHA incidences include medical treatment cases, restricted work day injuries, lost workday injuries, and fatalities. Only NSP-ND results will be counted.

OSHA = # of incidences X 200,000 hours / number of labor hours worked

The Performance Standard

A benchmark OSHA rate will be developed using the average annual OSHA results for all of the utilities participating in a NCEA safety survey. About 7-10 midwestern utilities submit their safety results each year. An average of the annual results from 1994-1998 constitutes the PLUS plan benchmark. A range of acceptable performance will be constructed by determining boundaries which are +/- 15% of the benchmark.

Utilities Surveyed: Black Hills Power & Light, Interstate Power, Midwest Power Systems, Minnesota Power, Montana-Dakota Utilities, NW Public Service, Otter Tail Power, Superior Water, Light & Power, Iowa-Illinois Gas & Electric, MidAmerican Energy, NSP.

NCEA Results

	<u>OSHA</u>
	<u>Index</u>
1994	3.37
1995	6.12
1996	6.46
1997	5.68
1998	5.92
Average	5.41
Adj. Ave. ¹	5.91
Median	5.92
Lower Limit	4.90
Proposed Standard ²	5.74
Upper Limit	6.60

¹ Excludes years with maximum and minimum results.

² Reflects an average of each of the simple average, adj. Average, and median.

PU-400-00-195; PU-401-00-36

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92 7-24-00
- C. Signature
X [Signature] ☐ Agent ☐ Addressee
- D. Is delivery address different from item 1? ☒ Yes
If YES, enter delivery address below: ☐ No

P.O. Box 2747
Fargo ND 58108

3. Service Type
☒ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? (Extra Fee) ☐ Yes

2. Article Number (Copy from service label)

7099 3220 0002 8476 8333

PS Form 3811, July 1999

Domestic Return Receipt

102595-99-M-1789

PU-400-00-195; PU-401-00-36

SENDER: COMPLETE THIS SECTION

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
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1. Article Addressed to:

Dave Sederquist
NSP
2302 Great Northern Dr
Fargo ND 58102

COMPLETE THIS SECTION ON DELIVERY

- A. Received by (Please Print Clearly) B. Date of Delivery
92 7-24-00
- C. Signature
X [Signature] ☐ Agent ☐ Addressee
- D. Is delivery address different from item 1? ☒ Yes
If YES, enter delivery address below: ☐ No

P.O. Box 2747
Fargo ND 58108

3. Service Type
☒ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? (Extra Fee) ☐ Yes

2. Article Number (Copy from service label)

7099 3220 0002 8476 8340

PS Form 3811, July 1999

Domestic Return Receipt

102595-99-M-1789

PU-400-00-195; PU-401-00-36

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1. Article Addressed to:

Bernadine Bruttay
NSP
215 S Cascade St
Fergus Falls MN 56538-0496

COMPLETE THIS SECTION ON DELIVERY

- A. Received by (Please Print Clearly) B. Date of Delivery
JUL 24 2000
- C. Signature
X [Signature] ☐ Agent ☐ Addressee
- D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

3. Service Type
☒ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? (Extra Fee) ☐ Yes

2. Article Number (Copy from service label)

7099 3220 0002 8476 8357

PS Form 3811, July 1999

Domestic Return Receipt

102595-99-M-1789

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- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Dave Lederquist
Northern States Power Company
2302 Great Northern Dr
Fargo ND 58102

2. Article Number (Copy from service label)

7000 0520 0022 8653 3331

PS Form 3811, July 1999

Domestic Return Receipt

102595-99-M-1789

COMPLETE THIS SECTION ON DELIVERY

A. Received by (Please Print Clearly)

B. Date of Delivery
1-3-01

C. Signature

X *[Signature]*

☐ Agent

☒ Addressee

D. Is delivery address different from item 1? ☐ Yes

If YES, enter delivery address below: ☐ No

Colleen Samma
P.O. Box 2747
Fargo ND 58108

3. Service Type

☒ Certified Mail

☐ Express Mail

☐ Registered

☐ Return Receipt for Merchandise

☐ Insured Mail

☐ C.O.D.

4. Restricted Delivery? (Extra Fee)

☐ Yes

SENDER: COMPLETE THIS SECTION

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- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Kent Larson
Northern States Power Company
2302 Great Northern Dr
Fargo ND 58102

2. Article Number (Copy from service label)

7000 0520 0022 8653 ~~3331~~ 3324

PS Form 3811, July 1999

Domestic Return Receipt

102595-99-M-1789

COMPLETE THIS SECTION ON DELIVERY

A. Received by (Please Print Clearly)

Nancy Freiss

B. Date of Delivery

1-3-01

C. Signature

X *[Signature]*

☐ Agent

☒ Addressee

D. Is delivery address different from item 1? ☐ Yes

If YES, enter delivery address below: ☐ No

3. Service Type

☐ Certified Mail

☐ Express Mail

☐ Registered

☐ Return Receipt for Merchandise

☐ Insured Mail

☐ C.O.D.

4. Restricted Delivery? (Extra Fee)

☐ Yes

SENDER: COMPLETE THIS SECTION

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- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Kent Larson
Northern States Power Company
2302 Great Northern Dr
Fargo ND 58102

2. Article Number (Copy from service label)

7000 0520 0022 8654 0070

PS Form 3811, July 1999

Domestic Return Receipt

102595-99-M-1789

COMPLETE THIS SECTION ON DELIVERY

A. Received by (Please Print Clearly)

Connie Bachmeier

B. Date of Delivery

1-16-01

C. Signature

X *[Signature]*

☐ Agent

☒ Addressee

D. Is delivery address different from item 1? ☐ Yes

If YES, enter delivery address below: ☐ No

3. Service Type

☒ Certified Mail

☐ Express Mail

☐ Registered

☐ Return Receipt for Merchandise

☐ Insured Mail

☐ C.O.D.

4. Restricted Delivery? (Extra Fee)

☐ Yes

PU-400-00-195

SENDER: COMPLETE THIS SECTION

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Dave Sederquist
Northern State Power Company
2302 West Northern Dr
 Fargo ND 58102

2. Article

PS Form

COMPLETE THIS SECTION ON DELIVERY

A. Received by (Please Print Clearly) B. Date of Delivery
Connie Bachmeier -1/6/01
 C. Signature ☐ Agent ☒ Addressee
x Connie Bachmeier
 D. Is delivery address different from item 1? ☐ Yes
 If YES, enter delivery address below: ☐ No

3. Service Type

- ☒ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? (Extra Fee)

☐ Yes

595-99-M-1789

PU-400-00-195

SENDER: COMPLETE THIS SECTION

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Bernadeen Brattley
Athen Sail Power Company
215 S Cascade St
Fergus Falls MN 56538-0696

2. Article Number (Copy from service label)

7000 0520 0022 8654 0094

PS Form 3811, July 1999

Domestic Return Receipt

102595-99-M-1789

COMPLETE THIS SECTION ON DELIVERY

A. Received by (Please Print Clearly) B. Date of Delivery
Dot Baker JAN 16 2001
 C. Signature ☐ Agent ☒ Addressee
x Dot Baker
 D. Is delivery address different from item 1? ☐ Yes
 If YES, enter delivery address below: ☐ No

3. Service Type

- ☒ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? (Extra Fee)

☐ Yes

Public Input



Public Service Commission

State of North Dakota

600 E Boulevard Ave. Dept. 408
Bismarck, North Dakota 58505-0480
e-mail: sab@oracle.psc.state.nd.us
TDD 800-366-6888
Fax 701-328-2410
Phone 701-328-2400

COMMISSIONERS

Bruce Hagen
President
Susan E. Wefald
Leo M. Reinbold

Executive Secretary
Jon H. Mielke

January 3, 2001

Mark Sherman
1832 Sixth Street SW
Minot, ND 58701

Dear Mr. Sherman:

Enclosed please find a copy of the recent Commission Order on the Northern States Power Performance Based Regulation Plan and a copy of the plan.

We appreciated your thoughtful comments on this proceeding. They did make a difference. The Commission considered your comments and was able to incorporate your ideas in our final order.

If you have any questions about the performance based regulation plan that is in place starting January 1, 2002, for NSP, please call us. Also, for others who may be interested, the Commission will post the NSP order and plan on our website in the near future. The Public Service Commission website address is <http://www.psc.state.nd.us>

Sincerely,


Susan E. Wefald
Commissioner

Enclosures

**STATE OF NORTH DAKOTA
PUBLIC SERVICE COMMISSION**

**Northern States Power Company
Performance Based Regulation
Application**

Case No. PU-400-00-195

FINDINGS OF FACT, CONCLUSIONS OF LAW AND ORDER

December 29, 2000

Appearances

Commissioners Bruce Hagen, Leo M. Reinbold, Susan E. Wefald.

James P. Johnson, Assistant General Counsel, Xcel Energy Services Inc., 800 Nicollet Mall, Minneapolis, MN 55402, appearing on behalf of Northern States Power Company d/b/a Xcel Energy.

William W. Binek, Chief Counsel, Public Service Commission, State Capitol, 600 East Boulevard, Bismarck, ND 58505, appearing on behalf of the Public Service Commission Staff.

Allen C. Hoberg, Administrative Law Judge and Director, Office of Administrative Hearings, 1707 North 9th Street - Lower Level, Bismarck, ND 58501-1882, appearing as procedural Hearing Officer.

Preliminary Statement

On April 20, 2000 Northern States Power Company (NSP or Company) filed an application for approval of a Performance-Based Regulation (PBR) plan for purposes of regulating NSP's retail electric operations in North Dakota. NSP termed its plan the Performance Linking Utility Stakeholders (PLUS) plan. NSP proposes the plan be in effect for a five year term from January 1, 2001 to December 31, 2005. If approved, the plan would create an alternative form of regulation for NSP's electric operations in North Dakota. NSP asserts the proposed plan would comply with the Commission's Guidelines for Filing Alternative Regulation Proposals issued September 20, 1995 in Case No. PU-439-94-590.

On July 19, 2000, the Commission issued a "Notice of Hearing and Notice of Public Discussion Meeting" in the instant case and in Case No. PU-401-00-36, a case involving a similar PBR plan filed by Otter Tail Power Company (Otter Tail). The notice scheduled a public discussion meeting for September 6, 2000 and public hearings for October 23-24, 2000. The notice set forth the following issues to be considered:

1. Are the plans consistent with Commission guidelines?
2. Would the plans result in quality service and reasonable electric rates?
3. Would the plans support safe and reliable electric infrastructure and the financial viability of the utilities?
4. Would implementing the plans be in the public interest?

On September 6, 2000, the Commission conducted a public discussion meeting as scheduled, with public participation available through ten video conference sites at Belcourt, Bismarck, Bottineau, Devils Lake, Fargo, Fort Totten, Grand Forks, Jamestown, Minot and Wahpeton, North Dakota. Any written comments received from members of the public during the course of the proceeding were filed in the public input file in this case.

On October 23-24, 2000, the Commission conducted public hearings as scheduled. At the conclusion of the hearings, the Hearing Officer required the parties to submit briefs and proposed findings of fact and conclusions of law by December 1, 2000. Alternatively, in lieu of briefs, NSP and Staff were permitted to submit a settlement agreement resolving the disputed issues.

On November 20, 2000, the Commission held an informal working session to discuss NSP's proposal. On November 29, 2000, NSP and Staff submitted a settlement agreement. The Commission held a second informal working session to discuss the agreement on December 1, 2000. On December 8, 2000 NSP and Staff filed an amendment to the settlement agreement and the Commission held additional working sessions to discuss the amendment on December 11 and 15, 2000. Following those working sessions, NSP and Staff submitted a revised settlement agreement on December 28, 2000.

Discussion

On September 20, 1995, after numerous workshops with industry and other interested parties, the Commission issued "Guidelines for Filing Alternative Regulation Proposals" (Guidelines) in Case No. PU-439-94-590. The Guidelines indicated the Commission would consider proposals for alternative forms of regulation from traditional "cost-based rate of return" regulation. The Guidelines set forth both goals and criteria for alternative regulation proposals, which include:

- Goals: a plan should (1) promote utility efficiencies; (2) align customer and shareholder interests; (3) maintain/improve customer service; (4) allow utilities to be flexible; (5) minimize regulatory costs; and (6) improve public participation.
- Criteria: a plan should be (1) comprehensive; (2) administratively simple; (3) easily communicated; (4) balanced; and (5) flexible.

- The guidelines indicated that any proposal (1) must show the utility's base rates are just and reasonable at the start of the alternative mechanism; (2) should be for a limited period of time, and include a review date; (3) provide for a periodic review of the utility's profits pursuant to criteria in the plan; (4) enable the Commission to judge the success of the plan at its completion; and (5) must not violate the Territorial Integrity Act.

Findings of Fact

1. NSP is a Minnesota corporation providing electric and natural gas public utility service in North Dakota. NSP and its predecessor ("Old NSP") have continuously provided electric public utility service in North Dakota pursuant to authorizations provided by North Dakota law or issued by the Commission. NSP provides retail electric service under Commission jurisdiction in the communities of Fargo, Grand Forks, Minot, West Fargo, Berthold, Burlington, Buxton, Des Lacs, Hatton, Larimore, Mayville, Portland, Reynolds and Thompson, North Dakota, and certain surrounding areas.
2. NSP is a utility operating company subsidiary of Xcel Energy Inc., which was created by the merger of Old NSP and New Century Energies, Inc. on August 18, 2000. Xcel Energy Inc. is a registered holding Company subject to the jurisdiction of the U.S. Securities and Exchange Commission ("SEC") under the Public Utility Holding Company Act ("PUHCA
3. NSP's application for approval of its PLUS plan was filed pursuant to a settlement agreement between NSP and Commission staff (Staff) in Case Nos. PU-400-99-418, an application requesting approval of NSP's merger with New Century Energies, Inc., and PU-400-98-246, a Staff investigation of NSP's electric earnings. This prior settlement agreement was approved by a May 10, 2000 Commission Order in those dockets.
4. The key components of NSP's PLUS plan include 1) a "dynamic allowed ROE" range which can vary based on Company performance, 2) a revenue sharing mechanism, 3) establishment of service performance standards, and 4) price capping flexibility to adjust prices under specified circumstances.
5. NSP proposes to implement its plan for the period January 1, 2001 to December 31, 2005. The Commission finds this term will allow sufficient time to evaluate operations under this alternative regulation plan.
6. The annual performance and financial reporting provisions of the plan, as modified by the revised settlement agreement, are reasonable. The interim review proposed for June 2003 is reasonable and consistent with the Guidelines.

7. Concurrently and independently with plan implementation, NSP will reduce non-fuel base retail electric rates to NSP's North Dakota electric service customers by \$261,000 annually (approximately 0.25%), pursuant to the Commission order dated May 10, 2000, in Case Nos. PU-400-99-418 (Merger with New Century Energies, Inc.) and PU-400-98-246 (Electric Rate Investigation). The Commission finds this rate adjustment results in just and reasonable initial rates at the time the plan is initiated.

8. The proposed baseline Return on Equity ("ROE") of 12.0%, the ROE deadband of +/- 1.0% around the baseline, and the annual dynamic ROE adjustments in terms of "basis points," subject to NSP's performance under each performance standard, are reasonable. The baseline ROE is comparable to the ROE used to resolve utility earnings investigations over the past few years, and the +/- 1% deadband is within a zone of reasonableness.

9. The proposed revenue sharing mechanism, as modified by the revised settlement agreement, is reasonable. This mechanism provides:

If NSP's reported actual earnings fall within the ROE deadband around the authorized ROE (as adjusted by the performance points) in a plan year, no revenue sharing will take place.

If NSP's actual reported earnings for any plan year exceed the deadband, the corresponding revenue 'sufficiency' will be calculated, and 50% of this dollar amount will be refunded to customers during the July billing cycle of the following year. Customers of record on March 31 following the Plan year will be issued refunds by bill credit prorated on the basis of their electric usage for the twelve months ending March 31.

If NSP's actual reported earnings for any plan year are below the deadband, 50% of the corresponding revenue "deficiency" may be recovered through a surcharge on NSP's electric rates effective no later than 24 months after the Plan year. However, NSP has agreed to defer recovery of a reported fiscal year deficiency by recording the amount as a regulatory asset until the following plan year revenue sharing amount, if any, is reported. If the prior year deficiency is fully offset by the current year reported revenue sufficiency, the sufficiency will be used to eliminate the regulatory asset, and no rate surcharge will be imposed. If the deficiency from the prior year is not fully offset, any remaining deficiency balance may be reflected in rates applicable to bills issued between the 18th and 24th month following the plan year when the deficiency occurred, subject to the Rate Change procedures described herein.

10. Treatment of NSP's economic development expenditures as a jurisdictional expense for financial reporting purposes is reasonable. This will provide greater consistency in treatment of this cost component between the NSP and Otter Tail plans.

11. The proposed reliability performance measures and standards, as modified by the revised settlement agreement, are reasonable. The Customer Average Interruption Duration Index (CAIDI) and System Average Interruption Frequency Index (SAIFI) are individual reliability measures widely used in the electric utility industry, the product of which is the System Average Interruption Duration Index (SAIDI) reliability measure originally proposed by NSP. By using both component standards, NSP will be measured on both the frequency of customer outages and the time it takes to restore power. Each measure will carry a potential reward or penalty of a 25 basis point adjustment to the authorized ROE deadband.

12. The proposed customer satisfaction performance measures, as modified by the revised settlement agreement, are reasonable. NSP will be measured based on both the relationship surveys for all three customer classes (Residential, Commercial, Large Industrial), and two transaction surveys relating to NSP's call center and electric service functions. The survey results will reflect the percentage of respondents who give NSP an 'excellent' or 'very good' rating. Each of the two survey standards will carry a potential reward or penalty of a 25 basis point adjustment to the authorized ROE deadband.

13. The proposed pricing measures and standards, as modified by the revised settlement agreement, are reasonable. NSP will be measured by 1) its average residential price per kWh compared to the 26 jurisdiction mid-western utility peer group; and 2) the annual change in average residential price relative to the change for the lowest priced utility in the peer group. The price measures will be calculated annually based on utility price data compiled in the Edison Electric Institute's "Typical Bills and Average Rate Report" for the 12 month period ending December 31st. Each of the two price measures will carry a potential reward or penalty of a 25 basis point adjustment to the authorized ROE deadband.

14. The proposed employee safety measure and standards, are reasonable. To be consistent with the other individual plan standards, it is appropriate that the employee safety measure carry a potential reward or penalty of a 25 basis point adjustment to the authorized ROE deadband.

15. The proposed price cap factor, as modified by the revised settlement agreement, is reasonable. The price cap factor will be the lower of 1) the annual percentage change in the utility peer group's average residential price per kWh for the reporting year, or 2) 60% of the change in the Consumer Price Index (CPI) for the reporting year.

16. The proposed rate change criteria, as modified by the revised settlement agreement, are reasonable. The plan imposes an electric rate freeze on NSP whenever: 1) its previous year reported ROE was higher than 100 basis points below the baseline ROE (as adjusted for performance), or 2) NSP's average residential rates were higher than the utility peer group average residential rate. If neither condition exists, then NSP may increase its electric rates by an overall percentage not to exceed the price cap factor, subject to the rate change procedures of the plan.

17. The proposed rate decrease criteria, as modified by the revised settlement agreement are reasonable. It is appropriate that NSP be required to reduce its retail electric rates under the plan if: 1) NSP's reported ROE for the plan reporting year was more than 100 basis points above the baseline ROE (as adjusted for performance), 2) NSP's average residential rates are higher than the PLUS utility peer group average residential rate, and 3) the price cap factor is negative.

18. The proposed rate change procedure described in the revised settlement agreement is reasonable and consistent with state law. To implement any permissive rate change or mandatory rate reduction, NSP must file a notice of rate change and accompanying tariffs under N.D.C.C. § 49-05-05 after submission of the plan year performance report on May 1 but at least 30 days before the effective date of the proposed rates (July 1).

19. The revised settlement agreement contemplates that any notice of rate change filed under the plan will not be suspended by the Commission under N.D.C.C. § 49-05-06, but the revised rates would be allowed to go into effect on the date proposed. The plan allows the Commission to order a one-time billing "true up" if the Commission determines, after hearing, that the notice of rate change filed by NSP was not reflective of the plan results or requirements.

20. The Commission agrees that rates established consistent with the plan are presumed just and reasonable, and non-discriminatory. The Commission also appreciates that the revised settlement agreement provides an ability to require billing true-ups as an alternative to suspending rate changes. However, the Commission's statutory authority and responsibility to suspend rate filings when it is necessary and appropriate to do so cannot be contracted away. Further, this Commission cannot act to bind a future Commission. Therefore, the Commission does not approve the Section 4.D. Rate Change Procedure of the revised settlement agreement to the extent that section is inconsistent with this finding.

21. Any increases or decreases in costs of electric service caused by governmentally imposed changes in taxes or accounting practices will be implemented within 60 days of the effective date of the change.

22. Use of 36 months of historic demand data for purposes of annual plan financial reporting is reasonable because it will mitigate volatility in the jurisdictional allocation factor. The use of a 36 month jurisdictional demand allocator is only for financial reporting purposes under the plan and has no precedential effect in future electric rate proceedings after the plan term expires or the plan is suspended or terminated.

23. The plan procedures for suspension or termination of the plan during the five year term are reasonable because they provide protections for both North Dakota electric customers and NSP. As provided by the revised settlement agreement, NSP

may request, or the Commission may on its own motion initiate a proceeding, to suspend or terminate the Plan prior to December 31, 2005 in the event of:

- Passage of retail access legislation at either the federal or state level;
- Merger and acquisition events affecting NSP's structure and operations;
- Natural disasters affecting NSP's North Dakota electric operations (major storms, floods, etc.);
- Unusual events affecting NSP's operations (major generating plant failure, damage to major transmission or distribution lines, etc.); or
- Material and sustained earnings extremes (defined as returns on equity +/- 5.0% from the ROE deadband, prior to sharing).

24. The plan is consistent with Commission guidelines.

25. The plan promotes quality service and reasonable electric rates.

26. The plan promotes safe and reliable electric infrastructure and the financial viability of the utility.

27. Implementing the plan is in the public interest.

From the foregoing Findings of Fact, the Commission makes its:

Conclusions Of Law

1. The Commission has jurisdiction over the parties and the subject matter of this proceeding.

2. For purposes of initial plan implementation, NSP's recently adjusted electric rates effective January 1, 2001 are just and reasonable and non-discriminatory.

3. Rates established consistent with the plan during the plan term are appropriately presumed just and reasonable and non-discriminatory.

4. The plan promotes quality service and reasonable electric rates.

5. The plan promotes safe and reliable electric infrastructure and the financial viability of the utility.

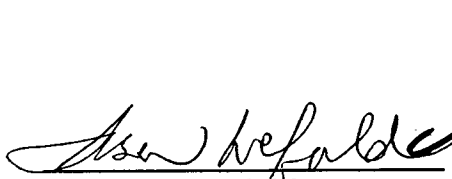
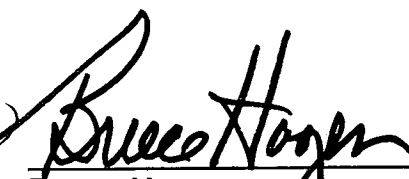
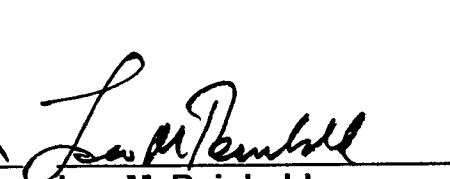
6. Implementing the plan is in the public interest.

Order

The Commission orders:

1. The attached revised settlement agreement is approved, except as specified in Findings of Fact paragraph 20.
2. NSP's PLUS plan, as modified by the approved portion of the attached revised settlement agreement, is approved.
3. NSP d/b/a Xcel Energy is authorized to implement the plan as modified by the revised settlement agreement for its electric utility operations in the State of North Dakota for the term January 1, 2001 to December 31, 2005.
4. NSP shall submit a single comprehensive stand-alone document describing the plan as modified by the approved portion of the attached revised settlement agreement by January 31, 2001.
5. NSP shall submit all annual performance and financial reports required by the plan (as modified) by May 1st of each plan year. The Commission may require interim reports during the plan term as necessary.
6. The plan is be subject to suspension or termination for good cause, as provided in the revised settlement agreement.
7. The Commission will review the operation and results of the plan upon receipt of reports for the 2002 plan year.

PUBLIC SERVICE COMMISSION

		
Susan E. Wefald Commissioner	Bruce Hagen President	Leo M. Reinbold Commissioner

STATE OF NORTH DAKOTA
PUBLIC SERVICE COMMISSION

**Otter Tail Power Company
Performance Based Regulation
Application**

Case No. PU-401-00-36

**Northern States Power Company
Performance Based Regulation
Application**

Case No. PU-400-00-195

**CONCURRING OPINION
COMMISSIONER SUSAN E. WEFALD**

December 29, 2000

Today the Commission is adopting Performance Based Regulation plans for purposes of regulating Northern States Power Company's and Ottertail's retail electric operations in North Dakota. This plan is the result of months of study and work by the Commission, Commission Staff, and utility representatives.

The plan promotes utility efficiencies, aligns customer and shareholder interests, works to maintain or improve customer service, allows utilities to be flexible, minimizes regulatory costs, and improves public participation. In other words, it is a win – win situation, good for consumers and good for NSP and Ottertail.

The companies will be measured on four areas of performance with this plan. These areas are reliability, customer satisfaction, price standards, and an employee safety standard.

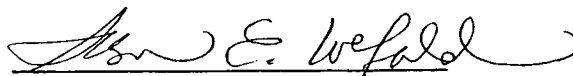
Customers should know that they play a role in determining the companies' performance each year. Each company will be doing several surveys of customers each year to determine the customers' satisfaction with their electric service.

Also, public input played a role in determining the provisions of the settlement. Ideas from letters received from the public were incorporated into the settlement.

The plan will be in place for 5 years and will be evaluated after 2 years.

These particular performance based regulation plans are unique to our state and our utilities. For anyone wishing to study the plans in more detail, the Commission order and the settlements will be available very soon on the Commission web site. The Commission and our staff will be happy to discuss the plans at any time.

I am proud of the work done by all parties on this project and am committed to the operational success of these plans.


Commissioner Susan E. Wefald

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

Northern States Power Company
Performance-Based Regulation Proposal

Case No. PU-400-00-195

FINAL SETTLEMENT AGREEMENT

This Final Settlement Agreement ("Final Agreement") is entered into this 27th day of December, 2000, by and between Northern States Power Company, a Minnesota corporation ("NSP" or "the Company") and the North Dakota Public Service Commission litigation staff ("Staff"). This Settlement Agreement resolves all outstanding issues in the above-captioned proceeding before the North Dakota Public Service Commission ("Commission") in a manner consistent with the public interest.

This Final Agreement consolidates and incorporates all relevant provisions from the "Settlement Agreement" dated November 30, 2000, and the "Amendment and Clarification to November 30, 2000 Settlement Agreement" previously executed and filed by the parties. This Final Agreement also consolidates and incorporates all revisions agreed to by the Company, Otter Tail Power Company and Staff reflecting their negotiations and the hearing and Commission working sessions held in this matter.

PRELIMINARY STATEMENT

1. Commission Alternative Regulation Guidelines, Case No. PU-439-94-590

On September 20, 1995, the Commission issued "Guidelines for Filing Alternative Regulation Proposals" ("Guidelines") in Case No. PU-439-94-590, after

conducting both a workshop and public input sessions to discuss different forms of regulation for electric utilities. The Guidelines indicated the Commission would consider proposals for alternative forms of regulation from traditional "cost-based rate of return" regulation. The Guidelines set forth both goals and criteria for alternative regulation proposals.

2. Summary of Record

On April 20, 2000, NSP filed a "Proposal for a Performance-Based Regulation Plan" ("Petition") asking the Commission to approve the Company's proposed performance based regulation ("PBR") plan, called the "PLUS" plan ("Plan"), for purposes of regulating NSP's retail electric operations in North Dakota. The key components of PLUS include 1) a "dynamic allowed ROE" range which can vary based on Company performance, 2) a revenue sharing mechanism, 3) establishment of service performance standards, and 4) price capping and flexibility to adjust prices under specified circumstances. If approved, the Plan would create an alternative form of regulation for the Company's electric operations in North Dakota, as contemplated by the Guidelines. In its Petition, the Company asserted:

- The PLUS Plan meets the stated goals and criteria identified by the Commission Guidelines.
- The PLUS Plan is an appropriate regulatory model because it provides benefits to customers and to North Dakota's economy which extend beyond traditional cost-based regulation, while at the same time ensuring that the Company's North Dakota electric rates are just and reasonable and the Company's operations have the opportunity to maintain financial strength.

- The PLUS Plan will work better than traditional cost-based regulation to promote a balanced emphasis on utility efficiency, service quality, and economic development in North Dakota, while maintaining the customer protections provided by traditional regulation.
- The PLUS Plan provides North Dakota regulation with an automatic, pre-defined mechanism to pass the benefits of a financially healthy utility on to its stakeholders. Unlike traditional, cost-based regulation, which can be a slow and adversarial, the PLUS Plan offers an efficient, win/win approach to utility regulation. PLUS places the regulatory focus more on results and less on process.
- As restructuring of the electric industry occurs, performance based regulation will play a role in facilitating the transition to a more competitive environment. The PLUS regulatory model better simulates a competitive market by creating meaningful incentives which promote high quality service and low cost.
- Since PLUS offers the Company the potential to achieve above-average returns on its North Dakota electric business if the Company's performance meets the thresholds set forth in the plan, PLUS will also create an additional incentive for NSP to invest its limited capital resources in North Dakota (other things being equal).

On July 19, 2000, the Commission issued a "Notice of Hearing and Notice of Public Discussion Meeting" in the instant docket and Case No. PU-401-00-36, a docket involving a similar PBR plan filed by Otter Tail Power Company ("Otter Tail").

On August 29, 2000, presiding Administrative Law Judge Allen C. Hoberg of the Office of Administrative Hearings issued a Pre-hearing Order which established procedural dates, hearing procedures, and other preliminary matters.

The Commission conducted a joint public hearing by video conference on September 6, 2000, with public participation available through ten video conference sites, including three in the Company's electric service area (Fargo, Grand Forks, Minot). No members of the public submitted oral comments opposing approval of the Plan at the public hearing.

Pursuant to the procedural schedule established by Judge Hoberg, NSP submitted pre-filed direct testimony in support of the PLUS Plan on September 29, 2000. On October 13, 2000, the Staff submitted pre-filed direct testimony recommending certain modifications to the PLUS Plan. On October 20, 2000, the Company submitted pre-filed rebuttal testimony responding to the Staff direct testimony.

On October 23 and 24, 2000, the Commission conducted a joint evidentiary hearing considering both NSP's PLUS Plan and Otter Tail's similar PBR plan in Case No. PU-401-00-36. Judge Hoberg presided over the hearing. The Petition and pre-filed testimony of both Companies and Staff were accepted into the record, and the witnesses were subject to cross examination by counsel and questions by the Commissioners and Advisory Staff.

At the conclusion of the evidentiary hearing, the Commission urged the parties to initiate discussions to resolve the areas of the Plans in which Staff and the Companies held differing views. The companies committed to a December 1 deadline for submitting to the Commission a settlement agreement.

Staff, NSP and Otter Tail held settlement discussions on November 2, 2000 in Jamestown, North Dakota, and held numerous telephone and electronic discussions since that date in an effort to reach a comprehensive settlement regarding implementation of performance based regulation in North Dakota.

On November 20, 2000, the Commission conducted a regularly scheduled and noticed working session with parties present in which the companies' PBR proposals and Staff's recommendations were discussed.

On November 30, 2000, NSP and Staff executed and filed a "Settlement Agreement" to resolve all outstanding issues in this proceeding.

On December 1, 2000, the Settlement Agreement was considered by the Commission at a regularly scheduled and noticed working session in order to allow the Commission and Advisory Staff to ask questions and develop a record supporting approval of the Settlement Agreement. Both the Company and Staff, the only parties to the proceeding, were present. The Commission expressed a desire to have more time to review the Agreements, and hold another working session.

On December 11, 2000, the Settlement Agreement was again considered at a regularly scheduled and noticed Commission working session, with both the Company and Staff again present. At this second working session, the Advisory Staff submitted two memos raising issues regarding the Plan as revised by the Settlement Agreement. The Commission indicated further clarifications and/or modifications to the Settlement Agreement and/or the Company's PLUS Plan were warranted prior to Commission approval of the Plan and Settlement Agreement.

Based on the Commission's request to clarify and amend the November 30 Settlement Agreement, the Company and Staff executed and filed an "Amendment and Clarification to November 30, 2000 Settlement Agreement" ("Amendment") on December 14, 2000. The Amendment included Plan changes or clarifications regarding 1) the ROE threshold for rate changes; 2) the "efficiency commitment" used in calculating the Price Cap Factor; 3) the procedures to be used in case of an exogenous event; 4) the process for extending the Plan term; and 5) the process for collection of surcharges from customers for unrecovered earnings deficiencies during a Plan year.

On December 15, 2000, the Amendment was considered at a third regularly scheduled and noticed Commission working session. Staff was present, and the Company participated by telephone. At this third working session, the Advisory Staff raised an issue regarding the revised Price Cap Factor "efficiency commitment" adjustment, which the Company and Staff modified in the Amendment to address concerns raised by Advisory Staff at the December 11, 2000 working session. The Company stated it would be willing to reinstate the Price Cap Factor efficiency commitment contained in the Settlement Agreement.

At this final working session, the Company and Staff also agreed to consolidate the terms of the November 30, 2000 Settlement Agreement, the December 14, 2000 Amendment, and the clarification regarding the "efficiency commitment", and submit a consolidated settlement document to the Commission no later than December 28, 2000. This Final Agreement provides the consolidated document.

3. The Plan and this Final Agreement Serve the Public Interest

Both the Company and Staff submitted pre-filed and oral testimony generally supporting implementation of performance-based regulation for the Company's electric utility operations in North Dakota. The Company and Staff differed, however, on the appropriate Plan performance standards and reward/penalty criteria. The record (the testimony of Dr. Karl McDermott) supports use of broad and balanced performance standards and symmetrical reward/penalty criteria, but the Company and Staff agree the record does not require approval of either the specific components of the Company's original Plan or the Staff recommendations without modification. In addition, Commissioner comments and questions at the evidentiary hearing and working sessions supported consideration of possible alternative performance standards. Dr. McDermott recommended the final Plan performance standards and reward/penalty criteria reflect the policy objectives of the Commission.

Based on the record in this matter, including the Petition, testimony, hearing, working sessions, Settlement Agreement and Amendment, the Company and Staff believe this Final Agreement is supported by the record, is consistent with the public interest, is consistent with the Commission's Guidelines on for Filing Alternative Regulation Proposals, will result in quality service and reasonable rates to North Dakota ratepayers, and supports the safe and reliable electric infrastructure and the financial viability of the Company. Other documentation in support of the Final Agreement is attached hereto.

As a result, implementation of the Company's PBR Plan, as revised, would serve the public interest. Accordingly, the Parties jointly recommend that the Commission

approve this Final Agreement. The Parties request the Commission issue an order approving this Final Agreement and modified PLUS Plan in their entirety, without conditions or modifications.

TERMS OF FINAL AGREEMENT

1. PLUS Plan Terms

A. Implementation/Term/Extension of Plan

As proposed by NSP and supported by Staff, the PLUS Plan will commence on January 1, 2001. Concurrently and independently, NSP will reduce non-fuel base retail electric rates to the Company's North Dakota electric service customers by \$261,000 annually (approximately 0.25%), pursuant to the Commission order dated May 10, 2000, in Case Nos. PU-400-99-418 (Merger with New Century Energies, Inc.) and PU-400-98-246 (Electric Rate Investigation). For purposes of initial Plan implementation, the Company's restated electric rates effective January 1, 2001 are deemed just and reasonable.

Except as provided herein, the PLUS Plan will remain in effect for a five year term ending December 31, 2005. Prior to July 1, 2005, the Company may file for an extension and/or modification of the Plan if so desired. Absent such a filing and a further order of the Commission extending the Plan, the PLUS Plan will automatically terminate on December 31, 2005.

B. Reporting/Review

Each year, on or before May 1, NSP will submit a comprehensive earnings and performance report for the previous calendar year fiscal period, as detailed in the Company's Petition.

The Commission will conduct an informal review hearing after May 1, 2003, but no later than June 30, 2003, to assess the Plan's results after two years.

2. ROE Deadband/Revenue Sharing

A. Baseline ROE and "Deadband"

The initial baseline Return on Equity ("ROE") for purposes of the Plan will be 12.0%. An ROE deadband of +/- 1.0% will be established around the baseline.

During the Plan term, the ROE deadband shall be subject to the annual dynamic ROE adjustments in terms of "basis points" depending on the Company's performance under each Plan performance standard, as provided herein. If the net performance basis points are positive (award), the upper end of the ROE deadband increases. If the net performance points are negative (penalty), the lower end of the ROE deadband is decreased. The baseline does not change.

Attachment 1 to this Final Agreement provides an example of the dynamic ROE bandwidth and revenue sharing mechanisms provided by this Final Agreement.

B. Revenue Sharing

If the Company's reported actual earnings fall within the ROE deadband around the authorized ROE (as adjusted by the performance points) in a given Plan year, no revenue sharing will take place. If the Company's actual reported earnings for any given Plan year exceed the deadband, the corresponding revenue 'sufficiency' will be calculated, and 50% of this dollar amount will be refunded to customers during the July billing cycle of the following year. Customers of record on March 31 following the Plan year will be issued refunds by bill credit prorated on the basis of their electric usage for the twelve months ending March 31.

The Petition proposed that 10 percent of any reported revenue sufficiency amount in any Plan year be used for economic development investments. The Staff indicated general support for economic development investments, but did not support the Plan's revenue sharing mechanism for this purpose. Pursuant to this Final Agreement, all sharing will be 50/50 between Customers and the Company. However, the Company may record economic development expenses incurred in a Plan year as a jurisdictional expense for purposes of annual financial reporting.

If earnings are below the deadband, 50% of the corresponding revenue deficiency may be recovered through a surcharge on the Company's electric rates effective no later than 24 months after the Plan year, as directed by the Financial Accounting Standards Board ("FASB"). However, NSP will defer a reported fiscal year deficiency amount as a regulatory asset until the following Plan year revenue sharing amount, if any, is reported. If the prior year deficiency is fully offset by a current year reported revenue sufficiency, the sufficiency will be used to eliminate the regulatory asset, and no rate surcharge will be imposed. If the deficiency from the prior year is not fully offset, any remaining deficiency balance will be billed through a rate surcharge and collected over the remaining six-month period beginning July 1 of the year following the Plan fiscal reporting year, unless otherwise requested by either the Company or Commission Staff and approved by the Commission.

The customer share of any Plan refund or deficiency surcharge will be shown separately as a "performance-based dividend" or "performance-based surcharge" on customer bills.

Any deferred deficiency balance remaining at the end of the 5-year Plan term will first be considered as part of an on-going Plan or alternatively, collected from customers through a surcharge.

Plan dividends paid or surcharges received will be excluded from the Company's return on equity calculation for the Plan year in which the said dividends or surcharges are actually implemented.

3. Performance Standards

A. Reliability

The Petition proposed a service reliability standard measurement using the weather normalized "System Average Interruption Duration Index" ("SAIDI") pursuant to the methodology established by the IEEE. Pursuant to this Final Agreement, two standards will be used in the PLUS Plan for purposes of measuring reliability: 1) customer average interruption duration index ("CAIDI"), and 2) system average interruption frequency index ("SAIFI").

CAIDI and SAIFI are individual reliability measures widely used in the electric utility industry, the product of which is the SAIDI result. By using both component standards, the Company will be measured on both the frequency of customer outages and the time it takes to restore power. Annual results for each measure will be weather-normalized to exclude storm day outages. Targets are based on achieving a SAIDI result of 80 minutes, which was developed using historical NSP outage results in North Dakota, and a consideration of the Otter Tail Plan target. Each measure will carry a potential reward and/or penalty of a 25 basis point adjustment to the authorized ROE deadband.

The following table defines the revised performance standards for reliability (see Attachment 1):

Measure	Award Threshold	Target	Penalty Threshold
CAIDI	< 75.6 minutes	89.0 minutes	> 102.4 minutes
SAIFI	< 0.77 outages/yr.	0.90 outages/yr.	> 1.04 outages/yr.

B. Customer Satisfaction

The Petition proposed a single customer satisfaction measure based on North Dakota customer responses to a single overall question contained in Company “relationship” surveys of all customer classes (Residential, Commercial and Large Industrial), based on the percentage of respondents providing a “top three box” rating (‘excellent’, ‘very good’, or ‘good’). Staff recommended use of a “transaction” survey, and also proposed using a “top two box” standard (i.e., customers who rate the Company’s performance ‘excellent’ or ‘very good’) for customer surveys.

Pursuant to this Final Agreement, the PLUS Plan will use two survey standards for purposes of measuring customer satisfaction: 1) an average satisfaction score from the relationship surveys for all three customer classes (Residential, Commercial, Large Industrial), and 2) an average satisfaction score from two transaction surveys relating to the Company’s call center and electric service functions. The survey scores will reflect the percentage of respondents who give NSP an ‘excellent’ or ‘very good’ rating. Targets are based on historic company-wide NSP survey results from the previous three years, and will be revised after two Plan years to reflect responses from North

Dakota customers only. Each of the two survey standards will carry a potential reward and/or penalty of a 25 basis point adjustment to the authorized ROE deadband.

The following table defines the Plan performance standards for customer service for at least the first two plan years:

Measure	Award Threshold	Target	Penalty Threshold
Relationship survey positive response %	> 84.0%	81.0%	< 78.0%
Transaction survey positive response %	> 66.0%	63.0%	< 60.0%

C. Price Standard

The Petition proposed a price standard comparing the Company's average Residential electric revenue per kWh for the Plan year to the average residential revenue/kWh for a comparison group of 26 mid-western utility jurisdictions. Staff proposed a price comparison measuring the change in the Company's residential electric revenue/kWh in the Plan year to the change for the ten lowest-priced utilities in the comparison group.

Pursuant to this Final Agreement, two price standards will be used in the PLUS Plan for purposes of measuring competitive price: 1) the Company's relative average residential price per kWh compared to the mid-western utility peer group; and 2) the annual change in average residential price relative to the change for the lowest priced utility in the peer group. The price targets are calculated annually based on utility price data compiled in an Edison Electric Institute publication entitled Typical Bills and Average Rate Report issued twice per year. For purposes of the PLUS Plan, the "winter" edition (reflecting the 12 month period ending December 31st) will be used.

Each of the two price measures will carry a potential reward and/or penalty of a 25 basis point adjustment to the authorized ROE deadband.

The following table defines the revised Plan performance standards for price:

Measure	Award Threshold	Target	Penalty Threshold
Competitive Res'l price position	< 85% of target	peer group avg. Residential price/kWh	> 115% of target
Annual change in Res'l avg. price	< (target-.05¢/kwh)	annual change in lowest priced utility Res'l avg. price	> (target+.05¢/kwh)

D. Employee Safety Standard

The Petition proposed an employee safety standard based on the Company's Occupational Safety and Health Administration ("OSHA") incident rate in the Plan year compared to historic performance of a number of regional utilities participating in a North Central Electric Association safety survey. The OSHA incident rate represents the number of safety-related incidents per 100 employees. The Petition proposed a reward and/or penalty of a 50 basis point adjustment to the baseline ROE.

Pursuant to this Final Agreement, the PLUS Plan will include an employee safety measurement based on the OSHA incident rate. The target is based primarily on historical results for Group 1 utilities (more than 7,000 employees) in the Edison Electric Institute survey, but also reflects consideration of what would provide an acceptable "stretch" for NSP's North Dakota operations. To be consistent with the other individual Plan standards, the employee safety measure will carry a potential reward and/or penalty of a 25 basis point adjustment to the authorized ROE deadband.

The following table defines the Plan performance standards for employee safety:

Measure	Award Threshold	Target	Penalty Threshold
OSHA incident rate	< 3.70	4.32	> 5.00

4. Changes in Base Rates

Attachment 1 to this Final Agreement provides a description the relationship of the Plan's dynamic ROE mechanism to the electric rate change criteria provided by this Final Agreement. Attachment 2 provides a flow chart of the price change criteria provided by this Final Agreement.

A. Price Cap Factor

Pursuant to this Final Agreement, the PLUS Plan will calculate a Price Cap Factor by determining the lower of 1) the annual percentage change in the utility peer group's average residential price per kWh for the reporting year, and 2) 60% of the change in the Consumer Price Index (CPI) for the reporting year.¹ The CPI for the Plan reporting year is computed by averaging the annual CPI reported at the end of each calendar quarter. The Price Cap Factor will determine the highest annual percentage rate increase allowed under the Plan, or the amount of a required rate decrease.

B. Rate Change Criteria

Pursuant to this Final Agreement, the PLUS Plan imposes an electric rate freeze on the Company whenever (i) its previous fiscal year ROE exceeds the baseline ROE,

¹ As such, the change to efficiency commitment factor provided in the Amendment (annual CPI – 0.8%) is replaced by the efficiency commitment in the Settlement Agreement (60% of annual CPI).

as adjusted pursuant to the performance points, minus 100 basis points (1.0%);² or (ii) the Company's average residential rates are higher than the utility peer group average residential rate. If neither condition exists, the Company may change rates by an overall percentage not to exceed the Price Cap Factor.

C. Required Rate Decrease Criteria

The Company shall reduce its retail electric rates pursuant to the PLUS Plan if (i) the Company's reported ROE for the Plan reporting year exceeded the baseline ROE, as adjusted pursuant to the performance points, plus 100 basis points (1.0%); (ii) the Company's average residential rates are higher than the PLUS utility peer group average residential rate; and (iii) the Price Cap Factor is negative.

D. Rate Change Procedure

To implement any permissive rate change pursuant to Section B or mandatory rate reduction pursuant to Section C, the Company shall file a notice of rate change and the accompanying tariffs pursuant to N.D.C.C. 49-05-05 not later than June 1, following completion of the Plan year and submission of the Plan performance report on May 1.

² As shown for illustrative purposes in Attachment 1, the lower ROE threshold could be 11.13% minus 100 basis points, or 10.13%, assuming the Company's performance would result in performance penalties in all seven Plan performance categories. In this example, a base electric rate freeze would be in effect if NSP's reported earnings in North Dakota for the prior Plan year were above 10.13%.

Similarly, the upper threshold could be 12.88% minus 100 basis points, or 11.88%, assuming the Company's performance would result in performance awards in all seven Plan performance categories. In this example, a base electric rate freeze would be in effect if the Company's reported earnings for the prior Plan year were above 11.88%.

If the Company's performance was within all of the Plan performance bandwidths, and no adjustment was made to the baseline ROE pursuant to the dynamic ROE mechanisms, a base electric rate freeze would be in effect if the Company's reported earnings in the prior Plan year exceeded 11.00%.

The revised rates shall be effective on or after July 1 following the Plan year. Base rate changes will be across-the-board to all customer classes unless otherwise requested by the Company and approved by the Commission.

Such rate change will not be suspended by the Commission under N.D.C.C. 49-05-06, but the revised rates shall be allowed to go into effect on the date proposed. If the Commission determines after investigation and hearing that the changed rates do not comply with the Plan terms as prescribed herein, the Commission may prospectively establish the rates it finds to be consistent with the Plan terms, and order a one-time billing true-up for the impact of the discrepancy since either the inception of the rate change or the previous 12 month period, whichever is less. Rates established consistent with the Plan are presumed just and reasonable, and non-discriminatory.

E. Exogenous Events.

Changes in base rates are subject to the price cap mechanisms included in this Final Agreement. However, any increases or decreases in costs of electric service caused by governmentally imposed changes in taxes and/or accounting practices shall be implemented within 60 days of the effective date of the change.

5. Other Terms and Conditions

A. Fuel Clause Adjustment

This Agreement and the Company's revised PBR Plan does not change the Company's existing fuel clause adjustment ("FCA") mechanism in its North Dakota Electric Rate Book tariff schedules. The comparative price standard provided above shall be calculated using total Residential revenue per kWh including the fuel clause adjustments in effect during the Plan reporting year.

B. Demand Allocator Factor

For purposes of calculating the Company's jurisdictional expenses for the PLUS Plan reporting year, 36 months of historical demand data will be used to establish the Demand Allocation factor (known as D10). The Demand Allocation factor is used to assign production and transmission related costs and investment to NSP's retail electric jurisdictions in North Dakota, South Dakota and Minnesota. The Petition demonstrated use of 36 months of demand data will mitigate volatility in this allocation factor. The use of a 36 month demand allocator is only for financial reporting purposes under the Plan. Use of a 36 month historic allocator for the Plan shall have no precedential effect in future electric rate increase applications after the Plan term expires or the Plan is suspended or terminated

C. Suspension/Termination of Plan

The PBR Plan will remain in effect for five years beginning January 1, 2001. However, the Company and Staff reserve the right to request adjustment, suspension, or termination of the Plan under the following events:

- Federal and/or state tax law changes;
- Passage of retail access legislation at either the federal or state level;
- Merger and acquisition events affecting the Company's structure and operations;
- Natural disasters affecting the Company's North Dakota electric operations (major storms, floods, etc.);
- Unusual events affecting the Company's operations (major generating plant failure, damage to major transmission or distribution lines, etc.); or

- Material and sustained earnings extremes (defined as returns on equity +/- 5.0% from the ROE deadband, prior to sharing).

It is anticipated the Commission and Company will make reasonable efforts to resolve any condition that could otherwise trigger a Company application or Commission motion to suspend the Plan before any decision to terminate operation of the Plan during the Plan term.

D. Applicability and Scope

Each of the provisions of this Final Agreement is in consideration for each and every other provision. This Final Agreement is subject to the approval of the Commission. If this Final Agreement and the PLUS Plan (as revised by this Final Agreement) are not approved in their entirety without modification by vote of the Commission by December 31, 2000, the Company, at its option, may submit written notice to the Commission that this Final Agreement is null and void and the Plan and Petition are withdrawn. Such notice shall be submitted no later than January 5, 2001.

This Final Agreement shall be binding on the parties hereto, and upon their successors, assigns, agents and representatives.

E. Effective Date

Except as provided herein, this Final Agreement shall be effective on the date of the final Commission order approving the Plan (as revised) and this Final Agreement without modification. This Final Agreement shall remain in full force and effect for the Plan term.

F. Effect of Settlement Negotiations

It is understood and agreed that all offers of settlement and discussions related thereto are privileged and may not be used in any manner in connection with proceedings in this case or otherwise, except as provided by law. In the event the Commission does not approve this Final Agreement, the Final Agreement shall not constitute part of the record in this proceeding and no part thereof may be used for any purpose in this proceeding or otherwise. This Final Agreement shall not in any respect constitute a determination by the parties hereto as to the merits of any specific allegations or contentions made by the parties in Case No. PU-400-00-195.

G. Counterparts

This Final Agreement may be executed in separate, identical counterparts.

H. Agreement Drafted Jointly

This Final Agreement shall be deemed to have been drafted jointly by Staff and NSP for purposes of construing or interpreting the meaning of any provision of this Final Agreement.

Northern States Power Company

By: James P. Johnson
James P. Johnson
Assistant General Counsel
Xcel Energy Services Inc., Agent for
Northern States Power Company

**North Dakota Public Service
Commission Staff**

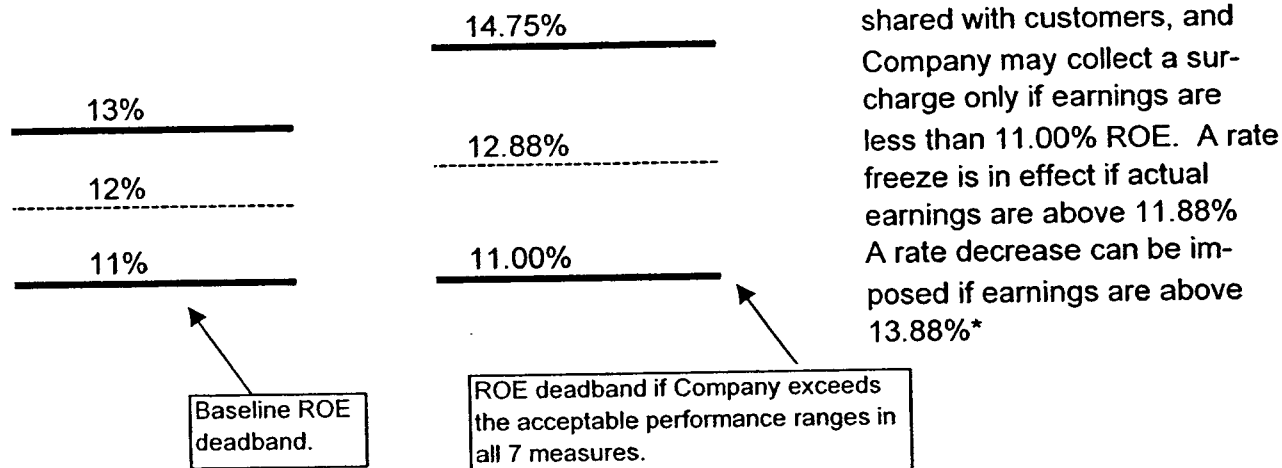
By: William W. Binek
William W. Binek
Chief Counsel
North Dakota
Public Service Commission
December 28, 2000

Date: December 28, 2000

Revenue Sharing and Price Change Mechanisms Amended Settlement Proposal

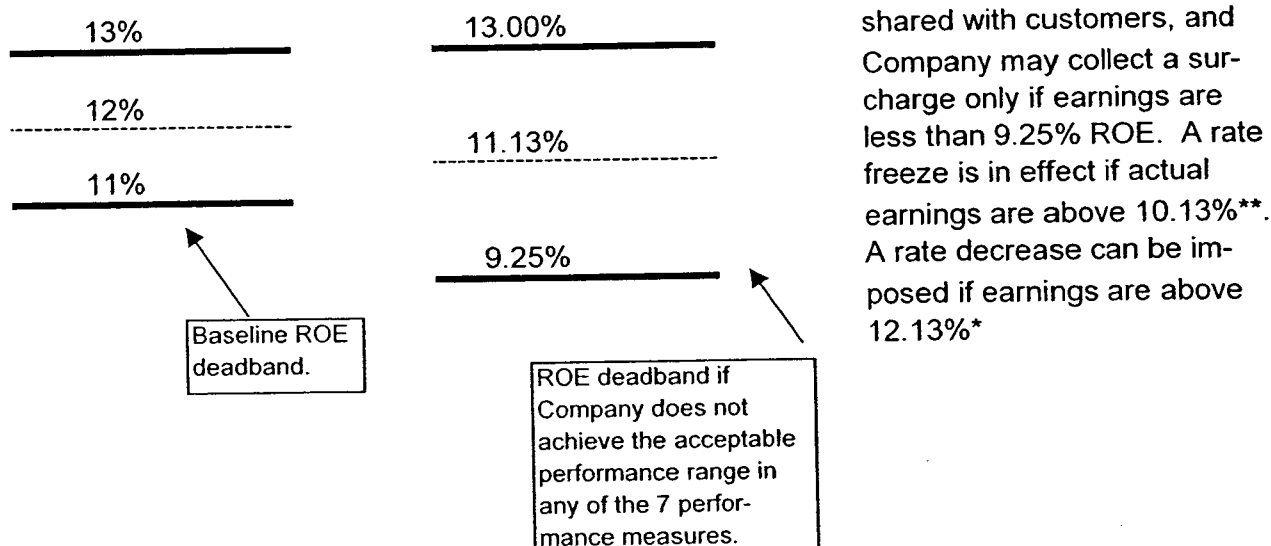
Assume all 7 performance measures are met, each worth 25 basis points

If net result of performance points is positive, only the *upper* limit of the ROE deadband increases.



Assume a penalty for all 7 performance measures, each worth 25 basis points

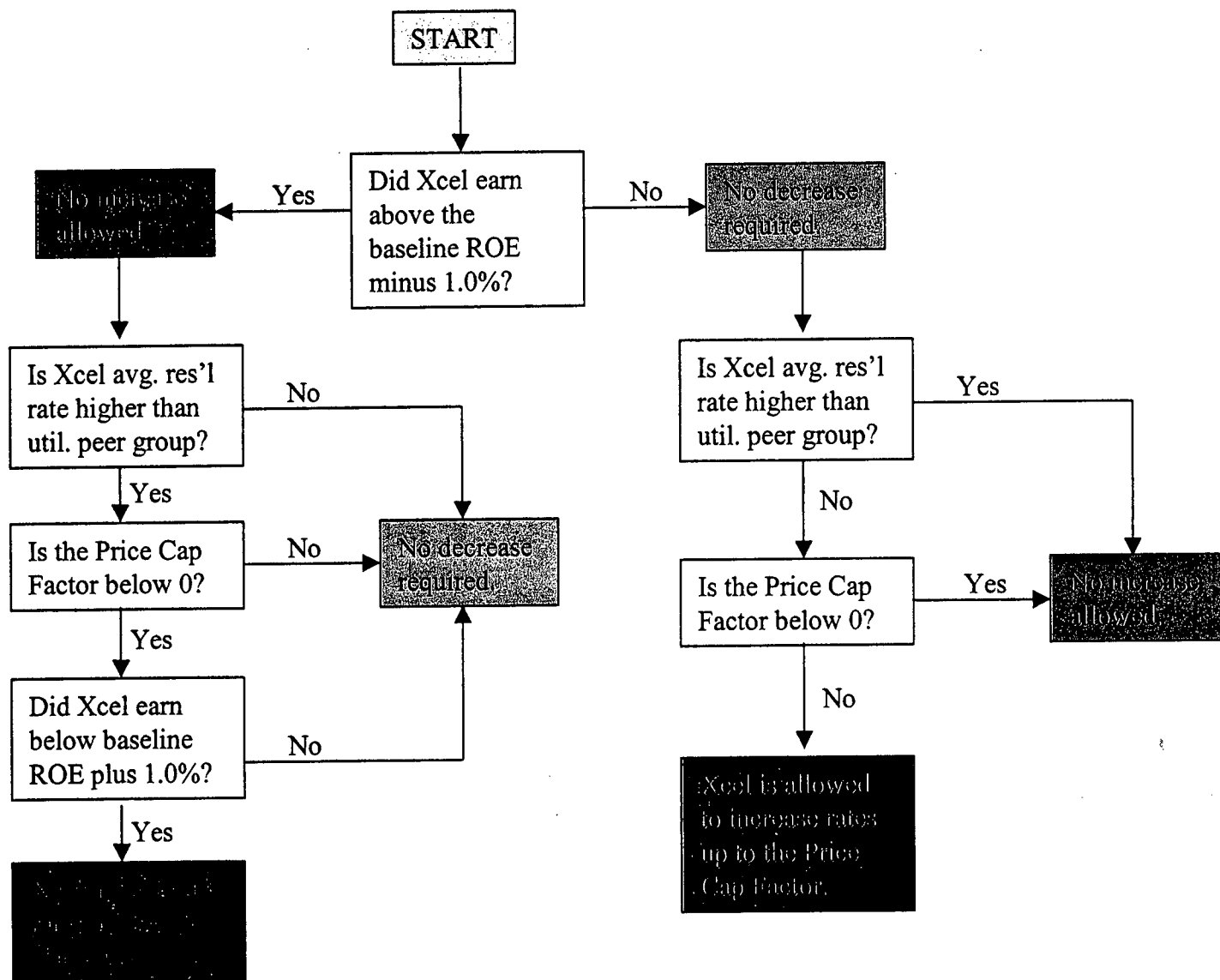
If net result of performance points is negative, only the *lower* limit of the ROE 'deadband' is reduced.



* The rate freeze threshold is equal to the baseline (12.88% in this example) minus 1.00%, or 11.88%. Decreases can be imposed at 12.88%+1.0%, or 13.88%.

** The rate freeze threshold is equal to the baseline (11.13% in this example) minus 1.00%, or 10.13%. Decreases can be imposed at 11.13%+1.0%, or 12.13%.

Decision Model for PLUS PBR Price Cap Mechanism



Price Cap Factor = lower of the utility peer group average annual price change or 60% of CPI



Public Service Commission

State of North Dakota

COMMISSIONERS

Bruce Hagen
President
Susan E. Wefald
Leo M. Reinbold

600 E Boulevard Ave. Dept. 408
Bismarck, North Dakota 58505-0480
e-mail: sab@oracle.psc.state.nd.us
TDD 800-366-6888
Fax 701-328-2410
Phone 701-328-2400

Executive Secretary
Jon H. Mielke

October 9, 2000

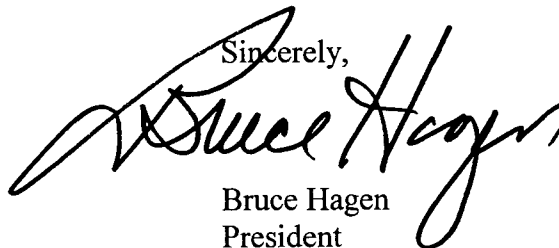
Mr. Mark Sherman
1832 6th Street SW
Minot ND 58701

Dear Mr. Sherman:

Thank you for your letter of October 4, 2000 expressing your views on the Northern States Power Performance-Based Regulation plan. The Commission has scheduled a hearing in this matter on October 23, 2000, beginning at 1:30 p.m. in the Commission Hearing Room. A copy of the hearing notice is enclosed.

Again, thank you for writing. Your letter will be placed in the public input file in this case.

Sincerely,



Bruce Hagen
President

BH/cm
Enclosure

4 October 2000

Mr. Bruce Hagen, President
ND Public Service Commission
600 East Boulevard
Department 408
Bismarck, ND 58505-0480

Dear Mr. Hagen:

Subject: Northern States Power Company's Proposal for Performance-Based Regulation

I would like to express my views on two items included in the NSP PLUS plan. The items are the ROE dead-band and the 10 percent portion of earnings above the ROE dead-band set aside for economic development.

The lower limit on the ROE dead-band should be fixed at 11% (or some other percentage deemed appropriate by the PSC) and not allowed to vary with the acceptable baseline earnings. NSP's proposal places the dead-band lower limit at 11% when the allowed baseline earnings are at 12% and allows the lower limit to increase to 13% when allowed baseline earnings are at 14%. Allowing the lower limit to increase with the baseline will encourage NSP management to make more risky business decisions than otherwise would be acceptable to NSP management. I believe this because NSP will increase their profits through the profit sharing plan when the risky venture is successful, but NSP only stands to be penalized 50% of actual losses below the dead-band lower limit if the venture fails and I as a consumer will be expected to pay the other 50% of losses up to the lower limit.

NSP's proposal includes a provision to use some profit sharing funds for economic development. The proposal states "Decisions regarding funded projects will be at the discretion of NSP management." The 10% portion of the profit sharing is not NSP's money and NSP management should not be in charge of spending these funds. It is reasonable that the funds be spent in NSP service territory, however, the funds should be turned over to established economic development mechanisms such as the Minot Magic Fund for distribution.

Please feel free to contact me at 701-721-1421 or 1832 - 6th St SW, Minot, ND 58701 with any questions or concerns.

Sincerely,

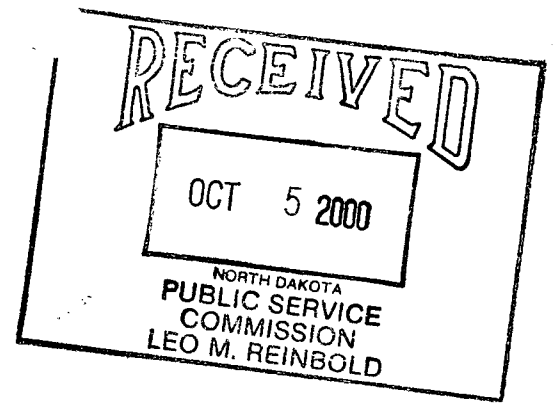


Mark Sherman

cc: Comm
Legal
Pub

4 October 2000

Mr. Leo M. Reinbold, Commissioner
ND Public Service Commission
600 East Boulevard
Department 408
Bismarck, ND 58505-0480



Dear Mr. Reinbold:

Subject: Northern States Power Company's Proposal for Performance-Based Regulation

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Please feel free to contact me at 701-721-1421 or 1832 - 6th St SW, Minot, ND 58701 with any questions or concerns.

Sincerely,

Mark Sherman

cc: Com
Legal
PUB (u)
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Public Service Commission

State of North Dakota

COMMISSIONERS

Bruce Hagen
President
Susan E. Wefald
Leo M. Reinbold

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Fax 701-328-2410
Phone 701-328-2400

Executive Secretary
Jon H. Mielke

September 5, 2000

Lynn Harpster
RR 2 Box 14
East Grand Forks ND 58201

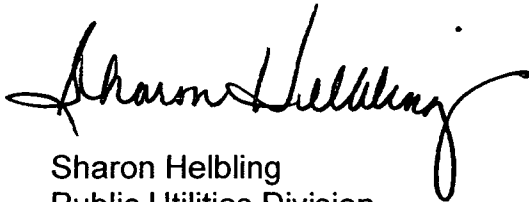
Dear Mr. Harpster:

Thank you for writing us concerning NSP's electric rates.

I have enclosed a copy of the Notice of Hearing and Notice of Public Discussion Meeting. The hearing is scheduled for October 23, 2000, and anyone is welcome to attend.

The public discussion meeting will be held on September 6, via interactive television beginning at 12 noon; the locations are listed in the notice.

Sincerely,



Sharon Helbling
Public Utilities Division

Sdh

Enclosure

0/3/2000

N. Dak Public Service Commission
Bismarck, N. Dak.

Dear Sirs:

I live in Minn. but have property in N. Dak. As I read the folder from N.S.P. on electric rates, it reminds me of the Republicans & Democrats. They are trying to make a rate increase look like it is good for the Customer. There is nothing wrong in paying for electrical service by the K.W.H. They want to compare the rates with 7 Midwest states. This has nothing to do with rates. They are trying to raise the rate to compare with the 7 other states. After what they going to try to do with gas rates, this is just another way to raise rates. Please think very seriously about voting them more money.

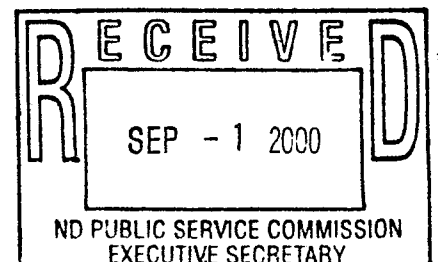
C. Comm
Legal
And (4)

Loren Harper

RR 2

Box 14

East Grand Forks, N. Dak 58201



Offer Jail Pub. Serv.

Wed. Sept. 6, 2000

* Robert Spencer, Cando

* Jim Greene, Osake

present from
Lake Region State College

Eugene Hammer - Otter Tail Power - Rugby
Jim Dahl - Otter Tail Power - Bottineau

Otter Tail Public Hearing

Noon - 1:50 PM

9/6/00

MSU Bottineau

Wold Room

9/6/00

PBR Public Discussion MeetingsBismarck.

<u>Name</u>	<u>Address</u>	<u>Representing</u>
Jerry Lein	Bismarck	PSC
Val Diller	✓	✓
MARLOWE JOHNSON	Jamestown	OTB
BOB GRAVELINE	BISMARCK	USND
Mona Jeffcoat Bacco	Bismarck	PSC
Rosalie Newald	Wilton	Customer
Officer McDonald	Wilton	CUSTOMER
Bill Bond	Bismarck	PSC
Patrick Fahn	Bismarck	PSC
Commissioners Weferla, Hagen & Reinhold		

PU-400-00-195
 PU-401-00-36

HARD COPY OF Videotape of Public Discussion meeting / Seven tapes
of joint hearing

DOCKET SEQUENCE NO. 16 + 17

EXHIBIT _____

CASE NO. PU-400-00-195

ON FILE IN

STATE ARCHIVES

CONTROL NUMBER: 80051