NG97-021

NG97-021

DOCKET NO.

In the Matter of IN THE MATTER OF THE APPLICATION FOR AN ORDER ESTABLISHING A NATURAL GAS ~~LOCAL DISTRIBUTION~~ UTILITY, AND TO ESTABLISH INITIAL NATURAL GAS TRANSPORTATION RATES FOR NORTHERN STATES POWER COMPANY

file fee

Public Utilities Commission of the State of South Dakota

DATE	MEMORANDA
12/16 97	Filed and Docketed;
1/20 98	Jurisdiction Letter;
1/22 98	Order Assessing Filing Fee and Establishing Intervention Deadline;
1/28 98	Order Granting Request;
2/6 98	Motion to Intervene by MidAmerican;
2/9 98	Letter to Intervene by PAM;
2/17 98	NSP's reply to Petitions to Intervene;
2/23 98	Amended Letter to Intervene by PAM;
3/3 98	Notice of Appearance (Robert C. Riter, Jr.);
4/7 98	Motion to Amend Application;
4/7 98	Amended Application;
4/15 98	Amended Motion for Intervention and Comment by MidAmerican;
5/6 98	Order Regarding Jurisdiction and Approving Intervention;
6/3 98	NSP's Response to MidAmerican's First Set of Data Requests;
11/18 98	Order for and Notice of Hearing;
12/11 98	Testimony and Exhibit of Gregory A. Rislov on behalf of Comm Staff;
12/11 98	Testimony and Exhibits of Robert L. Knadle on behalf of Comm Staff;
12/23 98	Rebuttal Testimony and Schedules of James A. Smith;
12/23 98	Rebuttal Testimony and Schedules of James C. Seitz;
12/23 98	Confidential Exhibit, JCS-1 Schedule 8 Rebuttal Testimony of James C. Seitz;
12/29 98	Errata Corrections to James C. Seitz Rebuttal Testimony;
1/4 99	Surrebuttal of Gregory A. Rislov;
1/4 99	Rebuttal Exhibit;

1/8/99	Transcript of Hearing held on 1/4/99;
2/8/99	Applicant's Opening Brief;
3/8/99	Staff's Brief;
3/9/99	Brief of Intervenor Mid American;
4/1/99	Applicant's Reply Brief;
5/12/99	Find of Fact and Con of Law, Notice of Entry of Order;
5/12/99	Docket Closed

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OF COUNSEL
WARREN W. MAY

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January 9, 1998

RECEIVED
JAN 09 1998
SOUTH DAKOTA PUBLIC UTILITIES COMMISSION

<u>HAND CARRIED</u>

Mr. William Bullard, Jr.
Executive Director
Public Utilities Commission
State Capitol
500 East Capitol Avenue
Pierre, South Dakota 57501-5070

RE: **IN THE MATTER OF THE APPLICATION FOR AN ORDER ESTABLISHING A NATURAL GAS LOCAL DISTRIBUTION UTILITY, AND TO ESTABLISH INITIAL NATURAL GAS TRANSPORTATION RATES FOR NORTHERN STATES POWER COMPANY**
Docket NG97-021
Our file: 0185

Dear Bill:

Enclosed is a letter to the Commission addressing the issue which was raised in yesterday's Commission meeting concerning this docket. We ask that you notice an ad hoc meeting for Monday, January 12, 1998.

I will be happy to forward this letter to Suzan Stewart by telecopier.

The question for the Commission is whether it will acknowledge NSP's application and filing in this docket and permit the flow of construction gas to accommodate Hutchinson Technologies, Inc., subject to the ultimate decision of the Commission in this docket as to NSP's status as a natural gas utility in this state and as to the approval of its tariffs.

Thank you very much.

Yours truly,

MAY, ADAM, GERDES & THOMPSON LLP

BY: Dave Gerdes

DAG:mw
Enclosure
cc/enc: Suzan Stewart, by fax 712-252-7396
Jim Wilcox

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January 9, 1998

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SOUTH DAKOTA PUBLIC
UTILITIES COMMISSION

Jim Burg, Chairman
Pam Nelson, Vice Chairman
Laska Schoenfelder, Commissioner
Public Utilities Commission
State Capitol
500 East Capitol Avenue
Pierre, South Dakota 57501-5070

RE: **IN THE MATTER OF THE APPLICATION FOR AN ORDER ESTABLISHING A NATURAL GAS LOCAL DISTRIBUTION UTILITY, AND TO ESTABLISH INITIAL NATURAL GAS TRANSPORTATION RATES FOR NORTHERN STATES POWER COMPANY**
Docket NG97-021
Our file: 0185

Dear Chairman Burg and Commissioners Nelson and Schoenfelder:

This letter is written on behalf of Northern States Power Company as a follow-up to the presentation which was made to you during your regular meeting on January 8, 1998. By this filing NSP seeks to clarify its intentions with respect to this filing in view of the concerns raised by MidAmerican Energy at yesterday's hearing.

NSP has made a detailed filing with the Commission which includes prefiled testimony and exhibits fully explaining the project. Nothing stated in this letter is intended to change the substance of that filing. At this point NSP seeks to flow construction gas to its one customer, which is under contract, Hutchinson Technologies, Inc., located in the Sioux Empire Development Park No. 5 in northeast Sioux Falls, South Dakota. To accomplish this, NSP simply asks the Commission to acknowledge that for this limited purpose NSP is entitled to flow construction gas, subject to the Commission's ultimate decision in this docket as to NSP's status as a natural gas utility and as to the approval of NSP's final tariff.

The pipeline and associated facilities have been constructed in compliance with Federal and State safety standards to ensure safety to the public and the Hutchinson Technologies construction site. Further, Commission staff has monitored the progress of construction. The line is ready to flow gas.

NSP understands and acknowledges that MidAmerican Energy, and perhaps others, are entitled to intervene in this proceeding and contest all or any part of the relief sought in this docket. The risk of going forward is NSP's, and it is willing to do so. NSP understands that it has the burden of going forward and obtaining the Commission's approvals sought in this docket. In the meantime, NSP requests that the Commission accommodate Hutchinson Technologies' need for construction gas.

Yours truly,

MAY, ADAM, GERDES & THOMPSON LLP

BY:

DAG:mw

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January 20, 1998

RECEIVED
JAN 20 1998
SOUTH DAKOTA PUBLIC
UTILITIES COMMISSION

HAND CARRIED

Mr. William Bullard, Jr.
Executive Director
Public Utilities Commission
State Capitol
500 East Capitol Avenue
Pierre, South Dakota 57501-5070

RE: **IN THE MATTER OF THE APPLICATION FOR AN ORDER ESTABLISHING A NATURAL GAS LOCAL DISTRIBUTION UTILITY, AND TO ESTABLISH INITIAL NATURAL GAS TRANSPORTATION RATES FOR NORTHERN STATES POWER COMPANY**
Docket NG97-021
Our file: 0185

Dear Bill:

Enclosed are an original and ten copies of a jurisdiction letter requested by the Commission in the above docket.

Yours truly,

MAY, ADAM, GERDES & THOMPSON LLP

BY:

DAG:mw

Enclosures

cc/enc: Jim Wilcox
John Winter
J.P. Johnson, Esq.

RECEIVED

JAN 20 1998

SOUTH DAKOTA PUBLIC
UTILITIES COMMISSION

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January 20, 1998

Jim Burg, Chairman
Pam Nelson, Vice Chairman
Laska Schoenfelder, Commissioner
Public Utilities Commission
State Capitol
500 East Capitol Avenue
Pierre, South Dakota 57501-5070

RE: **IN THE MATTER OF THE APPLICATION FOR AN ORDER ESTABLISHING A NATURAL GAS LOCAL DISTRIBUTION UTILITY, AND TO ESTABLISH INITIAL NATURAL GAS TRANSPORTATION RATES FOR NORTHERN STATES POWER COMPANY**
Docket NG97-021
Our file: 0185

Dear Chairman Burg and Commissioners Nelson and Schoenfelder:

At its ad hoc meeting of January 12, 1998, the Commission acknowledged Northern States Power Company-South Dakota's ("NSP-SD") application and filing in this docket and permitted the flow of construction gas to accommodate Hutchinson Technology, Inc. During those proceedings, Commissioner Schoenfelder asked for a written statement from the Company outlining its reasons for advocating that the Commission has jurisdiction to regulate NSP-SD as a gas utility. This letter is intended to fulfill that function.

"The Commission shall regulate to the extent provided in this chapter every <u>public utility</u> as defined herein." (Emphasis supplied). SDCL § 49-34A-4.

"'Public utility,' any person operating, maintaining, or controlling in this state equipment or facilities for the purpose of providing gas or electric service to or for the public in whole or in part, in this state." SDCL § 49-34A-1(12).

"'Intrastate natural gas pipeline,' any natural gas pipeline located entirely within the state that transports gas from a receipt point to <u>one or more locations</u> for customers other than the pipeline operator." (Emphasis supplied) [exceptions not relevant to this application are omitted]. SDCL § 49-34A-1(9A).

"'Gas utility,' any person operating, maintaining, or controlling in this state equipment or facilities for providing gas service to or for the public." SDCL § 49-34A-1(9).

"'Gas service,' retail sale of natural gas or manufactured gas distributed through a pipeline to fifty or more customers or the sale of transportation services by an intrastate natural gas pipeline." (Emphasis supplied) SDCL § 49-34A-1(8).

From the foregoing it is clear that the Commission has the obligation to regulate a public utility, and that a public utility is one which maintains or controls equipment or facilities for the purpose of providing gas. It is important to note that the Commission's jurisdiction is invoked when a company <u>maintains or controls</u> equipment <u>for the purpose of</u> (not that is actually serving) providing gas. Schedule 2 of Dan Woehrle's testimony contained in NSP-SD's application describes the project in detail. On page 1 of his testimony Mr. Woehrle summarizes the project as follows:

> NSP is proposing to construct, maintain and operate a new natural gas distribution system consisting of a steel pipeline approximately 3.5 miles in length, regulating and metering facilities, and a 60 PSIG polyethylene distribution system. These proposed facilities will be constructed, maintained, and operated according to standards which meet or exceed the minimum federal safety standard for transportation of natural gas described in United States Department of Transportation Safety Regulations, Title 49, Code of Federal Regulations, Part 192.

At page 4 of his testimony accompanying NSP-SD's application, Jim Wilcox states:

> NSP-SD is now planning to construct a 3.5 mile long, 4.5 inch diameter steel distribution lateral pipeline from near the terminus of the 13 mile Angus C. Anson natural gas fuel supply pipeline to the new Hutchinson Technologies, Inc., facility in the Sioux Empire Development Park number 5 in northeast Sioux Falls, South Dakota.

From the foregoing, it is apparent that NSP-SD will be ". . . operating, maintaining, or controlling in this state equipment or facilities for the purpose of providing gas . . . to or for the public in whole or in part . . . ." NSP-SD is therefore a "public utility" which the Commission "shall regulate."

Not only is NSP-SD a "public utility," it is also a "gas utility" because it is "operating, maintaining, or controlling in this state equipment or facilities for providing gas service to or for the public." Clearly, the facility constructed by NSP-SD meets the definition of an "intrastate natural gas pipeline" and by transporting gas for hire through that pipeline NSP-SD has provided a gas service. Beyond that, however, NSP-SD is maintaining facilities capable of providing gas service to fifty or more customers, and can thus invoke the Commission's regulation because is it without question a "public utility" which must be regulated by the Commission under SDCL § 49-34A-4.

The operation of an intrastate natural gas pipeline clearly means that NSP-SD is providing a gas service, thus entitling it to be a gas utility. Even if the facility was not viewed as an intra-state gas pipeline, however, NSP-SD would still be subject to regulation as a "gas utility," because it is "public utility" capable of providing gas service to or for the public. The Company is a "public utility" because of its electric operations. The new gas service represented by this docket is viewed by the Company as an extension of its existing services. It would be odd for NSP-SD's electric services to be regulated while the gas services provided by the same legal entity and personnel were not.

In addition to the foregoing, the Commission's statutory authority clearly permits it to regulate those voluntarily requesting it. The Commission has recognized this authority and established a precedent by accepting rate and tariff jurisdiction over the AMPIP pipeline even though it served only one customer, its corporate parent. Docket NG95-017.

The South Dakota Supreme Court has ruled that the Commission has subject matter jurisdiction over those subjects of inquiry given it by statute. *State ex rel. Johnson vs. Public Utilities Commission*, 381 NW2d 226 (SD 1986). Ample statutory authority exists not only to justify Commission jurisdiction but to mandate it.

In conclusion, the Company is clearly a public utility and subject to regulation. As such, it is also just as clearly a gas utility, whether or not it provides service to fifty or more customers. Thus, the Company is entitled to an order from the Commission establishing NSP-SD as a natural gas utility regulated by the Commission. It is further the position of the Company that, since the Commission has the jurisdiction, if the Company wishes to be regulated as to rates, the Commission can provide that regulation.

Yours truly,

MAY, ADAM, GERDES & THOMPSON LLP

BY: David A. Gerdes

DAG:mw

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF SOUTH DAKOTA

IN THE MATTER OF THE APPLICATION FOR AN ORDER ESTABLISHING A NATURAL GAS LOCAL DISTRIBUTION UTILITY, AND TO ESTABLISH INITIAL NATURAL GAS TRANSPORTATION RATES FOR NORTHERN STATES POWER COMPANY	)	**ORDER ASSESSING FILING FEE AND ESTABLISHING INTERVENTION DEADLINE** **NG97-021**

On December 16, 1997, Northern States Power Company (NSP), filed with the Public Utilities Commission (Commission) an application for an order establishing a natural gas local distribution utility, and to establish initial natural gas transportation rates. The initial rate will allow NSP-SD to serve the new Hutchinson Technology, Inc. (HTI) facility in the Sioux Empire Development Park Number 5 in eastern Sioux Falls, SD through a new distribution lateral pipeline. HTI had contacted NSP-SD and requested the proposed service. The proposed tariff, rate schedule, and form of service agreement would establish NSP-SD as a regulated utility in the state of South Dakota, subject to Commission jurisdiction. The proposed maximum rate is a volumetric rate per Mcf with a per month fixed customer service charge. At present, only HTI is affected by the proposed rate and tariff. The HTI plant is expected to be in commercial operation in February of 1998.

NSP is also requesting that the Commission waive the tariff schedule arrangement and form of tariff rules found at ARSD 20:10:13:04 and 20:10:13:05 to the extent necessary to accept the proposed tariff and rates on the proposed effective date of January 16, 1998. NSP also requests waiver of any other Commission rules necessary to allow the tariff and rate to be effective on the date requested. NSP has further requested the Commission to approve the proposed initial rate, subject to refund and subject to hearing, within 30 days following the date of the filing.

SDCL 49-1A-8 authorizes the Commission to require a deposit of up to one hundred thousand dollars ($100,000) in the South Dakota Public Utilities Commission's (SDPUC) regulatory assessment fee fund to defray Commission expenses incident to analyzing and ruling upon this type of filing. Pursuant to SDCL 1-26-17.1 and ARSD 20:10:01:15.02 and .03, any individual or entity may file a petition to intervene or may comment on the merits of NSP's filing on or before February 9, 1998.

At its regularly scheduled meeting of January 8, 1998, the Commission considered this matter. The Commission found that pursuant to SDCL 49-1A-8, NSP shall be assessed a filing fee as requested by the executive director up to the statutory limit of $100,000. The Commission further directed the executive director to set an intervention deadline in this matter. It is therefore

ORDERED that NSP shall deposit a filing fee, to be established by the executive director, in the SDPUC regulatory fee fund and it shall deposit any additional amounts as requested by the executive director; and it is further

ORDERED, that any individual or entity may file with the Commission its petition to intervene no later than February 9, 1998.

Dated at Pierre, South Dakota, this 22nd day of January, 1998.

CERTIFICATE OF SERVICE

The undersigned hereby certifies that this document has been served today upon all parties of record in this docket, as listed on the docket service list, by facsimile or by first class mail, in properly addressed envelopes, with charges prepaid thereon.

By: Delaine Kolbo

Date: 1/23/98

(OFFICIAL SEAL)

BY ORDER OF THE COMMISSION:

James A. Burg

JAMES A. BURG, Chairman

Pam Nelson

PAM NELSON, Commissioner

Laska Schoenfelder

LASKA SCHOENFELDER, Commissioner

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF SOUTH DAKOTA

IN THE MATTER OF THE APPLICATION FOR AN ORDER ESTABLISHING A NATURAL GAS LOCAL DISTRIBUTION UTILITY, AND TO ESTABLISH INITIAL NATURAL GAS TRANSPORTATION RATES FOR NORTHERN STATES POWER COMPANY	**))))))**	**ORDER GRANTING REQUEST** **NG97-021**

On December 16, 1997, Northern States Power Company (NSP), filed with the Public Utilities Commission (Commission) an application for an order establishing a natural gas local distribution utility, and to establish initial natural gas transportation rates. The initial rate will allow NSP-SD to serve the new Hutchinson Technology, Inc. (HTI) facility in the Sioux Empire Development Park Number 5 in eastern Sioux Falls, SD through a new distribution lateral pipeline. HTI had contacted NSP-SD and requested the proposed service. The proposed tariff, rate schedule, and form of service agreement would establish NSP-SD as a regulated utility in the state of South Dakota, subject to Commission jurisdiction. The proposed maximum rate is a volumetric rate per Mcf with a per month fixed customer service charge. At present, only HTI is affected by the proposed rate and tariff.

NSP is also requesting that the Commission waive the tariff schedule arrangement and form of tariff rules found at ARSD 20:10:13:04 and 20:10:13:05 to the extent necessary to accept the proposed tariff and rates on the proposed effective date of January 16, 1998. NSP also requests waiver of any other Commission rules necessary to allow the tariff and rate to be effective on the date requested. NSP has further requested the Commission to approve the proposed initial rate, subject to refund and subject to hearing, within 30 days following the date of the filing.

At its regularly scheduled meeting of January 8, 1998, the Commission ordered that pursuant to SDCL 49-1A-8, NSP shall be assessed a filing fee as requested by the executive director up to the statutory limit of $100,000 and February 9, 1998, was established as the deadline for intervention. The Commission took under advisement the request by NSP to permit it to flow gas to its one customer, HTI.

On January 12, 1998, at a duly noticed ad hoc meeting, the Commission considered the matter of permitting NSP to flow gas in order to accommodate its one customer, HTI. The Commission unanimously voted to allow NSP to flow gas through its pipeline, subject to refund, in order to accommodate its customer, HTI. It is therefore

ORDERED that NSP shall be allowed to flow gas through its pipeline, subject to refund, in order to accommodate its customer, HTI.

Dated at Pierre, South Dakota, this 28th day of January, 1998.

CERTIFICATE OF SERVICE

The undersigned hereby certifies that this document has been served today upon all parties of record in this docket, as listed on the docket service list, by facsimile or by first class mail, in properly addressed envelopes, with charges prepaid thereon.

By Delaine Kolbo

Date 1/28/98

(OFFICIAL SEAL)

BY ORDER OF THE COMMISSION:

James A. Burg
JAMES A. BURG, Chairman

Pam Nelson
PAM NELSON, Commissioner

Laska Schoenfelder
LASKA SCHOENFELDER, Commissioner

MidAmerican
ENERGY

MidAmerican Energy Company
401 Douglas Street
P.O. Box 778
Sioux City, Iowa 51101
712 277-7587 Telephone
712 252-7396 Fax

RECEIVED

FEB 06 1998

SOUTH DAKOTA PUBLIC
UTILITIES COMMISSION

Suzan M. Stewart
Managing Attorney

February 5, 1998

OVERNIGHT DELIVERY

William Bullard, Jr.
Executive Director
South Dakota Public Utilities Commission
State Capitol Building
Pierre, SD 57501

In Re: MidAmerican Energy Company
Docket No. NG97-021

Dear Mr. Bullard:

Enclosed please find the original and 4 copies of the Motion to Intervene of MidAmerican Energy Company for filing in the above-captioned matter.

Please file stamp the extra copy and return to me in the self-addressed stamped envelope.

Very truly yours,

sh
Enc.

RECEIVED

FEB 06 1998

SOUTH DAKOTA PUBLIC UTILITIES COMMISSION

BEFORE THE PUBLIC UTILITIES COMMISSION
STATE OF SOUTH DAKOTA

In the Matter of the Application for an Order Establishing a Natural Gas Local Distribution Utility, and to Establish Initial Transportation Rates for Northern States Power Company	)))))	DOCKET NO. NG97-021

MOTION TO INTERVENE

COMES NOW, MidAmerican Energy Company ("MidAmerican") and moves to intervene in the above proceeding pursuant to SDCL 1-26-17.1 and ARSD 20:10:01:15.02 - .03 and to the Order issued by the South Dakota Public Utilities Commission ("Commission") in this docket on January 22, 1998.

1. MidAmerican is an Iowa corporation authorized to conduct business in the States of South Dakota, Iowa, Illinois and Nebraska. MidAmerican is a combination natural gas and electric utility and is the largest natural gas local distribution company ("LDC") in the State of South Dakota, with throughput of 124,075,348 therms of natural gas to 62,893 customers in 1997. MidAmerican serves 23 communities in the State of South Dakota.

2. Northern States Power ("NSP") has filed a petition in the above docket to establish a natural gas local distribution utility and to establish initial natural gas transportation rates. The proposed tariff, rate schedule, and form of service agreement would establish NSP-SD as a regulated utility in the State of South Dakota, subject to Commission jurisdiction. It is proposed that NSP-SD provide natural gas distribution services in areas presently served by MidAmerican.

The January 22, 1998, Commission Order established February 9, 1998, as the deadline to file a petition to intervene or comment on the merits of NSP's filing.

3. Any policy which may be developed in this proceeding will have an impact on future actions of LDCs. Additionally, NSP-SD proposes to serve an area presently served by MidAmerican. MidAmerican, therefore, has a substantial interest in the outcome of this proceeding and in any policy decisions developed therein.

4. The initial rate proposed will allow NSP-SD to serve the new Hutchinson Technology, Inc. ("HTI") facility in Sioux Falls, South Dakota. MidAmerican serves customers in this area and is therefore a competitor of the potential utility. MidAmerican has an interest in the basis of rates and services provided by the potential utility.

WHEREFORE, for the foregoing reasons, MidAmerican Energy Company moves to intervene in this proceeding and to be afforded all of the rights of any party thereto.

DATED this 5th day of February, 1998.

Respectfully Submitted,

MIDAMERICAN ENERGY COMPANY

By: ______________________

Suzan M. Stewart
Managing Attorney
P.O. Box 778
Sioux City, IA 51102
(712) 277-7587 (Voice)
(712) 252-7396 (Fax)

CERTIFICATE OF SERVICE

I certify that a true and correct copy of the attached Motion to Intervene in Docket No. NG97-021 was sent by first class, postage pre-paid, to the following:

Michael J. Hanson
Chief Executive & General Manager
Northern States Power Company
P.O. Box 988
Sioux Falls, SD 57101-0988

Mr. David A. Gerdes
Attorney at Law
P.O. Box 160
Pierre, SD 57501

PAM Natural Gas

PAM

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FEB 09 1998

SOUTH DAKOTA PUBLIC UTILITIES COMMISSION

February 5, 1998

Mr. William Bullard Jr.
Executive Director
South Dakota Public Utilities Commission
State Capital Building
500 E. Capitol
Pierre, SD 57501

Re: **Petition for Intervention**

PAM Natural Gas, LLC, (PNG) of Sioux Falls, South Dakota, petitioner, respectfully requests the South Dakota Public Utilities Commission to allow PNG to intervene in Docket NG97-021 filed by Northern States Power.

PNG is a natural gas marketer doing business in South Dakota. PNG represents natural gas customers using both transportation and sales gas. PNG would like to be involved in this docket to provide comments on the transportation tariffs submitted by Northern States Power. Our involvement is intended to ensure that the proposed tariff allows third party gas suppliers equal access to the pipeline installed by Northern States Power.

This Petition is made this date, February 5, 1998.

PAM Natural Gas, LLC

By ______________________
Jennifer Erickson
Chief Operating Officer
PAM Natural Gas
P.O. Box 5200
Sioux Falls, SD 57117-5200

LAW OFFICES
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OF COUNSEL:
WARREN W. MAY

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February 17, 1998

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SOUTH DAKOTA PUBLIC
UTILITIES COMMISSION

HAND CARRIED

Mr. William Bullard, Jr.
Executive Director
Public Utilities Commission
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Pierre, South Dakota 57501-5070

RE: **IN THE MATTER OF THE APPLICATION FOR AN ORDER ESTABLISHING A NATURAL GAS LOCAL DISTRIBUTION UTILITY, AND TO ESTABLISH INITIAL NATURAL GAS TRANSPORTATION RATES FOR NORTHERN STATES POWER COMPANY**
Docket NG97-021
Our file: 0185

Dear Bill:

Enclosed are an original and ten copies of a reply to PAM Natural Gas and MidAmerican's petitions to intervention the above docket. Also enclosed is an extra face page of the Petition, which please date stamp and return to me in the enclosed self-addressed stamped envelope. Please file the enclosures.

Yours truly,

MAY, ADAM, GERDES & THOMPSON LLP

BY: Dave Gerdes

DAG:mw

Enclosures

cc/enc: Jim Wilcox
John Winter
J.P. Johnson, Esq.

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FEB 17 1998
SOUTH DAKOTA PUBLIC
UTILITIES COMMISSION

BEFORE THE PUBLIC UTILITIES COMMISSION
STATE OF SOUTH DAKOTA

IN THE MATTER OF THE APPLICATION FOR AN ORDER ESTABLISHING A NATURAL GAS LOCAL DISTRIBUTION UTILITY, AND TO ESTABLISH INITIAL TRANSPORTATION RATES FOR NORTHERN STATES POWER COMPANY	)))))	NG97-021 NSP'S REPLY TO PETITIONS TO INTERVENE

For its reply to PAM Natural Gas' ("PNG") and MidAmerican's petitions to intervene, Northern States Power Company ("NSP") states as follows:

1. In its Motion (sic) to Intervene MidAmerican states in paragraph 3 that "Any policy which may be developed in this proceeding will have an impact on future actions of LDCs." NSP is unsure what, if any, policy issues might be addressed in this proceeding. However, to the extent that any such issues develop, NSP agrees that MidAmerican reasonably could have an interest in policy issues.

2. MidAmerican further states in paragraphs 2 and 3 that NSP-SD is proposing to provide natural gas service in areas " . . . presently served by MidAmerican". NSP believes that this assertion is incorrect. As indicated in its prefiled documents, NSP is proposing to provide service to a new facility in the Sioux Empire Development Park Number 5 located in northeast Sioux Falls. This is a new "greenfield" industrial park recently begun by the Sioux Falls Development Foundation. NSP is not aware of any other natural gas suppliers in this industrial park. SDCL § 9-35-3 provides for non-exclusive service territories for natural gas in South Dakota. Although MidAmerican serves customers in areas

adjacent to this industrial park, the customer with which NSP has a contract in the industrial park is not served by MidAmerican. Therefore, this service by NSP is not duplicative.

3. MidAmerican recognizes in point number 4 that it is a competitor of NSP's proposed natural gas utility. MidAmerican goes on to state that its interest in this matter is on the basis of rates and services provided by NSP. NSP believes that the basis of its rates and services is proprietary and confidential and should not be open review by competitors.

4. PNG limits its intervention " . . . to ensure that the proposed tariff allows third party gas suppliers equal access to the pipeline installed by Northern States Power." NSP's filing clearly shows that it seeks to be designated as a natural gas utility and to have its transport rate approved, recognizing that its pipeline is available to others for transport of gas under appropriate terms, rates and restrictions.

WHEREFORE NSP respectfully requests that the Commission limit PNG's and MidAmerican's intervention to policy issues.

Dated this 17th day of February, 1998.

MAY, ADAM, GERDES & THOMPSON LLP

BY: ______________________
DAVID A. GERDES
Attorneys for
503 South Pierre Street
P.O. Box 160
Pierre, South Dakota 57501-0160
Telephone: (605)224-8803
Fax: (605)224-6289

CERTIFICATE OF SERVICE

David A. Gerdes of May, Adam, Gerdes & Thompson LLP hereby certifies that on the 17th day of February, 1998, he mailed by United States mail, first class postage thereon prepaid, a true and correct copy of the foregoing in the above-captioned action to the following at their last known addresses, and sent via telefax to those indicated, to-wit:

Suzan M. Stewart
Managing Attorney
MidAmerican Energy Company
P.O. Box 778
Sioux City, Iowa 51102
Via Telefax: 712-252-7396

Jennifer Erickson
Chief Operating Officer
PAM Natural Gas
P.O. Box 5200
Sioux Falls, South Dakota 57117-5200
Via Telefax: 605-339-9909

Michael J. Hanson
Chief Executive and General Manager
Northern States Power Company
P.O. Box 988
Sioux Falls, South Dakota 57101-0988

David A. Gerdes

PAM
Natural
Gas

RECEIVED

FEB 23 1998

SOUTH DAKOTA PUBLIC
UTILITIES COMMISSION

February 18, 1998

Mr. William Bullard Jr.
Executive Director
South Dakota Public Utilities Commission
State Capital Building
500 E. Capitol
Pierre, SD 57501

Re: **Amended Petition for Intervention**

PAM Natural Gas, LLC, (PNG) of Sioux Falls, South Dakota, petitioner, respectfully requests the South Dakota Public Utilities Commission to allow PNG to intervene in Docket NG97-021 filed by Northern States Power.

PNG is a natural gas marketer doing business in South Dakota. PNG represents natural gas customers using both transportation and sales gas. PNG is interested in the filing submitted by Northern States Power. Our involvement is intended to ensure that the filing allows third party gas suppliers equal access to the pipeline installed by Northern States Power.

This Petition is made this date, February 18, 1998.

PAM Natural Gas, LLC

By: ______________________
Jennifer Erickson
Chief Operating Officer
PAM Natural Gas
P.O. Box 5200
Sioux Falls, SD 57117-5200

RECEIVED
FEB 23 1998
SOUTH DAKOTA PUBLIC
UTILITIES COMMISSION

STATE OF SOUTH DAKOTA
BEFORE THE PUBLIC UTILITIES COMMISSION

IN THE MATTER OF Application for an Order Establishing a Natural Gas Local Distribution Utility and to Establish Initial Natural Gas Transportation Rates for Northern States Power Company	Docket No. NG97-021

CERTIFICATE OF SERVICE

I hereby certify that I have caused the Amended Petition of Intervention to be served to Public Utilities Commission on February 18th, 1998 by first class mail, postage prepaid. The remainder of the service list was served by first class mail, postage prepaid, on this date.

Respectfully submitted this 18th day of February 1998.

Jennifer Erickson
PAM Natural Gas, LLC
Chief Operating Officer

SERVICE LIST
Michael J. Hanson
Chief Executive and General Manager
Northern States Power Company
P.O. Box 988
Sioux Falls, SD 57101-0988

Suzan M. Stewart
Managing Attorney
MidAmerican Energy Company
P.O. Box 778
Sioux City, IA 51102

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ROBERT B. ANDERSON
BRENT A. WILBUR
TIMOTHY M. ENGEL
MICHAEL F. SHAW
ROBERT K. SAHR

OF COUNSEL:
WARREN W. MAY

TELEPHONE
605 224-8803
TELECOPIER
605 224-6289

E-MAIL
dag@magt.com

February 26, 1998

RECEIVED
FEB 27 1998
SOUTH DAKOTA PUBLIC
UTILITIES COMMISSION

Jennifer Erickson
Chief Operating Officer
PAM Natural Gas
P.O. Box 5200
Sioux Falls, South Dakota 57117-5200

RE: **IN THE MATTER OF THE APPLICATION FOR AN ORDER ESTABLISHING A NATURAL GAS LOCAL DISTRIBUTION UTILITY, AND TO ESTABLISH INITIAL NATURAL GAS TRANSPORTATION RATES FOR NORTHERN STATES POWER COMPANY**
Docket NG97-021
Our file: 0185

Dear Ms. Erickson:

Please note that I have appeared as attorney on behalf of NSP in this proceeding. I would greatly appreciate it if you would in the future serve copies of your pleadings on me as required by Commission rules. I did not receive a copy of your amended petition for intervention, the existence of which I only learned of from Executive Director Bullard.

Yours truly,

MAY, ADAM, GERDES & THOMPSON LLP

BY: [signature]

DAG:mw

cc: Michael J. Hanson
Suzan M. Stewart
Jim Wilcox
Bill Bullard

LAW OFFICES
RITER, MAYER, HOFER, WATTIER & BROWN, LLP
Professional & Executive Building
319 South Coteau Street
P.O. Box 280
Pierre, South Dakota 57501-0280

R. C. RITER (1912-1994)
E. D. MAYER
ROBERT D. HOFER
ROBERT C. RITER, JR.
JERRY L. WATTIER
JOHN L. BROWN

DAVID A. PFEIFLE

TELEPHONE
605-224-5825
TELECOPIER
605-224-7102

RECEIVED
MAR 03 1998
SOUTH DAKOTA PUBLIC
UTILITIES COMMISSION

March 2, 1998

Mr. William Bullard, Jr.
Executive Director
South Dakota Public Utilities Commission
State of South Dakota
500 East Capitol
Pierre, SD 57501

Re: NG97-021
In the Matter of the Application for an Order Establishing a Natural Gas Local Distribution Utility, and to Establish Initial Natural Gas Transportation Rates for Northern States Power

Dear Mr. Bullard:

Enclosed herewith please find original Notice of Appearance and Certificate of Service in the above entitled matter. Please file same in your office.

Thank you.

Very truly yours,

RITER, MAYER, HOFER, WATTIER & BROWN, LLP

By

RCR Jr-wb

Enclosure

P.S. I enclose an additional copy of the Notice of Appearance. I would appreciate it if you would file stamp the same and return it to me. Thank you.

RECEIVED

MAR 03 1998

SOUTH DAKOTA PUBLIC UTILITIES COMMISSION

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF SOUTH DAKOTA

IN THE MATTER OF THE APPLICATION FOR AN ORDER ESTABLISHING A NATURAL GAS LOCAL DISTRIBUTION UTILITY, AND TO ESTABLISH INITIAL NATURAL GAS TRANSPORTATION RATES FOR NORTHERN STATES POWER COMPANY	NG 97-021 NOTICE OF APPEARANCE

PLEASE TAKE NOTICE that the undersigned, Robert C. Riter, Jr. of Riter, Mayer, Hofer, Wattier & Brown, LLP of Pierre, South Dakota, enters his appearance as co-counsel with Suzan M. Stewart, Attorney at Law of Sioux City, Iowa, on behalf of MidAmerican Energy Company in the above entitled action, and requests notice, by copy, of all matters.

DATED at Pierre, South Dakota this 2nd day of March, 1998.

RITER, MAYER, HOFER, WATTIER
& BROWN, LLP

By: ______________________
Robert C. Riter, Jr.
A member of said firm
319 S. Coteau - P. O. Box 280
Pierre, SD 57501-0280
Attorneys for MidAmerican
Energy Company
Trust National Association

CERTIFICATE OF SERVICE

I, Robert C. Riter, Jr., certify that true and correct copy of Notice of Appearance was mailed to the following by first class mail on the 2nd day of March, 1998:

Michael J. Hanson
Chief Executive & General Manager
Northern States Power Company
P. O. Box 988
Sioux Falls, SD 57101-0988

Mr. David A. Gerdes
Attorney at Law
P. O. Box 160
Pierre, SD 57501

Jennifer Erickson
Chief Operating Officer
PAM Natural Gas
P. O. Box 5200
Sioux Falls, SD 57117-5200

Robert C. Riter, Jr.

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ROBERT B. ANDERSON
BRENT A. WILBUR
TIMOTHY M. ENGEL
MICHAEL F. SHAW
ROBERT K. SAHR

OF COUNSEL
WARREN W. MAY

TELEPHONE
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E-MAIL
dag@magt.com

April 7, 1998

HAND DELIVERY

Mr. William Bullard, Jr.
Executive Director
Public Utilities Commission
State Capitol
500 East Capitol Avenue
Pierre, South Dakota 57501-5070

RECEIVED
APR 07 1998
SOUTH DAKOTA PUBLIC UTILITIES COMMISSION

RE: **NSP NATURAL GAS UTILITY APPLICATION**
Docket NG97-021
Our file: 0185

Dear Bill:

Enclosed are an original and ten copies of a Motion to Amend NSP's Application, to which is attached is the proposed Amended Application. Please file the enclosures. We would appreciate it if the commission could take this up at its next available meeting.

With a copy of this letter, I am sending copies of the enclosures to the service list.

Yours truly,

MAY, ADAM, GERDES & THOMPSON LLP

BY: Dave Gerdes

DAG:ak
Enclosures
cc/enc: Susan Stewart
Jennifer Erickson
Michael J. Hanson
Jim Wilcox
John Winter
James P. Johnson

RECEIVED

APR 07 1998

SOUTH DAKOTA PUBLIC UTILITIES COMMISSION

BEFORE THE PUBLIC UTILITIES COMMISSION
STATE OF SOUTH DAKOTA

IN THE MATTER OF THE APPLICATION FOR AN ORDER ESTABLISHING A NATURAL GAS LOCAL DISTRIBUTION UTILITY, AND TO ESTABLISH INITIAL TRANSPORTATION RATES FOR NORTHERN STATES POWER COMPANY	NG97-021 **MOTION TO AMEND APPLICATION**

COMES NOW Northern States Power Company-SD ("NSP-SD"), and moves the commission as follows:

1. To permit NSP-SD to amend its petition herein in the form and style attached hereto; and

2. To amend the title of the proceeding in the following style:

> IN THE MATTER OF THE APPLICATION FOR AN ORDER ESTABLISHING A NATURAL GAS UTILITY, AND TO ESTABLISH INITIAL NATURAL GAS TRANSPORTATION RATES FOR NORTHERN STATES POWER COMPANY.

WHEREFORE NSP-SD prays that the commission grant the motion as being consistent with the commission's statutory authority and the purposes for which NSP-SD seeks to provide natural gas transportation services.

Dated this 6 day of April, 1998.

MAY, ADAM, GERDES & THOMPSON LLP

BY [signature]
DAVID A. GERDES
Attorneys for NSP-SD
503 South Pierre Street
P.O. Box 160
Pierre, South Dakota 57501-0160
Telephone: (605)224-8803
Fax: (605)224-6289

CERTIFICATE OF SERVICE

David A. Gerdes of May, Adam, Gerdes & Thompson LLP hereby certifies that on the 7th day of April, 1998, he mailed by United States mail, first class postage thereon prepaid, a true and correct copy of the foregoing in the above-captioned action to the following at their last known addresses, to-wit:

Suzan M. Stewart
Managing Attorney
MidAmerican Energy Company
P.O. Box 778
Sioux City, Iowa 51102
Via Telefax: 712-252-7396

Jennifer Erickson
Chief Operating Officer
PAM Natural Gas
P.O. Box 5200
Sioux Falls, South Dakota 57117-5200
Via Telefax: 605-339-9909

Michael J. Hanson
Chief Executive and General Manager
Northern States Power Company
P.O. Box 988
Sioux Falls, South Dakota 57101-0988

David A. Gerdes

MidAmerican
ENERGY

RECEIVED

APR 15 1998

SOUTH DAKOTA PUBLIC
UTILITIES COMMISSION

MidAmerican Energy Company
401 Douglas Street
P.O. Box 778
Sioux City, Iowa 51101
712 277-7587 Telephone
712 252-7396 Fax

Suzan M. Stewart
Managing Attorney

April 14, 1998

OVERNIGHT DELIVERY

William Bullard, Jr.
Executive Director
South Dakota Public Utilities Commission
State Capitol Building
Pierre, SD 57501

In Re: Northern States Power Company
Docket No. NG97-021

Dear Mr. Bullard:

Enclosed please find the original and 4 copies of the Amended Motion for Intervention and Comment of MidAmerican Energy Company for filing in the above-captioned matter.

Please file stamp the extra copy and return to me in the self-addressed stamped envelope.

Very truly yours,

sh
Enc.
CC: Certificate of Service

RECEIVED

APR 15 1998

SOUTH DAKOTA PUBLIC UTILITIES COMMISSION

BEFORE THE PUBLIC UTILITIES COMMISSION
STATE OF SOUTH DAKOTA

IN THE MATTER OF THE APPLICATION FOR AN ORDER ESTABLISHING A NATURAL GAS UTILITY, AND TO ESTABLISH INITIAL NATURAL GAS TRANSPORTATION RATES FOR NORTHERN STATES POWER COMPANY	)	NG97-021 **AMENDED MOTION FOR INTERVENTION AND COMMENT**

COMES NOW MidAmerican Energy Company ("MidAmerican") and for its Amended Motion for Intervention and Comment in this proceeding submits as follows:

1. On February 6, 1998, MidAmerican filed its Motion to Intervene in the above-captioned proceeding regarding the request of Northern States Power Company-South Dakota ("NSP-SD") to establish a natural gas public utility in the State of South Dakota. The South Dakota Public Utilities Commission ("PUC") moved to grant MidAmerican's intervention without limitation at its Ad Hoc meeting held on February 18, 1998.

2. At its Meeting held on March 10, 1998, after discussion as to the definition of gas utility, NSP-SD agreed to amend its application. On April 7, 1998, Northern States Power Company-South Dakota ("NSP-SD") filed its Amended Application modifying its application to request authority for establishment of natural gas *utility* instead of a natural gas *local distribution utility*.

3. MidAmerican would also like to comment on the manner in which NSP-SD's amended application exceeds the scope of the Commission's expectation. MidAmerican's recollection of the discussion by the PUC at the March 10, 1998 meeting is that the PUC anticipated NSP-SD would amend its application to request authority to establish an *intrastate natural gas pipeline* company, pursuant to SDCL §49-34A-1(9A). NSP-SD instead now seeks to become a gas

utility. A *gas utility* (SDCL §49-34A-1(9)) may provide *gas service* (SDCL §49-34A-1(8)), which includes sales service to 50 or more customers as well as transportation services. It is only the *intrastate natural gas pipeline* (SDCL §49-34A-1(9A)) that exclusively provides transportation service and has no customer minimum. If the PUC should grant NSP-SD's amended application to become a gas utility, its authorization should be specifically limited to the provision of transportation services. More appropriately, the PUC should authorize NSP-SD to become an intrastate natural gas pipeline.

4. At the March 10, 1998 meeting, the PUC asked MidAmerican to amend its Motion for Intervention in the proceeding at such time as NSP-SD amended its Application. Accordingly, MidAmerican hereby requests the PUC to consider this Amended Motion as MidAmerican's Motion to continue to participate in this proceeding without limitation, holding the status of an intervenor. NSP-SD's amendment does not change MidAmerican's interest in this proceeding. MidAmerican will be affected by NSP-SD's proposed natural gas utility in the same manner as stated in its February 6, 1998 intervention. MidAmerican transports natural gas to customers in the area of NSP-SD's proposed intrastate natural gas pipeline and will be affected by its operations.

WHEREFORE, MidAmerican Energy Company respectfully moves the South Dakota Public Utilities Commission to grant its request for intervention without limitation in the above-captioned proceeding as may be amended and additionally respectfully requests the Public Utilities Commission to consider its comments regarding NSP-SD's amended application.

DATED this 14th day of April, 1998.

Respectfully Submitted,

MIDAMERICAN ENERGY COMPANY

By: ______________________

Suzan M. Stewart
Managing Attorney
P.O. Box 778
Sioux City, IA 51102

CERTIFICATE OF SERVICE

I certify that a true and correct copy of the attached Motion to Intervene in Docket No. NG97-021 was sent by first class, postage pre-paid, to the following:

Michael J. Hanson
Chief Executive & General Manager
Northern States Power Company
P.O. Box 988
Sioux Falls, SD 57101-0988

Ms. Jennifer Erickson
Chief Operating Officer
PAM Natural Gas
P.O. Box 5200
Sioux Falls, SD 57117-5200

Mr. David A. Gerdes
Attorney at Law
P.O. Box 160
Pierre, South Dakota 57501-0160

Robert C. Riter, Jr.
Attorney at Law
319 So. Coteau
P.O. Box 280
Pierre, South Dakota 57501-0280

DATED this 14th day of April, 1998.

[signature]

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF SOUTH DAKOTA

IN THE MATTER OF THE APPLICATION FOR AN ORDER ESTABLISHING A NATURAL GAS LOCAL DISTRIBUTION UTILITY, AND TO ESTABLISH INITIAL NATURAL GAS TRANSPORTATION RATES FOR NORTHERN STATES POWER COMPANY	))))))	**ORDER REGARDING JURISDICTION AND APPROVING INTERVENTION** **NG97-021**

On December 16, 1997, Northern States Power Company (NSP), filed with the Public Utilities Commission (Commission) an application for an order establishing a natural gas local distribution utility, and to establish initial natural gas transportation rates. The initial rate will allow NSP-SD to serve the new Hutchinson Technology, Inc. (HTI) facility in the Sioux Empire Development Park Number 5 in eastern Sioux Falls, South Dakota, through a new distribution lateral pipeline. HTI had contacted NSP-SD and requested the proposed service. The proposed tariff, rate schedule, and form of service agreement would establish NSP-SD as a regulated utility in the state of South Dakota, subject to Commission jurisdiction. The proposed maximum rate is a volumetric rate per Mcf with a per month fixed customer service charge. At present, only HTI is affected by the proposed rate and tariff. The HTI plant is expected to be in commercial operation in February of 1998. NSP also requested that the Commission waive the tariff schedule arrangement and form of tariff rules found at ARSD 20:10:13:04 and 20:10:13:05 to the extent necessary to accept the proposed tariff and rates on the proposed effective date of January 16, 1998. NSP further requested waiver of any other Commission rules necessary to allow the tariff and rate to be effective on the date requested. NSP has further requested the Commission to approve the proposed initial rate, subject to refund and subject to hearing, within 30 days following the date of the filing.

At its regularly scheduled meeting of January 8, 1998, the Commission ordered that pursuant to SDCL 49-1A-8, NSP shall be assessed a filing fee as requested by the executive director up to the statutory limit of $100,000 and February 9, 1998, was established as the deadline for intervention. The Commission took under advisement the request by NSP to permit it to flow gas to its one customer, HTI. On January 12, 1998, at a duly noticed ad hoc meeting, the Commission unanimously voted to allow NSP to flow gas through its pipeline, subject to refund, in order to accommodate its customer, HTI. Commissioner Schoenfelder also asked for clarification as to whether the Commission has jurisdiction to regulate NSP-SD as a gas utility. Intervention was granted to MidAmerican Energy. An intervention request was also received from PAM Natural Gas (PAM). The Commission requested that PAM refile its request for intervention to clarify the filing. On February 23, 1998, PAM filed another request for intervention.

On April 7, 1998, NSP filed an amended application requesting that the title of the application be amended to allow it to seek to be regulated as a gas utility. On April 15, 1998, MidAmerican Energy filed an amended motion to intervene based on NSP's amended application.

On April 22, 1998, at its regularly scheduled meeting, the Commission considered NSP's amended application as well as MidAmerican and PAM's request for intervention. The Commission unanimously voted to find that the Commission has jurisdiction in this matter. It also granted intervention to MidAmerican and PAM. The Commission further directed the executive director to establish a procedural schedule. It is therefore

ORDERED that the Commission has jurisdiction in this matter. It is further

ORDERED that MidAmerican and PAM be granted intervention.

Dated at Pierre, South Dakota, this 6th day of May, 1998.

CERTIFICATE OF SERVICE

The undersigned hereby certifies that this document has been served today upon all parties of record in this docket, as listed on the docket service list, by facsimile or by first class mail, in properly addressed envelopes, with charges prepaid thereon.

By Delaine Kolbo

Date 5/6/98

(OFFICIAL SEAL)

BY ORDER OF THE COMMISSION:

James A. Burg
JAMES A. BURG, Chairman

Pam Nelson
PAM NELSON, Commissioner

Laska Schoenfelder
LASKA SCHOENFELDER, Commissioner

LAW OFFICES
MAY, ADAM, GERDES & THOMPSON LLP
503 SOUTH PIERRE STREET
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GLENN W. MARTENS 1881-1963
KARL GOLDSMITH 1885-1966
THOMAS C. ADAM
DAVID A. GERDES
CHARLES M. THOMPSON
ROBERT B. ANDERSON
BRENT A. WILBUR
TIMOTHY M. ENGEL
MICHAEL F. SHAW
ROBERT A. SAHR

OF COUNSEL:
WARREN W. MAY

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June 2, 1998

RECEIVED
JUN 03 1998
SOUTH DAKOTA PUBLIC UTILITIES COMMISSION

HAND DELIVERED

Mr. William Bullard, Jr.
Executive Director
Public Utilities Commission
State Capitol
500 East Capitol Avenue
Pierre, South Dakota 57501-5070

RE: **NSP APPLICATION FOR A NATURAL GAS UTILITY**
Docket NG97-021
Our file: 0185

Dear Bill:

Enclosed are an original and ten copies of NSP's response to Mid-American's first set of data requests. Please file the enclosures. It is my understanding that staff will as a matter of course receive copies of this filing, and that I need not specifically serve additional copies on members of staff assigned to this docket.

With a copy of this letter I am sending copies of these responses to the service list.

Yours truly,

MAY, ADAM, GERDES & THOMPSON LLP

BY: Dave Gerdes

DAG:mw

Enclosures
cc: Jim Wilcox
cc/enc: Suzan Stewart
Jennifer Erickson

BEFORE THE PUBLIC UTILITIES COMMISSION
STATE OF SOUTH DAKOTA

IN THE MATTER OF THE APPLICATION FOR AN ORDER ESTABLISHING A NATURAL GAS UTILITY, AND TO ESTABLISH INITIAL NATURAL GAS TRANSPORTATION RATES FOR NORTHERN STATES POWER COMPANY	)))))	NG97-021

CERTIFICATE OF SERVICE

David A. Gerdes, of May, Adam, Gerdes & Thompson LLP hereby certifies that on the 2nd day of June, 1998, he mailed by United States mail, first class postage thereon prepaid, a true and correct copy of NSP's response to Mid-American's First Set of Data Requests in the above-captioned action to the following at their last known addresses, to-wit:

Suzan M. Stewart
Managing Attorney
MidAmerican Energy Company
P.O. Box 778
Sioux City, Iowa 51102

Jennifer Erickson
Chief Operating Officer
PAM Natural Gas
P.O. Box 5200
Sioux Falls, South Dakota 57117-5200

Dated this 3rd day of June, 1998.

MAY, ADAM, GERDES & THOMPSON LLP

BY: David A. Gerdes
DAVID A. GERDES
Attorneys for NSP-SD
503 South Pierre Street
P.O. Box 160
Pierre, South Dakota 57501-0160
Telephone: (605)224-8803
Fax: (605)224-6289

Northern States Power Company (Minn)
NSP-SD Gas Operations
Before the South Dakota PUC
Docket NG97-021
First Set MEC Data Requests
Response to: No. 1

☐ **Proprietary**

X **Non-Proprietary**

Question:
Please provide a copy of the NSP testimony filed in Docket No's. NG95-017 and NG97-015 discussed in Witness Wilcox testimony on Page 6, Line 19.

Response:
Attached are copies of the requested filings.

Response By: John Winter
Title: Sr. Regulatory Consultant
Company: NSP

November 2, 1995

William Bullard, Jr.
Executive Director
South Dakota Public Utilities Commission
500 East Capitol
Pierre, South Dakota 57501

NG95-017

Re: Application to Establish Initial Transportation Rates for AMPIP Intrastate Natural Gas Pipeline and Request for Declaratory Order

Dear Mr. Bullard:

Pursuant to S.D. Stat. 49-34A-10 and the Rules and Regulations of the South Dakota Public Utilities Commission, Chapter 20:10:13, Public Utility Rate Filing Rules, Associated Milk Producers Pipeline Inc. ("AMPIP"), a subsidiary of Associated Milk Producers, Inc. ("AMPI"), hereby submits for filing this application to establish initial rates and tariffs subject to the Commission's jurisdiction for an intrastate natural gas pipeline to be constructed to serve AMPI in the State of South Dakota. AMPIP requests the Commission allow the tariff and rate to be effective no later than thirty (30) days after filing, or December 1, 1995, in order to facilitate initial service to the AMPI plant in Freeman, South Dakota.

Pursuant to Rule 20:10:27, AMPIP is submitting two copies of this filing letter and associated schedules, and one copy of its initial Transportation Service Tariff.

Background

AMPI is a milk processing cooperative operating in twenty states. AMPI has one facility in South Dakota, located in Freeman; it is the only AMPI facility without natural gas service. Production costs at the Freeman facility are substantially higher than at other AMPI facilities due to higher energy costs. In order to control its operating costs and continue operations in Freeman, AMPI has opted to build and operate an intrastate natural gas pipeline that will provide natural gas to its Freeman plant.

On October 27, 1995, AMPI filed with the Secretary of State pursuant to S.D. Stat. 49-34-1 to form AMPIP as an operating subsidiary to own and operate the proposed intrastate pipeline. Exhibit 1 of this filing contains the testimony of Mr. Harlan Mammen, President of AMPIP, which further explains AMPIP, the need to provide natural gas to the AMPI Freeman Plant, and why AMPI decided to establish a jurisdictional intrastate pipeline affiliate to own and operate the pipeline.

At this time, AMPIP expects to initially provide transportation service to only one customer, the affiliated AMPI plant in Freeman, South Dakota. The terms and conditions and rates to be charged for this transportation service are contained in AMPIP's proposed tariff and service agreement included with this filing as Exhibit 4. AMPIP is authorized to state that AMPI supports Commission acceptance of the rates and tariffs effective December 1, 1995, without suspension, or change or subject to refund condition.

Contents of the Filing

Pursuant to Rule 20:10:13:39 (Subp.1), AMPIP is submitting the following exhibits in support of this filing:

Exhibit 1	Testimony of Mr. Harlan Mammen, Project Support
Exhibit 2	Testimony of Mr. Daniel Woehrle, Description of the Project and Technical Specifications
Exhibit 3	Testimony of Ms. Mary Gill, Cost of Service
Exhibit 4	Transportation Service Tariff
Exhibit 5	Statements Required by Chapter 20:10:13

Exhibit 4 contains a proposed initial Transportation Service Tariff that conforms with Commission Rules 20:10:13:02 through 20:10:13:14. The tariff provides for an initial transportation service to AMPI at a monthly flat fee. No other type of service will be offered on the proposed pipeline at this time. However, AMPIP may eventually provide transportation service to a gas utility (either municipal or investor-owned) serving the City of Freeman, or farm tap customers along the line. AMPIP would file additional initial rates and tariffs at some time in the future if customers request such additional services.

Pursuant to Rule 20:10:13:96, AMPIP submits as Exhibit 5 to this filing an overall cost of service. AMPIP is also sponsoring testimony supporting (i) this cost of service, and (ii) a description of the facilities and pipeline safety compliance plan.

Request for Declaratory Order

AMPIP believes this project meets the requirements of S.D. Stat. 49-4B.2.1(3)(b), and is therefore exempt from the Commission's transmission facilities permit requirements. Exhibit 3 contains the testimony of Mr. Dan Woehrle providing the general description of the project, as well as the design specifications.

AMPIP thus requests that the Commission Order accepting the initial rates also declare the pipeline to be a distribution facility which is exempt from pre-construction Commission transmission permitting review pursuant to S.D. Stat. 49-34B 2.1(3)(b).

Proposed Effective Date

Pursuant to Rule 20:10:13:15, AMPIP respectfully requests that the Commission accept this initial Transportation Service Tariff and rate for service to AMPI effective no later than December 1, 1995. This will allow AMPIP to establish its interconnection with Northern Natural Gas Company and begin providing service to AMPI in time for the majority of the 1995-1996 heating season. Since the tariff provides for service at cost and reasonable terms and conditions, AMPIP will allow AMPI to meet its energy needs at lower costs and thus allow AMPI to maintain production and employment in Freeman, thus accepting the tariff and initial rate on the date requested will serve the public interest.

This filing is being submitted November 2, 1995, and the rates and tariff are proposed to be effective no later than December 1, 1995. Pursuant to Rule 20:10:13:20, AMPIP requests the Commission allow this new tariff to be effective on less than 30 days notice. Since the customer supports approval of the proposed tariffs and rates on the date requested, the public interest would be served by accepting the tariff and rates for filing on less than 30 days notice.

AMPIP will file a compliance report, containing final tariff sheets and a signed copy of the Transportation Service Agreement upon final Commission order.

Requests for Waiver

Pursuant to Rule 20:10:13:08, AMPIP respectfully request waiver of the Commission's tariff format rule (20:10:13:05) to the extent necessary to accept the proposed tariff and rates on the date proposed. Since AMPIP will initially serve only one affected customers, the public interest will not be affected by granting such a waiver. AMPIP would revise its tariff to meet all Commission rules if and when it provides gas service to other, non-affiliated customers.

AMPIP requests waiver of any Commission rules necessary to allow the tariff and rate to be effective on the date requested.

Official Service List

AMPIP respectfully requests the following persons be placed on the Commission's official service list for this proceeding:

Mr. Harlan Mammen
Associated Milk Producers, Inc.
315 North Broadway
New Ulm, Minnesota 56073

Claire Taylor-Sherman
2800 Minnesota World Trade Center
30 E. 7th St.
St. Paul, Minnesota 55101-4999

Notice; Posting; Public Inspection

Pursuant to Rule 20:10:13:23, a copy of this filing is available for public inspection at the AMPIP office located at 136 East Railway, Freeman, S.D. 57029. AMPIP believes this filing complies with the requirements of the Commission's Rules and Regulations.

Pursuant to rule 20:10:13:17, AMPIP is providing written notice of this filing to AMPI. Pursuant to Rule 20:10:13:18, a copy of this written notice is posted at AMPIP's offices at 136 East Railway, Freeman, S.D. 57029.

Conclusion

AMPIP respectfully requests the Commission accept the proposed initial tariff for filing effective December 1, 1995 without suspension or change and without being subject to refund.

Please direct any questions or information requests about the contents of this report to the undersigned at (507) 354-8295.

Respectfully Submitted,

Harlan Mammen
President, AMPI Pipeline Inc.

Direct Testimony and Schedules
Mr. Harlan Mammen

Before the South Dakota Public Utilities Commission

In the Matter of the Application to Establish Initial Transportation Rates for an Intrastate Natural Gas Pipeline

Docket No.____________
Exhibit No. 1

November 1995

Mr. Harlan Mammen
Project Support
Docket No. __________

Q. Please state your name, business address and position with Associated Milk Producers Pipeline, Inc.

A. My name is Harlan Mammen. I am the President of AMPI Pipeline Inc., ("AMPIP") which is an intrastate natural gas pipeline to be constructed and operated in McCook, Turner and Hutchinson counties in southeastern South Dakota. The AMPIP pipeline will initially serve the Associated Milk Producers, Inc. ("AMPI") plant in Freeman, South Dakota. AMPI is the parent company of AMPIP.

Q. Have you previously testified before the Commission?

A. No.

Q. What are your current responsibilities, education and professional background?

A. As Assistant Regional Manager of AMPI, my current responsibilities include direct responsibility for manufacturing operations at fourteen processing plants in five midwestern states, including the plant located in Freeman, S.D.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to explain the history of AMPIP and to explain the need for natural gas service at the AMPI facility in Freeman, South Dakota.

Q. Please explain the history of AMPIP, Inc.

A. AMPIP is a subsidiary of AMPI. AMPI is a national milk producing cooperative operating in twenty states. AMPI's corporate headquarters are located in San Antonio Texas. AMPI has one facility located in the State of South Dakota, in Freeman. Production costs at this Freeman facility are substantially higher than at any other AMPI plant. This is in large part because the Freeman AMPI plant is the only AMPI site without natural gas service. AMPI presently purchases propane to meet the energy requirements of the Freeman plant.

Q. How has the lack of access to natural gas affected the operation of the Freeman plant?

A. AMPI is committed to the continued operation of the facility in Freeman, South Dakota, if it remains economic. The facility at Freeman is presently a processing plant. If AMPI cannot decrease production costs, the facility may be scaled back to handle only milk distribution. AMPI has been actively looking for several years at alternatives to secure natural gas service to the plant including service through extension of existing local distribution company ("LDC") service. However, no South Dakota LDC has constructed a system to serve Freeman.

Q. How does AMPI propose to get natural gas service to the Freeman facility?

A. AMPI is now pursuing a new option. AMPI has established a subsidiary (AMPIP) to build and operate an intrastate pipeline. AMPIP will be a subsidiary of AMPI and proposes to be an intrastate natural gas pipeline subject to the Commission's rate and tariff jurisdiction.

Q. Please explain the proposed pipeline.

A. On October 27, 1995 AMPI filed with the Secretary of State of South Dakota to form an operating subsidiary (AMPIP) that will own and operate the proposed intrastate pipeline. In addition, AMPI has entered into a contract with Northern States Power Company - Gas Utility ("NSP Gas") to build, operate and maintain the proposed pipeline. A general description of the proposed pipeline as well as the technical specifications are discussed in the testimony of Mr. Dan Woehrle of NSP Gas.

Q. Please describe why AMPIP proposes to construct an intrastate pipeline as opposed to a direct end user tap or use of retail LDC gas distribution service.

A. There are three reasons. First, as I mentioned earlier, there is no LDC which serves Freeman, and no existing LDC has offered a cost effective and reliable option. The AMPIP pipeline meets both of AMPI's needs.

Second, the AMPIP line will interconnect with facilities owned by Northern Natural Gas Company ("Northern") which are located near Marion, South Dakota. AMPI (or its wholesale natural gas supplier) will purchase interstate transportation service on Northern for delivery to AMPIP, and AMPIP will transport the gas to the AMPI plant. The Northern lateral facilities were constructed under FERC rules adopted pursuant to §311 of the Natural Gas Policy Act of 1978. Under FERC rules, all interstate transportation service through the lateral must be "on behalf of" an LDC or intrastate pipeline. See 18 CFR Part 284.102. As I understand it, establishing AMPIP as an intrastate pipeline allows AMPI to get gas service while Northern complies with FERC's §311 rules.

Third, this structure would allow for future change. Frankly, AMPI is not an expert at managing natural gas transportation systems. In that light, we contracted for certain pipeline operation and maintenance services from NSP Gas. However, we expect that retail natural gas service could be extended to the residents and businesses in Freeman as early as 1996. As I understand it, the City is looking at a couple of options: (i) establishing a municipal gas utility, which could buy the AMPIP line; or (ii) selecting an investor-owned LDC to extend service off AMPIP; this LDC might then be interested in owning and operating the pipeline. Another alternative would be for a third party to own and operate the intrastate pipeline, transporting for AMPI and a municipal or investor-owned LDC serving the City. Of course, any change in ownership of AMPIP would be subject to Commission review as provided by applicable statutes.

Thus the intrastate pipeline status of AMPIP allows for the project to proceed at this time, but provides flexibility to respond to future developments.

Q What are the benefits of the proposed pipeline?

A. Natural gas service, including the cost of gas supply, transport on Northern and transport to AMPI is expected to produce significant energy cost savings compared to the cost of alternative fuels. These savings could be increased if other customers (e.g. Freeman) take service and contribute to cost recovery. Moreover, additional customers would also presumable enjoy energy cost savings if they take service through the pipeline.

Q Please discuss how AMPIP will comply with the South Dakota pipeline safety code, S.D. Stat. Chap 49-34 B.

A. As an intrastate pipeline, AMPIP will be subject to the Commission's jurisdiction for pipeline safety matters. AMPIP's contractor (NSP Gas) will be working with the Commission Staff during construction and after the line is in service to ensure that applicable pipeline safety requirements are met. AMPIP has contracted with NSP Gas to manage annual and emergency maintenance after the line is in service. NSP Gas is an experienced distribution system operator, and has construction and O&M standards which comply with federal DOT codes under 49 CFR Part 192. As I understand it, S.D. Stat. 49-34B basically authorized the Commission to regulate the safety of intrastate and LDC pipeline systems to DOT code. In addition, NSP Gas will train AMPIP personnel to perform certain routine maintenance (odorant check, meter readings, C-P readings, patrolling and regulator pressure checks). AMPIP personnel will handle the day-to-day O&M checks, and AMPIP has contracted with NSP Gas to conduct the more significant annual DOT compliance work (leak survey, etc.). This arrangement should provide necessary safety inspections at reasonable cost to AMPIP customers.

Q Who will provide the gas supply for AMPI to be transported through AMPIP?

A. As the Commission knows, over the last decade the FERC has restructured the wholesale interstate pipeline industry. Northern Natural no longer provides gas supply services. Instead, AMPI can directly contract with any one of a number of wholesale gas suppliers, using Northern and AMPIP only for transport services.

Q Do you have any final comments?

A. AMPI views this proposal as a significant economic development step for AMPI, the City of Freeman, and southeastern South Dakota. The project will make the AMPI plant and Freeman more competitive, and will help attract economic development to the area. I hope the Commission will agree by approving the proposed tariff and proposed rate as promptly as practicable so the project may proceed.

Q Does this conclude your testimony?

A. Yes.

AFFIDAVIT

STATE OF MINNESOTA)
)
COUNTY OF BROWN)

Affiant, having been first duly sworn, on oath deposes and says:

That he has read the foregoing testimony and if asked the questions therein his answers in response would be as shown;

That the facts contained in said answers are true to the best of his knowledge and belief.

____
Harlan Mammen

SUBSCRIBED AND SWORN to before me this _____day of November, 1995.

____
Notary Public

Direct Testimony and Schedules
Mr. Dan Woehrle

Before the South Dakota Public Utilities Commission

In the Matter of the Application to Establish Initial Transportation Rates for an Intrastate Natural Gas Pipeline

Docket No._____________
Exhibit No. 2

November 1995

Mr. Dan Woehrle
Description of the Project and Technical Specifications

Q Please state your name, business address and position.

A My name is Dan Woehrle. I am a Specialty Engineer with Northern States Power Company - Gas Utility ("NSP Gas") located at 825 Rice Street in St. Paul, MN.

Q What are your current responsibilities, education and professional background?

A My current responsibilities include project management as well as engineering design and construction of natural gas distribution systems. Schedule 1 contains a complete resume of my educational and professional background.

Q Have you previously testified before the Commission?

A No. However, my previous work experience in South Dakota includes managing O & M services and pipeline safety compliance for the 13 mile intrastate natural gas pipeline which serves the NSP Angus Anson Generation Site near Sioux Falls, South Dakota. Thus I am familiar with the Commission's pipeline safety statutes and rules.

Q What is the purpose of your testimony?

A I am acting as the project engineer for construction of the AMPIP Intrastate Pipeline (AMPIP) project. AMPIP contracted with NSP Gas for construction and certain O & M services on the intrastate pipeline. I designed the project and will oversee construction. The purpose of my testimony is to explain the overall project, including the location of the pipeline, the design specifications, and the operation and maintenance plan for the pipeline.

Q Does your testimony include any schedules?

A Yes. Schedule 2 details the items discussed above.

Q Please summarize the information contained in Schedule 2?

A. Schedule 2 supports two conclusions. First the intrastate pipeline will operate at less than 20% of its specified minimum yield strength ("SMYS") and therefore qualifies as a distribution facility under 49 CFR Part 192 and S.D. Stat. 49-34B.8.1. This supports the conclusion that construction of the pipeline is exempt from the Commission's permitting authority under S.D. Stat. 49-34B.' Second, the O & M plan will meet applicable federal DOT and Commission pipeline safety requirements for distribution systems.

Q What is the expected in-service date for the pipeline?

A. If all regulatory approvals are received from the Commission, the AMPIP line could be in service as early as December 1, 1995.

Q Does this conclude your testimony?

A. Yes

AFFIDAVIT

STATE OF MINNESOTA)
)
COUNTY OF RAMSEY)

Affiant, having been first duly sworn, on oath deposes and says:

That he has read the foregoing testimony and if asked the questions therein his answers in response would be as shown;

That the facts contained in said answers are true to the best of his knowledge and belief.

Daniel Woehrle

Daniel Woehrle

SUBSCRIBED AND SWORN to before me this 1st day of November 1995.

Pauline M. Nielsen

Notary Public

PAULINE M. NIELSEN
NOTARY PUBLIC - MINNESOTA
RAMSEY COUNTY
My Comm. Expires Jan. 31, 2000

Schedule 1

Daniel J. Woehrle
Specialty Engineer, Natural Gas Services
Gas Marketing

CURRENT RESPONSIBILITIES (1995 - Present)

Position is directly responsible for engineering, design, construction, and project management of natural gas distibution systems developed for municipalities throughout the Midwest, and for end-user gas distribution systems. The position is directly accountable for gas network analysis, project budgets, project construction, and development of operating and maintanance support systems for NSP customers. This position is also responsible for compliance with all federal, state and local regulatory requirements for natural gas pipelines and gas distribution systems relative to the projects being constructed.

PREVIOUS EMPLOYMENT (Northern States Power Company)

Senior Gas Engineer	1993 - 1995
Superintendent, Gas Standards & Engineering	1990 - 1993
Gas Measurement Engineer	1986 - 1990
Gas Standards Engineer	1985 - 1986
Engineer II	1984 - 1985
Engineer I	1981 - 1984

EDUCATION

Masters in Business Administration, 1995
University of St. Thomas, St. Paul, Minnesota

Bachelor of Science, Mechanical Engineering, 1981
University of Minnesota, Minneapolis, Minnesota

PREVIOUS TESTIMONY

Northern States Power Company, NDPSC Docket PU-400-89-426
Application for Pipeline Siting.

AMPI Pipeline Project
General Description

PROJECT DESCRIPTION

The facilities for the proposed pipeline will involve line pipe - 4.500 inch outside diameter (O.D.) - and related materials which include: valves, flanges, pipe fittings, coating and wrapping materials, barricade posts, pipe supports, caution signs for crossings and other miscellaneous materials.

The proposed pipeline will start at the proposed Northern Natural Gas tie in point south of the City of Canistota in the NW1/4 of Section 24, Township 101N, Range 54W in McCook County. The pipeline will run south along 447th Avenue to Turner County Road #10, turn west along County #10 to Turner County #11, turn south along County #11 to State Highway #44, again turn west along Highway #44 to U.S. Highway 81, and then turn south along Hwy 81. The proposed pipeline will end at a district regulating station in the SE 1/4 of Section 26, Township 99N, Range 56W in Hutchinson County.

The proposed pipeline will be located entirely along existing public rights of way.

The 4.500 inch outside diameter (O. D.) pipe will have a pipe wall thickness of 0.219 inches. The 4.500 inch pipe used at uncased road crossings will have a 0.237 inch wall thickness. The type of pipe used will be American Petroleum Institute (API) 5L Grade X-46 electric resistance welded (ERW). The operating design pressure is 2238 psi for the 4.500 inch pipe.

The proposed maximum allowable operating pressure (MAOP) will be 720 pounds per square inch gauge (psig). Hoop stress at the MAOP is equivalent to 16 percent of the specified minimum yield strength (SMYS).

The proposed actual operating pressure will be 400 pounds per square inch gauge (psig). Hoop stress at the actual operating pressure is equivalent to 9 percent of the specified minimum yield strength.

AMPI Pipeline Project
Pipe Design Specifications

The United States Department of Transportation Safety Regulations, Title 49, Code of Federal Regulations (CFR), Part 192, prescribes minimum federal safety standards for transportation of natural gas by pipelines.

Pipe Size (outside diameter): 4.500 inches

Pipe Type:	The 4.500 inch pipe will be API 5LX Grade X-46 electric resistance welded (ERW).
API 5LX:	API is the American Petroleum Institute. API 5LX is a published specification for high-test steel pipe. This specification covers various grades of seamless and welded steel line pipe. Process of manufacture, chemical, and physical requirements, methods of test, and dimensions are included.
Grade X-46:	Designates pipe manufactured according to API specification 5LX with a specified minimum yield strength of 46,000 pounds per square inch.
ERW:	ERW pipe has one longitudinal seam, which is formed by electric resistance welding during the manufacturing process.

The composition of the pipe furnished shall conform to the chemical requirements specified in API-5LX Standard.

Carbon Percent	0.03%
Manganese (Maximum)	1.35%
Phosphorous (Maximum)	0.04%
Sulfur	0.04%

AMPI Pipeline Project
Pipe Design Factor (F):

Class location determines which design factor safety value is used in the design formula. The following design factor safety values used for natural gas steel pipe are based on the requirements of 49 CFR 192.111.

Class Location	Design Factor (F)
1	0.72
2	0.60
3	0.50
4	0.40

The AMPI pipeline is located in a Class 1 location. To allow for growth along the pipeline and to reduce future pipeline disturbance the entire length of the proposed pipeline will be designed for a Class 3 location with a design factor of 0.50.

Class Locations

The class location unit is an area that extends 220 yards on either side of the centerline of any continuous on-mile length of pipeline, unless otherwise noted.

A Class 1 location is any class location unit that has ten or less buildings intended for human occupancy.

A Class 2 location is any class location unit that has more than ten, but less than forty-six buildings intended for human occupancy.

A Class 3 location is any class location unit that has 46 or more buildings intended for human occupancy; or an area where the pipeline lies within 100 yards of either a building or a small, well defined outside area (such as a playground, recreation area, outdoor theater, or other public place of assembly) that is occupied by twenty or more persons on at least five days a week for ten weeks in any twelve-month period. (The days and weeks need not be consecutive).

A Class 4 location is any class location unit where buildings with four or more stories above ground are prevalent.

AMPI Pipeline Project
Design Formula For Steel Pipe

The design pressure for steel pipe is determined in accordance with the following formula (DOT 192.105):

$$P = \frac{2St \times F \times E \times T}{D}$$

P = Design pressure in pounds per square inch gauge.

S = Yield strength in pounds per square inch, determined in accordance with 192.107.

D = Nominal outside diameter of the pipe in inches.

t = Nominal wall thickness of the pipe in inches. If this is unknown, it is determined in accordance with 192.109. Additional wall thickness required for concurrent external loads in accordance with 192.102 may not be included in computing design pressure.

F = Design Factor determined in accordance with 192.111.

E = Longitudinal joint factor determined in accordance with 192.113.

T = Temperature derating factor determined in accordance with 192.115.

For 4.500 inch O.D., 0.219 inch wall, API-5L X-46 pipe:

$$P = \frac{2 \times 46{,}000 \times 0.219}{4.500} \times 0.50 \times 1.0 \times 1.0$$

P = 2238.0 PSIG

F = Design factor for all pipeline locations shall be 0.50.

E = Longitudinal joint factor for API-5L X-46 pipe is equal to 1.0.

T = Temperature derating factor is equal to 1.0 for gas temperatures up to 250F.

AMPI Pipeline Project
Operation and Maintenance

BLOCK VALVES

The Minimum Federal Safety Standards for Gas Lines as established in CFR 192.181 requires that each high pressure distribution system have valves spaced so as to reduce the time to shut down a section of main in an emergency. The valve spacing is determined by the operating pressure, the size of the mains, and the local physical conditions.

The AMPI pipeline will have block valves installed at intervals of approximately seven miles.

VALVES AND FLANGES

The design, construction, testing, and marking of the valves must comply with the requirements of the Minimum Federal Safety Standards for Gas Lines, 49 CFR 192.145 for valves and 192.147 for flanges.

All valves and flanges will be rated as American National Standards Institute (ANSI) Class 300.

Valves are governed by ANSI B16.34, Steel Valves, Flanged and Butt Welding End.

Flanges are governed by ANSI B16.5, Pipe Flanges and Flanged Fittings.

AMPI Pipeline Project
Operation and Maintenance

PIPELINE CAPACITY

The proposed pipeline and associated facilities are designed to have a maximum throughput capacity of 160,000 cubic feet per hour or 3.84 million cubic feet per day. The expected maximum flow will be 100,000 cubic feet per hour or 1.6 million cubic feet per day.

DEPTH OF COVER REQUIREMENTS

The U. S. DOT Pipeline Safety Regulations 49 CFR 192.327, requires that all gas distribution main be installed so that the depth of cover between the pipe and ground level is at least 24 inches.

The proposed pipeline shall be buried with a minimum level cover of not less than 36 inches in all areas where the pipeline lays in the right-of-way of any public drainage facility or any state, county, town or municipal street or highway. The pipeline will be installed at extra depth where it crosses a public street or highway, railroad, or protected waterway.

PIPELINE SAFETY

The U. S. DOT is responsible for establishing and enforcing safety standards for both interstate and intrastate operators. As a result, the DOT is responsible for 1) enforcing the standards for interstate operators and those intrastate operators the states do not assume responsibility for; and 2) monitoring the participating states to ensure that they are adequately enforcing the federal safety standards. The U. S. DOT Safety Regulations, Title 49, CFR, Part 192, prescribe the minimum federal safety standards for transportation of natural gas by pipelines.

AMPI Pipeline Project
Operation and Maintenance

The proposed pipeline will operate under the jurisdiction of the United States Department of Transportation. Minimum Federal Safety Standards for Gas Lines is contained in Part 192, Title 49, Code of Federal Regulations. Under these rules (192 Subpart L - Operations), AMPI is required to have: 1) an operation and maintenance plan; 2) a procedure for continuing surveillance of its facilities to determine and take appropriate action concerning changes in class location, failures, leakage history, corrosion, substantial changes in maintenance conditions; 3) a damage prevention program; 4) emergency plans; and 5) procedures for investigations of failures.

The proposed pipeline will be designed, constructed, operated, and maintained to ensure safe operation. Emergency plans will be developed in conjunction with local officials and will include notification of local officials in the event that an AMPI related accident occurs.

The pipeline system will be maintained in accordance with 49 CFR 192 Subpart M - Maintenance. These requirements include: 1) a pipeline patrol program; 2) distribution line leakage surveys; 3) line markers for distribution lines; 4) record keeping; 5) requirements for repair procedures; 6) field repair of welds and leaks; 7) testing of repairs; 8) inspection and testing of pressure limiting and regulating stations, telemetering or recording gauges; 9) valve maintenance; and 10) prevention of accidental ignition.

PATROLLING AND LEAK SURVEYS

The distribution pipeline facility shall be monitored periodically to determine and take appropriate action concerning changes in class locations, gas leakage, erosion, cathodic protection requirements and other conditions affecting safe pipeline operation, in accordance with DOT 192.

The pipeline shall be patrolled at intervals not exceeding fifteen months, but at least once each calendar year. Highway and railroad crossings shall be patrolled at intervals not exceeding seven and one-half months, but at least twice each calendar year, preferably spring and fall.

Direct Testimony and Schedules
Ms. Mary Gill

Before the South Dakota Public Utilities Commission

In the Matter of the Application to Establish Initial Transportation Rates for an Intrastate Natural Gas Pipeline

Docket No._____________
Exhibit No. 3

November 1995

Mary Gill
Cost of Service

Q. Please state your name, business address and position.

A. My name is Mary Gill. I am a Senior Gas Rate Analyst with Northern States Power Company - Gas Utility ("NSP Gas") located at 825 Rice Street in St. Paul, MN.

Q. What are your current responsibilities, education and professional background?

A. My current responsibilities include the development of demand and commodity revenue forecasts, calculation of the purchase gas adjustment, and development of regulatory filings. Additional responsibilities include rate design, and preparation of responses to customer inquiries. Schedule 1 contains a complete resume of my educational and professional background.

Q. Have you previously testified before the Commission?

A. No. However, I have provided testimony before the Federal Energy Regulatory Commission in various electric wholesale and transmission rate proceeding.

Q. What is the purpose of your testimony?

A. I am acting as a consultant on behalf of AMPI Intrastate Pipeline ("AMPIP") in this proceeding. The purpose of my testimony is to explain the overall cost of service for the project. Statement M contains the details of the costs associated with this project.

Q. Please explain Statement M.

A. Statement M shows a gross plant in service of $1,327,522. This is the total as-built installed cost of the project to AMPIP, pursuant to the construction agreement between AMPIP and NSP Gas. The cost includes materials such as line pipe, valves and metering as well as the capital contribution to Northern Natural Gas Company for installing a new town border station and certain start-up project services (field inspection and training).

Q. Please explain the expenses shown on Statement M.

A. The expenses include operation and maintenance, property taxes, depreciation and interest expense. I will explain the calculation of each item.

Q. Please continue.

A. The operation and maintenance of the pipeline includes training of three AMPIP employees and the operating requirements of the pipeline itself. (These AMPIP employees will be AMPI employees working on behalf of AMPIP on a part time basis). The training portion of the expense includes training in areas such as drug and alcohol policy, gas emergencies, odorizer instruments, regulator maintenance, odorizer training, cathodic protection and record keeping. It is estimated these activities will require 32 hours per person or a total of 96 hours per year. The annual operating requirements for the pipeline include activities such as C-P readings, odorant checks, meter reading, patrolling and regulator pressure checks. These activities are expected to require 48 hours per year. The total annual cost is $1,872.

Q. Are there additional O & M expenses?

A. Yes. In addition to the O & M expenses discussed above, AMPIP has contracted for certain annual O & M services (such as DOT annual safety inspections) with NSP Gas. The first year cost is $12,000. AMPIP will also incur certain expenses from its parent company AMPI. These expenses are considered "corporate services" and include such items as accounting, finance and legal services. It is estimated these expenses will be $6,000 per year.

Q. Will AMPI incur any regulatory expenses?

A. Yes. AMPIP will be assessed a gross receipts tax in accordance with S.D. Stat. 49-1A-3. This expense is expected to be approximately $300. Also, AMPIP will incur an assessment from the Department of Transportation for pipeline safety. This is expected to be $500 annually.

Q. What is the total amount of O & M expenses?

A. The total amount of O & M expense is $20,651 per year.

Q. What other expenses will AMPIP incur?

A. AMPIP will incur interest expense on the total cost of the project, $1,327,522. AMPIP's cost of acquiring funds is currently 9%. AMPIP proposes to finance the construction initially with 100% debt over 15 years. AMPIP will finance the construction through an intercompany loan with AMPI.

Q. Please explain the depreciation and depreciation expense shown on Statement M.

A. The plant in service will be depreciated over 45 years for book purposes at a rate of 2.44% per year. This depreciation percentage includes a removal rate of 10%, because the significant majority of the project will be constructed in rights of way or easements in agricultural areas.

Q. Have you performed an allocated cost of service study?

A. No. AMPIP will initially provide only one class of service, transportation service, to a single customer. This single customer is AMPIP's corporate parent. Therefore, no allocated cost of service is required. In the event AMPIP provides transportation service to other customers or classes in the future, it is my understanding that AMPIP would file additional rate schedules and a revised cost of service and rates for Commission approval.

Q. How have you calculated a rate for AMPI?

A. I have used a levelized annual revenue requirement model to derive a monthly flat fee. This method uses AMPIP's current cost of debt, 9%, to calculate the present value of AMPIP's total revenue requirement over the book life of the plant (45 years). The present value of each expense item is calculated and is then expressed as a percent of the original cost. This calculation is shown on page 2 of Statement M. The levelized annual revenue requirement in derived by applying this percentage to the plant in service, resulting in an annual requirement of $176,693. This total is then divided by 12 to derive the monthly payment of $14,724.

Q. Does this conclude your testimony?

A. Yes.

AFFIDAVIT

STATE OF MINNESOTA)
)
COUNTY OF RAMSEY)

Affiant, having been first duly sworn, on oath deposes and says:

That she has read the foregoing testimony and if asked the questions therein her answers in response would be as shown;

That the facts contained in said answers are true to the best of her knowledge and belief.

Mary E. Gill
Mary E. Gill

SUBSCRIBED AND SWORN to before me this 1st day of November 1995.

Pauline M. Nielsen
Notary Public

PAULINE M. NIELSEN
NOTARY PUBLIC - MINNESOTA
RAMSEY COUNTY
My Comm. Expires Jan. 31, 2000

MARY E GILL
Senior Gas Rate Analyst - Gas Finance and Rate Design
825 Rice Street, St. Paul, MN 55117

CURRENT RESPONSIBILITIES (June 1995 - Present)

This position is responsible for the development of demand and commodity revenue forecasts, calculation of the purchase gas adjustment, and development of regulatory filings. Additional responsibilities include rate design, and preparation of responses to customer inquiries.

PREVIOUS EMPLOYMENT

Wholesale Regulatory Consultant	1992 - June 1995
Rate Analyst	1989 - 1992
Accountant	1985 - 1989
Customer Account Trainee	1984 - 1985

EDUCATION

Bachelor of Arts, Business Administration - 1984
Hamline University, St. Paul

PREVIOUS TESTIMONY

Northern States Power Company, FERC Docket No. ER90-527. Application for Increase in Firm Wholesale Rates.

Northern States Power Company, FERC Docket No. ER93-385. Application for Increase in Firm Wholesale Rates.

Northern States Power Company, FERC Docket No. ER94-1113. Application for Change in Transmission Rates.

CONTINUING EDUCATION

Edison Electric Institute, "Electric Rate Fundamentals," 1989
Financial Accounting Institute, "Utility Finance and Accounting workshop,: 1992
Professional Training Systems Inc., "Electric Utility System Operations." 1992

Exhibit No. 4

Transportation Service Tariff

TARIFF SCHEDULES

APPLICABLE TO

INTRASTATE NATURAL GAS TRANSPORTATION SERVICE

OF

AMPI PIPELINE, INC.

General Office
315 North Broadway
New Ulm, MN 56073

South Dakota Office
136 East Railway
P.O. Box 430
Freeman, SD 57109

Filed with the South Dakota Public Utilities Commission
as SDPUC No. 1
November 2, 1995

Date Filed: November 2, 1995

Issued by: ______________________
Harlan Mammen
President

AMPI PIPELINE, INC.

GAS TRANSPORTATION SERVICE TARIFF

ORIGINAL VOLUME NO. 1

TABLE OF CONTENTS

PRELIMINARY STATEMENT

AMPI Pipeline, Inc. (hereafter "AMPIP" or "Transporter") is an intrastate natural gas pipeline company engaged in the business of transporting natural gas in intrastate commerce to end users in the State of South Dakota. AMPIP's System consists of approximately 20 miles of distribution pipeline located McCook, Turner and Hutchinson Counties, South Dakota. AMPIP takes delivery of natural gas from Northern Natural Gas Company near Marion, South Dakota, and redelivers it to end users along or at the terminus of AMPIP in Freeman, South Dakota.

GENERAL TERMS AND CONDITIONS

ARTICLE I
DEFINITIONS

1.1 "Btu" shall mean one British Thermal Unit.

1.2 "Contract Demand" shall mean the aggregate of the maximum daily quantities of gas, expressed in dkt per day, which Transporter is obligated to accept for transportation for the account of Shipper from the points of receipt as set forth in the Transportation Service Agreement ("TSA") between Transporter and Shipper.

1.3 "Contract Year" shall mean the twelve month period commencing November 1 and terminating on October 31 of each year, until this Agreement shall have expired or otherwise been terminated in accordance with its terms.

1.4 "Day" shall mean a period of 24 consecutive hours, starting at 12:00 Noon Central Standard Time.

1.5 "Dkt" shall mean the quantity of heat energy which is equivalent to 1,000,000 British Thermal Units (BTU). One "dkt" of gas means the quantity of gas which contains one dekatherm of heat energy. The total dekatherms are calculated by multiplying the gas volume in Mcf by its total gross heating value, divided by 1,000.

1.6 "Equivalent Quantities" shall mean the sum of the quantities of gas measured in dkt received by Transporter and delivered for the account of Shipper at the points of receipt and delivery during any given period of time reduced by the sum of Shipper's Pro Rata Share of Lost and Unaccounted For Gas resulting from the operations of the System during the same period of time. In the event the ownership of gas lost as a result of an event of force majeure can be reasonably identified, the quantity thereof shall be charged to the Shipper or Shippers so identified.

1.7 "Gas" shall mean natural gas, unmixed or any mixture of natural and artificial gas.

1.8 "Gross Heating Value" shall mean the number of Btus produced by the complete combustion, at a constant pressure, of the amount of gas which would occupy a volume of one (1) cubic foot at a temperature of 60 degrees Fahrenheit on a dry basis and at a pressure of 14.73 psia with air of the same temperature and pressure as the gas, when the products of combustion are cooled to the initial temperature of the gas and air, and when the water formed by combustion has been condensed to the liquid state.

1.9 "Maximum Daily Quantity" shall mean the maximum quantity expressed in dkt per day that the Transporter is obligated to receive for the account of Shipper at the point of receipt, as established in Exhibit A to Shipper's TSA.

1. 10 "Mcf" shall mean 1,000 cubic feet of gas determined in accordance with the measurement base described in Paragraph 3. 1 hereof.

1.11 "Month" shall mean the period beginning at 12:00 Noon Central Standard Time on the first day of a calendar month and ending at the same hour on the first day of the next succeeding month.

1.12 "Northern" shall mean Northern Natural Gas Company, its successors and assigns.

1.13 "Northern's Tariff" shall mean the Northern's FERC Gas Tariff as it may be in effect from time to time.

1.14 "Pro Rata Share" shall mean the ratio that the quantity of gas delivered to Transporter by or for the account of Shipper bears to the total quantity of gas delivered to Transporter by all shippers for transportation in the System during any given period of time.

1.15 "SDPUC" shall mean the South Dakota Public Utilities Commission or any commission, agency or other state governmental body succeeding to the powers of such commission.

1.16 "Shipper" shall mean any party to a TSA providing for transportation of natural gas on Transporter's System.

1.17 "System" shall mean the pipeline and related pipeline facilities at the time owned by Transporter.

1.18 "TSA" shall mean the Transportation Service Agreement between Transporter and Shipper in the form set forth in this Tariff.

1.19 "Unaccounted For Gas" shall mean the difference between the sum of all input quantities of gas to the System and the sum of all output quantities of gas from the System, which difference shall include but shall not be limited to gas used and accounted for in System operations, and gas lost as a result of an event of force majeure, the ownership of which cannot be reasonably identified.

ARTICLE II
QUALITY

2.1 Quality Standards of Gas Received by Transporter. The gas to be delivered by Transporter shall be of merchantable quality and shall meet the minimum quality standards of Northern, as may be established or revised from time to time in Northern's Tariff.

2.2 Quality Tests. At the point of receipt, Transporter may cause tests to be made, by approved standard methods in general use in the gas industry, to determine whether the gas conforms to the quality specifications set out in Paragraph 2.1 hereof. Such tests shall be made at such intervals as Transporter may deem reasonable, and at other times, but not more often than once per day, or at the request of Shipper.

2.3 Failure to Conform. If gas delivered by Shipper does not comply with the quality specifications set out in Paragraph 2.1 hereof, Transporter shall have the right, in addition to all other remedies available to it by law, to refuse to accept any such gas. Transporter may, at its option and upon notice to Shipper, accept receipt of gas not complying with the quality specifications set out in Paragraph 2. 1 herein provided. Transporter, at the expense of Shipper, may make all changes necessary to bring such gas into compliance with such specifications.

2.4 Quality Standards of Gas Transported By Transporter. Transporter shall use reasonable diligence to deliver gas for Shipper which shall meet the quality specifications set out in Paragraph 2. 1 hereof, but shall only be obligated to deliver gas of the quality which results from the commingling of the gas received by Transporter from Shipper and other shippers.

ARTICLE III
MEASUREMENT

3.1 Unit of Measurement and Metering Base. The volumetric measurement base shall be one cubic foot of gas at a pressure base of 14.73 pounds per square inch absolute, at a temperature base of 60°F, and without adjustment for water vapor content.

3.2 Atmospheric Pressure. For the purpose of measurement, the absolute atmospheric (barometric) pressure at each measuring station shall be the atmospheric pressure determined by calculations based on the actual elevation above sea level of the meter at the place of measurement, and shall be stated in pounds per square inch.

3.3 Temperature. If determined to be necessary in the sole discretion of Transporter, the temperature of the gas shall be determined at each point of measurement by means of a properly installed recording thermometer, an indicating thermometer, an electronic temperature measuring device, or a temperature compensating meter of standard manufacture acceptable to Transporter.

3.4 Specific Gravity. If determined to be necessary in the sole discretion of Transporter, the specific gravity of the gas shall be determined at each point of receipt by one of the following methods:

(a) By means of a properly installed recording gravitometer of standard manufacture acceptable to Transporter.

(b) If (a) is not considered feasible, then by use of a portable specific gravity balance of standard manufacture, or other standard device acceptable to Transporter and designed for such purpose or use in conjunction with a continuous sampler.

(c) Other methods acceptable to Transporter.

3.5 Measurement Procedures. Quantities of gas received and delivered hereunder shall be measured in accordance with Procedures contained in ANSI-API 2530, First Edition, AGA Committee Report No. 5, AGA Committee Report No. 7, and AGA Committee Report No. 8, or revisions or amendments thereto.

3.6 Measuring Equipment. Unless otherwise agreed, Transporter will provide, maintain, and operate necessary measuring and regulating stations equipped with flow meters and other necessary measuring equipment by which its quantities of gas delivered from Transporter hereunder shall be determined. Such measuring and regulating stations shall be so installed at the receipt point of the System and at other agreeable points. All flow, measuring, testing, and related equipment shall be of standard manufacture and type acceptable to Transporter.

Transporter and Shipper shall cause the chart on all gas measurement equipment to be changed, or mechanical or electronic indices read, by either Transporter or by Shipper's representative (where economical) on a daily basis. If telemetering is not installed, Shipper shall change recording charts on Transporter's delivery point metering facilities or otherwise read Transporter's meter on a daily basis at a time specified by Transporter. Shipper may install check measuring equipment, provided that such equipment shall be so installed as not to interfere with operation of Transporter.

When Transporter deems it necessary, telemetering equipment shall be installed on Shipper's delivery point meter(s). Transporter will install and maintain the telemetering facilities. Shipper shall provide, install and maintain a weatherproof phone service and electrical service outlet with appropriate grounding for telemetering equipment. Shipper and Transporter, in the presence of each other, shall have access to all measuring equipment at all reasonable times, but the reading, calibrating, and adjusting thereof shall be done by the Transporter, unless otherwise agreed. Shipper and Transporter shall have the right to be present at the time of any installing, reading, cleaning, changing, repairing, inspecting, testing, calibrating, or adjusting done in connection with all measuring equipment. The records from such measuring equipment shall remain the property of Transporter. Reasonable care shall be exercised in the installation, maintenance and operation of measuring equipment so as to avoid any inaccuracy in the determination of the quantity of gas received and delivered.

3.7 Calibration and Test of Meters. The accuracy of all measuring equipment shall be verified by the Transporter at reasonable intervals, and if requested, in the presence of representatives of Shipper. Transporter shall not be required to verify the accuracy of such equipment more frequently than once in any Contract Year. If either party at any time desires a special test of any measuring equipment, it will promptly notify the other, and the parties shall then cooperate to secure a prompt verification of the accuracy of such equipment. Transportation and related expenses incurred by Shipper or Transporter involved in the testing of meters shall be borne by the party incurring such expenses.

3.8 Correction of Metering Errors. If, upon any test, any measuring equipment is found to be in error, such errors shall be treated in the following manner: If the resultant aggregate error in the computed receipts or deliveries is not more than 2%, then previous receipts or deliveries shall be considered accurate. All equipment shall, in any case, be adjusted at the time of test to record to zero error. If, however, the resultant aggregate error in computed receipt or deliveries exceeds 2% at a recording corresponding to the average hourly rate of gas flow for the period since the last preceding test, the previous recordings of such equipment shall be corrected to zero error for any period which is known definitely or agreed upon. In case the period is not known definitely or agreed upon, such correction shall be for a period extending over one-half of the time elapsed since the date of the last test, not exceeding a correction period of 180 days.

3.9 Failure of Measuring Equipment. In the event any measuring equipment is out of service, or is found registering inaccurately and the error is not determinable by test, or by previous recording, receipts or deliveries through such equipment shall be estimated:

(a) By using the registration of any check meter or meters, if installed and accurately registering, or in the absence of (a);

(b) By correcting the error if the percentage of error is ascertainable by calibration, special test, or mathematical calculation, or in the absence of both (a) and (b) then;

(c) By estimating the quantity of receipt or delivery based on receipts or deliveries during preceding periods under similar conditions when the measuring equipment was registering accurately.

3.10 Preservation of Records. Shipper and Transporter shall preserve all test data, charts, and other similar records for a period of at least one year, or such longer period as may be required by the SDPUC or other jurisdictional public authority.

ARTICLE IV
RECEIPT AND DELIVERY POINTS

4.1 Point of Receipt. The initial point of receipt hereunder shall be the point of interconnection between the facilities of Transporter and the facilities of Northern located near Marion, South Dakota. Shipper shall deliver, or cause to be delivered, gas to Transporter at the point or receipt for transportation service, set forth in Exhibit A attached to Shipper's TSA.

4.2 Points of Delivery. The point(s) of delivery hereunder shall be the point(s) of connection between the facilities of Transporter and the facilities of Shipper, where Transporter shall deliver gas for the account of Shipper. Such point(s) of delivery are set forth in Exhibit A attached to Shipper's TSA. The establishment of any additional point of delivery at the request of Shipper shall be at the expense of Shipper.

ARTICLE V
SCHEDULES

5.1 Schedules. Prior to the first day of each month, Shipper shall furnish Transporter with a schedule showing the estimated daily quantities of gas Shipper desires Transporter to transport during such month. Such monthly schedule shall be provided at least one hour before the deadline for monthly nominations in Northern's Tariff. Thereafter Shipper shall on a daily basis advise Transporter of the volumes Shipper will deliver during the following day at least one hour prior to the time Transporter must submit daily nominations to Northern pursuant to Northern's Tariff. However, Shipper may establish a standing schedule of daily volumes, notifying Transporter prior to any day when Shipper's daily deliveries will differ from the standing schedule by more than the daily delivery variance (+/-) established in Northern's Tariff.

5.2 Departures from Schedules. Departures from the scheduled deliveries at the point of receipt shall be kept to the minimum permitted by operating conditions, and shall be balanced as soon as practicable. Shipper shall use its best efforts to give Transporter notice prior to proposed change of a daily quantity from that set forth in the schedule provided for in Paragraph 5. l hereof. Such notice shall be provided at times consistent with the notice period for intra-day nomination changes set forth in Northern's Tariff. Transporter may waive such notice upon request if, in its judgment, operating conditions permit such waiver. Transporter and Shipper shall inform each other of any other changes of deliveries immediately upon knowledge thereof.

5.3 Hourly Variation. Deliveries shall be made at uniform hourly rates to the extent practicable. Transporter's obligation to deliver shall not exceed 1/16th of Shipper's Maximum Daily Quantity in any given hour.

ARTICLE VI
DAILY AND MONTHLY BALANCING

6.1 Scheduling and Balancing Tolerances. It is recognized that the parties will be unable to control exactly the quantities of gas delivered and accepted hereunder on any day, and that deliveries by Shipper and redeliveries by Transporter may vary above or below the quantities scheduled on any day. However, nothing in this paragraph shall affect Shipper's obligation to pay for gas actually transported.

6.2 Daily Variances. The daily variance for a receipt point shall be the difference between the total quantities scheduled for receipt and the actual quantity delivered into Transporter's System. The daily variance for a delivery point shall be the shall be the difference between the total quantities scheduled and the actual quantity delivered by Transporter at such point on any day. Shipper shall take action to correct any daily variance between scheduled and actual receipts and deliveries occurring during the month by making adjustments to schedules, receipts or deliveries. In no event shall the daily excess or deficiency variance exceed the allowable daily point of delivery variation set forth in Northern's Tariff.

6.3 Monthly Imbalances. Shipper's monthly imbalance shall be the net total of daily variances from all receipt and delivery points. Such monthly imbalance shall be corrected in-kind through adjustments to Shipper's schedules, receipts or deliveries in order for Shipper to receive Equivalent Quantities, or by such other method as is then mutually agreed upon by the parties hereto. The cumulative daily variances during any month above or below the quantities scheduled shall not exceed the monthly point of delivery monthly variance set forth in Northern's Tariff.

6.4 Disposition of Excess Gas. In order to alleviate conditions that threaten the integrity of its System, Transporter may periodically acquire quantities of gas that are in excess of System needs. Transporter may make interruptible sales of such gas from time to time at the point of receipt pursuant to 18 CFR 284.402. Such sales shall be made under rates, terms and conditions mutually agreed upon between Transporter and the purchaser, provided that all such sales shall be fully interruptible.

ARTICLE VII
PRESSURE

7.1 Pressure at the Points of Receipt. Shipper shall cause the gas to be delivered at the points of receipt at a pressure sufficient to allow the gas to enter the System; however, Shipper shall not be required to deliver gas to the Transporter at any point of receipt at a pressure in excess of the minimum pressure specified with respect to each receipt point in Exhibit A of Shipper's TSA.

7.2 Pressure at Points of Delivery. Transporter shall deliver gas to Shipper's delivery points at the pressure existing in the Transporter's pipeline; however, Transporter must deliver gas to each point at a pressure not less than the minimum pressure specified with respect to each delivery point in Exhibit A to Shipper's TSA. Transporter, however, shall not be required or permitted to deliver gas at a pressure in excess of the maximum pressure specified for each point of delivery set forth in Exhibit A attached to Shipper's TSA.

ARTICLE VIII
BILLING AND PAYMENT

8.1 Billing. Unless otherwise agreed, on or before the 20th day of each month, Transporter shall render to Shipper a statement of the total amount of gas delivered by Transporter to Shipper at the points of receipt hereunder during the preceding month and the amount due. When information necessary for billing purposes is in the control of Shipper, Shipper shall furnish such information to Transporter on or before the 10th day of the month.

Shipper and Transporter shall have the right to examine at reasonable times, books, records, and charts of the other to the extent necessary to verify the accuracy of any statement, charge, or computation made under or pursuant to any of the provisions hereof.

8.2 Payment. Unless otherwise agreed, Shipper shall pay Transporter at its general office or at such other address as Transporter shall designate on or before the 28th day of the month, the amount due for the preceding month. If presentation of a bill by Transporter is delayed after the 20th day of the month, then the time of payment shall be extended accordingly unless Shipper is responsible for such delay.

8.3 Remedies for Failure to Pay. Should Shipper fail to pay all or any portion of any bill as herein provided when such amount is due, interest on the unpaid portion of the bill shall occur at a rate of one percent (1%) per month. If such failure to pay continues for 30 days after payment is due, Transporter may, in addition to any other remedy it may have hereunder, suspend further delivery of gas until such amount is paid, if authorized pursuant to the rules of the SDPUC.

8.4 Disputed Bills. If Shipper in good faith shall dispute the amount of any such bill or part thereof and shall pay to Transporter such amounts as it concedes to be correct and, at any time thereafter within 30 days of a demand made by Transporter, shall furnish a good and sufficient surety bond in an amount and with surety satisfactory to Transporter, guaranteeing payment to Transporter of the-amount ultimately found due upon such bills after a final determination which may be reached either by agreement or judgment of the courts, as may be the case, then Transporter shall not be entitled to suspend further delivery of gas unless and until default be made in the conditions of such bond.

8.5 Adjustment of Billing Errors. If it shall be found that at any time or times Shipper has been overcharged or undercharged in any form whatsoever under the provisions hereof and, in the case of an overcharge, Shipper shall have actually paid the bill containing such overcharge, then within 30 days after the final determination of such overcharge or undercharge, the appropriate party shall pay to the other party the amount of said overcharge or undercharge, net of any other amounts then payable hereunder. In the event an error is discovered in the amount billed in any statement rendered by Transporter, such error shall be adjusted within 30 days of the determination thereof provided that claim therefor shall have been made within one (I) year from the date of such statement. If the parties are unable to agree on the adjustment of any claimed error, any resort by either of the parties to legal procedure, either at law, in equity, or otherwise, shall be commenced within 12 months after the supposed cause of action is alleged to have arisen, or shall thereafter be forever barred.

ARTICLE IX
CONTROL OF GAS

9.1 Responsibility for Gas. As between the Shipper and Transporter hereto, Shipper shall be in exclusive control and possession of the gas until such has been delivered to Transporter at the point of receipt, and after such gas has been redelivered to or for the account of Shipper by Transporter at the point(s) of delivery. Transporter shall be in exclusive control and possession of such gas while same is in the System between the point of receipt and the point(s) of delivery. The party which shall be in exclusive control and possession of such gas shall be responsible for all injury or damage caused thereby.

ARTICLE X
FORCE MAJEURE

10. 1 Force Majeure. Neither party shall be responsible or held liable for any loss or damage resulting from failure to perform its obligations due to any cause beyond its reasonable control; provided, however, that such force majeure affecting the performance hereunder by either Shipper or Transporter shall not relieve such party of liability in the event of its own concurring negligence or in the event of its own failure to use due diligence to remedy the situation and to remove the cause in an adequate manner and with all reasonable dispatch; provided further, that no such causes affecting such performance shall relieve either party from its obligations to make payments as determined hereunder or entitle either party to exercise any right To offset against any such payment obligation.

10.2 Definition. The term "force majeure" as used herein shall mean acts of God, strikes, lockouts, or other industrial disturbances; acts of a public enemy, wars, blockades, insurrection, riots, epidemics, landslides, lightning, earthquakes, fires, storms, floods, washouts; arrests and restraints of the government, either federal or state, civil or military, civil disturbances; shutdowns for purposes of necessary repairs, relocation, or construction of facilities; breakage or accident to machinery or lines of pipe; the necessity for testing (as required by governmental authority or as deemed necessary by repairs or alterations to machinery or lines of pipe); failure of surface equipment or pipelines; accidents, breakdowns, inability of either parry hereto to obtain necessary material, supplies, or permits, or labor to perform or comply with an obligation or condition of this Agreement, rights of way, and any other causes, whether of the kind herein enumerated or otherwise, which are not reasonably in the control of the parry claiming suspension. It is understood and agreed that the settlement of strikes or lockouts shall be entirely within the discretion of the party having the difficulty and that the above requirement that any force majeure shall be remedied with all reasonable dispatch shall not require the settlement of strikes or lockouts by acceding to the demands of an opposing party when such course is inadvisable in the discretion of the party having the difficulty.

ARTICLE XI
INTERRUPTIONS

11.1 Notice of Interruption. Transporter shall at all times attempt to operate, or cause to be operated, its System in a manner designed to make possible, as nearly as practicable, continuous receipt of gas from, and delivery of gas to, Shipper in the respective quantities provided for in Shipper's TSA. If an interruption or curtailment of such receipt and/or delivery shall become necessary, Transporter shall at once attempt to notify Shipper by facsimile or telephone or other prompt means of communication of the nature, extent and probable duration of such interruption or curtailment and of the quantity of gas which Transporter estimates it will be able to receive from and deliver to Shipper during the period of interruption or curtailment, and shall give like notice of the cessation of such interruption or curtailment.

11.2 Allocation of Reduced Capacity. If the effective capacity of all or a portion of Transporter's System is reduced as a result of force majeure, repairs, maintenance or any other cause, whether similar or dissimilar, and some curtailment of the quantity of gas to be received from shippers under their transportation agreements is required as a result, the reduced capacity shall, during the period of curtailment, be allocated proportionately, according to their respective Maximum Daily Quantities, among those shippers whose gas must be received or delivered at or transported through, the affected facilities.

11.3 Scheduling of Receipts and Deliveries. Transporter shall schedule all quantities tendered under all services performed by Transporter in sequence as follows: first to Transporter's firm transportation shippers, by date of Agreement, and second to other Rate Schedules that may be approved, in the order of priority as may be approved by the SDPUC or other regulatory bodies with jurisdiction.

ARTICLE XII
INCORPORATION IN RATE SCHEDULES AND TRANSPORTATION AGREEMENTS

12.1 These General Terms and Conditions are incorporated in and are part of Transporter's Rate Schedules and Transportation Service Agreements. In the event of a conflict between these General Terms and Conditions and terms in Transporter's Rate Schedules or TSAs, these General Terms and Conditions shall govern.

RATE SCHEDULE - FIRM TRANSPORTATION SERVICE

1.0 Availability. This Rate Schedule is available for the transportation of natural gas on an firm basis for any Shipper where (i) Transporter has determined that sufficient System capacity exists to provide the service requested by Shipper, and (ii) Shipper has executed a Transportation Service Agreement ("TSA") wherein Transporter agrees to transport gas for Shipper's account up to a specific maximum daily quantity.

2.0 Gas Supply; Upstream Transportation. Shipper shall be responsible for arranging for all natural gas supplies and interstate transportation of Shipper's gas on Northern to the point of receipt.

3.0 Receipts and Deliveries. The Point of Receipt for all gas transporter by Transporter under this Rate Schedule shall be at the interconnection of Transporter's System with Northern located near Marion, South Dakota. The Point(s) of Delivery shall be at the point(s) designated in the Exhibit A attached to Shipper's TSA.

4.0 Rates and Charges. The rates for service under this Rate Schedule are as follows:

	Base Rate	Lost & Unaccounted Gas Percentage
Transportation Service - fixed monthly charge	$14,724/month	1%
Authorized Overrun Service fixed monthly charge option	$0.00 per Dkt	

However, Transporter has the right at any time and from time to time to file with the SDPUC to adjust the rates applicable to service under this Rate Schedule.

5.0 Daily Tolerance; Penalty Provisions. The daily tolerance level (+/-) from Shipper's daily scheduled volume shall be the daily variance establised in Northern's Tariff. Unless otherwise agreed, in the event the daily quantity of gas delivered by Shipper deviates above or below the daily scheduled volume in excess of the Northern Tariff tolerance level, a penalty of $5.00 per Dkt shall be assessed to Shipper for each Dkt in excess of the tolerance.

6.0 General Terms and Conditions. Any terms or conditions not specified in this Rate Schedule shall be determined consistent with Transporter's General Terms and Conditions, which are incorporated by reference into this Rate Schedule.

Sheets __ to __ reserved for future use.

INDEX OF SHIPPERS

Shipper	Rate Schedule	Effective Date	Expiration Date
Associated Milk Producers, Inc.	FT	12/01/95	10/31/2010

AMPI PIPELINE, INC.

TRANSPORTATION SERVICE AGREEMENT

WITH

ASSOCIATED MILK PRODUCERS, INC.

Dated November 1, 1995

This NATURAL GAS TRANSPORTATION SERVICE AGREEMENT ("Agreement") is made this 1st day of November, 1995, by and between AMPI Pipeline, Inc., a South Dakota corporation ("Transporter"), and Associated Milk Producers, Inc., a Kansas corporation ("Shipper").

WITNESSETH:

WHEREAS, Transporter will construct and operate a twenty mile intrastate natural gas distribution pipeline ("System") in McCook, Turner and Hutchinson Counties, South Dakota, subject to the jurisdiction of South Dakota Public Utilities Commission (the "SDPUC"); and

WHEREAS, the initial in-service delivery date is expected to be on or about December 1, 1995; and

WHEREAS, Shipper desires to have natural gas transported on Transporter's System to Shipper's plant located in Freeman, South Dakota, starting on the initial in-service delivery date; and

WHEREAS, Transporter is willing to provide such natural gas transportation service pursuant to the terms and conditions of its Transportation Service Tariff, SDPUC No. 1 and this Agreement;

NOW, THEREFORE, in consideration of the premises and the mutual covenants herein contained, the parties do covenant and agree as follows:

ARTICLE I

1.1 Obligation to Transport. Commencing with initial in-service date hereunder, Transporter shall receive at the point of receipt for the account of Shipper all gas which Shipper may cause to be delivered to Transporter, up to Shipper's Contract Demand as set forth in Exhibit A hereto, and transport such gas to the point(s) of receipt on a firm basis.

1.2 Term. This Agreement shall have an initial term commencing on the in-service date and continuing for a period of fifteen (15) Contract Years thereafter. For the purposes of this Agreement, the term "initial in-service date" shall mean December 1, 1995, unless such date is delayed by circumstances beyond the control of the parties. Unless terminated on six months written notice to Transporter prior to the termination date, this Agreement will continue in effect from year-to-year thereafter until terminated by Transporter or Shipper by six months written notice to the other party. The first Contract Year shall be the period from the in-service date to October 31, 1996.

1.3 Maximum Daily Quantities. Subject to Transporter's prior approval, Shipper from time to time shall stipulate a Maximum Daily Quantity of gas for delivery at each point of delivery. The initial Contract Demand shall be set forth in Exhibit A attached hereto. Any updating or other modification of Exhibit A as provided in this Paragraph 1.3 shall not be effective unless and until the updated or modified Exhibit A shall have been duly executed or initialled by both parties, subject to any necessary regulatory approval. Such a revised Exhibit A shall replace the prior Exhibit A and, by this reference, shall become a part of this Agreement. The daily deliveries at any point of receipt may exceed the Maximum Daily Quantity specified for such point of receipt on a temporary basis, provided the System in Transporter's sole judgment can accommodate the excess quantity.

1.4 Transportation Charge. Unless otherwise agreed, Transporter's charge to Shipper for transporting Shipper's quantities pursuant to this Agreement shall be the maximum rate set forth in Transporter's Transportation Service Tariff, SDPUC No. 1 (hereafter "Tariff") in effect from time to time.

1.5 Overrun Services. Upon request of Shipper and at Transporter's option, Transporter may receive and deliver for Shipper's account, on any day, quantities of gas in excess of Shipper's Maximum Daily Quantity; however, such quantities shall be received and delivered on a best efforts basis. Unless otherwise agreed, such overrun deliveries shall be subject to the maximum Authorized Overrun

Transportation ("AOT") commodity rate set forth in Transporter's Tariff in effect from time to time.

ARTICLE II

2.1 Changes in Rates and Charges. The service under this Agreement shall be supplied pursuant to the Rate Schedule and General Terms and Conditions of Transporter's Tariff as they now exist or may be changes from time to time. Transporter shall have the unilateral rights to file with the SDPUC or other appropriate regulatory authority to make changes in (a) the rates, charges, terms and conditions applicable to service pursuant to the Rate Schedule under which this service is rendered; and (b) any provision of the General Terms and Conditions in Transporter's Tariff. Without prejudice to Shipper's right to contest such changes, Shipper agrees to pay the effective rates and charges for service rendered pursuant to this Agreement.

2.2 Warranty. Shipper warrants for itself, its successors and assigns, that it will have at the time of delivery of gas for transportation hereunder good title or the good right to deliver such gas. Transporter warrants for itself, its successors and assigns, that it will at the time of delivery to others of the gas transported hereunder have good right to deliver such gas to others. Shipper warrants for itself, its successors and assigns, that the gas it delivers hereunder shall be free and clear of all liens, encumbrances and claims whatsoever. Shipper further warrants that it will indemnify Transporter and save it harmless from all suits, actions, debts, accounts, damages, costs, losses and expenses arising from or out of any adverse claims of any and all persons to said gas and/or to royalties, taxes, license fees or charges thereon which are applicable to such delivery of gas and that it will indemnify Transporter and save it harmless from all taxes or assessments which may be levied and assessed upon such delivery and which are by law payable by, and the obligation of, the party receiving such delivery.

2.3 Regulations. This Agreement, and all terms and provisions contained herein, and the respective obligations of the parties hereunder are subject to valid laws, orders, rules and regulations of duly constituted authorities having jurisdiction. Shipper shall furnish to Transporter all information as may be required to comply with the reporting requirements of duly constituted authorities having jurisdiction over the subject matter herein.

2.4 Notices. Except as herein otherwise provided, any notice, request, demand, statement, bill, or payment provided for in this Agreement, or any notice which either party may desire to give to the other, shall be in writing and shall be considered as duly delivered when mailed by First Class U.S. Mail to the Address of the parties hereto as follows:

TO TRANSPORTER:

AMPI Pipeline, Inc.
Attention: General Manager
136 East Railway
P.O. Box 430
Freeman, South Dakota 57109

TO SHIPPER:

Associated Milk Producers, Inc.
Attention: General Manager
315 North Broadway
New Ulm, MN 56073

or such other address as the parties may designate by written notice. Routine communications including monthly statements and payments, shall be considered as duly delivered when mailed by First Class U.S. Mail, overnight courier, or facsimile (with telephone confirmation of receipt).

2.5 Waivers. No waiver by either Shipper or Transporter of any one or more defaults in the performance of any provision hereunder shall operate or be construed as a waiver of any future default or defaults, whether of a like or a different character.

2.6 Applicable Law. This Agreement shall be governed by and interpreted in accordance with laws of the state of South Dakota.

2.7 Assignment. This Agreement is binding upon Transporter and Shipper, their successor and assigns. Either party may assign or pledge this Agreement under the provisions of any mortgage, deed of trust, indenture or similar instrument which it has executed or may execute hereafter covering substantially all of its properties; otherwise neither of the parties shall assign this Agreement or any of its rights hereunder unless it first shall have obtained the consent thereto in writing of the other party, which shall not be unreasonably withheld.

2.8 Dispute Resolution. Any controversy or claim arising out of or relating to this Agreement, or the alleged breach thereof, shall be subject to initial resolution by mediation. If Transporter and Shipper are unable to reach a resolution by mediation, then the controversy or claim may be submitted to the SDPUC for resolution. This Section shall survive the termination of this Agreement as necessary to resolve any disputes arising under this Agreement.

2.9 No Third Party Beneficiary. No provision of this Agreement shall be in any way inure to the benefit of any third person (including the public at large) so as to constitute any such person as a third party beneficiary of the Agreement or of any one or more of the terms hereof, or otherwise given rise to any cause of action in any person not a party hereto.

2.10 Exhibits. Exhibit A attached hereto is incorporated by reference and made part of this Agreement for all purposes.

IN WITNESS WHEREOF, the parties hereto have caused this Agreement to be executed by a duly authorized officer.

AMPI Pipeline, Inc.

By:__________________________

Title:________________________

Date:________________________

Associated Milk Producers, Inc.

By:__________________________

Title:________________________

Date:________________________

Exhibit A
Transportation Service Agreement
AMPI Intrastate Pipeline

Receipt Point	Meter No.

Delivery Point(s)	Meter No.

Annual Quantity: _________ Dkt

Maximum Daily Quantity: _________ Dkt

Transporter shall deliver Shipper's gas at a rate of flow not to exceed _____ cubic feet per hour at the point of delivery. Gas shall be delivered at such pressures and temperatures as may exist under the System operating conditions at such point of delivery. Operating pressures at this location shall normally be between _____ psig and ____ psig.

Exhibit No. 5

Statements Required By Chapter 20:10:13

AMPI Pipeline Company
List of Statements Included With This Filing
Pursuant to Chapter 20:10:13

Chapter	Statements	Basis for Omission or Applicable Reference
20:10:13:51	Statement A	Not Applicable (1)
20:10:13:52	Statement B	Not Applicable (1)
20:10:13:53	Statement C	Not Applicable (1)
20:10:13:54	Statement D	See Statement D
20:10:13:55	Schedule D-1	See Statement D
20:10:13:56	Schedule D-2	See Statement D
20:10:13:57	Schedule D-3	See Statement D
20:10:13:58	Schedule D-4	Not Applicable (1)
20:10:13:59	Schedule D-5	Not Applicable (1)
20:10:13:60	Schedule D-6	Not Applicable (1)
20:10:13:61	Schedule D-7	Not Applicable (1)
20:10:13:62	Schedule D-8	Not Applicable (1)
20:10:13:63	Schedule D-9	Not Applicable (1)
20:10:13:54	Statement E	Not Applicable
20:10:13:65	Statement E-1	Not Applicable (1)
20:10:13:66	Schedule E-2	Not Applicable (1)
20:10:13:67	Schedule E-3	Not Applicable (1)
20:10:13:68	Statement F	Not Applicable (1)
20:10:13:69	Schedule F-1	Not Applicable (1)
20:10:13:70	Schedule F-2	Not Applicable (1)
20:10:13:71	Schedule F-3	Not Applicable (1)
20:10:13:72 - 20:10:13:75	Statement G	See Statement G
20:10:13:76	Schedule G-1	Not Applicable (2)
20:10:13:77	Schedule G-2	Not Applicable (2)
20:10:13:78	Schedule G-3	Not Applicable (2)
20:10:13:79	Schedule G-4	Not Applicable (2)
20:10:13:80	Statement H	See Statement H
20:10:13:81	Schedule H-1	Not Applicable (1)
20:10:13:82	Schedule H-2	Not Applicable (1)
20:10:13:83	Schedule H-3	Not Applicable (1)
20:10:13:84	Schedule H-4	Not Applicable (1)
20:10:13:85	Statement I	See Statement I
20:10:13:86	Statement J	See Statement J
20:10:13:87	Schedule J-1	Not Applicable
20:10:13:88	Statement K	Not Applicable
20:10:13:89	Schedule K-1	Not Applicable
20:10:13:90	Schedule K-2	Not Applicable
20:10:13:91	Schedule K-3	Not Applicable
20:10:13:92	Schedule K-4	Not Applicable
20:10:13:93	Schedule K-5	Not Applicable
20:10:13:94	Statement L	See Statement L
20:10:13:95	Schedule L-1	Not Applicable

AMPI Pipeline Company
List of Statements Included With This Filing
Pursuant to Chapter 20:10:13

Chapter	Statements	Basis for Omission or Applicable Reference
20:10:13:96	Statement M	See Statement M
20:10:13:97	Statement N	See Statement N
20:10:13:98	Statement O	Not Applicable
20:10:13:99	Schedule O-1	Not Applicable
20:10:13:100	Statement P	Not Applicable
20:10:13:101	Statement Q	See Statement Q
20:10:13:102	Statement R	Not Applicable

(1) Since AMPIP is a recently formed company, this data does not exist.

(2) There have been no stock dividends, stock splits or changes in par or stated value. AMPIP has not issued any common or preferred stock or bonds. All AMPIP financial arrangements will be met through loan agreements with AMPI.

Associated Milk Producers Pipeline Company

Cost of Plant: 20:10:13:54

Line No.	Functional Classification	Balance
1	Distribution Plant	$1,327,522

Line No 1 - Total distribution plant from Statement M, Line 1, Column 3.

Detailed Plant Account: 20:10:13:55

It is anticipated that all of the distribution plant will be included in Account 101.

Plant Additions and Retirements for the Test Period: 20:10:13:56 and 20:10:13:57

The proposed distribution plant is expected to be placed in service on approximately December 1, 1995. Therefore no historical data exists. No changes to the proposed plant are anticipated at this time and therefore, $1,327,522 represents the plant balance.

Statement G

Associated Milk Producers Pipeline Company

Debt Capital: 20:10:13:73

Associated Milk Producers, Inc. (AMPI) will finance all debt for its subsidiary Associated Milk Producers Pipeline, Inc. (AMPIP). AMPI will provide all necessary operating capital for AMPIP at a rate of 9%.

Statement H

Associated Milk Producers Pipeline Company

Operating and Maintenance expenses: 20:10:13:80

The operating and maintenance expenses contained in Statement M and the corresponding FERC account numbers are as follows:

Expense Item	FERC Account No.
Training and operating requirements	880
SD Puc Assessment	928
DOT Pipeline Safety Assessment	880
Contract O & M	871 - 895
Corporate Services	920

Statement I

Associated Milk Producers Pipeline Company

Operating Revenues: 20:10:13:85

The flat fee per month for Transportation Service is $14,724.

Statement J

Associated Milk Producers Pipeline Company

Depreciation Expense: 20:10:13:86

As described in Statement E, AMPIP proposes to utilize a 2.44% annual depreciation rate. Based on the total cost of the pipeline facilities, the annual depreciation amount will be $32,451. The overall cost of service can be found in Statement M.

Statement L

Associated Milk Producers Pipeline Company

Other Taxes: 20:10:13:94

Property taxes for the proposed pipeline are estimated to be 1.18%. Property taxes for the first year are estimated to be $2,611. Annual property taxes thereafter are estimated at $15,665. The overall cost of service can be found in Statement M.

Associated Milk Producers Pipeline, Inc.
Statement M - Cost of Service
Levelized Annual Revenue Requirement

	Cost	Weight	Weighted Cost
Equity	0.00%	0.00%	0.0000%
Preferred Stock	0.00%	0.00%	0.0000%
Long term Debt	9.00%	100.00%	9.0000%
Short term Debt	0.00%	0.00%	0.0000%
		100.00%	9.0000%

Time Period (1)	Year (2)	Plant in Service Additions (3)	Net Investment Rate Base (4)	Debt Return (5)	Book Dep'n (6)	Operating Expenses (7)	Property Taxes (8)	Total Revenue Requirement (10)	Revenue Deficiency (Excess) (11)	9.0000% Present Value of Revenue Deficiency or (Excess) (12)
0	1995	1,327,522	1,311,297	59,008	16,226	20,651	2,611	98,496	98,496	98,496
1	1996	0	1,278,846	116,556	32,451	21,374	15,665	186,046	186,046	170,684
2	1997	0	1,246,395	113,636	32,451	22,122	15,665	183,873	183,873	154,763
3	1998	0	1,213,944	110,715	32,451	22,896	15,665	181,727	181,727	140,327
4	1999	0	1,181,493	107,795	32,451	23,697	15,665	179,608	179,608	127,239
5	2000	0	1,149,042	104,874	32,451	24,527	15,665	177,517	177,517	115,374
6	2001	0	1,116,591	101,953	32,451	25,385	15,665	175,455	175,455	104,618
7	2002	0	1,084,140	99,033	32,451	26,274	15,665	173,422	173,422	94,868
8	2003	0	1,051,689	96,112	32,451	27,193	15,665	171,421	171,421	86,031
9	2004	0	1,019,238	93,192	32,451	28,145	15,665	169,453	169,453	78,021
10	2005	0	986,787	90,271	32,451	29,130	15,665	167,517	167,517	70,761
11	2006	0	954,336	87,350	32,451	30,150	15,665	165,616	165,616	64,182
12	2007	0	921,885	84,430	32,451	31,205	15,665	163,751	163,751	58,219
13	2008	0	889,434	81,509	32,451	32,297	15,665	161,922	161,922	52,816
14	2009	0	856,983	78,589	32,451	33,428	15,665	160,132	160,132	47,919
15	2010	0	824,532	75,668	32,451	34,598	15,665	158,382	158,382	43,482
16	2011	0	792,081	72,748	32,451	35,809	15,665	156,672	156,672	39,461
17	2012	0	759,630	69,827	32,451	37,062	15,665	155,005	155,005	35,817
18	2013	0	727,179	66,906	32,451	38,359	15,665	153,381	153,381	32,516
19	2014	0	694,728	63,986	32,451	39,702	15,665	151,803	151,803	29,524
20	2015	0	662,277	61,065	32,451	41,091	15,665	150,272	150,272	26,813
21	2016	0	629,826	58,145	32,451	42,529	15,665	148,790	148,790	24,357
22	2017	0	597,375	55,224	32,451	44,018	15,665	147,358	147,358	22,130
23	2018	0	564,924	52,303	32,451	45,558	15,665	145,978	145,978	20,113
24	2019	0	532,473	49,383	32,451	47,153	15,665	144,652	144,652	18,285
25	2020	0	500,022	46,462	32,451	48,803	15,665	143,381	143,381	16,628
26	2021	0	467,571	43,542	32,451	50,511	15,665	142,169	142,169	15,126
27	2022	0	435,120	40,621	32,451	52,279	15,665	141,016	141,016	13,764
28	2023	0	402,669	37,700	32,451	54,109	15,665	139,925	139,925	12,530
29	2024	0	370,218	34,780	32,451	56,003	15,665	138,899	138,899	11,411
30	2025	0	337,767	31,859	32,451	57,963	15,665	137,938	137,938	10,397
31	2026	0	305,316	28,939	32,451	59,992	15,665	137,046	137,046	9,476
32	2027	0	272,865	26,018	32,451	62,092	15,665	136,225	136,225	8,642
33	2028	0	240,414	23,098	32,451	64,265	15,665	135,478	135,478	7,885
34	2029	0	207,963	20,177	32,451	66,514	15,665	134,807	134,807	7,198
35	2030	0	175,512	17,256	32,451	68,842	15,665	134,214	134,214	6,575
36	2031	0	143,061	14,336	32,451	71,251	15,665	133,703	133,703	6,009
37	2032	0	110,610	11,415	32,451	73,745	15,665	133,276	133,276	5,495
38	2033	0	78,159	8,495	32,451	76,326	15,665	132,937	132,937	5,028
39	2034	0	45,708	5,574	32,451	78,998	15,665	132,687	132,687	4,605
40	2035	0	13,257	2,653	32,451	81,763	15,665	132,532	132,532	4,219
41	2036	0	(19,195)	(267)	32,451	84,624	15,665	132,473	132,473	3,869
42	2037	0	(51,646)	(3,188)	32,451	87,586	15,665	132,514	132,514	3,551
43	2038	0	(84,097)	(6,108)	32,451	90,652	15,665	132,659	132,659	3,261
44	2039	0	(116,548)	(9,029)	32,451	93,825	15,665	132,911	132,911	2,998
45	2040	0	(132,773)	(11,219)	16,226	97,108	15,665	117,779	117,779	2,457
Project Totals		1,327,522			1,460,295	2,281,606				1,917,917

Levelized Annual Revenue Requirement - LARR

							$ PMT
	$92,483	$33,976	$34,202	$15,935	$176,596	$153,191	(176,596)

LARR - As a % of Original Cost

	6.97%	2.56%	2.58%	1.20%	13.30%

Time Period (1)	9.0000% Present Value of Debt Return (2)	9.0000% Present Value of Book Depreciation (3)	9.0000% Present Value of Operating Expenses (4)	9.0000% Present Value of Current Property Taxes (5)	Present Value of Revenue Requirements or (Excess) (6)
0	59,008	16,226	20,651	2,611	98,496
1	106,932	29,772	19,609	14,371	170,684
2	95,645	27,313	18,620	13,185	154,763
3	85,492	25,058	17,680	12,096	140,327
4	76,364	22,989	16,788	11,097	127,239
5	68,161	21,091	15,941	10,181	115,374
6	60,792	19,349	15,136	9,340	104,618
7	54,174	17,752	14,373	8,569	94,868
8	48,236	16,286	13,647	7,862	86,031
9	42,908	14,941	12,959	7,212	78,021
10	38,131	13,708	12,305	6,617	70,761
11	33,851	12,576	11,684	6,071	64,182
12	30,018	11,537	11,094	5,569	58,219
13	26,587	10,585	10,535	5,110	52,816
14	23,517	9,711	10,003	4,688	47,919
15	20,774	8,909	9,498	4,301	43,482
16	18,323	8,173	9,019	3,945	39,461
17	16,135	7,499	8,564	3,620	35,817
18	14,184	6,879	8,132	3,321	32,516
19	12,445	6,311	7,722	3,047	29,524
20	10,896	5,790	7,332	2,795	26,813
21	9,518	5,312	6,962	2,564	24,357
22	8,294	4,874	6,611	2,353	22,130
23	7,206	4,471	6,277	2,158	20,113
24	6,242	4,102	5,960	1,980	18,285
25	5,388	3,763	5,660	1,817	16,628
26	4,633	3,453	5,374	1,667	15,126
27	3,965	3,167	5,103	1,529	13,764
28	3,376	2,906	4,845	1,403	12,530
29	2,857	2,666	4,601	1,287	11,411
30	2,401	2,446	4,369	1,181	10,397
31	2,001	2,244	4,148	1,083	9,476
32	1,651	2,059	3,939	994	8,642
33	1,344	1,889	3,740	912	7,885
34	1,077	1,733	3,552	836	7,198
35	845	1,590	3,372	767	6,575
36	644	1,458	3,202	704	[illegible]
37	471	1,338	3,041	646	5,495
38	321	1,227	2,887	593	5,028
39	193	1,126	2,741	544	4,605
40	84	1,033	2,603	499	4,219
41	(8)	948	2,472	458	3,869
42	(85)	870	2,347	420	3,551
43	(150)	798	2,229	385	3,261
44	(204)	732	2,116	353	2,998
45	(232)	336	2,009	324	2,437
Project Total	1,004,408	368,905	371,452	173,062	1,917,917

Summary - LARR

Return Requirements	6.97%
Depreciation Requirement	2.56%
O&M and Property Taxes	3.78%
Total LARR	13.31%
Plant In Service	$1,327,522
Annual Requirement	$176,693
Monthly Flat Fee	$14,724

Statement N

Associated Milk Producers Pipeline Company

Allocated Cost of Service: 20:10:13:97

AMPIP expects that all of its revenue will initially be generated by the transportation of natural gas for only one customer, its affiliated AMPI plant in Freeman, South Dakota. Therefore, it is not necessary to allocate the cost of service shown on Statement M. AMPI has agreed to pay 100% of the initial cost of service. If AMPIP adds other customers at a later date, AMPIP will file with the Commission to establish rates, tariffs and cost allocations by class.

Statement Q

Associated Milk Producers Pipeline Company

Description of Utility Operations: 20:10:13:101

The proposed 4.5 inch O.D. distribution line of AMPIP will extend from a point on the existing Northern Natural Gas pipeline located at township 101 North, Range 54 West, Section 24, in McCook County, South Dakota, extending in a southerly direction along 447th Avenue to Turner County #10, turning west along County #10 to Turner County #15, turning South along County #10 to State Highway #44 again turn west along Highway #44 to US 81 and turn south along Highway 81. The proposed pipeline will end at a district regulating station in the SE 1/4 of Section 26, township 99N, Range 56W in Hutchinson County.

The sole identified customer at this point in time is AMPIP's affiliated company AMPI. The rate for service is agreed to between the pipelines and its affiliate. AMPIP may install additional taps for deliveries to potential customers along the proposed route as customer requests arise. AMPIP would file additional initial tariffs and rates as services may be added.

Associated Milk Producers, Inc. Pipeline, Inc.

Before the
South Dakota Public Utilities Commission

Application for Change in an Intrastate Natural Gas Transportation Rate

Docket NG97-015

September, 1997

September 5, 1997

William Bullard, Jr.
Executive Director
South Dakota Public Utilities Commission
500 East Capitol
Pierre, SD 57501

Re: Application to Establish a Revised Transportation Rate for Associated Milk Producers, Inc. Pipeline

Dear Mr. Bullard:

Pursuant to South Dakota Statute 49-34A-10 and the Rules and Regulations of the South Dakota Public Utilities Commission ("SDPUC" or "Commission"), Chapter 20:10:13, Public Utility Rate Filing Rules, Associated Milk Producers, Incorporated, Pipeline Incorporated. ("AMPIP"), a subsidiary of Associated Milk Producers, Inc. ("AMPI"), hereby submits for filing this application to revise its natural gas transportation services rate and tariff subject to the Commission's jurisdiction. The revised rate will allow AMPIP to serve both AMPI and the new municipal gas utility to be owned and operated by the City of Freeman, South Dakota ("Freeman"). The Commission was granted jurisdiction over AMPIP's rates and tariffs pursuant to SDCL 49-34A-1, Subd. 9A.

Pursuant to South Dakota Administrative Rules Section 20:10:13:26, AMPIP provides the following information:

(1) Name, Address, and Telephone Number of Pipeline

Associated Milk Producers, Incorporated, Pipeline, Incorporated
136 East Railway
P. O. Box 430
Freeman, South Dakota 57109
(605) 925-4234

(2) Tariff or Tariff Sheets Affected

The Commission approved AMPIP's initial Intrastate Natural Gas Transportation Service Tariff, SDPUC No. 1, in Docket NG95-017. Within the approved tariff, the rate sheet affected is known as Schedule FT (Firm Transportation Service). A copy of the revised Tariff, Schedule FT and form of Service Agreement are included herein as Exhibit 4. The Tariff conforms with the Commission Rules 20:10:13:02 through 20:10:13:14, with the exception of Rules 20:10:13:04 and 20:10:13:05, and provides for a volumetric transportation service rate. AMPIP respectfully seeks waiver of Rules 20:10:13:04 and 20:10:13:05. This request is addressed more fully in Section 12 of this document.

No other type of service or rate will be offered on the pipeline at this time. In the future, AMPIP may add additional farm tap customers along the line, at the same rate under Schedule FT. If needed, AMPIP will file additional rates and tariffs at a later time to meet the needs of additional customers.

(3) Description of Change

Background

AMPI is a national milk producing cooperative operating in twenty states. AMPI's corporate headquarters are located in Arlington, Texas. AMPI has one facility located in the State of South Dakota, in Freeman. Prior to the installation of AMPIP, production costs at this Freeman facility were substantially higher than at any other AMPI plant. This was due in large part to the fact that the Freeman AMPI plant was the only AMPI site without natural gas service. Two years ago, AMPI studied the feasibility of providing natural gas to the plant located in Freeman. The most economical way to do this was to establish a direct connection to the Northern Natural Gas Company interstate pipeline system near Marion, SD. However, because of certain FERC regulatory requirements, and to provide future flexibility, AMPI created AMPIP as a subsidiary of AMPI to own and operate the intrastate natural gas pipeline subject to the Commission's rate and tariff jurisdiction. In November 1995, AMPIP filed an application with the Commission to establish initial transportation rates for the pipeline. That application was in Docket NG95-017.

Early in 1997, the City of Freeman elected to create a municipal gas distribution utility. The pipeline will now serve Freeman in addition to the AMPI plant. This operational change presents a need to modify the approved fixed monthly transportation rate of $14,724. At this time, transportation service on the pipeline is firm in character.

Change in the Approved Rate

The rate proposed herein is a volumetric rate reflecting underlying cost data pertinent to the pipeline configured to serve Freeman, instead of the AMPI plant alone. Freeman will purchase a segment of 6" polyethylene pipeline from AMPIP within the city limits. That segment is 7,675 feet in length and also includes the service line and materials to the AMPI plant. This segment is valued at $111,600. The proposed transportation rate reflects this reduction in plant investment and reductions in associated costs. Pursuant to SDPUC 49-34A-35, this sale of utility plant does not require Commission approval as it is less than $200,000.

After over a year of operation, AMPIP now has an historical base of cost data to rely upon in setting its transportation rate. The proposed rate reflects that historical information. The attached testimony and schedules of Mr. John Winter, Exhibit 2, explain the cost data more completely.

(4) Reason for the Change

There are three major reasons for the rate change. First, the proposed rate is a volumetric rate per Mcf rather than the current monthly fixed charge. A volumetric rate allows more flexibility to both AMPIP and Freeman as customers are added within the municipality and volumes change over time. It also sends pricing signals to Freeman and AMPI related to their utilization of the pipeline facility. During periods of low use, customer bills will reflect that lower seasonal use, and vice versa. Second, a portion of the pipeline will be sold to the City of Freeman which changes the underlying cost data supporting the rate. Third, after slightly more than a year of operation, more accurate cost data is now available.

(5) Present Rate

The present rate is charged between AMPIP and its parent company, AMPI, for deliveries to the Freeman AMPI facility alone. The rate is a fixed fee of $14,724 per month.

(6) Proposed Rate

The Proposed rate is $0.99 per Mcf. That rate is developed by Mr. John Winter in Exhibit 2.

The proposed volumetric rate is accepted and agreed to by AMPIP's parent company, AMPI, and the City of Freeman, South Dakota. Freeman's Mayor Michael Schultz has submitted a statement of concurrence, Exhibit 3, indicating Freeman's acceptance of the proposed rate.

(7) Proposed Effective Date of the Rate

AMPIP requests the Commission allow the rate to be effective no later than thirty (30) days following the date of the filing, or October 5, 1997, in time for the 1997 - 1998 heating season for the City of Freeman Municipal Gas Utility. Deliveries to Freeman from the pipeline are expected to begin shortly after that date.

AMPIP further requests that, on a temporary basis, the Freeman AMPI plant remain on the present monthly fixed charge of $14,724 through December 31, 1997, allowing a transition period for residences and businesses within Freeman to complete conversion to natural gas. The plant will switch to the volumetric rate of $0.99 per Mcf on January 1, 1998. This will allow AMPIP to recover its costs during the transition period.

(8) Approximation of the Annual Revenue Effect

The proposed volumetric gas transportation rate, $0.99/Mcf, applied to the estimated Mcf volume of 214,000 yields revenues of $211,860. This amount is essentially the same as the levelized annual revenue requirement determined by Mr. Winter on his Schedule 3, Page 2 of 3, Exhibit 2.

(9) Points Affected

Pipeline deliveries will be made to the Freeman town border station ("TBS"). It is the only delivery point affected.

(10) Estimated Number of Customers Affected

Two customers, the City of Freeman, SD, and AMPIP's parent company AMPI are affected by the proposed rate change. AMPI remains a customer of the AMPIP pipeline at the same rate, terms, and conditions as Freeman. The AMPI plant will also be a transport customer for the City utility. Previously, AMPI paid 100% of AMPIP's cost of service. Following approval, AMPI and the City will share the cost based on their respective annual usage levels.

(11) Statement of Facts, Opinions, Documents and Exhibits to Support the Rate

Pursuant to Rule 20:10:13:39 (Subp. 1), AMPIP submits the following exhibits in support of this filing:

Exhibit 1	Testimony of Mr. Harlan Mammen, President of AMPIP
Exhibit 2	Testimony of Mr. John Winter, Cost of Service and Pipeline Rate (Pursuant to Rule 20:10:13:96)
Exhibit 3	Statement of Concurrence, Hon. Michael Schultz, Mayor of Freeman, SD
Exhibit 4	First Revised Transportation Service Tariff
Exhibit 5	Statements Required by Chapter 20:10:13

(12) Request Waiver of Rules 20:10:13:04 and 20:10:13:05 - Arrangement of Tariff Schedules and Form of Tariff Schedules Rules, Respectively

Pursuant to Rule 20:10:13:08, AMPIP respectfully requests waiver of the Commission's tariff schedule arrangement and form of tariff rules (20:10:13:04 and 20:10:13:05) to the extent necessary to accept the proposed tariff and rates on the date proposed. The rules require various detailed administrative requirements for tariff changes which are burdensome for AMPIP since it will serve only two customers. Mr. Mammen's testimony lists the significant changes, which have been accepted by AMPIP's two customers. Thus, the public interest will not be adversely affected by granting such a waiver. Also, for simplicity of administration, the attached tariff is the First Revised Tariff.

AMPIP requests waiver of any other Commission rules necessary to allow the tariff and rate to be effective on the date requested.

(13) Listing of Parties, Contacts, Legal Representatives, etc.

Mr. Harlan Mammen
Associated Milk Producers, Inc.
315 North Broadway
New Ulm, MN 56073

Mr. John D. Winter
Northern States Power Company
414 Nicollet Mall
Minneapolis, MN 55401

Ms. Claire Taylor-Sherman
2800 Minnesota World Trade Center
30 E. 7th Street
St. Paul, MN 55101-4999

Mr. Dale Strasser, City Attorney
P. O. Box 428
Freeman, SD 57029

(14) Notice; Posting; Public Inspection

Pursuant to rule 20:10:13:17, a copy of this filing is available for public inspection at the AMPIP office located at 136 East Railway, Freeman, SD 57039. Also, pursuant to rule 20:10:13:17, AMPIP is providing written notice of this filing to the City of Freeman, SD. Pursuant to Rule 20:10:13:18, a copy of the written notice is posted at AMPIP's offices at 136 East Railway, Freeman, SD.

(15) Conclusion

AMPIP respectfully requests that the Commission accept and approve the proposed intrastate transportation rate effective thirty (30) days after filing, or October 5, 1997. This will allow the tariff to be in effect in time for initial services to the Freeman utility and without suspension or change. AMPIP makes this request with full concurrence from the customers affected, the City of Freeman, SD and AMPI.

Dated: September 5, 1997

ASSOCIATED MILK PRODUCERS, INC. PIPELINE, INC.

By: Harlan Mammen

Harlan Mammen
President
(507) 354-8295

Direct Testimony and Schedules
Mr. Harlan Mammen

Before the South Dakota Public Utilities Commission

In the Matter of the Application to Establish Revised Transportation Rates for Associated Milk Producers Pipeline, Inc.

Docket No.______________
Exhibit No. 1

September 1997

Mr. Harlan Mammen
Project Support
Docket No. __________

Q. Please state your name, business address and position with Associated Milk Producers Pipeline, Inc.

A. My name is Harlan Mammen. I am the President of AMPI Pipeline Inc., ("AMPIP") which is an intrastate natural gas pipeline operated in McCook, Turner and Hutchinson counties in southeastern South Dakota. The AMPIP pipeline currently serves the Associated Milk Producers, Inc. ("AMPI") plant in Freeman, South Dakota. AMPIP is a wholly-owned subsidiary of AMPI.

Q. Have you previously testified before the South Dakota Public Utilities Commission ("SDPUC")?

A. Yes. I have provided written testimony before the Commission in Docket No. NG95-017. That filing established the initial transportation rates on the AMPIP pipeline.

Q. What are your current responsibilities, education and professional background?

A. As Assistant Regional Manager of AMPI, my current responsibilities include direct responsibility for manufacturing operations at fourteen processing plants in five midwestern states, including the plant located in Freeman, South Dakota.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to explain the history of AMPIP and to explain how AMPIP will provide natural gas transportation service for the municipal gas utility being established by the City of Freeman, and explain the economic benefits to both parties.

Q. Please explain the history of AMPIP, Inc.

A. AMPI is a national milk producing cooperative operating in twenty states. AMPI's corporate headquarters are located in San Antonio Texas. AMPI has one facility located in the State of South Dakota, in Freeman. Prior to the installation of AMPIP, production costs at this Freeman facility were substantially higher than at any other AMPI plant.

This was due, in large part to the fact that the Freeman AMPI plant was the only AMPI site without natural gas service. Two years ago, AMPI studied the feasibility of providing natural gas to the plant located in Freeman. The most economical way to do this was to establish a direct connection to the Northern Natural Gas Company interstate pipeline system near Marion, SD. However, because of certain FERC regulatory requirements, and to provide future flexibility, AMPI created AMPIP as a subsidiary of AMPI to own and operate the intrastate natural gas pipeline, subject to the Commission's rate and tariff jurisdiction. In November 1995, AMPIP filed an application with the Commission to establish initial transportation rates for the pipeline. That application was approved by the Commission.

Q. What has occurred since AMPIP went into service?

A. The initial pipeline was structured to allow flexibility to respond to future developments. We expected that retail natural gas service could be extended to the residents and businesses in Freeman at some future time. As I understand it, the City studied several options and has decided to establish a municipal gas utility to provide this service. The City utility would purchase wholesale transportation service from the AMPIP line. The City utility would purchase natural gas supplies from a third party, and interstate transportation from Northern Natural. AMPIP will not provide sales service.

The City, having decided to go ahead with forming a municipal gas utility, approached AMPIP about the possibility of AMPIP allowing the City to tap the AMPIP line and serve retail customers in the City. AMPIP has agreed to provide this access to the City under its Tariff and contract form on file with the Commission. The tariff rate and terms and conditions of service to AMPI and the City Utility will be the same, so AMPIP will provide service on a non-discriminatory basis.

Q. Has Freeman reviewed the rates and tariff terms and conditions proposed here?

A. Yes. Freeman has reviewed the tariff and associated rates contained in this filing and believes these rates and tariffs meet their requirements to provide economic, reliable natural gas service to the citizens and businesses of Freeman. The mayor, Mike Schultz, has provided a Certificate of Concurrence which is attached to this filing as Exhibit 3, indicating the City supports the proposed rate and tariff. The proposed rates are thus uncontested and should be promptly approved by the Commission.

Q. Are any facility changes required?

A. In order for the City to establish it's gas utility, AMPIP will sell a small portion of the current pipeline to the City. The portion of the pipeline to be sold is inside the City boundaries and connects the AMPI plant to AMPIP. As a result, the AMPI plant will become a retail transportation customer of the City utility. AMPIP will sell the portion of pipe to the City for $111,600, which is the net book value on AMPIP's books and records. As I understand the requirements of SDPUC 49-34A-35, this sale is not subject to Commission approval because it involves less than $200,000.

Q. What are the benefits of AMPIP providing wholesale natural gas transportation service to the City Municipal Utility?

A. Natural gas service, including the cost of gas supply, has produced energy cost savings for AMPI compared to the cost of alternative fuels. Moreover, retail customers of the City Utility would also presumably enjoy energy cost savings if they take service through the pipeline and the City Utility. The City Utility and AMPI will share the use of AMPIP, reducing the cost to AMPI, and using the facilities more efficiently. The public interest will be served.

Q. Who will provide the gas supply for Freeman to be transported through AMPIP?

A. As the Commission knows, over the last decade the FERC has restructured the wholesale interstate pipeline industry. Northern Natural no longer provides gas supply services. Instead, Freeman can directly contract with any one of a number of wholesale gas suppliers, using Northern and AMPIP only for transportation services.

Q. What tariff changes are proposed to the AMPIP tariff?

A. Most importantly, of course, the rate contained in the Firm Transportation rate schedule has been changed to reflect the cost of service in testimony sponsored by Mr. John Winter. Mr. Winter uses the AMPI and City Utility's billing determinants to arrive at the Firm Transportation rate of $0.99.

In addition, AMPIP is changing the definition of "gas day" to reflect the changes to Northern's FERC tariff to implement new Gas Industry Standards Board ("GISB") standards. FERC mandated all interstate pipelines us a "gas day" starting at 9:00 central clock time; Northern previously used a 12:00 Noon gas day.

AMPIP is also adding provisions whereby it can pass through to a shipper any imbalance penalties from Northern caused by the shipper. Northern received FERC approval to modify its imbalance penalty structure, including imposing "critical day" penalties of up to $113 per dkt, in order to maintain system integrity. See FERC Docket No. RP96-302. AMPIP does not anticipate such penalties being imposed on AMPIP since AMPI and the City Utility, or their supplier, will hold the transportation contract on Northern and should bear any imbalance penalties. However, if a penalty is imposed on AMPIP by Northern as a result of the actions of a shipper, the shipper should reimburse AMPIP since the cost of service supporting the proposed transportation rates does not include any penalty costs.

Finally, AMPIP is proposing a few "clean-up" changes which are not substantive. As I stated earlier, the City Utility has reviewed the proposed tariff, transportation contract and rate, and supports prompt Commission approval. The changes are proposed to be effective 30 days after filing.

Q. Do you have any final comments?

A. AMPIP views this proposal as a significant economic development step for the City of Freeman and southeastern South Dakota. The project will make the City of Freeman more competitive, and should help attract economic development to the area. I hope the Commission will agree by approving the proposed tariff and rate effective 30 days after filing, so that natural gas deliveries may take place prior to the 1997-1998 heating season.

Q. Does this conclude your testimony?

A. Yes.

AFFIDAVIT

STATE OF MINNESOTA)
)
COUNTY OF BROWN)

Affiant, having been first duly sworn, on oath deposes and says:

That he has read the foregoing testimony and if asked the questions therein his answers in response would be as shown;

That the facts contained in said answers are true to the best of his knowledge and belief.

Harlan Mammen

Harlan Mammen

SUBSCRIBED AND SWORN to me before me this 3rd day of September, 1997.

Notary Public

KENNETH R. SPOON
NOTARY PUBLIC-MINNESOTA

Direct Testimony and Schedules
John Winter

Before the South Dakota Public Utilities Commission

In the Matter of the Application to Establish Revised Transportation Rates for Associated Milk Producers Pipeline, Inc.

Docket ____________
Exhibit No. 2

September 1997

Q. Please state your name, position, and business address.

A. My name is John Winter. My position is Sr. Regulatory Consultant within the Regulatory Services Department of Northern States Power Company ("NSP"). My business address is 414 Nicollet Mall in Minneapolis, MN.

Q. What are your current responsibilities?

A. I am responsible for providing project management and team participation on various regulatory projects, particularly in the area of rates. I provide expert testimony, including development of underlying technical cost support, for the revenue requirements aspects of NSP regulatory proceedings. The cost support I prepare involves gathering revenue, expense, and plant investment data and determining the appropriate amounts related to the provision of utility services. My internal NSP clients include NSP-South Dakota, NSP-North Dakota, NSP-Electric (wholesale and transmission), and NSP-Natural Gas Services.

Q. What is your educational and professional background?

A. Schedule 1 contains a summary of my educational and professional background.

Q. Have you testified previously before this Commission?

A. As shown on Schedule 1, I appeared before this Commission in a Conservation Cost Recovery case. I also submitted cost of service testimony in Docket F-3422. The case was subsequently settled. I have provided direct and indirect support for numerous regulatory projects in South Dakota since the late 1970's.

Q. What is your role in this proceeding and the purpose of your testimony?

A. I am providing internal consulting services to NSP-Natural Gas Services ("NGS"), a division of NSP's Gas Utility. In this proceeding, NGS is providing consulting services to Associated Milk Producers, Inc. Pipeline ("AMPIP"), a subsidiary of Associated Milk Producers, Inc. ("AMPI"), and the City of Freeman, South Dakota ("City"), to develop and establish a rate for intrastate transportation for natural gas delivered on AMPIP to AMPI and Freeman's new municipal gas utility. Using cost data provided by AMPIP, my testimony describes the cost of service for the pipeline and establishes the proposed volumetric pipeline rate. AMPI and the City both contract with other parties for natural gas supply and AMPIP transports the gas. Mr. Harlan Mammen, Assistant Regional General Manager of AMPI and President of AMPIP, describes the AMPIP/Freeman contract in greater detail in his testimony.

Q. Please generally describe the development of the pipeline rate.

A. The pipeline rate is developed on Schedule 2 of my exhibits. Schedules 3 - 5 support that calculation. Consistent with Docket NG95-017, a levelized annual revenue requirement factor is developed and applied to gross plant investment to determine the annual revenue requirements of the pipeline system. The factor includes components reflecting debt service, depreciation, property taxes, operating and maintenance expenses, property insurance, and regulatory fees. The components are escalated where appropriate over a 45 year period, and then discounted at AMPIP's cost of capital to determine the levelized annual revenue requirements of $211,897. The proposed volumetric rate of $0.99/Mcf is determined by dividing the annual revenue requirements by the anticipated transportation volumes of 214,000 Mcf. This rate, if approved, will be applied to all transportation services for AMPI and Freeman's Municipal Gas Utility as described in the Gas Transportation Service Tariff Schedules, Exhibit No. 4 of this filing. The City will own and operate its municipal distribution system and provide retail transportation service to AMPI. This is not subject to SDPUC regulation.

Q. Please describe in more detail your development of the pipeline revenue requirements beginning with the pipeline investment.

A. Schedule 3, Page 1 of 3, shows the components of the pipeline's projected revenue requirements over the first 45 years of operation. AMPIP's original cost investment in the pipeline is $1,256,056 and is developed on my Schedule 4. It is also shown in Column C of Schedule 3, Page 1 of 3. That amount reflects AMPIP's original cost of the pipeline less the value of a small segment within the City of Freeman. The City will purchase that segment for $111,600. The investment is recovered over a 40 year book life at the rate of $30,704 per year. The annual depreciation is also developed on Schedule 4 and incorporated on Page 1 of 3 of Schedule 3 in Column F. This amount has been reduced to reflect the portion sold to the City. Property taxes begin at $30,576 per year (1996), reduced for the portion sold to the City, and are developed on Schedule 4 and incorporated on Page 1 of 3 of Schedule 3 in Column H. The property tax amounts are escalated at 2.75% per year. Tax depreciation uses alternative Modified Accelerated Cost Recovery System (MACRS) with a 22 year tax life on a straight line basis. The half-year convention is also used.

Q. Does the tax vs. book depreciation differences have an impact on the proposed rate?

A. Essentially, there is no impact. I have simplified the revenue requirements calculation by setting tax depreciation equal to book depreciation. Since this is a levelized determination, the result is essentially the same as if the tax vs. book differences were deferred and later flowed back.

Q. What have you used for cost of capital?

A. I have included interest on the pipeline debt at 9%, which is the rate on AMPIP's note payable.

Q. Please describe how you have estimated operating and maintenance expenses (O&M)?

A. Based on AMPIP's actual results of operations since 1995, I have incorporated their estimates of first year O&M expenses. I have shown those expenses, $39,450, on my Schedule 5. In addition, I have included reasonable escalators for each component of O&M reflecting historical, contractual, and expected increases over time. I then calculated the weighted overall escalator of 1.5%, which I used in determining the annual O&M over the life of the project.

Q. What was the result of your levelized annual present value calculation?

A. I determined that the levelized annual revenue requirement of the pipeline is $211,897. This amount is shown on Page 2 of 3, Schedule 3, and again in Schedule 2 where the pipeline rate is developed.

Q. Have you provided additional detail about your determination of AMPIP's proposed rate?

A. Yes. Each of Schedules 2 - 5 include a section showing Sources and Notes. These references provide additional documentation for the cost of service.

Q. Please describe the required filing statements included with this application.

A. Exhibit 5 of this filing consists of the required filing statements per Chapter 20:10:13 of the South Dakota Administrative Rules. The initial pages of that exhibit list the statements included, or that are not applicable. The reasons certain statements are not applicable is described on page two of the listing. Waiver of those statements not applicable is respectfully requested of the Commission.

Q. Is AMPIP proposing some form of purchased cost of gas adjustment mechanism?

A. Yes. Not unlike typical gas local distribution companies, AMPIP will be exclusively a gas transporter and will not provide sales service. However, AMPIP proposes to pass along uncontrollable charges imposed by Northern Natural Gas, the upstream interstate pipeline. The City may, in turn, elect to pass those costs on to its customers in its retail rates. Section 5.1 in the Gas Service Tariff, First Revised Sheet No. 16 discusses the pipeline cost adjustment.

Q. Do you have any concluding remarks?

A. Yes. The proposed rates are comparable to other utilities, reasonable, and represent a good value to energy supply. AMPIP respectfully requests Commission approval of AMPIP's proposed rates for intrastate transportation to its shippers (AMPI and Freeman, SD).

Q. Has the City of Freeman agreed to these rates?

A. Yes. In his Statement of Concurrence, Freeman's Mayor Michael Schultz expresses agreement on behalf of the Freeman with the proposed tariff terms, conditions, and rates. This consent to the proposed rates provides additional support for the Commission to approve the proposed rates without suspension.

Q. Does this conclude your testimony?

A. Yes it does.

Exhibit 2

List of Schedules

JOHN D. WINTER, CPA
Sr. Regulatory Consultant - Regulatory Services
414 Nicollet Mall
Mpls., MN 55401

CURRENT RESPONSIBILITIES (June 1992 - Present)

Directly responsible for providing project management and team participation on various regulatory projects, particularly in the area of rates. Provide expert testimony, including development of underlying technical cost support, for the revenue requirements aspects of regulatory proceedings. Internal clients are Northern States Power Company (NSP)-South Dakota, NSP-North Dakota, NSP-Electric (wholesale and transmission), and NSP-Natural Gas Services. Responsibilities frequently include overall project management/coordination. Leadership for the project team and participants is critical. A significant aspect of the position is the need to build credible and effective relationships with regulators in all jurisdictions.

EMPLOYMENT HISTORY (Northern States Power Company)

Sr. Regulatory Consultant	1994 - Present
Assistant to the Chief Financial Officer	1992 - 1993
Director, Financial Accounting, Budgets, and Reports	1990 - 1992
Director, Electric Finance and Information Management	1989 - 1990
Director, Electric Finance	1988 - 1989
Manager, Electric Financial Planning & Administration	1984 - 1988
Administrator, Revenue Requirements	1983 - 1984
Sr. Rate Analyst/Rate Analyst, Revenue Requirements	1979 - 1983
Accountant Sr., General Accounting	1977 - 1979
Accounting Specialist, Material Accounting	1976 - 1977

EDUCATION

Electric Utility System Operation	1993
The Masters Forum	1991 - 1992
Strategic Cost Management, Tuck at Dartmouth	1991
Public Utility Finance Seminar, Kidder Peabody	1989
Bachelor of Science - Accounting, University of Minnesota	1976

PROFESSIONAL CERTIFICATION AND ASSOCIATIONS

Certified Public Accountant (CPA) - Minnesota
Member, American Institute of CPA's (AICPA)
Member, Minnesota Society of CPA's

PREVIOUS TESTIMONY

FERC Application for Merger Approval (Primergy)	ER95-1358-000
North Dakota Application for Merger Approval (Primergy)	PU-400-95-340
North Dakota - Electric	PU-400-94-514
FERC Open Access Transmission Tariff	ER94-1113-000
FERC Transmission - Order 84 Sales for Resale	ER94-1090-000
FERC Wholesale	ER93-385-000
North Dakota - Electric	PU-400-92-399
Minnesota - Electric (Budgets and Budget Process)	E002/GR-91-001
South Dakota - Electric	F-3422
South Dakota Conservation Cost Recovery	PUC Hearing, 1981

AMPI Pipeline, Inc.
Freeman, South Dakota Rate
Pipeline Rate

Schedule 2

	Volume / Amount (A)	Volumetric Rates (B)
(1) Annual MCF	214,000	
(2) Annualized Revenue Requirements	$211,897	
(3) Total Blended Volumetric Rate		$0.99

Sources and Notes:

Line 1: Sales volume estimates, first full year. Per Freeman, AMPIP.

Line 2: Schedule 3, Page 2 of 2. Referred to as "Annual Requirement".

Line 3: Line 2 divided by Line 1 above.

AMPI Pipeline, Inc.
Statement M - Cost of Service
Levelized Annual Revenue Requirement - See Page 3 of 3 for Sources and Notes

Capital Structure (CS):	Cost	Weight	Weighted Cost
(CS1) Equity	0.00%	0.00%	0.0000%
(CS2) Preferred Stock	0.00%	0.00%	0.0000%
(CS3) Long-term Debt	9.00%	100.00%	9.0000%
(CS4) Short-term Debt	0.00%	0.00%	0.0000%
(CS5)		100.00%	9.0000%

	Time Period (A)	Year (B)	Plant in Service Additions (C)	Net Investment Rate Base (D)	Debt Return (E)	Book Dep'n (F)	Operating Expenses (G)	Property Taxes (H)	Total Revenue Requirement (I)	9.0000% Present Value of Revenue Deficiency or (Excess) (J)
(1)	0	1995	1,256,056	1,240,704	55,832	15,352	39,450	2,470	113,104	113,104
(2)	1	1996	0	1,210,000	110,282	30,704	40,045	30,528	211,559	194,091
(3)	2	1997	0	1,179,296	107,518	30,704	40,649	31,368	210,239	176,954
(4)	3	1998	0	1,148,592	104,755	30,704	41,263	32,230	208,952	161,349
(5)	4	1999	0	1,117,888	101,992	30,704	41,885	33,116	207,697	147,138
(6)	5	2000	0	1,087,184	99,228	30,704	42,517	34,027	206,477	134,196
(7)	6	2001	0	1,056,480	96,465	30,704	43,159	34,963	205,291	122,408
(8)	7	2002	0	1,025,776	93,702	30,704	43,810	35,924	204,140	111,672
(9)	8	2003	0	995,072	90,938	30,704	44,471	36,912	203,026	101,892
(10)	9	2004	0	964,368	88,175	30,704	45,142	37,927	201,948	92,983
(11)	10	2005	0	933,664	85,411	30,704	45,823	38,970	200,909	84,866
(12)	11	2006	0	902,960	82,648	30,704	46,515	40,042	199,909	77,471
(13)	12	2007	0	872,256	79,885	30,704	47,217	41,143	198,949	70,733
(14)	13	2008	0	841,552	77,121	30,704	47,929	42,275	198,029	64,593
(15)	14	2009	0	810,848	74,358	30,704	48,652	43,437	197,151	58,997
(16)	15	2010	0	780,144	71,595	30,704	49,386	44,632	196,317	53,896
(17)	16	2011	0	749,440	68,831	30,704	50,132	45,859	195,526	49,247
(18)	17	2012	0	718,736	66,068	30,704	50,888	47,120	194,780	45,008
(19)	18	2013	0	688,032	63,305	30,704	51,656	48,416	194,080	41,144
(20)	19	2014	0	657,328	60,541	30,704	52,435	49,748	193,428	37,620
(21)	20	2015	0	626,624	57,778	30,704	53,226	51,116	192,824	34,406
(22)	21	2016	0	595,920	55,014	30,704	54,030	52,521	192,269	31,474
(23)	22	2017	0	565,216	52,251	30,704	54,845	53,966	191,765	28,800
(24)	23	2018	0	534,512	49,488	30,704	55,672	55,450	191,314	26,359
(25)	24	2019	0	503,808	46,724	30,704	56,512	56,974	190,915	24,133
(26)	25	2020	0	473,104	43,961	30,704	57,365	58,541	190,571	22,100
(27)	26	2021	0	442,400	41,198	30,704	58,231	60,151	190,283	20,245
(28)	27	2022	0	411,696	38,434	30,704	59,109	61,805	190,053	18,551
(29)	28	2023	0	380,992	35,671	30,704	60,001	63,505	189,881	17,004
(30)	29	2024	0	350,288	32,908	30,704	60,906	65,251	189,769	15,590
(31)	30	2025	0	319,584	30,144	30,704	61,825	67,046	189,719	14,299
(32)	31	2026	0	288,880	27,381	30,704	62,758	68,890	189,733	13,120
(33)	32	2027	0	258,176	24,618	30,704	63,705	70,784	189,811	12,041
(34)	33	2028	0	227,472	21,854	30,704	64,666	72,731	189,955	11,055
(35)	34	2029	0	196,768	19,091	30,704	65,642	74,731	190,168	10,154
(36)	35	2030	0	166,064	16,327	30,704	66,633	76,786	190,450	9,329
(37)	36	2031	0	135,360	13,564	30,704	67,638	78,897	190,803	8,575
(38)	37	2032	0	104,656	10,801	30,704	68,659	81,067	191,230	7,885
(39)	38	2033	0	73,952	8,037	30,704	69,695	83,296	191,732	7,253
(40)	39	2034	0	43,248	5,274	30,704	70,746	85,587	192,311	6,674
(41)	40	2035	0	12,544	2,511	30,704	71,814	87,941	192,969	6,144
(42)	41	2036	0	0	564	12,544	72,897	90,359	176,365	5,151
(43)	42	2037	0	0	0	0	73,997	92,844	166,841	4,471
(44)	43	2038	0	0	0	0	75,114	95,397	170,511	4,192
(45)	44	2039	0	0	0	0	76,247	98,021	174,268	3,931
(46)	45	2040	0	0	0	0	77,398	100,716	178,114	3,686
(47)	Project Totals		1,256,056		2,312,243	1,256,056	2,592,358	2,655,481	8,816,137	2,305,982

	Levelized Annual Revenue Requirement - LARR			
(RR1)	$87,398	$31,799	$50,761	$41,967

	LARR - As a % of Original Cost			
(RR2)	6.96%	2.53%	4.04%	3.34%

	9.0000% Present Value of Debt Return (A)	9.0000% Present Value of Book Depreciation (B)	9.0000% Present Value of Operating Expenses (C)	9.0000% Present Value of Current Property Taxes (D)	Present Value of Revenue Requirements or (Excess) (E)
(1)	55,832	15,352	39,450	2,470	113,104
(2)	101,176	28,169	36,739	28,007	194,091
(3)	90,496	25,843	34,214	26,401	176,954
(4)	80,890	23,709	31,862	24,888	161,349
(5)	72,253	21,751	29,673	23,461	147,138
(6)	64,492	19,955	27,633	22,115	134,196
(7)	57,519	18,308	25,734	20,847	122,408
(8)	51,258	16,796	23,966	19,652	111,672
(9)	45,639	15,409	22,319	18,525	101,892
(10)	40,598	14,137	20,785	17,463	92,983
(11)	36,079	12,970	19,356	16,462	84,866
(12)	32,029	11,899	18,026	15,518	77,471
(13)	28,402	10,916	16,787	14,628	70,733
(14)	25,155	10,015	15,633	13,789	64,593
(15)	22,251	9,188	14,559	12,998	58,997
(16)	19,655	8,429	13,558	12,253	53,896
(17)	17,337	7,733	12,627	11,551	49,247
(18)	15,267	7,095	11,759	10,888	45,008
(19)	13,420	6,509	10,951	10,264	41,144
(20)	11,775	5,972	10,198	9,675	37,620
(21)	10,309	5,479	9,497	9,121	34,406
(22)	9,006	5,026	8,845	8,598	31,474
(23)	7,847	4,611	8,237	8,105	28,800
(24)	6,818	4,230	7,671	7,640	26,359
(25)	5,906	3,881	7,143	7,202	24,133
(26)	5,098	3,561	6,652	6,789	22,100
(27)	4,383	3,267	6,195	6,400	20,245
(28)	3,751	2,997	5,770	6,033	18,551
(29)	3,194	2,749	5,373	5,687	17,004
(30)	2,704	2,522	5,004	5,361	15,590
(31)	2,272	2,314	4,666	5,053	14,299
(32)	1,893	2,123	4,340	4,764	13,120
(33)	1,562	1,948	4,041	4,490	12,041
(34)	1,272	1,787	3,764	4,233	11,055
(35)	1,019	1,639	3,505	3,990	10,154
(36)	800	1,504	3,264	3,761	9,329
(37)	610	1,380	3,040	3,546	8,575
(38)	445	1,266	2,831	3,342	7,885
(39)	304	1,161	2,636	3,151	7,253
(40)	183	1,066	2,455	2,970	6,674
(41)	80	978	2,286	2,800	6,144
(42)	16	366	2,129	2,639	5,151
(43)	0	0	1,983	2,488	4,471
(44)	0	0	1,847	2,345	4,192
(45)	0	0	1,720	2,211	3,931
(46)	0	0	1,602	2,084	3,686
(47)	950,996	346,012	552,317	456,657	2,305,982

Summary - LARR (F)	Amounts (G)
Return	**6.96%**
Depreciation	**2.53%**
O&M and Prop Taxes	**7.38%**
Total LARR	**16.87%**
Plant In Service	**$1,256,056**
Annual Requirement	**$211,897**

AMPI Pipeline, Inc.
Statement M - Cost of Service
Levelized Annual Revenue Requirement
Sources and Notes

Schedule 3, Page 1 of 3:

Lines CS1 - CS5: AMPIP Cost of Capital. Debt only @ 9% Interest Rate

Line 1, Column A: Time Period for present value calculation.

Line 1, Column B: Year in service. Present value is life cycle beginning in 1995.

Line 1, Column C: Net pipeline expenditures. Reduced for sale of 7,675' to City of Freeman for $111,600.

Lines 1 - 46, Column D: Net investment reduced for accumulated depreciation for each year.

Line 1, Column E: One-half of end of first year investment ($1,240,704/2) applied to debt cost (9%).

Line 1, Column F: Book depreciation per AMPIP adjusted for sale of 7,675' to Freeman (half year). See Schedule 4.

Line 1, Column G: See Schedule 5.

Line 1, Column H: Actual Property Taxes per AMPIP for first year.

Lines 1 - 46, Column I: Sum of Columns E - H for corresponding lines.

Lines 1 - 46, Column J: Present Value of Column I @ Overall Cost of Capital (9%).

Lines 2 - 46, Column E: Average net investment applied to debt cost (9%).

Lines 2 - 46, Column F: Book depreciation per AMPIP adjusted for sale of 7,675' to Freeman. See Schedule 4.

Lines 2 - 46, Column G: Operating expenses per Schedule 5, escalated at rate determined on Schedule 5.

Lines 2 - 46, Column H: Property taxes per AMPIP adjusted for sale of 7,675' to Freeman. See Schedule 4. Escalated at 2.5% annually.

Line 47: Check totals.

Schedule 3, Page 2 of 3:

Line RR1: The levelized annual revenue requirements of the items reflected in the columns below.

Line RR2: The percent of original cost ($1,256,056) for the levelized revenue requirements shown on RR1.

Lines 1 - 46, Columns A - D: Annual present value of each revenue requirement component shown. The nominal amounts are from Schedule 3, Page 2 of 3, Columns E - H.

Lines 1 - 46, Column E: Annual present value of total revenue requirements. Matches Column J on Schedule 3, Page 1 of 3.

Line 47, Columns A - E: Total of annual present value amounts for each column. These amounts are then discounted to arrive at the amounts shown on Line RR1.

Columns F and G: Summary of Levelized Annual Revenue Requirements. Column F describes each component. Column G shows the LARR rate by component and the total. The LARR rate of 16.79% on Line 5, Column G is applied to the original cost of the pipeline shown on Line 8, Column G to arrive at the levelized annual revenue requirements shown on Line 10, Column G of $210,892. This amount is carried forward to Schedule 2 to determine the pipeline rate.

AMPI Pipeline, Inc. **Schedule 4**
Freeman, South Dakota Pipeline Rate
Plant Investment and Related Costs

Pipeline Sold to Freeman, SD			AMPIP Amounts (C)
(1) Pipeline Original Cost	$1,367,656		
(2) less: Portion Sold to City	111,600		
(3) **Net Pipeline Original Cost**			**$1,256,056**

Adjustments to Cost Items for Sold Portion

	Original Amount (A)	Percent Reduced (B)	
(4) **Annual Book Depreciation**	$33,432	8.16%	**$30,704**
(5) **Annual Property Taxes**	33,240	8.16%	**$30,528**

Sources and Notes:

Line 1: Pipeline original cost per AMPIP books and records.

Line 2: 7,675 Feet of 6" Steel to be sold to the City of Freeman, SD. This portion is within the city limits and thus on the City's side of the town border station.

Line 3: Net AMPIP original cost of the pipeline.

Line 4: Book depreciation per AMPIP's books and records shown in Column A. Percent reduced is determined above on Lines 1 - 3. Net AMPIP portion is shown in Column C.

Line 5: Property Taxes per AMPIP's books and records shown in Column A. Percent reduced is determined above on Lines 1 - 3. Net AMPIP portion is shown in Column C.

AMPI Pipeline, Inc.
Freeman, South Dakota Rate
Operating Expenses (O&M)

Schedule 5

	Amount (A)	Annual Escalator (B)	1 Year Escalated Amount (C)
(1) Contracted - Operating and Maintenance Day to day operations and maintenance of pipeline facility	$12,000	2.0%	$12,240
(2) AMPIP - Operating and Maintenance Costs Training, readings, patrolling of line by local AMPI personnel	$1,740	3.5%	$1,801
(3) Corporate Services Management, clerical, accounting and tax work	$6,710	3.5%	$6,945
(4) Audit and Legal Fees Outside legal and audit fees	$1,700	3.5%	$1,760
(5) Insurance Annual Fee	$15,000	0.0%	$15,000
(6) OPS Assessment Office of Pipeline Safety	$1,500	0.0%	$1,500
(7) Regulatory Fees Gross Receipts tax and DOT Pipeline Safety Assessment	$800	0.0%	$800
(8) Total	$39,450	1.5%	$40,045

Sources and Notes:

Line 1, Column A: Per AMPIP contract with NSP NGS for pipeline operations and maintenance services.
Line 1, Column B: Contract escalator.
Lines 1 - 7, Column C: Year 2 level of cost with escalator applied to year 1 historical-based amounts.
Line 2, Column A: AMPIP direct costs of employee pipeline maintenance activities.
Lines 2, 3, and 4, Column B: Annual escalator based on anticipated inflation.
Line 3, Column A: Portion of AMPI corporate costs associated with the pipeline.
Line 4, Column A: Audit and legal fees based on actual results.
Line 5, Column A: Insurance costs based on actual results.
Line 6, Column A: OPS assessment based on actual results.
Line 7, Column A: Regulatory fees based on actual results.
Line 8, Columns A and C: Sum of year 1 and year 2, respectively, O&M costs from Lines 1 - 7.
Line 8, Column B: Weighted annual O&M escalator based on expenses and individual escalators shown on Lines 1 - 7.

AFFIDAVIT

STATE OF MINNESOTA)
)
COUNTY OF RAMSEY)

Affiant, having been first duly sworn, on oath deposes and says:

That he has read the foregoing testimony and if asked the questions therein his answers in response would be as shown;

That the facts contained in said answers are true to the best of his knowledge and belief.

John D. Winter

SUBSCRIBED AND SWORN to me before me this 3rd day of September, 1997.

Notary Public

Exhibit No. 3

Letter of Concurrence

Honorable Mayor Michael Schultz
Freeman, SD

Michael Schultz, Mayor
City of Freeman, South Dakota
P. O. Box 178
Freeman, South Dakota 57029-0178

September 3, 1997

Mr. Harlan Mammen, President
AMPI Pipeline, Inc.
315 North Broadway
New Ulm, MN 56073

Re: Proposed AMPIP Transportation Rate

Dear Harlan:

On behalf of the City of Freeman, South Dakota, and its newly-formed municipal gas distribution utility, I concur with the AMPIP pipeline rate of $0.99 per Mcf proposed in your recent filing with the South Dakota Public Utilities Commission. I have conferred with the Freeman Utility Board, and we support the proposed rate as just and reasonable.

We look forward to the availability of natural gas in Freeman beginning this fall. This is a positive step forward for the city's residents and businesses.

Sincerely,

Michael Schultz

Michael Schultz, Mayor
Freeman, South Dakota

Exhibit No. 4

Transportation Service Tariff

TARIFF SCHEDULES

APPLICABLE TO

INTRASTATE NATURAL GAS TRANSPORTATION SERVICE

OF

AMPI PIPELINE, INC.

General Office
315 North Broadway
New Ulm, MN 56073

South Dakota Office
136 East Railway
P.O. Box 430
Freeman, SD 57109

Filed with the South Dakota Public Utilities Commission
as SDPUC No. 1

Date Filed: September 5, 1997

Issued by: Harlan Mammen
Harlan Mammen
President

AMPI PIPELINE, INC.

GAS TRANSPORTATION SERVICE TARIFF

ORIGINAL VOLUME NO. 1

TABLE OF CONTENTS

PRELIMINARY STATEMENT

AMPI Pipeline, Inc. (hereafter "AMPIP" or "Transporter") is an intrastate natural gas pipeline company engaged in the business of transporting natural gas in intrastate commerce to end users and municipal gas systems in the State of South Dakota. AMPIP's System consists of approximately 20 miles of distribution pipeline located McCook, Turner and Hutchinson Counties, South Dakota. AMPIP takes delivery of natural gas from Northern Natural Gas Company near Marion, South Dakota, and redelivers it to shippers at delivery points along or at the terminus of AMPIP in Freeman, South Dakota.

GENERAL TERMS AND CONDITIONS

ARTICLE I
DEFINITIONS

1.1 "Btu" shall mean one British Thermal Unit.

1.2 "Contract Demand" shall mean the aggregate of the maximum daily quantities of gas, expressed in dkt per day, which Transporter is obligated to accept for transportation for the account of Shipper from the points of receipt as set forth in the Transportation Service Agreement ("TSA") between Transporter and Shipper.

1.3 "Contract Year" shall mean the twelve month period commencing November 1 and terminating on October 31 of each year, until this Agreement shall have expired or otherwise been terminated in accordance with its terms.

1.4 "Day" shall mean a period of 24 consecutive hours, starting at 9:00 a.m. Central Clock Time, or such other 24 hour gas day period as established in Northern's Tariff.

1.5 "Dkt" shall mean the quantity of heat energy which is equivalent to 1,000,000 British Thermal Units (BTU). One "dkt" of gas means the quantity of gas which contains one dekatherm of heat energy. The total dekatherms are calculated by multiplying the gas volume in Mcf by its total gross heating value, divided by 1,000.

1.6 "Equivalent Quantities" shall mean the sum of the quantities of gas measured in dkt received by Transporter and delivered for the account of Shipper at the points of receipt and delivery during any given period of time reduced by the sum of Shipper's Pro Rata Share of Lost and Unaccounted For Gas resulting from the operations of the System during the same period of time. In the event the ownership of gas lost as a result of an event of force majeure can be reasonably identified, the quantity thereof shall be charged to the Shipper or Shippers so identified.

1.7 "Gas" shall mean natural gas, unmixed or any mixture of natural and artificial gas.

1.8 "Gross Heating Value" shall mean the number of BTUs produced by the complete combustion, at a constant pressure, of the amount of gas which would occupy a volume of one (1) cubic foot at a temperature of 60 degrees Fahrenheit on a dry basis and at a pressure of 14.73 psia with air of the same temperature and pressure as the gas, when the products of combustion are cooled to the initial temperature of the gas and air, and when the water formed by combustion has been condensed to the liquid state.

1.9 "Maximum Daily Quantity" shall mean the maximum quantity expressed in dkt per day that the Transporter is obligated to receive for the account of Shipper at the point of receipt, as established in Exhibit A to Shipper's TSA.

1.10 "Mcf" shall mean 1,000 cubic feet of gas determined in accordance with the measurement base described in Paragraph 3. 1 hereof.

1.11 "Month" shall mean the period beginning at 9:00 a.m. Central Clock Time on the first day of a calendar month and ending at the same hour on the first day of the next succeeding month.

1.12 "Northern" shall mean Northern Natural Gas Company, its successors and assigns.

1.13 "Northern's Tariff" shall mean the Northern's FERC Gas Tariff as it may be in effect from time to time.

1.14 "Pro Rata Share" shall mean the ratio that the quantity of gas delivered to Transporter by or for the account of Shipper bears to the total quantity of gas delivered to Transporter by all shippers for transportation in the System during any given period of time.

1.15 "SDPUC" shall mean the South Dakota Public Utilities Commission or any commission, agency or other state governmental body succeeding to the powers of such commission.

1.16 "Shipper" shall mean any party to a TSA providing for transportation of natural gas on Transporter's System. For purposes of Articles V and VI, "Shipper" shall also mean Shipper's Agent designated to provide day-to-day transportation management for Shipper. Shipper may change such designation from time to time upon written notice to Transporter.

1.17 "System" shall mean the pipeline and related pipeline facilities at the time owned by Transporter.

1.18 "TSA" shall mean the Transportation Service Agreement between Transporter and Shipper in the form set forth in this Tariff.

1.19 "Unaccounted For Gas" shall mean the difference between the sum of all input quantities of gas to the System and the sum of all output quantities of gas from the System, which difference shall include but shall not be limited to gas used and accounted for in System operations, meter errors (subject to Section 3.8) and gas lost as a result of an event of force majeure, the ownership of which cannot be reasonably identified.

ARTICLE II
QUALITY

2.1 Quality Standards of Gas Received by Transporter. The gas to be delivered by Transporter shall be of merchantable quality and shall meet the minimum quality standards of Northern, as may be established or revised from time to time in Northern's Tariff.

2.2 Quality Tests. At the point of receipt, Transporter may cause tests to be made, by approved standard methods in general use in the gas industry, to determine whether the gas conforms to the quality specifications set out in Paragraph 2.1 hereof. Such tests shall be made at such intervals as Transporter may deem reasonable, and at other times, but not more often than once per day, or at the request of Shipper.

2.3 Failure to Conform. If gas delivered by Shipper does not comply with the quality specifications set out in Paragraph 2.1 hereof, Transporter shall have the right, in addition to all other remedies available to it by law, to refuse to accept any such gas. Transporter may, at its option and upon notice to Shipper, accept receipt of gas not complying with the quality specifications set out in Paragraph 2. 1 herein provided. Transporter, at the expense of Shipper, may make all changes necessary to bring such gas into compliance with such specifications.

2.4 Quality Standards of Gas Transported By Transporter. Transporter shall use reasonable diligence to deliver gas for Shipper which shall meet the quality specifications set out in Paragraph 2. 1 hereof, but shall only be obligated to deliver gas of the quality which results from the commingling of the gas received by Transporter from Shipper and other shippers.

ARTICLE III
MEASUREMENT

3.1 Unit of Measurement and Metering Base. The volumetric measurement base shall be one cubic foot of gas at a pressure base of 14.73 pounds per square inch absolute, at a temperature base of 60°F, and without adjustment for water vapor content.

3.2 Atmospheric Pressure. For the purpose of measurement, the absolute atmospheric (barometric) pressure at each measuring station shall be the atmospheric pressure determined by calculations based on the actual elevation above sea level of the meter at the place of measurement, and shall be stated in pounds per square inch.

3.3 Temperature. If determined to be necessary in the sole discretion of Transporter, the temperature of the gas shall be determined at each point of measurement by means of a properly installed recording thermometer, an indicating thermometer, an electronic temperature measuring device, or a temperature compensating meter of standard manufacture acceptable to Transporter.

3.4 Specific Gravity. If determined to be necessary in the sole discretion of Transporter, the specific gravity of the gas shall be determined at each point of receipt by one of the following methods:

(a) By means of a properly installed recording gravitometer of standard manufacture acceptable to Transporter.

(b) If (a) is not considered feasible, then by use of a portable specific gravity balance of standard manufacture, or other standard device acceptable to Transporter and designed for such purpose or use in conjunction with a continuous sampler.

(c) Other methods acceptable to Transporter.

3.5 Measurement Procedures. Quantities of gas received and delivered hereunder shall be measured in accordance with Procedures contained in ANSI-API 2530, First Edition, AGA Committee Report No. 5, AGA Committee Report No. 7, and AGA Committee Report No. 8, or revisions or amendments thereto.

3.6 Measuring Equipment. Unless otherwise agreed, Transporter will provide, maintain, and operate necessary measuring and regulating stations equipped with flow meters and other necessary measuring equipment by which its quantities of gas delivered from Transporter hereunder shall be determined. Such measuring and regulating stations shall be so installed at the receipt point of the System and at other agreeable points. All flow, measuring, testing, and related equipment shall be of standard manufacture and type acceptable to Transporter.

Transporter and Shipper shall cause the chart on all gas measurement equipment to be changed, or mechanical or electronic indices read, by either Transporter or by Shipper's representative (where economical) on a daily basis. If telemetering is not installed, Shipper shall change recording charts on Transporter's delivery point metering facilities or otherwise read Transporter's meter on a daily basis at a time specified by Transporter. Shipper may install check measuring equipment, provided that such equipment shall be so installed as not to interfere with operation of Transporter.

When Transporter deems it necessary, telemetering equipment shall be installed on Shipper's delivery point meter(s). Transporter will install and maintain the telemetering facilities. Shipper shall provide, install and maintain a weatherproof phone service and electrical service outlet with appropriate grounding for telemetering equipment. Shipper and Transporter, in the presence of each other, shall have access to all measuring equipment at all reasonable times, but the reading, calibrating, and adjusting thereof shall be done by the Transporter, unless otherwise agreed. Shipper and Transporter shall have the right to be present at the time of any installing, reading, cleaning, changing, repairing, inspecting, testing, calibrating, or adjusting done in connection with all measuring equipment. The records from such measuring equipment shall remain the property of Transporter. Reasonable care shall be exercised in the installation, maintenance and operation of measuring equipment so as to avoid any inaccuracy in the determination of the quantity of gas received and delivered.

3.7 Calibration and Test of Meters. The accuracy of all measuring equipment shall be verified by the Transporter at reasonable intervals, and if requested, in the presence of representatives of Shipper. Transporter shall not be required to verify the accuracy of such equipment more frequently than once in any Contract Year. If either party at any time desires a special test of any measuring equipment, it will promptly notify the other, and the parties shall then cooperate to secure a prompt verification of the accuracy of such equipment. Transportation and related expenses incurred by Shipper or Transporter involved in the testing of meters shall be borne by the party incurring such expenses.

3.8 Correction of Metering Errors. If, upon any test, any measuring equipment is found to be in error, such errors shall be treated in the following manner: If the resultant aggregate error in the computed receipts or deliveries is not more than 2%, then previous receipts or deliveries shall be considered accurate. All equipment shall, in any case, be adjusted at the time of test to record to zero error. If, however, the resultant aggregate error in computed receipt or deliveries exceeds 2% at a recording corresponding to the average hourly rate of gas flow for the period since the last preceding test, the previous recordings of such equipment shall be corrected to zero error for any period which is known definitely or agreed upon. In case the period is not known definitely or agreed upon, such correction shall be for a period extending over one-half of the time elapsed since the date of the last test, not exceeding a correction period of 180 days.

3.9 Failure of Measuring Equipment. In the event any measuring equipment is out of service, or is found registering inaccurately and the error is not determinable by test, or by previous recording, receipts or deliveries through such equipment shall be estimated:

(a) By using the registration of any check meter or meters, if installed and accurately registering, or in the absence of (a);

(b) By correcting the error if the percentage of error is ascertainable by calibration, special test, or mathematical calculation, or in the absence of both (a) and (b) then;

(c) By estimating the quantity of receipt or delivery based on receipts or deliveries during preceding periods under similar conditions when the measuring equipment was registering accurately.

3.10 Preservation of Records. Shipper and Transporter shall preserve all test data, charts, and other similar records for a period of at least one year, or such longer period as may be required by the SDPUC or other jurisdictional public authority.

ARTICLE IV
RECEIPT AND DELIVERY POINTS

4.1 Point of Receipt. The initial point of receipt hereunder shall be the point of interconnection between the facilities of Transporter and the facilities of Northern located near Marion, South Dakota. Shipper shall deliver, or cause to be delivered, gas to Transporter at the point or receipt for transportation service, set forth in Exhibit A attached to Shipper's TSA.

4.2 Points of Delivery. The point(s) of delivery hereunder shall be the point(s) of connection between the facilities of Transporter and the facilities of Shipper, where Transporter shall deliver gas for the account of Shipper. Such point(s) of delivery are set forth in Exhibit A attached to Shipper's TSA. Unless otherwise agreed, the establishment of any additional point of delivery at the request of Shipper shall be at the expense of Shipper.

ARTICLE V
SCHEDULES

5.1 Schedules. Prior to the first day of each month, Shipper shall furnish Transporter with a schedule showing the estimated daily quantities of gas Shipper desires Transporter to transport during such month. Such monthly schedule shall be provided at least one hour before the deadline for monthly nominations in Northern's Tariff. Thereafter Shipper shall on a daily basis advise Transporter of the volumes Shipper will deliver during the following day at least one hour prior to the time Transporter must submit daily nominations to Northern pursuant to Northern's Tariff. However, Shipper may establish a standing schedule of daily volumes, notifying Transporter prior to any day when Shipper's daily deliveries will differ from the standing schedule by more than the daily delivery variance (+/-) established in Northern's Tariff.

5.2 Departures from Schedules. Departures from the scheduled deliveries at the point of receipt shall be kept to the minimum permitted by operating conditions, and shall be balanced as soon as practicable. Shipper shall use its best efforts to give Transporter notice prior to proposed change of a daily quantity from that set forth in the schedule provided for in Paragraph 5.1 hereof. Such notice shall be provided at times consistent with the notice period for intra-day nomination changes set forth in Northern's Tariff. Transporter may waive such notice upon request if, in its judgment, operating conditions permit such waiver. Transporter and Shipper shall inform each other of any other changes of deliveries immediately upon knowledge thereof.

5.3 Hourly Variation. Deliveries shall be made at uniform hourly rates to the extent practicable. Transporter's obligation to deliver shall not exceed 1/16th of Shipper's Maximum Daily Quantity in any given hour.

ARTICLE VI
DAILY AND MONTHLY BALANCING

6.1 Scheduling and Balancing Tolerances. It is recognized that the parties will be unable to control exactly the quantities of gas delivered and accepted hereunder on any day, and that deliveries by Shipper and redeliveries by Transporter may vary above or below the quantities scheduled on any day. However, nothing in this paragraph shall affect Shipper's obligation to pay for gas actually transported.

6.2 Daily Variances. The daily variance for a receipt point shall be the difference between the total quantities scheduled for receipt and the actual quantity delivered into Transporter's System. The daily variance for a delivery point shall be the shall be the difference between the total quantities scheduled and the actual quantity delivered by Transporter at such point on any day. Shipper shall take action to correct any daily variance between scheduled and actual receipts and deliveries occurring during the month by making adjustments to schedules, receipts or deliveries. In no event shall the daily excess or deficiency variance exceed the allowable daily point of delivery variation set forth in Northern's Tariff.

6.3 Monthly Imbalances. Shipper's monthly imbalance shall be the net total of daily variances from all receipt and delivery points. Such monthly imbalance shall be corrected in-kind through adjustments to Shipper's schedules, receipts or deliveries in order for Shipper to receive Equivalent Quantities, or by such other method as is then mutually agreed upon by the parties hereto. The cumulative daily variances during any month above or below the quantities scheduled shall not exceed the monthly point of delivery monthly variance set forth in Northern's Tariff.

6.4 Disposition of Excess Gas. In order to alleviate conditions that threaten the integrity of its System, Transporter may periodically acquire quantities of gas that are in excess of System needs. Transporter may make interruptible sales of such gas from time to time at the point of receipt pursuant to 18 CFR 284.402. Such sales shall be made under rates, terms and conditions mutually agreed upon between Transporter and the purchaser, provided that all such sales shall be fully interruptible.

ARTICLE VII
PRESSURE

7.1 Pressure at the Points of Receipt. Shipper shall cause the gas to be delivered at the points of receipt at a pressure sufficient to allow the gas to enter the System; however, Shipper shall not be required to deliver gas to the Transporter at any point of receipt at a pressure in excess of the minimum pressure specified with respect to each receipt point in Exhibit A of Shipper's TSA.

7.2 Pressure at Points of Delivery. Transporter shall deliver gas to Shipper's delivery points at the pressure existing in the Transporter's pipeline; however, Transporter must deliver gas to each point at a pressure not less than the minimum pressure specified with respect to each delivery point in Exhibit A to Shipper's TSA. Transporter, however, shall not be required or permitted to deliver gas at a pressure in excess of the maximum pressure specified for each point of delivery set forth in Exhibit A attached to Shipper's TSA.

ARTICLE VIII
BILLING AND PAYMENT

8.1 Billing. Unless otherwise agreed, on or before the 20th day of each month, Transporter shall render to Shipper a statement of the total amount of gas delivered by Transporter to Shipper at the points of receipt hereunder during the preceding month and the amount due. When information necessary for billing purposes is in the control of Shipper, Shipper shall furnish such information to Transporter on or before the 10th day of the month.

Shipper and Transporter shall have the right to examine at reasonable times, books, records, and charts of the other to the extent necessary to verify the accuracy of any statement, charge, or computation made under or pursuant to any of the provisions hereof.

8.2 Payment. Unless otherwise agreed, Shipper shall pay Transporter at its general office or at such other address as Transporter shall designate on or before the 28th day of the month, the amount due for the preceding month. If presentation of a bill by Transporter is delayed after the 20th day of the month, then the time of payment shall be extended accordingly unless Shipper is responsible for such delay.

8.3 Remedies for Failure to Pay. Should Shipper fail to pay all or any portion of any bill as herein provided when such amount is due, interest on the unpaid portion of the bill shall occur at a rate of one percent (1%) per month. If such failure to pay continues for 30 days after payment is due, Transporter may, in addition to any other remedy it may have hereunder, suspend further delivery of gas until such amount is paid, if authorized pursuant to the rules of the SDPUC.

8.4 Disputed Bills. If Shipper in good faith shall dispute the amount of any such bill or part thereof and shall pay to Transporter such amounts as it concedes to be correct and, at any time thereafter within 30 days of a demand made by Transporter, shall furnish a good and sufficient surety bond in an amount and with surety satisfactory to Transporter, guaranteeing payment to Transporter of the-amount ultimately found due upon such bills after a final determination which may be reached either by agreement or judgment of the courts, as may be the case, then Transporter shall not be entitled to suspend further delivery of gas unless and until default be made in the conditions of such bond.

8.5 Adjustment of Billing Errors. If it shall be found that at any time or times Shipper has been overcharged or undercharged in any form whatsoever under the provisions hereof and, in the case of an overcharge, Shipper shall have actually paid the bill containing such overcharge, then within 30 days after the final determination of such overcharge or undercharge, the appropriate party shall pay to the other party the amount of said overcharge or undercharge, net of any other amounts then payable hereunder. In the event an error is discovered in the amount billed in any statement rendered by Transporter, such error shall be adjusted within 30 days of the determination thereof provided that claim therefor shall have been made within one (l) year from the date of such statement. If the parties are unable to agree on the adjustment of any claimed error, any resort by either of the parties to legal procedure, either at law, in equity, or otherwise, shall be commenced within 12 months after the supposed cause of action is alleged to have arisen, or shall thereafter be forever barred.

ARTICLE IX
CONTROL OF GAS

9.1 Responsibility for Gas. As between the Shipper and Transporter hereto, Shipper shall be in exclusive control and possession of the gas until such has been delivered to Transporter at the point of receipt, and after such gas has been redelivered to or for the account of Shipper by Transporter at the point(s) of delivery. Transporter shall be in exclusive control and possession of such gas while same is in the System between the point of receipt and the point(s) of delivery. The party which shall be in exclusive control and possession of such gas shall be responsible for all injury or damage caused thereby.

ARTICLE X
FORCE MAJEURE

10.1 Force Majeure. Neither party shall be responsible or held liable for any loss or damage resulting from failure to perform its obligations due to any cause beyond its reasonable control; provided, however, that such force majeure affecting the performance hereunder by either Shipper or Transporter shall not relieve such party of liability in the event of its own concurring negligence or in the event of its own failure to use due diligence to remedy the situation and to remove the cause in an adequate manner and with all reasonable dispatch; provided further, that no such causes affecting such performance shall relieve either party from its obligations to make payments as determined hereunder or entitle either party to exercise any right To offset against any such payment obligation.

10.2 Definition. The term "force majeure" as used herein shall mean acts of God, strikes, lockouts, or other industrial disturbances; acts of a public enemy, wars, blockades, insurrection, riots, epidemics, landslides, lightning, earthquakes, fires, storms, floods, washouts; arrests and restraints of the government, either federal or state, civil or military, civil disturbances; shutdowns for purposes of necessary repairs, relocation, or construction of facilities; breakage or accident to machinery or lines of pipe, the necessity for testing (as required by governmental authority or as deemed necessary by repairs or alterations to machinery or lines of pipe); failure of surface equipment or pipelines; accidents, breakdowns, inability of either party hereto to obtain necessary material, supplies, or permits, or labor to perform or comply with an obligation or condition of this Agreement, rights of way, and any other causes, whether of the kind herein enumerated or otherwise, which are not reasonably in the control of the parry claiming suspension. It is understood and agreed that the settlement of strikes or lockouts shall be entirely within the discretion of the party having the difficulty and that the above requirement that any force majeure shall be remedied with all reasonable dispatch shall not require the settlement of strikes or lockouts by acceding to the demands of an opposing party when such course is inadvisable in the discretion of the party having the difficulty.

ARTICLE XI
INTERRUPTIONS

11.1 Notice of Interruption. Transporter shall at all times attempt to operate, or cause to be operated, its System in a manner designed to make possible, as nearly as practicable, continuous receipt of gas from, and delivery of gas to, Shipper in the respective quantities provided for in Shipper's TSA. If an interruption or curtailment of such receipt and/or delivery shall become necessary, Transporter shall at once attempt to notify Shipper by facsimile or telephone or other prompt means of communication of the nature, extent and probable duration of such interruption or curtailment and of the quantity of gas which Transporter estimates it will be able to receive from and deliver to Shipper during the period of interruption or curtailment, and shall give like notice of the cessation of such interruption or curtailment.

11.2 Allocation of Reduced Capacity. If the effective capacity of all or a portion of Transporter's System is reduced as a result of force majeure, repairs, maintenance or any other cause, whether similar or dissimilar, and some curtailment of the quantity of gas to be received from shippers under their transportation agreements is required as a result, the reduced capacity shall, during the period of curtailment, be allocated proportionately, according to their respective Maximum Daily Quantities, among those shippers whose gas must be received or delivered at or transported through, the affected facilities.

11.3 Scheduling of Receipts and Deliveries. Transporter shall schedule all quantities tendered under all services performed by Transporter in sequence as follows: first to Transporter's firm transportation shippers, and second to other Rate Schedules that may be approved, in the order of priority as may be approved by the SDPUC or other regulatory bodies with jurisdiction.

ARTICLE XII
INCORPORATION IN RATE SCHEDULES AND TRANSPORTATION AGREEMENTS

12.1 These General Terms and Conditions are incorporated in and are part of Transporter's Rate Schedules and Transportation Service Agreements. In the event of a conflict between these General Terms and Conditions and terms in Transporter's Rate Schedules or TSAs, these General Terms and Conditions shall govern.

RATE SCHEDULE - FIRM TRANSPORTATION SERVICE

1.0 Availability. This Rate Schedule is available for the transportation of natural gas on an firm basis for any Shipper where (i) Transporter has determined that sufficient System capacity exists to provide the service requested by Shipper, and (ii) Shipper has executed a Transportation Service Agreement ("TSA") wherein Transporter agrees to transport gas for Shipper's account up to a specific maximum daily quantity.

2.0 Gas Supply; Upstream Transportation, New Facilities. Shipper shall be responsible for arranging for all natural gas supplies and interstate transportation of Shipper's gas on Northern to the point of receipt. Shipper must pay for all facilities required to physically connect to AMPIP's pipeline.

3.0 Receipts and Deliveries. The Point of Receipt for all gas transporter by Transporter under this Rate Schedule shall be at the interconnection of Transporter's System with Northern located near Marion, South Dakota. The Point(s) of Delivery shall be at the point(s) designated in the Exhibit A attached to Shipper's TSA.

4.0 Rates and Charges. The rates for service under this Rate Schedule are as follows:

	Base Rate	Lost & Unaccounted Gas Percentage
Transportation Service	$0.99/MMBTU	1%
Authorized Overrun Service	$0.99 per Dkt	

However, Transporter has the right at any time and from time to time to file with the SDPUC to adjust the rates applicable to service under this Rate Schedule.

5.0 Daily Tolerance; Penalty Provisions. The daily tolerance level (+/-) from Shipper's daily scheduled volume shall be the daily variance established in Northern's Tariff. Unless otherwise agreed, in the event the daily quantity of gas delivered by Shipper deviates above or below the daily scheduled volume in excess of the Northern Tariff tolerance level, and Transporter is assessed charges or penalties by Northern, Shipper shall pay, in addition to the appropriate rates contained in this tariff, an amount equal to any payment AMPIP is required to make to Northern.

6.0 General Terms and Conditions. Any terms or conditions not specified in this Rate Schedule shall be determined consistent with Transporter's General Terms and Conditions, which are incorporated by reference into this Rate Schedule.

Sheets 17 to 20 reserved for future use.

INDEX OF SHIPPERS

Shipper	Rate Schedule	Effective Date	Expiration Date
Associated Milk Producers, Inc.	FT	12/01/95	10/31/2010
City of Freeman, South Dakota	FT	09/01/97	10/31/2007

AGREEMENT FORMS
FIRM TRANSPORTATION

AMPI INTRASTATE PIPELINE, INC

TRANSPORTATION SERVICE AGREEMENT

WITH

[insert shipper name]

Dated [insert date]

This NATURAL GAS TRANSPORTATION SERVICE AGREEMENT ("Agreement") is made this ___ day of ________, 19__, by and between AMPI Intrastate Pipeline Company, a South Dakota corporation ("Transporter"), and ________________________, a ________ corporation ("Shipper").

WITNESSETH:

WHEREAS, Transporter owns and operates a twenty mile intrastate natural gas distribution pipeline ("System") in McCook and Hutchinson Counties, South Dakota, subject to the jurisdiction of South Dakota Public Utilities Commission (the "SDPUC"); and

WHEREAS, Shipper desires to have natural gas transported on Transporter's System to Shipper's System, and

WHEREAS, Transporter is willing to provide such natural gas transportation service pursuant to the terms and conditions of its Transportation Service Tariff, SDPUC No. 1 and this Agreement;

NOW, THEREFORE, in consideration of the premises and the mutual covenants herein contained, the parties do covenant and agree as follows:

ARTICLE 1

1.1 Obligation to Transport. Commencing with initial in-service date hereunder, Transporter shall receive at the point of receipt for the account of Shipper all gas which Shipper may cause to be delivered to Transporter, up to Shipper's Contract Demand as set forth in Exhibit A hereto, and transport such gas to the point(s) of receipt on an interruptible basis.

The transportation and delivery of gas hereunder is on a firm basis. Shipper agrees to cease using gas to the extent and for the periods of interruption requested by Transporter. Transporter will not be liable for any loss, injury or damage resulting to Shipper, its assigns or others, arising from the interruption or curtailment of gas service.

1.2 Term. This Agreement shall have an initial term commencing on _________________ and continuing for a period of ____ Contract Years thereafter. Unless terminated on six months written notice to Transporter prior to the termination date, this Agreement will continue in effect from year-to-year thereafter until terminated by Transporter or Shipper by six months written notice to the other party.

1.3 Maximum Daily Quantities. Subject to Transporter's prior approval, Shipper from time to time shall stipulate a Maximum Daily Quantity of gas for delivery at each point of delivery. The initial Contract Demand shall be set forth in Exhibit A attached hereto. Any updating or other modification of Exhibit A as provided in this Paragraph 1.3 shall not be effective unless and until the updated or modified Exhibit A shall have been duly executed or initialed by both parties, subject to any necessary regulatory approval. Such a revised Exhibit A shall replace the prior Exhibit A and, by this reference, shall become a part of this Agreement. The daily deliveries at any point of receipt may exceed the Maximum Daily Quantity specified for such point of receipt on a temporary basis, provided the System in Transporter's sole judgment can accommodate the excess quantity.

1.4 Transportation Charge. Unless otherwise agreed, Transporter's charge to Shipper for transporting Shipper's quantities pursuant to this Agreement shall be the maximum rate set forth in Transporter's Transportation Service Tariff, SDPUC No. 1 (hereafter "Tariff") in effect from time to time.

1.5 Overrun Services. Upon request of Shipper and at Transporter's option, Transporter may receive and deliver for Shipper's account, on any day, quantities of gas in excess of Shipper's Maximum Daily Quantity; however, such quantities shall be received and delivered on a best efforts basis. Unless otherwise agreed, such overrun deliveries shall be subject to the maximum Authorized Overrun Transportation ("AOT") commodity rate set forth in Transporter's Tariff in effect from time to time.

ARTICLE II

2.1 Changes in Rates and Charges. The service under this Agreement shall be supplied pursuant to the Rate Schedule and General Terms and Conditions of Transporter's Tariff as they now exist or may be changes from time to time. Transporter shall have the unilateral rights to file with the SDPUC or other appropriate regulatory authority to make changes in (a) the rates, charges, terms and conditions applicable to service pursuant to the Rate Schedule under which this service is rendered; and (b) any provision of the General Terms and Conditions in Transporter's Tariff. Without prejudice to Shipper's right to contest such changes, Shipper agrees to pay the effective rates and charges for service rendered pursuant to this Agreement.

2.2 Warranty. Shipper warrants for itself, its successors and assigns, that it will have at the time of delivery of gas for transportation hereunder good title or the good right to deliver such gas. Transporter warrants for itself, its successors and assigns, that it will at the time of delivery to others of the gas transported hereunder have good right to deliver such gas to others. Shipper warrants for itself, its successors and assigns, that the gas it delivers hereunder shall be free and clear of all liens, encumbrances and claims whatsoever. Shipper further warrants that it will indemnify Transporter and save it harmless from all suits, actions, debts, accounts, damages, costs, losses and expenses arising from or out of any adverse claims of any and all persons to said gas and/or to royalties, taxes, license fees or charges thereon which are applicable to such delivery of gas and that it will indemnify Transporter and save it harmless from all taxes or assessments which may be levied and assessed upon such delivery and which are by law payable by, and the obligation of, the party receiving such delivery.

2.3 Regulations. This Agreement, and all terms and provisions contained herein, and the respective obligations of the parties hereunder are subject to valid laws, orders, rules and regulations of duly constituted authorities having jurisdiction. Shipper shall furnish to Transporter all information as may be required to comply with the reporting requirements of duly constituted authorities having jurisdiction over the subject matter herein.

2.4 Notices. Except as herein otherwise provided, any notice, request, demand, statement, bill, or payment provided for in this Agreement, or any notice which either party may desire to give to the other, shall be in writing and shall be considered as duly delivered when mailed by registered or certified mail return receipt requested to the Address of the parties hereto as follows:

TO TRANSPORTER:

AMPI Intrastate Pipeline
Attention: General Manager
General Office
315 North Broadway
New Ulm, MN 56073

TO SHIPPER:

City of Freeman, South Dakota
Attention: Mr. Michael Schultz
P.O. Box 178
Freeman, South Dakota 57029-0178

or such other address as the parties may designate by written notice. Routine communications including monthly statements and payments, shall be considered as duly delivered when mailed by either registered, certified or ordinary mail.

2.5 Waivers. No waiver by either Shipper or Transporter of any one or more defaults in the performance of any provision hereunder shall operate or be construed as a waiver of any future default or defaults, whether of a like or a different character.

2.6 Applicable Law. This Agreement shall be governed by and interpreted in accordance with laws of the state of South Dakota.

2.7 Assignment. This Agreement is binding upon Transporter and Shipper, their successor and assigns. Either party may assign or pledge this Agreement under the provisions of any mortgage, deed of trust, indenture or similar instrument which it has executed or may execute hereafter covering substantially all of its properties; otherwise neither of the parties shall assign this Agreement or any of its rights hereunder unless it first shall have obtained the consent thereto in writing of the other party, which shall not be unreasonably withheld.

2.8 Dispute Resolution. Any controversy or claim arising out of or relating to this Agreement, or the alleged breach thereof, shall be subject to initial resolution by mediation. If Transporter and Shipper are unable to reach a resolution by mediation, then the controversy or claim may be submitted to the SDPUC for resolution. This Section shall survive the termination of this Agreement as necessary to resolve any disputes arising under this Agreement.

2.9 No Third Party Beneficiary. No provision of this Agreement shall be in any way inure to the benefit of any third person (including the public at large) so as to constitute any such person as a third party beneficiary of the Agreement or of any one or more of the terms hereof, or otherwise given rise to any cause of action in any person not a party hereto.

2.10 Exhibits. Exhibit A attached hereto is incorporated by reference and made part of this Agreement for all purposes.

IN WITNESS WHEREOF, the parties hereto have caused this Agreement to be executed by a duly authorized officer.

AMPI Intrastate Pipeline, Inc.

By: ____________________________

Title: ___________________________

Date: ___________________________

[Shipper Name]

By: ____________________________

Title: ___________________________

Date: ___________________________

Exhibit A
Transportation Service Agreement
AMPI Intrastate Pipeline

Receipt Point Meter No.

Delivery Point(s) Meter No.

Annual Quantity: _________ Dkt

Maximum Daily Quantity: _________ Dkt

Transporter shall deliver Shipper's gas at a rate of flow not to exceed _____ cubic feet per hour at the point of delivery. Gas shall be delivered at such pressures and temperatures as may exist under the System operating conditions at such point of delivery. Operating pressures at this location shall normally be between _____ psig and _____ psig.

Sheets 28 to 100 reserved for future use.

AMPI PIPELINE, INC.
TRANSPORTATION SERVICE AGREEMENT
WITH
CITY OF FREEMAN, SOUTH DAKOTA
Dated September __, 1997

This NATURAL GAS TRANSPORTATION SERVICE AGREEMENT ("Agreement") is made this ___ day of September, 1997, by and between AMPI Pipeline, Inc., a South Dakota corporation ("Transporter"), and the City of Freeman, a South Dakota municipal corporation ("Shipper").

WITNESSETH:

WHEREAS, Transporter owns and operates a twenty mile intrastate natural gas distribution pipeline ("Transporter's System") in McCook, Turner and Hutchinson Counties, South Dakota, subject to the jurisdiction of South Dakota Public Utilities Commission (the "SDPUC"); and

WHEREAS, Shipper is constructing a municipal natural gas utility system ("Shipper's System") with a planned in-service date on or about October 1, 1997; and

WHEREAS, Shipper desires to have natural gas transported on Transporter's System to Shipper's System, starting on the initial in-service date of Shipper's System; and

WHEREAS, Transporter is willing to provide such natural gas transportation service pursuant to the terms and conditions of its Transportation Service Tariff, SDPUC No. 1 (hereafter "Tariff") and this Agreement;

NOW, THEREFORE, in consideration of the premises and the mutual covenants herein contained, the parties do covenant and agree as follows:

ARTICLE I

1.1 Obligation to Transport Commencing with initial in-service date hereunder, Transporter shall receive at the point of receipt for the account of Shipper all gas which Shipper may cause to be delivered to Transporter, up to Shipper's Contract Demand as set forth in Exhibit A hereto, and transport such gas to the point(s) of delivery on a firm basis.

1.2 Term. This Agreement shall have an initial term commencing on the in-service date and continuing for a period of ten (10) Contract Years thereafter. For the purposes of this Agreement, the term "initial in-service date" shall mean October 1, 1997, unless such date is changed by circumstances beyond the control of the parties. Unless terminated on six months written notice to Transporter prior to the termination date, this Agreement will continue in effect from year-to-year thereafter until terminated by Transporter or Shipper by six months written notice to the other party. The first Contract Year shall be the period from the in-service date to October 31, 1998.

1.3 Maximum Daily Quantities. Subject to Transporter's prior approval, Shipper from time to time shall stipulate a Maximum Daily Quantity of gas for delivery at each point of delivery. The initial Contract Demand shall be set forth in Exhibit A attached hereto. Any updating or other modification of Exhibit A as provided in this Paragraph 1.3 shall not be effective unless and until the updated or modified Exhibit A shall have been duly executed or initialed by both parties, subject to any necessary regulatory approval. Such a revised Exhibit A shall replace the prior Exhibit A and, by this reference, shall become a part of this Agreement. The daily volumes at any point of receipt may exceed the Maximum Daily Quantity specified for such point of receipt on a temporary basis, provided Transporter's System in Transporter's sole judgment can accommodate the excess quantity.

1.4 Transportation Charge. Unless otherwise agreed, Transporter's charge to Shipper for transporting Shipper's quantities pursuant to this Agreement shall be the maximum rate set forth in Transporter's Tariff in effect from time to time.

1.5 Overrun Services. Upon request of Shipper and at Transporter's option, Transporter may receive and deliver for Shipper's account, on any day, quantities of gas in excess of Shipper's Maximum Daily Quantity; however, such quantities shall be received and delivered on a best efforts basis. Unless otherwise agreed, such overrun deliveries shall be subject to the maximum Authorized Overrun Transportation ("AOT") commodity rate set forth in Transporter's Tariff in effect from time to time.

ARTICLE II

2.1 Changes in Rates and Charges. The service under this Agreement shall be supplied pursuant to the Rate Schedule and General Terms and Conditions of Transporter's Tariff as they now exist or may be changes from time to time. Transporter shall have the unilateral right to file with the SDPUC or other appropriate regulatory authority to make changes in (a) the rates, charges, terms and conditions applicable to service pursuant to the Rate Schedule under which this service is rendered; and (b) any provision of the General Terms and Conditions in Transporter's Tariff. Without prejudice to Shipper's right to contest such changes, Shipper agrees to pay the effective rates and charges for service rendered pursuant to this Agreement.

2.2 Warranty. Shipper warrants for itself, its successors and assigns, that it will have at the time of delivery of gas for transportation hereunder good title or the good right to deliver such gas. Transporter warrants for itself, its successors and assigns, that it will at the time of delivery to others of the gas transported hereunder have good right to deliver such gas to others. Shipper warrants for itself, its successors and assigns, that the gas it delivers hereunder shall be free and clear of all liens, encumbrances and claims whatsoever. Shipper further warrants that it will indemnify Transporter and save it harmless from all suits, actions, debts, accounts, damages, costs, losses and expenses arising from or out of any adverse claims of any and all persons to said gas and/or to royalties, taxes, license fees or charges thereon which are applicable to such delivery of gas and that it will indemnify Transporter and save it harmless from all taxes or assessments which may be levied and assessed upon such delivery and which are by law payable by, and the obligation of, the party receiving such delivery.

2.3 Regulations. This Agreement, and all terms and provisions contained herein, and the respective obligations of the parties hereunder are subject to valid laws, orders, rules and regulations of duly constituted authorities having jurisdiction. Shipper shall furnish to Transporter all information as may be required to comply with the reporting requirements of duly constituted authorities having jurisdiction over the subject matter herein.

2.4 Notices. Except as herein otherwise provided, any notice, request, demand, statement, bill, or payment provided for in this Agreement, or any notice which either party may desire to give to the other, shall be in writing and shall be considered as duly delivered when mailed by First Class U.S. Mail to the Address of the parties hereto as follows:

TO TRANSPORTER:

AMPI Pipeline, Inc.
Attention: General Manager
136 East Railway
P.O. Box 430
Freeman, South Dakota 57109

TO SHIPPER:

City of Freeman
Attention: Mr. Michael Schultz
P.O. Box 178
Freeman, South Dakota 57029-0178

or such other address as the parties may designate by written notice. Routine communications including monthly statements and payments, shall be considered as duly delivered when mailed by First Class U.S. Mail, overnight courier, or facsimile (with telephone confirmation of receipt).

2.5 Waivers. No waiver by either Shipper or Transporter of any one or more defaults in the performance of any provision hereunder shall operate or be construed as a waiver of any future default or defaults, whether of a like or a different character.

2.6 Applicable Law. This Agreement shall be governed by and interpreted in accordance with laws of the state of South Dakota.

2.7 Assignment. This Agreement is binding upon Transporter and Shipper, their successor and assigns. Either party may assign or pledge this Agreement under the provisions of any mortgage, deed of trust, indenture or similar instrument which it has executed or may execute hereafter covering substantially all of its properties; otherwise neither of the parties shall assign this Agreement or any of its rights hereunder unless it first shall have obtained the consent thereto in writing of the other party, which shall not be unreasonably withheld.

2.8 Dispute Resolution. Any controversy or claim arising out of or relating to this Agreement, or the alleged breach thereof, shall be subject to initial resolution by mediation. If Transporter and Shipper are unable to reach a resolution by mediation, then the controversy or claim may be submitted to the SDPUC for resolution. This Section shall survive the termination of this Agreement as necessary to resolve any disputes arising under this Agreement.

2.9 No Third Party Beneficiary. No provision of this Agreement shall be in any way inure to the benefit of any third person (including the public at large) so as to constitute any such person as a third party beneficiary of the Agreement or of any one or more of the terms hereof, or otherwise given rise to any cause of action in any person not a party hereto.

2.10 Exhibits. Exhibit A attached hereto is incorporated by reference and made part of this Agreement for all purposes.

IN WITNESS WHEREOF, the parties hereto have caused this Agreement to be executed by a duly authorized officer.

AMPI Pipeline, Inc.

By:__________________________

Title:_________________________

Date:_________________________

City of Freeman, South Dakota, A Municipal Corporation
By:__________________________

Title:_________________________

Date:_________________________

Exhibit A
Transportation Service Agreement
AMPI Intrastate Pipeline

Receipt Point	Meter No.
Delivery Point(s)	Meter No.
Annual Quantity	________Dkt
Maximum Daily Quantity	________Dkt

Transporter shall deliver Shipper's gas at a rate of flow not to exceed _____cubic feet per hour at the point of delivery. Gas shall be delivered at such pressures and temperatures as may exist under the System operating conditions at such point of delivery. Operating pressures at this location shall normally be between _____psig and _____psig.

Exhibit No. 5

Statements Required By Chapter 20:10:13

AMPI Pipeline, Inc.
List of Statements Included With This Filing or Not Applicable
Pursuant to Chapter 20:10:13

Rule	Statements	Explanation
20:10:13:51	Statement A Balance Sheets	Not Applicable (1)
20:10:13:52	Statement B Income Statements	Not Applicable (1)
20:10:13:53	Statement C Earned Surplus	Not Applicable (1)
20:10:13:54	Statement D Cost of Plant	See Statement D
20:10:13:55	Schedule D-1 Plant Account Detail	See Statement D-1
20:10:13:56	Schedule D-2 Plant Additions, Retirements	See Statement D-2
20:10:13:57	Schedule D-3 Working Papers-Plant in Test Year	Not Applicable (1)
20:10:13:58	Schedule D-4 Working Papers-Plant for Previous Year	Not Applicable (1)
20:10:13:59	Schedule D-5 Working Papers-Capitalized Interest	See Statement D-5
20:10:13:60	Schedule D-6 Working Papers-Changes in Intangible Plant	Not Applicable (1)
20:10:13:61	Schedule D-7 Working Papers-Plant not Used and Useful	Not Applicable (1)
20:10:13:62	Schedule D-8 Working Papers-Property Records	Not Applicable (1)
20:10:13:63	Schedule D-9 Working Papers-Unapproved Acquired Plant	Not Applicable (1)
20:10:13:64	Statement E Accumulated Depreciation	See Statement E
20:10:13:65	Statement E-1 Working Papers-Change in Accumulated. Depreciation	Not Applicable (1)
20:10:13:66	Schedule E-2 Working Papers-Depreciation Method	See Statement E-2
20:10:13:67	Schedule E-3 Working Papers-Allocation of Overall Accounts	Not Applicable (1)
20:10:13:68	Statement F Working Capital	Not Applicable (1)
20:10:13:69	Schedule F-1 Monthly M&S, Fuel Stocks, Prepayments	Not Applicable (1)
20:10:13:70	Schedule F-2 Monthly M&S Two Previous Years	Not Applicable (1)
20:10:13:71	Schedule F-3 Data Used for Working Capital	Not Applicable (1)
20:10:13:72 - 20:10:13:75	Statement G Rate of Return, Debt Capital, Preferred Stock Capital, Common Stock Capital	See Statement G
20:10:13:76	Schedule G-1 Stock Dividends, Splits, or Changes	Not Applicable (2)
20:10:13:77	Schedule G-2 Common Stock Information	Not Applicable (2)
20:10:13:78	Schedule G-3 Reacquisition of Bonds or Preferred Stocks	Not Applicable (2)
20:10:13:79	Schedule G-4 Earnings per Share for Claimed Rate of Return	Not Applicable (2)
20:10:13:80	Statement H Operating and Maintenance Expenses (O&M)	See Statement H
20:10:13:81	Schedule H-1 Adjustments to O&M	Not Applicable (1)
20:10:13:82	Schedule H-2 Cost of Power and Gas	Not Applicable (1)
20:10:13:83	Schedule H-3 Working Papers for Listed Expense Accounts	Not Applicable (1)
20:10:13:84	Schedule H-4 Working Papers-Interdepartmental Transactions	Not Applicable (1)
20:10:13:85	Statement I Operating Revenues	See Statement I
20:10:13:86	Statement J Depreciation Expense	See Statement J
20:10:13:87	Schedule J-1 Other Depreciation/Amortization Expenses	Not Applicable
20:10:13:88	Statement K Income Taxes	Not Applicable
20:10:13:89	Schedule K-1 Working Papers-Federal Income Taxes	See Statement K
20:10:13:90	Schedule K-2 Book vs. Tax Depreciation Differences	Not Applicable
20:10:13:91	Schedule K-3 Working Papers-Consolidated Fed. Income Taxes	Not Applicable
20:10:13:92	Schedule K-4 Working Papers-Current Tax Greater than Consolidated	Not Applicable
20:10:13:93	Schedule K-5 Working Papers- Allowance for State Income Taxes	Not Applicable
20:10:13:94	Statement L Other Taxes	See Statement L
20:10:13:95	Schedule L-1 Working Papers for Other Taxes	Not Applicable

AMPI Pipeline, Inc.
List of Statements Included With This Filing or Not Applicable
Pursuant to Chapter 20:10:13

Rule	Statements	Explanation
20:10:13:96	Statement M Overall Cost of Service	See Statement M
20:10:13:97	Statement N Allocated Cost of Service	See Statement N
20:10:13:98	Statement O Comparison of Cost of Service	Not Applicable
20:10:13:99	Schedule O-1 Derivation of Increased Rates	Not Applicable
20:10:13:100	Statement P Fuel Cost Adjustment Factor	Not Applicable
20:10:13:101	Statement Q Description of Utility Operations	See Statement Q
20:10:13:102	Statement R Purchases from Affiliated Companies	See Statement R

(1) AMPIP requests waiver of this filing requirement and statement. AMPIP serves only two customers, AMPI and the City of Freeman, SD. Both customers concur with the proposed tariff and rate. To reduce the rate case expenses associated with the filing, AMPIP seeks waiver of the filing statements which are normally required but which do not directly support the cost of service, Statement M. Also, because AMPIP has been operating only since late 1995, the statement data may not exist.

(2) There have been no stock dividends, stock splits or changes in par or stated value. AMPIP has not issued any common or preferred stock or bonds. All AMPIP financial arrangements are met through loan agreements with AMPI.

Statement D

AMPI Pipeline, Inc.

Cost of Plant - Rule 20:10:13:54

Line No.	Functional Classification	Balance
1	Distribution Plant	$1,256,056

Line No 1 - Total distribution plant used in Statement M, Page 1 of 3, Line 1, Column C. Amount is determined on Schedule 4 of Exhibit 2.

AMPI Pipeline, Inc.

Detailed Plant Accounts - Rule 20:10:13:55

It is anticipated that all of the distribution plant will be included in Account 101.

AMPI Pipeline, Inc.

Plant Additions, Retirements - Rule 20:10:13:56

There are no material additions or retirements anticipated by AMPIP. However, as discussed elsewhere in this filing, a 7,675 foot portion of 6" polyethylene pipeline and metering equipment will be sold to the City of Freeman Municipal Gas Utility. The sale is at net book value of $111,600 representing no gain or loss on the sale assets. Since the amount is less than $200,000, no express approval for sale of utility assets is required by the Commission.

Statement D-5

AMPI Pipeline, Inc.

Capitalized Interest and Other Overheads During Construction - Rule 20:10:13:59

Interest was capitalized into plant in service on the dates shown:

Date	Description	Amount
12/31/95	Capitalized Interest - AMPI	$ 4,975.72
1/31/96	Capitalized Interest - AMPI	9,805.35
2/29/96	Capitalized Interest - AMPI	9,230.61
	Total	$ 24,011.68

AMPI Pipeline, Inc.

Accumulated Depreciation - Rule 20:10:13:64

AMPIP is depreciating the pipeline over 40 years at a rate of 2.45%. Statement M contains the overall cost of service study including depreciation expense and the effect of accumulated depreciation over the book life of the plant.

AMPI Pipeline, Inc.

Working Papers on Depreciation and Amortization Method - Rule 20:10:13:66

AMPIP utililizes straight-line depreciation for the pipeline at a rate of 2.45%, which is $30,704 per year. Statement M, the overall cost of service study, includes depreciation expense and the effect of accumulated depreciation over the book life of the plant. Schedule 4 of Exhibit 2 shows the determination of the amount.

Statement G

AMPI Pipeline, Inc.

Rate of Return and Debt Capital - Rules 20:10:13:72 and 20:10:13:73

Associated Milk Producers, Inc. (AMPI) will finance all debt for its subsidiary AMPI Pipeline (AMPIP). AMPI will provide all necessary operating capital for AMPIP at a rate of 9%.

AMPI Pipeline, Inc.

Operating and Maintenance Expense - Rule 20:10:13:80

The operating and maintenance expenses contained in Statement M are as follows. The amounts are based on AMPIP books and records. Because AMPIP has only been in operation for a short period of time, some reasonable estimates have been included. Sources and notes are shown.

	Amount (A)	Annual Escalator (B)	1 Year Escalated Amount (C)
(1) Contracted Operating and Maintenance Day to day operations and maintenance of pipeline facility	$12,000	2.0%	$12,240
(2) AMPIP Operating and Maintenance Costs Training, readings, patrolling of line by local AMPI personnel	$1,740	3.5%	$1,801
(3) Corporate Services Management, clerical, accounting and tax work	$6,710	3.5%	$6,945
(4) Audit and Legal Fees Outside legal and audit fees	$1,700	3.5%	$1,760
(5) Insurance Annual Fee	$15,000	0.0%	$15,000
(6) OPS Assessment Office of Pipeline Safety	$1,500	0.0%	$1,500
(7) Regulatory Fees Gross Receipts tax and DOT Pipeline Safety Assessment	$800	0.0%	$800
(8) Total	$39,450	1.5%	$40,045

Sources and Notes:

Line 1, Column A: Per AMPIP contract with NSP NGS for pipeline operations and maintenance services.
Line 1, Column B: Contract escalator.
Lines 1 - 7, Column C: Year 2 level of cost with escalator applied to year 1 historical-based amounts.
Line 2, Column A: AMPIP direct costs of employee pipeline maintenance activities.
Lines 2, 3, and 4, Column B: Annual escalator based on anticipated inflation.

Continued...

AMPI Pipeline, Inc.

Operating and Maintenance Expense - Rule 20:10:13:80

Line 3, Column A: Portion of AMPI corporate costs associated with the pipeline.
Line 4, Column A: Audit and legal fees based on actual results.
Line 5, Column A: Insurance costs based on actual results.
Line 6, Column A: OPS assessment based on actual results.
Line 7, Column A: Regulatory fees based on actual results.
Line 8, Columns A and C: Sum of year 1 and year 2, respectively, O&M costs from Lines 1 - 7.
Line 8, Column B: Weighted annual O&M escalator based on expenses and individual escalators shown on Lines 1 - 7.

AMPI Pipeline, Inc.

Operating Revenues - Rule 20:10:13:85

Revenues of $211,860 per year will be recovered from AMPI and the City of Freeman, South Dakota. The amount is the result of applying the volumetric rate of $0.99 per Mcf to the annual projected transportation volume of 214,000 Mcf.

AMPI Pipeline, Inc.

Depreciation Expense - Rule 20:10:13:86

As described in Statement E, AMPIP proposes to utilize a 2.45% annual depreciation rate. Based on the total cost of the pipeline facilities, the annual depreciation amount will be $30,704. The overall cost of service can be found in Statement M. Schedule 4 of Exhibit 2 shows the determination of depreciation expense.

AMPI Pipeline, Inc.

Income Taxes - Rule 20:10:13:88

AMPIP has no equity financing, and thus will not incur income tax expense. All costs will be deductible for income tax purposes. For cost of service purposes, book depreciation has been assumed to be equal to tax depreciation. Thus, deferred income taxes are not included in Statement M.

AMPI Pipeline, Inc.

Other Taxes - Rule 20:10:13:94

Based upon actual liabilities, Property taxes for the proposed pipeline are 2.43%. Property taxes for the first year were $2,470. Property taxes in 1996 were $33,240 (prior to the asset sale to Freeman). Thereafter, an annual escalator of 2.75% has been considered. The overall cost of service can be found in Statement M and in Exhibit 2. Schedule 4 of Exhibit 2 shows development of the property tax amount for Statement M.

AMPI Pipeline, Inc.

Cost of Service - Rule 20:10:13:96

The cost of service for AMPIP is shown on the following three schedules. These same schedules are replicated as Schedule 3, Pages 1 - 3, of Exhibit 2.

Page 1 of Statement M (Schedule 3 of Exhibit 2) shows development of the cost of service elements by year for 45 years. Column J reflects the present value of those amounts in total.

Page 2 of Statement M (Schedule 3 of Exhibit 2) depicts the determination of the levelized annual revenue requirements factor of 16.87%. In Column G, that factor applied to gross plant investment of $1,256,056 yields annual revenue requirements of $211,897.

Page 3 of Statement M (Schedule 3 of Exhibit 2) is a listing of sources and notes for the previous two pages.

Levelized Annual Revenue Requirement - See Page 3 of 3 for Sources and Notes

Capital Structure (CS):	Cost	Weight	Weighted Cost
(CS1) Equity	0.00%	0.00%	0.0000%
(CS2) Preferred Stock	0.00%	0.00%	0.0000%
(CS3) Long-term Debt	9.00%	100.00%	9.0000%
(CS4) Short-term Debt	0.00%	0.00%	0.0000%
(CS5)		100.00%	9.0000%

	Time Period (A)	Year (B)	Plant in Service Additions (C)	Net Investment Rate Base (D)	Debt Return (E)	Book Dep'n (F)	Operating Expenses (G)	Property Taxes (H)	Total Revenue Requirement (I)	9.0000% Present Value of Revenue Deficiency or (Excess) (J)
(1)	0	1995	1,256,056	1,240,704	55,832	15,352	39,450	2,470	113,104	113,104
(2)	1	1996	0	1,210,000	110,282	30,704	40,045	30,528	211,559	194,091
(3)	2	1997	0	1,179,296	107,518	30,704	40,649	31,368	210,239	176,954
(4)	3	1998	0	1,148,592	104,755	30,704	41,263	32,230	208,952	161,349
(5)	4	1999	0	1,117,888	101,992	30,704	41,885	33,116	207,697	147,138
(6)	5	2000	0	1,087,184	99,228	30,704	42,517	34,027	206,477	134,196
(7)	6	2001	0	1,056,480	96,465	30,704	43,159	34,963	205,291	122,408
(8)	7	2002	0	1,025,776	93,702	30,704	43,810	35,924	204,140	111,672
(9)	8	2003	0	995,072	90,938	30,704	44,471	36,912	203,026	101,892
(10)	9	2004	0	964,368	88,175	30,704	45,142	37,927	201,948	92,983
(11)	10	2005	0	933,664	85,411	30,704	45,823	38,970	200,909	84,866
(12)	11	2006	0	902,960	82,648	30,704	46,515	40,042	199,909	77,471
(13)	12	2007	0	872,256	79,885	30,704	47,217	41,143	198,949	70,733
(14)	13	2008	0	841,552	77,121	30,704	47,929	42,275	198,029	64,593
(15)	14	2009	0	810,848	74,358	30,704	48,652	43,437	197,151	58,997
(16)	15	2010	0	780,144	71,595	30,704	49,386	44,632	196,317	53,896
(17)	16	2011	0	749,440	68,831	30,704	50,132	45,859	195,526	49,247
(18)	17	2012	0	718,736	66,068	30,704	50,888	47,120	194,780	45,008
(19)	18	2013	0	688,032	63,305	30,704	51,656	48,416	194,080	41,144
(20)	19	2014	0	657,328	60,541	30,704	52,435	49,748	193,428	37,620
(21)	20	2015	0	626,624	57,778	30,704	53,226	51,116	192,824	34,406
(22)	21	2016	0	595,920	55,014	30,704	54,030	52,521	192,269	31,474
(23)	22	2017	0	565,216	52,251	30,704	54,845	53,966	191,765	28,800
(24)	23	2018	0	534,512	49,488	30,704	55,672	55,450	191,314	26,359
(25)	24	2019	0	503,808	46,724	30,704	56,512	56,974	190,915	24,133
(26)	25	2020	0	473,104	43,961	30,704	57,365	58,541	190,571	22,100
(27)	26	2021	0	442,400	41,198	30,704	58,231	60,151	190,283	20,245
(28)	27	2022	0	411,696	38,434	30,704	59,109	61,805	190,053	18,551
(29)	28	2023	0	380,992	35,671	30,704	60,001	63,505	189,881	17,004
(30)	29	2024	0	350,288	32,908	30,704	60,906	65,251	189,769	15,590
(31)	30	2025	0	319,584	30,144	30,704	61,825	67,046	189,719	14,299
(32)	31	2026	0	288,880	27,381	30,704	62,758	68,890	189,733	13,120
(33)	32	2027	0	258,176	24,618	30,704	63,705	70,784	189,811	12,041
(34)	33	2028	0	227,472	21,854	30,704	64,666	72,731	189,955	11,055
(35)	34	2029	0	196,768	19,091	30,704	65,642	74,731	190,168	10,154
(36)	35	2030	0	166,064	16,327	30,704	66,633	76,786	190,450	9,329
(37)	36	2031	0	135,360	13,564	30,704	67,638	78,897	190,803	8,575
(38)	37	2032	0	104,656	10,801	30,704	68,659	81,067	191,230	7,885
(39)	38	2033	0	73,952	8,037	30,704	69,695	83,296	191,732	7,253
(40)	39	2034	0	43,248	5,274	30,704	70,746	85,587	192,311	6,674
(41)	40	2035	0	12,544	2,511	30,704	71,814	87,941	192,969	6,144
(42)	41	2036	0	0	564	12,544	72,897	90,359	176,365	5,151
(43)	42	2037	0	0	0	0	73,997	92,844	166,841	4,471
(44)	43	2038	0	0	0	0	75,114	95,397	170,511	4,192
(45)	44	2039	0	0	0	0	76,247	98,021	174,268	3,931
(46)	45	2040	0	0	0	0	77,398	100,716	178,114	3,686
(47)	Project Totals		1,256,056		2,312,243	1,256,056	2,592,358	2,655,481	8,816,137	2,305,982

	Levelized Annual Revenue Requirement - LARR			
(RR1)	$87,398	$31,799	$50,761	$41,967

	LARR - As a % of Original Cost			
(RR2)	6.96%	2.53%	4.04%	3.34%

	9.0000% Present Value of Debt Return	9.0000% Present Value of Book Depreciation	9.0000% Present Value of Operating Expenses	9.0000% Present Value of Current Property Taxes	Present Value of Revenue Requirements or (Excess)
	(A)	(B)	(C)	(D)	(E)
(1)	55,832	15,352	39,450	2,470	113,104
(2)	101,176	28,169	36,739	28,007	194,091
(3)	90,496	25,843	34,214	26,401	176,954
(4)	80,890	23,709	31,862	24,888	161,349
(5)	72,253	21,751	29,673	23,461	147,138
(6)	64,492	19,955	27,633	22,115	134,196
(7)	57,519	18,308	25,734	20,847	122,408
(8)	51,258	16,796	23,966	19,652	111,672
(9)	45,639	15,409	22,319	18,525	101,892
(10)	40,598	14,137	20,785	17,463	92,983
(11)	36,079	12,970	19,356	16,462	84,866
(12)	32,029	11,899	18,026	15,518	77,471
(13)	28,402	10,916	16,787	14,628	70,733
(14)	25,155	10,015	15,633	13,789	64,593
(15)	22,251	9,188	14,559	12,998	58,997
(16)	19,655	8,429	13,558	12,253	53,896
(17)	17,337	7,733	12,627	11,551	49,247
(18)	15,267	7,095	11,759	10,888	45,008
(19)	13,420	6,509	10,951	10,264	41,144
(20)	11,775	5,972	10,198	9,675	37,620
(21)	10,309	5,479	9,497	9,121	34,406
(22)	9,006	5,026	8,845	8,598	31,474
(23)	7,847	4,611	8,237	8,105	28,800
(24)	6,818	4,230	7,671	7,640	26,359
(25)	5,906	3,881	7,143	7,202	24,133
(26)	5,098	3,561	6,652	6,789	22,100
(27)	4,383	3,267	6,195	6,400	20,245
(28)	3,751	2,997	5,770	6,033	18,551
(29)	3,194	2,749	5,373	5,687	17,004
(30)	2,704	2,522	5,004	5,361	15,590
(31)	2,272	2,314	4,660	5,053	14,299
(32)	1,893	2,123	4,340	4,764	13,120
(33)	1,562	1,948	4,041	4,490	12,041
(34)	1,272	1,787	3,764	4,233	11,055
(35)	1,019	1,639	3,505	3,990	10,154
(36)	800	1,504	3,264	3,761	9,329
(37)	610	1,380	3,040	3,546	8,575
(38)	445	1,266	2,831	3,342	7,885
(39)	304	1,161	2,636	3,151	7,253
(40)	183	1,066	2,455	2,970	6,674
(41)	80	978	2,286	2,800	6,144
(42)	16	366	2,129	2,639	5,151
(43)	0	0	1,983	2,488	4,471
(44)	0	0	1,847	2,345	4,192
(45)	0	0	1,720	2,211	3,931
(46)	0	0	1,602	2,084	3,686
(47)	950,996	346,012	552,317	456,657	2,305,982

Summary - LARR	**Amounts**
(F)	(G)
Return	**6.96%**
Depreciation	**2.53%**
O&M and Prop Taxes	**7.38%**
Total LARR	**16.87%**
Plant In Service	**$1,256,056**
Annual Requirement	**$211,897**

Schedule 3, Page 1 of 3:

Lines CS1 - CS5: AMPIP Cost of Capital. Debt only @ 9% Interest Rate

Line 1, Column A: Time Period for present value calculation.

Line 1, Column B: Year in service. Present value is life cycle beginning in 1995.

Line 1, Column C: Net pipeline expenditures. Reduced for sale of 7,675' to City of Freeman for $111,600.

Lines 1 - 46, Column D: Net investment reduced for accumulated depreciation for each year.

Line 1, Column E: One-half of end of first year investment ($1,240,704/2) applied to debt cost (9%).

Line 1, Column F: Book depreciation per AMPIP adjusted for sale of 7,675' to Freeman (half year). See Schedule 4.

Line 1, Column G: See Schedule 5.

Line 1, Column H: Actual Property Taxes per AMPIP for first year.

Lines 1 - 46, Column I: Sum of Columns E - H for corresponding lines.

Lines 1 - 46, Column J: Present Value of Column I @ Overall Cost of Capital (9%).

Lines 2 - 46, Column E: Average net investment applied to debt cost (9%).

Lines 2 - 46, Column F: Book depreciation per AMPIP adjusted for sale of 7,675' to Freeman. See Schedule 4.

Lines 2 - 46, Column G: Operating expenses per Schedule 5, escalated at rate determined on Schedule 5.

Lines 2 - 46, Column H: Property taxes per AMPIP adjusted for sale of 7,675' to Freeman. See Schedule 4. Escalated at 2.5% annually.

Line 47: Check totals.

Schedule 3, Page 2 of 3:

Line RR1: The levelized annual revenue requirements of the items reflected in the columns below.

Line RR2: The percent of original cost ($1,256,056) for the levelized revenue requirements shown on RR1.

Lines 1 - 46, Columns A - D: Annual present value of each revenue requirement component shown. The nominal amounts are from Schedule 3, Page 2 of 3, Columns E - H.

Lines 1 - 46, Column E: Annual present value of total revenue requirements. Matches Column J on Schedule 3, Page 1 of 3.

Line 47, Columns A - E: Total of annual present value amounts for each column. These amounts are then discounted to arrive at the amounts shown on Line RR1.

Columns F and G: Summary of Levelized Annual Revenue Requirements. Column F describes each component. Column G shows the LARR rate by component and the total. The LARR rate of 16.79% on Line 5, Column G is applied to the original cost of the pipeline shown on Line 8, Column G to arrive at the levelized annual revenue requirements shown on Line 10, Column G of $210,892. This amount is carried forward to Schedule 2 to determine the pipeline rate.

Statement N

AMPI Pipeline, Inc.

Allocated Cost of Service: 20:10:13:97

AMPIP expects that all of its revenue will initially be generated by the transportation of natural gas for two customers, AMPI and the City of Freeman, South Dakota. Based on projected usage in the first full year of the City Municipal Utlity, AMPI will pay approximately 67% of the total revenue requirement and the City Utility approximately 33%. If AMPIP adds other customers at a later date, AMPIP will file with the Commission to establish rates, tariffs and cost allocations by class.

AMPI Pipeline, Inc.

Description of Utility Operations: 20:10:13:101

AMPIP operates an intrastate natural gas pipeline extending from a point on the existing Northern Natural Gas interstate pipeline located at township 101 North, Range 54 West, Section 24, in McCook County, South Dakota, south along 447th Avenue to Turner County #10, west along County #10 to Turner County #15, South along County #10 to State Highway #44 again west along Highway #44 to US 81 and then south along Highway 81. The pipeline ends at a district regulating station in the SE 1/4 of Section 26, township 99N, Range 56W in Hutchinson County.

Since the pipeline began operations, the sole customer has been AMPI's milk processing plant in Freeman, SD. The rate proposed herein is to allow for service to both AMPI and a newly established municipal gas distribution utility in Freeman, SD. The AMPI plant will also be a retail transportation customer of the City of Freeman. The City of Freeman has concurred with the proposed rate. Mayor Michael Schultz has filed a statement of concurrence with this application.

In the future, AMPIP may install additional taps for deliveries to potential customers along the proposed route as customer requests arise. If necessary, AMPIP would file additional initial tariffs and rates as services may be added.

AMPI Pipeline, Inc.

Purchases from Affiliated Companies: 20:10:13:102

AMPIP is a wholly-owned subsidiary company of AMPI. To minimize operating costs, AMPIP utilizes services from the parent company in its day to day operations. Below is an explanation of those services and the amounts charged to AMPIP. This information is also shown on Schedule 5 of Exhibit 2, herein, and is addressed by Witness Mr. Winter in his testimony in Exhibit 2.

Annual Charges from AMPI to AMPIP
Year 1

AMPIP - O & M Costs Training, readings, patrolling of line by local AMPI personnel	$1,740
Corporate Services Management, clerical, accounting and tax work	$6,710
Total Charges to AMPIP from AMPI	$8,450

AMPI direct costs and corporate services are provided as a means of minimizing resource requirements for both AMPI and AMPIP.

AMPIP - O & M costs are primarily AMPI personnel used for patrolling the pipeline and providing meter readings and other operating data. Because they are located in Freeman and charge only a portion of their time, it is the most inexpensive alternative for this service.

Corporate services are related to tax and reporting requirements of AMPIP and AMPI, as well as general management of the pipeline business as a subsidiary of AMPI. A portion of management and management support time is included, as well as professional internal services related to accounting, auditing, and reporting. As with the direct costs, because the services provided are a portion of various employees' time, and they are familiar with the business, using their services is the lowest cost and most effective alternative.

Affiliate rate of return data associated with the provision of the services discussed above is not available.

Northern States Power Company (Minn)
NSP-SD Gas Operations
Before the South Dakota PUC
Docket NG97-021
First Set MEC Data Requests
Response to: No. 2

☐ **Proprietary**

X **Non-Proprietary**

Question:

Please provide the cost of competing alternatives discussed in Witness Wilcox testimony on Page 7, Lines 1-2.

Response:

The customer selected NSP based on their analysis of competing alternatives. NSP does not have access to prices that are proprietary information of competitors.

Response By:	Jim Wilcox
Title:	Manager of Government & Community Relations
Company:	NSP - SD

Northern States Power Company (Minn)
NSP-SD Gas Operations
Before the South Dakota PUC
Docket NG97-021
First Set MEC Data Requests
Response to: No. 3

☐ **Proprietary**

X Non-Proprietary

Question:

Please define how much of the total cost is the representative cost for NSP - South Dakota electric jurisdiction NSP Generation, as discussed (in)Witness Wilcox testimony on Page 8, Lines 5-6.

Response:

See John Winter testimony Schedule 7.

Response By: Jim Wilcox
Title: Manager of Government & Community Relations
Company: NSP - SD

Northern States Power Company (Minn)
NSP-SD Gas Operations
Before the South Dakota PUC
Docket NG97-021
First Set MEC Data Requests
Response to: No. 4

☐ **Proprietary**

X Non-Proprietary

Question:
What portion of the Angus C. Anson fuel delivery pipeline has been allocated to the Minnesota Jurisdictional electric system in NSP most recent electric rate case?

a.) How much investment, operating cost and depreciation is allocated to the Minnesota Jurisdiction?

b.) Provide documentation from the rate proceedings supporting these values.

Response:
The Angus C. Anson fuel delivery pipeline has not been included in electric rates in any NSPM jurisidiction. NSP's most recent electric rate cases pre-dated the installation of the pipeline.

Response By:	John Winter
Title:	Sr. Regulatory Consultant
Company:	NSP

Northern States Power Company (Minn)
NSP-SD Gas Operations
Before the South Dakota PUC
Docket NG97-021
First Set MEC Data Requests
Response to: No. 5

☐ **Proprietary**

X Non-Proprietary

Question:

Does NSP expect to service gas to more customers than the 11 customers mentioned in Witness Wilcox testimony on Page 9, Line 7?

Response:

See Wilcox testimony Page 9, beginning on Line 10.

Response By:	Jim Wilcox
Title:	Manager of Government & Community Relations
Company:	NSP - SD

Northern States Power Company (Minn)
NSP-SD Gas Operations
Before the South Dakota PUC
Docket NG97-021
First Set MEC Data Requests
Response to: No. 6

☐ **Proprietary**

X Non-Proprietary

Question:

Has NSP met with any of the MidAmerican gas customers to offer NSP gas service to these customers?

Response:

No.

Response By:	Jim Wilcox
Title:	Manager of Government & Community Relations
Company:	NSP - SD

Northern States Power Company (Minn)
NSP-SD Gas Operations
Before the South Dakota PUC
Docket NG97-021
First Set MEC Data Requests
Response to: No. 7

☐ **Proprietary**

X **Non-Proprietary**

Question:

Referring to Wilcox testimony on Page 9, how much capacity is available to service the additional customers?
a.) Is the 325 Mcf per hour of capacity expected to cover these customers?

Response:

Yes.

Response By:	Jim Wilcox
Title:	Manager of Government & Community Relations
Company:	NSP - SD

Northern States Power Company (Minn)
NSP-SD Gas Operations
Before the South Dakota PUC
Docket NG97-021
First Set MEC Data Requests
Response to: No. 8

☐ **Proprietary**

X **Non-Proprietary**

Question:

In Wilcox testimony on Page 10, Lines 5-7 indicates that municipalities have the authority to grant non-exclusive franchise agreements with various utilities capable of providing natural gas service. Has the City of Sioux Falls approved NSP to provide natural gas service in Sioux Falls?

Response:

No.

Response By:	Jim Wilcox
Title:	Manager of Government & Community Relations
Company:	NSP - SD

Northern States Power Company (Minn)
NSP-SD Gas Operations
Before the South Dakota PUC
Docket NG97-021
First Set MEC Data Requests
Response to: No. 9

☐ **Proprietary**

X Non-Proprietary

Question:

In Wilcox testimony on Page 9, Line 20-21, Mr. Wilcox states he is not aware of any other natural gas supplier presently serving that site. Do you know where MidAmerican's nearest gas main service is located from the site?

Response:

No.

Response By:	Jim Wilcox
Title:	Manager of Government & Community Relations
Company:	NSP - SD

Northern States Power Company (Minn)
NSP-SD Gas Operations
Before the South Dakota PUC
Docket NG97-021
First Set MEC Data Requests
Response to: No. 10

☐ **Proprietary**

X Non-Proprietary

Question:
Reference to Witness Winter testimony Page 1, Line 24, Mr. Winter filed testimony in Docket No. F-3422. Please provide a copy of the testimony and exhibits filed in this case.

Response:
Attached are copies of the requested testimony and exhibits. The direct testimony was filed in November, 1982. The rebuttal was filed in April, 1983. The case was subsequently settled.

Response By: John Winter
Title: Sr. Regulatory Consultant
Company: NSP

NEXT

DOCUMENT (S)

DISREGARD

BACKGROUND

Rebuttal Exhibit No. (JDW-2)

Witness John D. Winter

Before the Public Utilities Commission of
the State of South Dakota

In the Matter of the Application of Northern States Power Company
for Authority to Increase Rates for Electric Utility
Service in South Dakota

Docket No. F-3422

Cost of Service
Income Statement
and
Overall
Revenue Requirements

April, 1983

Exhibit ____ (JDW-2)

INDEX TO COST OF SERVICE AND

REVENUE REQUIREMENTS REBUTTAL

SCHEDULES

Northern States Power Company (Minnesota)
Electric Utility - South Dakota F-3422
RESTATEMENT OF SOUTH DAKOTA PUBLIC UTILITIES COMMISSION
Adjusted Year Ended June 30, 1982

Exhibit ___ (JDW-2)
Schedule 1

(Dollars in Thousands)

	Description	Staff's Position 6/30/82 (A)	Staff's Corrected Position (B)	NSP(M) Rebuttal Position (C)
1.	Average Rate Base	$82,144	$82,406	$85,271
2.	Return Earned With Present Rates	7,337	7,011	6,632
3.	Rate of Return Earned	8.93%	8.51%	7.78%
	Indicated Revenue Deficiency:			
4.	Staff Recommended Rate of Return	10.22%	10.22%	11.27%
5.	Earnings Requirements	8,395	8,422	9,610
6.	Earnings Deficiency	1,058	1,411	2,978
7.	Income Tax Effect	904	1,202	2,537
8.	Revenue Deficiency	1,962	2,613	5,515
9.	Revenue Deficiency Change for Mr. Weiss's Surplus Capacity Adjustment	(437)	(360)	
10.	Adjusted Revenue Deficiency	$ 1,525	$ 2,253	$ 5,515

Northern States Power Company (Minnesota)
Electric Utility - South Dakota F-3422
SUMMARY OF ADJUSTMENTS TO STAFF PRO FORMA OPERATING INCOME
Adjusted Year Ended June 30, 1982

(Dollars in Thousands)	Pro Forma 6-30-82 Per SDPUC Staff	Staff Acknowledged Corrections	Staff Corrected Position	Labor & FICA Tax Adjustment	Pensions Adjustment	Interest Synchronization Adjustment	Oil Sale Adjustment	Storm Damage Adjustment	Charitable Contributions Adjustment	Annualized Nuclear Decommissioning Accruals	Nuclear Decommissioning Accruals 25% Contingency	Coord. Agree. Expense Adjustment	O & M Inflation Adjustment	Adjustment to Related Items from Exh(MAH-2)	NSP(JW) Rebuttal Position
	(A)(1)	(B)(2)	(C)(2)	(D)(3)	(E)(4)	(F)(5)	(G)(6)	(H)(7)	(I)(8)	(J)(9)	(K)(10)	(L)(11)	(M)(12)	(N)(13)	(O)(14)
1. Operating Revenues	$40,068	$ (42)	$40,026	$	$	$	$(21)	$	$	$	$	$	$	$ 431	$40,436
Operating Expenses:															
2. Operating and Maintenance	21,550		21,550	100	38			32	25			31	236	431	22,492
3. Depreciation and Amortization	4,470		4,470							50	75			156	4,131
4. Taxes other than Income	5,345		5,346	6										8	5,388
Federal Income Taxes:															
5. Currently Payable	1,716	284	2,000	(49)	(17)	75	(10)	(15)	(12)			(14)	(109)	(118)	1,729
6. Deferred	1,085		1,085											(8)	1,077
7. Investment Tax Credit	555		555											(128)	427
8. Total Federal Income Taxes	3,356	284	3,640	(49)	(17)	75	(10)	(15)	(12)			(14)	(109)	(254)	3,233
9. Total Operating Expenses	32,731	284	33,015	57	21	75	(10)	17	13	50	75	17	127	369	33,804
10. Operating Income	$ 7,337	$(326)	$ 7,011	$(57)	$(21)	$(75)	$(11)	$(17)	$(13)	$(50)	$(75)	$(17)	$(127)	$ 62	$ 6,632

(1) See Exhibit (FDB-1), Schedule 2, Column D.
(2) See Exhibit ___ (JDW-2), Schedule 3, page 1 of 4.
(3) See Exhibit ___ (JDW-2), Schedule 4.
(4) See Exhibit ___ (JDW-2), Schedule 5.
(5) See Exhibit ___ (JDW-2), Schedule 6, page 1 of 2.
(6) See Exhibit ___ (JDW-2), Schedule 7.
(7) See Exhibit ___ (JDW-2), Shcedule 8.
(8) See Exhibit ___ (JDW-1), Schedule 11, page 1 of 4.
(9) See Exhibit ___ (JDW-2), Schedule 9.
(10) See Exhibit ___ (TJW-1), Schedule 2.
(11) See Exhibit ___ (JDW-2), Schedule 10.
(12) See Exhibit ___ (JDW-2), Schedule 11.
(13) See Exhibit ___ (MAH-2), Schedule 2, page 1 of 10, and Schedule 2, page 10 of 10. Non-revenue plant Split Rock.
(14) Columns D through M Summarized and added to Column C.

Exhibit ___ (JDW-2)
Schedule 2

Northern States Power Company (Minnesota)
Electric Utility - South Dakota F-3422
SUMMARY OF STAFF ACKNOWLEDGED INCOME
STATEMENT CORRECTIONS
Adjusted Year Ended June 30, 1982

(Dollars In Thousands)

	Staff Position as Recommended	Repair Allowance Amortization Tax Effect	Oil Sales Revenue Exclusion Overstated	Current Tax Effect of Balance of Flow-through Adjustment	Use of Proper CWIP Amount for Int Exp Calculation	Use of Proper act Int. Exp. for Int Adjustment	Corrected Staff Position as Recommended
	(A) (1)	(B) (2)	(C) (3)	(D) (4)	(E) (5)	(F) (6)	(G)
1. Operating Revenues	$40,068	$	$(42)	$	$	$	$40,026
Operating Revenues							
2. Operation and Maintenance	21,559						21,559
3. Depreciation and Amortization	4,470						4,470
4. Taxes other than Income	3,346						3,346
Federal Income Taxes							
5. Currently Payable	1,716	42	(19)	108	33	120	2,000
6. Deferred (Net)	1,085						1,085
7. Investment Tax Credit (Net)	555						555
8. Total Federal Income Taxes	$ 3,356	$ 42	$(19)	$ 108	$ 33	$ 120	$ 3,640
9. Total Operating Expenses	32,731	42	(19)	108	33	120	33,015
10. Operating Income	$ 7,337	$(42)	$(23)	$(108)	$(33)	$(120)	$ 7,011

(1) See Exhibit ___ (FDB-1), Schedule 2.
(2) Per Staff Response to NSP Data Request 5, Item 2.
(3) Per Staff Response to NSP Data Request 5, Item 3.
(4) Per Staff Response to NSP Data Request 5, Item 6, and subsequent telephone conversation with Staff.
(5) Per Staff Response to NSP Data Request 5, Item 12, See also page 4 of this Schedule.
(6) Per Staff Response to NSP Data Request 5, Item 4, See also page 4 of this Schedule.

Northern States Power Company (Minnesota)
Electric Utility - South Dakota F-3422
STAFF-ACKNOWLEDGED CORRECTIONS TO THE
RECOMMENDED RATE BASE AND TAX BASE
SHOWN IN EXHIBIT ___ (GAR-1) AND
IN EXHIBIT ___ (FDB-1)

Exhibit ___ (JDW-2)
Schedule 3
Page 2 of 4

(Dollars in Thousands)

	Adjustments to Rate Base
1. Reverse sign on unamortized Rate Case Expense:	
Rate Base as Recommended	$82,144 (1)
Reverse Unamortized Rate Case Expense Sign	270 (1)
Lead/lag Effects on Working Capital	(8)(4)
Corrected Staff Rate Base	$82,406
2. Reduce CWIP Included in Tax Calculation-Interest Expense Recognize Non-NSP owned portion of SHERCO III:	
CWIP used in Recommended Interest Calculation	$ 9,995 (2)
SHERCO III Adjustment	(2,143)(3)
Corrected CWIP to use in Tax Base	$ 7,852

(1) See Exhibit ___ (GAR-1), Schedule 1, page 1 of 5.
(2) See Exhibit ___ (FDB-1), Schedule 7, page 1 of 2.
(3) See Exhibit ___ (JDW-2), Schedule 3, page 3 of 4.
(4) See Exhibit ___ (MAH-2), Schedule 4, page 4 of 5.

Northern States Power Company (Minnesota)
Electric Utility - South Dakota F-3422
PRO FORMA ADJUSTMENT TO RESTATE CWIP
TO BE USED IN INTEREST EXPENSE DETERMINATION
Adjusted Year Ended June 30, 1982

		NSP Company A	NSP Minn. B	South Dakota C
	Average CWIP Balances			
1.	Production per Staff	$ 244,993	$ 211,396	$ 8,662
2.	Less portion of Sherco III not owned by NSP	60,610	52,298	2,143
3.	Adjusted Production	$ 184,383	$ 159,098	$ 6,519
4.	Transmission	22,087	19,058	764
5.	Distribution	24,378	24,378	1,967
6.	General	5,495	5,495	205
7.	Common	7,655	7,655	308
8.	Total	$ 243,998	$ 215,684	$ 9,763
	Less: Non-Revenue Producing Plant			
9.	Production	$ 53,752	$ 46,381	$ 1,900
10.	Transmission	-0-	-0-	-0-
11.	Distribution	110	110	9
12.	General	47	47	2
13.	Total	$ 53,909	$ 46,538	$ 1,911
	Corrected Average CWIP	$ 190,089	$ 169,146	$ 7,852

Per Staff workpapers, SHERCO III Adjustment per NSP, Staff workpapers.

Northern States Power Company (Minnesota)
Electric Utility - South Dakota F-3422
PRO FORMA ADJUSTMENT TO CORRECT SYNCHRONIZATION
OF INTEREST EXPENSE
Adjusted Year Ended June 30, 1982

Exhibit ____ (JDW-2)
Schedule 3
Page 4 of 4

		A(1)	B(1)	C
1.	Average Rate Base			$ 82,406
2.	CWIP not included in rate base			7,852
3.	Total			$ 90,258
	Portion Financed With			
4.	Short-Term Debt	$ 28,550	1.24%	$ 1,119
5.	Long-Term Debt	1,077,063	46.71%	42,160
6.	Preferred Stock	215,413	9.34%	
7.	Common Equity	861,650		
8.	Accumulated Deferred ITC	123,317		
9.	Total	$2,305,993		
	Pro Forma Interest			
10.	Short-Term Debt at 12.48% (1)			$ 140
11.	Long-Term Debt at 8.01% (1)			3,377
12.	Total			$ 3,517
13.	Actual Year Interest Expense			2,740
14.	Corrected Staff Adjustment to Interest Expense			777
15.	Originally Recommended Staff Adjustment			1,110
16.	Adjustment to Staff's Originally Recommended Interest Expense			(333)
17.	Tax Effect			$ 153

(1) See Exhibit ____ (FDB-1), Schedule 7, page 1 of 2.

Exhibit ___ (JDW-2)
Schedule 4
Page 1 of 3

Northern States Power Company (Minnesota)
Electric Utility - South Dakota F-3422
RESTATEMENT OF PRO FORMA ADJUSTMENT TO RECOGNIZE WAGE AND SALARY INCREASES
Adjusted Year Ended June 30, 1982

	Labor Adjusted for 1983(1) (A)	1984 Adjustment Factor (B) (3)	Labor Adjusted for 1984 (C)	Total NSP Co. Labor Adjustment (D)	NSP(M) Coord. Agr. Part. Ratio (E)	NSP(M) Labor Adjustment (F)	Dakota Allocation Factor (2) (G)	Dakota Labor Adjustment (H)	Staff's Position (I)	Adjustment to Staff's Position (J)
PRODUCTION										
Other Production										
1. Demand	$ 47,809,558	1.015000	$ 48,526,701	$ 5,808,944	.862867	$ 5,012,346	.040973	$205,371	$180,017	$25,354
2. Energy	18,491,313	1.015000	18,768,683	2,246,727	.849963	1,909,635	.037509	71,629	62,786	8,843
3. Total Production	$ 66,300,871		$ 67,295,384	$ 8,055,671		$ 6,921,981		$277,000	$242,803	$34,197
TRANSMISSION										
4. Generation Step-up	$ 587,155	1.015000	$ 595,962	$ 71,340	.862867	$ 61,557	.040973	$ 2,522	$ 2,211	$ 311
5. Bulk Supply	2,659,267	1.015000	2,699,156	323,106	.862867	278,798	.040279	11,230	9,843	1,387
6. Local - South Dakota	106,356	1.015000	107,951	12,922		12,922		12,922	11,327	1,595
7. - All Other	914,338	1.015000	928,053	111,093		111,093		0	0	0
8. Total Transmission	$ 4,267,116		$ 4,331,122	$ 518,461		$ 464,370		$ 26,674	$ 23,381	$ 3,293
DISTRIBUTION										
9. Local - South Dakota	$ 1,720,134	1.015000	$ 1,745,936	$ 208,999		$ 208,999		$208,999	$183,197	$25,802
10. - All Other	32,991,871	1.015000	33,486,749	4,008,569		4,008,569		0	0	0
11. Total Distribution	$ 34,712,005		$ 35,232,685	$ 4,217,568		$ 4,217,568		$208,999	$183,197	$25,802
CUSTOMER ACCOUNTING										
12. System	$ 10,522	1.015000	$ 10,680	$ 1,279		$ 1,279	.048730	$ 62	$ 55	$ 7
13. Local - South Dakota	683,359	1.015000	693,609	83,029		83,029		83,029	72,779	10,250
14. - All Other	12,458,151	1.015000	12,645,023	1,513,687		1,513,687		0	0	0
15. Total Customer Acctg	$ 13,152,032		$ 13,349,312	$ 1,597,995		$ 1,597,995		$ 83,091	$ 72,834	$10,257
CUSTOMER SERVICE & INFORMATION										
16. System	$ 156,118	1.015000	$ 158,460	$ 18,969		$ 18,969	.048730	$ 924	$ 810	$ 114
17. Local - South Dakota	155,622	1.015000	157,956	18,908		18,908		18,908	16,574	2,334
18. - All Other	2,334,328	1.015000	2,369,343	283,625		283,625		0	0	0
19. Total Customer Service & Information	$ 2,646,068		$ 2,685,759	$ 321,502		$ 321,502		$ 19,832	$ 17,384	$ 2,448
ADMINISTRATION & GENERAL										
20. System	$ 30,399,122	1.015000	$ 30,855,109	$ 3,693,546		$ 3,693,546	.042117	$155,561	$136,356	$19,205
21. Local - South Dakota	338,110	1.015000	343,182	41,082		41,082		41,082	36,010	5,072
22. - All Other	3,415,247	1.015000	3,466,476	414,958		414,958		0	0	0
23. Total Administration & General	$ 34,152,479		$ 34,664,767	$ 4,149,586		$ 4,149,586		$196,643	$172,366	$24,277
24. TOTAL ADJUSTMENT	$155,230,571	1.015000	$157,559,029	$18,860,783		$17,673,002		$812,239	$711,965	$100,274

(1) 1983 adjusted labor computed by applying increase factors to actual year labor.
Increase factors: 1.045421 X 1.070570
(81/82 Factor) (83 Factor)

(2) Exhibit ___ (MAH-1), Schedule 12, page 2 of 2. Factors: Production Demand-D10; Production Transmission-D50; Energy-E10; Customers-C10; Plant-Sales-RLTSAL.

(3) January 1, 1984 Labor Factor = (4.0% ÷ 12 × 4.5) + 1 = 1.015000.

Northern States Power Company (Minnesota)
Electric Utility - South Dakota F-3422
PRO FORMA ADJUSTMENT TO RESTATE FICA EXPENSE
Adjusted Year Ended June 30, 1982

Exhibit ____(JDW-2)
Schedule 4
Page 2 of 3

Description (A)	Labor Amounts (B)(1)	Percentage (C)	Distribution of Adjustment (D)	NSP(M) (E)
Percent of Labor in Production and Transmission:				
Production				
1. - Demand	$ 48,526,701	30.7991%	$ 420,144	$ 362,528(3)
2. - Energy	18,768,683	11.9122%	162,500	138,119(3)
3. Total Production	$ 67,295,384			
Transmission				
4. - Gen. Step Up	$ 595,962	0.3782%	$ 5,159	$ 4,452(3)
5. - Bulk Supply	2,699,156	1.7131%	23,369	20,164(3)
6. Total EHV Transmission	$ 3,295,118			
7. All Other Labor	$ 86,968,527	55.1974%	$ 752,972	$ 752,972
8. Total Labor	$157,559,029	100.0000%	$1,364,144(2)	$1,278,235
9. South Dakota Allocation Factor				4.5554%(4)
10. South Dakota FICA Increase				$ 58,229
11. Staff's Recommended FICA Increase				$ 52,424(5)
12. Adjustment to Staff's Recommended Increase				$ 5,805

(1) Exhibit ____(JDW-2), Schedule 4, page 1 of 2, Column C.
(2) Exhibit ____(JDW-2), Schedule 4, page 3 of 3, Column B, line 9.
(3) Reflects Application of NSP(M) Coordinating Agreement Participation Ratios. Demand: 86.2867% Energy: 84.9963%
(4) Exhibit ____(JDW-1), Schedule 8, page 3 of 4, Column B, line 1.
(5) Staff workpapers - FICA Increase, page 1 of 2.

Northern States Power Company (Minnesota)
Electric Utility - South Dakota F-3422
PROFORMA ADJUSTMENT TO RESTATE FICA EXPENSE
Adjusted Year Ended June 30, 1982

Exhibit ___ (JDW-2)
Schedule 4
Page 3 of 3

Description (A)	Amount (B)
1. Payroll subject to FICA tax at NSP(M) electric operating level as originally filed.	$ 141,129,119(1)
2. Total electric labor as originally filed.	$ 158,972,098(2)
3. Ratio subject to FICA.	.887760(3)
4. NSP's rebuttal electric labor amount.	$ 157,559,029(4)
5. Payroll subject to FICA tax at electric operating level.	$ 139,874,604(5)
6. FICA tax rate.	6.7%
7. Pro Forma FICA amount.	$ 9,371,598(6)
8. Actual FICA amount.	$ 8,007,454(7)
9. FICA adjustment.	$ 1,364,144

(1) Exhibit ___ (JDW-1), Schedule 8, page 4 of 4, Column A, sum of lines 3 and 4 times Column C, line 6.
(2) Exhibit ___ (JDW-1), Schedule 8, page 2 of 4, Column B, line 24.
(3) Line 1 ÷ line 2.
(4) Exhibit ___ (JDW-2), Schedule 4, page 1 of 3, Column C, line 24.
(5) Line 3 x line 5.
(6) Line 5 x line 6.
(7) Exhibit ___ (JDW-1), Schedule 8, page 3 of 4, Column A, line 2.

Northern States Power Company (Minnesota)
Electric Utility - South Dakota F-3422
PRO FORMA ADJUSTMENT TO RECOGNIZE PENSION
EXPENSE CONSISTENT WITH RATE YEAR ENDED
MAY 16, 1984
Adjusted Year Ended June 30, 1982

Exhibit ____ (JDW-2)
Schedule 5

1.	Pension Expense for Year Ended 5/17/84	$ 26,712,250 (1)
2.	Ratio to Reflect Employee Level at Year 6/82	1/1.00372 (2)
3.	Pension Expense for Year 5/17/84 Synchronized to Employee Levels at Year 6/82	$ 26,613,254
4.	Actual Year Accruals	$ 22,797,700
5.	Restated Adjustments	$ 3,815,554
6.	Electric Factor	.6727 (3)
7.	Electric Utility - NSP(M) Adjustment	$ 2,566,723
8.	Percent to NSP(M)	93.702% (4)
9.	Amount to NSP(M)	$ 2,405,071
10.	Percent to South Dakota	4.5554% (5)
11.	Amount - South Dakota	$ 109,561
12.	Staff Adjustment Recommended	71,952 (6)
13.	Additional Adjustment Required to Include Pension Costs Consistent with Costs Which will be Incurred in the Rate Year	$ 37,609

(1) Amounts per Company response to Staff Data Request No. 1, Item 26. 7/12 of 1983 Amount plus 5/12 of 1984 Amount.
(2) Average 6,208 employees year ended 5/84, 6,185 employees year 6/82. 6,208 ÷ 6,185 = 1.00372.
(3) See Exhibit ____ (JDW-1), Schedule 9.
(4) Allocated to NSP(M) on basis of labor expense in production, EHV functions, and participation ratios as shown in Staff workpapers.
(5) See Exhibit ____ (MAH-1), Schedule 12, Page 2 of 2.
(6) Per Staff workpapers.

Northern States Power Company (Minnesota)
Electric Utility - South Dakota F-3422
INTEREST SYNCHRONIZATION RESTATED
ADJUSTED year ended June 30, 1982

Exhibit ___ (JDW-2)
Schedule 6
Page 1 of 2

		(A) (1)	(B) (1)	(C)
1.	Average Rate Base			$85,271
(1)				
2.	CWIP not included in rate base			7,479 (3)
3.	TOTAL			$92,750
	Portion Financed With:			
4.	Short-Term Debt	$ 28,550	1.24%	$ 1,150
5.	Long-Term Debt	998,108	43.28%	$40,142
6.	Preferred Stock	223,694	9.70%	
7.	Common Equity	932,324		
8.	Accumulated Deferred ITC	123,317		
9.	TOTAL	$2,305,993		
	Pro-Forma Interest:			
10.	Short-Term Debt at 12.48% (1)			$ 144
11.	Long-Term Debt at 8.01% (1)			3,215
12.	TOTAL			$ 3,359
13.	Corrected Staff Interest Expense			$ 3,517 (4)
14.	Adjustment to Staff's Corrected Interest Expense			$ (158)
15.	Tax Effect			$ 73
				=======

(1) See Exhibit ___ (BJE-2), Schedule 11
(2) See Exhibit ___ (MAH-2), Schedule 11
(3) See Exhibit ___ (JDW-2), Schedule 3, Page 3 of 4, adjusted for NSP proposed non-revene plant additions:

Corrected Staff CWIP	$ 7,852
Add Staff NR Plant	1,911
Less NSP NR Plant	2,284
	$ 7,479

(4) See Exhibit ___ (JDW-2), Schedule 3, Page 4 of 4.

NSP Company (Minnesota)
Electric Utility - South Dakota F-3422
Staff Interest Calculation Components
Restated using Second-Class Common Equity

Exhibit ___ (JDW-2)
Schedule 6
Page 2 of 2

Staff Weighted Cost of Debt as Recommended (1)

		Amount (A)	Percent (B)	Cost (C)	Weighted Cost (D)
1.	Short-Term Debt	$ 28,550	1.24%	12.48%	0.15%
2.	Long-Term Debt	1,077,063	46.71	8.01	3.74
3.	Preferred Stock	215,413	9.34		
4.	Common Equity	861,650	37.37		
5.	Accumulated Deferred ITC	123,317	5.34		
6.	TOTAL	$2,305,993	100.00%		3.89%

Restated Staff Weighted Cost of Debt

		Amount (A)	Percent (B)	Cost (C)	Weighted Cost (D)
7.	Short-Term Debt	$ 28,550	1.24%	12.48%	0.15%
8.	Long-Term Debt	998,108	43.28	8.01	3.47
9.	Hypothetical Debt	78,955(2)	3.43	0	
10.	Preferred Stock	215,413	9.34		
11.	Common Equity	861,650	37.37		
12.	Accumulated Deferred ITC	123,317	5.34		
13.	TOTAL	$2,305,993	100.00%		3.62%
14.	Difference in Weighted Cost of Debt due to Hypothetical Second-Class Common Equity				0.27%

(1) See Exhibit ___ (FDB-1), Schedule 7, page 1 of 2.
(2) Portion of Second-Class Common Equity included Hypothetically as Debt in Staff's Interest calculation.

Northern States Power Company (Minnesota)
Electric Utility - South Dakota F-3422
RESTATEMENT OF PRO FORMA ADJUSTMENT TO OTHER MISCELLANEOUS REVENUES FOR NON-RECURRING OIL SALES
Adjusted Year Ended June 30, 1982

Exhibit ___ (JDW-2)
Schedule 7

(Dollars in Thousands)

	Total NSP Co.	NSP(M) Coord. Agree. Part. Ratio	Total NSP(M)	South Dakota Allocator	South Dakota Amount
	A	B	C	D	E
1. Oil Sale Revenues	$(2,635)	.849963(1)	$(2,239)	.037509(2)	$ (84)

2. Staff recommended total Operating Revenues (Reflects exclusion of 1/4 of profit on sale of oil. Objective was to exclude 3/4.)	$40,068
3. Correction to amortization of profit on sale of oil. (1/2 of profit on sale of oil)	(42)
4. Corrected Staff position (excludes 3/4 of profit on sale of oil)	$40,026
5. Adjustment to Staff's corrected position to exlude remaining 1/4 of profit on sale of oil.	(21)
6. Revenues reflecting 100% exclusion of oil sale revenues.	$40,005

(1) NSP(M) Coordinating Agreement energy participation factor.
(2) Exhibit ___ (MAH-1), Schedule 12, page 2 of 2. Energy Factor E10.

Northern States Power Company (Minnesota)
Electric Utility - South Dakota F-3422
PRO FORMA ADJUSTMENT TO DISTRIBUTION O&M
REFLECTING ABNORMAL STORM DAMAGE
Adjusted Year Ended June 30, 1982

Exhibit ___ (JDW-2)
Schedule 8

Actual Storm Damage Expense Incurred During the Period 1978-1982 per Company Books and Records:

1.	Year 1978	$ 72,283
2.	Year 1979	24,518
3.	Year 1980	61,701
4.	Year 1981	30,799
5.	Year 1982	202,009
6.	Total Five-Year Period	$391,310
7.	Average storm damage expense incurred over five-year period 1978-1982	$ 78,262
8.	1977-1981 five-year average expense level recommended by South Dakota Staff	$ 45,949
9.	Adjustment to increase storm damage expense	$ 32,313

Northern States Power Company (Minnesota)
Electric Utility - South Dakota F-3422
PRO FORMA ADJUSTMENT TO ANNUALIZE NUCLEAR
PLANT DECOMMISSIONING ACCRUALS
Adjusted Year Ended June 30, 1982

Exhibit ____ (JDW-2)
Schedule 9

	Actual Accruals A (1)	NSP(M) Co. B (2)	Book Depreciation Adjustment - South Dakota Factor C (3)	Book Depreciation Adjustment - South Dakota Amount D
July 1981	$ 0			
August	853,867			
September	853,867			
October	853,867			
November	853,867			
December	853,867			
January 1982	881,382			
February	881,382			
March	881,382			
April	881,382			
May	881,382			
June	881,382			
Total as recorded and included in Company's original filing	$ 9,557,627			
Additional month - July, 1981	853,867	$ 736,774	.040973	$ 30,188
Total annualized amount	$10,411,494			
Adjustment to Reserve for Depreciation (one-half)				$ 15,094

(1) NSP(M) Books and Records
(2) Allocated to NSP(M) at .862867
(3) Production demand

Northern States Power Company (Minnesota)
Electric Utility - South Dakota F-3422
PROFORMA ADJUSTMENT TO INCLUDE KNOWN AND
MEASURABLE CHANGES TO COORDINATING AGREEMENT EXPENSES
Adjusted Year Ended June 30, 1982

Exhibit ___ (JDW-2)
Schedule 10

(Dollars in Thousands)

	Production A	Transmission EHV B	Total C
1. Year 6/82 actual Coordinating Agreement expense net of Tyrone and precertification costs	20,003(1)	1,428(2)	
2. Adjusted expense reflecting proforma adjustments to NSP(W) costs consistent with NSP(M) costs	20,512(3)	1,665(3)	
3. Adjustment reflecting increased Coordinating Agreement expenses	509	237	
4. South Dakota factors	.040973(4)	.040279(5)	
5. South Dakota adjustment	$ 21	$ 10	$ 31

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(1) See Exhibit ___ (JDW-1), Schedule 5, page 3 of 9, Schedule 14, and Schedule 24. $8,848 + $12,616 - $1,461 = $20,003.
(2) Per NSP General Ledger less precertification. costs as shown on Exhibit ___ (JDW-1), Schedule 24.
(3) Per NSP(W) Analysis of Proforma Adjustment Impact on NSP(W) Costs.
(4) Demand - Production.
(5) Demand - Transmission.

Exhibit ___ (JDW-2)
Schedule 11
Page 1 of 2

Northern States Power Company (Minnesota)
Electric Utility - South Dakota F-3422
PRO FORMA ADJUSTMENT TO OPERATING AND MAINTENANCE EXPENSE - INFLATION
Adjusted Year Ended June 30, 1982

(Dollars in Thousands)	Year Ended June 30, 1982 Actual A	Expenses Excluded From Adjustment B	Labor Excluded C	Net 6-30-82 Actual O & M Expense D	NSP(M) Coord. Agree. Part. Ratio E	South Dakota Factor F	South Dakota Amount G	Inflation Factor H	Inflation Adjustment I
Production									
1. Demand	$ 90,590	$ 6,065(1)	$ 42,718	$ 41,807	.862867	.040973(14)	$ 1,478	.076	$ 112
2. Energy	233,255	200,566(2)	16,522	16,167	.849963	.037509(14)	515	.076	39
3. Total Production	$ 323,845	$ 206,631	$ 59,240	$ 57,974			$ 1,993		$ 151
Transmission									
4. Generation Step-Up	$ (1,374)	$ (2,660)(3)	$ 525	$ 761	.862867	.040973(14)	$ 27	.076	$ 2
5. Bulk Power	5,824	1,087(4)	2,376	2,361	.862867	.040279(14)	82	.076	6
6. Local-South Dakota	233	-0-	95	138			138	.076	10
7. -All Other	2,002	(151)(5)	817	1,336			-0-		-0-
8. Total Transmission	$ 6,685	$ (1,724)	$ 3,813	$ 4,596			$ 247		$ 18
Distribution									
9. South Dakota	$ 2,270	$ -0-	$ 1,537	$ 733		.040973	$ 30	.076	$ 2
10. All Other	47,024	19	29,478	17,527		-0-	-0-		-0-
11. Total Distribution	$ 49,294	$ 19(6)	$ 31,015	$ 18,260			$ 30		$ 2
Customer Accounting									
12. System	$ 15	$ -0-	$ 9	$ 6		.048730(14)	$ -0-		$ -0-
13. Local-South Dakota	974	110(7)	611	253			253	.076	19
14. -All Other	17,742	-0-	11,131	6,611		-0-	-0-		-0-
15. Total Cust. Acctg.	$ 18,731	$ 110	$ 11,751	$ 6,870			$ 253		$ 19
Customer Service & Information									
16. System	$ 259	$ 47(8)	$ 139	$ 73		.048730(14)	$ 4	.076	$ -0-
17. Local-South Dakota	254	37(9)	139	78			78	.076	6
18. -All Other	3,875	118(10)	2,086	1,671		-0-	-0-		-0-
19. Total Cust. Info.	$ 4,388	$ 202	$ 2,364	$ 1,822			$ 82		$ 6
Administrative & General									
20. System	$ 70,688	$ 33,106(11)	$ 27,162	$ 10,420		.041737(14)	$ 435	.076	$ 33
21. Local-South Dakota	555	205(12)	302	48			48	.076	7
22. -All Other	7,546	1,056(13)	3,051	3,439		-0-	-0-		-0-
23. Total A & G	$ 78,789	$ 34,367	$ 30,515	$ 13,907			$ 483		$ 40
24. Total	$ 481,732	$ 239,605	$138,698	$103,429			$ 3,088		$ 236

NOTE: See Exhibit ____(JDW-2), Schedule 11, page 2 of 2 for all footnotes.

Northern States Power Company (Minnesota)
Electric Utility - South Dakota F-3422
PRO FORMA ADJUSTMENT TO OPERATING AND
MAINTENANCE EXPENSE - INFLATION SCHEDULE FOOTNOTES
Adjusted Year Ended June 30, 1982

Exhibit ____(JDW-2)
Schedule 11
Page 2 of 2

(1) Purchased Power $1,690; Coord. Agree. $7,933; Non-Assoc. Utility Revenues $(3,558).

(2) Fuel $213,294; Purchased Power $48,076; Coord. Agree. $915; Non-Assoc. Utility Revenues $(61,719).

(3) Manitoba Hydro Revenues $(2660,000).

(4) CPA Revenues $(738,397); Coord. Agree. EHV Transmission $1,825,109.

(5) CPA Revenues $(151,345).

(6) Storm Damage $18,707.

(7) Postage Expense $110,460.

(8) Telephone Rates $47,100.

(9) Energy Audits $37,239.

(10) Energy Audits $118,221.

(11) Property Insurance $5,935,000; Pensions & Benefits $23,235,000; Injuries & Damages $3,936,000.

(12) Regulatory Expense $205,000.

(13) Regulatory Expense $1,056,000.

(14) See Exhibit ____(MAH-1), Schedule 12, page 1 of 2. Factors: customer, production-demand, energy, production-transmission, plant-sales (PLTSAL).

NEXT

DOCUMENT (S)

DISREGARD

BACKGROUND

Prepared Rebuttal Testimony of

John D. Winter

Before the Public Utilities Commission of
the State of South Dakota

In the Matter of the Application of Northern States Power Company
for Authority to Increase Rates for Electric Utility
Service in South Dakota

Docket No. F-3422

Cost of Service
Income Statement
and
Overall
Revenue Requirements

April, 1983

Prepared Rebuttal Testimony of
John D. Winter
Docket No. F-3422

1. Q. Please state your name and business address.

A. John D. Winter, 414 Nicollet Mall, Minneapolis, Minnesota 55401.

2. Q. Have you previously submitted testimony in regard to Docket F-3422?

A. Yes, I have submitted prepared testimony and Exhibit ___(JDW-1), pertaining to Cost of Service-Income Statement, and overall revenue requirements, which was part of the Company's original application in November, 1982.

3. Q. What is the purpose of your rebuttal testimony?

A. My rebuttal testimony is directed primarly to the testimony of Staff Witnesses Ms. Faye D. Brown and Mr. Robert L. Knadle, to the extent issues which they addressed affect the income statement. My testimony is organized by staff witness and specific issue, with some overlapping on those issues addressed by more than one staff witness. Issues supported by Staff Witnesses Weiss, Copeland, and Rislov are addressed by Company Witnesses Hervey, Ewers, and Caskey. I have incorporated the revenue requirement impact of the comments by other Company Witnesses into my summary of overall revenue requirements.

4\. Q. Please explain in detail, the organization of your rebuttal testimony.

A. The issues raised in testimony of Staff Witnesses, to which I offer rebuttal are as follows:

<u>Faye D. Brown</u>

1. Inclusion of staff-acknowledged corrections to their recommended revenue increase.
2. Inclusion of anticipated 1984 labor expense and related FICA tax increase.
3. Inclusion of pro forma pension costs.
4. Propriety of normalized versus flow-through accounting for tax timing differences.
5. Determination of interest expense for the calculation of income taxes.

<u>Robert L. Knadle</u>

1. Propriety of excluding non-recurring oil sale profits.
2. The propriety of recognizing the average of the <u>most</u> <u>recent</u> years for a storm damage expense adjustment.
3. The propriety of including charitable contributions as a legitimate and necessary cost of doing business.
4. Determination of the proper level of regulatory expense.

5. Q. Does your rebuttal testimony address any other issues?

A. Yes it does. In addition, I direct comments toward the following issues for which more specific information is known:

<u>Additional Topics</u>

1. Annualizing nuclear plant decommissioning sinking fund accruals consistent with the treatment in Docket No F-3382.
2. Restate nuclear plant decommissioning to exclude Mr. Weiss' 25% contingency adjustment.
3. The inclusion of increased purchased power expense resulting from increased Coordinating Agreement billings from NSP(W) to NSP(M).
4. Recognition of anticipated expense increases due to inflation.
5. Discussion of the current status of the extraordinary repair required at the Monticello generating station.
6. Comment on the current status of the Tyrone amortization and its impact on the Company's rebuttal position.

6. Q. Please explain your treatment of the Staff-acknowledged corrections you mentioned earlier.

A. In response to NSP Information Request No. 5, the Staff has acknowledged necessary corrections to their income statement and rate base. These corrections are required in order for the cost of service detail to be mechanically consistent with Staff's stated position and were the results of misunderstandings and very detailed calculations. The corrections involve the allocation of the Staff's excess capacity adjustment to South Dakota, the tax treatment of the repair allowance amortization, the amount of revenue reduction for oil sale profits, the allocation of actual year interest expense to NSP(W), and the inclusion of a necessary tax depreciation adjustment to properly synchronize it to the provision for deferred taxes in the flow-through adjustment. To properly restate their recommended increase, I show an itemized listing of these corrections on Schedule 3, and post the total adjustment to Column B of the income statement summary on Schedule 2 of my rebuttal Exhibit ___(JDW-2).

7. Q. Please describe the nature of the pro-forma adjustments you included in your original testimony, as detailed in Exhibit ___(JDW-1), in your rebuttal testimony, and Exhibit___(JDW-2).

A. The adjustments are based on the fact that changes in revenues and expenses will occur within 24 months of the historical test year ended June 30, 1982. A recently passed South Dakota statute permits the 24 month time frame rather than the previously allowed 12 month period. All of the pro-forma adjustments detailed in Exhibit___(JDW-1) and Exhibit___(JDW-2) are fully known and measurable, with reasonable certainty. There exists a need for a reasonableness standard for application to known and measurable pro-forma adjustments. This standard would imply with virtually complete certainty that a change will occur, and that the level of change, as it occurs, will closely parallel the filed adjustment as to net income effect. Recognizing and including comprehensive and complete pro-forma adjustments which are known and measurable, with reasonable certainty, is the only way to effectively approach a proper matching of revenues to costs when using a historical test year. Rates from this case will likely go into effect on May 17, 1983, and I have made every attempt to include adjustments to revenues and costs that will be realized in the year immediately following rate implementation, hereafter referred to the "rate year".

8. Q. Does the Staff address the ability of NSP to earn its authorized rate of return?

A. Yes, on page 3 of Ms. Brown's testimony she states:

> "I will present the Staff's determination of the revenue increase required for NSP's South Dakota electric operations which will provide NSP the opportunity to earn the overall rate of return recommended by Mr. Copeland in the proceeding".

9\. Q. If all of Staff's adjustments are accepted as presented will NSP be able to earn its recommended rate of return?

A. No, it would be impossible for NSP to earn its allowed rate of return. At the outset, a number of Staff's adjustments, such as interest synchronization use a hypothetical basis which will never exist. In addition, Staff proposes to exclude very real changes in revenues and expenses which are known and measurable, with reasonable certainty, and which will occur within 24 months following the end of the historical test year or during the rate year. As I address each issue I will discuss the specific way in which the Staff proposed adjustment will prevent the Company from earning its allowed rate of return.

10\. Q. Staff witness Brown has proposed to exclude a labor and FICA tax increase for 1984. How does this compare to the Commission's treatment of labor expense in Docket F-3382?

A. Ms. Brown's adjustment is inconsistent with prior Commission treatment. In Docket F-3382, labor increases reflecting the expected costs during the rate year were allowed. In that case, in which rates were implemented on December 15, 1981, 11 1/2 months or 23/24's of the January 1, 1982 wage increase was allowed by the Commission. This treatment allowed the Company to recover the labor costs actually incurred during the rate year.

Consistent with that treatment the Company requested, in its original filing, that it be allowed 4 1/2 months or 9/24 of an expected January 1, 1984 wage increase. Application of the previously described reasonableness standard would require two questions; (1) will a wage rate change occur on January 1, and (2) what is the level of change that will occur with reasonable certainty. The answer to the first question is yes. The latter question requires some judgement. Simply because January 1, 1984, does not occur prior to the date rates from this case go into effect, is not a sound reason to ignore the fact that increased labor costs will be incurred within eight months following the rate implementation date. Failure to recognize that wages will, with reasonable certainty, increase on January 1, 1984, will prevent NSP from earning its authorized return.

11. Q. Have you included an adjustment to increase labor expense due to a January 1, 1984, wage increase?

A. Yes, NSP's original filing included an adjustment to annualize 1981 and 1982 wage increases, which occurred during the actual year, plus a January 1, 1983 increase at an estimated 6.88%. In addition, an increase for January 1, 1984, was included at 6.88% for 4.5 months, or through May 16, 1984, the end of the rate year. The adjustment to actual test year labor expense originally requested was $924,119. In response to Staff Data Request No. 1, item 25, NSP reported that the actual January 1, 1983 increase was 7.057% rather than the 6.88% as included in the filing. Staff accepted and included the 7.057% which resulted in an adjustment of $711,965 to actual labor expense in the Staff recommended increase. However, Staff failed to include any increase for January 1, 1984 wage rates. The Company's rebuttal restatement includes a January 1, 1984 increase of 4%, a reduction from the original 6.88% in recognition of reduced inflation and potentially lower wage settlements. The 4% represents the low point of a range of 4% to 5.5% provided by the Compensation and Benefits Department within the Company. Data Resources, Inc. (DRI), in its latest forecast, projects that wage rates will increase an average of approximately 5% on January 1, 1984.

This revised adjustment is similar to the original adjustment in that it includes only those months of 1984 included in the rate year or the period of January through May 16, 1984. This wage increase is applied to only those employee levels at of the end of the test year and does not include any promotions which may have occurred since the end of the test year or during the rate year. In this way, the labor adjustment included in Exhibit___ (JDW-2) is absolutely consistent with the intent of the

Commission Order in Docket No. F-3382. This rebuttal adjustment results in a increase in Staff's position of $100,274 and is developed on page 1 of Schedule 4 before being posted to Column D of Schedule 2.

12. Q. How did you treat FICA taxes in your rebuttal Exhibit___(JDW-2)?

A. The amount of FICA tax included has been recomputed to correspond to the labor expense including the January 1, 1984 wage increase. Page 2 of Schedule 4 shows the development of the FICA tax adjustment of $5,805. The result is also posted to Column D of Schedule 2. As recomputed, this adjustment is consistent with the Commission's order in Docket No. F-3382, in that the costs will occur in the rate year. If anything, this adjustment is also conservative, due to the well publicized problems facing the future of the Social Security program. Social Security tax law changes may well result in additional increases in both the FICA wage base and rate in 1983 and 1984, which would increase NSP's FICA tax expense. This adjustment does not include possible wage or FICA rate changes that are not yet known with reasonable certainty.

13. Q. What comments do you have regarding Staff Witness Brown's pension adjustment?

A. In the Company's orginal filing, an adjustment of $110,636 was included to increase the pension expense level, reflecting the amount which will be incurred for the year ended May 16, 1984. Again this adjustment is consistent with the costs which will be incurred during the rate year and is within the 24 month time period statute. The adjustment was based on accruals determined in a completely arm's length manner by the Wyatt Company. Wyatt instructs NSP how much and when to pay the required amounts to Northwestern National Bank in Minneapolis, the Plan's trustee. NSP has no control over the estimate of the pension accruals, as they are determined by Wyatt according to stringent and complex pension and Employee Retirement Income and Security Act (ERISA) laws. Ms. Brown's adjustment to include only pension cost changes up until the effective date of rates for this case will further prevent NSP from earning its allowed rate of return.

14. Q. Are the amounts of pension expense reasonably certain to be a cost of service component in the rate year?

A. Based on actual pension investment performance, employee coverage, and a number of other factors, the Wyatt Company revises its pension accrual requirements each year. In the last four years the average revision has resulted in change of $\pm$ 0.84% in the annual accruals. Clearly this restatment is insignificant and we can conclude that the pension costs in the period ended May 16, 1984, are known and measurable, with reasonable certainty, and should be included in the South Dakota Cost of Service determination.

15. Q. Does your rebuttal Exhibit ___(JDW-2) reflect a restated pension adjustment?

A. Yes, Schedule 5 shows an amount of $109,561 for pension expense which is known and measurable with reasonable certainty. Also shown is the appropriate adjustment to Staff's position of $37,609, which is posted to Column E of Schedule 2.

16. Q. Please describe this restated adjustment.

A. In my restated adjustment, the Company accepts Staff's use of updated information as provided in response to Staff Data Request No. 1, item 26. I have also addressed a concern expressed by Ms. Brown in her response to NSP Data Request No. 5, item 10. In that response, Staff indicated a reluctance to accept an estimate for pension costs to be incurred over a future period. The concern was that more factors than just pension rates were considered in the NSP estimates. NSP interprets Staff's comments to focus on two concerns: 1) the number of employee's could change from the actual year ended June 30, 1982 to the rate year ended May 16, 1984, which would affect pension costs, and 2) the projected pension costs are NSP-estimates. To respond to the Staff's concerns; 1) I have reviewed the employee counts for the two periods I am comparing and adjusted both Staff's and Company's adjustment downward $408 to reflect consistent employee levels, and 2) I reiterate that these costs are not an NSP-estimate, but are instead prepared by the Wyatt Company, over which NSP has no control. NSP accepts Wyatt's amounts and begins payment and accrual in the proper time period.

17. Q. What is the Company's rebuttal position in this case on the normalization versus flow-through argument?

A. The Company accepts, with corrections, Staff's adjustment to flow-through all tax timing differences not requiring normalization by law. NSP strongly believes however, that normalization is the better approach for the treatment of all tax timing differences and clearly is in our customer's best interests.

18. Q. Has staff included a proper amount of interest expense for tax purposes?

A. No, they have not. Staff's proposal to synchronize interest for tax purposes with that interest actually available to the Company for South Dakota electric operations is well intended and appropriate in theory. However, the mechanics of the Staff adjustment are not consistent with interest synchronization as done by the Federal Energy Regulatory Commission or other regulatory commissions.

The actual interest available to the corporation as a deduction for income tax purposes is limited to that which the corporation will pay as a result of its actual short and long term borrowings. Throughout this case and prior Staff recommendations, the emphasis has been to reflect actual taxes and to accept only those adjustments which are known and measurable with reasonable certainty. It is known with absolute certainty that assumed interest deductions associated with hypothetical debt will not be available as an actual tax deduction. Ms. Brown attempts to do two things in her interest synchronization: (1) synchronize interest expense, and (2) reflect the capital structure recommended by Staff Witness Copeland. Mr. Copeland has recommended a reduction in the Company's common equity and has hypothetically rearranged the capital components to reflect 50% debt, 40% common equity and 10% preferred equity as an optimum capital structure for NSP. Even assuming Mr. Copeland is correct in his determination of rate of return, it is inappropriate to consider hypothetical interest.

Mr. Ewers will rebut Mr. Copeland's position. One way of looking at Mr. Copeland's proposal on capital structure is to consider that portion of common equity which he assigns to the debt component as second-class common equity which is assigned the debt rather than equity cost. This second class equity, although assigned a debt cost rate would not have an interest deduction associated with it. This would allow Ms. Brown to recognize Mr. Copeland's recommended capital structure, as well as synchronizing the interest deduction for ratemaking with the actual jurisdictional interest. Schedule 6, page 2 of 2, compares Staff's filed interest calculation with the proper interest calculation described herein.

To impute interest for tax deduction purposes, as Ms. Brown has done, confiscates part of the return requirement, which Mr. Copeland has determined to be appropriate. If Ms. Brown's adjustment is approved by the Commission and assuming all other revenue requirement components to be exactly as allowed, it would be mechanically impossible to earn the return recommended by Mr. Copeland.

19. Q. Do you have any further comments on this subject?

A. Yes. I would like to illustrate this point. Let's assume for a moment, that a utility filed a rate case with a lower than normal, say a 28%, common equity ratio, along with a 60% debt ratio, and a 12% preferred ratio. Staff decided that the common ratio was too low and presented an excessive risk to ratepayers and shareholders. To assist the utility in building common equity they recommended a hypothetical capital structure with 40% common equity included. To achieve this the debt ratio was hypothetically reduced to 50% and the preferred ratio to 10% in order to allow the increased common ratio. When calculating income taxes for the hypothetical utility, would it then be proper to reduce the tax deduction for interest by using a hypothetical 50% debt ratio rather than the utility's actual 60% ratio? Staff's response might be to suggest that actual interest should be used because it is available to the corporation. Thus, if it would be inappropriate to reduce the interest deduction below the actual available, as in the hypothetical, why is it appropriate to increase the interest deduction above the actual amount available as in Staff's adjustment to NSP's case. Any adjustment either way is not proper nor representative of the actual cost of service.

20. Q. Have you recomputed the proper interest deduction?

A. Yes, on Schedule 6, page 1 of 2, in my rebuttal Exhibit____ (JDW-2), I show the proper amount of interest expense and synchronize it to the rate base and CWIP adjustments discussed by Mr. Hervey. The interest expense the Company recommends is based on the capital components and costs as recommended by Mr. Ewers except for that related to short-term debt where Ms. Brown's level and rate has been accepted as being more representative of test year conditions. This computation accurately reflects the actual interest deduction available to NSP in the test year. The adjustment to Staff's interest expense level is also shown on Schedule 6, page 1 of 2, and this adjustment is posted to Column F, of Schedule 2.

21. Q. Staff Witness Knadle has proposed an adjustment to flow profits from non-recurring oil sales back to ratepayers. Please comment on his adjustment.

A. Revenues related to profits from oil sales are non-recurring in nature and unrepresentative of test year conditions. Since it is inappropriate to include such non-recurring items in a jurisdictional cost of service upon which to base future electric rates, the Company eliminated 100% of the revenues in its original filing. Staff has proposed to flow-back one fourth of those revenues in each year for four years, beginning with the test year in this case. Staff also proposes a negative working capital amount be included in rate base for the unamortized portion. Mr. Hervey includes an adjustment to reserve the amount negative working capital in his rebuttal testimony.

22. Q. How did the accounting procedure used by NSP for these oil sales affect ratepayers and shareholders?

A. The accounting treatment used to record these oil sales fairly shared any profits (or losses) between shareholders and ratepayers. In fact, the ratepayers may have even experienced a greater benefit than shareholders.

The purchases of the oil inventories that since were sold occurred over several years at prices that ranged from about 25¢/gallon to almost 90¢/gallon. As these purchases were made they were charged to the appropriate fuel stock account and the weighted average price of fuel on hand was adjusted accordingly (generally upward). When the oil was sold, it was credited back to fuel stocks at the most recent purchase price using a last in first out method (LIFO). Any difference between the original purchase price and the LIFO price, produces a benefit for the ratepayer by reducing the weighted average price of fuel on hand. Any fuel used after the sales were made reflects the benefit in the form of lower costs to ratepayers. The average price of oil on hand prior to the sales was 65¢/gallon. After the sales had been made it was reduced to 41¢/gallon. The average LIFO price was 74¢/gallon.

The profit, recorded as a miscellaneous operating revenue, was generated by the difference between the selling price and the LIFO price that was used to credit fuel stocks. The average selling price was 85¢/gallon. As can be seen, the ratepayer experienced a benefit in lower fuel stock prices by 24¢/gallon, while the shareholders were credited with an 11¢/gallon profit. The Company accounting for these oil sales was fair and reasonable, and needs no further adjustment for accounting and ratemaking.

23. Q. Do you have any further comments on the Staff's oil sale revenue adjustment?

A. Yes, in setting rates for a future period, it is necessary and proper to attempt to eliminate material and non-recurring, revenue and expense items. The fact that it is non-recurring means that it is unrepresentative of test year conditions. Since NSP is not in the business of selling oil, and NSP is not expected to sell oil again in the foreseeable future, the revenues from such a sale are an extraordinary item. It is clear that this is not a component of electric cost of service upon which to set future rates.

Another test that might be applied would be to ask if including the oil sale revenues placed NSP in the position of earning in excess of its allowed rate of return. With a rate of return earned during actual year ended June 30, 1982 of 8.21%, including all of oil sale revenue, it is obvious NSP was not earning excessively, but rather deficiently when compared to the authorized rate of return in Docket No. F-3382 which was 10.16%. If it is Staff's intent to recognize oil sales which were not contemplated in the last rate case, then it is also appropriate to recognize expenses which were not contemplated or allowed by the Commission. The significant difference between the authorized and earned returns in the actual year indicates that many real expenses were not recognized by the Commission Order in Docket No. F-3382. If the Commission is to amortize the oil sales, those expenses, in all fairness, should be similarly amortized. The Staff-proposed oil sale profit amortization adds another item to the long list of Staff adjustments which would prohibit NSP from earning the return authorized in this case. Historically NSP has never earned the return authorized, because of Staff adjustments similar to this. Schedule 7, details the necessary adjustment to exclude 100% of the oil sale revenue. Column G, of Schedule 2 brings it into the income statement Summary Schedule.

24. Q. Please discuss Staff Witness Knadle's storm damage adjustment.

A. Mr. Knadle adjusted the expense level to that of the average of five-years from 1977-1981. In the original filing, the Company included an adjustment using the five period time frame using years 1978 through 1981 and the first 9 months of 1982 actual data as the fifth period. Mr. Knadle states he is using the most recent information available. This cannot be true, since the Company used more recent data in its original adjustment. In order to include the most recent calendar year information possible, I have recomputed the adjustment using the period from 1978 through 1982, calendar years, as the base five-year period. Schedule 8 of my exhibit shows the development of the adjustment to Staff's expense level. The adjustment to include the average of the most recent five-year period is then posted to Column H of Schedule 2.

25. Q. How have your treated charitable contributions in your rebuttal exhibit?

A. I have included charitable contributions, as reflected on Schedule 11, page 1 of 4 in my Exhibit ___(JDW-1), in Column I of Schedule 2 in my Exhibit___(JDW-2). Charitable contributions are a legitimate and necessary cost of doing business for NSP and virtually all large companies. These contributions assist many South Dakota customers on a direct basis, and surely add to the quality of life and benefit all customers in the NSP South Dakota service territory. The Company's position is that the $25,151 is not excessive and is a reasonable test year operating expense.

26. Q. Have you any comments on Mr. Knadle's rate case expense adjustment?

A. Yes I have, Mr. Knadle removed $25,000 from the proposed two year amortization of rate case expenses, as filed, on the basis that actual Staff costs billed to NSP will be $50,000, not the maximum of $75,000 as provided by South Dakota Statute. The Company accepts that adjustment, and its corresponding adjustment to unamortized rate case expense per Mr. Hervey's testimony, on the basis that the reduced costs will be realized. If the Commission believes the billing to NSP for the current case will be $75,000, not $50,000 as Mr. Knadle estimates, the original adjustment, as filed, should be restored.

The Company also accepts Mr. Knadle's correction to the special hearing fund revenue factor. The net of his adjustments is a reduction to the NSP proposed rate year expense in the sum of $6,000.

27. Q. Mr. Knadle referenced the inclusion of overtime labor changes in rate case expense. Have you any comments on that?

A. Yes, NSP has included overtime labor in rate case expense amounts filed and approved in all previous rate cases. This is consistent with the FERC uniform system of accounts and is a legitimate rate case - related cost.

28. Q. What is the basis for including the additional items you referenced earlier?

A. It is NSP's objective to file a rate case that will provide a set of test year results which best simulate the results of the rate year, or the first year during which new rates will be in effect. Unless test revenues and costs are fully adjusted to reflect the relationships which will exist in this immediately future period, NSP will be precluded from earning its allowed rate of return. Many of Staff's adjustments will not allow revenues and costs to reflect their real relationship in the rate year. Adjustments are made as comprehensively as possible and the Company attempts to include information that is as up to date as possible. To fulfill this objective the Company proposes two additional adjustments for changes known and measurable with reasonable certainty. Those additional adjustments involve the Nuclear Plant Decommissioning sinking fund, Coordinating Agreement expense increases, and inflation.

29. Q. Please explain your adjustment to the Nuclear Plant Decommissioning Sinking Fund.

A. Depreciation accruals for the Decommissioning Sinking Fund began in August 1, 1981. Since the test year in this case begins one month earlier on July 1, 1981, it is necessary to add one month's accrual to the amount actually recorded in order to reflect a full year's effect in the test year. In Docket No. F-3382, the Staff accepted, and the Commission ordered, an annualization of the nuclear plant sinking fund accruals. This adjustment to annualize the decommissioning accruals in this case is consistent with Docket No. F-3382. Such an adjustment was inadvertently excluded from the Company's original filing, and reflects a known and measurable change. This adjustment is not an additional adjustment as much as its a fine-tuning of the Company's original position. Recognition of this change is necessary to determine the proper cost of service upon which to base future rates. Schedule 9, in my rebuttal Exhibit____(JDW-2), shows the necessary annualization adjustment of $30,188 to book depreciation. Column J of Summary Schedule 2 also shows the amount. Mr. Hervey also has reflected one half of this change as an adjustment to test year rate base.

30. Q. How does your Income Statement show the depreciation adjustment proposed by Staff Witness Weiss regarding decommissioning?

A. I have included an adjustment to reverse Mr. Weiss' book depreciation exclusion of $74,871 as shown on his Exhibit____

(THW-1), Schedule 2. As discussed by Mr. Ewers, this exclusion is inappropriate. The adjustment is reflected on my Summary Schedule 2 in Column K.

31. Q. Please describe the Coordinating Agreement expense adjustment.

A. Schedule 10 develops an adjustment to purchased power expense levels for expenses which will be incurred by NSP(M) for payments to NSP(W). NSP(W) bills NSP(M) for its share of fixed and variable production and Extra High Voltage transmission (EHV), costs just as NSP(M) bills NSP(W) for its share of those costs. As NSP(W)'s costs increase so will NSP(M)'s. The adjustment of $31,000 reflects labor increases, tax rate changes, and fixed charge increases or decreases which occurred, or will occur on NSP(W)'s books, consistent with those pro-forma adjustments included in this case. These cost changes will be billed to NSP(M) and are now more clearly known than they were at the time of the original filing. Column L of Schedule 2, reflects the adjustment amount in the income statement summary.

32. Q. You mentioned an adjustment for inflation, what have you done there?

A. At the time of the original filing, the Company moderated the requested increase by excluding an inflation adjustment. In the filing, the moderation was stressed as was the need for the Commission to grant substantially all of the requested increase due to the moderation steps taken prior to the filing. Because the Staff has greatly reduced or eliminated Company proposed adjustments, the Company finds it necessary to propose a reasonable inflation adjustment in response to Staff's proposals.

I have included, in my rebuttal exhibit, an adjustment to recognize the very real effects of inflation on expenses not adjusted elsewhere in this case. Inflation has been much lower in the very recent past and is likely to continue to be low into the foreseeable future. However, it is a known fact that price and cost increases, though smaller than in past, are still present in NSP's cost of service. Labor unions are still negotiating contracts with higher labor costs included, State and Local sales taxes on office and shop supplies are increasing, raw materials costs are are still increasing, and many cost factors are still experiencing upward price pressure. The inflation which occurred during the actual test year and throughtout the rate year is known and measurable with reasonable certainty.

The Company has used the Production Price Index (PPI) for finished goods in determining the additional test year expenses for those expenses not otherwise adjusted. The PPI for finished goods is a reasonable index to use for electric utility price changes because it is an index of producer's prices received in primary markets. Primary markets are the first markets in which the producer's products are sold. The PPI measures price changes on commodities which are directly used in the production and sale of electric energy. It is more accurate than all-commodities indices because it reflects a raw material price increase once, rather than several times. An example would be steel scrap. A price increase in steel scrap results in an increased price for sheet steel, and ultimately a price hike in autombiles. An all-commodities price index will reflect this increase three times; once in steel scrap, once in sheet steel, and once in automobiles. On the other hand, the finished goods index used in the Company's inflation adjustment would reflect only the change in automobile prices.

The PPI used here is further relevant to NSP costs because it is as up-to-date as possible. The price data is gathered monthly by a mail questionnaire. Respondents are asked to give the prices net of all discounts at either the freight on board (FOB) production location or the central marketing point. Because the index is based on relevant commodities, is conservative in its finished goods approach, is prepared on a timely basis, and is conservative in its net of discount and FOB production pricing components, it is an appropriate and conservative index to use for measuring reasonably certain expense changes in NSP's rate year.

The PPI for finished goods was reviewed for the actual test year ended June 30, 1982, the time period from June 30, 1982, to the beginning of the rate year on May 17, 1983, and as during the rate year ended May 16, 1984. Historical indices were used through the end of December, 1982, with projected indices through the end of the rate year based on NSP corporate planning assumptions such as growth in the economy, interest rate changes, etc. This results in an even more conservative adjustment because NSP's assumptions resulted in a lower inflation rate than did the use of DRI's assumptions. Indices reflecting price changes do not necessarily result directly in expense changes. Commodities are purchased, some in each month, over a period of time. Price increases occur gradually over time. To properly reflect NSP's expense changes, a factor of 59.67% was applied to each of the inflation rates experienced in the test year, the time between the test year and the rate year, and in the rate year. The factors for each period are:

	Base Inflation	Adjusted Inflation	Cumulative Compound Inflation
Actual TY Ended 6/30/82	2.40%	1.43%	1.43%
7/1/82 to 5/16/83	5.00%	3.00%	4.47%
5/17/83 to 5/16/84	5.00%	3.00%	7.60%

The inflation adjustment of $236,000 as developed on Schedule 11 and posted to Column M of Schedule 2, reflects a factor of 1.076 applied to actual year ended June 30, 1982, test year operating and maintenance expenses not adjusted elewhere in this proceeding. Clearly, the factor used and the approach in this adjustment, which is similar in approach to the inflation adjustment accepted by the Commission's in Docket No. F-3382, is a conservative and reasonable reflection of expense increases NSP will realize in the rate year. Rates in effect during the rate year in this case which do not recognize that a small and reasonable amount of inflation will exist, would be another reason revenues would not match costs.

33. Q. Please explain what is shown in Column N of Summary Schedule 2 in your rebuttal Exhibit___(JDW-2).

A. In Column N I reflect adjustments to plant related items consistent with adjustments Mr. Hervey discusses in his rebuttal testimony. To the extent the Company proposes to include a level of plant investment in addition to Staff's proposal, I have included the income statement effects of those adjustments in Column N of Summary Schedule 2. The items in Column N pertain to the inclusion of an appropriate level of non-revenue producing plant and an annualization of the Split Rock Substation investment.

34. Q. In your direct prefiled testimony you requested that the Commission consider accounting and ratemaking treatment of an extraordinary expense at the Monticello generating station. What is the status of your request?

A. Due to an unforeseen change of the Monticello refueling outage from mid-1983 to early 1984, the repair will not be completed until mid-1984, possibly beyond the end of this case's rate year. As far as the current case is concerned I withdraw any request for specific Commission consideration of this matter. The expense will be isolated, as it occurs, in a deferred debit. In the Company's next rate filing an amortization will be included that will allow NSP to recover this extraordinary cost in revenues to be collected beginning when rates from the next filing go into effect.

35. Q. Have you included an adjustment for the Tyrone amortization?

No, I have not. Stipulation discussions were not complete at the time our rebuttal position was being developed. As Staff has done in their recommendation, I have not included an expense amount for the Tyrone amortization. When the Stipulation on this issue is completed, the proper amount will be added to the Commission's final determination.

36. Q. Does this conclude your proposed rebuttal testimony?

A. Yes it does.

NEXT

DOCUMENT (S)

DISREGARD

BACKGROUND

Exhibit No. ______ (JDW-1)

Witness John D. Winter

Before the Public Utilities Commission of
the State of South Dakota

In the Matter of the Application of Northern States Power Company
for Authority to Increase Rates for Electric Utility
Service in South Dakota

Docket No. ______

COST OF SERVICE
INCOME STATEMENT
AND
OVERALL
REVENUE REQUIREMENTS

November 1982

INDEX TO COST OF SERVICE - INCOME STATEMENT AND REVENUE REQUIREMENT SCHEDULES

<u>Detail of Individual Pro Forma Adjustments</u>

Storm Damage	Schedule 16
Amortization of prior period deferrals in excess of 46%.	Schedule 17
Energy Audit Expenses	Schedule 18
Amortization of IRS Disallowed Repair Allowance	Schedule 19
Nuclear Regulatory Commission related employee changes	Schedule 20
Postal Rate Increase	Schedule 21
Reversal of NRC-required Expenditure	Schedule 22
Telephone Rates	Schedule 23
Purchased Power Expense	Schedule 24
Increase in Other Operating Revenue due to Effect of Appropriate Pro Forma Adjustments on NSP(M) and NSP(W) Coordinating Agreement Billings and affiliation with LSDP	Schedule 25
Restatement of Property Taxes to the Level of Calendar Year 1982 Accruals	Schedule 26
Computation of Federal Income Taxes with Present and Proposed Rates	Schedule 27

Northern States Power Company (Minnesota)
Electric Utility - State of South Dakota
ADJUSTED OPERATING REVENUES, OPERATING EXPENSES,
NET INCOME AND RETURN ON RATE BASE WITH
PRESENT AND PROPOSED RATES
Adjusted Year Ended June 30, 1982
(Dollars in Thousands)

Exhibit ___ (JDW-1)
Schedule I

	Test Year Ended June 30, 1982	
	Present Rates	Proposed Rates
1. Revenues	$ 40,821	$ 45,738
2. Expenses	33,755	36,016
Net Operating Income	$ 7,066	$ 9,722
4. Average Rate Base	$ 96,055	$ 86,055
5. Rate of Return on Average Rate Base	8.21%	11.30%

Northern States Power Company (Minnesota)
Electric Utility - State of South Dakota
OPERATING REVENUES, OPERATING EXPENSES AND
NET INCOME WITH PROPOSED RATES
Adjusted Year Ended June 30, 1982
(Dollars in Thousands)

Exhibit ___ (JDW-1)
Schedule 2

		Adjusted Test Year Ended 6-30-82 With Present Rates (A)	Proposed Increase (B)	Adjusted Test Year Ended 6-30-82 With Proposed Rates (C) (A + B = C)
	OPERATING REVENUES			
	Electric Revenues			
	Base Rates			
1.	Residential	$ 17,078	$ 2,559	$ 19,637
2.	Commercial and Industrial	19,281	2,297	21,578
3.	Public Street and Highway Lighting	401	61	462
4.	Other Sales to Public Authorities	0	0	0
5.	Total Electric Revenues	$ 36,760	$ 4,917	$ 41,677
6.	Other Operating Revenues	4,061	0	4,061
7.	Total Operating Revenues	$ 40,821	$ 4,917	$ 45,738
	OPERATING EXPENSES			
8.	Production	$ 14,163		$ 14,163
9.	Transmission	427		427
10.	Distribution	2,530		2,530
11.	Customer Accounts	1,068		1,068
12.	Customer Information	292		292
13.	Administrative and General	4,238		4,238
	Taxes:			
14.	Real Estate and Personal Property	2,995		2,995
15.	Payroll Taxes	434		434
16.	Federal Income Taxes	1,593	2,261	3,854
17.	Deferred Income Taxes	1,019		1,019
18.	Provision for Depreciation and Amortization	4,996		4,996
19.	Total Operating Expenses	$ 33,755	$ 2,261	$ 36,016
20.	Net Operating Income	$ 7,066	$ 2,656	$ 9,722

Northern States Power Company (Minnesota)
Electric Utility - State of South Dakota
SUMMARY OF ACTUAL NET INCOME AND AS
ADJUSTED AFTER PRO FORMA ADJUSTMENTS
Adjusted Year Ended June 30, 1982
(Dollars in Thousands)

PRO FORMA ADJUSTMENTS TO REFLECT TEST YEAR CONDITIONS

	06/30/82 Actual [A] (1)	Flow Through Treatment [B] (2)	Annualization of Ordered Rates F-3392 [C] (3)	Wage and FICA Increase [D] (4)	Increase in Pension Costs [E] (5)	Advertising Expenses [F] (6)	Charitable Contri-butions [G] (7)	Rate Case Expense & PUC Assess. [H] (8)	Insurance Expense Changes [I] (9)	Tyrone Energy Park Amorti-zation [J] (10)	Deferred Tyrone Cost Amortiza-tion [K] (11)	Storm Damage [L] (12)
Operating Revenues												
Electric Revenues												
Base Rates												
1 Residential	$ 15 503	$	$ 1 575	$	$	$	$	$	$	$	$	$
2 Commercial & Industrial	17 344		1 937									
3 Public Street & Highway Lighting	340		61									
4 Total Electric Revenues	33 187		3 573									
5 Gross Earnings	0											
6 Other Operating Revenues	3 785		(98)									
7 Total Operating Revenues	36 972		3 475									
Operating Expenses												
8 Production	12 461			346						807		
9 Transmission	411			31								
10 Distribution	2 270			225								35
11 Customer Accounts	975			89								
12 Customer Service & Information	267			21		(5)						
13 Administrative & General	3 768			211	122	(35)	25	(21)	150			
Taxes:												
14 Real Estate & Personal Property	2 772											
15 Gross Earnings	0											
16 Payroll Taxes	364			67								
17 Federal & State Income Taxes	1 602	68	1 598	(456)	(56)	18	(12)	7	(69)	(371)	(123)	(16)
18 Deferred Income Taxes	1 271	(90)										
19 Investment Tax Credit Adjustment	558											
20 Provision for Depreciation & Amortization	4 326										267	
21 Total Operating Expenses	31 045	(22)	1 598	534	66	(22)	13	(14)	81	436	144	19
22 Net Operating Income	$ 5 927	$ 22	$ 1 877	$ (534)	$ (66)	$ 22	$ (13)	$ 14	$ (81)	$ (436)	$ (144)	$ (19)

(1) Exhibit ____ (JDW-1), Schedule 4.
(2) Exhibit ____ (JDW-1), Schedule 6.
(3) Exhibit ____ (JDW-1), Schedule 7.
(4) Exhibit ____ (JDW-1), Schedule 8.
(5) Exhibit ____ (JDW-1), Schedule 9.
(6) Exhibit ____ (JDW-1), Schedule 10.
(7) Exhibit ____ (JDW-1), Schedule 11.
(8) Exhibit ____ (JDW-1), Schedule 12.
(9) Exhibit ____ (JDW-1), Schedule 13.
(10) Exhibit ____ (JDW-1), Schedule 14.
(11) Exhibit ____ (JDW-1), Schedule 15.
(12) Exhibit ____ (JDW-1), Schedule 16.

Northern States Power Company (Minnesota)
Electric Utility - State of South Dakota
SUMMARY OF ACTUAL NET INCOME AND AS
ADJUSTED AFTER PRO FORMA ADJUSTMENTS
Adjusted Year Ended June 30, 1982
(Dollars in Thousands)

PRO FORMA ADJUSTMENTS TO REFLECT TEST YEAR CONDITIONS

	Amortization of 46/48% Deferrals [N] (13)	Energy Audit Expenses [H] (14)	IRS Disallowed Repair Allowance [O] (15)	NRC Related Employee Changes [P] (16)	Postal Rate Increase [Q] (17)	Reversal of NRC Expenditures [R] (18)	Telephone Rate Increase [S] (19)	Purchased Power Expenses [T] (20)	Coordinating Agreement Revenues [U] (21)	Restatement of Property Tax [V] (22)	Effects of Changes to Plant Related Items [W] (23)	6/30/82 Adjusted Test Year [X] (24)
Operating Revenues												
Electric Revenues												
Base Rates												
1 Residential	$	$	$	$	$	$	$	$	$	$	$	$ 17 078
2 Commercial & Industrial												19 281
3 Public Street & Highway Lighting												401
4 Total Electric Revenues												36 760
5 Gross Earnings												
6 Other Operating Revenues									374			4 061
7 Total Operating Revenues									374			40 821
Operating Expenses												
8 Production				40		70		(60)			499	14 163
9 Transmission							1	(16)				427
10 Distribution												2 530
11 Customer Accounts					4							1 068
12 Customer Service & Information		9										292
13 Administrative & General							2				16	4 238
Taxes:												
14 Real Estate & Personal Property										127	96	2 995
15 Gross Earnings												0
16 Payroll Taxes				3								434
17 Federal & State Income Taxes	(7)	(4)	(5)	(20)	(2)	(32)	(1)	35	173	(58)	(676)	1 593
18 Deferred Income Taxes	(89)										(504)	588
19 Investment Tax Credit Adjustment											(127)	431
20 Provision for Depreciation & Amortization			92								311	4 996
21 Total Operating Expenses	(96)	5	87	23	2	38	2	(41)	173	69	(385)	33 755
22 Net Operating Income	$ 96	$ (5)	$ (87)	$ (23)	$ (2)	$ (38)	$ (2)	$ 41	$ 201	$ (69)	$ 385	$ 7 066

(13) Exhibit ____ (JDW-1), Schedule 17.
(14) Exhibit ____ (JDW-1), Schedule 18.
(15) Exhibit ____ (JDW-1), Schedule 19.
(16) Exhibit ____ (JDW-1), Schedule 20.
(17) Exhibit ____ (JDW-1), Schedule 21.
(18) Exhibit ____ (JDW-1), Schedule 22.
(19) Exhibit ____ (JDW-1), Schedule 23.
(20) Exhibit ____ (JDW-1), Schedule 24.
(21) Exhibit ____ (JDW-1), Schedule 25.
(22) Exhibit ____ (JDW-1), Schedule 26.
(23) Total of Adjustments Discussed in Mr. Harvey's Testimony and Shown in Exhibit ____ (MWH-1) on Schedules 5, 6, 7, 8, 9, 10, and 11. Also includes effect on A & G System Allocator, MUTUAL, of Rate Base Adjustments to Actual Year 6/82.
(24) Exhibit (JDW-1), Schedule 5.

NORTHERN STATES POWER COMPANY (MINNESOTA)
ELECTRIC UTILITY - STATE OF SOUTH DAKOTA
DETAIL OF OPERATING EXPENSES
ACTUAL YEAR ENDED JUNE 30, 1982
(DOLLARS IN THOUSANDS)

		OUT	IN	ALLOC	TOTAL NSP(M) ELECTRIC UTILITY	SOUTH DAKOTA RETAIL
	OPERATION AND MAINTENANCE EXPENSE					
	PRODUCTION EXPENSE					
1	SUPERVISION & ENGINEERING	OXPSE	XPSE	ZPSE	0	0
	FUEL					
2	CAPACITY COMPONENT	OXFD	XFD	D10	0	0
3	ENERGY COMPONENT	OXFE	XFE	E10	213.294	8.001
4	TOTAL FUEL	OXFT			213.294	8.001
	PURCHASED POWER					
	PURCHASES -					
5	CAPACITY COMPONENT	OXPPD1	XPPD1	D10	1.690	69
6	ENERGY COMPONENT	OXPPE1	XPPE1	E10	48.076	1.803
7	TOTAL PURCHASES	OXPP1			49.766	1.873
	COORDINATING AGREEMENT					
8	CAPACITY COMPONENT	OXPPD2	XPPD2	D10	7.933	325
9	ENERGY COMPONENT	OXPPE2	XPPE2	E10	915	34
10	TOTAL COORD AGREEMENT	OXPP2			8.848	359
	NON-ASSOC. UTILITY REVENUE					
11	CAPACITY COMPONENT	OXPPD3	XPPD3	D10	-3.558	-146
12	ENERGY COMPONENT	OXPPE3	XPPE3	E10	-61.719	-2.315
13	TOTAL NON ASSOC UTIL REV	OXPP3			-65.277	-2.461
14	TOTAL PURCHASED POWER	OXPPT			-6.663	-229
	OTHER PRODUCTION					
15	CAPACITY COMPONENT	OXOPD	XOPD	D10	84.525	3.463
16	ENERGY COMPONENT	OXOPE	XOPE	E10	32.689	1.226
17	TOTAL OTHER PRODUCTION	OXOPT			117.214	4.689
18	TOTAL PRODUCTION EXPENSE	OX10			323.845	12.461
	TRANSMISSION EXPENSE					
19	SUPERVISION & ENGINEERING	OXTSE	XTSE	ZTSE	0	0
	GENERATION STEP-UP					
20	SUBSTATION EXPENSE	OXTSG	XTSG	D10	1.286	53
21	MANITOBA HYDRO REVENUE	OXTLG	XTLG	D10	-2.660	-109
22	OTHER EXPENSE	OXTOG	XTOG	D10	0	0
23	TOTAL GENERATION SETP UP	OXTG			-1.374	-56
	SYSTEM BULK SUPPLY					
24	SUBSTATION EXPENSE	OXTSB	XTSB	D50	5.824	235
25	OTHER EXPENSE	OXTOB	XTOB	D50	0	0
26	TOTAL SYSTEM BULK SUPPLY	OXTB			5.824	235

Northern States Power Company (Minnesota)
Electric Utility - State of South Dakota
ACTUAL OPERATING REVENUES AND EXPENSES ASSIGNED AND/OR ALLOCATED TO THE STATE OF SOUTH DAKOTA RETAIL
Actual Year Ended June 30, 1982
(Dollars In Thousands)

Exhibit ______ (JDW-1)
Schedule 4
Page 1 of 9

			Page Within Schedule
	OPERATING REVENUES		
	Electric Revenues		
	Base Rates		
1.	Residential	$ 15,503	2 of 9
2.	Commercial & Industrial	17,344	2 of 9
3.	Public Street & Highway Lighting	340	2 of 9
4.	Total Electric Revenues	33,187	
5.	Other Operating Revenues	3,785	2 of 9
6.	Total Operating Revenues	$ 36,972	
	OPERATING EXPENSES		
7.	Production	$ 12,461	3 of 9
8.	Transmission	411	3 of 9, 4 of 9
9.	Distribution	2,270	4 of 9
10.	Customer Accounting	975	4 of 9
11.	Customer Service	267	4 of 9
12.	Administrative & General	3,768	4 of 9
	Taxes:		
13.	Real Estate & Personal Property	2,772	6 of 9
14.	Payroll Taxes	364	6 of 9
15.	Federal Income Taxes	1,602	Schedule 27
16.	Deferred Income Taxes	1,271	7 of 9
17.	Investment Tax Credit Adjustment-Net	558	8 of 9, 9 of 9
18.	Provision for Depreciation & Amortization	4,326	5 of 9, 6 of 9
19.	Total Operating Expenses	$ 31,045	
20.	Net Operating Income	$ 5,927	

NORTHERN STATES POWER COMPANY (MINNESOTA)
ELECTRIC UTILITY - STATE OF SOUTH DAKOTA
DETAIL OF OPERATING EXPENSES
ACTUAL YEAR ENDED JUNE 30, 1982
(DOLLARS IN THOUSANDS)

		OUT	IN	ALLOC	TOTAL NSP(M) ELECTRIC UTILITY	SOUTH DAKOTA RETAIL
	OPERATING REVENUES					
1	SALES OF REVENUES-ACTUAL	R01			872,595	33,187
2	SALES OF REVENUES-EFFECTIVE	PROREV	PROREV		0	0
	OTHER OPERATING REVENUES					
3	PRODUCT FUNCTION-CAPACITY	R11D	S11D	D10	52,977	2,171
4	PRODUCT FUNCTION-ENERGY	R11E	S11E	E10	32,509	1,219
5	TRANS STEP-UP FACILITY	R12	S12	D10	0	0
6	TRANSMISSION BULK SUPPLY	R12A	S12A	D50	2,426	98
	DISTRIBUTION FUNCTION					
7	OVERHEAD LINES	R15	S15		1,086	68
8	DIRECT ASSIGNMENT	R16	R16		6,147	229
9	TOTAL OTHER OPER REVENUE	R10			95,145	3,785
10	GROSS EARNINGS	R10A	PTRRT		0	0
11	TOTAL OPER REVENUES	R00			967,740	36,972

NORTHERN STATES POWER COMPANY (MINNESOTA)
ELECTRIC UTILITY - STATE OF SOUTH DAKOTA
DETAIL OF OPERATING EXPENSES
ACTUAL YEAR ENDED JUNE 30, 1982
(DOLLARS IN THOUSANDS)

		OUT	IN	ALLOC	TOTAL NSP(M) ELECTRIC UTILITY	SOUTH DAKOTA RETAIL
	LOCAL					
1	SUBSTATION EXPENSE	OXTSL	XTSL		2.235	233
2	OTHER EXPENSE	OXTOL	XTOL		0	0
3	TOTAL LOCAL	OXTL			2.235	233
4	TOTAL TRANSMISSION EXPENSE	OX50			6.685	411
	DISTRIBUTION EXPENSE					
5	TOTAL DISTRIBUTION EXP	OX60	X60A		49.294	2.270
	CUSTOMER ACCOUNTING EXPENSE					
6	SYSTEM	OX90S	X90S	C10	15	1
7	LOCAL	OX90L	X90L		18.716	974
8	TOTAL CUSTOMER ACCOUNT	OX90			18.731	975
	CUSTOMER SERVICE INFORMATION					
9	SYSTEM	OX93S	X93S	C10	259	13
10	LOCAL	OX93L	X93L		4.129	254
11	TOTAL CUSTOMER SERVICE	OX93			4.388	267
	ADMINISTRATIVE AND GENERAL EXPENSE					
12	SYSTEM	OX92S	X92S	PLTSAL	36.321	1.516
13	LOCAL	OX92L	X92L		8.101	555
14	PROPERTY INSURANCE	OXPI	XPI	D10	5.935	243
15	O&M PENSIONS AND BENEFITS	OXPB	XPB	LABOR	23.235	1.057
16	INJURIES AND CLAIMS	OXIAC	XIAC	C10	3.936	192
17	REGULATORY EXPENSE	OXRE	XRE		1.261	205
18	TOTAL A&G EXPENSE	OX92			78.789	3.768
19	TOTAL O & M EXPENSE	OXT			481.732	20.152

NORTHERN STATES POWER COMPANY (MINNESOTA)
ELECTRIC UTILITY - STATE OF SOUTH DAKOTA
DETAIL OF OPERATING EXPENSES
ACTUAL YEAR ENDED JUNE 30, 1982
(DOLLARS IN THOUSANDS)

EXHIBIT____(JDW-1)
SCHEDULE 4
PAGE 5 OF 9

		OUT	IN	ALLOC	TOTAL NSP(M) ELECTRIC UTILITY	SOUTH DAKOTA RETAIL
	DEPRECIATION EXPENSE					
1	PRODUCTION FUNCTION	DX10	XD10	D10	59,032	2,419
	TRANSMISSION FUNCTION					
2	GENERATION STEP UP	DX51	XD51	D10	2,672	109
3	BULK TRANSMISSION	DX52	XD52	D50	4,850	195
4	AREA SUBTRANSMISSION	DX53	XD53		1,481	152
5	DISTRIBUTION FUNCTION	DX55	XD55		299	2
6	DIRECT ASSIGNMENT	DX56	DX56		21	0
7	TOTAL TRANSMISSION PLT	DX50			9,323	459
	DISTRIBUTION FUNCTION					
	SUBSTATIONS					
8	GENERATION STEP UP	DX61A	XD61A	D10	12	0
9	BULK TRANSMISSION	DX61B	XD61B	D50	178	7
10	AREA SUBTRANSMISSION	DX61C	XD61C		186	24
11	DISTRIBUTION FUNCTION	DX61E	XD61E		3,718	186
12	DIRECT ASSIGNMENT	DX61F	DX61F		193	6
13	VAULTS	DX61G	DX61G		395	21
14	TOTAL DISTRIBUTION SUBS	DX61			4,682	245
	MASS PROPERTY					
15	TOTAL MASS PROPERTY	DX60A	DX60A		19,039	1,046
16	TOTAL DISTRIB FUNCTION	DX60			23,721	1,291
	GENERAL FUNCTION					
17	SYSTEM	DX90S	XD90S	D50	319	13
18	LOCAL	DX90L	XD90L		1,453	108
19	TOTAL GENERAL FUNCTION	DX90			1,772	121
	ELECTRIC COMMON					
20	SYSTEM	DX99S	XD99S	PTD	800	37
21	LOCAL	DX99L	XD99L		451	0
22	TOTAL ELECTRIC COMMON	DX99			1,251	37
23	TOTAL BOOK DEPRECIATION EXP	DX00			95,099	4,326

NORTHERN STATES POWER COMPANY (MINNESOTA)
ELECTRIC UTILITY - STATE OF SOUTH DAKOTA
DETAIL OF OPERATING EXPENSES
ACTUAL YEAR ENDED JUNE 30, 1982
(DOLLARS IN THOUSANDS)

EXHIBIT____(JDH-1)
SCHEDULE 4
PAGE 6 OF 9

		OUT	IN	ALLOC	TOTAL NSP(M) ELECTRIC UTILITY	SOUTH DAKOTA RETAIL
	TAXES OTHER THAN INCOME TAXES					
	REAL ESTATE AND PROPERTY TAXES					
1	PRODUCTION FUNCTION	PT10	TP10	D10	29,831	1,222
	TRANSMISSION FUNCTION					
2	GENERATION STEP UP	PT51	TP51	D10	3,261	134
3	BULK TRANSMISSION	PT52	TP52	D50	5,890	237
4	AREA SUBTRANSMISSION	PT53	TP53		1,800	183
5	DISTRIBUTION FUNCTION	PT55	TP55		360	3
6	DIRECT ASSIGNMENT	PT56	PT56		26	0
7	TOTAL TRANS FUNCTION	PT50			11,337	557
	DISTRIBUTION FUNCTION					
	SUBSTATIONS					
8	GENERATION STEP UP	PT61A	TP61A	D10	6	0
9	BULK TRANSMISSION	PT61B	TP61B	D50	108	4
10	AREA SUBTRANSMISSION	PT61C	TP61C		111	14
11	DISTRIBUTION FUNCTION	PT61E	TP61E		2,256	114
12	DIRECT ASSIGNMENT	PT61F	PT61F		117	4
13	VAULTS	PT61G	PT61G		236	13
14	TOTAL DISTRIBUTION SUBS	PT61			2,834	150
	MASS PROPERTY					
15	TOTAL MASS PROPERTY	PT60A	PT60A		18,957	784
16	TOTAL DISTRIB FUNCTION	PT60			21,791	934
	GENERAL FUNCTION					
17	SYSTEM	PT90S	TP90S	D50	37	1
18	LOCAL	PT90L	TP90L		473	31
19	TOTAL GENERAL FUNCTION	PT90			510	32
	ELECTRIC COMMON					
20	SYSTEM	PT99S	TP99S	PTD	587	27
21	LOCAL	PT99L	TP99L		291	0
22	TOTAL ELECTRIC COMMON	PT99			878	27
23	TOTAL REAL ESTATE & PROPERTY	PT0			64,347	2,772
	OTHER MISCELLANEOUS EXPENSES					
24	REVENUE RELATED TAXES	PTRRT	PTRRT		0	0
25	TOTAL PAYROLL TAXES	Z00	Y00	LABOR	8,007	364
26	REPAIR ALLOWANCE AMORTIZATN	PL0	LP0	RALLC	0	0
27	AMORT UNCOLLECT TYRONE EXP	ARTY	RAIE	RALLC	0	0

NORTHERN STATES POWER COMPANY (MINNESOTA)
ELECTRIC UTILITY - STATE OF SOUTH DAKOTA
DETAIL OF OPERATING EXPENSES
ACTUAL YEAR ENDED JUNE 30, 1982
(DOLLARS IN THOUSANDS)

		OUT	IN	ALLOC	TOTAL NSP(M) ELECTRIC UTILITY	SOUTH DAKOTA RETAIL
	INVESTMENT TAX CREDIT ALLOCATED TO CURRENT INCOME					
1	PRODUCTION - CAPACITY	CI10D	IC10	D10	1,939	79
2	NUCLEAR FUEL - ENERGY	CI10E	IC10E	E10	1,675	63
3	TOTAL PRODUCTION	CI10			3,614	142
	TRANSMISSION FUNCTION					
4	GENERATION STEP UP	CI51	IC51	D10	197	8
5	BULK TRANSMISSION	CI52	IC52	D50	186	7
6	AREA SUBTRANSMISSION	CI53	IC53		60	7
7	DISTRIBUTION FUNCTION	CI55	IC55		9	0
8	DIRECT ASSIGNMENT	CI56	CI56		1	0
9	TOTAL TRANSMISSION PLT	CI50			453	23
	DISTRIBUTION FUNCTION					
	SUBSTATIONS					
10	GENERATION STEP UP	CI61A	IC61A	D10	0	0
11	BULK TRANSMISSION	CI61B	IC61B	D50	2	0
12	AREA SUBTRANSMISSION	CI61C	IC61C		5	1
13	DISTRIBUTION FUNCTION	CI61E	IC61E		99	5
14	DIRECT ASSIGNMENT	CI61F	CI61F		5	0
15	VAULTS	CI61G	CI61G		8	0
16	TOTAL DISTRIBUTION SUBS	CI61			119	6
	MASS PROPERTY					
17	TOTAL MASS PROPERTY	CI60A	CI60A		785	51
18	TOTAL DISTRIB FUNCTION	CI60			904	57
	GENERAL FUNCTION					
19	SYSTEM	CI90S	IC90S	D50	26	1
20	LOCAL	CI90L	IC90L		161	11
21	TOTAL GENERAL FUNCTION	CI90			187	12
	ELECTRIC COMMON					
22	SYSTEM	CI99S	IC99S	PTD	146	7
23	LOCAL	CI99L	IC99L		87	0
24	TOTAL ELECTRIC COMMON	CI99			233	7
	TOTAL INVESTMENT TAX CREDIT					
25	ALLOCATED TO CURRENT INCOME	CI0			5,391	241

NORTHERN STATES POWER COMPANY (MINNESOTA)
ELECTRIC UTILITY - STATE OF SOUTH DAKOTA
DETAIL OF OPERATING EXPENSES
ACTUAL YEAR ENDED JUNE 30, 1982
(DOLLARS IN THOUSANDS)

EXHIBIT____(JDW-1)
SCHEDULE 4
PAGE 7 OF 9

		OUT	IN	ALLOC	TOTAL NSP(M) ELECTRIC UTILITY	SOUTH DAKOTA RETAIL
	PROVISION FOR DEFERRED INCOME TAXES FROM LIBERALIZED DEPRECIATION					
1	PRODUCTION - CAPACITY	PR10	RP10	D10	10.503	430
2	NUCLEAR FUEL - ENERGY	PR10E	RP10E	E10	-10.424	-391
3	TOTAL PRODUCTION PLANT	PR10A			79	39
	TRANSMISSION FUNCTION					
4	GENERATION STEP UP	PR51	RP51	D10	2.273	93
5	BULK TRANSMISSION	PR52	RP52	D50	3.279	132
6	AREA SUBTRANSMISSION	PR53	RP53		1.545	149
7	DISTRIBUTION FUNCTION	PR55	RP55		402	13
8	DIRECT ASSIGNMENT	PR56	PR56		15	0
9	TOTAL TRANSMISSION PLT	PR50			7.514	387
	DISTRIBUTION FUNCTION					
	SUBSTATIONS					
10	GENERATION STEP UP	PR61A	RP61A	D10	4	0
11	BULK TRANSMISSION	PR61B	RP61B	D50	46	2
12	AREA SUBTRANSMISSION	PR61C	RP61C		78	19
13	DISTRIBUTION FUNCTION	PR61E	RP61E		1.157	78
14	DIRECT ASSIGNMENT	PR61F	PR61F		47	1
15	VAULTS	PR61G	PR61G		53	7
16	TOTAL DISTRIBUTION SUBS	PR61			1.385	107
	MASS PROPERTY					
17	TOTAL MASS PROPERTY	PR60A	PR60A		8.778	600
18	TOTAL DISTRIB FUNCTION	PR60			10.163	707
	GENERAL FUNCTION					
19	SYSTEM	PR90S	RP90S	D50	349	14
20	LOCAL	PR90L	RP90L		584	57
21	TOTAL GENERAL FUNCTION	PR90			933	71
	ELECTRIC COMMON					
22	SYSTEM	PR99S	RP99S	PTD	1.535	70
23	LOCAL	PR99L	RP99L		165	-4
24	TOTAL ELECTRIC COMMON	PR99			1.700	66
25	TOTAL PROVISION FOR DEFERRED INCOME TAXES FROM LIB DEPRECIATION	PR0			20.389	1.271

NORTHERN STATES POWER COMPANY (MINNESOTA)
ELECTRIC UTILITY - STATE OF SOUTH DAKOTA
DETAIL OF OPERATING EXPENSES
ACTUAL YEAR ENDED JUNE 30, 1982
(DOLLARS IN THOUSANDS)

		OUT	IN	ALLOC	TOTAL NSP(M) ELECTRIC UTILITY	SOUTH DAKOTA RETAIL
	INVESTMENT TAX CREDIT GENERATED					
1	PRODUCTION - CAPACITY	DI10D	ID10	D10	4,747	194
2	NUCLEAR FUEL - ENERGY	DI10E	ID10E	E10	4,478	168
3	TOTAL PRODUCTION	DI10			9,225	362
4	TRANSMISSION FUNCTION	DI50	ID50	P50	2,550	125
5	DISTRIBUTION FUNCTION	DI60	ID60		4,030	236
6	GENERAL & COMMON FUNCTIONS	DI90	ID90		1,348	75
7	TOTAL INVEST TAX CT(GROSS)	DIS			17,153	798
8	NET INVESTMENT TAX CREDIT	DI00			11,762	558

Northern States Power Company (Minnesota)
Electric Utility - State of South Dakota
ADJUSTED OPERATING REVENUES AND EXPENSES ASSIGNED AND/OR ALLOCATED TO THE STATE OF SOUTH DAKOTA RETAIL
Adjusted Year Ended June 30, 1982
(Dollars in Thousands)

Exhibit _____ (JDW-1)
Schedule 5
Page 1 of 9

			Page Within Schedule
	OPERATING REVENUES		
	Electric Revenues		
	Base Rates		
1.	Residential	$ 17,078	2 of 9
2.	Commercial & Industrial	19,281	2 of 9
3.	Public Street & Highway Lighting	401	2 of 9
4.	Total Electric Revenues	$ 36,760	
5.	Other Operating Revenues	4,061	2 of 9
6.	Total Operating Revenues	$ 40,821	
	OPERATING EXPENSES		
7.	Production	$ 14,163	3 of 9
8.	Transmission	427	3 of 9, 4 of 9
9.	Distribution	2,530	4 of 9
10.	Customer Accounting	1,068	4 of 9
11.	Customer Service	292	4 of 9
12.	Administrative & General	4,238	4 of 9
	Taxes:		
13.	Real Estate & Personal Property	$ 2,995	6 of 9
14.	Payroll Taxes	434	6 of 9
15.	Federal Income Taxes	1,593	Schedule 27
16.	Deferred Income Taxes	588	7 of 9
17.	Investment Tax Credit Adjustment-Net	431	8 of 9, 9 of 9
18.	Provision for Depreciation & Amortization	4,996	5 of 9, 6 of 9
19.	Total Operating Expenses	$ 33,755	
20.	Net Operating Income	$ 7,066	

NORTHERN STATES POWER COMPANY (MINNESOTA)
ELECTRIC UTILITY - STATE OF SOUTH DAKOTA
DETAIL OF OPERATING EXPENSES
ADJUSTED YEAR ENDED JUNE 30, 1982
(DOLLARS IN THOUSANDS)

		OUT	IN	ALLOC	TOTAL NSP(M) ELECTRIC UTILITY	SOUTH DAKOTA RETAIL
	OPERATING REVENUES					
1	SALES OF REVENUES-ACTUAL	R01			888.514	36.760
2	SALES OF REVENUES-EFFECTIVE	PROREV	PROREV		0	0
	OTHER OPERATING REVENUES					
3	PRODUCT FUNCTION-CAPACITY	R11D	S11D	D10	60.005	2.459
4	PRODUCT FUNCTION-ENERGY	R11E	S11E	E10	34.276	1.286
5	TRANS STEP-UP FACILITY	R12	S12	D10	0	0
6	TRANSMISSION BULK SUPPLY	R12A	S12A	D50	2.932	118
	DISTRIBUTION FUNCTION					
7	OVERHEAD LINES	R15	S15		1.086	68
8	DIRECT ASSIGNMENT	R16	R16		3.514	131
9	TOTAL OTHER OPER REVENUE	R10			101.813	4.061
10	GROSS EARNINGS	R10A	PTRRT		0	0
11	TOTAL OPER REVENUES	R00			990.327	40.821

NORTHERN STATES POWER COMPANY (MINNESOTA)
ELECTRIC UTILITY - STATE OF SOUTH DAKOTA
DETAIL OF OPERATING EXPENSES
ADJUSTED YEAR ENDED JUNE 30, 1982
(DOLLARS IN THOUSANDS)

		OUT	IN	ALLOC	TOTAL NSP(M) ELECTRIC UTILITY	SOUTH DAKOTA RETAIL
	OPERATION AND MAINTENANCE EXPENSE					
	PRODUCTION EXPENSE					
1	SUPERVISION & ENGINEERING	OXPSE	XPSE	ZPSE	0	0
	FUEL					
2	CAPACITY COMPONENT	OXFD	XFD	D10	0	0
3	ENERGY COMPONENT	OXFE	XFE	E10	226.599	8.500
4	TOTAL FUEL	OXFT			226.599	8.500
	PURCHASED POWER					
	PURCHASES					
5	CAPACITY COMPONENT	OXPPD1	XPPD1	D10	1.690	69
6	ENERGY COMPONENT	OXPPE1	XPPE1	E10	48.076	1.803
7	TOTAL PURCHASES	OXPP1			49.766	1.873
	COORDINATING AGREEMENT					
8	CAPACITY COMPONENT	OXPPD2	XPPD2	D10	26.160	1.072
9	ENERGY COMPONENT	OXPPE2	XPPE2	E10	915	34
10	TOTAL COORD AGREEMENT	OXPP2			27.075	1.106
	NON-ASSOC. UTILITY REVENUE					
11	CAPACITY COMPONENT	OXPPD3	XPPD3	D10	-3.558	-146
12	ENERGY COMPONENT	OXPPE3	XPPE3	E10	-61.719	-2.315
13	TOTAL NON ASSOC UTIL REV	OXPP3			-65.277	-2.461
14	TOTAL PURCHASED POWER	OXPPT			11.564	518
	OTHER PRODUCTION					
15	CAPACITY COMPONENT	OXOPD	XOPD	D10	93.450	3.829
16	ENERGY COMPONENT	OXOPE	XOPE	E10	35.104	1.317
17	TOTAL OTHER PRODUCTION	OXOPT			128.554	5.146
18	TOTAL PRODUCTION EXPENSE	OX10			366.717	14.163
	TRANSMISSION EXPENSE					
19	SUPERVISION & ENGINEERING	OXTSE	XTSE	ZTSE	0	0
	GENERATION STEP-UP					
20	SUBSTATION EXPENSE	OXTSG	XTSG	D10	1.363	56
21	MANITOBA HYDRO REVENUE	OXTLG	XTLG	D10	-2.660	-109
22	OTHER EXPENSE	OXTOG	XTOG	D10	0	0
23	TOTAL GENERATION SETP UP	OXTG			-1.297	-53
	SYSTEM BULK SUPPLY					
24	SUBSTATION EXPENSE	OXTSB	XTSB	D50	5.774	233
25	OTHER EXPENSE	OXTOB	XTOB	D50	0	0
26	TOTAL SYSTEM BULK SUPPLY	OXTB			5.774	233

NORTHERN STATES POWER COMPANY (MINNESOTA)
ELECTRIC UTILITY - STATE OF SOUTH DAKOTA
DETAIL OF OPERATING EXPENSES
ADJUSTED YEAR ENDED JUNE 30, 1982
(DOLLARS IN THOUSANDS)

EXHIBIT____(JDW-1)
SCHEDULE 5
PAGE 4 OF 9

		OUT	IN	ALLOC	TOTAL NSP(M) ELECTRIC UTILITY	SOUTH DAKOTA RETAIL
	LOCAL					
1	SUBSTATION EXPENSE	OXTSL	XTSL		2.370	248
2	OTHER EXPENSE	OXTOL	XTOL		0	0
3	TOTAL LOCAL	OXTL			2.370	248
4	TOTAL TRANSMISSION EXPENSE	OX50			6.847	427
	DISTRIBUTION EXPENSE					
5	TOTAL DISTRIBUTION EXP	OX60	X60A		53.868	2.530
	CUSTOMER ACCOUNTING EXPENSE					
6	SYSTEM	OX90S	X90S	C10	16	1
7	LOCAL	OX90L	X90L		20.436	1.067
8	TOTAL CUSTOMER ACCOUNT	OX90			20.452	1.068
	CUSTOMER SERVICE INFORMATION					
9	SYSTEM	OX93S	X93S	C10	279	14
10	LOCAL	OX93L	X93L		4.739	278
11	TOTAL CUSTOMER SERVICE	OX93			5.018	292
	ADMINISTRATIVE AND GENERAL EXPENSE					
12	SYSTEM	OX92S	X92S	PLTSAL	40.291	1.697
13	LOCAL	OX92L	X92L		7.781	591
14	PROPERTY INSURANCE	OXPI	XPI	D10	8.500	348
15	O&M PENSIONS AND BENEFITS	OXPB	XPB	LABOR	25.914	1.180
16	INJURIES AND CLAIMS	OXIAC	XIAC	C10	4.845	236
17	REGULATORY EXPENSE	OXRE	XRE		1.241	185
18	TOTAL A&G EXPENSE	OX92			88.572	4.238
19	TOTAL O & M EXPENSE	OXT			541.474	22.718

NORTHERN STATES POWER COMPANY (MINNESOTA)
ELECTRIC UTILITY - STATE OF SOUTH DAKOTA
DETAIL OF OPERATING EXPENSES
ADJUSTED YEAR ENDED JUNE 30, 1982
(DOLLARS IN THOUSANDS)

		OUT	IN	ALLOC	TOTAL NSP(M) ELECTRIC UTILITY	SOUTH DAKOTA RETAIL
	DEPRECIATION EXPENSE					
1	PRODUCTION FUNCTION	DX10	XD10	D10	62.454	2.559
	TRANSMISSION FUNCTION					
2	GENERATION STEP UP	DX51	XD51	D10	2.672	109
3	BULK TRANSMISSION	DX52	XD52	D50	5.076	204
4	AREA SUBTRANSMISSION	DX53	XD53		1.524	195
5	DISTRIBUTION FUNCTION	DX55	XD55		299	2
6	DIRECT ASSIGNMENT	DX56	DX56		21	0
7	TOTAL TRANSMISSION PLT	DX50			9.592	511
	DISTRIBUTION FUNCTION					
	SUBSTATIONS					
8	GENERATION STEP UP	DX61A	XD61A	D10	12	0
9	BULK TRANSMISSION	DX61B	XD61B	D50	178	7
10	AREA SUBTRANSMISSION	DX61C	XD61C		186	24
11	DISTRIBUTION FUNCTION	DX61E	XD61E		3.718	186
12	DIRECT ASSIGNMENT	DX61F	DX61F		193	6
13	VAULTS	DX61G	DX61G		395	21
14	TOTAL DISTRIBUTION SUBS	DX61			4.682	245
	MASS PROPERTY					
15	TOTAL MASS PROPERTY	DX60A	DX60A		19.105	1.112
16	TOTAL DISTRIB FUNCTION	DX60			23.787	1.357
	GENERAL FUNCTION					
17	SYSTEM	DX90S	XD90S	D50	319	13
18	LOCAL	DX90L	XD90L		1.505	160
19	TOTAL GENERAL FUNCTION	DX90			1.824	173
	ELECTRIC COMMON					
20	SYSTEM	DX99S	XD99S	PTD	800	37
21	LOCAL	DX99L	XD99L		452	1
22	TOTAL ELECTRIC COMMON	DX99			1.252	38
23	TOTAL BOOK DEPRECIATION EXP	DX00			98.909	4.637

NORTHERN STATES POWER COMPANY (MINNESOTA)
ELECTRIC UTILITY - STATE OF SOUTH DAKOTA
DETAIL OF OPERATING EXPENSES
ADJUSTED YEAR ENDED JUNE 30, 1982
(DOLLARS IN THOUSANDS)

EXHIBIT____(JDW-1)
SCHEDULE 5

		OUT	IN	ALLOC	TOTAL NSP(M) ELECTRIC UTILITY	SOUTH DAKOTA RETAIL
	TAXES OTHER THAN INCOME TAXES					
	REAL ESTATE AND PROPERTY TAXES					
1	PRODUCTION FUNCTION	PT10	TP10	D10	32.589	1.335
	TRANSMISSION FUNCTION					
2	GENERATION STEP UP	PT51	TP51	D10	3.594	147
3	BULK TRANSMISSION	PT52	TP52	D50	6.845	276
4	AREA SUBTRANSMISSION	PT53	TP53		1.984	202
5	DISTRIBUTION FUNCTION	PT55	TP55		398	4
6	DIRECT ASSIGNMENT	PT56	PT56		28	0
7	TOTAL TRANS FUNCTION	PT50			12.849	629
	DISTRIBUTION FUNCTION					
	SUBSTATIONS					
8	GENERATION STEP UP	PT61A	TP61A	D10	7	0
9	BULK TRANSMISSION	PT61B	TP61B	D50	109	4
10	AREA SUBTRANSMISSION	PT61C	TP61C		112	14
11	DISTRIBUTION FUNCTION	PT61E	TP61E		2.259	114
12	DIRECT ASSIGNMENT	PT61F	PT61F		119	4
13	VAULTS	PT61G	PT61G		237	13
14	TOTAL DISTRIBUTION SUBS	PT61			2.843	150
	MASS PROPERTY					
15	TOTAL MASS PROPERTY	PT60A	PT60A		19.005	809
16	TOTAL DISTRIB FUNCTION	PT60			21.848	959
	GENERAL FUNCTION					
17	SYSTEM	PT90S	TP90S	D50	39	2
18	LOCAL	PT90L	TP90L		508	43
19	TOTAL GENERAL FUNCTION	PT90			547	45
	ELECTRIC COMMON					
20	SYSTEM	PT99S	TP99S	PTD	596	28
21	LOCAL	PT99L	TP99L		296	0
22	TOTAL ELECTRIC COMMON	PT99			892	28
23	TOTAL REAL ESTATE & PROPERTY	PT0			68.725	2.995
	OTHER MISCELLANEOUS EXPENSES					
24	REVENUE RELATED TAXES	PTRRT	PTRRT		0	0
25	TOTAL PAYROLL TAXES	Z00	Y00	LABOR	9.519	434
26	REPAIR ALLOWANCE AMORTIZATN	PL0	LP0	RALLC	92	92
27	AMORT UNCOLLECT TYRONE EXP	ARTY	RAIE	RALLC	267	267

NORTHERN STATES POWER COMPANY (MINNESOTA)
ELECTRIC UTILITY - STATE OF SOUTH DAKOTA
DETAIL OF OPERATING EXPENSES
ADJUSTED YEAR ENDED JUNE 30, 1982
(DOLLARS IN THOUSANDS)

EXHIBIT____(JDW-1)
SCHEDULE 5
PAGE 7 OF 9

		OUT	IN	ALLOC	TOTAL NSP(M) ELECTRIC UTILITY	SOUTH DAKOTA RETAIL
	PROVISION FOR DEFERRED INCOME TAXES FROM LIBERALIZED DEPRECIATION					
1	PRODUCTION - CAPACITY	PR10	RP10	D10	9,783	401
2	NUCLEAR FUEL - ENERGY	PR10E	RP10E	E10	-13,975	-524
3	TOTAL PRODUCTION PLANT	PR10A			-4,192	-123
	TRANSMISSION FUNCTION					
4	GENERATION STEP UP	PR51	RP51	D10	1,653	68
5	BULK TRANSMISSION	PR52	RP52	D50	3,060	123
6	AREA SUBTRANSMISSION	PR53	RP53		779	92
7	DISTRIBUTION FUNCTION	PR55	RP55		166	1
8	DIRECT ASSIGNMENT	PR56	PR56		13	0
9	TOTAL TRANSMISSION PLT	PR50			5,671	284
	DISTRIBUTION FUNCTION					
	SUBSTATIONS					
10	GENERATION STEP UP	PR61A	RP61A	D10	0	0
11	BULK TRANSMISSION	PR61B	RP61B	D50	11	0
12	AREA SUBTRANSMISSION	PR61C	RP61C		27	4
13	DISTRIBUTION FUNCTION	PR61E	RP61E		528	35
14	DIRECT ASSIGNMENT	PR61F	PR61F		37	0
15	VAULTS	PR61G	PR61G		56	1
16	TOTAL DISTRIBUTION SUBS	PR61			659	40
	MASS PROPERTY					
17	TOTAL MASS PROPERTY	PR60A	PR60A		4,884	344
18	TOTAL DISTRIB FUNCTION	PR60			5,543	384
	GENERAL FUNCTION					
19	SYSTEM	PR90S	RP90S	D50	41	2
20	LOCAL	PR90L	RP90L		-3	12
21	TOTAL GENERAL FUNCTION	PR90			38	14
	ELECTRIC COMMON					
22	SYSTEM	PR99S	RP99S	PTD	627	29
23	LOCAL	PR99L	RP99L		303	0
24	TOTAL ELECTRIC COMMON	PR99			930	29
25	TOTAL PROVISION FOR DEFERRED INCOME TAXES FROM LIB DEPRECIATION	PR0			7,990	588

Northern States Power Company (Minnesota)
Electric Utility - State of South Dakota
PRO FORMA ADJUSTMENT TO REGULATORY EXPENSE
Adjusted Year Ended June 30, 1982

Exhibit ____ (JDW-1)
Schedule 12
Page 2 of 2

	Concurrent F-3382 (A)	Amortizations Current Case (B)	Total (C)
1. Balance as of May 15, 1983	$ 51,269(1)	$ 170,807(2)	$ 222,076
2. Amortization to December 31, 1983	$ 51,269	$ 53,378	$ 104,647
3. Amortization to May 15, 1984	0	32,026	32,026
4. Total Rate Case Expense Amortization of First Year New Rate Will Be in Effect	$ 51,269	$ 85,404	$ 136,673
5. Average unamortized rate case expense			$ 153,740(3)

(1)	Total Amortization beginning January 1, 1982	$ 164,061
	1982 Amortization	(82,031)
	Amortization to May 15, 1983	(30,761)
	Balance as of May 15, 1983	$ 51,269

(2)	From: Docket F-3353	$ 11,258
	Docket F-3382	5,942
	Current Case	153,607
		$ 170,807

(3) Beginning of Year $222,076, End of Year $85,404, Average $153,740.

Northern States Power Company (Minnesota)
Electric Utility - State of South Dakota
PRO FORMA ADJUSTMENT TO REGULATORY EXPENSE
Adjusted Year Ended June 30, 1982

1.	Rate Case Expense	$ 136,673	(1)
2.	PUC Assessment Based on Projected Revenues	47,909	(2)
3.	Total Adjusted Expense	$ 184,582	
4.	Actual Regulatory Expense	205,399	
5.	Total South Dakota Adjustment	$ (20,817)	

(1) Exhibit ____ (JDW-1), Schedule 12, Page 2 of 2.

(2)

Present Revenues	$ 36,760,000
Approximate Increase	4,900,000
	$ 41,660,000
PUC Assessment Factor	.00115
	$ 47,909

NORTHERN STATES POWER COMPANY (MINNESOTA)
ELECTRIC UTILITY - STATE OF SOUTH DAKOTA
DETAIL OF OPERATING EXPENSES
ADJUSTED YEAR ENDED JUNE 30, 1982
(DOLLARS IN THOUSANDS)

		OUT	IN	ALLOC	TOTAL NSP(M) ELECTRIC UTILITY	SOUTH DAKOTA RETAIL
	INVESTMENT TAX CREDIT ALLOCATED TO CURRENT INCOME					
1	PRODUCTION - CAPACITY	CI10D	IC10	D10	2,203	90
2	NUCLEAR FUEL - ENERGY	CI10E	IC10E	E10	4,704	176
3	TOTAL PRODUCTION	CI10			6,907	267
	TRANSMISSION FUNCTION					
4	GENERATION STEP UP	CI51	IC51	D10	197	8
5	BULK TRANSMISSION	CI52	IC52	D50	206	8
6	AREA SUBTRANSMISSION	CI53	IC53		60	7
7	DISTRIBU\ION FUNCTION	CI55	IC55		9	0
8	DIRECT ASSIGNMENT	CI56	CI56		1	0
9	TOTAL TRANSMISSION PLT	CI50			473	23
	DISTRIBUTION FUNCTION					
	SUBSTATIONS					
10	GENERATION STEP UP	CI61A	IC61A	D10	0	0
11	BULK TRANSMISSION	CI61B	IC61B	D50	2	0
12	AREA SUBTRANSMISSION	CI61C	IC61C		5	1
13	DISTRIBUTION FUNCTION	CI61E	IC61E		99	5
14	DIRECT ASSIGNMENT	CI61F	CI61F		5	0
15	VAULTS	CI61G	CI61G		8	0
16	TOTAL DISTRIBUTION SUBS	CI61			119	6
	MASS PROPERTY					
17	TOTAL MASS PROPERTY	CI60A	CI60A		789	55
18	TOTAL DISTRIB FUNCTION	CI60			908	61
	GENERAL FUNCTION					
19	SYSTEM	CI90S	IC90S	D50	26	1
20	LOCAL	CI90L	IC90L		164	14
21	TOTAL GENERAL FUNCTION	CI90			190	15
	ELECTRIC COMMON					
22	SYSTEM	CI99S	IC99S	PTD	146	7
23	LOCAL	CI99L	IC99L		87	0
24	TOTAL ELECTRIC COMMON	CI99			233	7
	TOTAL INVESTMENT TAX CREDIT					
25	ALLOCATED TO CURRENT INCOME	CI0			8,711	373

NORTHERN STATES POWER COMPANY (MINNESOTA)
ELECTRIC UTILITY - STATE OF SOUTH DAKOTA
DETAIL OF OPERATING EXPENSES
ADJUSTED YEAR ENDED JUNE 30, 1982
(DOLLARS IN THOUSANDS)

		OUT	IN	ALLOC	TOTAL NSP(M) ELECTRIC UTILITY	SOUTH DAKOTA RETAIL
	INVESTMENT TAX CREDIT GENERATED					
1	PRODUCTION - CAPACITY	DI10D	ID10	D10	4,747	194
2	NUCLEAR FUEL - ENERGY	DI10E	ID10E	E10	4,478	168
3	TOTAL PRODUCTION	DI10			9,225	362
4	TRANSMISSION FUNCTION	DI50	ID50	P50	2,550	130
5	DISTRIBUTION FUNCTION	DI60	ID60		4,030	236
6	GENERAL & COMMON FUNCTIONS	DI90	ID90		1,348	75
7	TOTAL INVEST TAX CT(GROSS)	DIS			17,153	804
8	NET INVESTMENT TAX CREDIT	DI00			8,442	431

Northern States Power Company (Minnesota)
Electric Utility - State of South Dakota
PRO FORMA ADJUSTMENTS TO THE INCOME STATEMENT
REFLECTING FLOW THROUGH TREATMENT OF
DEFERRED TAXES
Adjusted Year Ended June 30, 1982
(Dollars in Thousands)

Exhibit _____ (JDW-1)
Schedule 6

	Actual Year 6/30/82 Normalized (A)	Actual Year 6/30/82 Flow Through (B)	Flow Through Adjustments (C) (1)
OPERATING REVENUES			
1. Total Retail Revenues	$ 33,187	$ 33,187	
2. Other Operating Revenues	3,785	3,785	
3. Total Operating Revenues	$ 36,972	36,972	
OPERATING EXPENSES			
4. Total Operating and Maintenance (O&M) Expenses	$ 20,152	$ 20,152	
Taxes:			
5. Real Estate and Personal Property	$ 2,772	$ 2,772	
6. Payroll Taxes	364	364	
7. Federal Income Tax	1,602	1,670	$ 68
8. Provision for Depreciation	4,326	4,326	
Deferred Taxes:			
9. Production	$ 39	$ 486	$ 447
10. Transmission	387	285	(102)
11. Distribution	707	371	(336)
12. General	71	9	(62)
13. Common	66	29	(37)
14. Total Deferred Taxes	$ 1,270	$ 1,180	$ (90)
15. Total Expenses	30,486	30,464	(22)
16. Operating Income	$ 6,486	$ 6,508	$ 22

(1) Flow through adjustments consist of flowing through all differences between tax and book depreciation not requiring normalization by law.

Northern States Power Company (Minnesota)
Electric Utility - State of South Dakota
ANNUALIZATION OF ORDERED RATES FROM F-3382
Adjusted Year Ended June 30, 1982

Exhibit ____ (JDW-1)
Schedule 7
Page 1 of 2

	Residential (A)	Commercial & Industrial (B)	Street & Highway Lighting (C)	Total South Dakota (D)
1. Annualized Revenues	$16,873,069	$18,991,277	$397,422	$36,261,768
2. Adjustment to Fuel Clause Revenues due to Additional Nuclear Fuel Expenses per Nonrevenue Producing Plant	205,000	290,000	4,000	499,000
3. Total	$17,078,069	$19,281,277	$401,422	$36,760,768
4. Actual Test Year Revenues	15,503,015	17,344,057	340,065	33,187,137
5. Adjustment to South Dakota Revenues	$ 1,575,054	$ 1,937,220	$ 61,357	$ 3,573,631

Northern States Power Company (Minnesota)
Electric Utility - State of South Dakota
SUMMARY OF PRO FORMA ADJUSTMENTS TO
OTHER MISCELLANEOUS REVENUES
Adjusted Year Ended June 30, 1982

Exhibit ___ (JDW-1)
Schedule 7
Page 2 of 2

		Total NSP(M) (A)	South Dakota Allocator (B)	South Dakota Amount (C)
1.	Oil Sale Revenue	$ (2,634,695)	.037509	$ (98,825)
2.	Forfeited Discounts	(11,372)		(11,372)
3.	Annualized Service Connection	11,570		11,570
4.	Total	$ (2,634,497)		$ (98,627)

(1) Production Energy Factor E10. See Exhibit ___ (MAH-1), Schedule 12, Page 2 of 2.

Northern States Power Company (Minnesota)
Electric Utility - State of South Dakota
PRO FORMA ADJUSTMENT TO RECOGNIZE WAGE AND SALARY INCREASES
Adjusted Year Ended June 30, 1982

Exhibit ____ (JDW-1)
Schedule 8
Page 1 of 4

		Total NSP(M) Labor Adjustment(6) (A)	South Dakota Allocation Factor (B)	South Dakota Labor Adjustment (C)
	Production			
	Other Production			
1	Demand	$ 6,244,156	4.0973% (1)	$ 255,842
2	Energy	2,415,054	3.7509% (2)	90,586
3	Total Production	$ 8,659,210		$ 346,428
	Transmission			
4	Generation Step Up	$ 76,685	4.0973% (1)	$ 3,142
5	Bulk Supply	347,313	4.0279% (3)	13,989
6	Local - South Dakota	13,891		13,891
7	All Other	119,417		
8	Total Transmission	$ 557,306		$ 31,022
	Distribution			
9	Local - South Dakota	$ 224,658		$ 224,658
10	All Other	4,308,895		
11	Total Distribution	$ 4,533,553		$ 224,658
	Customer Accounting			
12	System	$ 1,374	4.87308% (4)	$ 67
13	Local - South Dakota	89,250		89,250
14	All Other	1,627,094		
15	Total customer Accounting	$ 1,717,718		$ 89,317
	Customer Service & Information			
16	System	$ 20,390	4.87308% (4)	$ 994
17	Local - South Dakota	20,325		20,325
	All Other	304,874		
	Total Customer Service & Information	$ 345,589		$ 21,319
	Administrative & General			
20	System	$ 3,970,269	4.2117% (5)	$ 167,216
21	Local - South Dakota	44,159		44,159
22	All Other	446,048		
23	Total Administrative & General	$ 4,460,476		$ 211,375
24	Total Adjustment	$20,273,852		$ 924,119

(1) Production Demand D10 Per Exhibit ____ (MAH-1), Schedule 12, Page 2 of 2.
(2 Production Energy E10 " " " " "
(3) Transmission Demand D50 " " " " "
(4) Customer Factor C10 " " " " "
(5) Allocated on PLTSAL Factor for adjusted year 6/82 per Exhibit ____ (MAH-1), Schedule 12, Page 2 of 2.
(6) Per Column C, Exhibit ____ (JDW-1), Schedule 8, Page 2 of 4.

Northern States Power Company (Minnesota)
Electric Utility
PRO FORMA ADJUSTMENT TO RECOGNIZE WAGE AND SALARY INCREASES
Adjusted Year Ended June 30, 1982

Exhibit ____ (JDW-1)
Schedule 8
Page 2 of 4

		Total NSP(M) Electric		
		Actual Year Labor (1) (A)	Adjusted Labor (2) (B)	Labor Adjustment (C) (B - A = C)
	Production			
	Other Production			
1	Demand	$ 42,717,757	$ 48,961,913	$ 6,244,156
2	Energy	16,521,956	18,937,010	2,415,054
3	Total Production	$ 59,239,713	$ 67,898,923	8,659,210
	Transmission			
4	Generation Step Up	$ 524,622	$ 601,307	$ 76,685
5	Bulk Supply	2,376,050	2,723,363	347,313
6	Local - South Dakota	95,029	108,920	13,891
7	All Other	816,960	936,377	119,417
8	Total Transmission	$ 3,812,661	$ 4,369,967	557,306
	Distribution			
9	South Dakota	$ 1,536,937	$ 1,761,595	$ 224,658
10	All Other	29,478,180	33,787,075	4,308,895
11	Total Distribution	$ 31,015,117	$ 35,548,670	4,533,553
	Customer Accounting			
12	System	$ 9,401	$ 10,775	$ 1,374
13	Local - South Dakota	610,580	699,830	89,250
14	All Other	11,131,336	12,758,430	1,627,094
15	Total Customer Accounting	$ 11,751,317	$ 13,469,035	1,717,718
	Customer Service & Information			
16	System	$ 139,491	$ 159,881	$ 20,390
17	Local - South Dakota	139,048	159,373	20,325
18	All Other	2,085,718	2,390,592	304,874
19	Total Customer Service & Infomation	$ 2,364,257	$ 2,709,846	345,589
	Administrative & General			
20	System	$ 27,161,563	$ 31,131,833	$ 3,970,270
21	Local - South Dakota	302,100	346,259	44,159
22	All Other	3,051,518	3,497,565	446,047
23	Total Administrative & General	$ 30,515,181	$ 34,975,657	4,460,476
24	Total Adjustment	$ 138,698,246	$ 158,972,098	20,273,852

(1) Actual 6/30/82 Year Labor per Books and Records.
(2) Adjusted Labor Computed by Applying Increase Factor to Actual Year Labor.
Increase Factor: 1.045421 x 1.068800 x 1.025799 = 1.14617237334
(81/82 factor) (83 factor) (84 factor)

Northern States Power Company (Minnesota)
Electric Utility - State of South Dakota
PRO FORMA ADJUSTMENT TO FEDERAL
INSURANCE CONTRIBUTION ACT TAXES
Adjusted Year Ended June 30, 1982

Exhibit ____ (JDW-1)
Schedule 8
Page 3 of 4

	NSP(M) Total Electric (A)	Labor Allocation Factor (B)	South Dakota (C)
FICA Tax Adjustment			
1. Total FICA Tax Including Adjustments Reflecting Wage and Salary Increases	$ 9,455,651(3)	.045554 (1)	$ 430,743 (1)
2. Actual FICA Tax for year ended June 30, 1982	8,007,454	.045509 (2)	364,411 (2)
3. Adjustment to Reflect Increased FICA Taxes	$ 1,448,197		$ 66,332

(1) Jurisdictional amount is an expression of jurisdictional labor to total Company 6/30/82 adjusted labor per Exhibit ____(MAH-1), Schedule 12, Page 2 of 2.

(2) Jurisdictional amount is an expression of jurisdictional labor to total Company 6/30/82 actual labor per Exhibit ____(MAH-1), Schedule 12, Page 1 of 2.

(3) See Column C, Exhibit ____(JDW-1), Schedule 8, Page 4 of 4.

Northern States Power Company (Minnesota)
Electric Utility - State of South Dakota
PRO FORMA ADJUSTMENT TO RECOGNIZE WAGE AND
SALARY INCREASES
Adjusted Year Ended June 30, 1982

Exhibit ____ (JDW-1)
Schedule 8

		(A)	FICA Rate (B)	FICA Amount (C)
1.	Number of Employees Over 35,400 Limit - Adjusted Year Labor	3,104		
2.	Employee Limit	$ 35,400		
3.	Labor Cost - Number of Employees Over Limit - Social Security Application	$ 109,881,600 (3)	6.7%	$ 7,362,067
4.	Labor Cost - Number of Employees Up to Employee Limit	$ 96,749,614 (1)	6.7%	$ 6,482,224
5.	Total FICA Taxes			$ 13,844,291
6.	Electric - Operating Factor			68.3% (2)
7.	Electric Operating Amount			$ 9,455,651

(1) Per Payroll Accounting analysis.

(2) The relationship between electric operating and total NSP(M) labor expense.

(3) Col. A, Line 1 times Col. A, Line 2.

Northern States Power Company (Minnesota)
Electric Utility - State of South Dakota
PRO FORMA ADJUSTMENT TO INCLUDE INCREASED
PENSION AND BENEFITS COSTS
Adjusted Year Ended June 30, 1982

Exhibit ____ (JDW-1)
Schedule 9

	Year Ending May 31, 1984 (A)	Year Ended June 30, 1982 (B)	Increase (C)
1. Total NSP(M) All Utilities Pension Fund Payments	$ 26,408,050	$ 22,797,700	$ 3,610,350
2. Electric Utility Operating Pension Factor (the % Electric Pension Represents of the Total NSP(M) Pensions)			67.27%
3. Adjustment to Total Company Electric Pensions and Benefits			2,428,682
4. Adjustment due to introduction of Dental Plan			250,584
5. Total adjustment to NSP(M) Pensions and Benefits			$ 2,679,266
6. South Dakota Pension and Benefit Allocation Factor (Allocated on South Dakota Adjusted Year Labor Factor)			4.5554% (1)
7. Adjustment to South Dakota			$ 122,051

(1) Per Exhibit ___(MAH-1), Schedule 12, Page 2 of 2.

Northern States Power Company (Minnesota)
Electric Utility - State of South Dakota
PRO FORMA ADJUSTMENT DECREASING ADVERTISING
TO PROPER JURISDICTIONAL LEVEL
Adjusted Year Ended June 30, 1982

Exhibit ____ (JDW-1)
Schedule 10
Page 1 of 2

	Customer Information Account No. 909 (A)	A&G Account No. 930 (B)	Total (C)
1. Total General Ledger Amount Recorded and Allocated to South Dakota	$ 48,504	$ 54,861	$ 103,365
2. Less: Test Year June 30, 1982 State of South Dakota Included Advertising Expenses per Analysis	$ 43,277	$ 19,507	$ 62,784 (1)
3. Adjustment Decreasing Advertising Expense State of South Dakota	$ 5,227	$ 35,354	$ 40,581

(1) See Exhibit ____ (JDW-1), Schedule 10, Page 2 of 2.

Northern States Power Company (Minnesota)
Electric Utility - State of South Dakota
PRO FORMA ADJUSTMENT DECREASING ADVERTISING
TO PROPER JURISDICTIONAL LEVEL
Adjusted Year Ended June 30, 1982

Included State of South Dakota Advertising Expense by Category

1.	Rate Information	$ 11,014
2.	Energy Information	2,265
3.	Customer Information	2,194
4.	Storm and Outage Information	2,405
5.	Safety Education	14,916
6.	Appliance Conservation	10,985
7.	Budget Helper	5,879
8.	Insulation	380
9.	Energy Conservation	6,682
10.	Energy Audit	419
11.	Ask NSP	5,296
12.	Continuing Education	349
13.	TOTAL	$ 62,784

Northern States Power Company (Minnesota)
Electric Utility - State of South Dakota
PRO FORMA ADJUSTMENT TO INCLUDE ONE HALF
SELECTED DONATIONS IN COST OF SERVICE
Adjusted Year Ended June 30, 1982

Exhibit ____ (JDW-1)
Schedule 11
Page 1 of 4

	Category	
1.	Total United Way, Civic, and Educational Sioux Falls Division Donations Assigned to South Dakota Actual Test Year June 30, 1982	$ 50,301 (1)
2.	NSP Company Share: One-Half Amount Included in Cost of Service	$ 25,151

(1) See Exhibit ___(JDW-1): Schedule 11, Page 4 of 4.

Northern States Power Company (Minnesota)
Electric Utility - State of South Dakota
PRO FORMA ADJUSTMENT TO INCLUDE ONE HALF
SELECTED DONATIONS IN COST OF SERVICE
Adjusted Year Ended June 30, 1982

Exhibit ____ (JDW-1)
Schedule 11
Page 2 of 4

	South Dakota
United Way	
Sioux Empire United Way	$ 17,975
Civic	
Canton Fire Department	20
Lennox Fire Department	15
Fireman Funds, Salem, S.D.	3
Boy Scouts of America, Sioux Falls, S.D.	100
Crippled School Hospital & School Auxiliary, Sioux Falls, S.D.	25
Lennox Community Club, S.F.	250
Garretson Medical Clinic	1,000
Sioux Falls Chamber of Commerce	100
S.F. Chamber of Commerce Marketing Plan	2,000
Civic Fine Arts	200
O'Gorman Booster Club	100
S.D. Council on Economic Education	1,000
Minnehaha County Farm Bureau, S.F.	50
S.D. Chamber of Commerce Business Days Tickets, Pierre	13
S.D. Municipal League	30
S.F. Area Chamber of Commerce	20
S.F. Chamber of Commerce Business Days Tickets	20
Fire Fighters	10
Canton Chamber of Commerce 1977 Donation Returned	(500)
Sioux Chapter Association of Retarded Citizens	50
Fire Fighters Auxiliary Ball	30
Junior Service League	50
NCC Holiday Basketball Tournament	90
O'Gorman Friends	100
S.D. Symphony	40
S.D. Valley Hospital Auxiliary	30
Kiwanis Building Program	300
S.D. Symphony Tickets	40
S.F. Humane Society	35
Subtotal	$ 23,196

Northern States Power Company (Minnesota)
Electric Utility - State of South Dakota
PRO FORMA ADJUSTMENT TO INCLUDE ONE HALF
SELECTED DONATIONS IN COST OF SERVICE
Adjusted Year Ended June 30, 1982

Exhibit ____ (JTW-1)
Schedule 11
Page 3 of 4

	South Dakota
Civic (continued)	
American Legion Boys State	$ 65
Boys Club of S.F.	20
Minn-ia-kota Girl Scout Council	50
El RIAD Circus, Shrine Circus	97
Shrine Circus	205
S.F. Foundation of Christian Athletes	200
VFW Teener Baseball	100
YMCA Fund Drive (Century Club)	1,200
YMCA Worthy Boy - Camp Fund	100
B'nai B'rith Sportsman of the Year Banquet	40
Girls Club Camperships	50
Junior Achievement	59
Brock House Animals	500
S.F. Downtown Development Corporation	4,000
Volunteers of America Day Care Center	4,000
Canistota Development Corporation	150
North American Baptist Seminary	7,500
American Legion Girls State	65
McKennan Hospital Ball	45
Feathers & Follies - Girls Club	40
Civic & Dance Association	100
Sioux Falls Symphony	1,000
Sidewalk Arts Festival	100
Mardi Gras	30
March of Dimes Softball	20
American Legion Uniforms	25
Ashrae Research	60
Progressive Salem Association	20
S.F. Jaycee Foundation	225
S.F. Chamber of Commerce Farm Show	25
S.D. Community on Humanities	100
S.F. Chamber of Commerce - Sponsor Honor Student	20
S.F. Mayors' Prayer Breakfast	20
So. Sioux Kiwanis Club	20
Howard Wood Dakota Relays	50
S.F. Community Playhouse	65
YMCA Leaders Luncheon	22
YMCA Tabloid	50
YMCA Leaders Luncheon	100
Subtotal	$ 20,538

Northern States Power Company (Minnesota)
Electric Utility - State of South Dakota
PRO FORMA ADJUSTMENT TO INCLUDE ONE HALF
SELECTED DONATIONS IN COST OF SERVICE
Adjusted Year Ended June 30, 1982

	South Dakota
Civic (continued)	
Civic Air Patrol	$ 20
Crippled Children's Hospital	35
Salem Athlete Association	15
S.D. Symphony	132
S.F. Swim Team	150
American Cancer Society	330
Firehouse Coffeehouse	100
YMCA Trees	25
Centerville Fire Department	20
Canistota Fire Dept.	10
Alexandria, Fire Dept.	10
Bridgewater Fire Dept.	10
Emerg. Fire Dept.	10
Athletic Banquet, Centerville	10
Marion Jaycee, Marion	5
Junior Achievement, S.F.	1,200
Education	
Augustana College, S.F.	315
Augustana College, S.F.	100
Northern State College, S.F.	25
Sioux Falls College, S.F.	10
S.D. State College, S.F.	35
Education for Tomorrow, S.F.	350
Augustana College Regent	300
Augustana Booster Club	200
S.D. Foundation of Private College	1,000
University of South Dakota Athletic Scholarship	200
Environmental Education Association	25
SD Chamber of Commerce Youth Business Academy	150
Fellows of Augustana College	100
South Dakota State University Electrical Engineering Dept.	1,675
Subtotal Page 4	$ 6,567
Subtotal Page 3	20,538
Subtotal Page 2	23,196
TOTAL	$ 50,301

Northern States Power Company (Minnesota)
Electric Utility - State of South Dakota
INSURANCE EXPENSE CHANGES
Adjusted Year Ended June 30, 1982

Exhibit ____ (JDW-1)
Schedule 13

		Property Insurance (A)	Injuries & Damages (B)
1.	1983 Insurance Premiums	$ 6,559,250	$ 1,781,607
2.	1983 NEIL II Insurance Premiums	1,900,000	
3.	Total 1983 Insurance Premiums	$ 8,459,250	$ 1,781,607
4.	Actual Insurance Premiums recorded in the test year	5,893,791	1,600,942
5.	Adjustment to Actual amounts	$ 2,565,459	$ 180,665
6.	1983 Claims		$ 957,000
7.	Actual Claims during the test year		840,224
8.	Adjustment for Projected Claims		$ 116,776
9.	1983 Injury Compensation		$ 1,200,000
10.	Actual test year Injury Compensation		588,393
11.	Adjustment for Projected Injury Compensation		$ 611,607
12.	Total Adjustments to Insurance Expenses (line 5 + line 8 + line 11)	$ 2,565,459	$ 909,048
13.	South Dakota Factors	4.0973% (1)	4.873% (2)
14.	Impact on South Dakota Insurance Expenses	$ 105,115	$ 44,298

(1) Allocated on Production Demand Factor D10. See Exhibit ___(MAH-1), Schedule 12, Page 2 of 2.
(2) Allocated on Customer Factor C10. See Exhibit ___(MAH-1), Schedule 12, Page 2 of 2.

Northern States Power Company (Minnesota)
Electric Utility - State of South Dakota
PRO FORMA ADJUSTMENT TO PURCHASED POWER REFLECTING
THE AMORTIZATION OF ABANDONMENT COSTS
ASSOCIATED WITH TYRONE ENERGY PARK
Adjusted Year Ended June 30, 1982

Exhibit ____ (JDW-1)
Schedule 14

1. Effect on Books and Records Due to Tyrone Reversals and Restatements recorded in December, 1981	$ (21,490,133)
2. NSP(M) share of Actual billings for Tyrone from NSP(W) recorded during the test year	8,873,861
3. Net effect on NSP(M) books and records of Tyrone entries recorded during the test year	$ (12,616,272)
4. Adjustment to eliminate non-recurring prior and current period entries	$ 12,616,272
5. Restated Tyrone Amortization for the test year.	7,072,172
6. Required Adjustment to Restate Purchased Power Expense at the correct level	$ 19,688,444
7. South Dakota Factor (1)	4.0973%
8. South Dakota Impact	$ 806,695

(1) Production Demand Factor D10. See Exhibit___(MAH-1); Schedule 12, Page 2 of 2.

Northern States Power Company (Minnesota)
Electric Utility - State of South Dakota
PRO FORMA ADJUSTMENT TO INCLUDE AMORTIZATION
OF DEFERRED TYRONE RECOVERY
Adjusted Year Ended June 30, 1982

Exhibit ____ (JDW-1)
Schedule 15

	F-3353 11/23/80-12/15/81 (A)	F-3382 12/15/81-5/17/83 (B)	Total (C)
1. South Dakota Monthly Amortization Amortization	$ 23,352	$ 25,724	
2. Number of Deferred Months	13	17.5	
3. Total Amortization	303,576	450,170	
4. Carrying Charge	21,583 (1)	122,613 (1)	
5. Total to be Amortized as of 5-17-83	$ 325,159	$ 572,783	$ 897,942
6. Monthly Amortization while accruing carrying charges @ 1.1971% per month on unamortized portion over 55.5 months			$ 22,238
7. Test Year Amount			$ 266,856

(1) Monthly Compound Rate of 1.1362% Applied to the Deferred Accumulated Balance of Case F-3353. Monthly Compound Rate of 1.1971% for Case F-3382 per Ordered Capital Structure. Both Rates Computed and Applied are Consistent with Settlement Agreement in Docket F-3353.

8141150382

Northern States Power Company (Minnesota)
Electric Utility - State of South Dakota
PRO FORMA ADJUSTMENTS TO DISTRIBUTION
O&M REFLECTING ABNORMAL STORM DAMAGE
DURING YEAR ENDED 6/30/82
Adjusted Year Ended June 30, 1982

Exhibit ____ (JDW-1)
Schedule 16

		Distribution
	Storm damage expense incurred during period 1978 - 9/30/82	
1.	Year 1978	$ 72,283
2.	Year 1979	24,518
3.	Year 1980	61,701
4.	Year 1981	30,799
5.	Year 1982 through 9/30/82	78,117 (1)
6.	Total five-year period	$ 267,418
7.	Average storm damage expense incurred over five-year period 1978 - 9/30/82	53,484
8.	Year ended June 30, 1982 actual storm damage per Company books	18,701
9.	Adjustment to increase storm damage expense (line 7 less line 8)	$ 34,783

(1) Includes extraordinary expense of July, 1982 storm. Excludes balance of 1982.

Northern States Power Company (Minnesota)
Electric Utility - State of South Dakota
PRO FORMA ADJUSTMENT TO PROVISION FOR DEFERRED INCOME TAXES DUE TO AMORTIZATION OF TAX TIMING DIFFERENCES MADE IN EXCESS OF 46 PER CENT
Adjusted Year Ended June 30, 1982
(Dollars in Thousands)

Exhibit ____ (JDW-1)
Schedule 17

		Adjustment to Provision for Deferred Income Tax (A)	South Dakota Factor (B)	South Dakota Amount (C)
	Production:			
1.	Production Excluding Nuclear Fuel	$ (1,450)	.040973 (1)	$ (59)
2.	Nuclear Fuel	8	.037509 (2)	0
3.	Total Production	$ (1,442)		$ (59)
	Transmission:			
4.	Generation Step-Up	$ (41)	.040973 (1)	$ (2)
5.	Bulk Supply	(153)	.040279 (3)	(6)
6.	Direct Asignments-South Dakota	(4)		(4)
7.	All Other	(47)		0
8.	Total Transmission	$ (245)		$ (12)
	Distribution:			
9.	Generation Step-Up	$ 0	.040973 (1)	$ 0
10.	Bulk Supply	(3)	.040279 (3)	0
11.	Direct Assignments-South Dakota	(17)		(17)
12.	All Other	(323)		0
13.	Total Distribution	$ (343)		$ (17)
	General:			
14.	System	$ 0	.040279 (3)	$ 0
15.	Direct Assignments-South Dakota	0		0
16.	All Other	(26)		0
17.	Total General	$ (26)		$ 0
	Common:			
18.	System	$ (14)	.046274 (4)	$ (1)
19.	Direct Assignments-South Dakota	0		0
20.	All Other	(6)		0
21.	Total Common	$ (20)		$ (1)
22.	Total Electric	$ (2,076) (5)		$ (89)

(1) Production Demand Factor D10. See Exhibit ____(MAH-1), Schedule 12, Page 2 of 2.
(2) Production Energy Factor E10. " " " " "
(3) Transmission Demand Factor D50. " " " " "
(4) Prod., Trans., Dist. Factor PTD. " " " " "
(5) Seven Month Amount of Excess Deferral per Docket F-3382; Exhibit 24 (FDB-2), Schedule 4, Column C, Line 2.

Northern States Power Company (Minnesota)
Electric Utility - State of South Dakota
PRO FORMA ADJUSTMENT TO INCLUDE
ANNUALIZED ENERGY AUDIT EXPENSES
Adjusted Year Ended June 30, 1982

Exhibit ____ (JDW-1)
Schedule 18

		Sioux Falls Division	South Dakota Allocation Factor	South Dakota Amount
		A	B	C
1.	South Dakota Energy Audit Expense			$ 6,508
2.	General Office Expense Associated with South Dakota Energy Audits	$ 54,000	4.84%	2,614
3.	Total Energy Audit Expense			$ 9,122

(1) Allocated on 1981 Actual Space Heating Customer Factor.

Exhibit ________ (JDW-1)
Schedule 19

Northern States Power Company (Minnesota)
Electric Utility - State of South Dakota
PRO FORMA ADJUSTMENT TO RESTATE AMORTIZATION OF DISALLOWED REPAIR ALLOWANCE
AND WORKING CAPITAL REQUIREMENT
Adjusted Year Ended June 30, 1982
(Dollars in Thousands)

	Original Amount Taken A(1)	Final Amount Disallowed B(2)	Difference C (A-B=C)	Tax Rate D(1)	South Dakota Allocator E(1)	Amount Allowed F (C X D X E=F)	Allowable Flow-Through South Dakota G(1)	Amount Flowed-Through South Dakota H(1)	Difference I (H-G=I)	Period Rates in Effect J	Actual Amount Recoverable K ((I÷12) X J)
Docket F-3108:											
1. 1975	$ 15,567	$ 6,638	$ 8,929	.51514	.0391	$ 180	$ 36	$ 63	$ 27	32.5 mos	$ 73
2. 1976	15,407	7,158	8,249	.51514	.0391	166	167	313	147	32.5 mos	398
Docket F-3353:											
3. 1975 & 1976	30,974	13,795	17,179								
4. 1977	17,747	7,418	10,329								
5. 1978	17,927	3,802	14,125								
6. 1979	12,957	853	12,104								
7. Total	$ 79,605	$ 25,868	$ 53,737								
8. Average	$ 15,921	$ 5,174	$ 10,747	.46	.046159	$ 228	$ 228	$ 273	$ 45	12.5 mos	47
9. Total											518
10. Amount Amortized F-3302 12/81 - 5/83 (18 mos) @ ($129)											194 (3)
11. Remaining Amount to Recover @ 42 mos											$ 324
12. Annual Recovery - 42 mos Beginning 5/83.											$ 92
13. End of Year Amount											229 (4)
14. Average Working Capital Requirement											$ 275 (5)

(1) Per Docket No. F-3302 Staff Exhibit 25.
(2) Per Settlement with IRS.
(3) Reflects 18 mos of 5 year Amortization @ $129/year per Staff Exhibit 25.
(4) Line 11 less Line 12.
(5) (Line 11 plus Line 13) ÷ 2.

Northern States Power Company (Minnesota)
Electric Utility - State of South Dakota
PRO FORMA ADJUSTMENT TO RECOGNIZE NUCLEAR REGULATORY COMMISSION (NRC) RELATED EMPLOYEE CHANGES RESULTING IN INCREASED LABOR AND FICA TAXES
Adjusted Year Ended June 30, 1982

Exhibit ____ (JDW-1)
Schedule 20

	NSP(M) (A)	South Dakota Allocation Factor (B)	South Dakota (C)
Labor Expense Adjustment			
1. Number of Additional Employees Required due to NRC requirement:			
Total	27		
2. Average Annual Power Production Wage Adjusted for Labor Increases for the Test Year. (1)	$ 36,228		
3. Additional Labor Expense	$ 978,156	(2) 4.0973%	$ 40,078
FICA Tax Adjustment			
4. Additional Employees Required	27		
5. Wage Limit on FICA Taxes	$ 35,400		
6. Additional FICA Base Labor	$ 955,800		
7. FICA Tax Rate	6.7%		
8. Additional FICA Taxes	$ 64,039	(3) 4.5554%	$ 2,917

(1)	Monthly rate as of June 30, 1982	$ 2,754
	1983 Labor Increase Factor-Test Year	1.0688
	1983 Monthly Rate	$ 2,943
	1984 Labor Increase Factor-Test Year	1.025799
	Test Year	$ 3,019
		12
	Test Year	$ 36,228

(2) South Dakota Production Demand Factor D10, Per Exhibit ____ (MAH-1), Schedule 12, Page 2 of 2.
(3) South Dakota Labor Factor, Per Exhibit ____ (MAH-1), Schedule 12, Page 2 of 2

Northern States Power Company (Minnesota)
Electric Utility - State of South Dakota
PRO FORMA ADJUSTMENT TO ANNUALIZE POSTAL RATE INCREASE
Adjusted Year Ended June 30, 1982

Exhibit ____ (JDW-1)
Schedule 21

	Actual Postal Expense for the Four Month Period 7/1/81 - 10/31/81 A	Percent Increase (1) B	Postal Expense Increase C
South Dakota Postal Expense	$ 36,820	11.11%	$ 4,091

(1) To reflect postage increase from 18¢ to 20¢ effective November 1, 1981.

Northern States Power Company (Minnesota)
Electric Utility - State of South Dakota
PRO FORMA ADJUSTMENT TO PROPERLY RESTATE PRODUCTION EXPENSE AND RATE BASE REQUIRED BY NRC REVERSAL ENTRIES
Adjusted Year Ended June 30, 1982

Exhibit ____ (JDW-1)
Schedule 22

	Total NSP(M) Electric Utility (A)	South Dakota Allocation Factor (B)	South Dakota Amount (C)
1. Total Operating Expense Adjustment to Correct Prior Period Restatements Recorded in December, 1981 and February, 1982	$ 1,702,839	4.0973% (1)	$ 69,770
2. Adjustment to Beginning of Year Plant Investment	$ 1,702,839	4.0973% (1)	$ 69,770
3. Average Rate Base Adjustment (2)	$ 851,420	4.0973%	$ 34,885

(1) Demand Allocation Factor D10, See Exhibit ___(MAH-1), Schedule 12, Page 2 of 2.

(2) One-Half of Line 2.

Northern States Power Company (Minnesota)
Electric Utility - State of South Dakota
PRO FORMA ADJUSTMENT TO REFLECT THE EFFECT OF
OTHER ADJUSTMENTS ON COORDINATING
AGREEMENT BILLINGS
Adjusted Year Ended June 30, 1982
(Dollars in Thousands)

Exhibit ____ (JDW-1)
Schedule 25

		Total NSP(M) (A)	South Dakota Allocation Factor (B)	South Dakota (C)
1.	Coordinating Agreement Revenues - Demand Restated	$ 56,310	(1) 4.0973%	$ 2,307
	Less:			
2.	Actual Coordinating Agreement Revenues - Demand	52,977	4.0973%	2,171
3.	Adjustment to Coordinating Agreement Revenues - Demand	3,333	4.0973%	136
4.	LSDP Savings	3,695	4.0973%	151
5.	Total Adjustment to Coordinating Agreement Revenues - Demand	$ 7,028		$ 287
6.	Coordinating Agreement Revenues - Energy Restated	$ 37,217	(2) 3.7509%	$ 1,396
	Less:			
7.	Actual Coordinating Agreement Revenues - Energy	32,509	3.7509%	1,219
8.	Adjustment to Coordinating Agreement Revenues - Energy	4,708	3.7509%	177
9.	LSDP Savings	(2,941)	3.7509%	(110)
10.	Total Adjustment to Coordinating Agreement Revenues - Energy	$ 1,767		$ 67
11.	Coordinating Agreement Revenue Bulk Power - Restated	$ 2,932	(3) 4.0279%	$ 118
	Less:			
12.	Coordinating Agreement Revenue Bulk Power - Actual	2,426	4.0279%	98
13.	Total Adjustment to Coordinating Agreement Revenue Bulk Power	$ 506		$ 20
14.	Total Adjustment to Other Revenues - Coordinating Agreement (Lines 5 + 10 + 13)	$ 9,301		$ 374

(1) Production Demand Factor D10. Exhibit ___(MAH-1), Schedule 12, Page 2 of 2.
(2) Energy Factor E10. " " "
(3) Transmission Demand Factor D50. " " "

Northern States Power Company (Minnesota)
Electric Utility - State of South Dakota
COMPUTATION OF FEDERAL INCOME TAXES WITH
PRESENT AND PROPOSED RATES
Adjusted Year Ended June 30, 1982
(Dollars in Thousands)

Exhibit ____ (JDW-1)
Schedule 27

		State of South Dakota Electric		
		Present Rates		Proposed Rates
		6/30/82 Actual	6/30/82 Adjusted	6/30/82 Adjusted
1.	Average Rate Base	$ 73,931	$ 86,055	$ 86,055
2.	Average Construction Work in Progress	0	8,276(1)	8,276(1)
3.	Total Rate Base for Interest Expense Calculation	73,931	94,331	94,331
4.	Amount Represented by Debt @ .4548 - 6/30/82 Actual; .4554 - 6/30/82 Adjusted	33,624	42,958	42,958
5.	Amount Represented by Preferred Stock - $3.60 Series @ .0126 6/30/82 Actual; .0117 - 6/30/82 Adjusted	932	1,104	1,104
6.	Interest costs @ .0815 - 6/30/82 Actual; .0828 - 6/30/82 Adjusted	2,740	3,557	3,557
7.	Preferred Dividends Paid on $3.60 Series @ .0358 (P)	33	40	40
8.	NET OPERATING INCOME - BEFORE INCOME TAXES	7,529	8,660	13,577
Add:				
9.	Provision for Depreciation and Amortization	4,326	4,637	4,637
10.	Nuclear Fuel Consumed	1,496	2,418	2,418
11.	Deferred Income Taxes	1,271	588	588
12.	MV & DP Depreciation Charge Back	73	73	73
13.	Barge Depreciation Charged to Operations	4	4	4
14.	Investment Tax Credit Adjustment Net	558	431	431
15.	Repair Allowance Amortization	0	92	92
16.	TOTAL	7,728	8,243	8,243
Less:				
17.	Tax Deductions	7,287	8,123	8,123
18.	Interest Cost	2,740	3,556	3,556
19.	TOTAL	10,027	11,679	11,679
20.	NET TAXABLE INCOME (N)	5,230	5,224	10,141
	COMPUTATION OF INCOME TAXES			
21.	Preliminary Taxes @ .46(N) - .14(P)	2,401	2,397	4,658
22.	Less Investment Tax Credit - Generated	798	804	804
23.	FINAL FEDERAL INCOME TAXES	$ 1,603	$ 1,593	$ 3,854

(1) Consistent With Use of Gross of Tax AFUDC Rate as Discussed in Mr. Hervey's Testimony.

NEXT

DOCUMENT (S)

DISREGARD

BACKGROUND

Prepared Testimony of
John D. Winter

Before the Public Utilities Commission of
the State of South Dakota

In the Matter of the Application of Northern States Power Company
for Authority to Increase Rates for Electric Utility
Service in South Dakota

Docket No. ____________________

COST OF SERVICE
INCOME STATEMENT
AND
OVERALL
REVENUE REQUIREMENTS

November 1982

Docket No________
Prepared Testimony of
John D. Winter

1. Q. Please state your name, business address, and position with Northern States Power Company (Minnesota) (NSP).

A. John D. Winter, 414 Nicollet Mall, Minneapolis, Minnesota 55401. I am a Senior Rate Analyst in the Electric Revenue Requirements Department.

2. Q. What are your duties?

A. I am responsible for preparing cost of service studies for our various electric utility jurisdictions, as well as performing occasional special studies. This includes gathering and verifying the necessary revenue, expense, and plant data, and directly assigning or allocating this data to the proper utility and jurisdiction.

3. Q. What is your educational and professional background?

A. I am a graduate of the University of Minnesota, Minneapolis, with a Bachelor's Degree in Business Administration - Accounting. I hold a certificate as a Certified Public Accountant in the State of Minnesota. I am a member of the American Institute of Certified Public Accountants and the Minnesota Society of Certified Public Accountants.

4. Q. What is your work experience with Northern States Power Company?

A. I began my employment at NSP as an Accounting Specialist in Material Accounting in June, 1976. I worked in the areas of invoice processing, inventory control, and preparation of the department operating budget. In January, 1978, I was promoted to Accountant Senior in General Accounting where I was responsible for fuel accounting reports, and fuel clause adjustments, as well as special projects. In June, 1979, I transferred to Revenue Requirements as a Rate Analyst and was promoted to my current position in December, 1980. In Revenue Requirements I have been primarily responsible for the technical preparation supporting revenue requirements in South Dakota Docket Nos. F-3353, F-3382, and the current case. I have also been involved in all of the Minnesota and North Dakota electric rate cases filed since joining the department.

5. Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present financial data relating to the cost of service and revenue requirements of Northern States Power Company in connection with providing electric utility service in the State of South Dakota. My testimony specifically supports the income statement portion of the South Dakota cost of service. I also testify to the additional revenue requirements of $4,917,000, an increase of about 13.4%, necessary to provide an overall return on rate base of 11.30% as recommended by Mr. Ewers in Exhibit ___(BJE-1). Mr.

Hervey presents testimony and financial data supporting the rate base portion of the cost of service.

6. Q. Please explain the organization of your testimony.

A. My testimony consists of the following parts:

1. An outline of conclusions from our study of NSP's need for rate adjustment in South Dakota.

2. A discussion of fundamental principles and practices recognized in the study, and

3. A detailed discussion of Exhibit ___(JDW-1) which shows and sets forth NSP's need for a rate increase and supports the adjustments for known and measurable changes.

Outline of Conclusions

7. Q. Will you please outline the conclusions resulting from the study and analysis of NSP's South Dakota utility operations?

A . The results of our study, based on adjusted year ended June 30, 1982, shows that with present rates, NSP would earn only an 8.21% rate of return on an average rate base and a return of 8.63% on common equity. This is clearly inadequate in view of Mr. Ewers' testimony that an overall rate of return of 11.30%, reflecting a return on common equity of 16.00%, is needed to attract and maintain capital on reasonable terms. An overall

increase in revenues of $4,917,000, or about 13.4%, is necessary to earn the 11.30% overall rate of return recommended by Mr. Ewers.

Fundamental Principles

8. Q. Please continue to the second part of your testimony and discuss the fundamental principles and practices recognized in this study from which you have drawn your conclusions.

A. Two of the fundamental principles and practices are:

1. The need for allocations to determine a jurisdictional cost of service, and

2. The need for certain pro forma adjustments to the income statement when a historical test year is required.

9. Q. Please describe how you've allocated your income statement items and adjustments to South Dakota.

A. I have used allocation factors consistent with those discussed in Mr. Hervey's testimony. The factors chosen for each revenue and expense component, not directly assigned, are those which will allocate the proper amount of that component to South Dakota. The factor names used may be found within Schedule 4 for the actual year components and Schedule 5 for the adjusted test year components. The factor names may then be cross-referenced to Exhibit ___(MAH-1), Schedule 12, which shows their computation.

Pro Forma Adjustments

10. Q. You mentioned a need for certain pro forma adjustments when a historic test year is used for ratemaking. Please discuss the specific pro forma adjustments to which you refer.

A. The pro forma adjustments to which I refer relate to income statement changes that can be determined with reasonable certainty and are within the Commission's guidelines as discussed by Mr. Hervey.

The changes pertaining to the income statement include adjustments to:

1. Flow through treatment of certain tax-timing differences
2. Annualize retail rates ordered in Docket F-3382.
3. Operating labor
4. Pension costs
5. Advertising expenses
6. Charitable contributions
7. Regulatory expenses
8. Insurance premiums
9. Amortize abandonment costs associated with Tyrone, a proposed nuclear power plant.
10. Include an amortization of deferred Tyrone costs.
11. Storm damage
12. Amortize the remainder of tax deferrals made in prior years at a tax rate in excess of 46%.
13. Include energy audit expenses.
14. Include the amortization of disallowed repair allowance.
15. Labor expense due to employees added because of Nuclear Regulatory Commission (NRC) requirements
16. Postage costs
17. Production expense to reflect the reversals of prior period NRC-required construction expenditures.
18. Telephone expenses
19. Purchased power expense

21. Property taxes
22. Expenses related to plant investment and related items included as pro forma adjustments in Exhibit ___ (MAH-1).

Each of these adjustments will be discussed in detail in the third part of my testimony which explains Exhibit _____ (JDW-1).

All of these pro forma adjustments are necessary in order for the rates established in this case to be based on a set of test year earnings and investment relationships that come as close as possible to representing relationships and conditions that will exist during the period when the rates will be in effect.

Review of Exhibits

11. Q. Please outline the nature and mechanics of NSP's data in support of its application for an increase in rates.

A. The filing rules of the SDPUC as outlined in Chapter 20:10:13 specify the form for filing a rate increase application, requiring that certain data in the form of letters, statements, schedules, and working papers must be filed in support of the application.

The rules also provide that NSP may file additional information that it deems appropriate in support of its application. In order to provide continuity in organization of its presentation, NSP has prepared this application in essentially two parts.

The first portion, Exhibit_____(NSP-1) contains all of the specific statements and schedules required by the rules. The second portion consists of the testimony and the related exhibits of the various witnesses appearing on behalf of NSP's application. Where the formal statements or schedules required by the filing rules are represented by the formal exhibits of a witness, a sheet is provided in Exhibit _____(NSP-1) in its appropriate place stating that this filing requirement is met by the exhibit of the witness.

Also, an index at the beginning of Exhibit_____(NSP-1) lists all of the statements and schedules and specifies the witness who is sponsoring each item. In this manner, NSP has met its formal filing requirements through Exhibit_____(NSP-1) and is supporting its application by the direct submittal of testimony and exhibits which may or may not be included in the filing requirements.

12. Q. Will you please discuss the test period which you have used?

A. As a basis for establishing the cost of electric utility service of NSP for the State of South Dakota, I have used the year ended June 30, 1982 adjusted for known and measurable changes as the test year.

The schedules which I relied upon in my portion of the cost of service and revenue requirements presentation are principally

found in Statement N - Allocated Cost of Service, Exhibit ___ (NSP-1) (Section 20:10:13:97). These schedules have been included in my Exhibit _____(JDW-1) with reference thereto to Exhibit_____(NSP-1) as permitted in the filing rules. Exhibit__ ___(JDW-1) has been adjusted to reflect the test year items called for in Section 20:10:13:44.

It is hoped that this organization will assist the Commission with its analysis and understanding of the record.

13. Q. What is the source of the data you have included for the test year?

A. The actual year data comes from the official books and records of the Company and has been assigned or allocated to the State of South Dakota.

14. Q. Why has the Company not filed projected test year data in this case?

A. In past cases, NSP has strongly advocated the use of a test year period which coincides with the period when rates will be in effect. South Dakota remains the only jurisdiction in which NSP operates that persists in the use of historical test years. The Company hopes that the Commission will come to the realization that a projected test year is both appropriate and accurate for ratemaking.

This is the first NSP case since the statutory amendment which permits adjustments for changes occurring up to 24 months after the end of the test period. This should allow the Commission to consider, in most cases, the same anticipated costs which would form the basis for a fully projected test year. In theory, a fully adjusted historical year should look very much like a projected test year. A projected test year, however, is based directly on the operating budgets of the Company. By way of contrast, a fully adjusted historical period results from a long series of complex and laborious computations which serve no purpose beyond the immediate rate case. It is a little like trying to modify last year's car to look like the new model using a hammer and a welding torch. Why not simply purchase the new model?

In this filing, the Company has temporarily laid aside its advocacy of a projected test year, choosing to concentrate on implementation of the new 24 month standard. Some of the proposed adjustments project further into the future than those proposed in past cases. However, we have not gone as far as the new law might allow. The same restraint in minimizing the amount of the rate increase throughout the filing has affected the test year adjustment process. The adjustments we propose will help to reduce regulatory lag and attrition but will not eliminate them. The Company hopes that as the Commission gains

experience with adjustments reaching into the near future, it will more clearly see the wisdom of projected test year ratemaking.

15. Q. Previously, in the discussion of the test period utilized in this case, did you mention an exhibit which you have prepared in connection with this application?

A. Yes, I did.

16. Q. I show you what is marked and identified as Exhibit____(JDW-1) entitled, "Cost of Service-Income Statement and Overall Revenue Requirements" and ask if it was prepared by you or under your supervision?

A. Yes, it was.

17. Q. Please discuss the organization of your exhibit.

A. As an introduction, the first two pages of my exhibit are an index to the schedules. I should also explain that all dollar amounts in the exhibit are expressed in terms of thousands except for certain support schedules which show total dollar amounts and that the data shown for South Dakota is for the Company's operations within the state.

18. Q. Please proceed with the explanation of your exhibit.

A. On Schedule 1 I have shown a summary of the test year ended June 30, 1982, adjusted data for the electric utility operations in the State of South Dakota with present and proposed rates. All of the data shown on Schedule 1 has been transferred from subsequent schedules of my exhibit. In each situation, I have shown revenues, operating expense and net operating income. The net operating income is $7,066,000 with present rates and $9,722,000 with proposed rates. To measure the reasonableness of the amount of return, I have used the average adjusted original cost rate base as developed by Mr. Hervey which he shows to be $86,055,000. The last line shows the rate of return earned on average original cost rate base to be 8.21% at present rates and 11.30% with proposed rates.

19. Q. Will you please explain what Schedule 2 shows?

A. The purpose of Schedule 2 is to show the effect that the proposed rates will have on test year revenue and expenses. Shown in Column A is the adjusted test year ended June 30, 1982 data taken from Column X of Schedule 3. Column B shows the additional revenues and expenses resulting from the increased rates as proposed in this proceeding. The increased expense is income tax which the Company will pay as a result of the rate increase. Column C shows the results of adding the amounts of Columns A and B. I have then brought forward to Schedule 1 the summary data from Column C.

20. Q. How did you determine the amounts of the electric retail revenues?

A. The present and proposed electric retail revenues are those which Mr. Huso shows in his Exhibit ____(SVH-1), Schedule 1. The other operating revenues are recorded either directly for the South Dakota jurisdiction or, as in the case of revenues received from NSP(W), recorded in total and allocated to the South Dakota jurisdiction on a demand or energy basis as appropriate to reflect the demand or energy component of revenues received.

21. Q. Will you please explain what Schedule 3 shows?

A. This schedule shows, in detail, the net operating income as actually recorded for the period ended June 30, 1982, and as adjusted after pro forma adjustments. Column A shows actual amounts for the year ended June 30, 1982 and is supported by Schedule 4. Columns B through W include the pro forma adjustments necessary to reflect test year conditions on actual operating revenues and expenses. Schedules 6 through 26 develop the pro form adjustments found in these columns. Each of these test year adjustments will be discussed later in my testimony. Column X of this schedule shows the adjusted year ended June 30, 1982 amounts after all pro forma adjustments have been made and is supported by Schedule 5.

22. Q. Explain what is shown on Schedule 4.

A. Page 1 of Schedule 4 shows, and supports, the same detail of operating revenues and expenses as Column A of Schedule 3. The first page serves as an index to assist in the understanding of how the direct assignments and allocations are made from the total electric utility amounts to the South Dakota jurisdiction. The detailed manner in which these totals are determined is shown on the computer printouts comprising the subsequent eight pages.

23. Q. What is shown on Schedule 5?

A. Page 1 of Schedule 5 shows the same detail of operating revenue and expenses as is shown in Column X of Schedule 3. The arrangement and detail are similar in format to Schedule 4.

Pro Forma Adjustment Schedules

24. Q. Please continue with the explanation of your exhibit and a discussion of your adjustment to flow through tax timing differences not required by law to be normalized.

A. The next 21 schedules detail pro forma adjustments made in this filing. Schedule 6, the first of these, shows the changes necessary to reflect the Commission's preference for flowing through those tax benefits not required to be normalized. This adjustment is necessary because the Company's books and records reflect the normalized accounting treatment of its principle jurisdiction, Minnesota. While NSP continues to support normalization, the Company is also aware of the SDPUC past

treatment and indicated preference for flow through of tax deductions not required to be normalized.

The Company, per books and records, normalizes the tax-timing differences associated with capitalized overheads (payroll taxes, property taxes, sales taxes, and pensions included in construction); storage and disposal costs of nuclear fuel; decommissioning, salvage, and removal expenses associated with ultimate plant retirements; difference between book and guideline lives, as well as all other tax-timing differences. Prior to the enactment of the Economic Recovery Tax Act of 1981, NSP was not required to normalize those differences specifically mentioned. To the extent that ERTA requires normalization on post-1980 property, the amounts shown on Schedule 6 show continued Commission acceptance of this additional normalization. The normalization is required in order to qualify South Dakota customers for ERTA related benefits. In addition, prior period adjustments have been eliminated from Column B, which depicts flow through treatment, in order to remove abnormal situations.

The net effect of this adjustment is to increase net income by $22,000 and is posted to Column B of Schedule 3

25. Q. Have you made any additional pro forma adjustments regarding these tax-timing differences in this rate case?

A. Yes we have. In moderating the current filing, NSP has included an adjustment to provision for deferred income taxes to fully normalize, on a prospective basis, all tax timing differences resulting from the nuclear plant decommissioning and nuclear fuel sinking funds. These sinking funds provide for the investment's eventual decommissioning or disposal. For assets capitalized after 1980, any provisions to sinking funds are considered to be salvage and require normalization as ERTA is interpreted by the Company. This would apply to all Company-owned nuclear fuel placed in the reactor after December 31, 1980 and to any additional nuclear reactors for which the Company implemented a sinking fund or recovered negative salvage through depreciation rates.

Because of the negative salvage condition requiring the sinking funds, the book expense is in advance of recognition of the expense for tax purposes, thus creating a negative provision for deferred taxes under normalization. The Company, in moderating the filing, for administrative reasons, and to provide a better matching of costs and benefits, proposes to normalize all provisions to the sinking funds irrespective of the vintage generating the provisions. On a prospective basis, this full normalization of sinking funds results in a reduction in net income of $428,000, as shown on Pages 1 and 2 of Schedule 6 in Exhibit ___ (MAH-1), and is included in Column W of Schedule 3. The net income reduction reduces the cost of service by $751,000, including the rate base increase, due to the

prospective decrease in tax reserves. Tax reserves established due to flow through prior rate determinations currently in effect will be maintained until rates from this case become effective. Prospectively, under our proposal, those reserves will eventually turn around as the disposal costs are incurred.

26. Q. What other adjustment involving normalization do you propose to the Commission in this case?

A. I would strongly propose the Commission adopt full normalization of all tax timing differences. ERTA effectively eliminates, on a prospective basis, all but one significant flow through item. In order for NSP to use the ACRS depreciation without disqualification, the only remaining item from post-1981 additions which may be flowed through is Comprehensive Interperiod Tax Allocation (CITA) which for NSP consists of construction expenditures for payroll taxes, pension costs, property taxes, and sales taxes which may be deducted currently rather than capitalized. Normalizing CITA in the adjusted test year amounts to a cost of service increase of $472,000 with future cost of service reductions as it is flowed back over the life of the investment. Under flow through treatment, cost of service is reduced immediately with no future flowbacks to reduce cost of service. The mismatch of costs and benefits produced by flow through is clearly evident regarding CITA. Under flow through treatment the deduction for these CWIP related expenditures is used to reduce cost of service, which does not include the revenue requirements on the asset generating the deduction. Later when the asset becomes part of the rate base providing benefits to customers who are supporting the related revenue requirements, there is no CITA-related tax benefit available to offset the revenue requirements or to provide for proper matching of costs and benefits.

In addition, flow through of these CITA benefits is not equitable for customers or the Company. On one hand, due to the varying magnitude of construction expenditures, customers may not receive all benefits to which they are entitled. On the other hand, the authorized revenues are reduced during construction and increasingly so during heavy construction when the need for earnings and cash flow is the greatest.

NSP has taken the first step by including a large reduction in revenue requirements due to normalizing the sinking funds. As discussed by Mr. Berglund in his testimony, the South Dakota Commission should authorize full normalization including the CITA items. It would be unfair and inconsistent to accept only the aspects of normalization which provide current reductions in rates and not accept the aspects such as CITA which currently require an increase in rates. This is especially fair when, as in this circumstance, the net effect on South Dakota's customer is a reduction of $279,000. Full normalization would allow 100%

compliance with ERTA, a current reduction in the cost of service, and make South Dakota, on a prospective basis, consistent with NSP's other jurisdictions thereby reducing the costly administrative burden of maintaining two sets of tax books.

27. Q. Please explain further why NSP advocates normalization rather than flow through treatment of tax timing differences.

A. NSP maintains its books and records reflecting the fully normalized accounting treatment sanctioned by the Minnesota jurisdiction. This fully normalized treatment is also consistent with the regulation in North Dakota and that most recently required by the Federal Energy Regulatory Commission (FERC) in their final rule, Order No. 144. Within this Order, the FERC addresses and discards the rationale for flow through treatment traditionally proposed by SDPUC Staff and other proponents of flow through accounting. The FERC reiterates throughout the new rule that tax normalization better achieves the goals of equity in rates than does flow through. The Order appropriately determines that tax normalization synchronizes the recognition in rates of the deductibility of an expense with the recognition of the expense itself. Normalization achieves a proper allocation of income tax costs recognizing that the tax, like the plant-related costs that gives rise to it, is the result of construction expenditures. These costs are allocated to the service life of plant rather than to the construction period when the costs may have been actually paid by the utility.

28. Q. Please describe some of the advantages that the FERC lists in its Order.

A. The FERC lists the following advantages of its tax normalization policy:

1. Such a policy balances the obligations to ensure reasonable rates to rate payers while maintaining the financial integrity of the public utilities and natural gas pipelines it regulates.

2. Tax normalization is more properly cost-based than flow through.

3. Tax normalization meets the "actual taxes paid" principle from both policy and legal standpoints.

4. Tax normalization meets the just and reasonable rate standards of the Federal Power Act (FPA) and the Natural Gas Act (NGA).

5. Tax normalization is likely to result in rates and revenues that are more stable over time than flow through.

6. No adverse efficiency incentives are given to companies by the use of tax normalization.

7. The issuance of this generic rule requiring tax normalization will eliminate the ongoing controversy and

attendant uncertainty regarding the appropriate treatment of miscellaneous timing difference transactions in Commission's rate proceedings. The resulting administrative efficiency and clarity should benefit consumers, regulated utilities, and the Commission.

The SDPUC has patterned many of its adopted rules after the FERC rules. It would be appropriate and an indication of improvement in regulation for the SDPUC to also adopt normalization. The subject of normalization has been extensively studied and goes back to a FERC Commission Order No. 530 in 1975. Over 60 parties provided comments to the Commission regarding this subject in Docket No. RM80-42. There is ample basis for the SDPUC Commission to reconsider its previous determination and support full normalization in this and subsequent rate filings.

29. Q. What adjustments do you show to revenues on Schedule 7?

A. Page 1 of Schedule 7 shows the adjustments necessary to restate retail revenues to a level reflecting annualization of the ordered rates from Docket No. F-3382 which went into effect December 15, 1981. Page 2 of Schedule 7 shows adjustments to other operating revenues required to eliminate revenues from non-recurring oil sales, to eliminate forfeited discount revenues, and to annualize customer service connection revenues.

The adjustment to annualize retail revenues also removes any lag in recovery of actual year fuel expense by recognizing the eventual recovery of the expense through fuel clause revenues. Mr. Huso has provided the data for this adjustment and shows the annualized revenues on Schedule 1 of Exhibit ___(SVH-1).

The Order in Docket F-3382 eliminates forfeited discounts from test year consideration by allowing a 1% late payment charge to be recorded below the line, this is offset by a reduction in revenue lead days used in determining cash working capital to 20 days. Mr. Hervey addresses this issue in his testimony. Line 2 on Page 2 of Schedule 7 shows a reduction of $11,372 to other revenues.

A rate design change allowed in Docket F-3382 was to increase service connection fees from $10 to $12. The increase of $11,570 in other revenues shown on Line 3 of Page 2, Schedule 7, reflects the annualization of that increase.

Included in the retail revenue increase of $3,573,631 shown on Page 1 of Schedule 7 is an adjustment to fuel clause revenues of $499,000 to reflect increased test year nuclear fuel expenses related to the inclusion of non-revenue producing plant additions as discussed by Mr. Hervey. The $499,000 was allocated to retail class through the addition of .069¢/Kwh to the fuel clause adjustment as explained in Mr. Huso's testimony. The amounts from Schedule 7 are transferred to Column C of Schedule 3.

30. Q. Please continue with an explanation of the adjustment to payroll expenses.

A. Page 1 of Schedule 8 shows the pro forma adjustment necessary to reflect the known wage and salary increases which occurred during the year ended June 30, 1982, and those anticipated for 1983 and 1984. The adjustment was made using an approach similar to that used and adopted in Docket F-3382. First, actual test year labor was adjusted to reflect annualization of a merit increase in September, 1981, an overall increase on January 1, 1982, and a non-union merit increase granted on April 1, 1982. Then a 1983 increase percentage of 6.88%, as provided by the Compensation and Benefits Department, was applied to the actual test year labor expense including the test year annualization previously mentioned. Research performed by the Compensation and Benefits Department indicates that an increase of like magnitude will be granted for 1984. I have applied an increase percentage of about 2.76% to the results of my first two computations to restate test year labor expense to the level expected to be in effect during the first year following the expected effective date of rates from this case, thus including 4 1/2 months of 1984. This is similar to what was done and accepted by the Commission in Docket F-3382. An increase in expenses of $924,119 is posted to Column D of Schedule 3.

Page 3 of Schedule 8 shows the increased FICA taxes associated with wage and salary increases, as well as the increase in the maximum earnings subject to the FICA tax in 1983. The maximum taxable earnings increased from $29,700 in 1981 to $32,400 in 1982. As of July 7, 1982, $35,400 was expected to be the 1983 maximum which was used in the adjustment discussed herein. Employees' annual salaries were adjusted by the increase factor used in the payroll adjustment and then grouped by those above and below the salary cutoff of $35,400. The employee count and dollar spread was then used to compute the FICA tax adjustment. The result is an increase in FICA-related payroll taxes of $66,332 which is shown in Column D of Schedule 3. As of November 9, 1982, the federal government raised the 1983 maximum to $35,700 in response to shortfalls in current social security payments. Perhaps even more increases can be expected in the future.

31. Q. Please continue with your explanation of the pension adjustment shown on Schedule 9.

A. Schedule 9 shows an adjustment necessary to reflect the cost of pensions which the Company expects to incur in the year ended May of 1984. The pension accruals are developed annually by the Wyatt Company, a nationally recognized expert on pensions and benefits. These accruals are then disbursed to area banks who administrate the fund. The 1983 and 1984 amounts developed by the Wyatt Company become part of the basis for establishing the labor loading rate that will actually be applied to record labor

expense during the year following the effective date of rates for this case. In this way, the period chosen for the pension adjustment is consistent with the aforementioned labor adjustment. Also shown on Schedule 9 is an adjustment to include the annualized costs for the same period related to a dental plan beginning January 1, 1982. The total pensions and benefits adjustment amounts to an increase of $122,051 for the State of South Dakota and is also posted to Column E of Schedule 3.

32. Q. What is the purpose for the adjustment to advertising shown on Schedule 10?

A. This schedule shows a pro forma adjustment necessary to exclude portions of advertising expense actually incurred during year ended June 30, 1982. I have carefully reviewed the advertising expenses incurred and have included only those categories which directly benefit the ratepayer. The categories included are consistent with those included and allowed in Docket No. F-3382. Examples and an explanation of advertisements from each category have been included in Exhibit ___ (NSP-1). This adjustment reduces advertising costs to South Dakota by $40,581 and is also shown in Column F of Schedule 3.

33. Q. Have you included charitable contributions in your expenses?

A. Yes. Schedule 11 shows a pro forma adjustment to include $25,151 for contributions. This is one-half of selected charitable contributions which the Company made in South Dakota during the year ended June 30, 1982.

I have included only one-half of selected contributions in order to provide for a sharing of this expense between customers and shareholders. This proposal provides an equitable distribution of this cost for contributions which are reasonable in amount and directly beneficial to the South Dakota service area. Charitable contributions are a normal and appropriate corporate expense which should be included in the South Dakota cost of service. Under our proposal, the benefits to our customers and their community would clearly exceed the costs. Mr. Berglund and Mr. Butterwick provide further discussion on this matter. Column G of Schedule 3 reflects the amount shown on Schedule 11.

34\. Q. Please explain the regulatory expense adjustment shown on Schedule 12.

A. Schedule 12 shows the amount required to continue the amortization of rate case expenses from Docket F-3382, as well as provide for a similar amortization for expense relating to the current case. The difference between the actual expense incurred in Docket F-3382 versus that estimated and currently being amortized, plus the estimated costs for the current case including the increased South Dakota filing fee of $75,000, is

included as a separate layer of additional expense. As in Dockets F-3353, and F-3382, the new layer of expense is amortized over two years beginning May 17, 1983. The total test year expense also reflects the expiration of the F-3382 amortization December 15, 1983. The unamortized rate case expense is determined by averaging the amounts remaining from each amortization at May 17, 1983 and May 17, 1984. Mr. Hervey has included average unamortized rate case expenses in his determination of adjusted South Dakota rate base.

In addition to the rate case expense amortization adjustment is an amount of $47,909 to include the PUC special hearing fund assessment reflecting the requested level of revenues for the test year. The assessment is determined at the new rate of .00115 versus the old rate of. 00100.

The net adjustment to reduce test year regulatory expense by $20,817 has been posted to Column H of Schedule 3.

35\. Q. Has there been any change in the nuclear power replacement insurance issued through the Nuclear Electric Insurance Limited (NEIL) Company?

A. Yes, Beginning in 1982, additional coverages were purchased above those included in the allowed cost of service in Docket F-3382. The annualized cost for this additional protection (NEIL II) is developed on Schedule 13. NEIL II insurance provides coverage up to $500 million for excess property damage, specifically site decontamination, in the event a nuclear unit experiences a major failure.

36. Q. Are there any other adjustments to insurance expense within your study?

A. Yes. Schedule 13 also shows the results of a comparison between total insurance premiums including property insurance, NEIL I, NEIL II, medical claims, and injuries and damages premiums and claims that have occurred in the actual year ended June 30, 1982 and which are anticipated to occur in 1983. The sum of these changes, including a full year of NEIL II, results in an increase in operating expense of $149,413 for South Dakota and is also posted to Column I of Schedule 3.

37. Q. What adjustments are necessary regarding the amortization of the abandoned Tyrone nuclear generating plant?

A. Two adjustments are necessary to reflect the correct level of current expense in purchased power. First, an adjustment must be made to reverse the journal entries recorded in December, 1981 which pertained to prior periods and were required to restate the expenses recorded in those prior periods to the ordered amortization per FERC Opinion No. 134, issued December 3, 1981. Next, the current test year expense must be restated to the ordered level.

Removing the prior and current period expense reversals increases South Dakota test year expense by $516,927. Including the current amortization at the ordered level for a full year increases expense by $289,768. Those amounts are developed and combined on Schedule 14 and posted to Column J of Schedule 3.

38. Q. Please explain why the Company has again included in the South Dakota cost of service Tyrone amortization for a power plant cancelled by the Wisconsin PUC.

A. NSP firmly believes that as customers of all its jurisdictions share in the savings and increased reliability benefits of its integrated power system, so should those customers share in the risks and costs of that system. Mr. Hervey discusses the integrated system in his testimony. Had Tyrone been built, it would have produced low cost, reliable energy for South Dakota customers, as well as for all customers within NSP's service area. The cost of operating the plant would have been allocated to South Dakota customers on the same basis that the cost of amortizing it is allocated in this rate filing. From an accounting and ratemaking standpoint, the funds NSP advanced were for the development of a power plant that would eventually serve all of its customers' needs. Due to reasons unforeseen when the money was committed, mostly by contract, the plant required cancellation. NSP chose to follow prevailing precedent and requested the loss from ratepayers over a period of amortization, but did not request a return on the unamortized balance. This has been a common method to share the loss. The shareholder foregoes a return <u>on</u> funds he has advanced and the customer, over time, provides a return <u>of</u> those funds.

Recently the U.S. Eighth Circuit Court of Appeals upheld that decision. Recovery of Tyrone expenses has been allowed by courts in Minnesota and North Dakota, as well as in South Dakota's Hughes County Circuit Court. Clearly, the Tyrone expense is a proper component of South Dakota's cost of service.

39. Q. Please explain the adjustment for deferred Tyrone costs.

A. The deferred Tyrone costs are those deferred by the settlement agreement in Docket No F-3353 and by order in Docket F-3382. I have restated the Tyrone amortization to a ten year level and recomputed the amount deferred including carrying charges, per the F-3353 settlement agreement, from November 23, 1980 through December 14, 1981 consistent with the period rates from Docket F-3353 were in effect. I then continued accumulating the Tyrone expense from December 15, 1981 forward until rates from the current case go into effect, which we anticipate to be May 17, 1983. The carrying charges accrued during that period of time were computed based on the ordered capital structure from Docket F-3382, with the compounded monthly rate consistent with the methodology prescribed in Docket F-3353. The total accumulated

amount at May 17, 1983 is $897,942. I then computed the monthly amortization from that point until the likely termination of the FERC-required amortization projected to be January, 1988 (55.5 months) allowing for carrying charges computed by using the F-3382 compounded rate on the unpaid balance. This approach is consistent with the settlement agreement in Docket F-3353 and is similar to computing a mortgage payment. The monthly amortization related to the deferred amount is $22,238, and the test year amount is $266,856. Schedule 15 shows the amount developed with the result posted to Column K of Schedule 3.

40. Q. How were the expenses related to storm damage arrived at?

A. Schedule 16 shows the average of calendar years 1978-1981 plus the first nine months of 1982 compared to the storm damage incurred in the actual test year. No adjustment is necessary in transmission, and an adjustment of $34,783 was made to distribution restating the adjusted year storm damage expense to equal the average of the five above-mentioned periods. These adjustments will allow NSP to begin recovering, in the new rates, some of the excessive costs incurred as a result of the July, 1982 storm that hit Sioux Falls. Column L of Schedule 3 reflects this adjustment.

41. Q. How have you treated the amortization of prior period tax deferrals made in excess of 46%?

A. I have included the remaining seven months of the amortization which was continued in Docket F-3382. Mr. Hervey has included adjustments to accumulated deferred taxes to reflect the previous 29 months of the amortization in the beginning of the test year in the rate base development. An adjustment reducing the provision for deferred income taxes by $89,000 has been computed on Schedule 17 and included in Column M of Schedule 3.

42. Q. Please explain your adjustment to include energy audit expenses.

A. Schedule 18 shows the allocation of General Office and Sioux Falls division energy audit costs to South Dakota. These costs were measured for the year immediately following the likely date rates for this case will go into effect and included in the adjusted test year cost of service. $9,122 is posted to Column N of Schedule 3.

43. Q. Please describe your adjustment to amortize repair allowance.

A. Following an IRS review in 1981, agents determined that $39,575,000 in previously claimed repair allowance tax deductions did not qualify under their interpretation of the tax law. The tax deductions affecting South Dakota's rates were taken between 1975 and 1979. Due to the South Dakota Commission's position on flow through accounting, these deductions were flowed to customers in rates set in Dockets F-3062, F-3188, and F-3353. Docket No. F-3382 included a five

year amortization of the disallowed tax benefits customers had previously received as reductions in their rates. The average unrecovered balance was included in the rate base as a working capital item.

Negotiations with the IRS were completed in October, 1982 with the disallowed amount of repair allowance tax deductions set at $26,465,391. I have recomputed the amortization on a prospective basis, beginning May 17, 1983, and extending over the remaining life of the Commission-adopted amortization. The remaining amortization amount as of May 17, 1983 was computed giving full credit to ratepayers for the amounts included in rates until that time and is consistent with the method and format proposed by the SDPUC Staff in Docket F-3382. The amortization related to the test year of $92,000 is developed on Schedule 19 and included in Column O of Schedule 3. Mr. Hervey has included the test year average unrecovered amount of $275,000, in working capital.

44. Q. Have you included labor expense for additional employees required as the result of Nuclear Regulatory Commission (NRC) regulations?

A. Yes. A labor amount of $40,078 due to 27 employees, to be added through 1983, is shown on Schedule 20. These employees are required primarily to meet safety requirements contained in new

NRC regulations. Additional FICA of taxes of $2,917 have also been computed on Schedule 20. The results of this adjustment is posted to Column P of Schedule 3.

45. Q. Did postal rates increase during the test year?

A. Yes. Effective November 1, 1981, postage rates increased from 18¢ to 20¢. An adjustment of $4,091 to reflect the South Dakota portion is computed on Schedule 21 and posted to Column Q of Schedule 3.

46. Q. Why have you included an adjustment to reverse an NRC expenditure as shown on Schedule 22?

A. During 1979 and 1980, expenditures of $1,702,839 for the total Company, were required by the NRC for safety related improvements at the Prairie Island generating station. These expenditures were expensed at the time they were incurred. Following an accounting review, it was decided these expenditures should have been capitalized. Entries recorded in December, 1981 and February, 1982, reversed the expense and recorded it as plant investment. In doing so, South Dakota test year expenses were understated by $69,770. In view of the final disposition of the entries, the beginning-of-year nuclear plant investment balance was also understated by the same amount. To properly restate the production expense levels, I have reversed the

understatements due to the prior period expenditure. This results in an increase to other production operating expense. Mr. Hervey has increased beginning of year investment in the rate base by the same amount. The expense adjustment is shown in Column R of Schedule 3.

47. Q. Please explain the telephone expense increase you show on Schedule 23.

A. Schedule 23 shows the effect of two telephone rate increases on South Dakota operations. Rates for interstate private lines, used primarily between substations, increased 40% effective January 30, 1982. Annualization of that increase raises expense by $875. On October 18, 1982, the South Dakota PUC approved a settlement with Northwestern Bell allowing a 5.6% increase to go into effect November 15, 1982. The effects of that increase, $1,960, on local and private line service are also shown on Schedule 23. The results are posted to Column S of Schedule 3.

48. Q. Please briefly describe the Coordinating Agreement.

A. The Coordinating Agreement consists of an intercompany agreement among NSP-MN and its subsidiary companies, and Northern States Power Company (Wisconsin) (NSP-WI), and Lake Superior District Power Company (LSDP). It provides for the intercompany billing of costs associated with the generation and EHV transmission of electrical energy produced by each company. A fixed charge for facilities used to generate and transmit power is billed by each company to the other, as well as a variable charge related to fuel and other production costs. Due to the economics of a large scale integrated system with greater flexibility and larger, more efficient plants, production costs are lower which results in lower priced energy to customers. The Coordinating Agreement consists of three FERC approved rate schedules between NSP-MN, NSP-WI and LSDP. These rate schedule designations established in a FERC Order in Docket No. ER82-485-000, are FERC No's 416, 67 and 30. The original agreement between NSP-MN and NSP-WI was approved by FERC to become effective October 10, 1971. Subsequent to this approval, an amendment to the original agreement was approved by FERC to include the costs incurred in the development of the cancelled Tyrone Nuclear Plant in compliance with FERC opinion No. 134, issued December 3, 1981. This amendment has been included in the body of the Coordinating Agreement upon FERC's approval of LSDP becoming a third party to the Agreement in Docket No. ER82-485-000 and therefore is a statutory rate.

49. Q. What adjustments, if any, have you made to purchased power as affected by the Coordinating Agreement?

A. Beginning in 1982, precertification expenses relating to facility development costs are no longer being billed to NSP(M) from NSP(W). I have reduced purchased power expense

by $59,849 in production and $16,003 in bulk transmission (EHV) to reflect this change. I have included no additonal adjustments to reflect potentially higher pro forma levels of expense or investment that may exist within NSP(W) during the South Dakota test year. Those higher costs could require higher billings, and thus higher purchased power expense to NSP(M). Schedule 24 shows the development of those amounts. They are included in Column T of Schedule 3.

50. Q. How have the Coordinating Agreement revenues from NSP(W) been determined to reflect test year conditions in this case?

A. Plant investment and related items, along with expenses, associated with the production, EHV transmission, and system control functions were measured consistent with test year conditions. Those pro forma adjustments that would eventually be included in rates billed in accordance with the FERC-approved Coordinating Agreement were included in the cost measurements.

Pro forma adjustments in the following areas have been included: the production, EHV transmission, and system control portion of

1. Non-revenue producing plant and related items,
2. Annualizing the 115/345 KV bulk transmission addition,
3. Other production expense,
4. Insurance premiums,
5. Employees required as the result of NRC regulation.

6. The reversal of an NRC-required expenditure and,

7. The net effect of the LSDP affiliation.

Revenue from the Coordinating Agreement allocable to South Dakota has been adjusted upward by $374,000 and is shown on Schedule 25 and in Column U of Schedule 3.

51. Q. What is shown on Schedule 26?

A. Schedule 26 shows an adjustment to property tax expense reflecting the use of calendar year 1982 accruals. 1982 accruals were used because they are known and measurable and more closely match the level of expense which will occur during the period rates are in effect, than would the expense for the actual year ended June 30, 1982. The accruals used are based on year-end 1981 plant and reflect the latest mill rates available. The increase in property tax expense of $127,000 is included in Column V of Schedule 3.

52. Q. Please explain the adjustments you show in Column W of Schedule 3 titled, "Effects of Changes to Plant Related Items".

A. Column W of Schedule 3 summarizes the income statement impacts due to the rate base adjustments that Mr. Hervey describes in his testimony and shows in Exhibit ___ (MAH-1). This column also reflects the income statement impact of fully normalizing the nuclear plant decommissioning and nuclear fuel sinking

funds. Schedules 5, 7, 8, 9, 10, and 11 of Exhibit ___ (MAH-1) show adjustments to book depreciation, provision for deferred income taxes, tax depreciation, investment tax credit allocated to current income (flowback), and property taxes due to the inclusion of non-revenue producing plant additions, the use of a gross of tax AFDC rate, the annualization of the 115/345 KV transmission addition, and working capital adjustments.

Schedule 6 of Mr. Hervey's exhibit shows the effect on provision for deferred income taxes and accumulated deferred income taxes due to prospective full normalization of the sinking funds mentioned earlier.

53. Q. How are federal income taxes computed?

A. The adjusted test year current federal income tax liability has been computed in a manner consistent with that proposed by the SDPUC staff and accepted by the Commission in Docket F-3382. This approach synchronizes the interest expense tax deduction to the allocated South Dakota rate base but also includes the additional investment related to the construction work in progress (CWIP) allocated to South Dakota. The result is a higher deduction for interest and a lower current tax liability and is appropriate when used in conjunction with a gross of tax AFDC rate applied on all CWIP, including short term. Mr. Hervey discusses the use of a gross of tax AFDC rate in his testimony.

Schedule 27 shows the computation of federal income taxes with present and proposed rates. The calculation with present rates is shown for both the actual and adjusted test year after recognition of all pro forma adjustments. The calculation with proposed rates reflects on the adjusted test year. CWIP allocated and directly assigned to South Dakota as shown on Line 2, is added to rate base shown on Line 1 of Schedule 27. Line 4 shows the portion of this tax base shown on Line 3, represented by long term debt, which I have determined by dividing the average debt outstanding into the capitalization, plus the accumulated deferred investment tax credits. Line 5 shows the portion represented by the $3.60 series of preferred stock on which a portion of the dividend is a credit for income tax purposes. Line 6 develops the amount of interest associated with the debt amount shown on Line 2. The interest rate of 8.28% is the embedded cost of debt for the adjusted test year ending June 30, 1982. Line 7 is the result of applying the preferred dividend rate times the amount on Line 5. Line 8 shows net operating income before income taxes taken from Schedule 2. Lines 9 through 15 are items which are not deductible for income tax purposes and are, therefore, added to net operating income. Lines 17 and 18 are items deductible for tax purposes and are subtracted from net operating income, leaving the net taxable income as shown on Line 20. By applying the appropriate federal tax rate of 46% to the net taxable

income, the preliminary tax as shown on Line 21 results. From this amount, I have deducted the investment tax credit generated, leaving the federal income taxes for the year shown on Line 23.

54. Q. Do you have any additional comments?

A. Yes. Costs and investment levels in an electric utility of NSP's size are constantly changing. That is the reason for including pro forma adjustments in a historical test year. Very recently it was determined that extraordinary maintenance expense would be required at the Monticello nuclear generating station in late 1983. This expense results from the need to replace approximately 40,000 worn copper-based condenser tubes with a newly developed stainless steel type. The expense is anticipated to be about $15,000,000 on a total Company basis. Specific accounting treatment has not yet been determined, but it is very probable that the expense will be amortized over a three year period. Due to the uncertainty of the actual amount and the exact accounting treatment, no adjustment has been included in the current case. However, due to the magnitude and extraordinary nature of this expenditure, NSP requests that the South Dakota Commission allow the allocated South Dakota portion of this expense to be recorded as a deferred debit with the appropriate annual amortization included as a test year expense in future rate cases. The Company also requests, once the amortizaton begins, that the average net unrecovered portion be included in the rate base as a working capital item reflecting the use of shareholder-provided funds.

55. Q. Does this complete your testimony?

A. Yes, it does.

Northern States Power Company (Minn)
NSP-SD Gas Operations
Before the South Dakota PUC
Docket NG97-021
First Set MEC Data Requests
Response to: No. 11

☐ **Proprietary**

X Non-Proprietary

Question:
Witness Winter testimony, Page 2, Line 13-14 refers to maximum rates or rate caps. What do these terms mean to the customer? Is the maximum rate based on projected sales levels? If not, why, why not?

Response:
NSP is seeking approval of maximum rates in this proceeding. If approved, NSP may enter into agreements including rates up to the maximum approvel level. The rates are based on the maximum capacity of the pipeline. If rates were based on projected sales levels, each time a customer were added, new rates would have to be calculated and submitted for approval. This potentially burdensome requirement is avoided by obtaining approval for maximum rates based on pipeline volume capacity.

Response By: John Winter
Title: Sr. Regulatory Consultant
Company: NSP

Northern States Power Company (Minn)
NSP-SD Gas Operations
Before the South Dakota PUC
Docket NG97-021
First Set MEC Data Requests
Response to: No. 12

☐ **Proprietary**

X **Non-Proprietary**

Question:

Witness Winter in his testimony Page 2, Line 26 refers to other costs. What are these other costs? Do these costs include any cost allocations from NSP headquarters office and plant in Minnesota for any services provided? If yes, what are they and if no, please explain why not?

Response:

The "other costs" referred to above are shown on Schedule 5 of my pre-filed testimony (copy attached). They consist of monthly support and emergency service by ACA personnel (subsequently replaced by an agreement with Northwestern Public Service), management and support from NSP-SD, the OPS assessment, and regulatory fees. As stated, these costs include charges from the NSP-SD office. They do not include charges from the NSP-MN headquarters office. Due to the small size of NSP-SD Gas Operations, services from NSP-MN will be purchased only on an as needed basis. The need is expected to be very small.

Response By:	John Winter
Title:	Sr. Regulatory Consultant
Company:	NSP

Northern States Power Company - South Dakota **Schedule 5**
Gas Operations
Operating Expenses (O&M)
Statement FI

All of the O&M on this Schedule pertains to the NSP-SD 4.5" lateral pipeline that iwil serve HTI.	Amount (A)	Annual Escalator (B)	1 Year Escalated Amount (C)
(1) NSP - Operating and Maintenance Training, readings, patrolling of line by Angus Anson Plant personnel	$8,154	3.0%	$8,399
(2) ACA Supplemental Service Support and emergency services by ACA personnel	$3,600	3.0%	$3,708
(3) Services - NSP-SD Management and support	$7,200	3.0%	$7,416
(4) Insurance Estimated Annual Fee	$100	0.0%	$100
(5) OPS Assessment Estimate of Office of Pipeline Safety Assessments	$500	0.0%	$500
(6) Regulatory Fees Gross Receipts Tax Estimate	$300	0.0%	$300
(7) Total	$19,854	2.9%	$20,423

Sources and Notes:

Line 1, Column A: Direct costs of pipeline operations per NSP-SD Gas Operations budget. Consists of 12 hours per month at loaded labor of $37.56/hour and $20/hour for vehicle usage.

Line 2, Column A: Supplemental emergency service from ACA. One call per month @ $300/call.

Line 3, Column A: Services received from NSP-South Dakota personnel. Ten hours/month @ $60/hour.

Line 4, Column A: Insurance costs @ $0.03/$100 of investment per NSP's Risk Mgmt. Dept.

Line 5, Column A: Office of Pipeline Safety assessment based on a similarly situated intrastate pipeline in South Dakota.

Line 6, Column A: Annual regulatory fees based on Gross Receipts Tax. Calculation based on a similarly situated intrastate pipeline in South Dakota.

Column B: Annual escalators based on expectations of price inflation.

Column C: One-year escalations of amounts in Column A.

Line 7: Columns A and C are summarized and used to derive the overall escalator in Column B.

Northern States Power Company (Minn)
NSP-SD Gas Operations
Before the South Dakota PUC
Docket NG97-021
First Set MEC Data Requests
Response to: No. 13

☐ **Proprietary**

X Non-Proprietary

Question:

Witness Winter in his testimony Page 4, Line 14 refers to the maximum commodity rate of $.045 rate? Is this rate based on projected sales level or maximum throughput and why?

Response:

The $0.045 maximum rate for use of the Angus C. Anson 12" pipeline is based on the maximum likely throughput of a typical pipeline operation. The $0.045 rate was negotiated between NSP-SD Gas Operations and NSP-Generation. Specific approval of the $0.045 rate is not sought in this application.

Response By:	John Winter
Title:	Sr. Regulatory Consultant
Company:	NSP

Northern States Power Company (Minn)
NSP-SD Gas Operations
Before the South Dakota PUC
Docket NG97-021
First Set MEC Data Requests
Response to: No. 14

☐ **Proprietary**

X **Non-Proprietary**

Question:

Witness Winter in his testimony Page 4, Line 19-20, states that NSP Generation Pipeline is not subject to Commission jurisdiction. What is the basis of the argument?

Response:

The 12" fuel supply pipeline to the Angus C. Anson generating unit exists due to the natural gas needs of the 200 MW combustion turbine power plant. It is operated and controlled by NSP-Generation. As a point of clarification, the pipeline *is* subject to SDPUC jurisdiction as a component of electric generation costs. It is also subject to SDPUC pipeline safety jurisdiction. Thus, the revenue requirements associated with the 12" pipeline would be fully includable in electric rates as integral to the provision of electric supply service in all of NSP's electric sales jurisdictions. As stated in the response to MEC's request No. 4, however, the pipeline has not been included in electric rates due to timing of the Company's electric rate cases.

The agreement to tap the Angus C. Anson pipeline is between NSP-Generation and NSP-SD Gas Operations. Rates were negotiated and agreed upon. Cost support information for the rate ($0.045 per Mcf) is included in this application as a matter of support and convenience. The revenues billed and collected by NSP-Generation are regulated and will be credited back to the electric cost of service, reducing electric customers' rates. Specific approval for the $0.045 per Mcf rate is not sought in this application, and NSP is not proposing the PUC take the rate or service jurisdiction over the 12" line.

Response By: John Winter
Title: Sr. Regulatory Consultant
Company: NSP

Northern States Power Company (Minn)
NSP-SD Gas Operations
Before the South Dakota PUC
Docket NG97-021
First Set MEC Data Requests
Response to: No. 15

☐ **Proprietary**

X Non-Proprietary

Question:

Witness Winter in his testimony Page 4, Lines 24-28, and Page 5, Lines 1-5 states the cost of operation and maintenance expense of the 12 inch pipeline and 4.5 inch pipeline would be the same. Please explain the cost justification of how this can be the same?

Response:

The statements on Page 4, lines 27 and 28, and Page 5, lines 1 through 5 (copies attached), do not say that the operation and maintenance expense of the 12 inch and 4.5 inch pipelines are the same. The actual statement is (beginning on Page 4, line 27),

> "The major fixed charge rate components (capital recovery, property taxes, and book depreciation) are ***proportionately the same*** between the two segments of pipeline. The operating and maintenance expense component represents a ***reasonable proxy*** for the 12" line. Consequently, use of the 4.5" fixed charge rate provides a ***reasonable determination*** of the 12" line revenue requirements of $698,836." (emphasis added)

The reference to "proportionately" is based on the ratio of O&M expenses to gross plant investment. Clearly, the statement does not suggest that O&M expenses for the two lines are the same. O&M is part of the fixed charge rate which is applied to gross plant investment to derive revenue requirements. The implication is that O&M expense, on the basis of gross plant investment, is comparable between the two lines. This remains a reasonable conclusion.

Response By:	John Winter
Title:	Sr. Regulatory Consultant
Company:	NSP

Q Does the tax vs. book depreciation differences have an impact on the proposed rate?

A Essentially, there is no impact. I have simplified the revenue requirements calculation by setting tax depreciation equal to book depreciation. Since this is a levelized determination, the result is essentially the same as if the tax vs. book differences were deferred and later flowed back.

Q Have you provided additional detail about your determination of NSP-SD's maximum gas transportation rates?

A Yes. Each of Schedules 2 - 6 include a section showing Sources and Notes. These references provide additional documentation for the cost of service.

Q Are there any other aspects of the HTI rate you care to address?

A Yes. Included in the proposed maximum commodity rate is $0.045 per Mcf which NSP-SD has agreed to transfer to NSP-Generation for NSP-SD's use of the Angus Anson 12" fuel supply pipeline. For informational purposes, I have included the cost support for that rate in this application. However, NSP-SD is not seeking specific approval of that rate, nor is it requesting the Commission to assume jurisdictional authority over that facility, because the line will directly serve only NSP-Generation and NSP-SD, and thus not subject to Commission jurisdiction under SDCL 49-34A-1, Subd. 9A. The $0.044 per Mcf rate for use of the 12" supply line is supported by my informational calculations shown on Schedule 7.

Q How did you develop the rate for the 12" Angus Anson supply line?

A As the basis for negotiations between NSP-SD Gas Operations and NSP-Generation, I applied the fixed charge rate developed for the 4.5" line to the investment in the 12" line to determine the revenue requirements for the 12" line. The major fixed charge rate components (capital recovery, property taxes, and book depreciation) are proportionately the same between the two segments of pipeline The operating and maintenance expense component represents a reasonable proxy for the 12" line Consequently, use of the 4.5" fixed charge rate provides a reasonable determination of the 12" line revenue requirements of $698,836 The 12" line rate is determined by dividing the revenue requirements by a representative utilization of the line

Q Please describe the required filing statements included with this application
A Exhibit 5 of this filing consists of the required filing statements per Chapter 20:10:13 of the South Dakota Administrative Rules The initial pages of that exhibit list the statements included, or that are not applicable The reasons certain statements are not applicable is described on page two of the listing Waiver of those statements not applicable is respectfully requested from the Commission

Q Is NSP proposing some form of purchased cost of gas adjustment mechanism?
A Yes Unlike typical gas local distribution companies, NSP-SD will be exclusively a gas transporter and will not provide sales service However, NSP-SD proposes to pass along uncontrollable charges imposed by Northern Natural Gas, the upstream interstate pipeline Section 5.0 on the Firm Transportation Service Schedule, First Revised Sheet No. 15 discusses the pipeline cost adjustment It is also included in the Gas Transportation Service Agreement in Section 3.4, First Revised Sheet No. 21

Q Has HTI agreed to the rates consistent with those proposed in this application?
A Yes HTI has executed an agreement with NSP-SD for natural gas service to its new Sioux Falls facility using the form of agreement contained in the proposed tariff, at negotiated rates HTI's rates for natural gas transportation and the customer charge are at or below the maximum rates discussed previously and supported by the calculations and schedules contained herein

Northern States Power Company (Minn)
NSP-SD Gas Operations
Before the South Dakota PUC
Docket NG97-021
First Set MEC Data Requests
Response to: No. 16

☐ **Proprietary**

X **Non-Proprietary**

Question:
Referring to Witness Winter testimony on Page 5, Lines 25-27, please explain how HTI's rates are at or below maximum rates?

Response:
The rates contained in the agreement between NSP and HTI, on file with the Commission, are below the maximum rate represented in the NSP-SD application.

Response By: John Winter
Title: Sr. Regulatory Consultant
Company: NSP

Northern States Power Company (Minn)
NSP-SD Gas Operations
Before the South Dakota PUC
Docket NG97-021
First Set MEC Data Requests
Response to: No. 17

☐ **Proprietary**

X Non-Proprietary

Question:
Referring to Witness Winter testimony, Exhibit Schedule 2, is the rate of $0.214 based on maximum capacity? If this rate is based on maximum capacity what is the potential sales level usage needed to support the rate?

Response:
As shown on Schedule 2, the rate is based on the maximum capacity per hour of 306 Mcf (90% of the rated capacity of 340 Mcf per hour) and the number of hours per year the pipeline will likely be operated at capacity. The resulting volumetric divisor is 480,726 Mcf per year.

Response By:	John Winter
Title:	Sr. Regulatory Consultant
Company:	NSP

Northern States Power Company (Minn)
NSP-SD Gas Operations
Before the South Dakota PUC
Docket NG97-021
First Set MEC Data Requests
Response to: No. 18

☐ **Proprietary**

X **Non-Proprietary**

Question:
Referring to Witness Winter testimony, Exhibit Schedule 2, where are the costs for meter maintenance, service lines and balancing of gas supply service? What cost are included in the 14.08% fixed charge rate?

Response:
Costs for meter maintenance and service lines are included in the $60 per month shown on Line 9 of Schedule 2. Gas supply balancing is included in the gas supply service provided by HTI's gas supplier (currently EMI, a subsidiary of NSP), on behalf of HTI.

Response By: John Winter
Title: Sr. Regulatory Consultant
Company: NSP

Northern States Power Company (Minn)
NSP-SD Gas Operations
Before the South Dakota PUC
Docket NG97-021
First Set MEC Data Requests
Response to: No. 19

☐ **Proprietary**

X **Non-Proprietary**

Question:

Please refer to Witness Winter testimony, Exhibit Schedule 5. Please explain the basis to support the annual insurance cost of $100. Does this insurance cover the liability to operate and customer liability coverage? Is this insurance covered by NSP Company self-insurance or, actual outside insurance policies held by the Company?

Response:

Per the footnote on Schedule 5, the insurance cost is supported by a discussion with NSP's Risk Management Dept. The basis is an historical insurance cost of $0.03 per $100 of investment for these type of facilities. NSP self-insures pipeline facilities. NSP has operated a Gas Utility in Minnesota, North Dakota, and Wisconsin for decades and has extensive experience in assessing risks associated with these facilities.

Response By:	John Winter
Title:	Sr. Regulatory Consultant
Company:	NSP

Northern States Power Company (Minn)
NSP-SD Gas Operations
Before the South Dakota PUC
Docket NG97-021
First Set MEC Data Requests
Response to: No. 20

☐ **Proprietary**

X Non-Proprietary

<u>Question</u>:
Referring to Witness Winter's testimony, Exhibit Schedule 5, the reference of Sources and Notes cover each component of expense on the sheet. Are there S.D. cost allocations included from NSP headquarters operations in Minnesota? <u>Examples</u> of costs are supply operation costs, billing services and gas supply balancing service.

<u>Response</u>:
The question is not entirely clear. An allocation of cost from NSP-SD is included in the cost of service. The amount is shown on Schedule 5. Supply operation costs and the balancing service are included in HTI's gas supply arrangements, not in the pipeline cost of service. Operation services, as I understand them, and billing services are included in the costs allocated from NSP-SD. Meter reading and billing were assumed to be handled from the NSP-SD Sioux Falls office.

Response By:	John Winter
Title:	Sr. Regulatory Consultant
Company:	NSP

Northern States Power Company (Minn)
NSP-SD Gas Operations
Before the South Dakota PUC
Docket NG97-021
First Set MEC Data Requests
Response to: No. 21

☐ **Proprietary**

X Non-Proprietary

Question:

Referring to Witness Winter's testimony, Exhibit Schedule 7. Mr. Winter used the maximum volumes divided into the annual revenue requirement to determine a factor based on maximum sales. Shouldn't the assigned 325 demand peak hour capacity assigned to the Gas Distribution Company be used?

a.) If the 325 demand is used divided by 4,900 it equates to 6.63% of revenue requirement to be assigned directly to the Gas Distribution Company. Using the 6.63% times $698,836 total revenue requirement equals $46,332 of cost assignment to the Gas Distribution Company. If HTI were the only customer the capacity cost assigned would be $43,332 divided by 159,000 MCF sales equals $.273 per MCF. Isn't this the amount of cost which needs to be assigned to NSP Gas Distribution Company to recover their costs?

Response:

No. The approach outlined above, which refers to compensation agreed upon between NSP-SD Gas Operations and NSP-Generation, would result in a rate that is unacceptably high and disproportionate to other similarly-situated pipeline supply rates. As discussed in Response Nos. 13 and 14, the rate of $0.045 per Mcf is reasonable because the primary purpose of the 12" line is to provide fuel delivery to an electric peaking power plant. The revenues from NSP-SD would partially offset the revenue requirement on the 12" line in future NSP electric cases.

The agreed-upon rate is supported by reasonable assumptions. Full cost recovery of a regulated investment is the usual standard. However, in this case, full cost recovery without recognizing the atypical operating characteristics of the Angus C. Anson gas supply line is inappropriate. By pricing the 12" line usage more in line with a similarly situated gas pipeline, NSP-SD Gas Operations customers benefit from a economical delivery source, and NSP electric customers benefit from a previously unavailable cost offset.

Response By:	John Winter
Title:	Sr. Regulatory Consultant
Company:	NSP

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OF COUNSEL:
WARREN W. MAY

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E-MAIL
dag@magt.com

June 4, 1998

Mr. William Bullard, Jr.
Executive Director
Public Utilities Commission
State Capitol
500 East Capitol Avenue
Pierre, South Dakota 57501-5070

RECEIVED
JUN 05 1998
SOUTH DAKOTA PUBLIC UTILITIES COMMISSION

RE: **NSP NATURAL GAS UTILITY APPLICATION**
Docket NG97-021
Our file: 0185

Dear Bill:

This will confirm our telephone conversation of June 2, 1998. I had pointed out to you that the caption in this matter had not been changed as a part of the order regarding jurisdiction and approving intervention entered by the Commission dated May 6, 1998. Upon reflection, you advised me that it was an oversight that the caption was not changed and the order regarding jurisdiction and approving intervention provides the authority to change the caption. You indicated that the Commission will commence using the amended caption in all future filings.

The amended caption will be as stated in NSP's motion to amend application dated April 6, 1998, as follows:

> IN THE MATTER OF THE APPLICATION FOR AN ORDER ESTABLISHING A NATURAL GAS UTILITY, AND TO ESTABLISH INITIAL NATURAL GAS TRANSPORTATION RATES FOR NORTHERN STATES POWER COMPANY.

Thank you for looking into this for me. So that the other parties are advised, I am forwarding a copy of this letter to the service list.

Yours truly,

MAY, ADAM, GERDES & THOMPSON LLP

BY: Dave Gerdes

DAG:mw
cc: Jim Wilcox
Suzan Stewart
Jennifer Erickson

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF SOUTH DAKOTA

IN THE MATTER OF THE APPLICATION FOR AN ORDER ESTABLISHING A NATURAL GAS UTILITY, AND TO ESTABLISH INITIAL NATURAL GAS TRANSPORTATION RATES FOR NORTHERN STATES POWER COMPANY	)))))	**ORDER FOR AND NOTICE OF HEARING** **NG97-021**

On December 16, 1997, Northern States Power Company (NSP), filed with the Public Utilities Commission (Commission) an application for an order establishing a natural gas local distribution utility, and to establish initial natural gas transportation rates. The initial rate will allow NSP-SD to serve the new Hutchinson Technology, Inc. (HTI) facility in the Sioux Empire Development Park Number 5 in eastern Sioux Falls, South Dakota, through a new distribution lateral pipeline. HTI had contacted NSP-SD and requested the proposed service. The proposed tariff, rate schedule, and form of service agreement would establish NSP-SD as a regulated utility in the state of South Dakota, subject to Commission jurisdiction. The proposed maximum rate is a volumetric rate per Mcf with a per month fixed customer service charge. At present, only HTI is affected by the proposed rate and tariff. The HTI plant is expected to be in commercial operation in February of 1998. NSP also requested that the Commission waive the tariff schedule arrangement and form of tariff rules found at ARSD 20:10:13:04 and 20:10:13:05 to the extent necessary to accept the proposed tariff and rates on the proposed effective date of January 16, 1998. NSP further requested waiver of any other Commission rules necessary to allow the tariff and rate to be effective on the date requested. NSP has further requested the Commission to approve the proposed initial rate, subject to refund and subject to hearing, within 30 days following the date of the filing.

At its regularly scheduled meeting of January 8, 1998, the Commission ordered that pursuant to SDCL 49-1A-8, NSP shall be assessed a filing fee as requested by the executive director up to the statutory limit of $100,000 and February 9, 1998, was established as the deadline for intervention. The Commission took under advisement the request by NSP to permit it to flow gas to its one customer, HTI. On January 12, 1998, at a duly noticed ad hoc meeting, the Commission unanimously voted to allow NSP to flow gas through its pipeline, subject to refund, in order to accommodate its customer, HTI. Commissioner Schoenfelder also asked for clarification as to whether the Commission has jurisdiction to regulate NSP-SD as a gas utility. Intervention was granted to MidAmerican Energy. An intervention request was also received from PAM Natural Gas (PAM). The Commission requested that PAM refile its request for intervention to clarify the filing. On February 23, 1998, PAM filed another request for intervention.

On April 7, 1998, NSP filed an amended application requesting that the title of the application be amended to allow it to seek to be regulated as a gas utility. On April 15, 1998, MidAmerican Energy filed an amended motion to intervene based on NSP's amended application. On April 22, 1998, at its regularly scheduled meeting, the Commission found that the Commission has jurisdiction in this matter pursuant to SDCL Chapters 1-26 and 49-34A, specifically 1-26-17.1, 49-34A-4, 49-34A-6, 49-34A-8, 49-34A-10, 49-34A-11, 49-34A-12, 49-34A-13, 49-34A-13.1, 49-34A-17, 49-34A-19, 49-34A-21, and ARSD 20:10:01:15.02 and .03. It also granted intervention to MidAmerican and PAM.

The procedural schedule for testimony shall be as follows:

DATE	PROCEDURAL SCHEDULE
December 11, 1998	Staff and Intervenors' Prefiled Testimony Due
December 23, 1998	Rebuttal Testimony Due

A hearing shall be held at 1:30 p.m., on Monday, January 4, 1999, in Room 412, State Capitol Building, 500 East Capitol, Pierre, South Dakota. The hearing is open to the public. All persons so testifying shall be subject to cross-examination.

The issues at the hearing are whether the Commission shall grant NSP's request to establish natural gas transportation tariffs and whether the Commission shall grant NSP's request for a waiver of ARSD rules 20:10:13:04 and 20:10:13:05.

The hearing shall be an adversary proceeding conducted pursuant to SDCL Chapter 1-26. All parties have the right to be present and to be represented by an attorney. These rights and other due process rights shall be forfeited if not exercised at the hearing. If you or your representative fail to appear at the time and place set for the hearing, the Final Decision will be based solely on the testimony and evidence provided, if any, during the hearing or a Final Decision may be issued by default pursuant to SDCL 1-26-20. After the hearing the Commission will consider all evidence and testimony that was presented at the hearing. The Commission will then enter Findings of Fact, Conclusions of Law, and a Final Decision regarding this matter. As a result of this hearing, the Commission shall determine whether it shall grant NSP's request to establish natural gas transportation tariffs and whether it shall grant NSP's request for a waiver of ARSD rules 20:10:13:04 and 20:10:13:05. The Commission's Final Decision may be appealed by the parties to the state Circuit Court and the state Supreme Court as provided by law. It is therefore

ORDERED that the procedural schedule set forth above shall be followed by all parties to these proceedings. It is further

ORDERED that the hearing shall be held at 1:30 p.m., on Monday, January 4, 1999, in Room 412, State Capitol Building, 500 East Capitol, Pierre, South Dakota.

Pursuant to the Americans with Disabilities Act, this hearing is being held in a physically accessible location. Please contact the Public Utilities Commission at 1-800-332-1782 at least 48 hours prior to the hearing if you have special needs so arrangements can be made to accommodate you.

Dated at Pierre, South Dakota, this 18th day of November, 1998.

CERTIFICATE OF SERVICE

The undersigned hereby certifies that this document has been served today upon all parties of record in this docket, as listed on the docket service list, by facsimile or by first class mail, in properly addressed envelopes, with charges prepaid thereon.

By Delaine Kolbo

Date 11/18/98

(OFFICIAL SEAL)

BY ORDER OF THE COMMISSION:
Commissioners Burg, Nelson and Schoenfelder

William Bullard Jr

WILLIAM BULLARD, JR.
Executive Director

MidAmerican
ENERGY

MidAmerican Energy Company
401 Douglas Street
P.O. Box 778
Sioux City, Iowa 51101
712 277-7587 Telephone
712 252-7396 Fax

Suzan M. Stewart
Managing Attorney

FAX Received DEC 10 1998

RECEIVED
DEC 14 1998
SOUTH DAKOTA PUBLIC
UTILITIES COMMISSION

December 10, 1998

BY TELEFAX & U.S. MAIL DELIVERY

Mr. William Bullard, Jr.
Executive Secretary
South Dakota Public Utilities Commission
State Capitol Building
Pierre, SD 57501

In Re: Northern States Power Company
Docket No. NG97-021

Dear Mr. Bullard:

MidAmerican Energy Company hereby notifies the Commission that it does not intend to file prepared testimony in this proceeding. MidAmerican reserves the right to fully participate in the hearing scheduled for Monday January 4, 1999 and to file briefs.

Very truly yours,

SMStewart

CC: Service List

CERTIFICATE OF SERVICE

I hereby certify that a true and correct copy of the attached Letter in Docket No. NG97-021 was sent by first class, postage pre-paid, to the following:

David A. Gerdes
Attorney at Law
May, Adam, Gerdes & Thompson
P.O. Box 160
Pierre, SD 57501-0160

Karen Collins
Montana-Dakota Utilities Co.
400 North Fourth Street
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Jim Wilcox
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Jennifer Erickson
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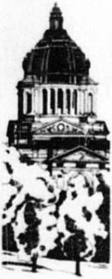
Robert C. Riter, Jr.
Attorney at Law
Riter, Mayer, Hofer, Wattier, Brown
P.O. Box 280
Pierre, SD 57501-0280

Dated this 10th day of December, 1998.

Sherry Hansel



South Dakota
Public Utilities Commission

State Capitol Building, 500 East Capitol Avenue, Pierre, South Dakota 57501-5070

December 11, 1998

Mr. William Bullard, Jr.
Executive Director
South Dakota Public Utilities Commission
500 E. Capitol Ave.
Pierre, SD 57501

RE: In the Matter of the Application for an Order Establishing a Natural Gas Utility, and to Establish Initial Natural Gas Transportation Rates for Northern States Power Company
NG97-021

Dear Mr. Bullard:

Pursuant to the South Dakota Public Utilities Commission's Order for and Notice of Hearing in the above-entitled matter, enclosed please find the prefiled testimony and exhibits of Gregory A. Rislov and Robert L. Knadle. Should you have any questions, please do not hesitate to contact me.

Sincerely,

Karen E. Cremer

Karen E. Cremer
Staff Attorney

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South Dakota Public Utilities Commission

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December 11, 1998

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Riter, Mayer, Hofer, Wattier & Brown
P. O. Box 280
Pierre, SD 57501-0280

Ms. Karen Collins
Montana-Dakota Utilities Co.
400 North Fourth Street
Bismarck, ND 58501

Re: In the Matter of the Application for an Order Establishing a Natural Gas Utility, and to Establish Initial Natural Gas Transportation Rates for Northern States Power Company
Docket NG97-021

Dear Folks:

Enclosed each of you will find copies of Testimony and Exhibit of Gregory A Rislov on behalf of the Commission Staff and Testimony and Exhibits of Robert L. Knadle on behalf of the Commission Staff. This is intended as service upon you by mail.

Sincerely,

Karen E. Cremer
Staff Attorney

Enc

CERTIFICATE OF SERVICE

I hereby certify that copies of Testimony and Exhibit of Gregory A. Rislov on behalf of the Commission Staff and Testimony and Exhibits of Robert L. Knadle on behalf of the Commission Staff were served on the following by mailing the same to them by United States Post Office First Class Mail, postage thereon prepaid, at the address shown below on this the 11th day of December, 1998.

Mr. David A. Gerdes
Attorney at Law
May, Adam, Gerdes & Thompson LLP
P. O. Box 160
Pierre, SD 57501-0160

Ms. Suzan M. Stewart
Managing Attorney
MidAmerican Energy Company
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Mr. Jim Wilcox
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Mr. Michael J. Hanson
Chief Executive and General Manager
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Ms. Jennifer Erickson
Chief Operating Officer
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Mr. Robert C. Riter, Jr.
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Karen E. Cremer

Karen E. Cremer
Staff Attorney
South Dakota Public Utilities Commission
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December 23, 1998

HAND DELIVERED

Mr. William Bullard, Jr.
Executive Director
Public Utilities Commission
State Capitol
500 East Capitol Avenue
Pierre, South Dakota 57501-5070

RECEIVED
DEC 23 1998
SOUTH DAKOTA PUBLIC
UTILITIES COMMISSION

RE: **NSP NATURAL GAS UTILITY APPLICATION**
Docket NG97-021
Our file: 0185

Dear Bill:

Enclosed for filing are original and ten copies of the rebuttal testimony and schedules of James A. Smith and Jamie Seitz.

One of the schedules accompanying **Jamie Seitz's testimony** is **proprietary and confidential.** I have placed a cover sheet on it and placed it separately with the enclosed materials. Please keep the confidential portions of this filing separate from the public portion.

With a copy of this letter, copies of the public portion of the rebuttal testimony and schedules are being sent to the service list. Thank you very much.

Yours truly,

MAY, ADAM, GERDES & THOMPSON LLP

BY:

DAG:mw
Enclosures
cc/enc: Jim Wilcox
James A. Smith
Jamie C. Seitz
cc/public enc: Suzan M. Stewart
Karen Collins
Kent Larson
Jennifer Erickson
Robert C. Riter, Jr.
Bob Knadle

CONFIDENTIAL

1

NSP

Northern States Power Company
Gas Utility

825 Rice Street
Saint Paul, Minnesota 55117-5485

December 29, 1998

William Bullard, Jr.
Executive Director
South Dakota Public Utilities Commission
500 East Capitol Avenue
Pierre, SD 57501

Re: Northern States Power Company – South Dakota
Docket No. NG97-021
Errata Corrections to NSP Rebuttal Testimony and Schedules

Dear Mr. Bullard:

In discussions with the South Dakota Public Utilities Commission Staff ("Staff"), Northern States Power Company – South Dakota (NSP-SD) realized several errata changes are needed to correct errors in the pre-filed rebuttal testimony filed by NSP - SD on December 23, 1998. All errata corrections are attached and shown in legislative format. The errata corrections should expedite the hearing procedures scheduled for January 4, 1998.

First, Page 9, Line 8 of the rebuttal testimony of Ms. Jamie Seitz should state $0.045 instead of $0.04. This change should be repeated on Schedule 5, Line 6 of Ms. Seitz's testimony.

Second, JCS – 1, Schedule 4 has been corrected to include an Interruptible Transportation commodity rate in the overtake purchase example.

Next, several minor typographical errors to JCS –1, Schedule 2 have been corrected, and are summarized as follows:

- Original Sheet No. 7, Section 3.4 (b)
  The word "of" was replaced with "to" and the misplaced "to" was deleted.
- Original Sheet No. 11, Section 7.2
  The references to "delivery point" now state "delivery point(s)".
- Original Sheet No. 12, Section 8.2
  The term "filing transmittal date" was replaced with "billing date".
- Original Sheet No. 20, Section 2.2
  The word "least" was added before the phrase "one hour prior to the time Transporter must submit daily nominations to Northern pursuant to Northern's tariffs".
- Original Sheet No. 21, Section 2.7
  The margins were corrected to clarify the undertake/overtake purchase rates. In addition, the abbreviation of Firm Transportation was left as TF because the official designation in Northern's tariff is to "TF" service. Therefore, to address Mr. Knedle's concerns about consistency, the abbreviation of Interruptible Transportation was changed to "TI" on Original Sheet No. 22.
- Original Sheet No. 22, Section 2.7
  The reference to the Argus C. Anson fuel supply pipeline surcharge was eliminated, consistent with Page 6, Lines 20-23 of Ms. Seitz's testimony.

Mr. William Bullard
December 29, 1998

- Original Sheet No. 22, Section 3.2
  The reference to +/- 5 percent daily tolerance zone was replaced with "daily delivery variance (+/-) established in Northern's tariff" to be consistent with other sections of the tariff.

Also, Staff had raised a question through Mr. Knadle's direct testimony regarding nomination procedures which NSP – SD inadvertently did not address in rebuttal testimony. Mr. Knadle requested the accuracy of the nomination procedures (described in section 2.2 of JCS-1 – Schedule 2, Original Sheet No. 20) be confirmed. NSP-SD has confirmed the section is accurate.

In addition, to provide further clarification, NSP has provided a summary of the proposed rates by class in Schedule 2, Original Sheet No. 17 of Ms. Seitz's testimony. This sheet was previously reserved for future use. The values shown on this summary would provide the upper and lower limits which would be used in the service charge section of the gas transportation agreement (JCS -1, Schedule 2), signed with individual customers.

Service

NSP will serve a copy of this letter and attachments on the parties indicated on the official service list for this proceeding. A certificate of service and service list is attached.

Conclusion

Thank you for your prompt attention to this matter. Please feel free to call Amy Liberkowski (651-229-2367) with any questions.

Sincerely,

James P. Johnson

James P. Johnson
Senior Attorney

cc: Service List

CERTIFICATE OF SERVICE

I, Mary E. Lewis, hereby certify that I on this day served copies of the foregoing document or summary on the attached service list by placing the document in the First Class U.S. Mail at St. Paul, Minnesota, or by having the document delivered by hand.

Dated this 29th day of December, 1998.

Mary E. Lewis
Mary E. Lewis
Northern States Power Company

Mr. David A. Gerdes
Attorney at Law
May, Adam, Gerdes & Thompson
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Mr. Robert C. Riter Jr.
Attorney at Law
Riter, Mayer, Hofer, Wattier & Brown
P.O. Box 280
Pierre SD 57501-0280

Q. Do you have any other changes based on Mr. Knadle's testimony?

A. Yes. Mr. Knadle recommends that the floor of the transportation rate be raised to minimally recover variable costs for the customer and to provide for some contribution toward NSP's distribution system fixed costs. Schedule 5 has been provided to identify the new minimum rate of \$0.12 per Dth to recover \$0.045 as a contribution to the Angus Anson pipeline, \$0.06 in incremental O&M costs and \$0.02 as a contribution to system fixed costs.

Mr. Knadle also recommends providing specific language on the determination of the customer charge for prospective customers. NSP-SD would like to establish a \$12 Customer Charge for Small Volume Customers (peak day requirements of less than 500 therms) and a \$50 Customer Charge for Medium Volume Customers (peak day requirements of 500 therms to 1,999 therms) in response to his request. Since customers with similar usage patterns will have the same metering requirements, it will be more practical to establish a customer charge based on typical meter costs for a particular class of customer. Schedule 6 contains the calculation of these charges.

Q. If these new customer charges are established, what corresponding transportation charges are you proposing?

Northern Staates Power Company - South Dakota
Gas Operations
Minimum Transportation Service Rate

Docket No. NG97-021
JCS-1 Schedule 5
Errata Corrected

Variable Operating Costs:

(1) Investment in HTI	$454,853
(2) Revised O&M LARR	6.02%
(3) Annual O&M Costs	$27,382.15
(4) HTI Annual Usage (MCF's)	480,726
(5) O&M Recovery Rate	0.06
(6) Angus Anson Pipeline Rate	$0.045
(7) Contribution to System Fixed Costs	$0.02
(8) Revised Minimum Transportation Rate	$0.12

(1) Actual Plant in Service per JAS-1, Schedule 3, page 1 of 3
(2) Revised O&M LARR factor per JAS-1, Schedule 3, page 2 of 3
(3) Revised O&M LARR * Investment in HTI
(4) Pipeline MCF Capacity per Hour (306) * Hour per Year equivalent for HTI @ Capacity (1,571)
(5) Annual O&M Costs / HTI Annual Usage
(6) Angus Anson Pipeline Rate per JAS, Schedule 2
(7) Contribution to System Fixed Costs
(8) O&M Recovery plus Angus Anson Pipeline Contribution plus Contribution to System Fixed Costs

Docket No. NG97-021
JCS - 1 Schedule 4
Errata Corrected

Examples of Monthly Cashout Mechanisms

1) Undertakes: Customer takes too little gas and must sell gas to NSP-SD's system.

Assumptions:

Index = $2.00/Dkt
TF Commodity Rate = $0.20 per Dkt^
Customer nominates 100 Dkt

Percent of Nomination Taken	Volume Taken (Dkt)	Under Nomination	Amount Paid to Customer to Purchase Gas Customer Did Not Use	
98%	98	-2	($2.00 + $0.20) * 2 Dkt =	$4.40
90%	90	-10	($2.00 + $0.20) * 0.75 * 10 Dkt =	$16.50
85%	85	-15	($2.00 + $0.20) * 0.5 * 15 Dkt =	$16.50

2) Overtakes: Customer takes too much gas and must purchase gas from NSP-SD's system.

Assumptions:

Index = $2.00/Dkt
TI Commodity Rate = $0.25 per Dkt^
Customer nominates 100 Dkt

Percent of Nomination Taken	Volume Taken (Dkt)	Over Nomination	Amount Customer Pays to Buy Gas	
102%	102	2	($2.00 + $0.25) * 2 Dkt =	$4.50
110%	110	10	($2.00 + $0.25) * 1.25 * 10 Dkt =	$28.13
115%	115	15	($2.00 + $0.25) * 1.5* 15 Dkt =	$50.63

^ The TF and TI commodity rates are for illustrative purposes only. However, the rates reflect the general structure of firm and interruptible transportation commodity rates where firm commodity rates are lower than interruptible commodity rates.

ARTICLE III
MEASUREMENT

3.1 Unit of Measurement and Metering Base. The volumetric measurement base shall be one cubic foot of gas at a pressure base of 14.73 pounds per square inch absolute, at a temperature base of 60 degrees Fahrenheit, and without adjustment for water vapor content.

3.2 Atmosphere Pressure. For the purpose of measurement, the absolute atmospheric (barometric) pressure at each measuring station shall be the atmospheric pressure determined by calculations based on the actual elevation above sea level of the meter at the place of measurement, and shall be stated in pounds per square inch.

3.3 Temperature. If determined to be necessary in the sole discretion of Transporter, the temperature of the gas shall be determined at each point of measurement by means of a properly installed recording thermometer, an indicating thermometer, an electronic temperature measuring device, or a temperature compensating meter of standard manufacture acceptable to Transporter.

3.4 Specific Gravity. If determined to be necessary in the sole discretion of Transporter, the specific gravity of the gas shall be determined at each point of receipt by one of the following methods:

(a) By means of a properly installed recording gravitometer of standard manufacture acceptable to Transporter.

(b) If (a) is not considered feasible, then by use of a portable specific gravity balance of standard manufacture, or other standard device acceptable to~~of~~ Transporter and designed for such purpose or use in conjunction with a continuous sampler.

(c) Other methods acceptable to Transporter.

3.5 Measurement Procedures. Quantities of gas received and delivered hereunder shall be measured in accordance with Procedures contained in ANSI-API 2530, First Edition, AGA Committee Report No. 5, AGA Committee Report No. 7, and AGA Committee Report No. 8, or revisions or amendments thereto.

3.6 Measuring Equipment. Unless otherwise agreed, Transporter will provide, maintain, and operate necessary measuring and regulating stations equipped with flow meters and other necessary measuring equipment by which ~~its~~ quantities of gas delivered from Transporter hereunder shall be determined. Such measuring and regulating stations shall be so installed at the receipt point of the System and at other agreeable points. All flow, measuring, testing, and related equipment shall be of standard manufacture and type acceptable to Transporter.

month by making adjustments to schedules, receipts or deliveries. In no event shall the daily excess or deficiency variance exceed the allowable daily point of delivery variation set forth in Northern's Tariff.

6.3 Monthly Imbalances. Shipper's monthly imbalance shall be the net total of daily variance from all receipts and delivery point(s). Such monthly imbalance shall be corrected in-kind through adjustments to Shipper's schedules, receipts or deliveries in order for Shipper to receive Equivalent Quantities, or by such other method as is then mutually agreed upon by the parties hereto. The cumulative daily variances during any month above or below the quantities scheduled shall not exceed the monthly point of delivery ~~monthly~~ variance set forth in Northern's tariff.

~~6.4 Disposition of Excess Gas. In order to alleviate conditions that threaten the integrity of its System, Transporter may periodically acquire quantities of gas that are in excess of System needs. Transporter may make interruptible sales of such gas form time to time at the point of receipt pursuant to 18 CFR 284.402. Such sales shall be made under rates, terms and conditions mutually agreed upon between Transporter and the purchaser, provided that all such sales shall be fully interruptible.~~

ARTICLE VII
PRESSURE

7.1 Pressure at the Points of Receipt. Shipper shall cause the gas to be delivered at the points of receipt at a pressure sufficient to allow the gas to enter the System; however, Shipper shall not be required to deliver gas to the Transporter at any point of receipt at a pressure in excess of the minimum pressure specified with respect to each receipt point in Exhibit A of Shipper's TSA.

7.2 Pressure at Points(s) of Delivery. Transporter shall deliver gas to Shipper's delivery point(s) at the pressure existing in the Transporter's pipeline; however, Transporter must deliver gas to each point at a pressure not less than the minimum pressure specified with respect to each delivery point in Exhibit A to Shipper's TSA. Transporter, however, shall not be required or permitted to deliver gas at a pressure in excess of the maximum pressure specified for each point of delivery set forth in Exhibit A attached to Shipper's TSA.

ARTICLE VIII
BILLING AND PAYMENT

8.1 Billing. Unless otherwise agreed, on or before the 10th day of each month, Transporter shall render to Shipper a statement of the total amount of gas delivered by Transporter to Shipper at the point(s) of ~~receipt~~ delivery hereunder during the preceding month and the amount due. When information necessary for billing purposes is in the control of Shipper, Shipper shall furnish such information to Transporter on or before the 10th day of the month.

Shipper and Transporter shall have the right to examine at reasonable times, books, records, and recording charts of the other to the extent necessary to verify the accuracy of any statement, charge, or computation made under or pursuant to any of the provisions hereof.

8.2 Payment. Unless otherwise agreed, Shipper shall pay Transporter at its general office or at such other address as Transporter shall designate ~~on or before the 28th day of the month, the amount due for the preceding month. If presentation of a bill by Transporter is delayed after the 20th day of the month, then the time of payment shall be extended accordingly unless shipper is responsible for such delay~~within 20 days after the billing date.

8.3 Remedies for Failure to Pay. Should Shipper fail to pay all or any portion of any bill as herein provided when such amount is due, interest on the unpaid portion of the bill shall occur at a rate of one percent (1%) per month. If such failure to pay continues for 30 days after payment is due, Transporter may, in addition to any other remedy it may have hereunder, suspend further delivery of gas until such amount is paid, if authorized pursuant to the rules of the SDPUC.

~~8.4 Disputed Bills. If Shipper in good faith shall dispute the amount of any such bill or part thereof and shall pay to Transporter such amounts as it concedes to be correct and, at any time thereafter within 30 days of a demand made by Transporter, shall furnish a good and sufficient surety bond in an amount and with surety satisfactory to Transporter, guaranteeing payment to Transporter of the amount ultimately found due upon such bills after a final determination which may be reached either by agreement or judgment of the courts, as may be the case, then Transporter shall not be entitled to suspend further delivery of gas unless and until default be made in the conditions of such bond.~~

8.4~~5~~ Adjustment of Billing Errors. In the event of a meter or billing error, as defined by the Public Utilities Commission, the Company shall recalculate the bills for service during the period of the error and make adjustments of bills in accordance with the rules prescribed by the Commission. If a customer has been overcharged as a result of the error, the recalculated amount will be refunded or, where applicable, a credit on a bill shall be made. If a customer has been undercharged as a result of the error, the Company may bill the customer if the amount due exceeds \$10.00. The first billing of the recalculated amount due will be separately billed on a form different from the normal bill form and include a complete explanation of the billing. ~~If it shall be found that at any time or times Shipper has been overcharged or undercharged in any form~~

service to Customer. However, Company may at its option, agree to provide backup gas service.

2.1 REQUIREMENTS AND DELIVERIES; POINT OF DELIVERY. Company agrees to accept delivery of Customer's gas at the inlet of Company's distribution system in Minnehaha County, SD and, on a firm basis, transport and deliver said gas to Customer's point(s) of delivery in volumes up to ___ MMBTU per day, or such other volumes as is mutually agreed. Customer's point(s) of delivery shall be the outlet of the meter installation(s) at ______________________________.

2.2 DAILY NOMINATIONS. Customer or Customer's Agent shall on a daily basis advise Company's gas dispatcher in St. Paul of the volumes Customer will request to be delivered during the following Gas Day. Customer may alternatively elect to make a standing nomination with Company, notifying Company on any day when customer's daily deliveries will differ from the standing nomination by the daily delivery variance (+/-) established in Northern's tariffs. ~~more than five (5) percent.~~ Customer shall submit daily or corrected standing nominations to Company at least one hour prior to the time Transporter must submit daily nominations to Northern pursuant to Northern's tariffs. ~~least 24 hours in advance of the start of the Gas Day.~~ Customer's daily or standing nomination shall be its best estimate of the expected utilization for the Gas Day. If Customer and Company mutually agree, Company will relay Customer's daily or standing nomination to Customer's Agent, gas supplier(s), and Transporter.

2.3 DISPATCHING. Customer will adhere to gas dispatching policies and procedures established by Company from time-to-time to facilitate service under this Agreement. Company will inform Customer of any changes in dispatching policies that may affect this Agreement as they occur.

2.4 RATE OF FLOW. The gas supply shall be transported to Customer at a rate of flow up to but not exceeding ________ cubic feet per hour at the point(s) of delivery. Gas shall be delivered at such pressures and temperatures as may exist under operating conditions at Customer's service location. Operating pressures at this location shall normally be _______ psi.

2.5~~7~~ REFUSAL OR DISCONTINUANCE OF SERVICE (a) With reasonable notice, the Company may refuse or discontinue gas service for any of the following reasons: failure to pay amounts payable when due; breach of contract for service; failure to provide the Company with reasonable access to its property or equipment; when the Company is unable to furnish gas service to Customer because it cannot obtain permits or necessary right-of-way; when necessary to comply with any order or request of any governmental authority having jurisdiction.

(b) Upon such notice as is reasonable under the circumstances, the Company may temporarily discontinue gas service when necessary to make repairs, replacements, or changes in Company's equipment or facilities.

(c) Without notice the Company may disconnect gas service to Customer in the event of an unauthorized use of or tampering with Company's equipment or in the event of a condition determined to be hazardous to the Customer, to other customers of the Company, to the public, or to the Company's employees, equipment, or service.

Any discontinuance of service will not relieve Customer from Customer's obligations to the Company.

2.68 BALANCING. Customer and Company agree to balance daily delivery point nominations with actual deliveries (as defined in Paragraph 3.2) on an ongoing basis. Customer agrees to exert its best efforts to keep daily deliveries within daily delivery variance (+/-) established in Northern's tariff. ~~five (5) percent of daily nomination.~~ Customer and Company shall balance as operationally necessary, but no less than monthly. Customer or Customer's Agent shall be responsible for balancing receipt point nominations made to Transporter with receipt point deliveries made by Customer or Customer's Agent's gas supplier(s).

2.97 MONTHLY CASHOUT MECHANISM. Unless otherwise agreed, Customer's monthly imbalance will be corrected by a cashout mechanism. Customer's monthly imbalance is the difference between (1) the sum of Customer's daily nominations for the month and (2) Customer's actual metered use. Monthly volumetric imbalances will not be carried forward to the next calendar month.

Undertake Purchase Payment: If Customer utilizes less gas than the volume Customer nominated and delivered to NSP system, Customer shall sell the undertake gas to NSP. Customer shall be paid an Undertake Purchase Payment equal to the monthly imbalance times the Undertake Purchase Rate.

Monthly Imbalance %	Undertake Purchase Rate
100% to 98%	Index + Transporter's Firm Transportation (TF) Commodity rate(s)
Less than 98% to 90%	[Index + Transporter's TF Commodity rate(s)] x 0.75
Less than 90%	[Index + Transporter's TF Commodity rate(s)] x 0.50

Overtake Charge: If Customer utilizes more gas than the volume Customer nominated and delivered to the NSP system, Customer shall purchase the overtake gas from NSP. Customer shall be assessed an Overtake Charge equal to the monthly imbalance times the Overtake Rate.

Monthly Imbalance %	Overtake Purchase Rate
100% to 102%	Index + Transporter's Interruptible Transportation ~~(IT)~~ (TI) Commodity rate(s)
Greater than 102% to 110%	[Index + Transporter's ~~IT~~ TI Commodity rate(s)] x 1.25
Greater than 110%	[Index + Transporter's ~~IT~~ TI Commodity rate(s)] x 1.50

Index for Monthly Cashout. The Index being used is Inside FERC Gas Market Report's first of the month "Prices of Spot Gas Delivered to Pipelines" for Northern Natural (Demarcation). Applicable pipeline commodity rate consists of all interstate pipeline charges including: GRI surcharge, ~~Angus C. Anson fuel supply pipeline surcharge,~~ fuel costs and commodity rate(s). All conditions of the monthly cashout mechanism apply unless Customer and NSP agree otherwise. However, NSP will treat similarly situated customers on a non-discriminatory basis.

3.~~02~~.8 CHARGES. Commencing with the date of initial deliveries of gas by Company, the charges for this transportation service shall be according to Appendix A.

2.9~~3.1~~ MONTHLY CUSTOMER CHARGE. As established in Appendix A. The customer charge shall not exceed the maximum charge on file with the South Dakota Public Utilities Commission.

3.0~~2~~ VOLUME CHARGE. A Volume Charge equal to the product of (i) the actual deliveries made by Company to Customer during the billing period, and the ~~fixed~~ rate per MMBtu stated in Appendix A. The volume metered by NSP will be considered the actual volume delivered by Company to Customer. All volumes will be adjusted for Btu content and supercompressibility. The volume charge per MMBTU shall not exceed the maximum charge on file with the South Dakota Public Utilities Commission.

3.1~~3~~ TAXES. In addition to the rates specified above, NSP shall collect any federal, state or local sales, use, excise, or other such taxes and fees that are legally effective and applicable to the service provided hereunder.

3.2~~4~~ PENALTY PROVISION. Customer shall be liable for any balancing or other penalties imposed on NSP by Transporter and caused by Customer's actions. Customer shall also be liable for any incremental costs incurred by Company, if any, caused by Customer's failure to stay within ~~the +/- 5 percent daily tolerance zone.~~ the daily delivery variance (+/-) established in Northern's tariff.

3.3~~5~~ ADDITIONAL CHARGE FOR USE DURING CURTAILMENT. If Customer fails to curtail use of gas hereunder when requested by Company, Customer shall pay, in addition to the appropriate above rates, either an amount equal to any payment Company is required to make to Transporter as a result of Customer's failure to curtail, or $10.00 per MMBtu of gas used in excess of the volume of gas to which customer is requested to curtail, whichever amount is greater. Such payments, however, shall not

Northern States Power Company
Sioux Falls, South Dakota
Gas Transportation Service Tariff SDPUC NO. 1

Docket No. NG97-021
JCS – 1 Schedule 2

Original Sheet No. 17

Transportation Rate Summary

Availability

Small Volume	Peak day requirements of less than 500 therms
Medium Volume	Peak day requirements of 500 therms to 1,999 therms
Large Volume	Peak day requirements of at least 2,000 therms

Maximum Customer Charge per Month

Small Volume	$12.00
Medium Volume	$50.00
Large Volume	$290.00

Distribution Charge per Therm

	Minimum	Maximum
Small Volume	$0.012	$0.1030
Medium Volume	$0.012	$0.0500
Large Volume	$0.012	$0.0239

Date Filed: Dec 16, 1997
SDPUC Docket No.:

Issued by: Kent T. Larson
Chief Executive & General Manager

Effective:
Order Date:

THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF SOUTH DAKOTA

IN THE MATTER OF THE APPLICATION FOR AN ORDER ESTABLISHING A NATURAL GAS UTILITY, AND TO ESTABLISH INITIAL NATURAL GAS TRANSPORTATION RATES FOR NORTHERN STATES POWER COMPANY	NG97-021

HEARD BEFORE THE PUBLIC UTILITIES COMMISSION

PROCEEDINGS:	January 4, 1999 1:30 P.M. Room 412, Capitol Building Pierre, South Dakota
PUC COMMISSION:	Jim Burg, Chairman Laska Schoenfelder, Commissioner Pam Nelson, Commissioner
COMMISSION STAFF PRESENT:	Rolayne Ailts Wiest Karen Cremer Bob Knadle Gregory A. Rislov David Jacobson
Reported by:	Lori J. Grode, RMR, RPR

ORIGINAL

A P P E A R A N C E S

For NSP: David A. Gerdes
503 South Pierre Street
P.O. Box 160
Pierre, SD 57501

For MidAmerican: Robert C. Riter, Jr.
P.O. Box 280
Pierre, SD 57501-0280

I N D E X

E X H I B I T S

P R O C E E D I N G S

CHAIRMAN BURG: We will begin the hearing. I'll begin the hearing for docket NG97-021, In the Matter of the Application for an Order Establishing a Natural Gas Utility and to Establish Initial Natural Gas Transportation Rates for Northern States Power Company.

The time is approximately 1:30 p.m.. The date is January 4, 1999, and the location of the hearing is Room 412, State Capitol Building, Pierre, South Dakota.

I am Jim Burg, Commission Chairman. Commissioners Laska Schoenfelder and Pam Nelson are also present. I am presiding over this hearing. This hearing was noticed pursuant to the Commission's Order For and Notice of Hearing issued November 18, 1998.

The issue at this hearing -- the issues at this hearing are whether the Commission shall grant NSP's request to establish natural gas transportation tariffs and whether the Commission shall grant NSP's request for a waiver of ARSD Rules 20:10:13:04 and 20:10:13:05.

All parties have the right to be present and to be represented by an attorney. All persons so testifying will be sworn in and subject to cross-examination by the parties. The Commission's final decision may be appealed by the parties to the South Dakota Circuit Court and State Supreme Court.

Rolayne Wiest will act as Commission counsel. She may provide recommended rulings on procedure and evidentiary matters. The Commission may overrule its counsel's preliminary rulings throughout the hearing. If not overruled, the preliminary rulings will become final rulings.

At this time I will take appearances of the parties. Northern States Power Company.

MR. GERDES: Mr. Chairman, members of the Commission, my name is Dave Gerdes. I'm a lawyer from Pierre with the firm of May, Adam, Gerdes, and Thompson. And with me representing the company is Denny Fulton, who is the director of Gas, Finance, and Rates for NSP.

CHAIRMAN BURG: Okay. MidAmerican.

MR. RITER: Yes, Mr. Chair, members of the Commission, Bob Riter. I'm an attorney from Pierre. I represent MidAmerican Energy Company. And with me today is Gregory Eldon (sp), who is the director of Energy Delivery Services for that company.

MS. CREMER: Karen Cremer with Commission staff.

CHAIRMAN BURG: At this time I will turn it over to Rolayne Wiest to conduct the hearing.

MS. WIEST: Is PAM Natural Gas here? They intervened. I guess not.

Are there any opening statements or any motions before we begin with the first witness by any of the parties? If not, you can begin, Mr. Gerdes.

MR. GERDES: Your Honor, the first item, I think, as far as NSP is concerned, we would stipulate to the admission into evidence of prenumbered exhibits 1 through 12, and would offer so stipulated to by the other parties.

MS. CREMER: Staff would so stipulate.

MS. WIEST: Any objection?

MR. RITER: I have not received yet a copy of Mr. Rislov's surrebuttal testimony. Maybe it's in the mail or --

MS. CREMER: I thought she faxed it to you this morning.

MR. RITER: She may have and I just didn't get it. I apologize.

MS. CREMER: Let me give you a copy.

MR. RITER: I don't have those two, Mr. Knadle's rebuttal exhibit, nor do I have right now Mr. Rislov's surrebuttal testimony. Furthermore, I understand that Mr. Winter will not be here today to testify, and so I'm going to withhold my objection, or reserve my objection relative to his testimony until after Mr. Smith testified because I believe Mr. Smith is the individual who indicated he can affirm the testimony of Mr. Winter. So before I'm willing to stipulate to the admission of that, I would want to make sure.

MS. WIEST: Is it only Mr. Winter's you would object to at this time or not?

MR. RITER: Yes.

MS. WIEST: Okay. Then we can stipulate Exhibits 1, 2, 3, 4, and 6 through 12; is that correct? Everyone's testimony in the application, with the exception of the direct testimony of John Winter?

MR. RITER: Yes, that's agreeable with MidAmerican.

MS. WIEST: Then Exhibits 1 through 4 and 6 through 12 have been admitted.

MR. GERDES: Call Jim Wilcox.

JIM WILCOX,

called as a witness, being first duly sworn, was examined and testified as follows:

DIRECT EXAMINATION

BY MR. GERDES:

Q. Mr. Wilcox, I'll show you what's been marked as Exhibit 3 and ask you if that is a copy of your prefiled testimony in this proceeding?
A. It is.
Q. Are there any corrections or additions which you wish to make to that testimony?
A. No, there are not.
Q. If you were placed under oath and asked the questions stated in this exhibit, would you make the answers stated in the exhibit?
A. Yes, I would.
MR. GERDES: I have no additional direct testimony, and I tender Mr. Wilcox for cross-examination.
MS. WIEST: Mr. Riter, do you have any questions?
MR. RITER: Yes, I do. Thank you.

CROSS-EXAMINATION

BY MR. RITER:
Q. Mr. Wilcox, I've had an opportunity to review your prefiled testimony and wanted to make some inquiry of you relative to that. You and I met before. You know who I am, don't you?
A. Sure.
Q. I notice in your prefiled testimony you had

indicated how much gas can be moved along with the Angus Anson pipeline on page four of your testimony where you testify about that. Okay?

A. Yes.

Q. Now, for sake of reference, should we call it the Angus Anson pipeline, or what terminology suits you best?

A. I think the Angus Anson pipeline is appropriate for the 12-inch main gas supply line to the Angus.

Q. That's the one that comes from down south of Sioux Falls and it parallels 229 and works its way up almost to highway Interstate 90 in the northern part?

A. It's a 13-mile line that begins from Northern's lateral main line just east of Harrisburg and then proceeds mostly north to the Angus Anson site which is nearly Interstate 90, yes.

Q. If I understood your testimony, you indicated the amount of Mcf's per hour that could be moved through that line; is that correct?

A. Yes, I did.

Q. And apparently right now there are two combustion turbines at the site that NSP has east of Sioux Falls?

A. Yes, there are.

Q. And that each of those could use up to 1,225 Mcf's per hour at peak load?
A. That's my understanding, yes.
Q. So right now even at peak load the most you would use out of that would be 2,450 Mcf's?
A. That's -- with the exception that NSP Generation has also now dedicated 900 Mcf's per hour from that pipeline for use at the Pathfinder Steam Plant.
Q. So they've dedicated that, and not necessarily using it, but it's dedicated for that possibility?
A. Yes. Well, it's being used on peak days.
Q. So that totals 3,350 then? Add 900 to 2,450?
A. Yes.
Q. And then there's a possibility that at some future time that NSP Generation could add a third combustion turbine at the site?
A. That's correct.
Q. And your estimate in your testimony that would be another 1,225 Mcf's?
A. Yes.
Q. That leaves the 325 Mcf's that apparently are excess even if you have three combustion turbines, have 900 going to the Pathfinder Steam Plant, and run

everything at maximum, you still got extra Mcf's coming up through that pipeline?

A. Yes, that's right.

Q. And this is -- these are the capacities, I guess, for the lack of a better terminology, that you're going to make available to the 4 1/2-foot line that runs west from the plant?

A. That's 4 1/2-inch line, yes.

Q. Now, if I understood your testimony, the reason NSP has proposed this distribution pipeline is, as you've said on page five, line nine, as a competitive alternative to customers in the Sioux Empire Development Park?

A. Yes.

Q. So you recognize this to be a competitive situation with MidAmerican Energy who also has gas run right out there right across the street from the HTI plant; correct?

A. I'm aware that MidAmerican serves gas in Sioux Falls and am not certain where their facilities are located.

Q. You've been out to the site of the HTI, though, haven't you?

A. I have.

Q. And right across the street to the south there's a Pepsi plant, isn't there?

A. Pepsi, there's a Pepsi facility somewhere in the industrial park area, yeah, south of the Hutchinson building, yes.

Q. And you don't know that that is served by MidAmerican?

A. I honestly don't, Bob.

Q. But, nonetheless, you understand, of course, that MidAmerican is a competitive supplier or pipeline company?

A. Yes.

Q. Now, in your testimony you indicated that NSP does not have any plans to extend natural gas service to customers beyond the development park?

A. That's right.

Q. Is that still true?

A. As far as I am aware. We are constrained by the amount of gas that we have so, yes.

Q. Well, you're constrained by the amount of gas, but yet you're only using in the HTI plant and the Jans Corporation and the county shop building only using 15, 18 percent of the capacity, aren't you?

A. I believe the commitment to Hutchinson is a confidential and proprietary number, but it is a significant percentage of the 325.

Q. In your filings you show that right now it's 66, I think, isn't it? Or 66,000 out of the 480,000. Are you familiar with that?

A. I think that's an annual or -- sometimes we mix Mcf per hour and MMBtu. So I recall the 66,000 but I don't recall the units or the time.

Q. Well, and maybe another witness -- I'm not trying to put you on the spot on this but maybe another witness will be more appropriate, but perhaps you know. Somewhere in the testimony there's some testimony from you or one of your company representatives indicating that there's 480,000, I believe, Mcf's available and it's on Exhibit 12, which is Mr. Knadle's rebuttal exhibit, I believe. And the third page of that reflects that there's 480,726 Mcf's, and I believe they're annually, that can flow through your line, that 4 1/2-inch line?

A. Yeah. I'm not certain now where that number comes from. Maybe I need to defer to someone else.

Q. Okay. Well, I apologize a little. But there's some of these document responses that you signed and some that were or not signed but you attested to and some that other individuals did?

A. Right.

Q. So I'll come back to that at a later time.

Were you a participant in the determination that a line extension would be made from the plant to the west over to the Hutchinson Technology?

MR. GERDES: It's objected to as calling for proprietary information. And it's also objected to as being outside of the scope of direct.

MS. WIEST: Has it been filed as proprietary, or it hasn't been filed?

MR. GERDES: It has not been filed, but it calls for proprietary information.

MS. WIEST: Do you have a response to that?

MR. RITER: If I might respond. We think it's important that there be a determination made relative to the decision that NSP has formulated that there will be a particular amount of gas that they can push through there, 480,000, and that the expenses ought to be divided by the 480,000 because we're interested in what kind of plan they have that would justify using 480,000 rather than 66,000, which is all the gas they're really using. So they must have some sort of a business plan we would think that would justify them to ask the Commission to base their rates upon not the amount of gas they're actually pushing through the line, but some amount that would be the maximum available.

MR. GERDES: Then, excuse me, Your Honor, but then I'll also add to my objection it's been asked and answered.

MS. WIEST: I guess I'm not sure about the relevance of asking for business plans, but when they were first beginning the operation, I think that was your question, so I will sustain the objection.

Q. Let me ask you a little bit different question, Mr. Wilcox. You know there is, as we've indicated -- as I made mention in Mr. Knadle's Exhibit 12, there is on that some calculations that your company put together relative to annualized revenue requirements?

MR. GERDES: Which page?

MR. RITER: On Knadle's exhibit, the third page.

Q. And I think that might have been put together initially by Mr. Winter, who's not here today. But did you have a chance to look over his testimony at all in preparation for --

A. I have. I don't happen to have it with me, but I would probably defer this to Mr. Smith, who's going to adopt Mr. Winter's testimony.

Q. And you're not really involved, if I understand correctly, then, in making decisions about maximum rates and hours at capacity and how much the flow-through might be, or the through-put might be on the line; is that true?

A. I'm not sure about decisions. It's just a matter of calculation, I think.

Q. Well, what I'm getting at, what I want to make sure I get from a proper witness -- if it's you, fine; if it's someone else, fine, too. But there are the calculations when NSP comes up with a maximum rate that they think they should charge. They calculated what the capacity per hour of the pipeline is and how many hours per year you believe you will run it at capacity. And are you familiar with the calculations of that nature?

A. I think I need to defer that to Mr. Smith.

Q. One of the things that staff has looked at some of the operation and maintenance expenses, and you would be more familiar with things of that nature, wouldn't you?

A. I think that's probably more in the area of Mr. Smith too.

Q. Okay. Tell me now, your office is in Sioux Falls, and what's your capacity with NSP?

A. My title is manager of the government and community relations.

Q. Is it fair to say then that you are not necessarily involved in determining the day-to-day operational issues, but more carrying them through to the public?

A. That's fair, yes.

Q. Now, back to the one question I asked you about extending the natural gas service. Has NSP now filed for a franchise in the city of Sioux Falls?

A. NSP is in the process of seeking a nonexclusive franchise agreement with the city of Sioux Falls, yes.

Q. Well, Mr. Wilcox, would you agree that NSP could benefit if there was increased volumes through the pipeline?

MR. GERDES: It's objected to as outside the scope of direct. Excuse me, let me finish my objection. And without proper foundation.

MR. RITER: If I might respond, in response to staff data request, the first set, response number three, Mr. Wilcox provides a response to a question from staff relative to those issues. I was just following up on that.

MS. WIEST: I'll allow it.

Q. So if you have -- do you have some of your data responses in front of you?

A. I do.
Q. If I draw your attention then so you know what I'm talking about, the first set of the staff data responses to number three.
A. Yes.
Q. Do you remember what my question was?
A. Maybe if you wouldn't mind restating it.
Q. All right. Would you agree that NSP would benefit if there were additional volumes transported through this pipeline?
A. Well, as I stated in my response to that question, and NSP certainly would benefit from increased volumes through the pipeline subject to capacity availability.
Q. But we talked about the capacity availability. There's substantial capacity right now in the Angus Anson pipeline, isn't there?
A. There's approximately 325 Mcf per hour available.
Q. Well, but there's this third combustion turbine isn't up and operating, is it?
A. That's correct. But I believe that capacity is being reserved for that possibility.
Q. But right now based upon what's happening today down in Sioux Falls, you've got a 1,225 excess

capacity that you've reserved, so to speak, for that purpose that you could at least be using during this period of time, couldn't you?

A. I really don't think that -- or couldn't say that that is available at the moment.

Q. Well, you've indicated that you could benefit from increased volume through the pipeline; correct?

A. Yes.

Q. And so if you could benefit, then so could customers benefit, couldn't they?

A. Yes.

Q. And you've indicated in there that there had been no other potential retail customer that's requested transportation through the line?

MR. GERDES: Objection. That's been asked and answered. Mr. Wilcox's first question was that they would benefit to the extent the capacity existed and was not committed.

MS. WIEST: Wasn't your question if there were anyone else asked?

MR. RITER: My question was whether any other potential retail customer had requested transportation through the line.

MS. WIEST: Objection overruled.

A. At the moment NSP is serving three customers in the industrial park area with natural gas transportation services.

Q. And in effect they've made those transportation services available by using the capacity of the Angus Anson pipeline using the excess capacity of the Angus Anson pipeline?

A. Yes.

Q. And using the 66,000 out of 480,000 Mcf's that would be the annual expectation on the Hutchinson Technology according to some data requests that you filed, or your company had, and even presupposing there's another 3,000, 4,000 annual from the county building and Jans Corporation there is substantial excess capacity at this time in that 4 1/2-inch line, is there not?

MR. GERDES: Objection. That's a misstatement of the record. There's been no identification of the nature of that calculation in Knadle rebuttal exhibit as to what it represents. Counsel is making an assumption.

MS. WIEST: I'm sorry, as to what represents?

MR. GERDES: As to what the 480,000 Mcf figure in the exhibit represents.

MS. WIEST: Your objection to --

MR. GERDES: Counsel's question assumes that's been determined as being applicable to the total amount available to the industrial park.

MS. WIEST: Do you have a response, Mr. Riter?

MR. RITER: Well, perhaps this witness doesn't have that knowledge. I thought it was pretty well understood with NSP what their calculations would show. And I would have thought this witness would be knowledgeable of that, but if he's not, then I'll ask it of someone else. Let me just ask it this way. I'll withdraw the question.

Q. Mr. Wilcox, have you not looked at what the calculations were that your company put together relative to that 4 1/2-inch pipeline and the maximum capacity of it per year?

A. I've had the chance to read all of our testimony, but my specific narrow focus, I guess, in my testimony is regarding the capacity and I think in terms of Mcf per hour, as I stated in my testimony.

Q. Now, if I understand correctly, as far as constructing your line extension, NSP has a policy that line extension will be -- or could be constructed if there's capacity available, for one thing. Is that true?

A. Yes.
Q. And if the project is cost-justified based on projected revenue?
A. Yes.
Q. Volumes and/or contract terms?
A. Yes.
Q. And that necessary regulatory or other approvals can be obtained?
A. Yes.
Q. When you did this line extension -- and that was in response to number 17 to the first set of the PUC staff's data requests and you gave that answer Mr. Wilcox. So apparently when the decision was made through NSP to extend this line this 4 1/2-inch line west from the plant, NSP looked at projected revenues, volumes and/or contract terms?
A. I'm not able to answer that.
Q. You're able to tell me that's the policy that normally is pursued, but you can't tell me that they actually did that?
A. I was not involved.
Q. Who would have been involved in that decision?
A. I'm not sure I can answer that either.
Q. Mr. Wilcox, I draw your attention to response

number seven to the PUC's third data request, and that's a response that you apparently put together. But I want to be fair with you. Is that something that you got the information from somebody else at NSP and you just put it together and submitted it under your name?

A. Yes.

Q. So who should I ask questions about relative to the Mcf's and the determinations? Is that Mr. Smith?

A. Yes.

Q. And the same thing, if you look at number 12, the third data response, that's under your name as well. Would that also be Mr. Smith that really has that information?

A. Mr. Woehrle.

Q. So you understand my difficulty is that because it was submitted under your name, I was assuming that you had the knowledge. And I wasn't trying to ask you questions about some area that wasn't your area of expertise, but I wanted to make sure that I ask it of someone that did have the knowledge.

MR. RITER: That's all I have. Thank you.

MS. WIEST: Ms. Cremer.

CROSS-EXAMINATION

BY MS. CREMER:

Q. Jim, on page seven of your testimony, line three, you talk about an imbalance penalty. What are those?

A. I need to defer that to Jamie Seitz.

Q. Okay. I'll just ask that of her later. Thank you. That's all I have.

MS. WIEST: Commissioners, any questions?

Any redirect, Mr. Gerdes?

REDIRECT EXAMINATION

BY MR. GERDES:

Q. Is there a characteristic concerning the HTI plant that was considered by NSP in setting aside the allocation, which I realize is proprietary for that plant, i.e. does that plant have growth plans that have to be taken into consideration?

A. Yes, it does.

MR. GERDES: That's all I have.

MS. WIEST: Thank you. Call your next witness.

MR. RITER: Could I just follow up on that one question?

MS. WIEST: Yes, you may.

RECROSS-EXAMINATION

BY MR. RITER:

Q. What are the growth plans you're testifying to in response to Mr. Gerdes' question?

A. I don't have any specifics. But we do know that at the moment Hutchinson is planning another building adjacent to their existing building.

Q. So there are future plans. And right now as you sit here, you have no knowledge of whether it will be two years or ten years?

A. No, I don't know when.

MR. RITER: Thank you.

MS. WIEST: Thank you.

MR. GERDES: Call Dan Woehrle,

DAN WOEHRLE,

called as a witness, being first duly sworn, was examined and testified as follows:

DIRECT EXAMINATION

BY MR. GERDES:

Q. Would you state your name, please?

A. Dan Woehrle.

Q. Mr. Woehrle, I'll show you what's been marked as Exhibit 4 and ask you if that is a copy of your prefiled testimony in this procedure?

A. Yes, it is.

Q. Do you have any corrections or additions to this exhibit?

A. No, I do not.

Q. If you were to respond to the questions posed in that exhibit, would your testimony be the same as stated in the exhibit?

A. Yes, it would.

MR. GERDES: I have no further questions. I'll tender for cross-examination.

MS. WIEST: Mr. Riter.

MR. RITER: Thank you.

CROSS-EXAMINATION

BY MR. RITER:

Q. Mr. Woehrle, when I was asking some questions of Mr. Wilcox, apparently some of the information that I was seeking from him you have available. Is that true?

A. I believe so.

Q. Okay. And I realize that might not have been in your prefiled testimony, so to that extent, I'd ask leave of the Commission to expand my cross-examination into some of the areas that Mr. Wilcox indicated were within your knowledge. I was asking Mr. Wilcox about information on the Hutchinson Technology plant. Apparently that's the plant that motivated the decision by NSP to put a 4 1/2-inch line in?

A. That's correct.

Q. And are you out of Sioux Falls or --

A. I'm out of the Twin Cities.

Q. I have to find that particular data request now. It was my recollection on these data requests that there is one of the requests where you indicated that Hutchinson Technology -- or Mr. Wilcox did indicate that Hutchinson Technology could at this point in time utilize 66,000 Mcf's annually.

A. That's correct.

Q. And then there was also -- there were also the county building and a Jans Corporation that could utilize approximately 4,000 Mcf's annually?

A. That's correct.

Q. So that's a total of 70,000 Mcf's that NSP thinks they will be able to sell the transportation of through that 4 1/2-inch line?

A. That's the existing connection row.

Q. Pardon me?

A. That's the existing connected row.

Q. Meaning right now that's all the customers you have that are utilizing that pipeline?

A. That's correct.

Q. And there are 480,000 Mcf's available on an

annual basis?
A. I'm not certain where you're getting your 480 from.
Q. Well, I got it --
A. On an annual basis, that's correct. It is on an annual basis.
Q. On an annual basis?
A. That's correct.
Q. 487,726; right?
A. That's correct.
Q. So on an annual basis there's 480,000, and there's really at this point in time only 70,000 Mcf's that's used of that possible capacity?
A. At this time, yes.
Q. Which is what, one-seventh of the total capacity is used at this time?
A. I can't do the math.
Q. Would you agree 70 is to 480 as one is to seven?
A. All right, I'll agree to that.
Q. Now, did you have anything to do with the calculations of the maximum rates that NSP has proposed relative to hours at capacity and annualized revenues that need to be met?
A. I was involved in calculating the capacity of

the pipeline. Calculating the operating hours I was not involved.

Q. So the hours that per year at capacity of 1,571, you weren't involved in determining that figure?

A. I was not.

Q. Who would have been involved in that?

A. I don't believe I can answer that. I don't know the answer to it.

Q. Somebody here today though?

A. I don't know if Jim Smith can answer that.

MR. RITER: That's all I have. Thanks.

MS. WIEST: Ms. Cremer.

MS. CREMER: I have none.

MS. WIEST: Commissioners? Redirect?

MR. GERDES: No further questions.

MS. WIEST: Thank you.

A. Thank you.

MR. GERDES: Call Mr. Smith.

JAMES A. SMITH,

called as a witness, being first duly sworn, was examined and testified as follows:

DIRECT EXAMINATION

BY MR. GERDES:

Q. Would you state your name, please.

A. My name is James A. Smith.

Q. And where do you work?
A. I work for Northern States Power Company headquartered at 414 Nicollet Mall, Minneapolis, Minnesota.
Q. I'll show you what's been marked as Exhibit 5, which is entitled Direct Testimony and Schedules of John Winter. Have you read that document previously?
A. Yes, I have.
Q. And is it true that Mr. Winter was unable to attend today because of other commitments?
A. Yes, it is.
Q. And do you adopt that testimony stated in Exhibit 5 as your own?
A. Yes, I do.
Q. And if you were sworn to testify under oath and if those questions were posed to you, would you make the answers stated in that exhibit?
A. Yes, I would.
MR. GERDES: Offer Exhibit 5.
MS. WIEST: Any objection to Exhibit 5?
MR. RITER: No objection.
MS. WIEST: If not, it's been admitted.
Q. While we're at it, Mr. Smith, I'll also show you what's been marked as Exhibit 8 and I'll ask you what that is?

A. Exhibit 8 is my rebuttal testimony to the staff testimony that was filed in this docket.

Q. And if you were asked the -- or do you have any corrections to that testimony?

A. No, I do not.

Q. And if you were asked the questions posed in that exhibit, would you make those answers today under oath if asked?

A. Yes, I would.

MR. GERDES: Tender Mr. Smith for cross-examination.

MS. WIEST: Mr. Riter.

MR. RITER: Thank you.

CROSS-EXAMINATION

BY MR. RITER:

Q. Good afternoon, Mr. Smith.

A. Good afternoon.

Q. As you know, I'm Bob Riter. I'm a lawyer from Pierre. I represent MidAmerican Energy in this matter, and I've had an opportunity to look at some of the data requests -- in fact, all of the data requests, as well as the testimony of Mr. Winter and yourself. And do you have in front of you the data request responses that NSP has filed?

A. Yes, I have them with me.

Q. Okay. Do you also have Mr. Winter's prefiled testimony in front of you?

A. Yes, I do.

Q. Now, Mr. Smith, would you agree that NSP has used annual Mcf's of 480,726 to determine the rates that they are proposing by way of a maximum and a minimum in this case?

A. Yes, that's true.

Q. If I understood your prefiled testimony and also the testimony of the prior witness, at this point in time there's just a little under 69,000 Mcf's that are utilized through that pipeline; is that true?

A. Yes, that's true.

MR. GERDES: Excuse me, counsel, is that per day?

MR. RITER: Well, based upon your annual -- based upon the annual figure of 480,726. There's 66,000 annually that is allocated for Hutchinson Technologies and a total of 2,979 for Jans Corporation and the county.

Q. I think, Mr. Smith, if you would look at Ms. Seitz's testimony, schedule seven, the last page of her testimony, she shows the estimated annual usage for Minnehaha County and Jans Corporation as 2,979.

A. That's correct.

Q. Is that consistent with your understanding?
A. Yes.
Q. And then you would agree, would you not, that with Hutchinson Technologies it's 66,000 Mcf's is the annual usage for that particular company, is it not?
A. I believe Mr. Woehrle's testimony indicates that there is an additional amount of gas that will be reserved or expected to be delivered to Hutchinson Technology.
Q. Well, drawing your attention to the third data request to the PUC response, number seven.
A. The third set?
Q. Yes, sir. Have you had a chance to review that, sir?
A. Yes.
Q. And wouldn't you agree based upon that production information that Hutchinson Technologies would use 66,000 Mcf's per year? At least that's your estimate, your company's estimate?
A. That's the initial consumption of Hutchinson Technology.
Q. So as we sit here today, that's what you suspect they're utilizing at this time?
A. Yes.
Q. So if we're speaking as of January 4, 1999,

Q. Is that consistent with your understanding?
A. Yes.
Q. And then you would agree, would you not, that with Hutchinson Technologies it's 66,000 Mcf's is the annual usage for that particular company, is it not?
A. I believe Mr. Woehrle's testimony indicates that there is an additional amount of gas that will be reserved or expected to be delivered to Hutchinson Technology.
Q. Well, drawing your attention to the third data request to the PUC response, number seven.
A. The third set?
Q. Yes, sir. Have you had a chance to review that, sir?
A. Yes.
Q. And wouldn't you agree based upon that production information that Hutchinson Technologies would use 66,000 Mcf's per year? At least that's your estimate, your company's estimate?
A. That's the initial consumption of Hutchinson Technology.
Q. So as we sit here today, that's what you suspect they're utilizing at this time?
A. Yes.
Q. So if we're speaking as of January 4, 1999,

we've got 66,000, plus another 2,979 for just a little bit less than 69,000 total annual Mcf's through that line; correct?

A. That's an estimate. That's as of probably January 1st, January 2nd, today, yes.

Q. Now, NSP has also determined what they believe to be the cost of that line extension, did they not?

A. Of which line extension?

Q. The 4 1/2-inch line extension.

A. Yes.

Q. What was that figure, approximately?

A. Approximately 365,000.

Q. I think was -- that the initial estimate. But was that increased, Mr. Smith? And again I draw your attention to your testimony schedule page one of three. Would that figure be closer to $454,000 rather than the 360? I think what happened, I think it changed from when Mr. Winter filed his initial testimony until you filed yours.

A. When Mr. Winter filed initial testimony, that was an estimate. My amount 454,853 is an actual cost that was incurred.

Q. So the cost was 454,000-some dollars?

A. Yes.

Q. Correct?
A. That's correct.
Q. Now, when NSP sat down and tried to figure out the rates that they were going to charge, they have to figure out how they can get enough money to generate adequate funds to pay for this facility, don't they?
A. Yes.
Q. And part of that is more complicated than I'm able to do, but you figure out an annual rate of return and pre-tax, post-tax dollars and look at all those things, don't you?
A. Yes.
Q. And then when you did that and came up with an annual levelized amount -- which is what happened next, didn't it? Didn't you come up with like a 95,000 or ninety-some thousand dollars which showed up that you needed to generate each year to -- that's on the next page, page two of your calculations. I think it shows 93,000-some dollars.
A. Yes.
Q. So that's what NSP wants to generate on an annual basis to pay for the line extension that it did out on that facility; right?
A. Yes.
Q. But now when NSP -- well, strike that

please. To generate the funding necessary to get your $93,000, NSP would have to sell all 480,000 Mcf's at the maximum rate to generate that figure, would they not?

A. That's correct.

Q. And all we're doing -- you're doing right now is you're selling 70,000, one-seventh of the amount that you need to sell to generate that income; right?

A. That's correct.

Q. And you're -- at least with that 66,000 you're selling to Hutchinson Technology, you're selling it at a rate lower than the maximum rate, which is the rate that you would need to generate that much money as well; correct?

A. I'm not sure if the rate Hutchinson has identified --

Q. I think your data responses say it's less than maximum. I don't think you say what the rate is, but you say that it's less than the maximum rate. Does that sound correct to you?

A. Yes.

Q. So back to my question then: If you sold -- even if you sold 480,000, if you sold it at the rate you're selling to Hutchinson Technology, you still wouldn't have the money necessary to generate the income to pay the $93,000, would you?

A. That's correct.

Q. So the maximum rates, even as you've established them, are not sufficient based upon current usage and current pricing schedule to generate the monies you need to generate to fund this project; is that true?

A. That's true in many initial constructed projects where the expected gas load as connected is being developed or in a state of growth, so to speak.

Q. So when we're talking about that issue, I presume NSP, as part of its determination to make the line extension, looked at those items that Mr. Wilcox talked about, and that is the possible volume that you might be able to -- that you could legitimately generate usage on that line; is that true?

A. I believe this filing as initially made was made specifically to serve the Hutchinson plant, and that the line share of that capacity available on that 4 1/2-inch lateral would be used to serve Hutchinson.

Q. You mean the majority would have been?

A. A significant amount, yes.

Q. Well, even taking the best estimates of your testimony, or your response to data requests -- and I draw your attention to the third data request, response number 12.

A. Yes.

Q. And apparently someone within NSP determined that at some point in time in the future the HTI, if they did expand, they could utilize more than the 66 Mcf's that they're currently utilizing.

A. I think when the project was considered that an expenditure the size of the Hutchinson line was not made without a thorough discussion with the customer of its future requirements and present requirements.

Q. But even under the most positive scenarios at some future time the Hutchinson Technology plant, according to that data request, is still not going to use more than a half of the through-put on that line, is it?

A. By my calculations it's going to use more than half of the through-put.

Q. Is it?

A. Yes.

Q. On response to number seven on those data requests -- or number 12 on the data requests you show that the maximum that it will apparently will ever be is 159 or 160 Mcf's; right?

A. Just checking Mr. Woehrle's testimony, and this is response about the future gas consumption or expected requirements of the Hutchinson line in addition to the initial amount that's being served presently. If you look at schedule two, page one of ten of Mr. Woehrle's project description, he indicates the current initial connected loads is 42 Mcf an hour.

Q. What page is that again? Excuse me.

A. Schedule two, page one of ten is a description of the project. It indicates the initial load is 42 Mcf an hour and that there's going to be a future load in 1999 of a 160 additional connected.

Q. Does it say additional?

A. Additional meter to be installed when the anticipated future load of 160 Mcf per hour is connected. That's a total of 200 two Mcf per hour out of the 306 available capacity on that line.

Q. Well, but look at third data -- I don't mean to be splitting hairs on this but I want to make sure I understand. So does the Commission. Look at response number 12 to the third data request. Do you have that in front of you, sir?

A. Yes, I do.

Q. And it says that the following work paper from a consulting engineer to HTI provides the basis for the 160 Mcf hour estimate. And you based it upon the fact that the facility is one-half the size of a facility -- or the facility in Wisconsin is one-half the size of the facility in Sioux Falls, or the plant expansion in Sioux Falls. And maybe that's my misunderstanding or maybe -- does it say that if one-half the size of the total plant when the plant is constructed, or the total plant with some future expansion?

A. Well, I'm referring -- I look at the data request and the question is asked with regard to HTI's future load. And the response given shows 160 Mcf per hour. And I also refer back to Mr. Woehrle's testimony. It's my conclusion that it's an additional load to what's presently connected.

Q. Let me ask you this: Do you have personal knowledge of that, or are you just interpolating from the data request response?

A. I'm interpreting the data response and the testimony that's been filed.

Q. Well, let's say for instance that that is accurate, that it's 160 plus 40 -- 42, so that would be 202 out of 325 rather than 160 out of 325. Is that right?

A. It's 202 out of 306 Mcf capacity per hour.

Q. The capacity is 325, but you discounted that by some figure to get the 306? I think it was in your testimony in there or somebody's testimony.

A. That number is discounted. I'm not sure if Mr. Woehrle responded to that or if it was a data response, but there was a reason given for that reduction.

Q. Are you familiar with that yourself, the reason for it?

A. I'm aware that the calculation was made. I could search for the data response.

Q. That's fine.

A. And look at it if you wish.

Q. No, that's not necessary for me. Thank you. So let's go back to what I was starting to ask in the first place. Even with the most rosy scenario you can paint with Hutchinson Technology expanding to this real significant expansion that seems like it would be maybe four times as big as it is now, there would still be a substantial amount of capacity unutilized on that 4 1/2-inch line; correct?

A. There's an amount of unused capacity that's available.

Q. Might be even under your scenario 70,000 Mcf, let's say, because if you subtracted 70 from the 306, that would get you 276.

A. You're speaking on an hourly basis or daily basis? Annual?

Q. Annual is what I'm trying to speak of. And you don't have to figure out for me. But would you agree, sir, that there is a substantial amount of capacity that's not utilized even under the rosiest of scenarios for Hutchinson Technology?

A. There's an amount of capacity available. I'm not saying --

Q. You're not going to buy my term of substantial?

A. No, it's by definition it's yours versus --

Q. Wouldn't you agree, though, that if one were to really try to determine the proper rate to be charged, that there ought to be a figure computed by determination the usage or the -- not the capacity, but the volume itself that's actually being utilized or pushed through there for utilization rather than the possible capacity? Because otherwise you're not going to collect any money on 70,000 or 80,000 Mcf's even at the maximum rate, are you?

A. You're going to collect money at 70 or 1,000 or 80,000 Mcf's.

Q. Who's going to pay that if you're not utilizing it? Did I confuse myself?

A. I think we're confused, yes.

Q. If you're not utilizing -- if you set the rate based upon full capacity, which is what you've done; correct?

A. That's correct.

Q. And you also set the rate based upon the maximum charge; correct?

A. That's correct.

Q. But we know as you sit here today even utilizing the rosiest of scenarios, that you don't have that maximum capacity, there's not that volume to sell, is there?

A. No. There would be additional customers that would be expected to be connected within the service territory.

Q. Well, then, but if you didn't connect additional customers, then obviously you would be required to use the higher rate. Or if Hutchinson Technology didn't expand its plant fourfold, you would be required to use a higher rate to get the necessary return to pay for this capital project, don't you?

A. Unless the company was willing to accept the rate that it had entered into with the customer.

Q. You mean NSP?

A. NSP, yes.

Q. To subsidize the lack of compensation for the payment of that line through either some other projects or stockholders doing it; would that be true?

A. NSP sought or is seeking a certificate of authority to become a gas distribution utility in South Dakota, and this project does provide -- or it has capacity available in which the company expands to grow its business where it's economically feasible to do that. So there has to be additional customers above the Hutchinson Technology estimated load and its future load in order to achieve the maximum annual revenue requirement that was determined for that project.

Q. So back to one of the questions I asked Mr. Wilcox: So did NSP determine -- when they made the decision to want to pursue this line extension, I presume that there was some decision made on what kind of a customer base or what kind of a sales volume can we obtain? And you had Hutchinson Technologies, but do you have anything else that would justify keeping the rate as low as it is that won't pay off on the return you need based upon the actual volume that's there?

A. Would you repeat that, please?

Q. Let me ask it again. It was kind of long and convoluted by the time I got done. I wasn't sure I understood it either. Before NSP does line extensions they look at the economics of it, don't they?

A. Yes.

Q. And in this case did NSP do that?

A. Yes, they did.

Q. And other than the prospective sales volume from Hutchinson Technologies, did they obtain any other sales volume estimates that would justify that extension?

A. I think that's an area that I'm not familiar with. I wasn't privy to the initial forecast or feasibility studies that were conducted regarding that potential project at the time.

Q. My review of the testimony that NSP submitted indicated that there were like eleven people that might be prospective customers and I presume based upon the fact that they granted easements for right-of-way of the line and then there was also Hutchinson Technology and ultimately you added on Jans Corporation and the Minnehaha County. But other than that, none of the records that NSP files show there's any other anticipated sales volume. Are you aware of any?

A. I'm not aware of any information that I have in my possession of what the potential is for eleven customers. I recall that there were eleven customers that were mentioned in the testimony at some point. But as to specifics, there was nothing that was -- that

I'm aware of.

Q. Okay. Did you think there is a feasibility study that NSP did, though, that might show future sales volume?

A. I'm not able to answer that.

Q. Is there anybody here with NSP that would be able to answer that, to your knowledge?

A. I'm not sure if there's anybody here that could answer that.

Q. If there is a feasibility study that would justify some sales volume in excess of what the sales volumes are to Hutchinson Technology as they now exist, would you be willing to provide that?

MR. GERDES: That's objected to as irrelevant to the issues in the case. If the company wants to start up a business, they can start it up. That's a proprietary function of a company.

MS. WIEST: Denied.

MR. GERDES: Part of the issues in this proceeding.

MR. RITER: My response would be that it would seem to me that before a line extension would be done, that there would be some sales volume estimates. Because if they're never going to reach the sales volume that they have set forth in their documents, then the rate ought to be based upon a realistic sales volume rather than merely capacity of the line. They're basing upon capacity and not sales volume.

MS. WIEST: Objection overruled.

Q. So my question again, then, if there is a feasibility study done to show sales volume as opposed to merely capacity, would you produce that?

MR. GERDES: I'm not sure this witness is qualified to answer the question. But on behalf of the company, if such a study exists, we would produce it.

MR. RITER: Thank you.

Q. Now, as Ms. Seitz indicated in the last page of her exhibits attached to her testimony, when new customers are tied onto that line, NSP incurs additional expense also, do they not?

A. Yes.

Q. And when they added the Jans Corporation and the county shop, they had to extend their line even further; and that expense shows up in her testimony, doesn't it?

A. Yes, it does.

Q. And that would be true in the future that if the sales volume did increase for NSP, they'd have additional expenses to add new locations?

A. Yes.

Q. So the total amount of money that would have to be repaid would increase also even if the sales volume grew, wouldn't it?

A. That doesn't increase the revenue requirement that's associated with the 4 1/2-inch transmission that we're talking about.

Q. It wouldn't. How do you get repaid for that? Like in this case it cost you $14,300 to extend the line to Jans Corporation and the county shop. How does NSP and stockholders get repaid for that then if it doesn't reflect in the rates?

A. Well, I think if you refer to the last exhibit that was filed, the surrebuttal exhibits of staff, that there have been some adjustments that have been adjusted which would establish a transportation rate; and that would apply to any gas that's moved across that what I refer to as that Hutch lateral. And, in addition, it would be customer-specific for a medium volume or small volume customer.

And the suggestions that staff has made, or the proposed adjustments, those can refer those questions to Ms. Seitz, but I think that we can adopt or accept some of the projections -- or the changes that the staff is proposing so that there will be a contribution to cost recovery of that Hutch lateral by additional customers that are added. And specifically initially it would be the two customers you referred to.

Q. I want to make sure I understand. I haven't had a chance, frankly, Mr. Smith, to look at that testimony. What you're saying is that you are recovering that cost, or staff proposes to recover that cost but just in a different manner?

A. There will be a cost recovery that will be established by a rate for any gas that's transported across that Hutchinson lateral.

Q. So that means -- are you telling me then that the more expense you have in the line, the more you're going to have to collect through your rates, aren't you?

A. The transportation rate is still established for that Hutchinson piece of that lateral. Call it the Hutchinson piece, the 4 1/2-inch steel. It's still established at a maximum capacity that's available for through-put. So as additional load is loaded in the industrial park, and we can refer to the possibility of those eleven customers connected, that would cause additional volumes to be transported across that Hutch lateral. That's going to contribute in amount of dollars that will be considered towards the revenue requirement of that Hutchinson lateral piece.

Q. But tell me then how does NSP and its stockholders get repaid for the $14,300 they spent on extending the line to Jans Corporation and the county building? Doesn't it have to be capitalized and recovered as well?

A. Yes. In addition to the cost for moving the gas across the Hutchinson piece, there will be a cost that's associated with from the terminus of that Hutchinson to the end serving Jans, for example.

Q. So back to what I was trying to make sure I was correct on, whenever you do expand the line to increase the sales volume and expand the lengths of it as opposed to the length of it to increase the sales volume, you're going to have additional expense that needs to be capitalized and recovered by the company, doesn't it?

A. Yes.

Q. So not only do we -- well, strike that. I would ask for an opportunity to visit with my client. We haven't seen staff's new rates and their calculations; and, frankly, I might be able to cut back some of my time if I have a chance to look at that before I continue with this witness, if I could have ten minutes?

MS. WIEST: Sure. Let's take a break.

(AT THIS TIME A SHORT RECESS WAS TAKEN.)

MS. WIEST: We'll go back on the record.

BY MR. RITER:

Q. Mr. Smith, we've got some more questions to ask you. I did have an opportunity to look at the rebuttal testimony and -- surrebuttal testimony, rather, and rebuttal exhibit of staff. And you've obviously looked at that as well; right?

A. That's correct.

Q. Would it not be true, sir, that even under that type of rate structure, there would still need to be the capacity -- still need to be the maximum rate paid for the 4 1/2-inch pipeline, the steel pipeline if that's what you call that 480,000 through-put to get the monies required to pay for that line?

A. Yes.

Q. Now, in schedule two of your testimony you talk about the large volume transportation and you show the 480,726 annual through-put required to generate the money at the maximum rate. Do you know, sir, as you sit here today, based upon any forecast sales information NSP has how, long it would be before they would achieve that 480,726 Mcf's?

A. I'm not aware of when that will occur.

Q. Mr. Smith, drawing your attention to some data requests that MidAmerican submitted, do you have copies of those in front of you?

A. No, I don't.

Q. The answer were filed to those I think it was back last summer.

MR. GERDES: What's the date of the responses?

MR. RITER: June 2nd, 1998.

MR. GERDES: Thank you.

A. Which one are you referring to?

Q. MidAmerican Energy submitted data requests to Northern States Power. I have copies of your answers and I would -- I was trying to draw your attention to those. Do you have those answers in front of you? They were filed like June 2nd.

A. Yes, I have several responses.

Q. All right. I was looking at response number four.

A. Is this referring to the Angus Anson fuel delivery pipeline?

Q. Yes, sir. And you're familiar with that pipeline, aren't you, the 13-mile pipeline that I think Mr. Wilcox described from Harrisburg up to the plant?

A. Yes.

Q. And that's 12-inch line, is it?
A. I believe it is, yes.
Q. And as I understand your response, that that line delivers gas to the facility up there that you use to generate electricity?
A. Yes.
Q. And if I understand Mr. Winter's request or response here, none of the costs of that pipeline had been included in any electric rates in any NSP jurisdiction.
MR. GERDES: I'll object to the question. What does electric rates have to do with this proceeding?
MR. RITER: Well, I believe it's important to show that they've allocated properly the amount they should have for the Angus Anson pipeline because none of it's going to be electric, maybe more of it ought to be going to this gas.
MS. WIEST: Objection overruled.
Q. Do you remember the question, sir?
A. Yes. I'm just -- I believe that statement is correct. I was trying to recall if NSP has had an electric rate case in the Minnesota jurisdiction subsequent to the construction of that Angus line. I don't believe they have. And I know that the South

Dakota has not had an electric rate case subsequent to the construction of that line.

Q. And was that like a three million dollar line, I think?

A. I believe that's the amount that's shown on Mr. Winter's schedule.

Q. So right now the only entity that's paying any portion of that line charge by way of rates would be the 4 1/2 cents that you want to allocate to this 4 1/2-inch line because of the Angus Anson pipeline?

A. That Angus line is capitalized and it's part of the electric utility. And that rate -- the electric utility rate base includes the Angus Anson line, and the results of operations revenues less expenses, for example, will take into consideration against that electric utility rate base. There is a return that's experienced on your electric utility rate base. In between rate cases, for example, when additional facilities are constructed, they aren't specifically become part of the rate structure until there is subsequent rate cases had and the investment rate base is determined.

Q. So -- excuse me.

A. But as you continue year to year, you're making capital additions, you're providing for depreciation accruals which have the effect of reducing your net investment so that your utility rate base would be declining if you were -- if you didn't make any capital additions.

Q. But as we sit here today, January 4, 1999, NSP has not included that cost in any of their electric rates by way of rates and returns on capital investments, have you, not yet? You're going to do that sometime in the future?

A. NSP has not had an electric rate case in any of its jurisdictions which would specifically include that Angus Anson investment.

Q. How long ago was that completed, Angus Anson, approximately?

A. I believe it was 1994, 1995. I'm not --

Q. So since 1994 or 1995 you haven't sought any rate increases on the electric rates to pay for the capital cost of that pipeline and you're just using the rate of return you presently have for that purpose.

A. The earned rate of return presumably was sufficient so that it would not be justified to seek a rate increase from any of the jurisdictions in which NSP operates.

Q. Drawing your attention to response number 12 of the same set.

A. Yes.
Q. And apparently NSP hasn't allocated any costs from their headquarters office to in 4 1/2-inch pipeline; is that correct?
A. That's what the response indicates.
Q. As you sit here today, as you've -- I mean that's your belief, too, is it not?
A. Reading the response, that's my belief.
Q. Okay.
A. Based on the response.
Q. So if there's no cost attributed to this facility by way of NSP headquarters office, who runs the business, extends the line, goes out and seeks new customers, if it's not the NSP office in St. Paul that's heading that up?
A. I believe those are marketing plans and those are developed at the local level. They are not conducted from the St. Paul office, for example.
Q. You heard Mr. Wilcox's testimony, though, didn't you, where he's, well, one of the local individuals in charge of your operations in South Dakota, isn't he?
A. Yes.
Q. And you heard his testimony where he didn't -- I believe anyway. I don't mean to paraphrase his

testimony necessarily -- that he wasn't aware of the sales volumes that are anticipated in the marketing that's anticipated relative to it.

A. That may have been his testimony.

Q. Now, Mr. Smith, in the calculations NSP has put together, they show, I think, 1,571 hours as the number of hours that the line, the 4 1/2-inch line would run at capacity.

A. Yes.

Q. Is that right? Let me ask you this question: Do you know how the 1,571 hours was computed?

A. Yes, I do.

Q. Okay. How was that?

A. The current connected capacity of HTI, or Hutchinson, is 42 Mcf an hour. They have an annual consumption of 66,000 Mcf, initial connected load or projected load. Dividing 66,000 Mcf by the 42 Mcf an hour is 1,571 hours at capacity.

Q. Would the plant operate every one of those hours at capacity?

A. It's projected that that is the number of hours on an annual basis that the plant would operate at capacity.

Q. But would it?

MR. GERDES: Objected to. Calls for speculation.

MS. WIEST: Overruled.

A. I don't know.

Q. Now, back to the Angus Anson pipeline, what's the annual capacity on that, do you know, Mr. Smith?

MR. GERDES: Are you talking about the pipeline or the power plant?

MR. RITER: I'm sorry, the pipeline.

A. I know the maximum capacity per hour as to what the annual maximum capacity, mathematically, if you did the math.

Q. If we looked at Mr. Winter's testimony, schedule seven -- do you have that in front of you, sir?

A. Yes.

Q. Okay. It looks like the pipeline capacity per hour is 4,900 hours.

A. 4,900 Mcf per hour.

Q. I'm sorry, yes, thank you. And the hours per year capacity are 3,200?

A. Yes.

Q. So if you multiply the 4,900 by the 3,200, would that get you your maximum annual capacity then on that line?

A. That would get you the number of hours that it would operate on annual basis at capacity. It would give an Mcf value.

Q. Yeah, it gets you your Mcf value.

A. Yes.

Q. So that would be the maximum through-put of that line, wouldn't it?

A. Yes, it would be.

Q. And if you multiply those figures, wouldn't it come out to about 15,680,000?

A. That's correct.

Q. And what is the annual through-put of the Angus Anson pipeline? Less than that, isn't it?

A. I don't know what the annual through-put is.

Q. Is there anybody here that would, do you know?

A. I'm not sure.

Q. Do you know where Mr. Winter came up with those hours at capacity and the Mcf capacity of that pipeline?

A. I believe Mr. Winter developed a proxy for what the hours at capacity would be based on the estimated hours of capacity for the 4 1/2-inch Hutchinson lateral. The upstream pipeline would operate at a higher load factor. And based on the downstream Hutchinson piece that he devised an estimate of what the upstream capacity would be on a capacity basis.

Q. Would you agree because part of the rate that's being proposed for the 4 1/2-inch line comes from an allocated rate that NSP has given to the use of the Angus Anson pipeline; is that not true?

A. Part of the rate contains an amount that's paid to NSP Generation towards cost contribution of the Angus Anson piece.

Q. And wouldn't you agree that -- well, strike that. In Mr. Wilcox's testimony he testified relative to the 4,900 Mcf's per hour that could go through the Angus Anson pipeline which is consistent with this particular exhibit; right?

A. That's correct.

Q. And then you heard testimony about the two turbines that would each use 1,225 at peak capacity?

A. Yes.

Q. And then 900 for the Pathfinder steam plant?

A. Yes.

Q. And then a possibility of another 1,225 if there was another turbine put on; correct?

A. That's correct.

Q. So as you sit here today, though, that 1,225 turbine in the future isn't being utilized and the other two turbines at a maximum require 1,225 Mcf's don't use that much, do they?

A. Theoretically they're using 1,225 each.

Q. Theoretically meaning?

A. Well, I lost you someplace in the train of the question.

Q. Here's what I'm trying to understand. It seems that you have allocated 4 1/2 cents from the Angus Anson pipeline, but you've allocated that surmising that the through-put of that pipeline used for the 4 1/2-inch pipeline would be a percentage of the total through-put. Is that what you did?

A. An estimate was made of the total capacity of the Angus supply line when it operates at full capacity.

Q. And then you utilized the 325 compared to the 4,900; is that right? The capacity of the 4 1/2-inch versus the capacity of the Angus Anson? What I'm trying to get at is how did you come up with 4 1/2 cents? How did you come up with allocating 4 1/2 cents per Mcf is the proper amount to be allocated for use of Angus Anson pipeline to pump that 325 Mcf's -- transport that 325 Mcf's through that line?

A. That was a negotiated rate with NSP

Generation.

Q. All right. So negotiated between NSP Generation and who?

A. NSP South Dakota Gas Business Unit.

Q. And they're both what, wholly-owned subsidiaries of NSP, the parent corp?

A. These are business units within NSP. They aren't wholly-owned subsidiaries. They're part of NSP, electric, utility, and NSP gas.

Q. So certain persons, division, or department negotiated with another persons and said here's what we're going to allocate toward this rate would be 4 1/2 cents?

A. There were internal discussions that took place as to what a proper cost contribution would be.

Q. Were you a party to that?

A. No, I was not.

Q. Wouldn't you agree, sir, that if that line, rather than just capacity, had a through-put of rather than 15 million, let's say two million, and if 400,000 of that Mcf's was used for the 4 1/2-inch line, that the rate that would be proper would be higher than what might be proper if it was a 15 million through-put rather than two million through-put?

A. Once you establish a rate that is at a lower volume, for example, as you suggest, and then in the event that additional sales are made, the company then is in a position of overearning or overrecovering, and that's not the intent of the transportation tariff that was filed.

Q. Well, and I'm not suggesting what the intent was. All I was trying to determine was whether or not the proper allocation of a part of this rate from the Angus Anson pipeline would vary dependent upon what percentage of the through-put from the Angus Anson pipeline you're actually using for the HTI and these other entities. Isn't that true?

A. Well, there was a cost determination that was made based on the investment in the Angus line and then there was a revenue requirement factor that was applied that was based on a cost study that was done for the Hutchinson line and used as a revenue requirement applicable to the Angus supply line and then a rate that was developed based on a total capacity per hour of that Angus supply line.

Q. So right now on this 3.1 million dollar line, if you ran the 4 1/2-inch line at capacity, you would be paying about $21,000 a year toward that line, wouldn't it? That 4 1/2 cents times 450 or whatever it was?

A. It would contribute in excess of 21,000 by your calculations.

Q. And right now that's the only -- that would be the only rate payer that's really paying rates based upon the cost of that Angus Anson pipeline until you have a new filing on your electric rates. Right?

A. Until there's a filing in the electric jurisdiction, that investment in the Angus Anson is not part of the investment rate base that was used to establish retail rates in the South Dakota jurisdiction, for example, or the Minnesota jurisdiction.

Q. Mr. Smith, drawing your attention to John Winter's testimony, page five, just so there's no question about it, I think I asked you before about HTI's rates. And on lines 25 and 26 he indicates that rates are at or below the maximum rates discussed previously. Does that sound correct to you?

A. Yes.

Q. And then drawing your attention to schedule five of his testimony on the operating expenses, there's nothing there that shows up for sales expense or as we discussed before, is there? There's services that NSP has in South Dakota but that talks about management and support.

A. I would have to refer to Mr. Winter's notes to see if he does have a description of what he envisions by management and support. Specifically the support, if that's a sales charge, I don't know without referring to the notes.

Q. And back to the Angus Anson pipeline, as you sit here today, do you know how often it is at full capacity? What percent of the time?

A. Well, currently it's not operating at full capacity because the additional turbine hasn't been constructed.

Q. In your exhibit you say hours at full capacity, 3,200 hours.

A. That's in my exhibit, yes.

Q. So if you took 365 days times 24, would that give you the percent of the time it's at full capacity? Or how would you figure that out?

A. I would have to refer to some additional delivery information to determine what -- or how often that -- how often or as to what the size of the volume is that it's operating at capacity.

Q. Drawing your attention to the first set of PUC staff data requests, response number 20, do you have that in front of you, sir?

A. I have that.

Q. Drawing your attention to the second paragraph in Mr. Winter's response, does it indicate that the Angus Anson pipeline operates at peak only 300 hours a year?

A. That was the information that was available to Mr. Winter when he answered this response.

Q. And as you sit here today, you've adopted his testimony, haven't you? You don't have any information to the contrary of that, do you?

A. No, I don't.

Q. So wouldn't you agree, sir, that if there was -- if it was actually operating at a peak 300 hours rather than the larger figure that I've misplaced -- rather than 1,570 hours, that the share of the expense of the Angus Anson pipeline that ought to be attributable to the rates in this case would be higher because it makes up a larger usage of the transportation services that line provides?

A. No. Angus was constructed to support the electric utility and its generating requirements. And there's only an amount to 325 Mcf, approximately 303,000 that's excess capacity that's available to provide a firm service beyond what is required for the electric utility.

Q. But regardless of the reason it was initially constructed, you're now utilizing it or for a secondary purpose, aren't you, and that is to get in the gas transportation business and charge people such and such such as Hutchinson Technology for that service?

A. There's a small amount of capacity that's available that allows NSP to get in the gas distribution business and offer energy alternatives.

Q. There's a small amount, but if it's 325 and you divide it by -- or into 1,000 rather than into 10,000, let's say, obviously a bigger percentage should be attributable to a particular rate, should it not?

A. No.

Q. It shouldn't be?

A. No.

Q. In other words, from your perspective, the negotiated rate is fair no matter what percent of the Angus Anson pipeline is used for that purpose?

A. At this point the contribution to the Angus Anson is a reasonable contribution to cost recovery.

MR. RITER: That's all I have.

MS. WIEST: Ms. Cremer.

MS. CREMER: I don't have any questions.

MS. WIEST: Commissioners? Redirect?

MR. GERDES: A couple of things, if I may.

REDIRECT EXAMINATION

BY MR. GERDES:

Q. First of all, you made some reference to Mr. Rislov's surrebuttal testimony which was just filed, I believe, today as well as to the exhibit that accompanied that testimony; is that correct?

A. That's correct.

Q. And did I understand your testimony correctly that on behalf of NSP you would adopt the methodology that he suggests in his testimony and in that exhibit?

A. Yes. Mr. Rislov's presentation and the staff's exhibit produces a result that will allow transportation rates for various existing customers and incremental customers that achieve the desired result. His methodology produces approximately the same results that I had filed in my rebuttal for the Hutchinson rates. It's a reasonable solution.

Q. Now, Mr. Riter questioned you at some length about the fact that there's more capacity in the line than which is presently being utilized. Tell me based on your experience whether that is or is not an unusual occurrence in the start-up operation such as we're talking about here.

A. That's not an unusual occurrence.

Q. Why?

A. For the one thing, for the simple fact that once you establish a rate and, for example, if you established a transportation rate that was based on first year volumes or second year volumes, that rate would be such that it would probably be higher than the anticipated rate given the market that you expect to attach. So that once if you established in the initial rate, then the subsequent sales were made that exceed the volume which you used to establish that rate, you're in a situation where you're overrecovering that cost to service.

Q. Does it also have anything to do with competition and creating competition by the entry into the market?

A. Yes. It puts you at a disadvantage as to what is a competitive rate what you can charge.

Q. Do I understand that it's NSP -- one of NSP's purposes to provide a competitive alternative for energy in the industrial park in Sioux Falls?

A. Yes.

Q. You were asked at some length about NSP's response to MidAmerican Energy Company's first set of data requests, specifically response number 12, which dealt with allocation of costs. And you were asked about allocating the cost of the NSP Minnesota headquarters. Do you recall that line of questioning?

A. Yes.

Q. And if you look at that response, does it -- I'll let you get it first. If you look at that response, does it not by its terms indicate why charges for NSP Minnesota headquarters were not taken into consideration?

A. Yes.

Q. And what does it say is the reason they were not?

A. Due to the small size of the NSP South Dakota gas operations, the services will be purchased only on an as-needed basis. They are expected to be very small, diminimus.

Q. And, finally, Mr. Smith, this may be self-evident, but what is your understanding of the purpose that would eventually be used for the excess capacity that we've been talking about in this pipeline?

A. The purpose of the excess capacity is to support growth.

Q. More customers?

A. More customers, yes.

MR. GERDES: That's all I have. Thank you.

MS. WIEST: Just to clarify then. Going back to Mr. Rislov's surrebuttal, NSP is adopting his recommendation that the costs of HTI's extension and meter set be removed from the general cost of service and assigned directly to HTI; is that correct?

A. That's correct.

MS. WIEST: And then you're also adopting his revised exhibit which shows a levelized annual revenue requirement?

A. Yes.

MS. WIEST: And his question on line 23, I believe it was the second page, then states how will NSP recover these costs? And then he mentions a number of options. Has NSP chosen an option?

A. I would defer that to with Ms. Seitz. I'm not sure if we have a desired option. Presently he's calculated as a volumetric charge based on the consumption that flows, and that fits in with what I had, or have in my rebuttal testimony. But Witness Seitz may provide you with a more definitive answer of that.

MS. WIEST: And I believe you stated earlier you are seeking authority to become a gas distribution facility as opposed to intrastate pipeline; is that correct?

MR. GERDES: I think technically we're asking to be an intrastate pipeline.

MS. WIEST: I think he said distribution.

MR. GERDES: I think that was a misstatement.

MS. WIEST: Any other questions of this witness?

MR. RITER: I do, real briefly.

RECROSS-EXAMINATION

BY MR. RITER:

Q. Mr. Smith, when you talk about start-up operations and the difficulty of knowing what your volume is going to be and that's why businesses such as NSP do sales forecasts and business plans and feasibility studies, don't they?

A. Yes.

Q. And that's what you're going to produce if you've got one right feasibility study?

A. I believe it was indicated that we would produce that.

Q. And as far as competition, Mr. Gerdes asked you about competition, and it's important to be competitive certainly on rates and service. But wouldn't you agree, sir, that even in competition you still need to recover your costs?

A. Costs need to be recovered.

Q. And NSP, even being a good competitor in this case, out in the industrial park needs to recover its costs and that should be part of the requirement of any rate that's imposed, shouldn't it?

A. Yes.

Q. Because if you don't have a rate established that covers the costs, then it can be artificially low for a period of time, but then ultimately either NSP has to increase it dramatically or else the business suffers, competition suffers because it is an artificially low rate during the time frame where it sits low, doesn't it?

A. Rate can be established below maximum for a period of time. Anticipated growth can take place to make up the shortfall so that you are achieving a full cost recovery.

Q. But even in this particular case again, Mr. Smith, even if you had the entire 300 -- entire capacity sold, which you don't, the rate would have to be at the maximum for you to recover your costs, wouldn't it?

A. Yes.

Q. And one last question for you. I was looking at your fifth set of responses to the PUC, Public Utilities Commission, number two. Do you have that in front of you, sir?

A. Yes.

Q. And it says that a "grossed up" rate should have been used, and it says the grossed up rate would not lower the maximum rate but the gross -- if the grossed up rate would have been used, would it have increased the maximum rate?

MR. GERDES: I'll object to that question as being outside the scope of redirect.

MS. WIEST: Any response, Mr. Riter? I don't remember the --

MR. RITER: I don't remember if it was either.

MS. WIEST: Sustained.

MR. RITER: That's all I have.

MS. WIEST: Any other questions of this witness? If not, thank you. Next witness.

MR. GERDES: Call Jamie Seitz.

JAMIE C. SEITZ,

called as a witness, being first duly sworn, was examined and testified as follows:

DIRECT EXAMINATION

BY MR. GERDES:

Q. Would you state your name, please?

A. Jamie C. Seitz.

Q. And where do you work?

A. I work for Northern States Power Company, the gas utility at Rice Street in St. Paul.

Q. And showing you what's been marked as Exhibit 9, I'll ask you if that is a copy of your prefiled -- excuse me, your prefiled rebuttal testimony?

A. Yes, it is.

Q. And do you have any corrections or changes to that testimony? And before you answer that question --

A. I believe the proprietary schedule is missing.

Q. And there were also some errata that was filed. Does that reflect the errata that was filed, can you tell?

A. This does not.

Q. And I'll you show you what's been marked as Exhibit 10 and I'll ask you if that is the errata that is corrections to your initial document that was also filed?

A. Yes, it is.

Q. And if one were to take Exhibit 10 and add it to Exhibit 8, one would then have your testimony as you seek to give it; is that correct?

A. Yes, it does.

Q. Nine, excuse me. And if you were asked the questions stated in Exhibits 9 and 10, would you give

the testimony that's reflected in those two exhibits?
A. Yes, I would.
Q. Now, Exhibit 9 does omit a proprietary exhibit which you filed with your testimony; correct?
A. Yes.
Q. And was that at my suggestion since some participants have not signed a confidentiality agreement in this case?
A. Yes, it was.
MR. GERDES: All right. I'd tender the witness for cross-examination.
MS. WIEST: Mr. Riter.
MR. RITER: Thank you.

CROSS-EXAMINATION

BY MR. RITER:
Q. Good afternoon, Ms. Seitz.
A. Good afternoon.
Q. I'm Bob Riter. I'm a lawyer for one of the intervenors, MidAmerican Company, and I've got a few questions for you on your testimony. The area that I really wanted to spend the most time with you is on page five of your testimony. Now, you've included in the tariff the provision, the proposed provision, that would limit sales of transportation services only to retail accounts; is that true?

A. That's correct.

Q. And Mr. Knadle, in his testimony, questioned that; correct?

A. Yes.

Q. And part of your response was responding to the questions he's raised; right?

A. Yes.

Q. And apparently in Minnesota you limit it to retail customers?

A. Yes.

Q. And apparently in North Dakota you limit it to retail customers, although there are exceptions that you make that say if there's sufficient financial consideration provided, then it can be supplied for resale or certain exceptions anyway?

A. I believe that was for a trailer park situation.

Q. Was for a what?

A. I believe that was for a trailer park situation, but usually it's just the end users that we're delivering gas.

Q. Wouldn't you agree, Ms. Seitz, that the more transportation services you can sell from that line, ultimately the more money NSP will make and the more likelihood is that the rates will remain good for the users of the transportation services?

A. That would be true, but there's several unresolved issues when you do deliver to say a third party. We're working on restructuring any other jurisdictions in Minnesota and North Dakota, and there are issues that come up like who will do the billing and the provider of last service. Say if we would have a third party and their gas did not show up, would NSP be the provider of last service? So...

Q. There are technical questions that you have?

A. Yes, yes. And a jurisdiction where we're only serving three customers, we want to be consistent with the other jurisdictions.

Q. Well, you include in paragraph -- excuse me, line 18 you say if the Commission were to order gas service restructuring, NSP would remove this provision at that time. What do you mean by that?

A. Some of the states around the country are mandating that gas be unbundled transportation and the transportation distribution and the buying gas, that they be separated. And if we were ordered in South Dakota, we would do so at that time.

Q. Now, so if one were to satisfy those conditions that you mentioned earlier relative to making sure, you know, whose responsibility it is and items of that nature, would NSP then in that case be willing to sell to a third party for possible resale?

A. If we were mandated, yes.

Q. But when you testified a little earlier though when we were talking about -- I think you testified about conditions that were of concern to NSP such as whose responsibility would it be if the flow didn't occur and things of that nature. If those issues were resolved, would you have any objection to there being an elimination of the prohibition against sale for resale?

A. I think we would still want to be consistent within our jurisdictions because the gas controlled for all three states is at Rice Street and all the operational issues would have to be similar. So I don't think we would want to do -- unless we were mandated, I don't think we would want to try one jurisdiction without having the same conditions on all jurisdictions.

Q. Now, Mr. Knadle, in his testimony or rebuttal testimony, made comments that upon what do you base -- what authority do you have to refuse sale for resale? Do you remember that? And I could get that out, but I think that's kind of what his comments were that you were responding to.

A. Could you refer me to that?
Q. Sure.
MR. RITER: Is it all right if I approach the witness?
MS. WIEST: Yes.
Q. On Mr. Knadle's testimony it looks like it's original sheet 15, he's made some notes. Do you have that?
A. Oh.
MR. GERDES: Excuse me, what's the sheet number?
MR. RITER: 15.
Q. If you look down at the bottom, he's got (34) What authority allows to you impose this restriction? Do you see that, ma'am?
A. Yes.
Q. And in your response do you specify any particular authority to impose that restriction?
A. No. I know of no South Dakota authority.
Q. That's just an internal procedure that NSP would like the Commission to adopt as part of the tariff?
A. Yes, again, because of so many unresolved issues.
Q. Well, even if a third party were to buy the

service ultimately to resell it, wouldn't it just be another transport customer for NSP?

MR. GERDES: Well, I'm going to object to the question, and maybe counsel can clear it up. But I would object to it as being a legal question, because we would take the position that if the Commission were to order that it would be tantamount to ordering restructuring of the gas business in South Dakota, we would submit that's not contemplated under the current utility rules in South Dakota.

MS. WIEST: But aren't you asking for authority as an intrastate pipeline, not as a gas distribution company.

MR. GERDES: Yes, we are, that's correct.

MS. WIEST: And wouldn't an intrastate pipeline supply gas to both the retail and wholesale? What revisions is there in intrastate law?

MR. GERDES: I don't think even in state law an intrastate pipeline is required to take --

MS. WIEST: There isn't any restriction to retail, is there?

MR. GERDES: No, no, but they don't have to take all covers either.

MS. WIEST: How is the question a legal question then?

MR. GERDES: It's asking her position on that issue.

MS. WIEST: Would you agree it is a legal question, Mr. Riter?

MR. RITER: No, I don't agree it's a legal question. I think it relates to their request for conditions in the tariff and whether or not they ought to be approved, or whether something of this nature allowing the possibility of a sale for resale would ultimately lower the rates because more people would be wanting to buy those transportation services.

MS. WIEST: Can you repeat your question then?

(The question was read by the Court Reporter.)

A. I believe that would be a wholesale transaction then.

Q. A wholesale transaction for transportation services?

A. Yes, if that third party would go ahead and then turn around and resell it. I mean if it did not resell it, then I would say that would be the ultimate customer. But if it's going to resell it, then I would say it's a wholesale transaction.

Q. But if I were to sell a widget to you and you sold it to Mr. Wilcox, which would be a wholesale transaction, I guess my transaction between you and I, or if I sold it direct to Mr. Gerdes, I'm still getting the money that I need to get to run my business to pay my bills. And why should there be a distinction between a sale for resale under your tariff?

A. But wouldn't that ultimately raise the cost of that customer then?

Q. To Mr. Wilcox?

A. Yes, if I added my --

Q. It could. But that would be your concern. Because if I wanted to buy the transportation service -- if you wanted to buy it from me, maybe you could buy it from me for less than you could buy it from someone else or put it in yourself.

A. I believe the purpose of the tariff as filed was just for the ultimate customer.

Q. But wouldn't you agree that the operation would be the same by way of what NSP would do for a customer, whether the customer did it for his own retail purposes or individual purposes or wholesale purposes?

A. No. There are several things that could come up. If we were to sell it to a third party, there would be other things like balancing for other customers rather than balancing for one. There could be ultimate billing problems, the same problem I told you about earlier. If that party then does not provide the gas, I mean, are we obligated? You're still going to have all these issues that until they're resolved on a statewide basis, I don't think you can impose it on one utility.

Q. Although some of those things could be handled contractually between you and the third party to whom the services were provided.

A. They ultimately could be, but I don't think as a company our policy is to go that way. We want to do it, you know, for our jurisdictions as a whole to be consistent and not contractually.

Q. But in this particular case, I mean you've got a maximum rate for transportation services for a large volume customer and a minimum rate, but you can charge me one rate within that range and charge Mr. Gerdes another rate, couldn't you?

A. Yeah, the flexible rate the way it's set up, yes.

Q. So the flexibility in the rating wouldn't be any different necessarily than the flexibility in the contract provisions between you and third parties either, would it?

A. The rate wouldn't be but the operations of it would be.

Q. But what you're selling is transportation services, not gas; right?

A. Right.

Q. And a wholesaler might need those transportation services or someone like a wholesaler just as much as a retailer; right?

A. Could you repeat the question?

Q. Sure. A wholesaler, somebody who's buying it for resale, might need those transportation services just as much as would someone buying it for his or her own use.

A. Potentially, yes.

Q. And NSP could possibly garner more income if they didn't have the restriction?

A. Potentially, yes.

Q. And this sort of tariff would allow NSP to pick and choose customers based upon what they were using the transportation services for?

A. No. Right now we're just delivering to the ultimate customer.

Q. So to the extent that you're picking and choosing, you're saying we will choose to deal with the ultimate customer, but we will choose not to deal with sellers for resale?

A. Yes.

Q. And right now then Angus Anson pipeline is accessible only to NSP?

A. Yes.

Q. Although in a way you're using -- it's accessible to Hutchinson Technologies and the Jans Corporation because you're using that to deliver the transportation services that they need as well, aren't you?

A. Yes.

Q. Also in the tariff, as I understand it, that on telemetering, which is schedule two, section seven, apparently you've modified that tariff after Mr. Knadle brought up some issues on it. And it appears now that you will charge a customer for telemetering if you deem it necessary?

A. Yes.

Q. So if some customer may be charged for telemetering and others you may a not depending upon what you decide?

A. Could you give me the reference again to that?

Q. Sure. I've got it original sheet number 22, it says at the top, section seven on that page.

A. Yes, that was additional language put in in response to his question.

Q. So the way the tariff would be now if you wanted to charge for telemetering costs it would be your decision, NSP's decision?

A. Yes.

Q. So you might charge for one customer and not the other?

A. It would depend on the size. For a small customer it may not be economical to install that.

Q. Back to the Anson pipeline, inasmuch as you are now in a way using it for providing services to third parties in addition to NSP, if you were requested to provide access to that line, would you have the same attitude as far as sale for resale that you would for 4 1/2-inch pipeline?

A. I think NSP Generation would have to make that decision, not anyone here because they are in control of that line right now.

Q. Okay.

MR. RITER: That's all I have. Thank you.

MS. WIEST: Ms. Cremer.

MS. CREMER: Thank you.

CROSS-EXAMINATION

BY MS. CREMER:

Q. Good afternoon. I had asked Jim Wilcox earlier about an imbalance penalty. Can you tell us what that is?

A. That is when the amount that's used is different than the amount that's nominated. And if there are penalties incurred, that's passing along the penalties to the customer causing the line to go out of balance.

Q. And that's just a pass-through to them?

A. Yes.

Q. Okay. And I need to clarify. You agree with staff's tariff changes as they're found on Exhibit 10? That's your latest.

A. The errata, yes.

Q. That would be your latest changes that you agree to. Have there been any filed since then that you agree to?

A. No. We are accepting Mr. Rislov's recommendation on his different methodology. And one of the provisions is that we would change the tariff to identify that. And I don't have any language to that right now because we just received that today, but we were in agreement that we would do that.

Q. Okay. In Mr. Rislov's testimony it talks and I believe -- I don't have the page written down, but it's probably page two of his surrebuttal. And he talks about you need to assign the costs. Do you know how NSP is proposing to assign those costs? Were you going to do it -- he suggested that it be done either averaged or directly assigned. Do you know?

A. Is this in regards to the question that Mr. Smith deferred?

Q. Yes.

A. Okay. I believe we would choose the volumetric surcharge on Mr. Rislov's rebuttal exhibit page six of six, he's identified that amount as a volumetric surcharge. And we would accept that condition, his separation of costs also.

Q. Okay. That's Mr. Knadle's exhibit actually.

A. Oh, I'm sorry.

Q. Okay. On page seven of your testimony -- and Mr. Knadle had asked that NSP revise the tariffs to delete references to requirements as provided in Northern's tariff. And it's my understanding that NSP opposes that. And referring to your response from Jim Johnson on the 31st, December 31st, NSP says that should you do so would be burdensome and onerous, I believe, was their reasoning. Can you tell me how many times per year does Northern change its daily deliverance variance?

A. I believe Mr. Johnson's response was just about all provisions. The daily deliverance variance -- and I'm trying to think. I thought there was another provision. But if it's just the daily deliverance variance where we refer to that -- if you want a percentage, the current percentage, it changed from, I believe, five percent to three percent on November 1st of their filed gas rate change. We're willing to do that. It's just that all the other provisions that change during the year, we thought that that would be administratively burdensome.

Q. So the daily delivery variance you have no problem with?

A. No.

Q. What are the other ones that you do?

A. The ones that Mr. Johnson were referring to were the Gas Industry Standards Board, the GISB; and I think he had cited the number of times it has changed.

Q. I believe --

A. Six times since 1996. That's just GISB alone.

Q. Is that a number of pages? Or are we talking three pages or thousands of pages, or do you know?

A. The Northern Tariff is hundreds, I would assume.

Q. But that would change -- all hundreds of those pages would change each time?

A. No, it would just reference whatever they're changing at the time.

Q. Okay.

A. But the reference to just the delivery variance, I don't believe that that changes as dramatically as everything else; and we would be willing to incorporate that.

Q. Okay. How would NSP notify its customers if it wasn't in the tariff?

A. Well, we could put -- we could send out the changes like we do when we make our PGA filings in different state commissions, we update those with any changes that Northern is providing. Or actually their gas supplier would probably be aware of that at the same time that NSP would be.

Q. What about like monthly nominations, how often do those change?

A. I would imagine about the same as the daily delivery. I'm not aware of it.

Q. Do you know about daily nominations? Do those change very often?

A. I'm not aware of how many times.

Q. One or 20 times a year? I mean do you have any idea?

A. No, I don't. But if it's a percentage that you would want incorporated for those, we could do that. I believe our interpretation was every time they change, but it fits the -- if it's a percentage, we're agreeable to that.

Q. On page 15 of the tariff, the original sheet 15, do you have that, 4.0? I've kind of got them separated your original ones and then your faxed copy. That's kind of how I --

A. Okay. My original that was filed?

Q. Yeah.

A. I have 4.0 rates and charges.

Q. Right. Where it reads the rates per service under this rate schedule are included in the appendix of the Gas Transportation Agreement, should that read instead of in the appendix of the Gas Transportation Agreement, should that read instead original sheet 16? Because if you look at the page right behind it, it looks like you left it blank for that reason.

A. Yes, it refers to the sheet after that, the summary.

Q. Look at original page 16. And then, see, when you have to go -- it's so confusing. You have to go to your original sheet 17, which is on Exhibit 10.

So you've got original sheet 15 of Exhibit 9; then look at original sheet 17 of Exhibit 10.

A. You're right, it is confusing.

Q. That's the one.

A. Okay.

Q. See it says transportation rate summary. Should that read original sheet 16?

A. Yes.

Q. Okay.

A. The numbering is off, I believe, is true, yes.

Q. Right. I just wanted to check. I got a number of those. Okay. On original sheet 18 of Exhibit 9?

A. Which is the index of shippers?

Q. I've got -- do you have original sheet 18 on 1.1, character of service?

A. That's my problem. Okay. Let me go through this. Okay. I'm on original sheet number 18.

Q. 1.1, character of service?

A. Yes.

Q. See where it reads 3.2, section 3.2?

A. Yes.

Q. Should that be 2.9 and 3.0?

A. Yes.

Q. Okay. Now go to Exhibit 10, original sheet 21. And under Balancing, 2.6, should that read paragraph 3.0 rather than 3.2?

A. Yes.

Q. Okay. Then staying with that same Exhibit 10, go to original sheet 22. At the very bottom of the page it just tails off, such payments, however, shall not... And my question is should that have the language as found on original sheet 21, which is in Exhibit 9, should it have the remainder of the language of the paragraph from 3.3 and all of 4.0?

A. Yes, it should.

Q. Okay.

A. I apologize for that.

Q. That's all right.

A. Secretarial staff was a little weak before Christmas.

MS. CREMER: That's all I have.

MS. WIEST: Commissioners?

CHAIRMAN BURG: I have a couple of quick ones. First one, you said that the imbalance penalty, that question about the imbalancement, could that penalty be assessed for both over and under usage of the reserve?

A. Yes, it can.

CHAIRMAN BURG: Okay. And then the other one I have -- this question was already asked and I just want a clarification. On page seven of your testimony when Ms. Cremer asked about on item number 14, Mr. Knadle asked, and it goes on to say how you disagreed with the tariff reference being required, Mr. Knadle asked that NSP-SD revise the tariff to delete references to requirements as provided Northern Tariff and you objected. You know, has an agreement been reached on that?

A. Yes. Our objection was to all the changes within Northern's tariffs, and now that we have it down to just the imbalance daily, what was it daily and monthly, if it's a percentage, we can provide that, whatever is current in Northern's tariff.

CHAIRMAN BURG: So it's your feeling that given that exchange that we just had between you and staff, that you agree to what they want? Do you feel they have accepted -- that that's adequate without meaning all the changes?

A. I believe so.

CHAIRMAN BURG: Okay. I wanted to clarify that for our information. And this one I've got to be a little more careful if it's in the confidential part. I did not and I don't want to talk about any figures. I did not understand that between the different -- and, again, if this correction violates proprietary, just somebody tell me. The differences between the different customers, why there should be a variation in the customer charges between individual separate customers.

A. I believe I can answer that, can't I? These customers are smaller than the original Hutch. And because they're a smaller size, they have smaller metering requirements. And so what we tried to do was develop a customer chart based on their metering requirements.

CHAIRMAN BURG: What do you mean by -- excuse me. Explain a little more what you mean by metering requirements. Size of meter?

A. Yes, because they're a smaller customer, they have a smaller size of meter. So what we did is we use the same methodology but we calculated what a customer charge would be based on their own metering requirements.

CHAIRMAN BURG: And then you're doing those on a volumetric basis?

A. No.

CHAIRMAN BURG: Is that why the volumetric charges would be different?

A. Yes. The customer charge is based on the metering requirements, but then their volumetric charge was based on the extension cost that those two additional customers imposed on the system.

CHAIRMAN BURG: So they had different extension costs so that's why there's different volumetric rates?

A. Yes.

CHAIRMAN BURG: Okay. That clarifies my question.

COMMISSIONER SCHOENFELDER: All right. I want to go back to your tariff sheets and the misnumbering. I went through them myself over the weekend and this morning. I found some errors; staff has found other errors. I just would like to reiterate that they are numbered correctly and that those things will make sense once when you file them.

A. Yes.

COMMISSIONER SCHOENFELDER: I would like to have your assurance that you're going to do that. I also would like to have you go to page seven on your rebuttal testimony. And Commissioner Burg asked you some questions about the Northern tariff and your exchange with staff. I have a major question about that. My understanding is that Northern's tariff is hundreds, if not thousands, of pages deep long. And I don't know that anywhere where you suggest here that your customer wants to view the Northern tariff they should go to the Internet. I don't know that I necessarily think that is the proper way to file a tariff or to have someone reference a tariff. So I would like to see you come up with something else there if that's possible. I don't think a customer probably -- a transportation customer might be able to go to the Internet, but they may not be able to also.

A. And I think by putting in the percentage, that will do it.

COMMISSIONER SCHOENFELDER: Will that solve that problem?

A. Yes, and all of the numbering corrections and what we've discussed today. We'll file that in our compliance filing once the order is received.

COMMISSIONER SCHOENFELDER: Thank you.

MS. WIEST: I had a question on your system exit charges. And I believe your tariff says that system exit charges shall apply as determined by the company. And I believe Mr. Knadle had a request for clarification on that. My question is does this apply only if the customer leaves a system prior to the end of a customer's contract, or when do you assess those exit charges?

A. I'll give you an example if I can. Could we go to Mr. Smith's schedule three, page one of three?

CHAIRMAN BURG: The original filing?

A. No, Mr. Smith's rebuttal. And we can put the formula, which would be the plant in service additions minus the number of years times the book depreciation for those years. Say in the time period under year, well, 2000, if they would leave the system, the net investment would be the 480,000. And that would be the original plant in service addition minus the depreciation, so we would ask that customer that the 480,000 be -- that he make that contribution because that's the investment that we had supplied.

MS. WIEST: He would pay 480,000 to leave?

CHAIRMAN BURG: Wouldn't that have to be prorated to that customer?

A. I believe this is.

CHAIRMAN BURG: This is for one customer?

A. This is Hutch's cost.

MS. WIEST: But it's just totally in your discretion, system exit charges shall apply as determined by the company?

A. It would be the net unrecovered investment.

MS. WIEST: Where is that in your tariff?

A. It's in Appendix A. Right now what it currently says is system exit charges will also apply as determined by the company. I believe what we agreed to do was add how that formula would be determined, what the net unrecovered investment would be at the time they exited the system.

MS. WIEST: But you haven't added that yet?

A. No.

MS. WIEST: And I'm not sure if this was answered. Does this apply if only the customer leaves the system? You mentioned that HTI has a contract. Does it apply only if the customer leaves the system prior to the end of the customer's contract? Or what if HTI leaves at the end of their contract, can you still apply a system exit charge and does HTI know this?

A. I don't know. I don't have that answer.

MR. GERDES: Can we supply that?

MS. WIEST: Why don't you get back to me on that. And then I believe in Mr. Rislov's testimony, his original testimony, page seven, line 21, he asked that NSP file operations reports with the Commission no less than annually. Does NSP agree to that?

A. Yes. I believe in Mr. Smith's testimony we had asked that the first report be filed May of 2000 for '98 and '99 costs.

MS. WIEST: I think they were two separate filings, is my understanding. I could be wrong. This was the operations reports. He also asked there be a review in the year 2000. But this is an operations report no less than annually. But you're saying that's the same thing, you're just filing one thing in the year 2000?

A. I believe that's true, yes.

MS. WIEST: And then going back to the question on your limitation to retail customers, on page five of your testimony you referenced the Minnesota and North Dakota gas rate books. You say which contain a similar provision. Are those for gas distribution?

A. The North Dakota and Minnesota?

MS. WIEST: Yes.

A. Yes.

MS. WIEST: So they're not for a pipeline, a transport pipeline, interstate pipeline facility?

A. No. In Minnesota and North Dakota it's a distribution system.

MS. WIEST: Any other questions from the Commissioners?

CHAIRMAN BURG: Your questioning brought one that isn't clarified for me yet. She asked if you -- if it was optional whether you got an exiting fee. Is it optional or is it mandatory that that be charged? Because the way the language is, I could almost read it either way. I don't remember which page was that language on?

MS. WIEST: System exit charges shall apply as determined by the company.

CHAIRMAN BURG: As determined, okay. That's what my question was. As determined by the company means the company would be determining. You're going to put further language in on that, but they shall apply. Okay. That answers that, that's fine.

MS. WIEST: Any other questions from the Commissioners? Any redirect?

MR. GERDES: I have no redirect. We've covered the part about the clarifications on Mr. Rislov's testimony and what the changes to the tariff would be based on that. That was the only thing I had. I have nothing.

MS. WIEST: Thank you. Any other witnesses from NSP? Do you have any other witnesses Mr. Gerdes?

MR. GERDES: No, we have no other witnesses. NSP rests.

MS. WIEST: Does the Commission want to

continue at this time with staff's?

(DISCUSSION HELD OFF THE RECORD.)

MS. WIEST: We'll take a very quick break.

(AT THIS TIME A SHORT RECESS WAS TAKEN.)

GREGORY A. RISLOV,

called as a witness, being first duly sworn, was examined and testified as follows:

DIRECT EXAMINATION

BY MS. CREMER:

Q. Would you state your name for the record.

A. My name is Gregory A Rislov.

Q. And your address?

A. My business address is Public Utilities Commission, State Capitol Building, Pierre, South Dakota, 57501.

Q. And by whom are you employed?

A. By the Public Utilities Commission.

Q. In what capacity?

A. As a Commission advisor.

Q. Are you familiar with Docket NG97-021?

A. This docket, yes.

Q. Before you you have what's been marked as Exhibit 6. Can you identify that, please?

A. Yes. That was the testimony initially prefiled in this docket.

Q. Okay. And you also have Exhibit 11 that's been admitted. Can you tell us what that is?

A. It's the surrebuttal testimony I submitted this morning.

Q. Do you have any corrections or changes or modifications to Exhibit 6?

A. Not that I know of.

Q. And do you have any changes, corrections, or modifications to Exhibit 11?

A. Again, not that I know.

Q. Could you summarize your testimony for us, please?

A. I presented the cost of service analysis for Northern States Power Company gas operations here in South Dakota. My testimony essentially follows the same line that NSP used in developing a 45-year levelized cost of service. I believe in general that's what I've done.

Q. Okay. What is your recommendation to the Commission?

A. My recommendation to the Commission? I have a levelized annual revenue requirement is one. I have $80,655 for NSP gas in South Dakota and a levelized year 45 years cost of service basis.

Q. Did you factor in the public interest in your recommendation?

A. I developed a cost of service based on the regulatory principles adopted by this Commission in the past. I developed the cost of service based on the legal requirements imposed by both the statutes and the rules which govern the PUC.

Q. And does that include public interest?

A. In my belief, yes.

Q. What sort of factors does that include?

A. Developing cost of service based on fair and reasonable principles.

MS. CREMER: That's all I have. Thank you.

MS. WIEST: Mr. Gerdes.

CROSS-EXAMINATION

BY MR. GERDES:

Q. Mr. Rislov, referring to your initial testimony on pages eight and nine, you recommend that NSP gas cost of service be reviewed in the year 2000, assuming we're all here after our computers crash, based on 1999's results. Do I understand correctly that you're asking for a one-time review, not an annual review?

A. Yes.

MR. GERDES: Thank you. That's all I have.

MR. RITER: Thank you.

CROSS-EXAMINATION

BY MR. RITER:

Q. Mr. Rislov, when Mr. Wilcox testified, he indicated that this area in development in the northeast part of Sioux Falls is a competitive situation where there is various businesses that may seek to construct their business there and it's competitive amongst the company that might want to serve them in their energy needs. Would you agree that area is a competitive area?

A. From my understanding, NSP's original extension of natural gas lines was to an area that had been unserved by Minnegasco at that point. But when we use the word competition, it implies many things. There are other fuels that could be used as well. So in general, I think the word competition would apply whether or not MidAmerican extended pipeline into that area, yeah.

Q. If I were to tell you that there was a Pepsi plant just right across the street from the HTI building that was served by MidAmerican at the time that NSP came into the Hutchinson Technology site, would that -- if that were to be true, would that be also indicative of a competitive situation?

A. Possibly. It depends upon what size the line was going to the Pepsi plant and whether or not that line could serve the Hutchinson Technologies Industries building. It may have been that MidAmerican would have had to construct ten miles of pipeline to get enough capacity. I just don't know.

Q. And you're not familiar with the type of service they have at the Pepsi plant in Sioux Falls?

A. No, I'm not.

Q. You know they've -- I think they've already done that. NSP has extended their line out to the Jans Corporation and to the county area out there, county shop, or whatever that building is. Are there crisscrossing lines in that area, do you know?

A. No, I don't.

Q. Now, in response to Ms. Cremer's question, you indicated that you took public interest into consideration. And we're looking at fair and reasonable rates; is that right?

A. That's correct.

Q. There's been testimony from NSP's witnesses about the fact that as a start-up business down there, it's hard to know exactly what their volume is going to be. You heard that testimony, didn't you?

A. Yes, I have.

Q. And in other situations that you've been involved in as a staff person, have you seen situations where there had been feasibility studies done to try to determine what demand there may be for the product in a particular area that a business is seeking a company -- seeking to extend their line?

A. I have.

Q. Mr. Rislov, in your testimony, your prefiled testimony, you indicated, I think, on page four of that testimony, that you were concerned -- lines three and four. You were concerned that NSP's South Dakota electric operation may be burying some of the costs for the gas operation, but this concern was mitigated by the limited size and scope of the gas operation. And it continues on, but without reading the rest of it, is that a concern, from your perspective, to make sure that the costs that are required to be paid by gas customers are paid by them and the costs that are electric customers' are paid by them so there's not cross-subsidization between those areas?

A. It will be an issue for me. It's not right at the moment.

Q. It will be from the perspective that if NSP's gas operations grow, that that might be more of a concern? Or what do you mean by that?

A. Until NSP files to change their electric rates, the cost of Angus Anson line is not included in the electric rates, so at this point there can be no effect on their electric operations.

Q. When they file, then that's where the determination will try to be made is the allocation proper on the Angus Anson pipeline between gas and electric?

A. That's where I believe it should be done, yes.

Q. Mr. Rislov, in your testimony, prefiled testimony, on page seven, lines 16 through 19, there was a question asked, is staff recommending changes in sales units? And you replied that, no, inadequate information precludes any possibility of making a reasoned long-term estimate. And I want to make sure I'm understanding correctly your testimony. Are you saying that at this stage that it's impossible or precludes any possibility that you can determine what their volume might be as opposed to their capacity in this line, the volume of sales as opposed to capacity?

A. I'm not sure if I understand your question.

Q. Well, NSP has based their rate request upon capacity, maximum capacity, as opposed to sales volume, as I understand it anyway. And so I'm wondering is that what you were talking about on line 17 at this time, that there's inadequate information to make a reasoned long-term estimate on sales units?

A. Again, maybe I don't understand it. If I could explain, capacity certainly is an issue as it relates to the potential volumes that can go through that line. But what I'm talking about here are the annual volumes.

Q. So you're suggesting, you know, that the 481,000 is their capacity that they're talking about where they multiplied -- I think they multiplied maximum -- or hours at maximum rate times something?

A. No.

Q. Okay. Then what are you talking about? You say in your testimony you have 481 Mcf's as a basis for the rate cap.

A. 481,000.

Q. Yes, I'm sorry. Upon what do you base that figure then?

A. That was an NSP estimate generated based on what they believed to be the load factor reported by HTI, or what HTI expected load factor would be. That was used as a surrogate for the small system.

Q. Now, the testimony from, I think it was Mr. Smith today, although it may have been another witness, relative to what would happen if Hutchinson

Technologies expanded and increased their business size by fourfold. Would that figure -- even if they did expand, to that extent would that figure still be short of that 481 that they were suggesting might be available or might be needed?

A. I'm not quite sure what you mean by fourfold. If it means what they use four times the current estimated volume of gas, the 480, yes, would exceed it. But, again, I'm not certain if that's what you're asking.

Q. Well, it's my recollection -- and I was hoping I could grab it, but I'll try to be quicker than that. My recollection was they said there's 66,000. Am I --

A. Yes.

Q. Does that sound right at this point in time?

A. Correct.

Q. And that they're estimating that if Hutchinson Technology grew their business substantially, that I think Mr. Smith's testimony was it might increase to another 140 -- or I can't remember exactly. I know it was over 200 when they got to it.

A. I think you're mixing and matching hourly versus annual volumes.

Q. I could be.

A. But, yes, there is, based on the material we have from NSP, an expected growth with Hutchinson Technologies this calendar year that would grow them significantly from where they're currently at.

Q. My question then, would that growth grow them to the 481?

A. Not with Hutchinson Technologies alone, no.

Q. It would grow them to like 225 or something; isn't that right?

A. It would grow them more than that.

Q. Okay. So the 481,000 Mcf's as a basis for the rate cap would be a figure in excess of what would be used by Hutchinson Technologies, even assuming they grow with the expansion of the plant?

A. It would incorporate usage of other customers as well.

Q. But at this time, wouldn't you agree -- I think as you mentioned in your testimony that you can't make a reasoned long-term estimate of what that growth might be?

A. That's accurate.

Q. Mr. Rislov, on lines on the next page, lines 30 and 31, you've indicated as far as recommendations that the case has necessarily placed heavy reliance upon estimates that have varying degrees of support.

And is that -- are you referring to the volume or the usage? Or what all are you referring to with the estimates that have varying degrees of support?

A. A good example is the sales issue we just talked about. I expect that's less than -- from a plant estimate that's based, for the most part, on tools. But still there are costs yet to be finalized.

Q. Let me just ask you one quick follow-up question, Mr. Rislov. If they increase sales, they're going to have to increase plant, extend their lines, and if I understand the rates that you've now put together on your rebuttal -- excuse me, Mr. Knadle's rebuttal exhibits, they would make some provision, would they, for those additional costs to be passed on to the entities that mandate, so to speak, the additional line extension? Or how would that be recovered?

A. If I could point to my surrebuttal on the second page, beginning with line one, I explain in a nutshell, the steel pipe and the regulating equipment at the end of the steel pipe would be system costs. The plastic extensions would become specific customer costs.

Q. Okay. And then they would recover that through the volume surcharge?

A. I suggest in my testimony, beginning on line 24 of that same page, that that is one option.

Q. And that's the option I think Ms. Seitz was suggesting that they might opt for?

A. Yes.

MR. RITER: That's all I have. Thank you.

MS. WIEST: Commissioners?

CHAIRMAN BURG: I have basically just one. You stated that if none of the costs -- you stated that none of the costs of the gas operation can be received from the electric customers without an electric rate case, and thus you aren't concerned at this time. And also I think you had added because of the very, very small amount, it would almost be imperceptible. More on a generic question, should the Commission be concerned about predatory or below cost pricing has an effect on other gas customers, or customers, I should say, of other competitive gas companies? Is that a factor we should even consider?

A. I believe you should.

CHAIRMAN BURG: In this case is there any indication that it is below costs?

A. It's difficult with a start-up company to specify costs the way we do in a normal rate setting.

CHAIRMAN BURG: Do you feel that on this

review that you recommended in year 2000, do you feel it would be more identifiable at that time whether they're recovering all their costs?

A. I think whenever we can improve the data, we can improve our decision making.

CHAIRMAN BURG: You're saying, if that's the case, we should reconsider the decision or open the decision for further --

A. Well, if nothing else, there may be plant costs, there may be changes in customer numbers, a whole host of finalizations that we just simply don't have at this point.

CHAIRMAN BURG: Okay. That's all I have.

MS. WIEST: Any other questions of the Commissioners? Mr. Rislov, what type of review are you recommending be done in the year 2000, a rate case or review by staff or what?

A. I believe we need rate case type data to make the cost of service review.

MS. WIEST: So are you recommending that they be ordered to file a new rate case by May 1st of 2000?

A. Yes.

MS. WIEST: And then I believe on page seven, line 21, you mention that NSP Gas should be required to file an operations report with this Commission no less than annually. That's different than your rate case you want filed May 1st, 2000; right?

A. Right.

MS. WIEST: Have they agreed to this?

A. I can't say they've agreed to either one. I was hoping for a Commission order.

MS. WIEST: Okay. There is discussion in their rebuttal testimony on they were proposing a netted tax discount rate. If they've accepted your surrebuttal, does that mean they've abandoned that?

A. I would say so.

MS. WIEST: That's all I have. Any redirect?

MS. CREMER: No.

MS. WIEST: Thank you, Mr. Rislov. Any other questions? Witnesses?

MS. CREMER: Yes. We'd call Bob Knadle.

ROBERT L. KNADLE,

called as a witness, being first duly sworn, was examined and testified as follows:

DIRECT EXAMINATION

BY MS. CREMER:

Q. Would you state your name for the record, please.

A. Robert L. Knadle.

Q. What is your address, Bob?

A. South Dakota Public Utilities Commission, State Capitol Building, Pierre, South Dakota.

Q. Are you familiar with Docket NG97-021?

A. Yes, I am.

Q. Were you the analyst assigned to this docket?

A. I was one of the analysts.

Q. In front of you there is Exhibit 7. Is that your prefiled testimony?

A. Yes, it is.

Q. Do you have any -- well, and then there's also Exhibit 12, which is titled rebuttal exhibit. Is that in front of you also?

A. Yes, it is.

Q. Do you have any changes or modifications or corrections to Exhibit 7?

A. Several. On page four, line 12, insert the following: On December 10, 1998, NSP provided staff with updated amounts for plant in service per NSP's response to staff's fourth data request, question number four. I have reviewed this data and would recommend to Staff Witness Rislov that he incorporate 413,871 in place of my previous recommendation of 364,718 for plant in service.

On page four, line 25, insert the following:

On December 23 and December 13, '98, NSP filed revisions to their proposed gas transportation service tariff. These revisions can be found on JCS-1, schedule two attached to the rebuttal testimony of Jamie Seitz. The company has accepted staff's minor changes, provided further clarification and further support for all of the items listed on page four of my testimony except for the following items:

Number one, and it's item number 34 on my testimony, which basically says transporter is not obligated to provide transportation service for resale. Staff requested -- what authority allows you to impose this restriction. NSP's response was that, "If the Commission were to order gas service restructuring so a supplier like Enron could contract directly with NSP-South Dakota for transportation service, NSP-South Dakota would remove this provision at this time." I think this is a legal matter and should be briefed.

Number two, item number 42, which was, however, the company may at its option agree to provide backup gas service. Staff request was if you intend to provide this service, provide a specific tariff for this. NSP's response was "NSP agrees to do so if customers request this service." My recommendation would be to eliminate this language from the tariff and the company can file specific language for Commission approval when the need arises.

Number three, item number 66, which was system exit charges will also apply as determined by the company. Staff requested that the company provide specific tariff authority and a basis for the calculation on the charges. The company did not provide specific tariff authority and the basis for the calculation on the charge. My recommendation would be to eliminate the language from the tariff.

My understanding now is that the company has agreed to provide specific language for a Commission review or staff review. At this point I might need some help from Rolayne and tell me if what we would need to do if the company does provide the language and staff reviews it, how we would have to proceed from this point? Would we have to open up for additional hearing or items be briefed? I just want to make sure that due process is --

MS. WIEST: I assume you could always comment on the language through a brief, but of course if you needed to actually put anything on the record, then we'd have to open it up for a hearing again. It depends on what you guys need to do to make the record.

MS. CREMER: I was thinking of MidAmerican also. One option would be to leave the record open. They could file their language. If anyone has objection to the language, they could formally file and we could, you know, then do a further hearing or see what objections were to the language.

MS. WIEST: Right. The question is whether you need to go more in hearing or if you want to just put objections in the brief itself.

MS. CREMER: Right.

MS. WIEST: But then you can make that recommendation to us in writing, too, whatever you guys want to come up with.

A. Thank you. Item number four, which was number 63, basically was throughout the tariff references are made to specifications or provisions in Northern Natural Gas Company's tariff. The majority of these relate to nominations and delivery variances. Staff requested that the company replace these specifications or provisions with the actual specifications or provisions provided in Northern's tariff. NSP opposes this requirement because Northern's tariff can change almost monthly and NSP tariff administration would be extremely burdensome. It also stated if the customer wants to review

Northern's tariff it is available on the Internet. NSP-South Dakota could provide a copy of Northern's changes upon customer's request. My recommendation would be to require NSP-SD to replace these specifications or provisions with actual specifications or provisions provided in Northern's tariff or require the company to provide on a timely basis to the customer and the Commission any changes in Northern's tariff that would affect NSP's gas transportation tariff.

Through the testimony of Jamie Seitz, NSP basically said that they would provide the provisions in Northern's tariff that relates to nominations and deliverances which are the majority of those concerns I have. And if they agree to do that, I guess my concern is no longer there.

And on page five, line 17, delete .199 per MMBtu and insert the following: .213 cents per MMBtu for the Angus Anson pipeline and NSP Gas Transportation. Staff's rebuttal Exhibit RLK-1, page one of six, detail staff's recommendations and maximum customer charges and minimum and maximum distribution charges per therm for the small volume, medium volume, (no recommended maximum rate for distribution) and large volume customer classes. NSP has proposed a maximum distribution charge of five cents per therm for the medium volume Class. NSP is not currently serving any medium volume customers. Therefore, staff would recommend that NSP file for Commission approval a maximum rate calculated in the same manner as found on rebuttal exhibit RLK-1, pages five and six, when data becomes available for the medium volume class.

And also if you go to Exhibit RLK-1, schedule one, line four.

MR. RITER: Pardon me, I didn't get that.

A. Exhibit RLK-1, schedule one, line four, which is insurance in amount under column A should read $124.00. And that also should be carried over to Column C, $124.00. And then if you go to the total, the total column A would be 18,188. And the total on column C would be 18,713.

CHAIRMAN BURG: What was column A?

A. 18,188. Column C, 18,713. And if you would go to Exhibit RLK-1, schedule three, which is the last page, on line one, replace the 73,938 with 80,655.

COMMISSIONER SCHOENFELDER: Say where we're at again, please?

A. If you go to the schedule three, which would be the last page of my exhibit, if you place the 73,938 on line one with 80,655. Line three would go from .154

to .168. The total maximum transportation rate on line five would go from .199 to .213. Hopefully that's all I have.

Q. Bob, can you just summarize for us what your testimony is, then, in light of the corrections.

A. Basically my testimony was making comment and made recommendations to Staff Witness Rislov on specific operating income and rate base amounts and I also commented and made recommendations on NSP's proposed transportation tariff. And I also made a recommendation on NSP's maximum customer charge per month and distribution charge per therm for the small volume, medium volume, and large volume customers.

Q. And those numbers can be found in your exhibits, your schedule?

A. Yes. Those numbers can be found in my Rebuttal Exhibit RLK-1, page 106.

Q. NSP has requested it be granted a waiver of a ARSD 20:10:13:04 and 20:10:13:05. Do you have a recommendation as to that waiver?

A. Yes. I would recommend that they be granted that waiver.

MS. CREMER: That's all the questions I would have.

MS. WIEST: Mr. Gerdes.

MR. GERDES: I have no questions. And by that I hope the Commission will understand that we're agreeing with the modifications that Mr. Rislov -- excuse me, Mr. Knadle has suggested. And I would also state on behalf of the company that we would agree, as was suggested as to the proposed change to item 66 in the tariff, that we would agree to submit language and then have it commented on by the parties as was discussed between Ms. Wiest and Ms. Cremer.

MS. WIEST: Anything else?

MR. GERDES: No.

MS. WIEST: Mr. Riter?

MR. RITER: Thank you.

CROSS-EXAMINATION

BY MR. RITER:

Q. Mr. Knadle, why do you think those two rules ought to be waived?

A. Okay. Basically the two rules address -- one is a sample forms on Rule 20:10:13:04, and there's some minor language related to changes in the tariff. And Rule 20:10:13:05 basically talks about section numbers in the tariff. And the company doesn't have any section numbers. So they were minor changes.

MR. RITER: All right.

A. Just format change.

MR. RITER: Thank you. That's all I have.

MS. WIEST: Commissioners?

CHAIRMAN BURG: I don't have anything.

MS. WIEST: Was it your understanding that NSP has agreed to all the numbers on your rebuttal exhibit?

A. That's my understanding.

MS. WIEST: So as of right now, what are the disagreements with NSP?

A. Disagreements that the Commission needs to decide?

MS. WIEST: Disagreements. What are the remaining disagreements between NSP and staff at this time? The system exit charges they'll propose?

A. The system exit charges is one. The other one was gas, to provide backup gas service in the tariff. And the company wants to leave it in. I recommend they delete it. And then there's an issue of the transporter is not obligated to provide transportation service for resell, which I deem it's a legal issue.

MS. WIEST: Right. And it's your understanding NSP hasn't agreed to that; is that correct?

A. That's my understanding.

MS. WIEST: So do you understand that NSP will file incremental surcharges in the tariff?

A. Related to?

MS. WIEST: I believe I think he's relating to the volumetric surcharges, those options that were discussed in the testimony.

A. I believe if you look at my rebuttal exhibit RLK-1, page five of six, on line five, I think that's the incremental charges you're talking about would be basically the line extension off the steel main. That would be correct.

MS. WIEST: Okay.

A. And then if you look at rebuttal exhibit RLK-1, page six of six, on line five, also that would be for large volume customers. I believe that's the incremental surcharge you're talking about, which is included in the maximum rate that carries forward to page one of that exhibit.

MS. WIEST: Okay. Thank you. Any other questions of this witness?

MR. RITER: I do on the incremental surcharge.

RECROSS-EXAMINATION

BY MR. RITER:

Q. Are you talking about if they were to extend the line to another customer, is that the incremental surcharge? Because there would be an additional charge that you really couldn't estimate at this point in time, can you?

A. For what we have for the small volume transportation incremental surcharge, if you will, if that's what you want to call it, I would call it a line extension off the main steel pipe, the 12,107 is related basically to that line extension and that's for the small volume customers. We don't have one for the medium volume customers. They don't have any data on that right now. And if you look -- if you go to page six, line one, essentially approximately 41,000 is related to the line extension to the large volume customer, which is HTI.

Q. But what if they were to expand or extend the line for another two blocks from the Jans Corporation site, would it still be that same factor that would be a volume cost for that new customer?

A. The small volume rate is -- I don't know if I'm getting into confidentiality stuff on this one or not. You'll have to --

MR. GERDES: Could I have the question again, please?

(The question was read by the Court

Reporter.)

A. Could I approach Mr. Gerdes and ask him if it's confidential or not?

MR. RITER: I don't care.

MS. WIEST: If there's no objection, go ahead.

MR. GERDES: Well, if it relates to proprietary information, I do want to object.

Even though it may constitute proprietary information, we've told Mr. Knadle to go ahead and talk about it.

A. Okay. The small volume transportation commodity rate on page five of six, line one, uses an estimated plant in service of 12,107 for those two small volume customers you're talking about. What the 12,107 includes is half of the plastic extension. It's a two-inch plastic pipe, I believe. It includes -- the calculation there includes half of that two-inch plastic extension. And they do have room if they had two more customers of the same size and volume as the ones they have now, then the rate would be the same for those and that's approximately half of the capacity on the line. So assuming two identical customers come on, then it would work out to the same rate.

Q. Then my last question would be then but if we went -- if NSP went two blocks beyond where the line stops now, so they had to put more line in --

A. Okay.

Q. -- how does that get recovered?

A. It would get recovered -- if they charge them the rate here between a minimum and maximum, assume they charge them the maximum, they would recover some of this estimated plant in service for small volume customers if they went up to 100 percent of capacity on that line. That's one of the reasons why Mr. Rislov recommended that we look at it down the line.

MS. WIEST: Any other questions of this witness?

CHAIRMAN BURG: Well, you know, just to follow up, if I understood what I heard before, that the new costs would all be assessed to the new customer. And what we're talking about now is just some of the common costs, would that be accurate?

A. This would be the costs that are outside of the steel pipeline. What the company proposed was is that they want to have different rates for three different class of customers: Small volume, medium volume, and large volume. So these are the initial rates they have for those classes. And if they do come in down the line, those costs will change based on the new costs that they have.

MS. WIEST: Any other questions? If not, thank you. Any rebuttal witnesses?

MR. GERDES: None.

MS. WIEST: Let's go off the record.

(A DISCUSSION WAS HELD OFF THE RECORD.)

MS. WIEST: With respect to the briefs, NSP will file their brief along with their revised tariff 30 days after receipt of the transcript. Any other parties may file a reply brief 30 days from the date of service of the brief of NSP. And NSP may file optional rebuttal brief ten days, 15 days, 20 from the date?

MR. GERDES: Could you give me 20?

MS. WIEST: That's fine, 20 days from the date of the service of brief by staff and MidAmerican. Is there anything else at this time? I won't close the hearing in case -- I mean close it down in case somebody has any desire to put any additional testimony as to any issues that might come up.

COMMISSIONER SCHOENFELDER: Didn't NSP agree to file something later or something?

MS. WIEST: That was the system exit charges language and that should now be part of their tariff. Is there anything else?

MR. RITER: They also agreed to file a

business plan.

MS. WIEST: Feasibility study if they have one. I think that was all.

MR. GERDES: That's what my notes say.

MS. WIEST: If that's all, we're done for today. Thank you.

(THE HEARING CONCLUDED AT 5:50 P.M.)

STATE OF SOUTH DAKOTA)
)
COUNTY OF HUGHES)

I, Lori J. Grode, RMR, Notary Public, in and for the State of South Dakota, do hereby certify that the above hearing, pages 1 through 130, inclusive, was recorded stenographically by me and reduced to typewriting.

I FURTHER CERTIFY that the foregoing transcript of the said hearing is a true and correct transcript of the stenographic notes at the time and place specified hereinbefore.

I FURTHER CERTIFY that I am not a relative or employee or attorney or counsel of any of the parties, nor a relative or employee of such attorney or counsel, or financially interested directly or indirectly in this action.

IN WITNESS WHEREOF, I have hereunto set my hand and seal of office at Pierre, South Dakota, this 7th day of January 1998.

Lori J. Grode

Lori J. Grode, RMR, RPR

NG97-021

Northern States Power Company
South Dakota

Before the
South Dakota Public Utilities Commission

Application for an Order Establishing a Natural Gas Local Distribution Utility, and to Establish Initial Natural Gas Transportation Rates for Northern States Power Company

Docket ____________________

December 1997

EXHIBIT
1

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Northern States Power Company
South Dakota

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and General Manager
500 West Russell Street
P.O. Box 988
Sioux Falls, SD 57101-0988
Telephone (605) 339-8358 fax 339-8204

December 16, 1997

William Bullard, Jr
Executive Director
South Dakota Public Utilities Commission
500 East Capitol Avenue
Pierre, SD 57501

Re: Application for an Order Establishing a Natural Gas Local Distribution Utility and Establish Initial Natural Gas Transportation Rates for Northern States Power Company - South Dakota

Dear Mr. Bullard:

Pursuant to South Dakota Statute 49-34A-10 and the Rules and Regulations of the South Dakota Public Utilities Commission ("SDPUC" or "Commission"), Chapter 20:10:13, Public Utility Rate Filing Rules, Northern States Power Company - South Dakota ("NSP-SD"), a business unit of Northern States Power Company ("NSP") hereby submits for filing this application to establish NSP-SD as a regulated natural gas local distribution utility and to establish its initial natural gas transportation services rate and tariff subject to the Commission's jurisdiction.

The initial rate will allow NSP-SD to serve the new Hutchinson Technology, Inc. ("HTI") facility in the Sioux Empire Development Park Number 5 in eastern Sioux Falls, South Dakota through a new distribution lateral pipeline. HTI had contacted NSP-SD and requested the proposed service.

Pursuant to South Dakota Administrative Rules Section 20:10:13:26, NSP-SD provides the following information:

(1) Name and address of the public utility.

Northern States Power Company - South Dakota
500 West Russell Street
P.O. Box 988
Sioux Falls, SD 57101-0988
(605) 339-8350

(2) Section and Sheet number of tariff schedule.

A copy of the proposed Tariff, Firm Transportation Service rate schedule and Form of Service Agreement are included herein as Exhibit 5. The Tariff conforms with the Commission Rules 20:10:13:02 through 20:10:13:14, with the exception of Rules 20:10:13:04 and 20:10:13:05. NSP-SD seeks waiver of Rules 20:10:13:04 and 20:10:13:05. This request is addressed more fully in Section 12 of this document.

No other type of service or rate will be offered on the pipeline at this time. In the future, NSP-SD may add additional customers under the Firm Transportation service schedule. If needed, NSP-SD will file additional rates and tariffs at a later time to meet the needs of additional gas customers.

(3) Description of the change.

The proposed tariff, rate schedule and form of service agreement would establish NSP-SD as a regulated gas utility in the State of South Dakota, subject to Commission jurisdiction. The reasons for the proposal are described in the testimony of Mr. Jim Wilcox in Exhibit Number 2. The initial rate proposed herein is a volumetric rate reflecting underlying cost data pertinent to the pipeline configured to serve the Hutchinson Technologies plant. The cost support for this rate is explained by Mr. John Winter in Exhibit number 4.

(4) Reason for the change.

NSP presently serves retail natural gas to customers in Minnesota and North Dakota. NSP (Wisconsin) provides retail natural gas service in Wisconsin and Michigan. In 1994, NSP's electric generation business unit ("NSP Generation") completed construction of a 13 mile intrastate natural gas fuel delivery pipeline from near Harrisburg, SD to the Angus C. Anson Generating Site east of Sioux Falls. This pipeline was built by NSP Generation with a capacity to provide natural gas for up to four 125 MW combustion turbines. At present only two combustion turbines have been constructed. NSP Generation has determined this natural gas pipeline is available to serve NSP-SD so it can redeliver natural gas to retail natural gas customers in the vicinity of the Angus C. Anson site. NSP-SD will construct a distribution lateral extension to the Hutchinson Technologies plant. A portion of the revenues to NSP-SD from the proposed transportation services will be transferred to NSP Generation and applied as a credit to the electric generation revenue requirements for the intrastate fuel delivery pipeline in future electric rate cases.

(5) Present rate.

None.

(6) Proposed rate.

The proposed maximum rate is a volumetric rate per Mcf with a per month fixed customer service charge. The cost basis for the proposed rate is supported by Mr. John Winter in Exhibit 4. NSP-SD proposes to establish an initial rate which allows the rate for service to a particular customer to be negotiated between a minimum and a maximum rate.

(7) Proposed effective date of the rate.

NSP-SD requests the Commission allow the rate to be accepted for filing, subject to refund, at the earliest possible date, preferably within 30 days following the date of the filing. The HTI plant is expected to be in commercial operation in February of 1998. However, gas service will be needed for construction heat prior to that time. The final rates and tariff terms and conditions would be those approved by the Commission's final order after hearing.

(8) Approximation of the annual amount of increase or decrease in revenue.

The proposed maximum volumetric gas transportation rate, $0.214 / Mcf applied to the estimated volume of 159,000 Mcf per year yields estimated revenues of $34,000 per year at maximum rates.

(9) Points affected

Natural gas will be received into the distribution lateral pipeline at the Angus C. Anson regulator station. Because the proposed three mile distribution pipeline falls within the definition in SDCL 49-41B-2.1(3b) of operating at less than twenty percent of specified minimum yield strength as defined by 49 CFR 192.3, this pipeline is not a transmission facility and, as such, no Commission permit is required under SDCL 49-41B-1. However, NSP-SD recognizes that pursuant to SDCL 49-34B this proposed pipeline will fall under Commission jurisdiction for pipeline safety review purposes. NSP Generation is not seeking the Commission to take jurisdiction over the intrastate fuel supply natural gas pipeline serving the Angus C. Anson generating station, since this pipeline only directly serves NSP Generation, and is thus exempt from Commission jurisdiction under SDCL 49-34A-1(9A).

(10) Estimated number of customers affected.

At present only Hutchinson Technologies is affected by the proposed rate and tariff.

(11) Statement of facts, expert opinions, documents, and exhibits to support the proposed changes.

Pursuant to Rule 20:10:13:39 (subp 1), NSP-SD submits the following exhibits in support of this filing:

Exhibit 2	Testimony of Mr. Jim Wilcox, Project Support
Exhibit 3	Testimony of Mr. Dan Woehrle, Technical Support
Exhibit 4	Testimony of Mr. John Winter, Cost of Service and Pipeline Rate (Pursuant to Rule 20:10:13:96)
Exhibit 5	Proposed Transportation Service Tariff
Exhibit 6	Statements Required by Chapter 20:10:13

(12) Request Waiver of Rules 20:10:13:04 and 20:10:13:05 - Arrangement of Tariff Schedules and Form of Tariff Schedule Rules, Respectively

Pursuant to Rule 20:10:13:08, NSP-SD respectfully requests waiver of the Commission's tariff schedule arrangement and form of tariff rules (20:10:13:04 and 20:10:13:05) to the extent necessary to accept the proposed tariff and rates on the date proposed. The rules require various detailed administrative requirements for tariff changes which are burdensome for NSP-SD since it will initially serve only one customer. Also, for simplicity of administration, the attached tariff requests waiver of any other Commission rules necessary to allow the tariff and rate to be effective on the date requested.

(13) Listing of Parties, Contacts, Legal Representatives, etc.

Michael J. Hanson,
Chief Executive & General Manager
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PO Box 988
Sioux Falls, SD 57101-0988

James P. Johnson,
Senior Attorney
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David A. Gerdes,
Attorney
May Adam Gerdes & Thompson
P.O. Box 160
Pierre, SD 57501-0160

(14) Notice; Posting; Public Inspection

Pursuant to Rule 20:10:13:17, a copy of this filing is available for public inspection at the NSP-SD office located at 500 West Russell Street, Sioux Falls, South Dakota.

(15) Conclusion

NSP-SD respectfully requests that the Commission accept the proposed rate and tariff for filing, subject to refund and subject to hearing, at the earliest possible date, preferably within 30 days following the date of the filing. Such an order would establish NSP-SD as a local natural gas distribution utility in the State of South Dakota pursuant to SDCL 49-34A-1, subject to Commission jurisdiction.

Dated: December 16, 1997

Northern States Power Company - South Dakota

By: ______________________

Michael A. Hanson
Chief Executive and General Manager
(605) 339-8358

Exhibit No. 5

Transportation Service Tariff

TARIFF SCHEDULES

APPLICABLE TO

INTRASTATE NATURAL GAS TRANSPORTATION SERVICE

OF

NORTHERN STATES POWER COMPANY - SOUTH DAKOTA

500 W. Russell St.
PO BOX 988
Sioux Falls, SD 57101

Filed with the South Dakota Public Utilities Commission
as SDPUC No. 1

Date Filed: December 16, 1997

Issued by:________________________
Michael J. Hanson
Chief Executive & Gen. Mgr.

NORTHERN STATES POWER COMPANY - SOUTH DAKOTA

GAS TRANSPORTATION SERVICE TARIFF

ORIGINAL VOLUME NO. 1

TABLE OF CONTENTS

PRELIMINARY STATEMENT

Northern States Power Company - South Dakota (hereafter "NSP-SD" or "Transporter") is an electric utility and prospectively a natural gas utility company planning to engage in the business of transporting and distributing natural gas in intrastate commerce to end users in the State of South Dakota. NSP's system consists of approximately three miles of distribution lateral pipeline in Minnehaha County, South Dakota. NSP-SD will take delivery of natural gas at the compressor station located on the Angus C. Anson site east of Sioux Falls and deliver it to end-use customers along or at the terminus of the NSP distribution lateral line in Sioux Falls, South Dakota.

GENERAL TERMS AND CONDITIONS

ARTICLE 1
DEFINITIONS

1.1 "Btu" shall mean one British Thermal Unit.

1.2 "Contract Demand" shall mean the aggregate of the maximum daily quantities of gas, expressed in dkt per day, which Transporter is obligated to accept for transportation for the account of Shipper from the points of receipt as set forth in the Transportation Service Agreement ("TSA") between Transporter and Shipper.

1.3 "Contract Year" shall mean the twelve month period commencing November 1 and terminating on October 31 of each year, until this Agreement shall have expired or otherwise been terminated in accordance with its terms.

1.4 "Day" shall mean the period of 24 consecutive hours, starting at 9:00 a.m. Central Clock Time, or such other 24 hour gas day period as established in Northern's Tariff.

1.5 "Dkt" shall mean the quantity of heat energy which is equivalent to 1,000,000 British Thermal Units (BTU). One "dkt" of gas means the quantity of gas which contains one dekatherm of heat energy. The total dekatherms are calculated by multiplying the gas volume in Mcf by its total gross heating value, divided by 1,000.

1.6 "Equivalent Quantities" shall mean the sum of quantities of gas measured in dkt received by Transporter and delivered for the account of Shipper at the points of receipt and delivery during any given period of time reduced by the sum of Shipper's Pro Rata Share of Lost and Unaccounted For Gas resulting from the operations of the System during the same period of time. In the event the ownership of gas lost as a result of an event of force majeure can be reasonably identified, the quantity thereof shall be charged to the Shipper or Shippers so identified.

1.7 "Gas" shall mean natural gas, unmixed or any mixture of natural and artificial gas.

1.8 "Gross Heating Value" shall mean the number of BTU's produced by the complete combustion, at a constant pressure, of the amount of gas which would occupy a volume of one (1) cubic foot at a temperature of 60 degrees Fahrenheit on a dry basis and at a pressure of 14.73 psia with air of the same temperature and pressure as the gas, when the products of combustion are cooled to the initial temperature of the gas and air, and when the water formed by combustion has been condensed to the liquid state.

1.9 "Maximum Daily Quantity" shall mean the maximum quantity expressed in dkt per day that the Transporter is obligated to receive for the account of Shipper at the point of receipt, as established in Exhibit A to Shipper's TSA.

1.10 "Mcf" shall mean 1,000 cubic feet of gas determined in accordance with the measurement base described in Paragraph 3.1 hereof.

1.11 "Month" shall mean the period beginning at 9:00 a.m. Central Clock Time on the first day of the calendar month and ending at the same hour on the first day of the next succeeding month.

1.12 "Northern" shall mean Northern Natural Gas Company, its successors and assigns.

1.13 "Northern's Tariff" shall mean the Northern's FERC Gas Tariff as it may be in effect from time to time.

1.14 "Pro Rata Share" shall mean the ratio that the quantity of gas delivered to Transporter for the account of Shipper to the total quantity of gas delivered to Transporter by all shippers for transportation in the System during any given period of time.

1.15 "SDPUC" shall mean the South Dakota Public Utilities Commission or any commission, agency or other state governmental body succeeding to the powers of such commission.

1.16 "Shipper" shall mean any party to a TSA providing for transportation of natural gas on Transporter's System. For purposes of Articles V and VI, "Shipper" shall also mean Shipper's Agent designated to provide day-to-day transportation management for Shipper. Shipper may change such designation from time to time upon written notice to Transporter.

1.17 "System" shall mean the pipeline and related pipeline facilities at the time owned by Transporter.

1.18 "TSA" shall mean the Transportation Service Agreement between Transporter and Shipper in the form set forth in this Tariff.

1.19 "Unaccounted For Gas" shall mean the difference between the sum of all input quantities of gas to the System and the sum of all output of gas from the System, which difference shall include but shall not be limited to gas used and accounted for in System operations, meter errors (subject to Section 3.8) and gas lost as a result of an event for force majeure, the ownership of which cannot be reasonably identified.

ARTICLE II
QUALITY

2.1 Quality Standards of Gas Received by Transporter. The gas to be delivered by Transporter shall be of merchantable quality and shall meet the minimum quality standards, as may be established or revised from time to time in Northern's Tariff.

2.2 Quality Tests. At the point of receipt, Transporter may cause tests to be made, by approved standard methods in general use in the gas industry, to determine whether the gas conforms to the quality specifications set out in Paragraph 2.1 hereof. Such tests shall be made at such intervals as Transporter may deem reasonable, and at other times, but not more often than once per day, or at the request of Shipper.

2.3 Failure to Conform. If gas delivered by Shipper does not comply with the quality specifications set out in Paragraph 2.1 hereof, Transporter shall have the right, in addition to all other remedies available to it by law, to refuse to accept any such gas. Transporter may, at its option and upon notice to Shipper, accept receipt of gas not complying with the quality specifications set out in Paragraph 2.1 herein provided. Transporter, at the expense of Shipper, may make all changes necessary to bring such gas into compliance with such specifications.

2.4 Quality Standards of Gas Transported By Transporter. Transporter shall use reasonable diligence to deliver gas for Shipper which shall meet the quality specifications set out in Paragraph 2.1 hereof, but shall only be obligated to deliver gas of the quality which results from the commingling of gas received by Transporter from Shipper and other shippers.

ARTICLE III
MEASUREMENT

3.1 Unit of Measurement and Metering Base. The volumetric measurement base shall be one cubic foot of gas at a pressure base of 14.73 pounds per square inch absolute, at a temperature base of 60 degrees Fahrenheit, and without adjustment for water vapor content.

3.2 Atmosphere Pressure. For the purpose of measurement, the absolute atmospheric (barometric) pressure at each measuring station shall be the atmospheric pressure determined by calculations based on the actual elevation above sea level of the meter at the place of measurement, and shall be stated in pounds per square inch.

3.3 Temperature. If determined to be necessary in the sole discretion of Transporter, the temperature of the gas shall be determined at each point of measurement by means of properly installed recording thermometer, an indicating thermometer, an electronic temperature measuring device, or a temperature compensating meter of standard manufacture acceptable to Transporter.

3.4 Specific Gravity. If determined to be necessary in the sole discretion of Transporter, the specific gravity of the gas shall be determined at each point of receipt by one of the following methods:

(a) By means of a properly installed recording gravitometer of standard manufacture acceptable to Transporter.

(b) If (a) is not considered feasible, then by use of a portable specific gravity balance of standard manufacture, or other standard device acceptable of Transporter and designed for such purpose or use in conjunction with a continuous sampler.

(c) Other methods acceptable to Transporter.

3.5 Measurement Procedures. Quantities of gas received and delivered hereunder shall be measured in accordance with Procedures contained in ANSI-API 2530, First Edition, AGA Committee Report No. 5, AGA Committee Report No. 7, and AGA Committee Report No. 8, or revisions or amendments thereto.

3.6 Measuring Equipment. Unless otherwise agreed, Transporter will provide, maintain, and operate necessary measuring and regulating stations equipped with flow meters and other necessary measuring equipment by which its quantities of gas delivered from Transporter hereunder shall be determined. Such measuring and regulating stations shall be so installed at the receipt point of the System and at other agreeable points. All flow, measuring, testing, and related equipment shall be of standard manufacture and type acceptable to Transporter.

Transporter and Shipper shall cause the chart on all gas measurement equipment to be changed, or mechanical or electronic indices read, by either Transporter or by Shipper's representative (where economical) on a daily basis. If telemetering is not installed, Shipper shall change recording charts on Transporter's Delivery point metering facilities or otherwise read Transporter's meter on a daily basis at a time specified by Transporter. Shipper may install check measuring equipment, provided that such equipment shall be so installed as not to interfere with operation of Transporter.

When Transporter deems it necessary, telemetering equipment shall be installed on Shipper's delivery point meter(s). Transporter will install and maintain the telemetering facilities. Shipper shall provide, install and maintain a weatherproof phone service and electrical service outlet with appropriate grounding for telemetering equipment. Shipper and Transporter, in the presence of each other, shall have access to all measuring equipment at all reasonable times, but the reading, calibrating, and adjusting thereof shall be done by the Transporter, unless otherwise agreed. Shipper and Transporter shall have the right to be present at the time of any installing, reading, cleaning, changing, repairing, inspecting, testing, calibrating, or adjusting done in connection with all measuring equipment. The records from such measuring equipment shall remain the property of Transporter. Reasonable care shall be exercised in the installation, maintenance and operation of measuring equipment so as to avoid any inaccuracy in the determination of the quantity of gas received and delivered.

3.7 Calibration and Test of Meters. The accuracy of all measuring equipment shall be verified by the Transporter at reasonable intervals, and if requested, in the presence of representatives of Shipper. Transporter shall not be required to verify the accuracy of such equipment more frequently than once in Contract Year. If either party at any time desires a special test of any measuring equipment, it will promptly notify the other, and the parties shall then cooperate to secure a prompt verification of the accuracy of such equipment. Transportation and related expenses incurred by Shipper or Transporter involved in the testing of meters shall be done by the party incurring such expense.

3.8 Correction of Metering Errors. If, upon any test, any measuring equipment is found to be in error, such errors shall be treated in the following manner: If the resultant aggregate error in the computed receipts or deliveries is not more than 2%, then previous receipts of deliveries shall be considered accurate. All equipment shall, in any case, be adjusted at the time of test to record to zero error. If, however, the resultant aggregate error in computed receipt or deliveries exceeds 2% at a recording corresponding to the average hourly rate of gas flow for the period since the last preceding test, the previous recordings of such equipment shall be corrected to zero error for any period which is known definitely or agreed upon. In case the period is not known definitely or agreed upon, such correction shall be for a period extending

over one-half of the time elapsed since the date of the last test, not exceeding a correction period of 180 days.

3.9 Failure of Measuring Equipment. In the event any measuring equipment is out of service, or is found registering inaccurately and the error is not determinable by test, or by previous recording, receipts or deliveries through such equipment shall be estimated:

(a) By using the registration of any check meter or meters, if installed and accurately registering, or in the absence of (a);

(b) By correcting the error if the percentage of error is ascertainable by calibration, special test, or mathematical calculation, of in the absence of both (a) and (b) then;

(c) By estimating the quantity of receipt or delivery based on receipts or deliveries during preceding periods under similar conditions when the measuring equipment was registering accurately.

3.10 Preservation of Records. Shipper and Transporter shall preserve all test data, charts, and other similar records for a period of at least one year, or such longer period as be required by the SDPUC or other jurisdictional public authority.

ARTICLE IV
RECEIPT AND DELIVERY POINTS

4.1 Point of Receipt. The initial point of receipt hereunder shall be the point of interconnection between the facilities of Transporter and the facilities of Northern States Power Company - Generation located in Minnehaha County, South Dakota. Shipper shall deliver, or cause to be delivered, gas to Transporter at the point or receipt for transportation service, set for in Exhibit A attached to Shipper's TSA.

4.2 Points of Delivery. The point(s) of delivery hereunder shall be the point(s) of connection between the facilities of Transporter and the facilities of Shipper, where Transporter shall deliver gas for the account of Shipper. Such point(s) of delivery are set forth in Exhibit A attached to Shipper's TSA. Unless otherwise agreed, the establishment of any additional point of delivery at the request of Shipper shall be at the expense of Shipper.

ARTICLE V
SCHEDULES

5.1 Schedules. Prior to the first day of each month, Shipper shall furnish Transporter with a schedule showing the estimated daily quantities of gas Shipper desires Transporter to transport during such month. Such monthly schedule shall be provided at least one hour before the deadline for monthly nominations in Northern's Tariff. Thereafter Shipper shall on a daily basis advise Transporter of the volumes Shipper will deliver during the following day at least one hour prior to the time Transporter must submit daily nominations to Northern pursuant to Northern's Tariff. However, Shipper may establish a standing schedule of daily volumes, notifying Transporter prior to any day when Shipper's daily deliveries will differ from the standing schedule by more than the daily delivery variance (+/-) established in Northern's Tariff.

5.2 Departures from Schedules. Departures from the scheduled deliveries at the point of receipt shall be kept to the minimum permitted by operating conditions, and shall be balanced as soon as practicable. Shipper shall use its best efforts to give Transporter notice prior to proposed change of a daily quantity from that set forth in the schedule provided for in Paragraph 5.1 hereof. Such notice shall be provided at times consistent with the notice period for intra-day nomination changes set forth in Northern's Tariff. Transporter may waive such notice upon request if, in its judgment, operating conditions permit such waiver. Transporter and Shipper shall inform each other of any other changes of deliveries immediately upon knowledge thereof.

5.3 Hourly Variation. Deliveries shall be made at uniform hourly rates to the extent practicable. Transporter's obligation to deliver shall not exceed 1/16th of Shipper's Maximum Daily Quantity in any given hour.

ARTICLE VI
DAILY AND MONTHLY BALANCING

6.1 Scheduling and Balancing Tolerances. It is recognized that the parties will be unable to control exactly the quantities of gas delivered and accepted hereunder on any day, and that deliveries by Shipper and redeliveries by Transporter may vary above or below the quantities scheduled on any day. However, nothing in this paragraph shall affect Shipper's obligation to pay for gas actually transported.

6.2 Daily Variance. The daily variance for a receipt point shall be the difference between the total quantities scheduled for receipt and the actual quantity delivered into Transporter's System. The daily variance for a delivery point shall be the difference between the total quantities scheduled and the actual quantity delivered by Transporter at such point on any day. Shipper shall take action to correct any daily variance between scheduled and actual receipts and deliveries occurring during the

month by making adjustments to schedules, receipts or deliveries. In no event shall the daily excess or deficiency variance exceed the allowable daily point of delivery variation set forth in Northern's Tariff.

6.3 Monthly Imbalances. Shipper's monthly imbalance shall be the net total of daily variance from all receipts and delivery points. Such monthly imbalance shall be corrected in-kind through adjustments to Shipper's schedules, receipts or deliveries in order for Shipper to receive Equivalent Quantities, or by such other method as is then mutually agreed upon by the parties hereto. The cumulative daily variances during any month above or below the quantities scheduled shall not exceed the monthly point of delivery monthly variance set forth in Northern's tariff.

6.4 Disposition of Excess Gas. In order to alleviate conditions that threaten the integrity of its System, Transporter may periodically acquire quantities of gas that are in excess of System needs. Transporter may make interruptible sales of such gas form time to time at the point of receipt pursuant to 18 CFR 284.402. Such sales shall be made under rates, terms and conditions mutually agreed upon between Transporter and the purchaser, provided that all such sales shall be fully interruptible.

ARTICLE VII
PRESSURE

7.1 Pressure at the Points of Receipt. Shipper shall cause the gas to be delivered at the points of receipt at a pressure sufficient to allow the gas to enter the System; however, Shipper shall not be required to deliver gas to the Transporter at any point of receipt at a pressure in excess of the minimum pressure specified with respect to each receipt point in Exhibit A of Shipper's TSA.

7.2 Pressure at Points of Delivery. Transporter shall deliver gas to Shipper's delivery points at the pressure existing in the Transporter's pipeline; however, Transporter must deliver gas to each point at a pressure not less than the minimum pressure specified with respect to each delivery point in Exhibit A to Shipper's TSA. Transporter, however, shall not be required or permitted to deliver gas at a pressure in excess of the maximum pressure specified for each point of delivery set forth in Exhibit A attached to Shipper's TSA.

ARTICLE VIII
BILLING AND PAYMENT

8.1 Billing. Unless otherwise agreed, on or before the 10th day of each month, Transporter shall render to Shipper a statement of the total amount of gas delivered by Transporter to Shipper at the points of receipt hereunder during the preceding month and the amount due. When information necessary for billing

purposes is in the control of Shipper, Shipper shall furnish such information to Transporter on or before the 10th day of the month.

Shipper and Transporter shall have the right to examine at reasonable times, books, record, and charts of the other to the extent necessary to verify the accuracy of any statement, charge, or computation made under or pursuant to any of the provisions hereof.

8.2 Payment. Unless otherwise agreed, Shipper shall pay Transporter at its general office or at such other address as Transporter shall designate on or before the 28th day of the month, the amount due for the preceding month. If presentation of a bill by Transporter is delayed after the 20th day of the month, then the time of payment shall be extended accordingly unless shipper is responsible for such delay.

8.3 Remedies for Failure to Pay. Should Shipper fail to pay all or any portion of any bill as herein provided when such amount is due, interest on the unpaid portion of the bill shall occur at a rate of one percent (1%) per month. If such failure to pay continues for 30 days after payment is due, Transporter may, in addition to any other remedy it may have hereunder, suspend further delivery of gas until such amount is paid, if authorized pursuant to the rules of the SDPUC.

8.4 Disputed Bills. If Shipper in good faith shall dispute the amount of any such bill or part thereof and shall pay to Transporter such amounts as it concedes to be correct and, at any time thereafter within 30 days of a demand made by Transporter, shall furnish a good and sufficient surety bond in an amount and with surety satisfactory to Transporter, guaranteeing payment to Transporter of the amount ultimately found due upon such bills after a final determination which may be reached either by agreement or judgment of the courts, as may be the case, then Transporter shall not be entitled to suspend further delivery of gas unless and until default be made in the conditions of such bond.

8.5 Adjustment of Billing Errors. If it shall be found that at any time or times Shipper has been overcharged or undercharged in any form whatsoever under the provisions hereof and, in the case of an overcharge, Shipper shall have actually paid the bill containing such overcharge, then within 30 days after the final determination of such overcharge or undercharge, the appropriate party shall pay to the other party the amount of said overcharge or undercharge, net of any other amounts then payable hereunder. In the event an error is discovered in the amount billed in any statement rendered by Transporter, such error shall be adjusted within 30 days of the determination thereof provided that claim therefor shall have been made within one (1) year from the date of such statement. If the parties are unable to agree on the adjustment of any claimed error, any resort by either of the parties to legal procedure, either by law, in equity, or otherwise, shall be commenced within 12 months after the supposed cause of action is alleged to have arisen, or shall thereafter be forever barred.

ARTICLE IX
CONTROL OF GAS

9.1 Responsibility for Gas. As between the Shipper and Transporter hereto, Shipper shall be in exclusive control and possession of the gas until such has been delivered to Transporter at the point of receipt, and after such gas has been redelivered to or for the account of Shipper by Transporter at the point(s) of delivery. Transporter shall be in exclusive control and possession of such gas while same is in the System between the point or receipt and the point(s) of delivery. The party which shall be in exclusive control and possession of such gas shall be responsible for all injury or damage caused thereby.

ARTICLE X
FORCE MAJEURE

10.1 Force Majeure. Neither party shall be responsible or held liable for any loss or damage resulting from failure to perform its obligations due to any cause beyond its reasonable control; provided, however, that such force majeure affecting the performance hereunder by either Shipper or Transporter shall not relieve such party of liability in the event of its own concurring negligence or in the event or its own failure to use due diligence to remedy the situation and to remove the cause in an adequate manner and with all reasonable dispatch; provided further, that no such causes affecting such performance shall relieve either party from its obligation to make payments as determined hereunder or entitle either party to exercise any right to offset against any such payment obligation.

10.2 Definition. The term "force majeure" as used herein shall mean acts of God, strikes, lockouts, or other industrial disturbances: acts of a public enemy, wars, blockades, insurrection, riots, epidemics, landslides, lightning, earthquakes, fires, storms, floods, washouts; arrests and restraints of the government, either federal or state, civil or military, civil disturbances; shutdowns for purposes of necessary repairs, relocation, or construction of facilities; breakage or accident to machinery or lines of pipe; the necessity for testing (as required by governmental authority or as deemed necessary by repairs or alteration to machinery or lines of pipe); failure of surface equipment or pipelines; accidents, breakdowns, inability of either party hereto to obtain necessary material, supplies, or permits, or labor to perform or comply with an obligation or condition of this Agreement, rights of way, and any other causes, whether of the kind herein enumerated or otherwise, which are not reasonably in the control of the party claiming suspension. It is understood and agreed that the settlement of strikes or lockouts shall be entirely within the discretion of the party having the difficulty and that the above requirement that any force majeure shall be remedied with all reasonable dispatch shall not require the settlement of strikes or lockouts by acceding to the demands of an opposing party when such course is inadvisable in the discretion of the party having the difficulty.

ARTICLE XI
INTERRUPTIONS

11.1 Notice of Interruption. Transporter shall at all times attempt to operate, or cause to be operated, its System in a manner designed to make possible, as nearly as practicable, continuous receipt of gas from, and delivery of gas to, Shipper in the respective quantities provided for in Shipper's TSA. If an interruption or curtailment of such receipt and/or delivery shall become necessary, Transporter shall at once attempt to notify Shipper by facsimile or telephone or other prompt means of communication of the nature, extent and probable duration of such interruption or curtailment and of the quantity of gas which Transporter estimates it will be able to receive from and deliver to Shipper during the period of interruption or curtailment, and shall give like notice of the cessation of such interruption or curtailment.

11.2 Allocation of Reduced Capacity. If the effective capacity of all or a portion of Transporter's System is reduced as a result of force majeure, repairs, maintenance or any other cause, whether similar or dissimilar, and some curtailment of the quantity of gas to be received from shippers under their transportation agreements is required as a result, the reduced capacity shall, during the period of curtailment, be allocated proportionately, according to their respective Maximum Daily Quantities, among those shippers whose gas must be received or delivered at or transported through, the affected facilities.

11.3 Scheduling of Receipts and Deliveries. Transporter shall schedule all quantities tendered under all services performed by Transporter in sequence as follows: First to Transporter's firm transportation shippers, and second to other Rate Schedules that may be approved, in the order of priority as may be approved by the SDPUC or other regulatory bodies with jurisdiction.

ARTICLE XII
INCORPORATION IN RATE SCHEDULES AND TRANSPORTATION AGREEMENTS

12.1 These General Terms and Conditions as incorporated in and are part of Transporter's Rate Schedules and Transportation Service Agreements. In the event of a conflict between these General Terms and Conditions and terms in Transporter's Rate Schedules or TSA's, these General Terms and Conditions shall govern.

RATE SCHEDULE - FIRM TRANSPORTATION SERVICE

1.0 Availability. This Rate Schedule is available for the transportation of natural gas on a firm basis for any end user Shipper where (i) Transporter has determined that sufficient System capacity exists to provide the service requested by Shipper, and (ii) Shipper has executed a Transportation Service Agreement ("TSA") wherein Transporter agrees to transport gas for Shipper's account up to a specific maximum daily quantity. Transporter is not obligated to provide transportation service for resale.

2.0 Gas Supply; Upstream Transportation, New Facilities. Shipper shall be responsible for arranging for all natural gas supplies and interstate transportation of shipper's gas on Northern to the point of receipt. Transporter will arrange for transportation on the NSP-Generation intrastate pipeline on behalf of Shipper. Unless otherwise agreed, Shipper must pay for all facilities required to physically connect to Transporter's pipeline.

3.0 Receipts and Deliveries. The Point of Receipt for all gas transported by Transporter under this Rate Schedule shall be at the interconnection of Transporter's System with Northern States Power Company - Generation located in Minnehaha County, South Dakota. The Point(s) of Delivery shall be at the point(s) designated in the Exhibit A attached to Shipper's TSA.

4.0 Rates and Charges. The rates for service under this Rate Schedule are included in the appendix of the Gas Transportation Agreement. However, Transporter has the right at any time to file with the SDPUC to adjust the rates applicable to service under this Rate Schedule.

5.0 Daily Tolerance; Penalty Provisions. The daily tolerance level (+/-) from Shipper's daily scheduled volume shall be the daily variance established in Northern's Tariff. Unless otherwise agreed, in the event the daily quantity of gas delivered by Shipper deviates above or below the daily scheduled volume in excess of the Northern's Tariff tolerance level, and Transporter is assessed charges or penalties by Northern, Shipper shall pay, in addition to the appropriate rates contained in this tariff, an amount equal to any payment Transporter is required to make to Northern.

6.0 General Terms and Conditions. Any terms of conditions not specified in this Rate Schedule shall be determined consistent with Transporter's General Terms and Conditions, which are incorporated by reference into this Rate Schedule.

Sheet 16 reserved for future use.

INDEX OF SHIPPERS

Shipper	Rate Schedule	Effective Date	Expiration Date
Hutchinson Technology, Inc.	FT	12/01/97	2/28/2008

NATURAL GAS TRANSPORTATION SERVICE AGREEMENT

This Gas Transportation Agreement ("Agreement") is made this ___ day of , 19 __, by and between NORTHERN STATES POWER COMPANY, a Minnesota corporation, (hereinafter called "NSP" or "Company"), and ___________________, a Minnesota corporation, (hereinafter called "Customer"). Customer will enter into agreement to purchase natural gas and have that gas delivered to a town border station of Company. Customer and Company desire to enter into this Agreement to have said gas transported by Company to Customer's plant facilities.

WITNESSETH: The parties hereto, each in consideration of the agreement of the other, agree as follows:

1.0 TERM. This Agreement shall commence on ___________________, and continue until _______________, and, if not terminated by at least 180 days prior notice, shall continue further until so terminated.

1.1 CHARACTER OF SERVICE. The transportation and delivery of gas hereunder is on a firm basis. In consideration for NSP's agreement to provide firm transportation service at the rates set forth in Section 3.2, Customer agrees to utilize natural gas transported by NSP for all the non-electric energy requirements of the Plant equipment for the term of this Agreement. However, Customer may use a fuel other than natural gas in the case of (i) a force majeure or other emergency condition on the NSP distribution system or Transporter's pipeline system, as provided in this Agreement or Transporter's Tariff, or (ii) a failure of Customer's gas supply as defined in Section 2.0 for reasons beyond the control of Customer.

1.2 CONTINUITY OF SERVICE. The Company will endeavor to provide continuous service but does not guarantee an uninterrupted or undisturbed supply of gas. The Company shall not be responsible for any loss or damage resulting from the interruption or disturbance of service for any cause other than the gross negligence of the Company. The Company shall not be liable for any loss of profits or other consequential damages resulting from the use of service or any interruption or disturbance of service.

2.0 LIMITATION ON OBLIGATION TO DELIVER. This Transportation Agreement is expressly contingent upon Customer or Customer's Agent's procurement of natural gas supplies and interstate pipeline transportation to the Company receipt point in Minnehaha County, SD. If Customer or Customer's Agent fails to deliver gas to Company at the designated town border station, Customer shall immediately cease using gas. Company is not obligated to provide backup sales service to Customer. However, Company may at its option, agree to provide backup gas service.

2.1 <u>REQUIREMENTS AND DELIVERIES; POINT OF DELIVERY</u>. Company agrees to accept delivery of Customer's gas at the inlet of Company's distribution system in <u>Minnehaha County, SD</u> and, on a firm basis, transport and deliver said gas to Customer's point of delivery in volumes up to ____ MMBTU per day, or such other volumes as is mutually agreed. Customer's point of delivery shall be the outlet of the meter installation at ____.

2.2 <u>DAILY NOMINATIONS</u>. Customer or Customer's Agent shall on a daily basis advise Company's gas dispatcher in St. Paul of the volumes Customer will request to be delivered during the following Gas Day. Customer may alternatively elect to make a standing nomination with Company, notifying Company on any day when customer's daily deliveries will differ from the standing nomination by more than five (5) percent. Customer shall submit daily or corrected standing nominations to Company at least 24 hours in advance of the start of the Gas Day. Customer's daily or standing nomination shall be its best estimate of the expected utilization for the Gas Day. If Customer and Company mutually agree, Company will relay Customer's daily or standing nomination to Customer's Agent, gas supplier(s), and Transporter.

2.3 <u>DISPATCHING</u>. Customer will adhere to gas dispatching policies and procedures established by Company from time-to-time to facilitate service under this Agreement. Company will inform Customer of any changes in dispatching policies that may affect this Agreement as they occur.

2.4 <u>RATE OF FLOW</u>. The gas supply shall be transported to Customer at a rate of flow up to but not exceeding ________ cubic feet per hour at the point of delivery. Gas shall be delivered at such pressures and temperatures as may exist under operating conditions at Customer's service location. Operating pressures at this location shall normally be _______ psi.

2.7 <u>REFUSAL OR DISCONTINUANCE OF SERVICE</u> (a) With notice, the Company may refuse or discontinue gas service for any of the following reasons: failure to pay amounts payable when due; breach of contract for service; failure to provide the Company with reasonable access to its property or equipment; when the Company is unable to furnish gas service to Customer because it cannot obtain permits or necessary right-of-way; when necessary to comply with any order or request of any governmental authority having jurisdiction.

(b) Upon such notice as is reasonable under the circumstances, the Company may temporarily discontinue gas service when necessary to make repairs, replacements, or changes in Company's equipment or facilities.

(c) Without notice the Company may disconnect gas service to Customer in the event of an unauthorized use of or tampering with Company's equipment or in the event of a condition determined to be hazardous to the Customer, to other customers of the Company, to the public, or to the Company's employees, equipment, or service.

Any discontinuance of service will not relieve Customer from Customer's obligations to the Company.

2.8 BALANCING. Customer and Company agree to balance daily delivery point nominations with actual deliveries (as defined in Paragraph 3.2) on an ongoing basis. Customer agrees to exert its best efforts to keep daily deliveries within five (5) percent of daily nomination. Customer and Company shall balance as operationally necessary, but no less than monthly. Customer or Customer's Agent shall be responsible for balancing receipt point nominations made to Transporter with receipt point deliveries made by Customer or Customer's Agent's gas supplier(s).

2.9 MONTHLY CASHOUT MECHANISM. Unless otherwise agreed, Customer's monthly imbalance will be corrected by a cashout mechanism. Customer's monthly imbalance is the difference between (1) the sum of Customer's daily nominations for the month and (2) Customer's actual metered use. Monthly volumetric imbalances will not be carried forward to the next calendar month.

Undertake Purchase Payment: If Customer utilizes less gas than the volume Customer nominated and delivered to NSP system, Customer shall sell the undertake gas to NSP. Customer shall be paid an Undertake Purchase Payment equal to the monthly imbalance times the Undertake Purchase Rate.

Monthly Imbalance %	Undertake Purchase Rate
100% to 98%	Index + Transporter's Firm Transportation (TF)
Commodity rate(s)	
98% to 90%	[Index + Transporter's TF Commodity rate(s)] x 0.75
Less than 90%	[Index + Transporter's TF Commodity rate(s)] x 0.50

Overtake Charge: If Customer utilizes more gas than the volume Customer nominated and delivered to the NSP system, Customer shall purchase the overtake gas from NSP. Customer shall be assessed an Overtake Charge equal to the monthly imbalance times the Overtake Rate.

Monthly Imbalance %	Overtake Purchase Rate
100% to 102%	Index + Transporter's Interruptible Transportation (IT)
Commodity rate(s)	
102% to 110%	[Index + Transporter's IT Commodity rate(s)] x 1.25
Greater than 110%	[Index + Transporter's IT Commodity rate(s)] x 1.50

Index for Monthly Cashout. The Index being used is Inside FERC Gas Market Report's first of the month "Prices of Spot Gas Delivered to Pipelines" for Northern Natural (Demarcation). Applicable pipeline commodity rate consists of all interstate pipeline charges including: GRI surcharge, Angus C. Anson fuel supply pipeline surcharge, fuel costs and commodity rate(s). All conditions of the monthly cashout mechanism apply

unless Customer and NSP agree otherwise. However, NSP will treat similarly situated customers on a non-discriminatory basis.

3.0 CHARGES. Commencing with the date of initial deliveries of gas by Company, the charges for this transportation service shall be according to Appendix A.

3.1 MONTHLY CUSTOMER CHARGE. As established in Appendix A. The customer charge shall not exceed the maximum charge on file with the South Dakota Public Utilities Commission.

3.2 VOLUME CHARGE. A Volume Charge equal to the product of (i) the actual deliveries made by Company to Customer during the billing period, and the fixed rate per MMBtu stated in Appendix A. The volume metered by NSP will be considered the actual volume delivered by Company to Customer. All volumes will be adjusted for Btu content and supercompressibility. The volume charge per MMBTU shall not exceed the maximum charge on file with the South Dakota Public Utilities Commission.

3.3 TAXES. In addition to the rates specified above, NSP shall collect any federal, state or local sales, use, excise, or other such taxes and fees that are legally effective and applicable to the service provided hereunder.

3.4 PENALTY PROVISION. Customer shall be liable for any balancing or other penalties imposed on NSP by Transporter and caused by Customer's actions. Customer shall also be liable for any incremental costs incurred by Company, if any, caused by Customer's failure to stay within the +/- 5 percent daily tolerance zone.

3.5 ADDITIONAL CHARGE FOR USE DURING CURTAILMENT. If Customer fails to curtail use of gas hereunder when requested by Company, Customer shall pay, in addition to the appropriate above rates, either an amount equal to any payment Company is required to make to Transporter as a result of Customer's failure to curtail, or $10.00 per MMBtu of gas used in excess of the volume of gas to which customer is requested to curtail, whichever amount is greater. Such payments, however, shall not preclude Company from shutting off Customer's gas supply in the event of Customer's failure to curtail gas use thereof when requested by Company to do so.

4.0 PAYMENT OF BILLS. All bills are payable at Company's office on or before the tenth day succeeding the date bill is rendered for service supplied by Company in the preceding month. Should Customer fail to remit the full amount when due, Customer shall pay a Late Payment Charge of 1% to be added to the next month's bill after the date due.

4.1 DISPUTED BILLS. If Customer in good faith disputes the amount of any monthly billing or part thereof, Customer shall pay Company the amount Customer believes to be correct and notify Company in writing of the basis for disputing the bill. Company shall promptly investigate the matter and submit a corrected bill to Customer.

If Customer has underpaid the amount actually due, Customer shall within five (5) days remit the additional amount due. If Customer has overpaid the amount actually due, Company shall refund the overpayment by a credit to Customer's next bill. Company agrees to waive the late payment charge for the disputed portion of any bill if Customer disputed the bill in good faith.

5.0 BILLING ADDRESSES, CURTAILMENT NOTICES, OTHER NOTICES. The applicable addresses and/or telephone numbers for billing, curtailment notices, and other notices under this Agreement are provided in the Appendix C to this Agreement.

6.0 TITLE TO GAS. Unless otherwise agreed, Customer shall possess title to Customer's gas while being transported by Company. However, Company may, if the parties mutually agree, take title to Customer's gas to arrange interstate or intrastate pipeline transportation from Transporter to Company's receipt point.

6.1 WAIVER OF LIABILITY. Customer shall hold Company blameless for any termination of gas service caused by failure of Customer, Customer's Agent, Customer's gas supplier(s) or Transporter to deliver gas to Company's designated receipt point.

7.0 TELEMETERING. Telemetering equipment shall be installed on Customer's premises in order to measure daily and monthly deliveries to Customer. Company will install and maintain the telemetering facilities. Customer shall provide, install and maintain a weatherproof phone service and electrical service outlet with appropriate grounding for telemetering equipment at Customer's cost.

8.0 REGULATORY AUTHORITY. This agreement is subject to all valid laws, orders, rules and regulations of any and all duly constituted authorities having jurisdiction over the subject matter herein and is subject to the receipt of any necessary authorization for the transportation service contemplated herein.

9.0 REPORTING REQUIREMENTS. Customer shall furnish to NSP all information as may be required or appropriate to comply with reporting requirements of duly constituted authorities having jurisdiction over the subject matter herein.

10.0 CONFIDENTIALITY. The terms of this contract, including but not limited to Customer's delivered price of gas, NSP's customer charge and volume charge, the volume of gas transported, and all other material terms of this contract shall be kept confidential by NSP and Customer, except to the extent that any information must be disclosed to a third party as required by law or for the purpose of effectuating transportation of the subject gas pursuant to this Agreement.

11.0 SUCCESSION, ASSIGNMENT. This Agreement shall inure to and be equally binding on the respective parties, their successors and assigns. Neither party

shall assign this Agreement and rights hereunder without the written approval of the other party. Such approval shall not be unreasonably withheld.

12.0 ENTIRE AGREEMENT; MODIFICATION AND WAIVER. This Agreement, together with all documents attached hereto which NSP has signed or initialed intending to make them a part hereof, constitutes the entire agreement between the parties relating to the transaction described herein and supersedes any and all prior oral or written understandings. No addition to or modification of any provision hereof shall be binding upon NSP, and NSP shall not be deemed to have waived any provision hereof or any remedy available to it unless such addition, modification or waiver is in writing and signed by a duly authorized employee of NSP.

13.0 SEVERABILITY. If any provision hereof is held to be unenforceable by final order of any regulatory authority or court of competent jurisdiction, such provision shall be severed herefrom and shall not affect the interpretation or enforceability of the remaining provisions hereof.

IN WITNESS WHEREOF, the parties have duly executed this Agreement effective the date and year first written above.

NORTHERN STATES POWER COMPANY	______________________
	Customer
By ______________________	By ______________________
Title ______________________	Title ______________________
Date ______________________	Date ______________________

APPENDIX A
GAS TRANSPORTATION AGREEMENT
DATED ______________
FOR
(Customer name)

I. Delivery Period

The Agreement and the rates, terms and conditions contained herein, will be in effect for a term commencing ________________, and continuing through _____________, and then shall be renegotiated.

II. Delivery Point and Charges

(a) Delivery Point

NSP will transport the Customer's gas supplies to customer's facility, located at ____________________________under this Agreement at the following rate:

(b) NSP Transportation Service Charges

The maximum Customer Charge is $287.00 per month.
Transportation local delivery volume charge will not exceed $0.213 per MMBtu transported and not be less than $0.044 per MMBtu transported.

(c) Annual Minimum Local Delivery Charge

Customer agrees to an Annual Minimum Local Delivery Charge of ___________ as determined by the Company.

System Exit Charges will also apply as determined by the Company.

III. Contract Quantity

Customer nominates a maximum daily Contract Quantity of ______ MMBtu.

NSP is not obligated to provide firm transportation service in excess of Customer's Contract Quantity unless NSP agrees to amend this Agreement in writing. However, NSP may at its option provide daily overrun transportation service to Customer on an interruptible basis if Customer so requests. The interruptible overrun local delivery charge per MMBtu shall be the same as the firm local delivery charge set forth above.

APPENDIX B
DEFINITIONS

"Btu" shall mean British Thermal Unit and shall be the quantity of heat required to raise the temperature of one (1) pound of water one degree Fahrenheit at sixty (60) degrees Fahrenheit.

"Contract Quantity" shall mean the daily quantity of natural gas which NSP is obligated to deliver on a firm basis to Customer pursuant to this Agreement.

"Contract Year" shall mean the twelve month calendar period set forth in Appendix A.

"Customer" shall mean Hutchinson Technology Inc. For purposes of this Agreement, the term Customer also includes Customer's Agent.

"Customer's Agent" shall mean (if applicable) the party or entity designated by Customer in Nomination Statement to perform day-to-day supply and/or delivery management functions for Customer. Subject to NSP's approval, Customer may change such designation from time to time upon written notice to NSP.

"Delivery Point" shall mean the outlet side of the NSP meter located on NSP's natural gas distribution system at Customer's Plant service locations.

"FERC" means the Federal Energy Regulatory Commission or successor agency.

"Firm Transportation" shall mean transportation service which is not subject to interruption except for emergencies or for failure of Customer to deliver gas to NSP at the Receipt Point for transportation to Customer.

"Gas" shall mean natural gas, manufactured gas, or other forms of gaseous energy which conform to the quality specifications in Transporter's Tariff.

"Gas Day" shall mean the 24 hour period determined in accordance with Transporter's Tariff.

"Interruptible Transportation" shall mean transportation service which is subject to interruption at Company's option.

"MMBtu" shall mean one million (1,000,000) BTUs. One MMBtu is equal to one (1) "Dekatherm" or ten (10) "Therms."

"Receipt Point" shall mean the inlet point of the NSP gas distribution system where NSP takes receipt of gas from Transporter.

"Transporter" shall mean Northern Natural Gas Company.

"Transporter's Tariff" shall mean Northern's FERC Gas Tariff on file with the FERC from time to time.

APPENDIX C
NOTICES AND CONTACT LIST

C-1 Notices to NSP:

Northern States Power Company
Attn: SD Gas Operations
P. O. Box 988
500 West Russell St.
Sioux Falls, SD 57101-0988

Notices and Bills to Customer:

C-2 Day to day communications

Wm. Duff Robinson
Senior Engineer
phone 605-339-8345
fax 605-339-8204

Jerry Peterson
Coordinator New Business Dev.
phone 605-339-8310
fax 605-339-8204

Day to day communications to Customer

C-3 Gas Transportation Communications

NSP Gas Control (24 Hours/day):

Northern States Power Company
Gas Control
825 Rice Street
St. Paul, MN 55117
phone: 612-229-5527
fax 612-229-2370

Customer's Agent

Statement D

Northern States Power Company - South Dakota
Gas Operations

Cost of Plant - Rule 20:10:13:54

Line No	Functional Classification	Balance
1	Distribution Plant	$383,218

Line No 1 - Distribution plant, less the cost of meters ($18,500) is used in Statement M, Page 1 of 3, Line 1, Column C. A detailed breakdown is shown on Schedule 4 of Exhibit 4.

Statement E

Northern States Power Company - South Dakota
Gas Operations

Accumulated Depreciation - Rule 20:10:13:64

NSP is depreciating the pipeline over 45 years with a -50% removal expense value. This results in a rate of 3.33%, which is mathematically equivalent to adding 50% to the project cost and recovering it on a straight-line basis over 45 years (with the first year at 50% due to the BOY/EOY average of plant investment applied to the 3.33% rate). The result is Accumulated Depreciation of $541,606 (Column H of Schedule 3, Page 1 of 3, in Exhibit 4) over the book life of the investment.

Statement M contains the overall cost of service study including the effect of Accumulated Depreciation offsetting Gross Plant Investment over the book life of the plant.

Northern States Power Company - South Dakota
Gas Operations

Working Papers on Depreciation and Amortization Method - Rule 20:10:13:66

NSP is depreciating the pipeline over 45 years with a -50% removal expense value. This results in a rate of 3.33%, which is mathematically equivalent to adding 50% to the project cost and recovering it on a straight-line basis over 45 years (with the first year at 50% due to the BOY/EOY average of plant investment applied to the 3.33% rate). The result is annual book depreciation of $12,036. Statement M, the overall cost of service study, includes depreciation expense and the effect of accumulated depreciation over the book life of the plant.

The rate can be determined by applying 1.5 (cost of the plant plus 50% for removal expense) to a hypothetical investment of $100. The result is $150. That amount recovered over 45 years yields a rate of 3.33% per year ($150/45 = 3.33%).

The -50% salvage value reflects the cost of decommissioning the pipeline at the end of its book life. Consistent with industry practice, the pipeline would be purged of gas and liquids, pumped full of a solution of sand and water, and the ends capped and sealed. The purged and sealed line would remain in place indefinitely.

Statement G

Northern States Power Company - South Dakota
Gas Operations

Rate of Return and Debt Capital - Rules 20:10:13:72 and 20:10:13:73

1996 Historical Cost of Capital
NSP - Minnesota Company

	Capitalization Amounts ($thousands) (A)	Ratio (B)	Rate (C)	Weighted Costs (D)	Net of Tax Return (E)
(1) Long Term Debt	$1,497,303	40.9736%	7.0953%	2.9072%	1.8897%
(2) Short Term Debt	264,064	7.2261%	5.5173%	0.3987%	0.2591%
(3) Preferred Stock	240,469	6.5804%	5.1408%	0.3383%	0.3383%
(4) Common Equity	1,652,477	45.2199%	11.2500%	5.0872%	5.0872%
(5) Total Capitalization	$3,654,313				
(6) **Required Rate of Return**				**8.7314%**	
(7) **Net of Tax Return**					**7.5744%**

Sources and Notes:

Column A per NSP books and records.

Column B: Column A amounts for Lines 1 - 4 compared to the total shown in Column A, Line 5.

Column C per NSP books and records.

Column D: Product of Column B times Column C.

Column E: Net of tax rates. Long and short term debt returns absent the tax effect due to their deductibility on NSP's federal income tax return. Tax rate @ 35%. Rates in Lines 1 and 2 consist of the rates in Column D multiplied times 1 minus the tax rate, or 0.65.

Northern States Power Company - South Dakota
Gas Operations

Operating and Maintenance Expense - Rule 20:10:13:80

The operating and maintenance expenses contained in Statement M are shown below. The statement contains reasonable estimates of several items due to the start-up nature of the operation. Sources and notes are shown.

	Amount (A)	Annual Escalator (B)	1 Year Escalated Amount (C)
(1) NSP - Operating and Maintenance Training, readings, patrolling of line by Angus Anson Plant personnel	$8,154	3.0%	$8,399
(2) ACA Supplemental Service Support and emergency services by ACA personnel	$3,600	3.0%	$3,708
(3) Services - NSP-SD Management and support	$7,200	3.0%	$7,416
(4) Insurance Estimated Annual Fee	$100	0.0%	$100
(5) OPS Assessment Estimate of Office of Pipeline Safety Assessments	$500	0.0%	$500
(6) Regulatory Fees Gross Receipts Tax Estimate	$300	0.0%	$300
(7) Total	$19,854	2.8%	$20,423

Sources and Notes:

Line 1, Column A: Direct costs of pipeline operations per NSP-SD Gas Operations budget. Consists of 12 hours per month at loaded labor of $37.56/hour and $20/hour for vehicle usage.

Line 2, Column A: Supplemental emergency service from ACA. One call per month @ $300/call.

Line 3, Column A: Services received from NSP-South Dakota personnel. Ten hours/month @ $60/hour.

Line 4, Column A: Insurance costs @ $0.03/$100 of investment per NSP's Risk Mgmt. Dept.

Line 5, Column A: Office of Pipeline Safety assessment based on a similarly situated intrastate pipeline in South Dakota.

Line 6, Column A: Annual regulatory fees based on Gross Receipts Tax. **Calculation based on** a similarly situated intrastate pipeline in South Dakota.

Column B: Annual escalators based on expectations of price inflation.

Column C: One-year escalations of amounts in Column A.

Line 7: Columns A and C are summarized and used to derive the overall escalator in Column B.

Statement I

Northern States Power Company - South Dakota
Gas Operations

Operating Revenues - Rule 20:10:13:85

Revenues recovered from Hutchinson Technologies, Inc. will be the negotiated rate for transportation, not to exceed the proposed maximum rate of $0.213 per Mcf, applied to HTI's monthly volumes. In addition, NSP will bill a monthly customer charge not to exceed the proposed maximum customer charge of $277 per month.

Statement J

Northern States Power Company - South Dakota
Gas Operations

Depreciation Expense - Rule 20:10:13:86

As described in Statements E and E-2, NSP proposes to utilize a 3.33% annual depreciation rate. Based on the total cost of the pipeline facilities, the annual depreciation amount will be $12,036. The overall cost of service can be found in Statement M.

NSP is depreciating the pipeline over 45 years with a -50% removal expense value, the basis for the 3.33% rate. This is mathematically equivalent to adding 50% to the project cost and recovering it on a straight-line basis over 45 years (with the first year at 50% due to the BOY/EOY average of plant investment applied to the 3.33% rate). The result is annual book depreciation of $12,036. Statement M, the overall cost of service study, includes depreciation expense and the effect of accumulated depreciation over the book life of the plant.

The rate can be determined by applying 1.5 (cost of the plant plus 50% for removal expense) to a hypothetical investment of $100. The result is $150. That amount recovered over 45 years yields a rate of 3.33% per year ($150/45 = 3.33%).

The -50% salvage value reflects the cost of decommissioning the pipeline at the end of its book life. Consistent with industry practice, the pipeline would be purged of gas and liquids, pumped full of a solution of sand and water, and finally the ends would be capped and sealed. The purged and sealed line would remain in place indefinitely.

Statement K

Northern States Power Company - South Dakota
Gas Operations

Income Taxes - Rule 20:10:13:88

Income taxes are determined on Schedule 3, Page 1 of 3 in Exhibit 2. The tax rate used is 35%. For cost of service purposes, book depreciation has been assumed to be equal to tax depreciation. Thus, deferred income taxes are not included in Statement M.

Statement L

Northern States Power Company - South Dakota
Gas Operations

Other Taxes - Rule 20:10:13:94

Property taxes for the proposed pipeline are determined using a rate of 2.43%. The rate is the same used for a similarly situated South Dakota intrastate gas pipeline owned by the Associated Milk Producers (Docket NG97-015). For 1997 two months are included (November and December). Thereafter the amounts represent a full year of tax. An annual escalator of 3.5%, a reflecting recent significant increases in South Dakota utility property taxes, has been included. The overall cost of service is included in the Filing Statements as Statement M, and as Schedule 3 in Exhibit 4.

Northern States Power Company - South Dakota
Gas Operations
Statement XI - Cost of Service
4.5" NSP-SD Lateral Pipeline Levelized Annual Revenue Requirement - See Page 3 of 3 for Sources and Notes

Capital Structure (CS):

	Cost	Weight	Weighted Cost	Net of Tax Cost
(CS1) Equity	11.25%	45.220%	5.0872%	5.0872%
(CS2) Preferred Stock	5.14%	6.580%	0.3383%	0.3383%
(CS3) Long-term Debt	7.10%	40.974%	2.9072%	1.8897%
(CS4) Short-term Debt	5.52%	7.226%	0.3987%	0.2591%
(CS5)		100.000%	8.7314%	7.5744%

	Time Period (A)	Year (B)	Plant in Service Additions (C)	Net Investment Rate Base (D)	Equity Return (E)	Taxes on Equity Return (F)	Debt Return (G)	Book Dep'n (H)	Operating Expenses (I)	Property Taxes (J)	Total Revenue Requirement (K)	Present Value of Revenue Deficiency or (Excess) Discounted At 7.5744% (L)
(1)	0	1997	364,718	358,700	9,731	3,406	5,929	6,018	3,309	1,459	29,851	29,851
(2)	1	1998	0	346,664	19,135	6,697	11,659	12,036	20,423	9,060	79,009	73,446
(3)	2	1999	0	334,629	18,482	6,469	11,261	12,036	21,007	9,377	78,632	67,949
(4)	3	2000	0	322,593	17,829	6,240	10,863	12,036	21,609	9,705	78,282	62,883
(5)	4	2001	0	310,557	17,176	6,012	10,466	12,036	22,228	10,045	77,961	58,216
(6)	5	2002	0	298,522	16,523	5,783	10,068	12,036	22,865	10,396	77,670	53,915
(7)	6	2003	0	286,486	15,870	5,554	9,670	12,036	23,519	10,760	77,409	49,951
(8)	7	2004	0	274,450	15,217	5,326	9,272	12,036	24,193	11,137	77,180	46,296
(9)	8	2005	0	262,415	14,564	5,097	8,874	12,036	24,886	11,526	76,983	42,927
(10)	9	2006	0	250,379	13,911	4,869	8,476	12,036	25,599	11,930	76,820	39,819
(11)	10	2007	0	238,343	13,258	4,640	8,078	12,036	26,332	12,347	76,691	36,954
(12)	11	2008	0	226,308	12,605	4,412	7,680	12,036	27,086	12,779	76,598	34,310
(13)	12	2009	0	214,272	11,952	4,183	7,283	12,036	27,862	13,227	76,542	31,871
(14)	13	2010	0	202,236	11,299	3,955	6,885	12,036	28,660	13,690	76,523	29,620
(15)	14	2011	0	190,200	10,646	3,726	6,487	12,036	29,481	14,169	76,544	27,541
(16)	15	2012	0	178,165	9,993	3,498	6,089	12,036	30,325	14,665	76,604	25,623
(17)	16	2013	0	166,129	9,340	3,269	5,691	12,036	31,193	15,178	76,707	23,850
(18)	17	2014	0	154,093	8,687	3,040	5,293	12,036	32,087	15,709	76,852	22,213
(19)	18	2015	0	142,058	8,034	2,812	4,895	12,036	33,006	16,259	77,041	20,700
(20)	19	2016	0	130,022	7,381	2,583	4,497	12,036	33,951	16,828	77,276	19,301
(21)	20	2017	0	117,986	6,728	2,355	4,099	12,036	34,923	17,417	77,558	18,007
(22)	21	2018	0	105,951	6,075	2,126	3,702	12,036	35,924	18,027	77,889	16,811
(23)	22	2019	0	93,915	5,422	1,898	3,304	12,036	36,952	18,658	78,269	15,704
(24)	23	2020	0	81,879	4,769	1,669	2,906	12,036	38,011	19,311	78,701	14,678
(25)	24	2021	0	69,843	4,116	1,441	2,508	12,036	39,099	19,987	79,186	13,729
(26)	25	2022	0	57,808	3,463	1,212	2,110	12,036	40,219	20,686	79,726	12,849
(27)	26	2023	0	45,772	2,810	983	1,712	12,036	41,371	21,410	80,322	12,034
(28)	27	2024	0	33,736	2,157	755	1,314	12,036	42,556	22,159	80,977	11,278
(29)	28	2025	0	21,701	1,504	526	916	12,036	43,775	22,935	81,692	10,576
(30)	29	2026	0	9,665	851	298	518	12,036	45,028	23,738	82,469	9,925
(31)	30	2027	0	(2,371)	198	69	121	12,036	46,318	24,569	83,310	9,320
(22)	31	2028	0	(14,406)	(455)	(159)	(277)	12,036	47,645	25,428	84,217	8,758
(33)	32	2029	0	(26,442)	(1,108)	(388)	(675)	12,036	49,009	26,318	85,192	8,236
(34)	33	2030	0	(38,478)	(1,761)	(616)	(1,073)	12,036	50,413	27,240	86,237	7,750
(35)	34	2031	0	(50,513)	(2,414)	(845)	(1,471)	12,036	51,857	28,193	87,355	7,298
(36)	35	2032	0	(62,549)	(3,067)	(1,073)	(1,869)	12,036	53,342	29,180	88,548	6,877
(37)	36	2033	0	(74,585)	(3,720)	(1,302)	(2,267)	12,036	54,869	30,201	89,817	6,484
(38)	37	2034	0	(86,621)	(4,373)	(1,531)	(2,665)	12,036	56,441	31,258	91,166	6,118
(39)	38	2035	0	(98,656)	(5,026)	(1,759)	(3,063)	12,036	58,057	32,352	92,997	5,777
(40)	39	2036	0	(110,692)	(5,679)	(1,988)	(3,460)	12,036	59,720	33,484	94,113	5,458
(41)	40	2037	0	(122,728)	(6,332)	(2,216)	(3,858)	12,036	61,431	34,656	95,716	5,160
(42)	41	2038	0	(134,763)	(6,985)	(2,445)	(4,256)	12,036	63,190	35,869	97,409	4,881
(43)	42	2039	0	(146,799)	(7,638)	(2,673)	(4,654)	12,036	65,000	37,125	99,195	4,621
(44)	43	2040	0	(158,835)	(8,291)	(2,902)	(5,052)	12,036	66,861	38,424	101,076	4,377
(45)	44	2041	0	(170,870)	(8,944)	(3,130)	(5,450)	12,036	68,776	39,769	103,056	4,148
(46)	45	2042	0	(176,888)	(9,434)	(3,302)	(5,748)	6,018	70,746	41,161	99,441	3,721
(47) Project Totals			364,718		224,493	78,573	136,788	541,606	1,831,152	959,798	3,772,411	1,031,812

Northern States Power Company - South Dakota
Gas Operations
Statement M - Cost of Service
4.5" NSP-SD Lateral Pipeline Levelized Annual Revenue Requirement - See Page 3 of 3 for Sources and Notes

LARR						
(RR1)	$12,422	$4,348	$7,569	$12,492	$29,828	$14,533

			LARR - As a % of Original Cost			
(RR2)	3.41%	1.19%	2.08%	3.42%	8.18%	3.98%

	7.5744% Present Value of Equity Return (A)	7.5744% Present Value of Taxes on Equity Return (B)	7.5744% Present Value of Debt Return (C)	7.5744% Present Value of Book Depreciation (D)	7.5744% Present Value of Operating Expenses (E)	7.5744% Present Value of Current Property Taxes (F)	Present Value of Revenue Requirements or (Excess) (G)	Summary - LARR (H)	Amounts (I)
(1)	9,731	3,406	5,929	6,018	3,309	1,459	29,851	Return	6.68%
(2)	17,788	6,226	10,838	11,188	18,985	8,422	73,446	Depreciation	3.42%
(3)	15,971	5,590	9,731	10,400	18,153	8,103	67,949	O&M and Prop Taxes	12.16%
(4)	14,322	5,013	8,727	9,668	17,358	7,796	62,883		
(5)	12,826	4,489	7,815	8,987	16,598	7,501	58,216	Total LARR	22.26%
(6)	11,469	4,014	6,989	8,355	15,872	7,216	53,915		
(7)	10,240	3,584	6,240	7,766	15,177	6,943	49,951		
(8)	9,128	3,195	5,562	7,220	14,512	6,680	46,296	Plant In Service	$364,718
(9)	8,121	2,842	4,948	6,711	13,877	6,427	42,927		
(10)	7,211	2,524	4,394	6,239	13,269	6,184	39,819	Annual Requirement	$81,186
(11)	6,388	2,236	3,893	5,799	12,688	5,950	36,954		
(12)	5,646	1,976	3,440	5,391	12,132	5,724	34,310		
(13)	4,977	1,742	3,032	5,011	11,601	5,507	31,871		
(14)	4,373	1,531	2,665	4,659	11,093	5,299	29,620		
(15)	3,831	1,341	2,334	4,331	10,607	5,098	27,541		
(16)	3,342	1,170	2,037	4,026	10,143	4,905	25,623		
(17)	2,904	1,016	1,769	3,742	9,699	4,719	23,850		
(18)	2,511	879	1,530	3,479	9,274	4,541	22,213		
(19)	2,159	756	1,315	3,234	8,868	4,369	20,700		
(20)	1,843	645	1,123	3,006	8,480	4,203	19,301		
(21)	1,562	547	952	2,794	8,109	4,044	18,007		
(22)	1,311	459	799	2,598	7,753	3,891	16,811		
(23)	1,088	381	663	2,415	7,414	3,743	15,704		
(24)	889	311	542	2,245	7,089	3,602	14,678		
(25)	714	250	435	2,087	6,779	3,465	13,729		
(26)	558	195	340	1,940	6,482	3,334	12,849		
(27)	421	147	257	1,803	6,198	3,208	12,034		
(28)	300	105	183	1,676	5,927	3,086	11,278		
(29)	195	68	119	1,558	5,667	2,969	10,576		
(30)	102	36	62	1,448	5,419	2,857	9,925		
(31)	22	8	13	1,347	5,182	2,749	9,320		
(32)	(47)	(17)	(29)	1,252	4,955	2,645	8,758		
(33)	(107)	(37)	(65)	1,164	4,738	2,544	8,236		
(34)	(158)	(55)	(96)	1,082	4,531	2,448	7,750		
(35)	(202)	(71)	(123)	1,005	4,332	2,355	7,298		
(36)	(238)	(83)	(145)	935	4,142	2,266	6,877		
(37)	(269)	(94)	(164)	869	3,961	2,180	6,484		
(38)	(293)	(103)	(179)	808	3,788	2,098	6,118		
(39)	(314)	(110)	(191)	751	3,622	2,018	5,777		
(40)	(329)	(115)	(201)	698	3,463	1,942	5,458		
(41)	(341)	(119)	(208)	649	3,312	1,868	5,160		
(42)	(350)	(123)	(213)	603	3,167	1,797	4,881		
(43)	(356)	(125)	(217)	561	3,028	1,729	4,621		
(44)	(359)	(126)	(219)	521	2,895	1,664	4,377		
(45)	(360)	(126)	(219)	484	2,769	1,601	4,148		
(46)	(353)	(124)	(215)	225	2,647	1,540	3,721		
(47)	157,866	55,253	96,191	158,747	379,065	184,689	1,031,812		

Schedule 3, Page 1 of 3:

Lines CS1 - CS5: 1996 Actual NSP Capital Structure. See Schedule 6 of this exhibit. The components of the overall return of 8.7314% are used to determine the annual cost of financing the project. The net of tax return is used to discount the 45 year amounts to the present value. The Return on Common Equity based on most recent authorized in Docket EL92-016.

Line 1, Column A: Time Period for present value calculation.

Line 1, Column B: Year in service. Present value is life cycle beginning in 1995.

Line 1, Column C: Pipeline investment.

Lines 1 - 46, Column D: Net investment reduced for accumulated depreciation for each year.

Line 1, Column E: One-half of end of first year investment applied to weighted common and preferred equity cost).

Line 1, Column F: Income taxes on the equity return determined in Col. E. Tax rate is 35%.

Line 1, Column G: One-half of end of year investment applied to the weighted debt cost.

Line 1, Column H: Book depreciation based on 45 year book life and 50% negative salvage value (3.3%).

Line 1, Column I: See Schedule 5. Amount reflects two months of expense in 1997.

Line 1, Column J: Property Tax estimate based on similarly situated intrastate pipeline in South Dakota.

Lines 1 - 46, Column K: Sum of Columns E - H for corresponding lines.

Lines 1 - 46, Column L: Present Value of Column K @ Net of Tax Cost of Capital.

Lines 2 - 46, Column E: Average net investment applied to weighted common and preferred equity costs.

Lines 2 - 46, Column F: Income taxes on the equity return determined in Col. E @ 35%.

Lines 2 - 46, Column G: Average net investment applied to the weighted debt cost.

Lines 2 - 46, Column H: Book depreciation based on 45 year book life and negative 50% salvage value (3.3%).

Lines 2 - 46, Column I: Operating expenses per Schedule 5, escalated at rate determined on Schedule 5.

Lines 2 - 46, Column J: Estimated property taxes based on similarly situated intrastate pipeline in South Dakota.

Line 47: Check totals.

Schedule 3, Page 2 of 3:

Line RR1: The levelized annual revenue requirements of the items reflected in the columns below.

Line RR2: The percent of original investment cost for the levelized revenue requirements shown on RR1.

Lines 1 - 46, Columns A - G: Annual present value of each revenue requirement component shown. The nominal amounts are from Schedule 3, Page 2 of 3, Columns E - J.

Lines 1 - 46, Column E: Annual present value of total revenue requirements. Matches Column L on Schedule 3, Page 1 of 3.

Line 47, Columns A - G: Total of annual present value amounts for each column. These amounts are then discounted to arrive at the amounts shown on Line RR1.

Columns H and I: Summary of Levelized Annual Revenue Requirements. Column H describes each component. Column I shows the LARR rate by component and the total. The LARR rate shown on Line 5, Column I is applied to the original cost of the pipeline shown on Line 8, Column I to arrive at the levelized annual revenue requirements shown on Line 10, Column G. This amount is carried forward to Schedule 2 to determine the pipeline rate used to serve HTI (4.5" lateral).

Statement Q

Northern States Power Company - South Dakota
Gas Operations

Description of Utility Operations: 20:10:13:101

Please see Mr. Dan Woehrle's testimony and schedules in Exhibit 3 of this application, and Mr. Jim Wilcox's testimony in Exhibit 2 of this application for descriptions of the NSP-SD Gas Operation's utility operations.

RECEIVED
APR 07 1998
SOUTH DAKOTA PUBLIC
UTILITIES COMMISSION

BEFORE THE PUBLIC UTILITIES COMMISSION
STATE OF SOUTH DAKOTA

IN THE MATTER OF THE APPLICATION FOR AN ORDER ESTABLISHING A NATURAL GAS UTILITY, AND TO ESTABLISH INITIAL NATURAL GAS TRANSPORTATION RATES FOR NORTHERN STATES POWER COMPANY	)))))	NG97-021 **AMENDED APPLICATION**

COMES NOW Northern States Power Company-South Dakota ("NSP-SD") and amends its application herein dated December 16, 1997, as follows:

1. NSP-SD seeks to be regulated as a gas utility as defined by SDCL § 49-34A-1(9). NSP-SD is a "public utility" as defined in SDCL § 49-34A-1(12) and provides gas service, as defined in SDCL § 49-34A-1(8) by the sale to end use customers of transportation services through an intrastate natural gas pipeline.

2. As indicated in its application, NSP-SD seeks to charge transportation rates for the transportation of natural gas to end-use customers. At the present time, NSP-SD has one customer, Hutchinson Technology, Inc., located in the Sioux Empire Development Park No. 5 in eastern Sioux Falls, South Dakota. NSP-SD seeks an order from the commission describing the extent to which it can and will regulate transportation rates. Because NSP operates a 3.5 mile, 4 inch steel intrastate gas pipeline for the transportion of gas, NSP believes that the commission has rate jurisdiction over this pipeline.

3. NSP does not at this time seek to be designated as a local distribution gas utility. To the extent that its application states to the contrary, NSP-SD hereby withdraws any portion of its application seeking certification as a natural gas local distribution utility.

WHEREFORE NSP prays that the commission schedule and hold such hearings as may be necessary to justify NSP-SD's application and approve and certify NSP-SD as a gas utility subject to regulation by the commission in accordance with its statutory authority.

EXHIBIT
2

Dated this 6 day of April, 1998.

MAY, ADAM, GERDES & THOMPSON LLP

BY: [signature]
DAVID A. GERDES
Attorneys for NSP-SD
503 South Pierre Street
P.O. Box 160
Pierre, South Dakota 57501-0160
Telephone: (605)224-8803
Fax: (605)224-6289

CERTIFICATE OF SERVICE

David A. Gerdes of May, Adam, Gerdes & Thompson LLP hereby certifies that on the 7th day of April, 1998, he mailed by United States mail, first class postage thereon prepaid, a true and correct copy of the foregoing in the above-captioned action to the following at their last known addresses, to-wit:

Suzan M. Stewart
Managing Attorney
MidAmerican Energy Company
P.O. Box 778
Sioux City, Iowa 51102
Via Telefax: 712-252-7396

Jennifer Erickson
Chief Operating Officer
PAM Natural Gas
P.O. Box 5200
Sioux Falls, South Dakota 57117-5200
Via Telefax: 605-339-9909

Michael J. Hanson
Chief Executive and General Manager
Northern States Power Company
P.O. Box 988
Sioux Falls, South Dakota 57101-0988

[signature]
David A. Gerdes

Direct Testimony and Schedules
Mr. Jim Wilcox

Before the South Dakota Public Utilities Commission

In the Matter of the Application for an Order Establishing A Local Distribution Gas Utility, and Establishing Initial Gas Transportation Rates for Northern States Power Company - South Dakota

Docket No. ____________

Exhibit No. 2

December 1997

Q. Please State your name, business address and position with Northern States Power Company ("NSP").

A My name is Jim Wilcox. I am Manager of Government and Community Relations for Northern States Power Company - South Dakota Business Unit ("NSP-SD"). NSP is an investor owned utility operating in five states in the upper Midwest. NSP-SD presently provides electric service to customers in 36 communities in eastern South Dakota.

Q. Have you previously testified before the South Dakota Public Utilities Commission ("SDPUC" or "Commission")?

A. Yes. I have provided written testimony before the Commission in Docket No. EL92-016, a general rate case in 1992, and I have provided verbal testimony in a number of regulatory matters in the years 1991 through the present.

Q. What are your current responsibilities, education and professional background?

A. As Manager of Government and Community Relations for NSP-SD, my current responsibilities include encouraging economic development in the communities NSP-SD serves, organizing and leading NSP-SD employee involvement in the communities in which NSP-SD provides service, and acting as NSP-SD's liaison with the South Dakota Legislature and the Commission. My education includes a Bachelor of Science Degree in Electrical Engineering from South Dakota State

University and a Masters Degree in Business Administration from St. Thomas University in St. Paul, Minnesota. I am a registered Professional Engineer in the State of Minnesota.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to explain the history of the development of gas transportation facilities by NSP in South Dakota, and to explain the benefits of NSP-SD's entry into the natural gas business in South Dakota.

Q. What is the history of natural gas development by NSP in South Dakota?

A. In 1994, NSP's Generation Business Unit ("NSP Generation") constructed a 13 mile natural gas pipeline to provide fuel delivery for the new combustion turbines being installed at the Angus C. Anson Generating Site. More recently, NSP has been providing natural gas expertise to the communities of Freeman, Humboldt, Crooks and Garretson, South Dakota. Personnel from NSP's gas distribution Business Unit ("NSP Gas") have been assisting these communities to establish municipal natural gas utilities, for the first time bringing natural gas service to the residents of these communities.

Q. What are NSP-SD's plans for developing natural gas in Sioux Falls?

A. NSP-SD is now planning to construct a 3.5 mile long, 4.5 inch diameter steel distribution lateral pipeline from near the terminus of the 13 mile Angus C. Anson natural gas fuel supply pipeline to the new Hutchinson Technologies, Inc. facility in the Sioux Empire Development Park number 5 in northeast Sioux Falls, South Dakota.

Q. Is there enough capacity remaining on the Angus C. Anson natural gas fuel supply pipeline to serve NSP-SD so that NSP-SD can in turn serve retail end users such as Hutchinson Technologies?

A. Yes. The Angus C. Anson natural gas fuel supply pipeline was sized by NSP Generation to serve up to four 125 MW combustion turbines. That is, the 12 inch pipe providing fuel delivery to the Angus C. Anson site has the capability to deliver 4,900 Mcf per hour of natural gas at a maximum allowable operating pressure of 900 psig. At present only two combustion turbines have been installed. Each combustion turbine requires 1,225 Mcf of natural gas per hour at peak load. Since construction was completed in 1994, NSP Generation has dedicated 900 Mcf per hour to serve the Pathfinder Steam plant also on the Angus C. Anson site. If NSP Generation adds the third combustion turbine at the Angus C. Anson site, there will still remain about 325 Mcf per hour of capacity to serve NSP-SD, so it can serve end-users with firm natural gas. This capability exceeds the expected firm natural gas needs of the Hutchinson Technologies facility. These natural gas facilities are more completely described by Mr. Dan Woehrle in Exhibit No. 3.

Q. What are the benefits of NSP-SD providing natural gas transportation services to customers in eastern Sioux Falls such as HTI?

A. Natural gas service, including the cost of gas supply, will provide energy cost savings to customers as compared to the cost of alternative fuels. Further, NSP-SD sees this as an economic development effort. This distribution lateral pipeline provides a competitive alternative to customers in the Sioux Empire Development Park Number 5 in northeast Sioux Falls and will assist in attracting and expanding business in Southeastern South Dakota.

Q. Please discuss how NSP-SD will comply with the South Dakota pipeline safety code, SDCL 49-34B.

A. Because the proposed distribution lateral pipeline would be an intrastate pipeline, NSP-SD will be subject to the Commission's jurisdiction for pipeline safety matters. NSP-SD and NSP Gas will be working with the Commission Staff during construction and after the line is in service to ensure that applicable pipeline safety requirements are met. NSP Gas has extensive experience in operating natural gas distribution systems in other states, and has construction and O&M standards which comply with federal DOT codes under 49 CFR Part 192. SDCL 49-34B authorizes the Commission to regulate the safety of intrastate and LDC pipeline systems to DOT code. Routine maintenance (odorant checks, meter readings, corrosion protection readings, patrolling and regulator pressure checks) will be performed as well as an annual leak survey in compliance with DOT standards.

Q. Who will provide the gas supply for customers to be transported through the NSP-SD distribution lateral pipeline?

A. As the Commission is aware, over the last decade the FERC (Federal Energy Regulatory Commission) has restructured the wholesale interstate natural gas pipeline industry. Northern Natural Gas Company no longer provides gas supply services. Instead, Hutchinson Technologies can directly contract with any one of a number of wholesale gas suppliers, using Northern Natural, the Angus C. Anson intrastate fuel delivery pipeline and NSP-SD's distribution lateral pipeline only for transportation services.

Q. What tariff is proposed in this filing?

A. NSP-SD is proposing a tariff similar to the intrastate pipeline service tariff approved for Associated Milk Producers, Inc. Pipeline ("AMPIP"). See Docket Numbers NG95-017 and NG97-015. The rate contained in the Firm Transportation rate schedule reflects the cost of service in testimony sponsored by Mr. John Winter in Exhibit 4. Mr. Winter proposes a maximum rate, with the actual rate for a specific customer (such as HTI) negotiated based on the cost of competing alternatives. NSP-SD is also adding provisions whereby it can pass through to a shipper any imbalance penalties from Northern caused by the shipper. Northern received FERC approval to modify its imbalance penalty structure, including imposing "critical day" penalties of up to $113 per dkt, in order to maintain system integrity. See FERC Docket No. RP96-302. NSP-SD does not anticipate such penalties being imposed on NSP-SD since Hutchinson Technologies (or their supplier) will hold the transportation contract on Northern and should bear any imbalance penalties. However, if a penalty is imposed on NSP-SD by Northern as a result of the actions of a shipper, the shipper should reimburse NSP-SD since the cost of service supporting the proposed transportation rates does not include any penalty costs.

Q. Describe the proposed Transportation Service Agreement.

A. The proposed service agreement is a standard form agreement to be used with each third party transportation service customer, and is modeled after AMPIP's form of agreement. The service agreement with Hutchinson Technologies is not provided in this filing, but will be provided as a confidential and proprietary document to the Commission and Staff upon request.

Q. Will the retail natural gas services to customers like HTI contribute any revenue to NSP Generation's customers for the use of the 13 mile Angus C. Anson pipeline initially installed as a fuel supply pipeline to the Angus C. Anson power plant?

A. Yes. The proposed service only includes use of the 3.5 mile NSP-SD distribution line. However, the proposed rate includes a representative cost for NSP-SD's use of the NSP Generation line. This revenue to NSP Generation will act as a revenue credit to the cost and use of the Angus C. Anson fuel delivery pipeline in future NSP-SD electric rate proceedings. The calculation of this payment is detailed in testimony by Mr. John Winter in exhibit number 4. This payment is appropriate to avoid any cross subsidization of the NSP-SD natural gas business by NSP Generation's electric customers.

Q. Is NSP-SD proposing to establish Commission rate and tariff jurisdiction over the 13 mile Angus C. Anson intrastate fuel supply pipeline as part of this proposal?

A. No. NSP-SD will own and operate the proposed 3.5 mile distribution lateral pipeline, and has received permission from NSP-Generation to transport gas over the Angus C. Anson natural gas fuel supply line for a fee. NSP-SD will arrange transportation over the Angus C. Anson natural gas fuel supply line on behalf of retail customers taking service on the distribution line. However, NSP-Generation will provide gas transportation service only to itself and to NSP-SD. Both of these entities are business units of the NSP Corporation. As NSP-SD understands SDCL

49-34A-1(9A), definition of "Intrastate natural gas pipelines," the Commission was only granted jurisdiction over pipelines which provide service to non-affiliated customers.

Q. Does NSP-SD intend to connect to and begin serving other natural gas customers?

A. As a part of acquiring easements for the pipeline to serve Hutchinson Technologies, NSP-SD has committed to providing natural gas service to 11 customers along the length of the distribution lateral pipeline. These customers will be served under the proposed tariff or under tariffs that will be filed for Commission approval in 1998 prior to the next heating season. Although additional pipeline capacity exists, NSP-SD has no immediate plans to connect additional customers, nor does NSP-SD have any plans to extend natural gas service to customers beyond those who may reside within the Sioux Empire Development Park Number 5 or on the Angus C. Anson site.

Q. Are there other suppliers already serving the Sioux Empire Development Park Number 5 in northeast Sioux Falls?

A. No. The Sioux Empire Development Park Number 5 in northeast Sioux Falls is a new "greenfield" industrial park with development recently begun by the Sioux Falls Development Foundation. Because this is a new site, NSP is not aware of any other natural gas suppliers presently serving this site.

Q. Are there other suppliers in the Sioux Falls area with exclusive rights to serve customers within the City of Sioux Falls?

A. No. Unlike electric service territories established by South Dakota Statute and South Dakota Public Utilities Commission Administrative Rules in 1975, natural gas utilities are not granted exclusive service territories. Rather, South Dakota municipalities have the authority, to grant non-exclusive franchise agreements with various utilities capable of providing natural gas services.

Q. South Dakota statutes do not mandate Commission regulation of natural gas utilities with fewer than fifty customers. Why are you proposing to offer this service on a regulated basis?

A. First, NSP-SD is already regulated by the Commission for its retail electric services. The proposed natural gas transportation service is simply a new regulated business. Second, as noted by Mr. Dan Woehrle in exhibit 3, the proposed facility will be subject to Commission pipeline safety jurisdiction. Finally, SDCL 9-35-3 allows municipalities to grant natural gas franchises to Commission regulated natural gas utilities relatively easily. By filing a tariff and being subject to the jurisdiction of the Commission, we believe NSP-SD meets this requirement.

Q. Do you have any final comments?

A. NSP-SD views this proposal as a significant economic development step for the City of Sioux Falls. The project will make Hutchinson Technologies more competitive, thus ensuring their continued success and location in Sioux Falls. NSP-SD hopes the Commission will agree by accepting the proposed tariff for filing at the earliest possible date within 30 days following the date of the filing, subject to refund and additional proceedings. If the Commission modifies the proposed rate or tariff after hearing, the final NSP-SD rate and tariff would be consistent with the Commission's final order in this proceeding.

Q. Does this conclude your testimony?

A. Yes.

Jim Wilcox
Project Support

Docket No. _______

AFFIDAVIT

STATE OF SOUTH DAKOTA)
)
COUNTY OF MINNEHAHA)

Affiant, having been first duly sworn, on oath deposes and says:

That he has read the foregoing testimony and if asked the questions therein his answers in response would be as shown;

That the facts contained in said answers are true to the best of his knowledge and belief.

James C. Wilcox
James C. Wilcox

SUBSCRIBED AND SWORN to me before me this 9 day of December 1997.

Mary E. Thoen
Notary Public

MARY E. THOEN
SEAL NOTARY PUBLIC SOUTH DAKOTA SEAL

Direct Testimony and Schedules
Mr. Dan Woehrle

Before the South Dakota Public Utilites Commission

In the Matter of the Application for an Order
Establishing A Local Distribution Gas Utility, and
Establishing Initial Gas Transportation Rates
for Northern States Power Company

Description of the Project and Technical Specifications

Docket No. ____________
Exhibit No. 3

December 1997

EXHIBIT
4

Q Please state your name, business address and position.

A. My name is Dan Woehrle. I am Manager of Engineering and Operations, Natural Gas Services with Northern States Power Company - Gas Utility ("NSP Gas") located at 825 Rice Street in St. Paul, MN.

Q. What are your current responsibilities, education, and professional background?

A. My current responsibilities include project development and management as well as engineering, design, code compliance and construction of natural gas distribution systems. Schedule 1 contains a complete resume of my educational and professional background.

Q. Have you previously testified before the Commission?

A. Yes. I provided testimony in Docket NG95-017, The application by Associated Milk Producers, Inc. Pipeline ("AMPIP") to establish an initial Intrastate Natural Gas Transportation Service Tariff.

Q. Please summarize the information contained in Schedule 2?

A. NSP is proposing to construct, maintain and operate a new natural gas distribution system consisting of a steel pipeline approximately 3.5 miles in length, regulating and metering facilities, and a 60 PSIG polyethelene distribution system. These proposed facilities will be constructed, maintained, and operated according to standards which meet or exceed the minimum federal safety standard for transportation of natural gas described in United States Department of Transportation Safety Regulations, Title 49,Code of Federal Regulations, Part 192.

Q Will the proposed distribution lateral pipeline to serve Hutchinson Technologies, Inc. be subject to Commission pipeline safety jurisdiction?

A Yes. Like the existing line serving the Angus C. Anson plant, the pipeline will be subject to Commission pipeline safety jurisdiction.

Q Does this conclude your testimony?

A Yes.

Current Responsibilities (1995 - Present)

Position is directly responsible for engineering, design, construction, and project management of natural gas distrubution systems developed for end-user gas distribution systems. The position is directly accountable for gas network analysis, project budgets, project construction, and development of operating and maintenance support systems for NSP customers. This position is also responsible for compliance with all federal, state and local regulatory requirements for natural gas pipelines and gas distribution systems relative to the projects being constructed.

I previously provided engineering and construction management services for the Associated Milk Producers, Inc. Pipeline project, and the municipal distribution projects in Crooks, Garretson and Freeman, South Dakota.

Previous Employment (Northern States Power Company)

Manager of Engineering and Operations	1997 - Present
Specialty Engineer	1995 - 1997
Senior Gas Engineer	1993 - 1995
Superintendent, Gas Standards & Engineering	1990 - 1993
Gas Measurement Engineer	1986 - 1990
Gas Standards Engineer	1985 - 1986
Engineer II	1984 - 1985
Engineer I	1981 - 1984

Education

Masters Degree in Business Administration, 1995
University of St. Thomas, St. Paul, Minnesota

Bachelor of Science Degree, Mechanical Engineering, 1981
University of Minnesota, Minneapolis, Minnesota

NSP South Dakota Pipeline Project

General Description

PROJECT DESCRIPTION

The proposed distribution pipeline will be a distribution lateral line off of the existing pipeline which serves the NSP Angus Anson Generating Site. The new lateral line is proposed to start at a take-off point just upstream of the existing NSP Plant regulating facility in the SE1/4 of Section 30, Township 102N, Range 48W in Minnehaha County. The pipeline will run west along a private easement on NSP property, will cross the Big Sioux River and will continue west along private easements to be purchased just north of the 60th Street road right-of way. The line will cross 60th Street at Sycamore Avenue and will then proceed west along private easements to be purchased just south of 60th Street, crossing Highway 229. The proposed pipeline will end at a district regulating station to be located on a private easement near the entrance to Hutchinson Technologies, Inc ("HTI") property in the NE 1/4 of Section 34, Township 102N, Range 49W in Minnehaha County.

In addition, a 60 PSIG polyethylene distribution system will be installed to serve the HTI facility. The HTI meter will be designed to measure the initial connected load of 42 MCF/H with room available for an additional meter to be installed when the anticipated future (1999) load of 160 MCF/H is connected.

The facilities for the proposed pipeline will involve line pipe - 4.500 inch outside diameter (O.D.) - and related materials which include: valves, flanges, pipe fittings, coating and wrapping materials, barricade posts, pipe supports, caution signs for crossings and other miscellaneous materials.

The 4.500 inch outside diameter (O. D.) pipe will have a pipe wall thickness of 0.237 inches. The type of pipe used will be American Petroleum Institute (API) 5L Grade X-46 electric resistance welded (ERW). The operating design pressure is 2422 psi for the 4.500 inch pipe.

The proposed maximum allowable operating pressure (MAOP) will be 900 pounds per square inch gauge (psig). Hoop stress at the MAOP is equivalent to 19 percent of the specified minimum yield strength (SMYS).

NSP South Dakota Pipeline Project

Pipe Design Specifications

The United States Department of Transportation Safety Regulations, Title 49, Code of Federal Regulations (CFR), Part 192, prescribes minimum federal safety standards for transportation of natural gas by pipelines.

Pipe Size (outside diameter): 4.500 inches

Pipe Type: The 4.500 inch pipe will be API 5LX Grade X-46 electric resistance welded (ERW).

API 5LX: API is the American Petroleum Institute. API 5LX is a published specification for high-test steel pipe. This specification covers various grades of seamless and welded steel line pipe. Process of manufacture, chemical, and physical requirements, methods of test, and dimensions are included.

Grade X-46: Designates pipe manufactured according to API specification 5LX with a specified minimum yield strength of 46,000 pounds per square inch.

ERW: ERW pipe has one longitudinal seam, which is formed by electric resistance welding during the manufacturing process.

The composition of the pipe furnished shall conform to the chemical requirements specified in API-5LX Standard.

Carbon Percent	0.03%
Manganese (Maximum)	1.35%
Phosphorous (Maximum)	0.04%
Sulfur	0.04%

NSP South Dakota Pipeline Project

Pipe Design Factor (F)

Class location determines which design factor safety value is used in the design formula. The following design factor safety values used for natural gas steel pipe are based on the requirements of 49 CFR 192.111.

Class Location	Design Factor (F)
1	0.72
2	0.60
3	0.50
4	0.40

The NSP South Dakota lateral pipeline will be located in a Class 1 and Class 2 location. To allow for growth along the pipeline and to reduce potential future pipeline disturbance the entire length of the proposed pipeline will be designed for a Class 3 location with a design factor of 0.50.

Class Locations

The class location unit is an area that extends 220 yards on either side of the centerline of any continuous on-mile length of pipeline, unless otherwise noted.

A Class 1 location is any class location unit that has ten or less buildings intended for human occupancy.

A Class 2 location is any class location unit that has more than ten, but less than forty-six buildings intended for human occupancy.

A Class 3 location is any class location unit that has 46 or more buildings intended for human occupancy, or an area where the pipeline lies within 100 yards of either a building or a small, well defined outside areas such as a playground, recreation area, outdoor theater, or other public place of assembly that is occupied by twenty or more persons on at least five days a week for ten weeks in any twelve-month period. The days and weeks need not be consecutive.

A Class 4 location is any class location unit where buildings with four or more stories above ground are prevalent.

NSP South Dakota Pipeline Project

Design Formula For Steel Pipe

The design pressure for steel pipe is determined in accordance with the following formula (DOT 192.105):

$$P = \frac{2St \times F \times E \times T}{D}$$

P = Design pressure in pounds per square inch gauge.

S = Yield strength in pounds per square inch, determined in accordance with 192.107.

D = Nominal outside diameter of the pipe in inches.

t = Nominal wall thickness of the pipe in inches. If this is unknown, it is determined in accordance with 192.109. Additional wall thickness required for concurrent external loads in accordance with 192.102 may not be included in computing design pressure.

F = Design Factor determined in accordance with 192.111.

E = Longitudinal joint factor determined in accordance with 192.113.

T = Temperature derating factor determined in accordance with 192.115.

<u>For 4.500 inch O.D., 0.237 inch wall, API-5L X-46 pipe:</u>

$$P = \frac{2 \times 46{,}000 \times 0.237}{4.500} \times 0.50 \times 1.0 \times 1.0$$

P = 2422.0 PSIG

F = Design factor for all pipeline locations shall be 0.50.

E = Longitudinal joint factor for API-5L X-46 pipe is equal to 1.0.

T = Temperature derating factor is equal to 1.0 for gas temperatures up to 250F.

NSP South Dakota Pipeline Project

Operation and Maintenance

BLOCK VALVES

The Minimum Federal Safety Standards for Gas Lines as established in CFR 192.181 requires that each high pressure distribution system have valves spaced so as to reduce the time to shut down a section of main in an emergency. The valve spacing is determined by the operating pressure, the size of the mains, and the local physical conditions.

The NSP-SD lateral pipeline will have block valves installed at the take-off from the Angus Anson Pipeline and at the inlet to the district regulating station (an interval of approximately three miles).

VALVES AND FLANGES

The design, construction, testing, and marking of the valves must comply with the requirements of the Minimum Federal Safety Standards for Gas Lines, 49 CFR 192.145 for valves and 192.147 for flanges.

All valves and flanges will be rated as American National Standards Institute (ANSI) Class 600.

Valves are governed by ANSI B16.34, Steel Valves, Flanged and Butt Welding End.

Flanges are governed by ANSI B16.5, Pipe Flanges and Flanged Fittings.

NSP South Dakota Pipeline Project

Operation and Maintenance

PIPELINE CAPACITY

The proposed pipeline and associated facilities are designed to have a maximum throughput capacity of 940,000 cubic feet per hour or 22.56 million cubic feet per day. The expected maximum flow to HTI will be 202,000 cubic feet per hour and 750,000 cubic feet per day.

DEPTH OF COVER REQUIREMENTS

The U. S. DOT Pipeline Safety Regulations 49 CFR 192.327, requires that all gas transmission main be installed so that the depth of cover between the pipe and ground level is at least 36 inches.

The proposed pipeline shall be buried with a minimum level cover of not less than 36 inches in all areas where the pipeline lays in the right-of-way of any public drainage facility or any state, county, town or municipal street or highway. The pipeline will be installed at extra depth where it crosses a public street or highway, railroad, or protected waterway.

PIPELINE SAFETY

The U. S. DOT is responsible for establishing and enforcing safety standards for both interstate and intrastate operators. As a result, the DOT is responsible for 1) enforcing the standards for interstate operators and those intrastate operators the states do not assume responsibility for; and 2) monitoring the participating states to ensure that they are adequately enforcing the federal safety standards. The U. S. DOT Safety Regulations, Title 49, CFR, Part 192, prescribe the minimum federal safety standards for transportation of natural gas by pipelines.

NSP South Dakota Pipeline Project

Operation and Maintenance

The proposed pipeline will operate under the jurisdiction of the United States Department of Transportation. Minimum Federal Safety Standards for Gas Lines is contained in Part 192, Title 49, Code of Federal Regulations. Under these rules (192 Subpart L - Operations), South Dakota Region is required to have: 1) an operation and maintenance plan, 2) a procedure for continuing surveillance of its facilities to determine and take appropriate action concerning changes in class location, failures, leakage history, corrosion, substantial changes in maintenance conditions; 3) a damage prevention program, 4) emergency plans; and 5) procedures for investigations of failures.

The proposed pipeline will be designed, constructed, operated, and maintained to ensure safe operation. Emergency plans will be developed in conjunction with local officials and will include notification of local officials in the event that an NSP-SD related accident occurs.

The pipeline system will be maintained in accordance with 49 CFR 192 Subpart M - Maintenance. These requirements include: 1) a pipeline patrol program; 2) distribution line leakage surveys; 3) line markers for distribution lines; 4) record keeping; 5) requirements for repair procedures; 6) field repair of welds and leaks; 7) testing of repairs; 8) inspection and testing of pressure limiting and regulating stations, telemetering or recording gauges; 9) valve maintenance; and 10) prevention of accidental ignition.

PATROLLING AND LEAK SURVEYS

The pipeline facility shall be monitored periodically to determine and take appropriate action concerning changes in class locations, gas leakage, erosion, cathodic protection requirements and other conditions affecting safe pipeline operation, in accordance with DOT 192.

The pipeline shall be patrolled at intervals not exceeding 7-1/2 months, but at least twice times each calendar year. Highway and railroad crossings shall be patrolled at intervals not exceeding 4-1/2 months, but at least four times each calendar year.

AFFIDAVIT

STATE OF MINNESOTA)
)
COUNTY OF RAMSEY)

Affiant, having been first duly sworn, on oath deposes and says:

That he has read the foregoing testimony and if asked the questions therein his answers in response would be as shown;

That the facts contained in said answers are true to the best of his knowledge and belief.

Dan Woehrle

SUBSCRIBED AND SWORN to me before me this 5th day of December 1997.

Pauline M. Nielsen
Notary Public

PAULINE M. NIELSEN
NOTARY PUBLIC - MINNESOTA
RAMSEY COUNTY
My Comm. Expires Jan. 31 2000

PROFESSIONAL CERTIFICATION AND ASSOCIATIONS

Certified Public Accountant (CPA) - Minnesota
Member, American Institute of CPA's (AICPA)
Member, Minnesota Society of CPA's

PREVIOUS TESTIMONY

South Dakota - Associated Milk Producers Pipeline, Inc.	NG97-015
FERC Application for Merger Approval (Primergy)	ER95-1358-000
North Dakota Application for Merger Approval (Primergy)	PU-400-95-340
North Dakota - Electric	PU-400-94-514
FERC Open Access Transmission Tariff	ER94-1113-000
FERC Transmission - Order 84 Sales for Resale	ER94-1090-000
FERC Wholesale	ER93-385-000
North Dakota - Electric	PU-400-92-399
Minnesota - Electric (Budgets and Budget Process)	E002/GR-91-001
South Dakota - Electric	F-3422
South Dakota Conservation Cost Recovery	PUC Hearing, 1981

Northern States Power Company - South Dakota **Schedule 2**
Gas Operations
Development of Rates
Maximum and Proposed Large Volume Transportation
Customer Charge

The natural gas maximum transportation rate developed below pertains to NSP's newly installed 4.5" lateral pipeline extending from the Angus Anson Supply line to the Sioux Empire Development Park 5, which will serve HTI. The proposed maximum rate in Column B of $0.214 per Mcf includes $0.045 per Mcf for use of the Angus Anson line (Line 4). That rate is a pass-through to HTI. NSP-SD is not seeking approval of the Angus Anson portion of the rate. For information, Schedule 7 of Exhibit 4 shows a calculation supporting the $0.045 per Mcf charge for use of the Angus Anson line.

	Amounts		Maximum Rates
	(A)		(B)
4.5" NSP-SD Lateral Pipeline Rate			
(1) Annualized Revenue Requirements	$81,186		
(2) Pipeline MCF Capacity per Hour	306		
(3) Hours Per Year @ Capacity	1,571		$0.169
(4) Angus Anson Pipeline Rate			$0.045
(5) Total Transportation Rate			$0.214
Customer Charge			
(6) Investment in Metering at HTI	$18,500		
(7) Annualized Fixed Charge Rate less O&M	14.08%		
(8) Annualized Metering Revenue Requirements	$2,605		
(9) Annual Meter Reading and Billing Costs	$720		
(10) Total Customer Costs Supporting Customer Charge	$3,325	Monthly	$277

Sources and Notes:

Line 1: Revenue Requirements per Schedule 3, Page 2 of 3.
Line 2: 90% of Pipeline capacity of 340 Mcf/Hr.
Line 3, Col A: Hours per Year equivalent for HTI @ capacity.
Line 3, Col. B: Line 1/Line 2 times Line 3, Col. A.
Line 4, Column B: Negotiated rate for Angus C. Anson pipeline. See text for further discussion.
Line 5, Column B: Total maximum natural gas transportation supported by cost evidence.
Line 5, Column C: Total natural gas transportation rate agreed to between NSP and HTI.
Line 6: Meter investment at HTI per Schedule 5.
Line 7: Fixed charge rate from Schedule 3, Page 2 of 3, less O&M component.
Line 8: Line 6 times Line 7.
Line 9: Meter reading, billing, and service costs (O&M) at $60 per month.
Line 10: Total customer costs in Col. A. Monthly maximum customer charge in Col. B. Proposed rate in Col. C.

Northern States Power Company - South Dakota
Gas Operations
Statement M - Cost of Service
4.5" NSP-SD Lateral Pipeline Levelized Annual Revenue Requirement - See Page 3 of 3 for Sources and Notes

Capital Structure (CS):

	Cost	Weight	Weighted Cost	Net of Tax Cost
(CS1) Equity	11.25%	45.220%	5.0872%	5.0872%
(CS2) Preferred Stock	5.14%	6.580%	0.3383%	0.3383%
(CS3) Long-term Debt	7.10%	40.974%	2.9072%	1.8897%
(CS4) Short-term Debt	5.52%	7.226%	0.3987%	0.2591%
(CS5)		100.000%	8.7314%	7.5744%

	Time Period (A)	Year (B)	Plant in Service Additions (C)	Net Investment Rate Base (D)	Equity Return (E)	Taxes on Equity Return (F)	Debt Return (G)	Book Dep'n (H)	Operating Expenses (I)	Property Taxes (J)	Total Revenue Requirement (K)	Present Value of Revenue Deficiency or (Excess) Discounted At 7.5744% (L)
(1)	0	1997	364,718	358,700	9,731	3,406	5,929	6,018	3,309	1,459	29,851	29,851
(2)	1	1998	0	346,664	19,135	6,697	11,659	12,036	20,423	9,060	79,009	73,446
(3)	2	1999	0	334,629	18,482	6,469	11,261	12,036	21,007	9,377	78,632	67,949
(4)	3	2000	0	322,593	17,829	6,240	10,863	12,036	21,609	9,705	78,282	62,883
(5)	4	2001	0	310,557	17,176	6,012	10,466	12,036	22,228	10,045	77,961	58,216
(6)	5	2002	0	298,522	16,523	5,783	10,068	12,036	22,865	10,396	77,670	53,915
(7)	6	2003	0	286,486	15,870	5,554	9,670	12,036	23,519	10,760	77,409	49,951
(8)	7	2004	0	274,450	15,217	5,326	9,272	12,036	24,193	11,137	77,180	46,296
(9)	8	2005	0	262,415	14,564	5,097	8,874	12,036	24,886	11,526	76,983	42,927
(10)	9	2006	0	250,379	13,911	4,869	8,476	12,036	25,599	11,930	76,820	39,819
(11)	10	2007	0	238,343	13,258	4,640	8,078	12,036	26,332	12,347	76,691	36,954
(12)	11	2008	0	226,308	12,605	4,412	7,680	12,036	27,086	12,779	76,598	34,310
(13)	12	2009	0	214,272	11,952	4,183	7,283	12,036	27,862	13,227	76,542	31,871
(14)	13	2010	0	202,236	11,299	3,955	6,885	12,036	28,660	13,690	76,523	29,620
(15)	14	2011	0	190,200	10,646	3,726	6,487	12,036	29,481	14,169	76,544	27,541
(16)	15	2012	0	178,165	9,993	3,498	6,089	12,036	30,325	14,665	76,604	25,623
(17)	16	2013	0	166,129	9,340	3,269	5,691	12,036	31,193	15,178	76,707	23,850
(18)	17	2014	0	154,093	8,687	3,040	5,293	12,036	32,087	15,709	76,852	22,213
(19)	18	2015	0	142,058	8,034	2,812	4,895	12,036	33,006	16,259	77,041	20,700
(20)	19	2016	0	130,022	7,381	2,583	4,497	12,036	33,951	16,828	77,276	19,301
(21)	20	2017	0	117,986	6,728	2,355	4,099	12,036	34,923	17,417	77,558	18,007
(22)	21	2018	0	105,951	6,075	2,126	3,702	12,036	35,924	18,027	77,889	16,811
(23)	22	2019	0	93,915	5,422	1,898	3,304	12,036	36,952	18,658	78,269	15,704
(24)	23	2020	0	81,879	4,769	1,669	2,906	12,036	38,011	19,311	78,701	14,678
(25)	24	2021	0	69,843	4,116	1,441	2,508	12,036	39,099	19,987	79,186	13,729
(26)	25	2022	0	57,808	3,463	1,212	2,110	12,036	40,219	20,686	79,726	12,849
(27)	26	2023	0	45,772	2,810	983	1,712	12,036	41,371	21,410	80,322	12,034
(28)	27	2024	0	33,736	2,157	755	1,314	12,036	42,556	22,159	80,977	11,278
(29)	28	2025	0	21,701	1,504	526	916	12,036	43,775	22,935	81,692	10,576
(30)	29	2026	0	9,665	851	298	518	12,036	45,028	23,738	82,469	9,925
(31)	30	2027	0	(2,371)	198	69	121	12,036	46,318	24,569	83,310	9,320
(32)	31	2028	0	(14,406)	(455)	(159)	(277)	12,036	47,645	25,428	84,217	8,758
(33)	32	2029	0	(26,442)	(1,108)	(388)	(675)	12,036	49,009	26,318	85,192	8,236
(34)	33	2030	0	(38,478)	(1,761)	(616)	(1,073)	12,036	50,413	27,240	86,237	7,750
(35)	34	2031	0	(50,513)	(2,414)	(845)	(1,471)	12,036	51,857	28,193	87,355	7,298
(36)	35	2032	0	(62,549)	(3,067)	(1,073)	(1,869)	12,036	53,342	29,180	88,548	6,877
(37)	36	2033	0	(74,585)	(3,720)	(1,302)	(2,267)	12,036	54,869	30,201	89,817	6,484
(38)	37	2034	0	(86,621)	(4,373)	(1,531)	(2,665)	12,036	56,441	31,258	91,166	6,118
(39)	38	2035	0	(98,656)	(5,026)	(1,759)	(3,063)	12,036	58,057	32,352	92,597	5,777
(40)	39	2036	0	(110,692)	(5,679)	(1,988)	(3,460)	12,036	59,720	33,484	94,113	5,458
(41)	40	2037	0	(122,728)	(6,332)	(2,216)	(3,858)	12,036	61,431	34,656	95,716	5,160
(42)	41	2038	0	(134,763)	(6,985)	(2,445)	(4,256)	12,036	63,190	35,869	97,409	4,881
(43)	42	2039	0	(146,799)	(7,638)	(2,673)	(4,654)	12,036	65,000	37,125	99,195	4,621
(44)	43	2040	0	(158,835)	(8,291)	(2,902)	(5,052)	12,036	66,861	38,424	101,076	4,377
(45)	44	2041	0	(170,870)	(8,944)	(3,130)	(5,450)	12,036	68,776	39,769	103,056	4,148
(46)	45	2042	0	(176,888)	(9,434)	(3,302)	(5,748)	6,018	70,746	41,161	99,441	3,721
(47)	Project Totals		364,718		224,493	78,573	136,788	541,606	1,831,152	959,798	3,772,411	1,031,812

Northern States Power Company - South Dakota
Gas Operations
Statement M - Cost of Service
4.5" NSP-SD Lateral Pipeline Levelized Annual Revenue Requirement - See Page 3 of 3 for Sources and Notes

LARR						
(RR1)	$12,422	$4,348	$7,569	$12,492	$29,828	$14,533

			LARR - As a % of Original Cost			
(RR2)	3.41%	1.19%	2.08%	3.42%	8.18%	3.98%

	7.5744% Present Value of Equity Return (A)	7.5744% Present Value of Taxes on Equity Return (B)	7.5744% Present Value of Debt Return (C)	7.5744% Present Value of Book Depreciation (D)	7.5744% Present Value of Operating Expenses (E)	7.5744% Present Value of Current Property Taxes (F)	Present Value of Revenue Requirements or (Excess) (G)	Summary - LARR (H)	Amounts (I)
(1)	9,731	3,406	5,929	6,018	3,309	1,459	29,851	Return	6.68%
(2)	17,788	6,226	10,838	11,188	18,985	8,422	73,446	Depreciation	3.42%
(3)	15,971	5,590	9,731	10,400	18,153	8,103	67,949	O&M and Prop Taxes	12.16%
(4)	14,322	5,013	8,727	9,668	17,358	7,796	62,883		
(5)	12,826	4,489	7,815	8,987	16,598	7,501	58,216	Total LARR	22.26%
(6)	11,469	4,014	6,989	8,355	15,872	7,216	53,915		
(7)	10,240	3,584	6,240	7,766	15,177	6,943	49,951		
(8)	9,128	3,195	5,562	7,220	14,512	6,680	46,296	Plant In Service	$364,718
(9)	8,121	2,842	4,948	6,711	13,877	6,427	42,927		
(10)	7,211	2,524	4,394	6,239	13,269	6,184	39,819	Annual Requirement	$81,186
(11)	6,388	2,236	3,893	5,799	12,688	5,950	36,954		
(12)	5,646	1,976	3,440	5,391	12,132	5,724	34,310		
(13)	4,977	1,742	3,032	5,011	11,601	5,507	31,871		
(14)	4,373	1,531	2,665	4,659	11,093	5,299	29,620		
(15)	3,831	1,341	2,334	4,331	10,607	5,098	27,541		
(16)	3,342	1,170	2,037	4,026	10,143	4,905	25,623		
(17)	2,904	1,016	1,769	3,742	9,699	4,719	23,850		
(18)	2,511	879	1,530	3,479	9,274	4,541	22,213		
(19)	2,159	756	1,315	3,234	8,868	4,369	20,700		
(20)	1,843	645	1,123	3,006	8,480	4,203	19,301		
(21)	1,562	547	952	2,794	8,109	4,044	18,007		
(22)	1,311	459	799	2,598	7,753	3,891	16,811		
(23)	1,088	381	663	2,415	7,414	3,743	15,704		
(24)	889	311	542	2,245	7,089	3,602	14,678		
(25)	714	250	435	2,087	6,779	3,465	13,729		
(26)	558	195	340	1,940	6,482	3,334	12,849		
(27)	421	147	257	1,803	6,198	3,208	12,034		
(28)	300	105	183	1,676	5,927	3,086	11,278		
(29)	195	68	119	1,558	5,667	2,969	10,576		
(30)	102	36	62	1,448	5,419	2,857	9,925		
(31)	22	8	13	1,347	5,182	2,749	9,320		
(32)	(47)	(17)	(29)	1,252	4,955	2,645	8,758		
(33)	(107)	(37)	(65)	1,164	4,738	2,544	8,236		
(34)	(158)	(55)	(96)	1,082	4,531	2,448	7,750		
(35)	(202)	(71)	(123)	1,005	4,332	2,355	7,298		
(36)	(238)	(83)	(145)	935	4,142	2,266	6,877		
(37)	(269)	(94)	(164)	869	3,961	2,180	6,484		
(38)	(293)	(103)	(179)	808	3,788	2,098	6,118		
(39)	(314)	(110)	(191)	751	3,622	2,018	5,777		
(40)	(329)	(115)	(201)	698	3,463	1,942	5,458		
(41)	(341)	(119)	(208)	649	3,312	1,868	5,160		
(42)	(350)	(123)	(213)	603	3,167	1,797	4,881		
(43)	(356)	(125)	(217)	561	3,028	1,729	4,621		
(44)	(359)	(126)	(219)	521	2,895	1,664	4,377		
(45)	(360)	(126)	(219)	484	2,769	1,601	4,148		
(46)	(353)	(124)	(215)	225	2,647	1,540	3,721		
(47)	157,866	55,253	96,191	158,747	379,065	184,689	1,031,812		

Northern States Power Company - South Dakota
Gas Operations
Levelized Annual Revenue Requirement
Sources and Notes - Statement M

Schedule 3, Page 1 of 3:

Lines CS1 - CS5: 1996 Actual NSP Capital Structure. See Schedule 6 of this exhibit. The components of the overall return of 8.7314% are used to determine the annual cost of financing the project. The net of tax return is used to discount the 45 year amounts to the present value. The Return on Common Equity based on most recent authorized in Docket EL92-016

Line 1, Column A: Time Period for present value calculation

Line 1, Column B: Year in service. Present value is life cycle beginning in 1995

Line 1, Column C: Pipeline investment

Lines 1 - 46, Column D: Net investment reduced for accumulated depreciation for each year

Line 1, Column E: One-half of end of first year investment applied to weighted common and preferred equity cost)

Line 1, Column F: Income taxes on the equity return determined in Col. E. Tax rate is 35%

Line 1, Column G: One-half of end of year investment applied to the weighted debt cost

Line 1, Column H: Book depreciation based on 45 year book life and 50% negative salvage value (3.3%)

Line 1, Column I: See Schedule 5. Amount reflects two months of expense in 1997

Line 1, Column J: Property Tax estimate based on similarly situated intrastate pipeline in South Dakota

Lines 1 - 46, Column K: Sum of Columns E - H for corresponding lines

Lines 1 - 46, Column L: Present Value of Column K @ Net of Tax Cost of Capital

Lines 2 - 46, Column E: Average net investment applied to weighted common and preferred equity costs

Lines 2 - 46, Column F: Income taxes on the equity return determined in Col. E @ 35%

Lines 2 - 46, Column G: Average net investment applied to the weighted debt cost

Lines 2 - 46, Column H: Book depreciation based on 45 year book life and negative 50% salvage value (3.3%)

Lines 2 - 46, Column I: Operating expenses per Schedule 5, escalated at rate determined on Schedule 5

Lines 2 - 46, Column J: Estimated property taxes based on similarly situated intrastate pipeline in South Dakota

Line 47: Check totals

Schedule 3, Page 2 of 3:

Line RR1: The levelized annual revenue requirements of the items reflected in the columns below

Line RR2: The percent of original investment cost for the levelized revenue requirements shown on RR1

Lines 1 - 46, Columns A - G: Annual present value of each revenue requirement component shown. The nominal amounts are from Schedule 3, Page 2 of 3, Columns E - J

Lines 1 - 46, Column E: Annual present value of total revenue requirements. Matches Column L on Schedule 3, Page 1 of 3

Line 47, Columns A - G: Total of annual present value amounts for each column. These amounts are then discounted to arrive at the amounts shown on Line RR1

Columns H and I: Summary of Levelized Annual Revenue Requirements. Column H describes each component. Column I shows the LARR rate by component and the total. The LARR rate shown on Line 5, Column I is applied to the original cost of the pipeline shown on Line 8, Column I to arrive at the levelized annual revenue requirements shown on Line 10, Column G. This amount is carried forward to Schedule 2 to determine the pipeline rate used to serve HTI (4.5" lateral)

Northern States Power Company - South Dakota
Gas Operations
Plant Investment - 4.5" Lateral HTI Line

Schedule 4

	Pipeline Costs (A)	**Amounts** (B)
(1)	4.5" coated steel main - 17,260 ft @ $11.44/ft	$197,500
(2)	X-Ray @ $20.00/joint	8,250
(3)	High pressure tie-in using full encirclement sleeve	10,000
(4)	High Pressure meter set at take-off with telemetry	25,000
(5)	District regulator station with heater	30,000
(6)	6" PE service to HTI - 1,600 feet @ $8.73 per foot	13,968
(7)	Design and engineering costs	20,000
(8)	Additional Boring Costs at Big Sioux River Crossing	20,000
(9)	Property Easements	40,000
(10)	Total Pipeline Project Costs	$364,718
(11)	Customer meter at HTI	$8,000
(12)	Additional meter at HTI in 1999	10,500
(13)	Total Meter Costs at HTI	$18,500

Sources and Notes:

Lines 1 - 9: Estimated pipeline original cost investment.

Line 10: Total estimated pipeline original cost investment.

Lines 11 - 12: Meter Costs Phase I and II.

Line 13: Total Meter Costs. Used for Customer Charge.

Northern States Power Company - South Dakota **Schedule 5**
Gas Operations
Operating Expenses (O&M)
Statement H

All of the O&M on this Schedule pertains to the NSP-SD 4.5" lateral pipeline that iwll serve HTI.	Amount (A)	Annual Escalator (B)	1 Year Escalated Amount (C)
(1) NSP - Operating and Maintenance Training, readings, patrolling of line by Angus Anson Plant personnel	$8,154	3.0%	$8,399
(2) ACA Supplemental Service Support and emergency services by ACA personnel	$3,600	3.0%	$3,708
(3) Services - NSP-SD Management and support	$7,200	3.0%	$7,416
(4) Insurance Estimated Annual Fee	$100	0.0%	$100
(5) OPS Assessment Estimate of Office of Pipeline Safety Assessments	$500	0.0%	$500
(6) Regulatory Fees Gross Receipts Tax Estimate	$300	0.0%	$300
(7) Total	$19,854	2.9%	$20,423

Sources and Notes:

Line 1, Column A: Direct costs of pipeline operations per NSP-SD Gas Operations budget. Consists of 12 hours per month at loaded labor of $37.56/hour and $20/hour for vehicle usage.

Line 2, Column A: Supplemental emergency service from ACA. One call per month @ $300/call.

Line 3, Column A: Services received from NSP-South Dakota personnel. Ten hours/month @ $60/hour.

Line 4, Column A: Insurance costs @ $0.03/$100 of investment per NSP's Risk Mgmt. Dept.

Line 5, Column A: Office of Pipeline Safety assessment based on a similarly situated intrastate pipeline in South Dakota.

Line 6, Column A: Annual regulatory fees based on Gross Receipts Tax. Calculation based on a similarly situated intrastate pipeline in South Dakota.

Column B: Annual escalators based on expectations of price inflation.

Column C: One-year escalations of amounts in Column A.

Line 7: Columns A and C are summarized and used to derive the overall escalator in Column B.

Northern States Power Company - South Dakota **Schedule 6**
Gas Operations
Cost of Capital - Statement G
1996 Historical Year

	Capitalization Amounts ($thousands) (A)	Ratio (B)	Rate (C)	Weighted Costs (D)	Net of Tax Return (E)
(1) Long Term Debt	$1,497,303	40.9736%	7.0953%	2.9072%	1.8897%
(2) Short Term Debt	264,064	7.2261%	5.5173%	0.3987%	0.2591%
(3) Preferred Stock	240,469	6.5804%	5.1408%	0.3383%	0.3383%
(4) Common Equity	1,652,477	45.2199%	11.2500%	5.0872%	5.0872%
(5) Total Capitalization	$3,654,313				
(6) **Required Rate of Return**				**8.7314%**	
(7) **Net of Tax Return**					**7.5744%**

Sources and Notes:

1996 actual capitalization and costs for NSP-Minnesota Company

Column A per NSP books and records

Column B: Column A amounts for Lines 1 - 4 compared to the total shown in Column A, Line 5

Column C per NSP books and records

Column D: Product of Column B times Column C. These weighted costs are used to determine the financing costs on a year-by-year basis

Column E: Net of tax rates. Long and short term debt returns absent the tax effect due to their deductibility on NSP's federal income tax return. Tax rate @ 35%. Rates in Lines 1 and 2 consist of the rates in Column D multiplied times 1 minus the tax rate, or 0.65. The net of tax rate if used to discount the 45 year annual amounts to the present value.

Northern States Power Company - South Dakota **Schedule 7**
Gas Operations
Cost Support for Transfer Price Between South Dakota Gas Operations &
NSP Generation for Use of the Angus Anson Supply Line

The calculations below support the amount per Mcf to be transferred between NSP-SD Gas Operations and NSP-Generation for NSP-SD's use of the Angus Anson supply pipeline.

The rate of $0.045 per Mcf will be passed on by NSP-SD to HTI as part of their total distribution rate.

NSP-SD does not seek SDPUC jurisdiction over that line, nor approval of the negotiated rate. This Schedule is included as information only.

12" NSP-Generation Line (Angus Anson Supply)	Amounts (A)	Unit Rate (B)
(1) Investment	$3,139,426	
(2) Annualized Fixed Charge Rate	22.26%	
(3) Annualized Revenue Requirements	$698,836	
(4) Pipeline MCF Capacity per Hour	4,900	
(5) Hours Per Year @ Capacity	3,200	$0.045

Sources and Notes:

Line 1: NSP-Generation recorded investment in Angus Anson pipeline.

Line 2: Fixed charge rate developed for NSP line. Used as a proxy for a specific Angus Anson pipeline rate.

Line 3: Line 4 times Line 5.

Line 4: Capacity of Angus Anson 12" line.

Line 5: Hours per Year equivalent at capacity. Amount is twice the NSP-SD HTI lateral based on significantly greater utilization of the larger "transmission" pipeline vs. a smaller distribution pipeline. This relationship is typical within the industry.

AFFIDAVIT

STATE OF MINNESOTA)
)
COUNTY OF HENNEPIN)

Affiant, having been first duly sworn, on oath deposes and says:

That he has read the foregoing testimony and if asked the questions therein his answers in response would be as shown;

That the facts contained in said answers are true to the best of his knowledge and belief.

John D. Winter

SUBSCRIBED AND SWORN to me before me this 10th day of December, 1997.

Notary Public

SHARON K. LASSEK
Notary Public-Minnesota
Hennepin County
My Comm. Expires Jan 31, 2000

Direct Testimony and Schedules
John Winter

Before the South Dakota Public Utilities Commission

In the Matter of the Application for an Order
Establishing A Local Distribution Gas Utility, and
Establishing Gas Transportation Rates for Northern States Power Company

Cost Support and Rates

Docket ___________
Exhibit No. 4

November 1997

Cost Support, Maximum Rates, and Proposed Rates

Q. Please state your name, position, and business address.

A. My name is John Winter. My position is Sr. Regulatory Consultant within the Regulatory Services Department of Northern States Power Company ("NSP"). My business address is 414 Nicollet Mall in Minneapolis, MN.

Q. What are your current responsibilities?

A. I am responsible for providing project management and team participation on various regulatory projects, particularly in the area of rates. I provide expert testimony, including development of underlying technical cost support, for the revenue requirements aspects of NSP regulatory proceedings. The cost support I prepare involves gathering revenue, expense, and plant investment data and determining the appropriate amounts related to the provision of utility services. My internal NSP clients include NSP-South Dakota ("NSP-SD"), NSP-North Dakota, NSP-Electric (wholesale and transmission), and NSP-Natural Gas Services.

Q. What is your educational and professional background?

A. Schedule 1 contains a summary of my educational and professional background.

Q. Have you testified previously before this Commission?

A. As shown on Schedule 1, I have appeared before this Commission in a Conservation Cost Recovery case. I also submitted cost of service testimony in Docket F-3422. The case was subsequently settled. In September of this year, I submitted gas transportation cost support testimony for a pipeline owned by Associated Milk Producers, Inc. Pipeline ("AMPIP"). That matter is presently pending before this Commission. In addition, I have provided direct and indirect support for numerous regulatory projects in South Dakota since the late 1970's.

Q. What is the purpose of your testimony?

A. My testimony describes the cost of service for an intrastate natural gas distribution pipeline which will serve the Sioux Empire Development Park 5 in Sioux Falls, South Dakota. I also describe the proposed rates and support their determination. Customers within the industrial park, the first of which is Hutchinson Technologies, Inc. ("HTI"), will contract with other parties for natural gas supply. NSP-SD will transport the gas. Mr. Wilcox describes the proposed tariff and service to HTI in greater detail in his testimony.

Q. Please generally describe the rates and their development.

A. My testimony supports two rates in this application which are considered to be maximum rates, or "rate caps". The first is the maximum rate per Mcf for transportation service on the newly-constructed 4.5" NSP-SD lateral pipeline of $0.169 per Mcf. The second maximum rate supported by my testimony is the proposed customer charge of $277 per month. The actual rate for an individual customer would be negotiated based on competitive options subject to the rate caps supported by my testimony and accompanying Schedules 2 through 7.

The maximum pipeline rate is developed on Schedule 2 of my exhibits. Schedules 3 - 6 support those calculations. A levelized annual revenue requirement factor was developed and applied to gross plant investment to determine the annual revenue requirements of the new 4.5" NSP-SD pipeline system. The factor includes components reflecting return on common equity, income taxes, debt service, depreciation, property taxes, operating and maintenance expenses, property insurance, and other costs. The components are escalated, where appropriate, over a 45 year period, and then discounted at NSP's net of tax cost of capital of 7.5744% to determine the levelized annual revenue requirement of $81,186.

Q. Please continue.

A. The maximum rate for the 4.5" pipeline is determined by dividing the annual revenue requirements by the anticipated volume on the 4.5" line. The calculations are shown on Schedule 2. The result is the maximum rate of $0.169 per Mcf.

Q. How was the maximum customer charge rate developed?

A. Schedule 5 shows the meter costs of $18,500. I then applied an adjusted fixed charge rate to the meter investment. To determine the fixed charge rate, I reduced the 4.5" fixed charge rate, developed on Pages 1 and 2 of Schedule 3, by the O&M component. The result is annualized meter revenue requirements of $2,605. I then added meter reading, billing, and service O&M of $720 per year to than amount. The result is a maximum customer charge of $277 per month, as shown on Schedule 2.

Q. Please explain in greater detail the fixed charge rate developed in Schedule 3.

A. Page 1 of Schedule 3 shows the development of discounted revenue requirements for the NSP-SD 4.5" pipeline. The capital structure used is based on NSP's 1996 actual capital costs. Likewise, the preferred stock and debt costs are as recorded in 1996. The equity return is as authorized in the most recent NSP-SD rate case, Docket EL92-016. Book depreciation is based on a 45 year book life with negative salvage value of 50%. Operating and Maintenance (O&M) expenses are developed and explained on Schedule 5. A 2.9% weighted escalator is also developed on Schedule 5 and used on Page 1 of Schedule 3. Property taxes, at a rate of 2.4%, are based on a similarly situated South Dakota intrastate pipeline owned by the AMPIP. They are escalated at 3.5% per year.

Q. Does the tax vs. book depreciation differences have an impact on the proposed rate?

A. Essentially, there is no impact. I have simplified the revenue requirements calculation by setting tax depreciation equal to book depreciation. Since this is a levelized determination, the result is essentially the same as if the tax vs. book differences were deferred and later flowed back.

Q. Have you provided additional detail about your determination of NSP-SD's maximum gas transportation rates?

A. Yes. Each of Schedules 2 - 6 include a section showing Sources and Notes. These references provide additional documentation for the cost of service.

Q. Are there any other aspects of the HTI rate you care to address?

A. Yes. Included in the proposed maximum commodity rate is $0.045 per Mcf which NSP-SD has agreed to transfer to NSP-Generation for NSP-SD's use of the Angus Anson 12" fuel supply pipeline. For informational purposes, I have included the cost support for that rate in this application. However, NSP-SD is not seeking specific approval of that rate, nor is it requesting the Commission to assume jurisdictional authority over that facility, because the line will directly serve only NSP-Generation and NSP-SD, and thus not subject to Commission jurisdiction under SDCL 49-34A-1, Subd. 9A. The $0.045 per Mcf rate for use of the 12" supply line is supported by my informational calculations shown on Schedule 7.

Q. How did you develop the rate for the 12" Angus Anson supply line?

A. As the basis for negotiations between NSP-SD Gas Operations and NSP-Generation, I applied the fixed charge rate developed for the 4.5" line to the investment in the 12" line to determine the revenue requirements for the 12" line. The major fixed charge rate components (capital recovery, property taxes, and book depreciation) are proportionately the same between the two segments of pipeline The operating and maintenance expense component represents a reasonable proxy for the 12" line Consequently, use of the 4 5" fixed charge rate provides a reasonable determination of the 12" line revenue requirements of $698,836 The 12" line rate is determined by dividing the revenue requirements by a representative utilization of the line

Q. Please describe the required filing statements included with this application

A. Exhibit 5 of this filing consists of the required filing statements per Chapter 20:10:13 of the South Dakota Administrative Rules The initial pages of that exhibit list the statements included, or that are not applicable The reasons certain statements are not applicable is described on page two of the listing Waiver of those statements not applicable is respectfully requested from the Commission

Q. Is NSP proposing some form of purchased cost of gas adjustment mechanism?

A. Yes Unlike typical gas local distribution companies, NSP-SD will be exclusively a gas transporter and will not provide sales service However, NSP-SD proposes to pass along uncontrollable charges imposed by Northern Natural Gas, the upstream interstate pipeline. Section 5.0 on the Firm Transportation Service Schedule, First Revised Sheet No 15 discusses the pipeline cost adjustment It is also included in the Gas Transportation Service Agreement in Section 3.4, First Revised Sheet No. 21.

Q. Has HTI agreed to the rates consistent with those proposed in this application?

A. Yes HTI has executed an agreement with NSP-SD for natural gas service to its new Sioux Falls facility using the form of agreement contained in the proposed tariff, at negotiated rates HTI's rates for natural gas transportation and the customer charge are at or below the maximum rates discussed previously and supported by the calculations and schedules contained herein

Q. Does this conclude your testimony?

A. Yes it does.

JOHN D. WINTER, CPA
Sr. Regulatory Consultant - Regulatory Services
414 Nicollet Mall
Mpls., MN 55401

CURRENT RESPONSIBILITIES (June 1992 - Present)

Directly responsible for providing project management and team participation on various regulatory projects, particularly in the area of rates. Provide expert testimony, including development of underlying technical cost support, for the revenue requirements aspects of regulatory proceedings. Internal clients are Northern States Power Company (NSP)-South Dakota, NSP-North Dakota, NSP-Electric (wholesale and transmission), and NSP-Natural Gas Services. Responsibilities frequently include overall project management/coordination. Leadership for the project team and participants is critical. A significant aspect of the position is the need to build credible and effective relationships with regulators in all jurisdictions.

EMPLOYMENT HISTORY (Northern States Power Company)

Sr. Regulatory Consultant	1994 - Present
Assistant to the Chief Financial Officer	1992 - 1993
Director, Financial Accounting, Budgets, and Reports	1990 - 1992
Director, Electric Finance and Information Management	1989 - 1990
Director, Electric Finance	1988 - 1989
Manager, Electric Financial Planning & Administration	1984 - 1988
Administrator, Revenue Requirements	1983 - 1984
Sr. Rate Analyst/Rate Analyst, Revenue Requirements	1979 - 1983
Accountant Sr., General Accounting	1977 - 1979
Accounting Specialist, Material Accounting	1976 - 1977

EDUCATION

Electric Utility System Operation	1993
The Masters Forum	1991 - 1992
Strategic Cost Management, Tuck at Dartmouth	1991
Public Utility Finance Seminar, Kidder Peabody	1989
Bachelor of Science - Accounting, University of Minnesota	1976

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SOUTH DAKOTA PUBLIC
UTILITIES COMMISSION

BEFORE THE
PUBLIC UTILITIES COMMISSION
STATE OF SOUTH DAKOTA

IN THE MATTER OF THE APPLICATION FOR
AN ORDER ESTABLISHING A NATURAL GAS
UTILITY, AND TO ESTABLISH INITIAL
NATURAL GAS TRANSPORTATION RATES FOR
NORTHERN STATES POWER COMPANY

DOCKET NO. NG97-021

TESTIMONY AND EXHIBIT OF GREGORY A RISLOV
ON BEHALF OF THE COMMISSION STAFF
DECEMBER, 1998

EXHIBIT
4

BEFORE THE
PUBLIC UTILITIES COMMISSION
STATE OF SOUTH DAKOTA

IN THE MATTER OF THE APPLICATION FOR
AN ORDER ESTABLISHING
A NATURAL GAS [redacted] UTILITY,
AND TO ESTABLISH INITIAL TRANSPORTATION RATES
FOR NORTHERN STATES POWER COMPANY

Docket No. NG97-021
Testimony of Gregory A. Rislov
On Behalf of the Commission Staff
December 1998

Q. Please state your name, address, and present position.

A. My name is Gregory A. Rislov; my business address is: Public Utilities Commission (PUC), State Capitol Building, Pierre, S.D. 57501; I am currently employed as a commission advisor.

Q. What are your educational background and experience?

A. I was graduated in 1976 from the University of South Dakota in Vermillion with a Bachelor of Science degree in Business Administration, majoring in Accounting. In 1980 I received a Master of Business Administration degree from the same institution. I began work with the PUC as a utility analyst in July 1976. I was named Director of the Fixed Utilities Division in April of 1984, a position I held until July of 1998. I was then transferred to the position I now hold, that of commission advisor.

Q. Does your new position include assuming an adversarial staff role in contested case filings?

A. No. This docket and others were filed prior to the time I changed duties. I have continued to work on these dockets until completion.

Q. What is your regulatory experience?

A. Although the main focus of my work has been statutorily prescribed costing analysis of utility operations and administration of rate cases and other dockets, I also become involved in general and policy matters related to utility regulation. I have testified before the South Dakota Senate, House, and various interim legislative committees on a variety of matters which could affect rates and costs of service. I have appeared before the public, when directed by the Commissioners, on behalf of the PUC.

Q. Have you previously testified before this Commission?

A. Yes, in approximately 50 major electric, natural gas, and telecommunications dockets. I have participated in many dockets where settlement was reached with no need for testimony preparation.

Q. What is the purpose of your testimony in this proceeding?

A. I will make specific cost of service recommendations for the Northern States Power Company (NSP-gas) natural gas transport rate and additional testimony on various other provisions related to service delivery. I am sponsoring Exhibit_(GAR-1) that numerically depicts my recommendations.

Q. What Is NSP-gas?

A. It is a new jurisdictional operation in South Dakota. NSP-electric has been operating for many years. NSP-gas has been operating for approximately one year. The filing made by NSP was predicated on service to one customer, with the potential for more joining the system.

Q. What are the unique features, if any, of NSP's cost of service filing?

A. A forecasted, forty-five (45) year levelized cost of service and a limited number of customers included in the original projections.

Q. Why is this unique?

A. We have twice developed rates on a forecasted, levelized cost of service. In both previous cases the rates were based on serving at least one community, not just one or several customers.

Q. Does this Commission allow filings based on forecasted costs of service?

A. The Commission rules require that filings be made based on historical costs, but allow for applicants to also file parallel, forecasted costs of service. This case has a limited amount of historical data because NSP-gas is a start-up company. This coupled with the fact that costs are being projected over forty-five years means that data must be forecasted.

Q. What data is known?

A. There are some actual plant numbers, and some actual operating and maintenance (O&M) amounts for 1998. The structure is known, as is the depreciation rate. But even this known data must be estimated for the future as a 45-year levelized cost of service looks 45 years into the future.

Q. Cost of service is one part of the equation for determining rates. Another is sales. Do you have actual sales data?

A. We have some actual sales data. But it has limited value as it is not complete. The customers are not operating on a steady-state basis. This is a start-up operation, not a mature one.

Q. What is included in the NSP-gas rate base?

A. Estimated plant-in-service, exclusive of meter costs, and accumulated depreciation.

Q. Why have meter costs been excluded from rate base?

A. It is NSP-gas's intention to assess metering costs directly to the customer. In other words, they become customer costs.

Q. Is this appropriate?

A. Yes, even though large companies may find it more convenient and less cumbersome to combine and assess metering costs by customer class. I shall discuss meter costs and other customer costs in more detail later.

Q. Is plant-in-service estimated?

A. We have actual cost data supported by invoices for the bulk of the costs. One feature of plant-in-service is that the 45-year levelized cost of service does not estimate any plant additions. There likely will be additions as time goes on, but NSP-gas has not forecasted any. Because NSP-gas proposes to assess a considerable portion of customer-related costs directly to the customer, the addition of new customers may have limited cost impacts on the company. This serves to improve the quality of NSP-gas's plant forecast.

Q. Should other rate base items be included?

A. NSP-gas has made no claim for other rate base items. It is reasonable to expect that costs are limited in this type of operation. It is also reasonable to expect that other types of shared rate based costs could be allocated from other jurisdictions.

Q. Is staff offering adjustments to NSP-gas's rate base?

A. No. Although I am concerned that NSP's South Dakota electric operation may be bearing some costs for the gas operation, this concern is mitigated by the limited size and scope of the gas operation, and the difficulty in making any reasonable estimated allocation. For example, revenues, labor costs, and customers are three common allocation bases. NSP-gas numbers on these items are dwarfed by NSP-SD-electric's numbers, as well as comparable gas numbers in other states. Any allocation based on these comparisons would yield virtually nonexistent costs.

Q. Did you review NSP gas's filed operating income components?

A. Yes.

Q. What conclusions did you reach?

A. Operating income components, like rate base components, are comparatively limited. For example, operation and maintenance expense (O&M) is either contracted, actual, or based on conservative estimates. O&M expenses relate to operating the system, maintenance, management, emergency services, insurance, and regulatory fees. Staff's adjusted O&M, as explained by Staff witness Knadle, totals $18,164 before annual escalation of 2.9%.

Q. Explain the annual escalation.

A. The entire cost of service must, as a starting point, be based on an annual cost of providing service. NSP-gas chose to average the cost of service over a 45-year period. This means that a cost of service must be prepared for each of 45 years. A logical way of doing this is by preparing a current year's cost of service and using it as a basis for determining the cost of service for the next 44 years. One way to adjust is to estimate inflation's effect each year, and add that effect to the prior year's costs. NSP-gas termed this inflation percentage as the "Annual Escalator." The application of the annual escalator was the means to adjust O&M for each of the forecasted years.

Q. Are there any other costs included in the cost of service?

A. Yes. Property taxes, depreciation, return on investment, and income taxes are the other costs.

Q. Would you describe each?

A. Yes. The property taxes in staff's cost of service are based on the estimated plant, an 85% valuation, and the effective Minnehaha County tax rate supporting 1997 payments. The effect of the latter two is a rate of 2.341%. The first year reflects two months, or 1/6th of the annual amount. The annual amount is thereafter escalated by 3% for each succeeding year of the levelized cost of service.

Q. Do staff's estimated property taxes match those of NSP-gas?

A. No. NSP-gas used an estimated rate of 2.4% and escalated taxes at 3.5% per year. The legislature intends that taxes should increase by no more than the lesser of 3% or the growth in a Consumer Price Index. This implies that 3% is the maximum rate of escalation.

Continuing on, staff's recommended depreciation is straight-line and based on the estimated 45-year plant life and 30% negative salvage. The NSP-gas proposed depreciation incorporates 50% negative salvage. Staff's lower negative salvage rate is consistent with the Minnesota Public Utilities Commission Docket No. E, GOO2/D-97-1307 Order Certifying Depreciation Rates and Methods.

Q. Is this Commission bound by the Minnesota PUC?

A. No. But NSP-gas is also Minnesota jurisdictional, and to that extent is bound by the Order which is based on a recent depreciation study. The Minnesota standard appears reasonable.

Q. What is your recommended return on investment?

A. Staff is not taking issue with NSP-gas's requested 8.7314% overall return on investment and 11.25% requested common stock equity return. The equity return is comparable to returns recommended in the past several years to this Commission. While staff has no evaluation or knowledge of comparable risk enterprises, it seems logical that a start-up operation, with few customers and uncertain sales, in an industry becoming increasingly competitive, and with a 45.22% common equity ratio is facing a considerable amount of uncertainty. The 11.25% is a reasonable equity return.

Q. The 45 year levelized cost of service includes a 2.9% annual escalation for operation and maintenance (O&M) expenses. What is the basis for the 2.9%?

A. There are six separate categories of costs included in the O&M expenses. As shown on Staff witness Knadle's Exhibit_(RLK-1), Schedule 1, three categories are inflated at 3%, and three others are not escalated. The weighted effect is a 2.9% escalator for total O&M. The 3% escalator must suffice to cover increases in activity, inflation, and any ommissions in the original estimate.

Q. Would you explain the calculation of income taxes?

A. Income taxes are assessed on the equity return. NSP-gas applied 35% to the equity return to generate pro forma income taxes. I applied 53.84615% to the equity return to generate income taxes. NSP-gas failed to consider the "tax-on-tax" effect when constructing a revenue requirement.

Q. Was the determination of each of the 45 years' costs of service and estimated sales the end of your analysis?

A. No. NSP-gas requested a levelized cost of service. The only point in doing a 45-year forecast is to develop a levelized cost of service.

Q. What is a levelized cost of service?

A. A "levelized" cost of service is an average cost of service over a period of years which incorporates time value of money.

Q. What is the purpose of using a levelized cost of service?

A. Sales and cost of service naturally change each year. In a mature, large company these changes, on a percentage basis, tend to be relatively small. In a small, new company the percentage changes can be very large, and the sales and related rates needed to recover the costs can be dramatically different. A levelized cost of service is designed to "average" the cost of service and related revenue requirement.

Q. What causes this dramatic change?

A. In a start-up company, all plant is new and sales of product must be generated . A strict rate base, rate of return revenue requirement may lead to unmarketable product costs per unit of sales in early years. This is because fixed and unavoidable costs and undepreciated plant values in early years would be spread over comparatively limited sales units. As sales grow and plant is depreciated, the per unit costs will drop.

Q. Do you simply average the costs of service for 45 years?

A. No. The time value of money must be considered. The timing of cash flows differs with the actual compared to the levelized cost of service. This difference is "zeroed out" on a value basis by adding carrying costs to either the actual or levelized cost of service.

Q. How is this done?

A. By equating the "net present value" of the actual and the levelized cost of service for the 45 years as I have done on my exhibit.

Q. What is the result of your levelization?

A. An annual revenue requirement of $73,938. This compares to NSP-gas's annual revenue requirement of $81,186.

Q. A key component of present value analysis is the discount rate. What is your discount rate?

A. NSP-gas's overall cost of capital, 8.7314%.

Q. Given you employed NSP-gas's cost of capital, is there is no resulting issue on the discount rate?

A. There is an issue as NSP-gas used a net-of-tax rate. NSP-gas has not yet filed any support for doing so, nor can we find any support for a net-of-tax rate.

Q. How does your levelization affect NSP-gas's filed rate?

A. Because NSP-gas's rate is negotiated, staff's lower revenue requirement will only affect the ceiling rate absent any change in sales units.

Q. Is staff recommending any change in sales units?

A. No. Inadequate information precludes any possibility of making a reasoned long-term estimate. NSP-gas, as shown on Schedule 2 of NSP-gas witness Winter, is using annual throughput of approximately 481,000 Mcf as a basis for the rate cap. Review of available data does not suggest a higher level of throughput for the short-term, and thus lowering of the rate cap. This issue should be revisited as operations mature. NSP-gas should be required to file operations reports with this Commission, no less than annually.

Q. You stated earlier that you would discuss customer costs in more detail. What are you recommending for customer costs?

A. NSP-gas's calculation of HTI's customer costs are depicted on NSP-gas witness Winter's Schedule 2. He has assigned all metering costs, including a carrying charge on unpaid meter costs, and all meter reading, billing, and service costs to the customer charge.

Q. Is this appropriate?

A. To the extent customer costs can be identified, this is supportable. It is in fact preferable to have each customer pay identifiable, customer-specific costs as it avoids customer-by-customer subsidization.

Q. Do all companies do this?

A. No. I think this Commission and jurisdictional companies have moved in this direction, but generally existing customer charge costing causes some customers to subsidize others. It is difficult to remove subsidization as it must be done through what most customers believe is a radical and unfair rate design change. The best policy is to correctly establish customer charge principles at the outset.

Q. You agree with the intent of NSP-gas's proposed customer charge. Do you also agree with the costs?

A. I have changed the fixed charge rate to match differing staff inputs. My comparable rate is 13.60%. 13.60% should be substituted for 14.08% when calculating the annual metering charge revenue requirements. While I am not recommending any further changes, I am concerned about the two other cost inputs, metering investment and annual meter reading, billing, and service costs.

Q. What are your concerns?

A. We have no firm, final accounting of the meter investment, or any support for the estimated meter reading, billing, and service costs.

Q. What do you recommend to lessen your concern?

A. Meter costs are to be customer specific. Tariff provisions should state clearly how those costs should be made known and approved by the customer, and how they are formulaically developed into a customer charge. Obviously meter reading and billing costs must be estimated until historical data has been generated. Even so, NSP-gas has not specified any details of either the costs included and the nature of the generation of those costs. I realize those type of costs will be incurred, but absent any support, I have no reason to either agree or disagree with the estimate. NSP-gas needs to either support, or not bill for any annual costs.

Q. Do you have any further recommendations?

A. This case has necessarily placed heavy reliance upon estimates that have varying degrees of support. The sales number is used for each of the 45 years, though one can expect the current estimate will only coincidentally mirror the actual results. By necessity we use estimates for a start-up utility, but we will develop actuals. I recommend that NSP-gas's cost of service be reviewed in 2000, based on 1999's results.

I also recognize that NSP-gas has supplied only limited updates to their original filing. There is a likelihood that the numbers in this filing will change prior to hearing time. Staff supports any attempt to lessen the uncertainty of the inputs.

Q. I have no further questions.

NORTHERN STATES POWER COMPANY
Docket NG97-021 - South Dakota -Gas

Exhibit_(GAR-1)

Time Period (a)	Year (b)	Plant In Service Additions (c)	Net Investment Rate Base (d)	Equity Return (e)	Taxes on Equity Return (f)	Debt Return (g)	Book Depr. (h)	Operating Expenses (i)	Property Taxes (j)	Total Revenue Requirement (k)	Levelized Requirement npv(k)=npv(L) (L)
0	1997	364,718	359,448	9,751	5,250	5,941	5,270	3,027	1,422	30,662	73,938
1	1998	0	348,908	19,216	10,347	11,709	10,540	18,689	8,794	79,295	73,938
2	1999	0	338,368	18,644	10,039	11,360	10,540	19,231	9,058	78,873	73,938
3	2000	0	327,828	18,072	9,731	11,012	10,540	19,789	9,330	78,474	73,938
4	2001	0	317,288	17,500	9,423	10,663	10,540	20,363	9,610	78,099	73,938
5	2002	0	306,748	16,929	9,115	10,315	10,540	20,953	9,898	77,750	73,938
6	2003	0	296,208	16,357	8,807	9,967	10,540	21,561	10,195	77,426	73,938
7	2004	0	285,668	15,785	8,500	9,618	10,540	22,186	10,501	77,129	73,938
8	2005	0	275,128	15,213	8,192	9,270	10,540	22,829	10,816	76,859	73,938
9	2006	0	264,588	14,641	7,884	8,921	10,540	23,491	11,140	76,618	73,938
10	2007	0	254,048	14,069	7,576	8,573	10,540	24,173	11,474	76,405	73,938
11	2008	0	243,508	13,497	7,268	8,224	10,540	24,874	11,819	76,222	73,938
12	2009	0	232,968	12,926	6,960	7,876	10,540	25,595	12,173	76,070	73,938
13	2010	0	222,428	12,354	6,652	7,527	10,540	26,337	12,538	75,949	73,938
14	2011	0	211,888	11,782	6,344	7,179	10,540	27,101	12,915	75,861	73,938
15	2012	0	201,348	11,210	6,036	6,831	10,540	27,887	13,302	75,806	73,938
16	2013	0	190,808	10,638	5,728	6,482	10,540	28,696	13,701	75,785	73,938
17	2014	0	180,268	10,066	5,420	6,134	10,540	29,528	14,112	75,800	73,938
18	2015	0	169,728	9,495	5,112	5,785	10,540	30,384	14,535	75,852	73,938
19	2016	0	159,188	8,923	4,805	5,437	10,540	31,265	14,972	75,941	73,938
20	2017	0	148,648	8,351	4,497	5,088	10,540	32,172	15,421	76,068	73,938
21	2018	0	138,108	7,779	4,189	4,740	10,540	33,105	15,883	76,236	73,938
22	2019	0	127,568	7,207	3,881	4,391	10,540	34,065	16,360	76,444	73,938
23	2020	0	117,028	6,635	3,573	4,043	10,540	35,053	16,851	76,695	73,938
24	2021	0	106,488	6,063	3,265	3,695	10,540	36,069	17,356	76,988	73,938
25	2022	0	95,948	5,492	2,957	3,346	10,540	37,115	17,877	77,327	73,938
26	2023	0	85,408	4,920	2,649	2,998	10,540	38,192	18,413	77,711	73,938
27	2024	0	74,868	4,348	2,341	2,649	10,540	39,299	18,965	78,143	73,938
28	2025	0	64,328	3,776	2,033	2,301	10,540	40,439	19,534	78,624	73,938
29	2026	0	53,788	3,204	1,725	1,952	10,540	41,612	20,120	79,154	73,938
30	2027	0	43,248	2,632	1,417	1,604	10,540	42,819	20,724	79,736	73,938
31	2028	0	32,708	2,060	1,109	1,256	10,540	44,060	21,346	80,372	73,938
32	2029	0	22,168	1,489	802	907	10,540	45,338	21,986	81,061	73,938
33	2030	0	11,628	917	494	559	10,540	46,653	22,646	81,808	73,938
34	2031	0	1,088	345	186	210	10,540	48,006	23,325	82,612	73,938
35	2032	0	(9,452)	(227)	(122)	(138)	10,540	49,398	24,025	83,475	73,938
36	2033	0	(19,992)	(799)	(430)	(487)	10,540	50,830	24,746	84,401	73,938
37	2034	0	(30,532)	(1,371)	(738)	(835)	10,540	52,305	25,488	85,389	73,938
38	2035	0	(41,072)	(1,942)	(1,046)	(1,184)	10,540	53,821	26,253	86,442	73,938
39	2036	0	(51,612)	(2,514)	(1,354)	(1,532)	10,540	55,382	27,040	87,562	73,938
40	2037	0	(62,152)	(3,086)	(1,662)	(1,880)	10,540	56,988	27,851	88,751	73,938
41	2038	0	(72,692)	(3,658)	(1,970)	(2,229)	10,540	58,641	28,687	90,011	73,938
42	2039	0	(83,232)	(4,230)	(2,278)	(2,577)	10,540	60,342	29,548	91,344	73,938
43	2040	0	(93,772)	(4,802)	(2,586)	(2,926)	10,540	62,091	30,434	92,752	73,938
44	2041	0	(104,312)	(5,374)	(2,893)	(3,274)	10,540	63,892	31,347	94,238	73,938
45	2042	0	(109,582)	(5,802)	(3,124)	(3,536)	5,270	65,745	32,287	90,840	73,938
Totals		364,718		308,481	166,105	187,966	474,300	1,691,392	816,818	3,645,062	3,401,148
Net present value				145,573	78,386	88,702	113,188	272,867	130,086	828,802	828,798

SOURCES

Cols. [a] &[b]: 45 yr. service period beginning in 1998
[c] Per NSP, Schedule 4, John Winter, and testimony of staff witness Knadle
[d] Col. [c] less Col. [h]
[e] NSP Sch. 3, p.1, weighted preferred and common equity return x average (beg. and end) rate base
[f] Col [e] x "gross-up" tax factor of .5384615
[g] NSP Sch. 3, p.1, weighted cost of short- and long-term debt (.033059) x ave. rate base
[h] Depreciation based on 45 yr. life and 30% negative salvage. Testimony of Staff witness Rislov, page 5
[i] Per Staff Exhibit_(RLK-1), Schedule 1
[J] Tax rate of .02341 and escalation factor of 3%. Testimony of Staff witness Rislov, page 5
[k] Total of Cols. e,f,g,h,i and j
[L] Levelized annual revenue requirement to equate net present values of Cols. [k] and [L]

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SOUTH DAKOTA PUBLIC
UTILITIES COMMISSION

BEFORE THE
PUBLIC UTILITIES COMMISSION
STATE OF SOUTH DAKOTA

IN THE MATTER OF THE APPLICATION FOR AN ORDER ESTABLISHING A NATURAL GAS UTILITY, AND TO ESTABLISH INITIAL NATURAL GAS TRANSPORTATION RATES FOR NORTHERN STATES POWER COMPANY

DOCKET NO. NG97-021

TESTIMONY AND EXHIBITS OF ROBERT L KNADLE
ON BEHALF OF THE COMMISSION STAFF
DECEMBER, 1998

EXHIBIT
7

BEFORE THE
PUBLIC UTILITIES COMMISSION
STATE OF SOUTH DAKOTA

IN THE MATTER OF THE APPLICATION FOR
AN ORDER ESTABLISHING A NATURAL GAS
UTILITY, AND TO
ESTABLISH INITIAL NATURAL GAS
TRANSPORTATION RATES FOR NORTHERN
STATES POWER COMPANY

DOCKET NO. NG97-021

TESTIMONY AND EXHIBITS OF ROBERT L. KNADLE
ON BEHALF OF THE COMMISSION STAFF
DECEMBER, 1998

Q. Please state your name, business address and current position.

A. My name is Robert L. Knadle and my business address is Public Utilities Commission, State Capitol Building, Pierre, South Dakota 57501. I am presently employed as a utility analyst with the Fixed Utilities Division of the Public Utilities Commission.

Q. Please describe your educational background and experience.

A. I have been with the Public Utilities Commission since March of 1980. I received a Bachelor of Science Degree in Commercial Economics from South Dakota State University in December of 1979. I have attended a number of seminars and workshops on utility related matters during my employment with the Commission.

Q. Have you previously presented testimony before this Commission?

A. Yes. I have presented written and oral testimony and exhibits on numerous occasions before this Commission, primarily on electric and natural gas matters.

Q. Are you familiar with Northern States Power Company-Gas's (NSP) application in this matter?

A. Yes. I have reviewed the Company's prefiled testimony, exhibits, working papers and data responses that were supplied by NSP at the request of Commission Staff.

Q. What is the purpose of your testimony in this proceeding?

A. I shall comment and make recommendations to Staff Witness Rislov on the following operating income and rate base amounts included in the cost of service proposed by the Company:

1. ACA supplemental service

2. Office of Pipeline Safety Assessments

3. Regulatory fees

4. Plant in service

I shall also comment and make recommendations on NSP's proposed Transportation Service Tariff which is detailed in Exhibit No. 5 of the initial filing.

Q. What is your recommendation with regard to ACA supplemental service?

A. NSP's amount of $3,600 as found on Winter's Schedule 5 is related to emergency service to be provided by Angus C. Anson personnel. NSP's response to Staff's third data request, question number three, states that the ACA supplemental service was replaced by a memorandum of understanding with Northwestern Public Service Company to provide standby and emergency operation and maintenance services. My recommendation would be to replace NSP's amount with an amount of $2,100 which reflects NWPS' annual fee plus a specific charge for each hour of work performed.

Q. Could you explain NSP's estimate of $500 for the Office of Pipeline Safety assessments as found on Winters's Schedule 5?

A. NSP's amount of $500 is based on a similarly situated intrastate pipeline in South Dakota. I have spoken to Martin Bettmann, the Commission Staff member who has pipeline safety responsibilities. He stated that two trips per year are required for each entity unless there is construction which needs to be inspected. His estimate for the two required trips is $330 which is based on costs billed to an entity similar and in close proximity to NSP's facilities. I am recommending NSP's adjustment be lowered by $170 to total a reduced amount of $330.

Q. What is your recommendation with regard to NSP's amount for regulatory fees as found on Winter's Schedule 5?

A. I recommend that NSP's amount be reduced by $50 to total a revised annualized cost of $250. My recommendation is based on SDCL 49-1A-3 which essentially says that a rate regulated company is levied a tax of .0015 on the company's annual gross receipts or $250, whichever is greater. The $250 charge equates to gross receipts of approximately $167,000, an amount which is considerably higher than NSP-gas's levelized revenue requirement.

Q. Please continue.

A. Exhibit__(RLK-1), Schedule 1 incorporates the above-mentioned adjustments to the Company's proposed operation and maintenance expenses. I recommend to Staff Witness Rislov that he include the amounts depicted on this schedule in his determination of NSP's levelized revenue requirement. Staff has a number of outstanding data requests on operation and maintenance expenses that may change the aforementioned recommendation.

Q. What is your recommended amount of plant in service?

A. NSP, per Winter's Schedule 4, has estimated that plant in service exclusive of customer meter costs is $364,718. Staff has requested and received invoices and account detail for the amounts depicted on Schedule 4 per NSP's response to Staff's initial data request, question eighteen. This data consists of invoices for materials, labor, excavation and backfill for the project, totalling to an amount of approximately $318,000 as of July 13, 1998, exclusive of meterset costs. This represents approximately 87% of NSP's initial estimate of $364,718. Staff in its fourth data request asked for available updates to plant in service and operation and maintenance expenses. NSP has indicated to me that their initial plant in service estimate is considerablely lower than their actual expenditures. I am awaiting reply to our remaining data requests to consider this. For the time being, and based on currently available data, I am recommending to Staff Witness Rislov that he incorporate NSP's original estimate of $364,718 in his determination of the levelized revenue requirement subject to further adjustment, if necessary.

Q. Please explain Exhibit__(RLK-1), Schedule 2.

A. Schedule 2 is comprised of a number of NSP's proposed Transportation Service Tariff Sheets that Staff believes need either further clarification, minor changes, or further support. For ease of review I have footnoted the areas that Staff feels need to be addressed by the Company. I classify the footnotes by the following categories:

1. Minor Changes---(1), (2), (3), (5), (6), (7), (8), (10), (11), (12), (13), (14), (15), (16), (17), (18), (19), (20), (22), (23), (24), (25), (26), (27), (28), (32), (33), (35), (36), (37), (38), (41), (43), (44), (45), (49), (50), (51), (53), (55), (61), (64), (67), and (70).

2. Clarification---(4), (9), (29), (30), (31), (39), (46), (47), (48), (52), (54), (56), (58), (59), (60), (62), (63), (65), (69), and (71).

3. Further Support Required---(21), (34), (40), (42), (57), (66), and (68).

Staff has submitted these concerns to NSP via a sixth data request dated December 4, 1998. We are awaiting the Company's response.

Q. Could you explain what NSP is proposing for transportation service charges?

A. Yes. NSP is proposing a maximum customer charge of $277.00 per month based on a specific customer costs as determined on Winter's Schedule 2. NSP proposes a transportation local delivery volume charge which will not exceed $0.214 per MMBtu transported and not be less than $0.045 per MMBtu transported. These rates are also determined on Winter's Schedule 2.

Q. Do you have any concerns related to these transportation service charges?

A. Yes. Since the customer charge is based on a specific customer costs, I believe that NSP should provide specific language on how customer charges would be determined for any prospective customer. NSP's proposed transportation local delivery charge could be flexed between a ceiling of $.214 and a floor of $.045, with the floor representing the charges or costs related to the use of the Angus Anson pipeline. I recommend that the floor be raised to minimally recover variable costs for the customer and to provide for some contribution toward NSP's distribution system fixed costs.

Q. Do you have a schedule which indicates Staff's recommended maximum transportation rate?

A. Exhibit__(RLK-1), Schedule 3 details Staff's recommended maximum transportation rate of $0.199 per MMBtu.

Q. I have no further questions at this time.

Northern States Power Company
South Dakota-Gas
Operation and Maintenance

Exhibit__(RLK-1)
Schedule 1

	Amount A	Annual Escalator B	1 Year Escalated Amount C
1. NSP-operation & maintenance	$8,154	3.0%	$8,399
2. NWPS contract service	$2,130	3.0%	$2,194
3. Services-NSP-SD	$7,200	3.0%	$7,416
4. Insurance	$100	0.0%	$100
5. OPS assessment	$330	0.0%	$330
6. Regulatory fees	$250	0.0%	$250
7. Total	$18,164	2.9%	$18,689

Sources
Column A, lines 1, 3 and 4: NSP Witness Winter's Schedule 5
Column A, line 2: NSP' response to Staff data request number 3, questions 2 and 3, annual amount plus 3 trips at 3 hours per trip.
Column A, line 5: Estimate from Martin Bettmannn, Staff Engineer
Column A, line 6: Assessment per SDCL 49-1A-3

Northern States Power Company
South Dakota-Gas
Staff Comments And Recommendations On Tariffs

Staff recommends that NSP satisfactorily address Staff's concerns as listed throughout the tariffs comprising this exhibit.

TARIFF SCHEDULES

APPLICABLE TO

INTRASTATE NATURAL GAS TRANSPORTATION SERVICE

OF

NORTHERN STATES POWER COMPANY - SOUTH DAKOTA

500 W. Russell St.
PO BOX 988
Sioux Falls, SD 57101

Filed with the South Dakota Public Utilities Commission
as SDPUC No. 1

Date Filed: December 16, 1997

Issued by:
Michael J. Hanson (1)
Chief Executive & Gen. Mgr.

(1) Change to current person on all tariff pages

PRELIMINARY STATEMENT

Northern States Power Company - South Dakota (hereafter "NSP-SD" or "Transporter") is an electric utility and prospectively a natural gas utility company planning to engage in the business of transporting and distributing natural gas in intrastate commerce to end users in the State of South Dakota. NSP's system consists (2) of approximately three miles of distribution lateral pipeline in Minnehaha County, South Dakota. NSP-SD will take delivery of natural gas at the compressor station located on the Angus C. Anson site east of Sioux Falls and deliver it to end-use customers along or at the terminus of the NSP distribution lateral line in Sioux Falls, South Dakota.

(2) Is this amount accurate? If not, please change.

GENERAL TERMS AND CONDITIONS

ARTICLE 1
DEFINITIONS

1.1 "Btu" shall mean one British Thermal Unit.

1.2 "Contract Demand" shall mean the aggregate of the maximum daily quantities of gas, expressed in dkt per day, which Transporter is obligated to accept for transportation for the account of Shipper from the points of receipt as set forth in the Transportation Service Agreement ("TSA") between Transporter and Shipper.

1.3 "Contract Year" shall mean the twelve month period commencing November 1 and terminating on October 31 of each year, until ~~this Agreement shall have~~ expired or otherwise been terminated in accordance with its terms. (3)

1.4 "Day" shall mean the period of 24 consecutive hours, starting at 9:00 a.m. Central Clock Time, or such other 24 hour gas day period as established in Northern's Tariff.

1.5 "Dkt" shall mean the quantity of heat energy which is equivalent to 1,000,000 British Thermal Units (BTU). One "dkt" of gas means the quantity of gas which contains one dekatherm of heat energy. The total dekatherms are calculated by multiplying the gas volume in Mcf by its total gross heating value, divided by 1,000.

1.6 "Equivalent Quantities" shall mean the sum of quantities of gas measured in dkt received by Transporter and delivered for the account of Shipper at the points of receipt and delivery during any given period of time reduced by the sum of Shipper's
(4) Pro Rata Share of Lost and Unaccounted For Gas resulting from the operations of the System during the same period of time. In the event the ownership of gas lost as a result of an event of force majeure can be reasonably identified, the quantity thereof shall be charged to the Shipper or Shippers so identified.

1.7 "Gas" shall mean natural gas, unmixed or any mixture of natural and artificial gas.

1.8 "Gross Heating Value" shall mean the number of BTU's produced by the complete combustion, at a constant pressure, of the amount of gas which would occupy a volume of one (1) cubic foot at a temperature of 60 degrees Fahrenheit on a dry basis and at a pressure of 14.73 psia with air of the same temperature and pressure as the gas, when the products of combustion are cooled to the initial temperature of the gas and air, and when the water formed by combustion has been condensed to the liquid state.

(3) Insert " the TSA has
(4) How shall this be determined? Provide tariff language.

ARTICLE III
MEASUREMENT

3.1 Unit of Measurement and Metering Base. The volumetric measurement base shall be one cubic foot of gas at a pressure base of 14.73 pounds per square inch absolute, at a temperature base of 60 degrees Fahrenheit, and without adjustment for water vapor content.

3.2 Atmosphere Pressure. For the purpose of measurement, the absolute atmospheric (barometric) pressure at each measuring station shall be the atmospheric pressure determined by calculations based on the actual elevation above sea level of the meter at the place of measurement, and shall be stated in pounds per square inch.

3.3 Temperature. If determined to be necessary in the sole discretion of Transporter, the temperature of the gas shall be determined at each point of
(5) measurement by means of properly installed recording thermometer, an indicating thermometer, an electronic temperature measuring device, or a temperature compensating meter of standard manufacture acceptable to Transporter.

3.4 Specific Gravity. If determined to be necessary in the sole discretion of Transporter, the specific gravity of the gas shall be determined at each point of receipt by one of the following methods.

(a) By means of a properly installed recording gravitometer of standard manufacture acceptable to Transporter.

(b) If (a) is not considered feasible, then by use of a portable specific gravity (6) balance of standard manufacture, or other standard device acceptable ~~of~~ Transporter and designed for such purpose or use in conjunction with a continuous sampler.

(c) Other methods acceptable to Transporter.

3.5 Measurement Procedures. Quantities of gas received and delivered hereunder shall be measured in accordance with Procedures contained in ANSI-API 2530, First Edition, AGA Committee Report No. 5, AGA Committee Report No. 7, and AGA Committee Report No. 8, or revisions or amendments thereto.

3.6 Measuring Equipment. Unless otherwise agreed, Transporter will provide, maintain, and operate necessary measuring and regulating stations equipped (7) with flow meters and other necessary measuring equipment by which ~~the~~ quantities of gas delivered from Transporter hereunder shall be determined. Such measuring and regulating stations shall be so installed at the receipt point of the System and at other agreeable points. All flow, measuring, testing, and related equipment shall be of standard manufacture and type acceptable to Transporter.

(5) Insert "a"
(6) Insert "to"
(7) Delete

(8)

Transporter and Shipper shall cause the chart on all gas measurement equipment to be changed, or mechanical or electronic indices read, by either Transporter or by Shipper's representative (where economical) on a daily basis. If telemetering is not installed, Shipper shall change recording charts on Transporter's Delivery point metering facilities or otherwise read Transporter's meter on a daily basis at a time specified by Transporter. Shipper may install check measuring equipment, provided that such equipment shall be so installed as not to interfere with operation of Transporter.

(9)

When Transporter deems it necessary, telemetering equipment shall be installed on Shipper's delivery point meter(s). Transporter will install and maintain the telemetering facilities. Shipper shall provide, install and maintain a weatherproof phone service and electrical service outlet with appropriate grounding for telemetering equipment. Shipper and Transporter, in the presence of each other, shall have access to all measuring equipment at all reasonable times, but the reading, calibrating, and adjusting thereof shall be done by the Transporter, unless otherwise agreed. Shipper and Transporter shall have the right to be present at the time of any installing, reading, cleaning, changing, repairing, inspecting, testing, calibrating, or adjusting done in connection with all measuring equipment. The records from such measuring equipment shall remain the property of Transporter. Reasonable care shall be exercised in the installation, maintenance and operation of measuring equipment so as to avoid any inaccuracy in the determination of the quantity of gas received and delivered.

3.7 Calibration and Test of Meters. The accuracy of all measuring equipment shall be verified by the Transporter at reasonable intervals, and if requested, in the presence of representatives of Shipper. Transporter shall not be required to verify the accuracy of such equipment more frequently than once in Contract Year. If either party at any time desires a special test of any measuring equipment, it will promptly notify the other, and the parties shall then cooperate to secure a prompt verification of the accuracy of such equipment. Transportation and related expenses incurred by Shipper or Transporter involved in the testing of meters shall be ~~done~~ by the party incurring such expense. (10)

3.8 Correction of Metering Errors. If, upon any test, any measuring equipment is found to be in error, such errors shall be treated in the following manner. (11) If the resultant aggregate error in the computed receipts or deliveries is not more than 2%, then previous receipts ~~of~~ deliveries shall be considered accurate. All equipment shall, in any case, be adjusted at the time of test to record to zero error. If, however, the resultant aggregate error in computed receipt or deliveries exceeds 2% at a recording corresponding to the average hourly rate of gas flow for the period since the last preceding test, the previous recordings of such equipment shall be corrected to zero error for any period which is known definitely or agreed upon. In case the period is not known definitely or agreed upon, such correction shall be for a period extending

(8) Insert "recording"
(9) Provide language of who is responsible for these costs
(10) Insert "borne"
(11) Insert "or"

over one-half of the time elapsed since the date of the last test, not exceeding a correction period of 180 days.

3.9 Failure of Measuring Equipment. In the event any measuring equipment is out of service, or is found registering inaccurately and the error is not determinable by test, or by previous recording, receipts or deliveries through such equipment shall be estimated:

(a) By using the registration of any check meter or meters, if installed and accurately registering, or in the absence of (a);

(b) By correcting the error if the percentage of error is ascertainable by calibration, special test, or mathematical calculation, ~~of~~ in the absence of both (a) and (b) then; (12)

(c) By estimating the quantity of receipt or delivery based on receipts or deliveries during preceding periods under similar conditions when the measuring equipment was registering accurately.

3.10 Preservation of Records. Shipper and Transporter shall preserve all test data, charts, and other similar records for a period of at least one year, or such longer period as be required by the SDPUC or other jurisdictional public authority.

(13)

ARTICLE IV
RECEIPT AND DELIVERY POINTS

4.1 Point of Receipt. The initial point of receipt hereunder shall be the point of interconnection between the facilities of Transporter and the facilities of Northern States Power Company - Generation located in Minnehaha County, South Dakota. Shipper shall deliver, or cause to be delivered, gas to Transporter at the point or receipt for transportation service, set ~~for~~ in Exhibit A attached to Shipper's TSA. (14)

4.2 Points of Delivery. The point(s) of delivery hereunder shall be the point(s) of connection between the facilities of Transporter and the facilities of Shipper, where Transporter shall deliver gas for the account of Shipper. Such point(s) of delivery are set forth in Exhibit A attached to Shipper's TSA. Unless otherwise agreed, the establishment of any additional point of delivery at the request of Shipper shall be at the expense of Shipper. (15

(12) Insert "or"
(13) Insert "may"
(14) Insert "forth"
(15) Insert "(s)"

ARTICLE V
SCHEDULES

5.1 Schedules. Prior to the first day of each month, Shipper shall furnish Transporter with a schedule showing the estimated daily quantities of gas Shipper desires Transporter to transport during such month. Such monthly schedule shall be provided at least one hour before the deadline for monthly nominations in Northern's Tariff. Thereafter Shipper shall on a daily basis advise Transporter of the volumes Shipper will deliver during the following day at least one hour prior to the time Transporter must submit daily nominations to Northern pursuant to Northern's Tariff. However, Shipper may establish a standing schedule of daily volumes, notifying Transporter prior to any day when Shipper's daily deliveries will differ from the standing schedule by more than the daily delivery variance (+/-) established in Northern's Tariff.

5.2 Departures from Schedules. Departures from the scheduled deliveries at the point of receipt shall be kept to the minimum permitted by operating conditions, and shall be balanced as soon as practicable. Shipper shall use its best efforts to give Transporter notice prior to proposed change of a daily quantity from that set forth in the schedule provided for in Paragraph 5.1 hereof. Such notice shall be provided at times consistent with the notice period for intra-day nomination changes set forth in Northern's Tariff. Transporter may waive such notice upon request if, in its judgment, operating conditions permit such waiver. Transporter and Shipper shall inform each other of any other changes of deliveries immediately upon knowledge thereof.

5.3 Hourly Variation. Deliveries shall be made at uniform hourly rates to the extent practicable. Transporter's obligation to deliver shall not exceed 1/16th of Shipper's Maximum Daily Quantity in any given hour.

ARTICLE VI
DAILY AND MONTHLY BALANCING

6.1 Scheduling and Balancing Tolerances. It is recognized that the parties will be unable to control exactly the quantities of gas delivered and accepted hereunder on any day, and that deliveries by Shipper and redeliveries by Transporter may vary above or below the quantities scheduled on any day. However, nothing in this ~~paragraph~~ shall affect Shipper's obligation to pay for gas actually transported.

(16)

6.2 Daily Variance. The daily variance for a receipt point shall be the difference between the total quantities scheduled for receipt and the actual quantity delivered into Transporter's System. The daily variance for a delivery point shall be the difference between the total quantities scheduled and the actual quantity delivered by Transporter at such point on any day. Shipper shall take action to correct any daily variance between scheduled and actual receipts and deliveries occurring during the

(16) Insert "article"

month by making adjustments to schedules, receipts or deliveries. In no event shall the daily excess or deficiency variance exceed the allowable daily point of delivery variation set forth in Northern's Tariff.

6.3 Monthly Imbalances. Shipper's monthly imbalance shall be the net total (18)
(17) of daily variance from all receipt~~s~~ and delivery points. Such monthly imbalance shall be corrected in-kind through adjustments to Shipper's schedules, receipts or deliveries in order for Shipper to receive Equivalent Quantities, or by such other method as is then mutually agreed upon by the parties hereto. The cumulative daily variances during any month above or below the quantities scheduled shall not exceed the monthly point of delivery ~~monthly~~ variance set forth in Northern's tariff.

(19)

6.4 Disposition of Excess Gas. In order to alleviate conditions that threaten the integrity of its System, Transporter may periodically acquire quantities of gas that are in excess of System needs. Transporter may make interruptible sales of such gas
(20) ~~form~~ time to time at the point of receipt pursuant to 18 CFR 284.402. Such sales shall (21)
be made under rates, terms and conditions mutually agreed upon between Transporter and the purchaser, provided that all such sales shall be fully interruptible.

ARTICLE VII
PRESSURE

(22)

7.1 Pressure at the Point~~s~~ of Receipt. Shipper shall cause the gas to be
(23) delivered at the point~~s~~ of receipt at a pressure sufficient to allow the gas to enter the System, however, Shipper shall not be required to deliver gas to the Transporter at any point of receipt at a pressure in excess of the minimum pressure specified with respect to each receipt point in Exhibit A of Shipper's TSA.

(24)

7.2 Pressure at Points of Delivery. Transporter shall deliver gas to Shipper's delivery points at the pressure existing in the Transporter's pipeline; however, Transporter must deliver gas to each point at a pressure not less than the minimum pressure specified with respect to each delivery point in Exhibit A to Shipper's TSA. Transporter, however, shall not be required or permitted to deliver gas at a pressure in excess of the maximum pressure specified for each point of delivery set forth in Exhibit A attached to Shipper's TSA.

ARTICLE VIII
BILLING AND PAYMENT

8.1 Billing. Unless otherwise agreed, on or before the 10th day of each
(25) month, Transporter shall render to Shipper a statement of the total amount of gas (26)
delivered by Transporter to Shipper at the points of ~~receipt~~ hereunder during the preceding month and the amount due. When information necessary for billing

* See next page

(17) Delete "s"

(18) Insert "(s)"

(19) Delete

(20) Insert "from"

(21) Do these sales require Commission authority which has not been requested from the Commission? Provide detail.

(22) Delete "s"

(23) Delete "s"

(24) Insert "(s)"

(25) Insert "(s)"

(26) Insert "delivery"

purposes is in the control of Shipper, Shipper shall furnish such information to Transporter on or before the 10th day of the month.

(28) (27) Shipper and Transporter shall have the right to examine at reasonable times, books, record, and charts of the other to the extent necessary to verify the accuracy of any statement, charge, or computation made under or pursuant to any of the provisions hereof.

8.2 Payment. Unless otherwise agreed, Shipper shall pay Transporter at its (29) general office or at such other address as Transporter shall designate ~~on or before the 28th day of the month, the amount due for the preceding month. If presentation of a bill by Transporter is delayed after the 20th day of the month, then the time of payment shall be extended accordingly unless shipper is responsible for such delay.~~

8.3 Remedies for Failure to Pay. Should Shipper fail to pay all or any portion of any bill as herein provided when such amount is due, interest on the unpaid portion of the bill shall occur at a rate of one percent (1%) per month. If such failure to pay continues for 30 days after payment is due, Transporter may, in addition to any other remedy it may have hereunder, suspend further delivery of gas until such amount is paid, if authorized pursuant to the rules of the SDPUC.

(30)

8.4 Disputed Bills. If Shipper in good faith shall dispute the amount of any such bill or part thereof and shall pay to Transporter such amounts as it concedes to be correct and, at any time thereafter within 30 days of a demand made by Transporter, shall furnish a good and sufficient surety bond in an amount and with surety satisfactory to Transporter, guaranteeing payment to Transporter of the amount ultimately found due upon such bills after a final determination which may be reached either by agreement or judgment of the courts, as may be the case, then Transporter shall not be entitled to suspend further delivery of gas unless and until default be made in the conditions of such bond.

8.5 Adjustment of Billing Errors. If it shall be found that at any time or times Shipper has been overcharged or undercharged in any form whatsoever under the provisions hereof and, in the case of an overcharge, Shipper shall have actually paid the bill containing such overcharge, then within 30 days after the final determination of such overcharge or undercharge, the appropriate party shall pay to the other party the amount of said overcharge or undercharge, net of any other amounts then payable hereunder. (31) In the event an error is discovered in the amount billed in any statement rendered by Transporter, such error shall be adjusted within 30 days of the determination thereof provided that claim therefor shall have been made within one (1) year from the date of such statement. If the parties are unable to agree on the adjustment of any claimed error, any resort by either of the parties to legal procedure, either by law, in equity, or otherwise, shall be commenced within 12 months after the supposed cause of action is alleged to have arisen, or shall thereafter be forever barred.

* See next page

(27) Insert "a"

(28) Insert "recording"

(29) Insert "within 20 days after the filling transmittal date"

(30) Delete "entire section" or revise to comply with ARSD 20:10:17:12. If you delete revise the numbering of the remaining paragraphs.

(31) Revise to comply with ARSD 20:10:17:09

ARTICLE IX
CONTROL OF GAS

9.1 Responsibility for Gas. As between the Shipper and Transporter hereto, Shipper shall be in exclusive control and possession of the gas until such has been delivered to Transporter at the point of receipt, and after such gas has been redelivered to or for the account of Shipper by Transporter at the point(s) of delivery.
(32) Transporter shall be in exclusive control and possession of such gas while same is in the System between the point ~~or~~ receipt and the point(s) of delivery. The party which shall be in exclusive control and possession of such gas shall be responsible for all injury or damage caused thereby.

ARTICLE X
FORCE MAJEURE

10.1 Force Majeure. Neither party shall be responsible or held liable for any loss or damage resulting from failure to perform its obligations due to any cause beyond its reasonable control, provided, however, that such force majeure affecting the performance hereunder by either Shipper or Transporter shall not relieve such party of (33)
liability in the event of its own concurring negligence or in the event ~~or~~ its own failure to use due diligence to remedy the situation and to remove the cause in an adequate manner and with all reasonable dispatch; provided further, that no such causes affecting such performance shall relieve either party from its obligation to make payments as determined hereunder or entitle either party to exercise any right to offset against any such payment obligation.

10.2 Definition. The term "force majeure" as used herein shall mean acts of God, strikes, lockouts, or other industrial disturbances; acts of a public enemy, wars, blockades, insurrection, riots, epidemics, landslides, lightning, earthquakes, fires, storms, floods, washouts; arrests and restraints of the government, either federal or state, civil or military, civil disturbances; shutdowns for purposes of necessary repairs, relocation, or construction of facilities; breakage or accident to machinery or lines of pipe; the necessity for testing (as required by governmental authority or as deemed necessary by repairs or alteration to machinery or lines of pipe), failure of surface equipment or pipelines; accidents, breakdowns, inability of either party hereto to obtain necessary material, supplies, or permits, or labor to perform or comply with an obligation or condition of this Agreement, rights of way, and any other causes, whether of the kind herein enumerated or otherwise, which are not reasonably in the control of the party claiming suspension. It is understood and agreed that the settlement of strikes or lockouts shall be entirely within the discretion of the party having the difficulty and that the above requirement that any force majeure shall be remedied with all reasonable dispatch shall not require the settlement of strikes or lockouts by acceding to the demands of an opposing party when such course is inadvisable in the discretion of the party having the difficulty.

(32) Insert "of"
(33) Insert "of"

RATE SCHEDULE - FIRM TRANSPORTATION SERVICE

1.0 Availability. This Rate Schedule is available for the transportation of natural gas on a firm basis for any end user Shipper where (i) Transporter has determined that sufficient System capacity exists to provide the service requested by Shipper, and (ii) Shipper has executed a Transportation Service Agreement ("TSA") wherein Transporter agrees to transport gas for Shipper's account up to a specific maximum daily quantity.
(34) — Transporter is not obligated to provide transportation service for resale.

2.0 Gas Supply; Upstream Transportation, New Facilities. Shipper shall be responsible for arranging for all natural gas supplies and interstate transportation of shipper's gas on Northern to the point of receipt. Transporter will arrange for transportation on the NSP-Generation intrastate pipeline on behalf of Shipper. Unless otherwise agreed, Shipper must pay for all facilities required to physically connect to Transporter's pipeline.

3.0 Receipts and Deliveries. The Point of Receipt for all gas transported by Transporter under this Rate Schedule shall be at the interconnection of Transporter's System with Northern States Power Company - Generation located in Minnehaha County, South Dakota. The Point(s) of Delivery shall be at the point(s) designated in the Exhibit A attached to Shipper's TSA.

4.0 Rates and Charges. The rates for service under this Rate Schedule are included in the appendix of the Gas Transportation Agreement. However, Transporter has the right at any time to file with the SDPUC to adjust the rates applicable to service under this Rate Schedule.

5.0 Daily Tolerance; Penalty Provisions. The daily tolerance level (+/-) from Shipper's daily scheduled volume shall be the daily variance established in Northern's Tariff. Unless otherwise agreed, in the event the daily quantity of gas delivered by Shipper deviates above or below the daily scheduled volume in excess of the Northern's Tariff tolerance level, and Transporter is assessed charges or penalties by Northern, Shipper shall pay, in addition to the appropriate rates contained in this tariff, an amount equal to any payment Transporter is required to make to Northern.

(35.

6.0 General Terms and Conditions. Any terms ~~of~~ conditions not specified in this Rate Schedule shall be determined consistent with Transporter's General Terms and Conditions, which are incorporated by reference into this Rate Schedule.

(34) What authority allows you to impose this restriction?
(35) Insert "and"

Northern States Power Company
Sioux Falls, South Dakota
Gas Transportation Service Tariff SDPUC NO. 1

Original Sheet No. 17

INDEX OF SHIPPERS

Shipper	Rate Schedule	Effective Date	Expiration Date
Hutchinson Technology, Inc.	FT	12/01/97	2/28/2008

(36) update this list for new customers

Date Filed Dec 16 1997 Issued by: Michael J. Hanson Effective

NATURAL GAS TRANSPORTATION SERVICE AGREEMENT

This Gas Transportation Agreement ("Agreement") is made this ____ day of ____, 19__, by and between NORTHERN STATES POWER COMPANY, a Minnesota corporation, (hereinafter called "NSP" or "Company"), and ________________, ~~a Minnesota corporation~~, (hereinafter called "Customer"). Customer will enter into agreement to purchase natural gas and have that gas delivered to a ~~town border station of Company~~. Customer and Company desire to enter into this Agreement to have said gas transported by Company to Customer's plant facilities. (27) (38)

WITNESSETH: The parties hereto, each in consideration of the agreement of the other, agree as follows:

1.0 TERM. This Agreement shall commence on ________________, and continue until ________________, and, if not terminated by at least 180 days prior notice, shall continue further until so terminated.

1.1 CHARACTER OF SERVICE. The transportation and delivery of gas hereunder is on a firm basis. In consideration for NSP's agreement to provide firm transportation service at the rates set forth in Section 3.2, Customer agrees to utilize natural gas transported by NSP for all the non-electric energy requirements of the Plant equipment for the term of this Agreement. However, Customer may use a fuel other than natural gas in the case of (i) a force majeure or other emergency condition on the NSP distribution system or Transporter's pipeline system, as provided in this Agreement or Transporter's Tariff, or (ii) a failure of Customer's gas supply as defined in Section 2.0 for reasons beyond the control of Customer. (39)

1.2 CONTINUITY OF SERVICE. The Company will endeavor to provide continuous service but does not guarantee an uninterrupted or undisturbed supply of gas. The Company shall not be responsible for any loss or damage resulting from the interruption or disturbance of service for any cause other than the gross negligence of the Company. The Company shall not be liable for any loss of profits or other consequential damages resulting from the use of service or any interruption or disturbance of service. (40)

2.0 LIMITATION ON OBLIGATION TO DELIVER. This Transportation Agreement is expressly contingent upon Customer or Customer's Agent's procurement of natural gas supplies and interstate pipeline transportation to the Company receipt point in Minnehaha County, SD. If Customer or Customer's Agent fails to deliver gas to Company at the designated ~~town border station~~, Customer shall immediately cease using gas. Company is not obligated to provide backup sales service to Customer. However, Company may at its option, agree to provide backup gas service. (41) (42)

* See next page

(37) Delete

(38) Insert " specified receipt point"

(39) What about NSP - generation line?

(40) Support the use of this modifier.

(41) Insert " receipt point "

(42) If you intend to provide this service, provide a specific tariff for this.

2.1 REQUIREMENTS AND DELIVERIES; POINT OF DELIVERY. Company agrees to accept delivery of Customer's gas at the inlet of Company's distribution system in Minnehaha County, SD and, on a firm basis, transport and deliver said
(43) gas to Customer's point of delivery in volumes up to ___ MMBTU per day, or such other volumes as is mutually agreed. Customer's point of delivery shall be the outlet of (44)
the meter installation at ______________________________
(45)

2.2 DAILY NOMINATIONS. Customer or Customer's Agent shall on a daily
(46) basis advise Company's gas dispatcher in St. Paul of the volumes Customer will request to be delivered during the following Gas Day. Customer may alternatively elect to make a standing nomination with Company, notifying Company on any day when customer's daily deliveries will differ from the standing nomination by more than five (5) (47)
percent. Customer shall submit daily or corrected standing nominations to Company at
(48) least 24 hours in advance of the start of the Gas Day. Customer's daily or standing nomination shall be its best estimate of the expected utilization for the Gas Day. If Customer and Company mutually agree, Company will relay Customer's daily or standing nomination to Customer's Agent, gas supplier(s), and Transporter.

2.3 DISPATCHING. Customer will adhere to gas dispatching policies and procedures established by Company from time-to-time to facilitate service under this Agreement. Company will inform Customer of any changes in dispatching policies that may affect this Agreement as they occur.

2.4 RATE OF FLOW. The gas supply shall be transported to Customer at a (49)
rate of flow up to but not exceeding ________ cubic feet per hour at the point of delivery. Gas shall be delivered at such pressures and temperatures as may exist under operating conditions at Customer's service location. Operating pressures at this location shall normally be _______ psi.

(50) (51)

~~2.7~~ REFUSAL OR DISCONTINUANCE OF SERVICE (a) With notice, the Company may refuse or discontinue gas service for any of the following reasons: failure to pay amounts payable when due; breach of contract for service; failure to provide the Company with reasonable access to its property or equipment; when the Company is unable to furnish gas service to Customer because it cannot obtain permits or necessary right-of-way; when necessary to comply with any order or request of any governmental authority having jurisdiction.

(b) Upon such notice as is reasonable under the circumstances, the Company may temporarily discontinue gas service when necessary to make repairs, replacements, or changes in Company's equipment or facilities.

(c) Without notice the Company may disconnect gas service to Customer in the event of an unauthorized use of or tampering with Company's equipment or in the event of a condition determined to be hazardous to the Customer, to other customers of the Company, to the public, or to the Company's employees, equipment, or service.

(43) Insert "(a)"

(44) Insert "(a)"

(45) Insert "(a)"

(46) Is this correct?

(47) (48) make consistent with Article V, Paragraph 5.1

(49) Insert "(a)"

(50) Insert "2.5" and renumber remaining paragraphs

(51) Insert "reasonable"

Any discontinuance of service will not relieve Customer from Customer's obligations to the Company.

2.8 BALANCING. Customer and Company agree to balance daily delivery point nominations with actual deliveries (as defined in Paragraph 3.2) on an ongoing basis. Customer agrees to exert its best efforts to keep daily deliveries within five (5) — (52) percent of daily nomination. Customer and Company shall balance as operationally necessary, but no less than monthly. Customer or Customer's Agent shall be responsible for balancing receipt point nominations made to Transporter with receipt point deliveries made by Customer or Customer's Agent's gas supplier(s).

2.9 MONTHLY CASHOUT MECHANISM. Unless otherwise agreed, Customer's monthly imbalance will be corrected by a cashout mechanism. Customer's monthly imbalance is the difference between (1) the sum of Customer's daily nominations for the month and (2) Customer's actual metered use. Monthly volumetric imbalances will not be carried forward to the next calendar month.

Undertake Purchase Payment: If Customer utilizes less gas than the volume Customer nominated and delivered to NSP system, Customer shall sell the undertake gas to NSP. Customer shall be paid an Undertake Purchase Payment equal to the monthly imbalance times the Undertake Purchase Rate.

Monthly Imbalance %	Undertake Purchase Rate
100% to 98%	Index + Transporter's Firm Transportation (TF) Commodity rate(s)
(53) 98% to 90%	[Index + Transporter's TF Commodity rate(s)] x 0.75
(54) Less than 90%	[Index + Transporter's TF Commodity rate(s)] x 0.50

(5

Overtake Charge: If Customer utilizes more gas than the volume Customer nominated and delivered to the NSP system, Customer shall purchase the overtake gas from NSP. Customer shall be assessed an Overtake Charge equal to the monthly imbalance times the Overtake Rate.

Monthly Imbalance %	Overtake Purchase Rate
100% to 102%	Index + Transporter's Interruptible Transportation (IT) Commodity rate(s)
(55) 102% to 110%	[Index + Transporter's IT Commodity rate(s)] x 1.25
(56) Greater than 110%	[Index + Transporter's IT Commodity rate(s)] x 1.50

Index for Monthly Cashout. The Index being used is Inside FERC Gas Market Report's first of the month "Prices of Spot Gas Delivered to Pipelines" for Northern Natural (Demarcation). — (5? Applicable pipeline commodity rate consists of all interstate pipeline charges including GRI surcharge, Angus C. Anson fuel supply pipeline surcharge, fuel costs and commodity rate(s). All conditions of the monthly cashout mechanism apply.

* See next page

(52) Make consistent with Article V, Paragraph 5.1

(53) Insert "less than"

(54)(56) Should this read ?:

0 - 2 %

greater than 2% to 10%

greater than 10%

(55) Insert "greater than"

(57) Provide an example and label each charge included for each separate rate.

(58) Should this be eliminated as Argus Anson line is not interstate?

unless Customer and NSP agree otherwise. However, NSP will treat similarly situated customers on a non-discriminatory basis.

3.0 CHARGES. Commencing with the date of initial deliveries of gas by Company, the charges for this transportation service shall be according to Appendix A.

3.1 MONTHLY CUSTOMER CHARGE. As established in Appendix A. The customer charge shall not exceed the maximum charge on file with the South Dakota Public Utilities Commission.

3.2 VOLUME CHARGE. A Volume Charge equal to the product of (i) the actual deliveries made by Company to Customer during the billing period, and the fixed rate – (59) per MMBtu stated in Appendix A. The volume metered by NSP will be considered the actual volume delivered by Company to Customer. All volumes will be adjusted for Btu content and supercompressibility. The volume charge per MMBTU shall not exceed the maximum charge on file with the South Dakota Public Utilities Commission.

3.3 TAXES. In addition to the rates specified above, NSP shall collect any federal, state or local sales, use, excise, or other such taxes and fees that are legally effective and applicable to the service provided hereunder.

3.4 PENALTY PROVISION. Customer shall be liable for any balancing or other penalties imposed on NSP by Transporter and caused by Customer's actions. Customer shall also be liable for any incremental costs incurred by Company, if any, caused by Customer's failure to stay within the +/- 5 percent daily tolerance zone. (60)

3.5 ADDITIONAL CHARGE FOR USE DURING CURTAILMENT. If Customer fails to curtail use of gas hereunder when requested by Company, Customer shall pay, in addition to the appropriate above rates, either an amount equal to any payment Company is required to make to Transporter as a result of Customer's failure to curtail, or $10.00 per MMBtu of gas used in excess of the volume of gas to which customer is requested to curtail, whichever amount is greater. Such payments, however, shall not preclude Company from shutting off Customer's gas supply in the event of Customer's failure to curtail gas use thereof when requested by Company to do so.

(61) 4.0 PAYMENT OF BILLS. All bills are payable at Company's office on or before the ~~tenth~~ day succeeding the date bill is rendered for service supplied by Company in the preceding month. Should Customer fail to remit the full amount when due, Customer shall pay a Late Payment Charge of 1% to be added to the next month's bill after the date due.

4.1 DISPUTED BILLS. If Customer in good faith disputes the amount of any monthly billing or part thereof, Customer shall pay Company the amount Customer believes to be correct and notify Company in writing of the basis for disputing the bill. Company shall promptly investigate the matter and submit a corrected bill to Customer.

* See next page

(59) appendix A doesn't give a fixed rate or a contractual fixed rate. Clarify

(60) make consistent with article V, Paragraph 5.1

(61) Insert " 20 th"

If Customer has underpaid the amount actually due, Customer shall within five (5) days remit the additional amount due If Customer has overpaid the amount actually due, Company shall refund the overpayment by a credit to Customer's next bill. Company agrees to waive the late payment charge for the disputed portion of any bill if Customer disputed the bill in good faith

5.0 BILLING ADDRESSES, CURTAILMENT NOTICES, OTHER NOTICES The applicable addresses and/or telephone numbers for billing, curtailment notices, and other notices under this Agreement are provided in the Appendix C to this Agreement

6.0 TITLE TO GAS Unless otherwise agreed, Customer shall possess title to Customer's gas while being transported by Company However, Company may, if the parties mutually agree, take title to Customer's gas to arrange interstate or intrastate pipeline transportation from Transporter to Company's receipt point

6.1 WAIVER OF LIABILITY Customer shall hold Company blameless for any termination of gas service caused by failure of Customer, Customer's Agent, Customer's gas supplier(s) or Transporter to deliver gas to Company's designated receipt point

(62)

7.0 TELEMETERING Telemetering equipment shall be installed on Customer's premises in order to measure daily and monthly deliveries to Customer Company will install and maintain the telemetering facilities Customer shall provide, install and maintain a weatherproof phone service and electrical service outlet with appropriate grounding for telemetering equipment at Customer's cost

8.0 REGULATORY AUTHORITY This agreement is subject to all valid laws, orders, rules and regulations of any and all duly constituted authorities having jurisdiction over the subject matter herein and is subject to the receipt of any necessary authorization for the transportation service contemplated herein

9.0 REPORTING REQUIREMENTS Customer shall furnish to NSP all information as may be required or appropriate to comply with reporting requirements of duly constituted authorities having jurisdiction over the subject matter herein

10.0 CONFIDENTIALITY The terms of this contract, including but not limited to Customer's delivered price of gas, NSP's customer charge and volume charge, the volume of gas transported, and all other material terms of this contract shall be kept confidential by NSP and Customer, except to the extent that any information must be disclosed to a third party as required by law or for the purpose of effectuating transportation of the subject gas pursuant to this Agreement

11.0 SUCCESSION, ASSIGNMENT This Agreement shall inure to and be equally binding on the respective parties, their successors and assigns Neither party

(62) Make consistent with sheet 8, Paragraph 3.6 and provide language of who is responsible for these costs.

shall assign this Agreement and rights hereunder without the written approval of the other party. Such approval shall not be unreasonably withheld.

12.0 ENTIRE AGREEMENT; MODIFICATION AND WAIVER. This Agreement, together with all documents attached hereto which NSP has signed or initialed intending to make them a part hereof, constitutes the entire agreement between the parties relating to the transaction described herein and supersedes any and all prior oral or written understandings. No addition to or modification of any provision hereof shall be binding upon NSP, and NSP shall not be deemed to have waived any provision hereof or any remedy available to it unless such addition, modification or waiver is in writing and signed by a duly authorized employee of NSP.

13.0 SEVERABILITY. If any provision hereof is held to be unenforceable by final order of any regulatory authority or court of competent jurisdiction, such provision shall be severed herefrom and shall not affect the interpretation or enforceability of the remaining provisions hereof.

IN WITNESS WHEREOF, the parties have duly executed this Agreement effective the date and year first written above.

NORTHERN STATES POWER COMPANY	______________________
	Customer
By ______________________	By ______________________
Title ______________________	Title ______________________
Date ______________________	Date ______________________

(63) Throughout the tariffs references are made to specifications or provisions in Northern Natural Gas Company's tariff. Replace these specifications or provisions with the actual specifications or provisions provided in Northern's tariff.

APPENDIX A
GAS TRANSPORTATION AGREEMENT
DATED ______________
FOR
(Customer name)

I. Delivery Period

The Agreement and the rates, terms and conditions contained herein, will be in effect for a term commencing ________________, and continuing through ______________, and then shall be renegotiated.

(64)

II. Delivery Point and Charges

(a) Delivery Point

NSP will transport the Customer's gas supplies to customer's facility, located at ____________________________under this Agreement at the following rate:

(b) NSP Transportation Service Charges

(68) The maximum Customer Charge is $287.00 per month.
Transportation local delivery volume charge will not exceed $0.213 per MMBtu transported and not be less than $0.044 per MMBtu transported. (65)

(c) Annual Minimum Local Delivery Charge

Customer agrees to an Annual Minimum Local Delivery Charge of ___________ as determined by the Company.

System Exit Charges will also apply as determined by the Company. (66)

III. Contract Quantity

Customer nominates a maximum daily Contract Quantity of ______ MMBtu.

(67) NSP is not obligated to provide firm transportation service in excess of Customer's Contract Quantity unless NSP agrees to amend this Agreement in writing. However, NSP may at its option provide daily overrun transportation service to Customer on an interruptible basis if Customer so requests. The interruptible overrun local delivery charge per MMBtu shall be the same as the firm local delivery charge set forth above.

* See next page

(64) Insert "(s)"

(65) Insert " before applicable taxes and fees" if necessary.

(66) Provide tariff authority and basis for the calculation of charges.

(67) Insert " maximum daily"

(68) This applies to a specific customer. Need to revise so it is applicable to anyone.

APPENDIX B
DEFINITIONS

"Btu" shall mean British Thermal Unit and shall be the quantity of heat required to raise the temperature of one (1) pound of water one degree Fahrenheit at sixty (60) degrees Fahrenheit.

"Contract Quantity" shall mean the daily quantity of natural gas which NSP is obligated to deliver on a firm basis to Customer pursuant to this Agreement.

(69) "Contract Year" shall mean the twelve month calendar period set forth in Appendix A.

"Customer" shall mean Hutchinson Technology Inc. For purposes of this Agreement, the term Customer also includes Customer's Agent.

(70) "Customer's Agent" shall mean (if applicable) the party or entity designated by Customer in Nomination Statement to perform day-to-day supply and/or delivery management functions for Customer. Subject to NSP's approval, Customer may change such designation from time to time upon written notice to NSP.

"Delivery Point" shall mean the outlet side of the NSP meter located on NSP's natural gas distribution system at Customer's Plant service locations.

"FERC" means the Federal Energy Regulatory Commission or successor agency.

"Firm Transportation" shall mean transportation service which is not subject to interruption except for emergencies or for failure of Customer to deliver gas to NSP at the Receipt Point for transportation to Customer.

"Gas" shall mean natural gas, manufactured gas, or other forms of gaseous energy which conform to the quality specifications in Transporter's Tariff.

"Gas Day" shall mean the 24 hour period determined in accordance with Transporter's Tariff.

"Interruptible Transportation" shall mean transportation service which is subject to interruption at Company's option.

"MMBtu" shall mean one million (1,000,000) BTUs. One MMBtu is equal to one (1) "Dekatherm" or ten (10) "Therms."

(71) "Receipt Point" shall mean the inlet point of the NSP gas distribution system where NSP takes receipt of gas from Transporter.

* see next page

(69) Reconcile this with Original Sheet 4, Paragraph 1.3. Also appendix A doesn't specify a 12 month period.

(70) Insert "the"

(71) Is this accurate considering the Anson line?

Northern States Power Company
South Dakota-Gas
Development of Rate

Exhibit__(RLK-1)
Schedule 3

1.	Staff levelized revenue requirement	$73,938
2.	Annual throughput	480,726
3.	NSP-Gas transportation rate	$0.154
4.	Angus Anson Pipeline rate	0.045
5.	Total maximum transportation rate	$0.199

Sources
Line 1: Staff Exhibit__(GAR-1)
Line 2: Winter's Schedule 2 (306 times 1571)
Line 3: Line 1 divided by line 2
Line 4: Winter's Schedule 2

Rebuttal Testimony and Schedules
Mr. James A. Smith

Before the Public Utilities Commission
State of South Dakota

In the Matter of the Application for an Order
Establishing a Natural Gas Utility, and to
Establish Initial Natural Gas Transportation Rates for
Northern States Power Company

Docket No. NG97-021
Exhibit ___ (JAS-2)

December 1998

EXHIBIT

Cost Support, Maximum Rates, and Proposed Rates

Q. Please state your name, business address, and position with Northern States Power Company.

A. My name is James A. Smith. I am employed by Northern States Power Company ("NSP" or "the Company"), 414 Nicollet Mall, Minneapolis, Minnesota, 55401, as a Senior Regulatory Consultant in the Regulatory Services department.

Q. What are your current responsibilities?

A. I prepare various financial and operational analyses, jurisdictional cost of service studies and revenue requirement determinations. This involves the coordination and consolidation of operating revenue, expense and capital investment data from departments throughout the Company, and assignment and allocation of the appropriate amounts to utility and regulatory jurisdictions. My internal NSP clients include NSP's Gas Utility operation, which has historically provided retail gas service in North Dakota and Minnesota; and Viking Gas Transmission Company, a wholly-owned interstate gas pipeline subsidiary of NSP.

Q. What is your educational and professional background?

A. Schedule 1 contains a complete resume of my educational and professional background.

Q. Have you previously testified before this Commission?

A. No I have not.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to supplement the direct testimony filed by John Winter in this proceeding and provide updated cost of service information for the NSP-South Dakota Region (NSP-SD) intrastate natural gas distribution pipeline which serves the Sioux Empire Development Park 5 in Sioux Falls, South Dakota. I will also provide updated cost of service information which supports the maximum rates (for transportation service and the customer charge) proposed by Mr. Winter

Q. Please describe the effect of the updated cost of service data on the development of transportation service rates and the monthly customer charge.

A. The maximum rate per MCF for transportation service on the 4.5 inch NSP-SD lateral pipeline is $0.194 per MCF. The proposed maximum customer charge is $290 per month. The updated maximum pipeline rate is developed on Schedule 2 of my exhibits. Schedules 3 through 6 support those calculations. The schedules are similar to those provided by Mr. Winter in his direct testimony; where much of the data is the same or has been updated or corrected as I will describe further. I adopt Mr. Winter's direct testimony and will act as the Company's cost of service witness for the hearings.

Q. Please describe the adjustments you made to the original cost of service filed by Mr. Winter.

A. The cost of service was updated for the actual constructed cost of the 4.5 inch lateral pipeline and the cost of the initial HTI meter set, as recorded on the books and records of the Company. Also, virtually all of the adjustments or corrections SDPUC Staff identified in its direct testimony were incorporated into my updated cost of service. I believe the only difference between Staff's proposal and my cost of service version is the selection of the discount rate used to develop the levelized annual revenue requirement factor. Staff used the overall weighted cost of capital as the discount rate whereas I used a discount rate that was a "net of tax" rate based on the overall cost of capital. I discuss this issue further below.

Q. What was the total cost of the pipeline project that you incorporated into your cost of service?

A. The total cost of the pipeline project was $454,853. A copy of the cover page to NSP-SD's response to SDPUC Staff data request No. 4 - 4 is shown as Schedule 8 in exhibits accompanying my testimony. The cost of the initial meter set ($8,521) was incorporated into the calculation of the customer charge for Hutchinson Technology, Inc. (HTI), NSP-SD's first gas customer.

Q. Please identify the SDPUC Staff adjustments and corrections that you incorporated into your cost of service.

A. With regard to pipeline operation and maintenance (O & M) expenses, Mr. Knadle recommended specific adjustments to line items for the replacement of ACA supplemental service with Northwestern Public Service standby service, lower Office of Pipeline Safety Assessments and regulatory fees. These adjustments reduce the Company's original filed O & M expense base amount by $1,690 to an amount of $18,164. I have incorporated those changes into my cost of service model and on Schedule 5 of my exhibit.

Q. What other SDPUC Staff adjustments and corrections have you incorporated into your cost of service model?

A. Other adjustments or corrections were identified in Mr. Rislov's testimony and relate to property taxes, depreciation and income taxes.

Property taxes: In my cost of service model I have incorporated a property tax calculation based on a valuation of eighty five percent of original cost. I have adjusted the base period effective tax rate to 2.341%. I have changed the escalation of property taxes to a rate of 3% from the former rate of 3.5 %.

Depreciation: Depreciation rates certified by the Minnesota Public Utilities Commission are also applied to capital asset accounting procedures in the

North and South Dakota jurisdictions. The rates last certified in Docket No. E,G002/D-97-1307 (order dated December 1997) for steel transmission and distribution mains provide an average service life of 45 years and negative salvage of -30 %. I have incorporated this rate into my cost of service model.

<u>Income taxes</u>: As Mr. Rislov points out in his testimony, NSP-SD's original cost of service model failed to consider the "tax on tax" effect when calculating pro forma income taxes on the equity return. I have corrected the model to calculate income taxes at a factor of 53.846% applied to the equity return.

Q. Please explain the "net of tax" discount rate used to calculate the net present value of the annual revenue requirements of the project's service life.

R. The "net of tax" rate of return calculation is shown on Schedule 6, Column E. The "net of tax" calculation is based on the weighted cost of capital which is also shown on Schedule 6 at Column D. Staff is not taking issue with NSP-SD's proposed 8.7314% overall return on investment and requested 11.25% return on common stock equity.

The "net of tax" return is used for evaluating investment alternatives and is considered the after tax cost of invested capital. The after-tax cost of an equity investment in plant and facilities is the weighted cost of equity capital. The financed or debt portion of a plant investment has a financial benefit because of the tax deductibility of interest for calculating the income tax liability. The after-tax cost of the debt portion of invested debt capital is determined by multiplying the weighted cost of debt by one minus the tax rate (35% being the tax rate in this case). The "net of tax" rate of return used as the discount rate to calculate the net present value of annual revenue requirements was 7.5744%.

Q. Should any additional changes be made to the way the proposed monthly customer charge was calculated?

A. No. I have updated the capital costs for the initial installation of the HTI meter set. An additional meter will be installed at HTI in 1999. These costs can be updated in the report to the Commission recommended by Mr. Rislov. An analysis of the cost of meter reading and billing and account expense can also be provided when actual operating history becomes available. For now, the projected $60 per month cost to cover meter reading, billing and customer accounting is a reasonable projection. The meter reading costs will involve labor and related costs, vehicle costs for travel to the site to obtain readings and costs associated with billing, collection and customer accounting matters.

Q. Is NSP-SD willing to review the cost of service in 2000, based on 1999's operating results?

A. Yes, we can accommodate Staff's recommendation since 1999 will be NSP-SD's first full year of operating experience for the intrastate pipeline facilities. However, NSP-SD would suggest the report be filed on May 1, 2000, because May 1st is the date NSP typically files its jurisdictional gas and electric reports in its other jurisdictions (North Dakota and Minnesota) for the prior actual calendar year. Jurisdictional cost separations may affect the cost of service review for the intrastate pipeline rates in question in the instant proceeding, and a May 1st filing date would thus be both administratively convenient and provide a more accurate report.

Q. Does that conclude your testimony?

A. Yes.

AFFIDAVIT

STATE OF MINNESOTA)
)
COUNTY OF HENNEPIN)

Affiant, having been first sworn, on oath deposes and says:

That he has read the foregoing testimony and if asked the questions therein his answers in response would be as shown;

That the facts contained in said answers are true to the best of his knowledge and belief.

James A. Smith

James A. Smith

SUBSCRIBED AND SWORN to me before me this 22nd day of December, 1998.

Sharon K. Lassek

Notary Public

SHARON K. LASSEK
NOTARY PUBLIC-MINNESOTA
HENNEPIN COUNTY
My Commission Expires 1/31/2000

James A. Smith
Senior Regulatory Consultant - Regulatory Services
414 Nicollet Mall, Minneapolis, Minnesota 55401

CURRENT RESPONSIBILITIES (Northern States Power Company)
(March 1991 - Present)
Within the scope of this position, jurisdictional cost of service studies and revenue requirement determinations are prepared for the Company. Data is gathered from various departments throughout the Company related to revenues, expenses and plant investment. Appropriate assignments and allocations are made of amounts to utility and jurisdiction. Internal clients are Northern States Power Company - Gas Utility and Viking Gas Transmission Company.

PREVIOUS EMPLOYMENT

London Diagnostics, Inc., Controller	1990-1991
JAS & Associates, Contract Consulting	
Services to Natural Gas Utilities	1989-1990
Midwest Energy Company; Director, Rates	1981-1989
Assistant Director, Rates	1977-1981
Rate Analyst	1967-1977

EDUCATION

St. Thomas University, Bachelor of Arts Accounting

PREVIOUS TESTIMONY

F.E.R.C.	Cost of Service	RP98-290-000
Minnesota	Revenue Requirements	GR-97-1606
Minnesota	Revenue Requirements	GR-92-1186
Iowa	Revenue Requirements	RPU-85-19
Florida	Capital Structure	840268
Minnesota	Capital Structure	GR-83-333
Minnesota	Capital Structure	GR-81-780
Iowa	Capital Structure	RPU-82-47
Minnesota	Revenue Requirements	GR-80-472
Iowa	Revenue Requirements	RPU-77-15/78-29
Iowa	Revenue Requirements	RPU-76-44
Minnesota	Revenue Requirements	GR-77-221
Iowa	Revenue Requirements	RPU-502
Iowa	Revenue Requirements	RPU-367

Northern States Power Company - South Dakota **Schedule 2**
Gas Operations
Development of Rates
Maximum and Proposed Large Volume Transportation
Customer Charge

The natural gas maximum transportation rate developed below pertains to NSP's newly installed 4.5" lateral pipeline extending from the Angus Anson Supply line to the Sioux Empire Development Park 5, which will serve HTI. The proposed maximum rate in Column B of $0.239 per Mcf includes $0.045 per Mcf for use of the Angus Anson line (Line 4). That rate is a pass-through to HTI. NSP-SD is not seeking approval of the Angus Anson portion of the rate. For information, Schedule 7 of Exhibit 4 shows a calculation supporting the $0.045 per Mcf charge for use of the Angus Anson line.

	Amounts (A)		Maximum Rates (B)
4.5" NSP-SD Lateral Pipeline Rate			
(1) Annualized Revenue Requirements	$93,290		
(2) Pipeline MCF Capacity per Hour	306		
(3) Hours Per Year @ Capacity	1,571	480,726 Mcf	$0.194
(4) Angus Anson Pipeline Rate			$0.045
(5) Total Transportation Rate			$0.239
Customer Charge			
(6) Investment in Metering at HTI	$19,021		
(7) Annualized Fixed Charge Rate less O&M	14.49%		
(8) Annualized Metering Revenue Requirements	$2,756		
(9) Annual Meter Reading and Billing Costs	$720		
(10) Total Customer Costs Supporting Customer Charge	$3,476	Monthly	$290

Sources and Notes:

Line 1: Revenue Requirements per Schedule 3, Page 2 of 3.
Line 2: 90% of Pipeline capacity of 340 Mcf/Hr.
Line 3, Col A: Hours per Year equivalent for HTI @ capacity.
Line 3, Col. B: Line 1/(Line 2 times Line 3), Col. A.
Line 4, Column B: Negotiated rate for Angus C. Anson pipeline. See text for further discussion.
Line 5, Column B: Total maximum natural gas transportation supported by cost evidence.
Line 6: Meter investment at HTI per Schedule 5.
Line 7: Fixed charge rate from Schedule 3, Page 2 of 3, less O&M component.
Line 8: Line 6 times Line 7.
Line 9: Meter reading, billing, and service costs (O&M) at $60 per month.
Line 10: Total customer costs in Col. A. Monthly maximum customer charge in Col. B.

Northern States Power Company - South Dakota
Gas Operations
Statement M - Cost of Service
4.5" NSP-SD Lateral Pipeline Levelized Annual Revenue Requirement - See Page 3 of 3 for Sources and Notes

Schedule 3
Page 1 of 3

Capital Structure (CS)	Cost	Weight	Weighted Cost	Net of Tax Cost
(CS1) Equity	11.25%	45.220%	5.0872%	5.0872%
(CS2) Preferred Stock	5.14%	6.580%	0.3383%	0.3383%
(CS3) Long-term Debt	7.10%	40.974%	2.9072%	1.8897%
(CS4) Short-term Debt	5.52%	7.226%	0.3997%	0.2591%
(CS5)		100.000%	8.7314%	7.5744%

	Time Period (A)	Year (B)	Plant in Service Additions (C)	Net Investment Rate Base (D)	Equity Return (E)	Taxes on Equity Return (F)	Debt Return (G)	Book Dep'n (H)	Operating Expenses (I)	Property Taxes (J)	Total Revenue Requirement (K)	Present Value of Revenue Deficiency or (Excess) Discounted At 7.5744% (L)
(1)	0	1997	454,853	448,283	12,161	6,548	7,410	6,570	3,027	1,775	37,491	37,491
(2)	1	1998	0	435,142	23,965	12,904	14,602	13,141	18,688	10,968	94,269	87,631
(3)	2	1999	0	422,001	23,252	12,520	14,168	13,141	19,228	11,297	93,606	80,889
(4)	3	2000	0	408,861	22,539	12,137	13,734	13,141	19,783	11,635	92,969	74,681
(5)	4	2001	0	395,720	21,826	11,753	13,299	13,141	20,355	11,985	92,358	68,967
(6)	5	2002	0	382,579	21,113	11,369	12,865	13,141	20,942	12,344	91,774	63,706
(7)	6	2003	0	369,439	20,400	10,985	12,430	13,141	21,547	12,714	91,218	58,861
(8)	7	2004	0	356,298	19,688	10,601	11,996	13,141	22,169	13,096	90,690	54,400
(9)	8	2005	0	343,157	18,975	10,217	11,562	13,141	22,810	13,489	90,192	50,292
(10)	9	2006	0	330,016	18,262	9,833	11,127	13,141	23,468	13,893	89,724	46,508
(11)	10	2007	0	316,876	17,549	9,449	10,693	13,141	24,146	14,310	89,288	43,023
(12)	11	2008	0	303,735	16,836	9,065	10,258	13,141	24,843	14,739	88,883	39,813
(13)	12	2009	0	290,594	16,123	8,681	9,824	13,141	25,561	15,182	88,511	36,855
(14)	13	2010	0	277,454	15,410	8,298	9,390	13,141	26,299	15,637	88,173	34,129
(15)	14	2011	0	264,313	14,697	7,914	8,955	13,141	27,058	16,106	87,871	31,617
(16)	15	2012	0	251,172	13,984	7,530	8,521	13,141	27,840	16,589	87,604	29,302
(17)	16	2013	0	238,031	13,271	7,146	8,086	13,141	28,643	17,087	87,374	27,167
(18)	17	2014	0	224,891	12,558	6,762	7,652	13,141	29,471	17,600	87,183	25,199
(19)	18	2015	0	211,750	11,845	6,378	7,217	13,141	30,322	18,128	87,031	23,384
(20)	19	2016	0	198,609	11,132	5,994	6,783	13,141	31,197	18,672	86,919	21,709
(21)	20	2017	0	185,469	10,419	5,610	6,349	13,141	32,098	19,232	86,848	20,164
(22)	21	2018	0	172,328	9,706	5,226	5,914	13,141	33,025	19,809	86,821	18,739
(23)	22	2019	0	159,187	8,993	4,843	5,480	13,141	33,979	20,403	86,835	17,423
(24)	23	2020	0	146,047	8,280	4,459	5,045	13,141	34,960	21,015	86,900	16,208
(25)	24	2021	0	132,906	7,567	4,075	4,611	13,141	35,969	21,645	87,008	15,085
(26)	25	2022	0	119,765	6,854	3,691	4,177	13,141	37,008	22,295	87,165	14,048
(27)	26	2023	0	106,624	6,141	3,307	3,742	13,141	38,077	22,964	87,371	13,090
(28)	27	2024	0	93,484	5,428	2,923	3,308	13,141	39,176	23,653	87,629	12,204
(29)	28	2025	0	80,343	4,716	2,539	2,873	13,141	40,308	24,362	87,938	11,383
(30)	29	2026	0	67,202	4,003	2,155	2,439	13,141	41,471	25,093	88,302	10,627
(31)	30	2027	0	54,062	3,290	1,771	2,004	13,141	42,669	25,846	88,721	9,926
(32)	31	2028	0	40,921	2,577	1,387	1,570	13,141	43,901	26,621	89,197	9,276
(33)	32	2029	0	27,780	1,864	1,004	1,136	13,141	45,169	27,420	89,732	8,675
(34)	33	2030	0	14,639	1,151	620	701	13,141	46,473	28,242	90,328	8,118
(35)	34	2031	0	1,499	438	236	267	13,141	47,815	29,090	90,986	7,601
(36)	35	2032	0	(11,642)	(275)	(148)	(168)	13,141	49,196	29,962	91,708	7,122
(37)	36	2033	0	(24,783)	(988)	(532)	(602)	13,141	50,617	30,861	92,496	6,677
(38)	37	2034	0	(37,923)	(1,701)	(916)	(1,036)	13,141	52,078	31,787	93,352	6,265
(39)	38	2035	0	(51,064)	(2,414)	(1,300)	(1,471)	13,141	53,582	32,741	94,279	5,881
(40)	39	2036	0	(64,205)	(3,127)	(1,684)	(1,905)	13,141	55,129	33,723	95,277	5,525
(41)	40	2037	0	(77,345)	(3,840)	(2,068)	(2,340)	13,141	56,721	34,735	96,349	5,194
(42)	41	2038	0	(90,486)	(4,553)	(2,452)	(2,774)	13,141	58,359	35,777	97,498	4,885
(43)	42	2039	0	(103,627)	(5,266)	(2,835)	(3,209)	13,141	60,045	36,850	98,725	4,599
(44)	43	2040	0	(116,768)	(5,979)	(3,219)	(3,643)	13,141	61,778	37,955	100,033	4,332
(45)	44	2041	0	(129,908)	(6,692)	(3,603)	(4,077)	13,141	63,562	39,094	101,423	4,083
(46)	45	2042	0	(136,479)	(7,226)	(3,891)	(4,403)	6,570	65,398	40,267	96,714	3,619
(47) Project Totals			454,853		384,951	207,281	234,550	591,332	1,685,963	1,018,685	4,122,770	1,186,377

Northern States Power Company - South Dakota **Schedule 3**
Gas Operations **Page 2 of 3**
Statement M - Cost of Service
4.5" NSP-SD Lateral Pipeline Levelized Annual Revenue Requirement - See Page 3 of 3 for Sources and Notes

LARR						
(RR1)	$16,757	$9,023	$10,210	$13,638	$27,388	$16,336

	LARR - As a % of Original Cost					
(RR2)	3.68%	1.98%	2.24%	3.00%	6.02%	3.59%

"Net of Tax" Discount Rate

	7.5744% Present Value of Equity Return	7.5744% Present Value of Taxes on Equity Return	7.5744% Present Value of Debt Return	7.5744% Present Value of Book Depreciation	7.5744% Present Value of Operating Expenses	7.5744% Present Value of Current Property Taxes	Present Value of Revenue Requirements or (Excess)	Summary LARR	Amounts
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
(1)	12,161	6,548	7,410	6,570	3,027	1,775	37,491	Return	7.90%
(2)	22,278	11,996	13,574	12,215	17,373	10,195	87,631	Depreciation	3.00%
(3)	20,093	10,819	12,243	11,355	16,616	9,762	80,889	O&M and Prop Taxes	9.61%
(4)	18,106	9,749	11,032	10,556	15,892	9,347	74,681		
(5)	16,298	8,776	9,931	9,813	15,199	8,949	68,967	Total LARR	20.51%
(6)	14,656	7,892	8,930	9,122	14,537	8,569	63,706		
(7)	13,164	7,088	8,021	8,479	13,904	8,204	58,861		
(8)	11,809	6,359	7,196	7,882	13,298	7,855	54,400	Plant In Service	$454,853
(9)	10,580	5,697	6,447	7,327	12,719	7,521	50,292		
(10)	9,466	5,097	5,768	6,811	12,165	7,202	46,508	Annual Requirement	$93,290
(11)	8,456	4,553	5,152	6,332	11,635	6,895	43,023		
(12)	7,541	4,061	4,595	5,886	11,128	6,602	39,813		
(13)	6,713	3,615	4,091	5,472	10,643	6,321	36,855		
(14)	5,965	3,212	3,634	5,086	10,179	6,053	34,129		
(15)	5,288	2,847	3,222	4,728	9,736	5,795	31,617		
(16)	4,677	2,519	2,850	4,395	9,312	5,549	29,302		
(17)	4,126	2,222	2,514	4,086	8,906	5,313	27,167		
(18)	3,630	1,954	2,212	3,798	8,518	5,087	25,199		
(19)	3,183	1,714	1,939	3,531	8,147	4,871	23,384		
(20)	2,780	1,497	1,694	3,282	7,792	4,664	21,709		
(21)	2,419	1,303	1,474	3,051	7,453	4,465	20,164		
(22)	2,095	1,128	1,276	2,836	7,128	4,275	18,739		
(23)	1,804	972	1,099	2,636	6,817	4,094	17,423		
(24)	1,544	832	941	2,451	6,520	3,919	16,208		
(25)	1,312	706	799	2,278	6,236	3,753	15,085		
(26)	1,105	595	673	2,118	5,965	3,593	14,048		
(27)	920	495	561	1,969	5,705	3,440	13,090		
(28)	756	407	461	1,830	5,456	3,294	12,204		
(29)	610	329	372	1,701	5,218	3,154	11,385		
(30)	482	259	294	1,581	4,991	3,020	10,627		
(31)	368	198	224	1,470	4,774	2,892	9,926		
(32)	268	144	163	1,367	4,566	2,769	9,276		
(33)	180	97	110	1,270	4,367	2,651	8,675		
(34)	103	56	63	1,181	4,177	2,538	8,118		
(35)	37	20	22	1,098	3,995	2,430	7,601		
(36)	(21)	(12)	(13)	1,021	3,821	2,327	7,122		
(37)	(71)	(38)	(43)	949	3,654	2,228	6,677		
(38)	(114)	(61)	(70)	882	3,495	2,133	6,265		
(39)	(151)	(81)	(92)	820	3,343	2,042	5,881		
(40)	(181)	(98)	(110)	762	3,197	1,956	5,525		
(41)	(207)	(111)	(126)	708	3,058	1,872	5,194		
(42)	(228)	(123)	(139)	659	2,925	1,793	4,886		
(43)	(245)	(132)	(149)	612	2,797	1,717	4,599		
(44)	(259)	(139)	(158)	569	2,675	1,644	4,332		
(45)	(269)	(145)	(164)	529	2,559	1,574	4,083		
(46)	(270)	(146)	(165)	246	2,447	1,507	3,619		
(47)	212,957	114,669	129,759	173,322	348,062	207,608	1,186,377		

Northern States Power Company - South Dakota
Gas Operations
Levelized Annual Revenue Requirement
Sources and Notes - Statement M

Schedule 3, Page 1 of 3:

Lines CS1 - CS5: 1996 Actual NSP Capital Structure. See Schedule 6 of this exhibit. The components of the overall return of 8.7314% are used to determine the annual cost of financing the project. The net of tax return is used to discount the 45 year amounts to the present value. The Return on Common Equity based on most recent authorized in Docket EL92-016.

Line 1, Column A: Time Period for present value calculation.

Line 1, Column B: Year in service. Present value is life cycle beginning in 1995.

Line 1, Column C: Pipeline investment.

Lines 1 - 46, Column D: Net investment reduced for accumulated depreciation for each year.

Line 1, Column E: One-half of end of first year investment applied to weighted common and preferred equity cost).

Line 1, Column F: Income taxes on the equity return determined in Col. E. "Gross up" tax factor is .5384615.

Line 1, Column G: One-half of end of year investment applied to the weighted debt cost.

Line 1, Column H: Book depreciation based on 45 year book life and 30% negative salvage value (2.889%).

Line 1, Column I: See Schedule 5. Amount reflects two months of expense in 1997.

Line 1, Column J: Property Tax estimate based on Staff witness Rislov principles, page 5, escalated annually at 3.5 percent.

Lines 1 - 46, Column K: Sum of Columns E - II for corresponding lines.

Lines 1 - 46, Column L: Present Value of Column K @ Net of Tax Cost of Capital.

Lines 2 - 46, Column E: Average net investment applied to weighted common and preferred equity costs.

Lines 2 - 46, Column F: Income taxes on the equity return determined in Col. E. "Gross up" tax factor is .5384615.

Lines 2 - 46, Column G: Average net investment applied to the weighted debt cost.

Lines 2 - 46, Column H: Book depreciation based on 45 year book life and negative 30% salvage value (2.889%).

Lines 2 - 46, Column I: Operating expenses per Schedule 5, escalated at rate determined on Schedule 5.

Lines 2 - 46, Column J: Estimated property taxes based on Staff witness Rislov principles, page 5, escalated annually at 3.5 percent.

Line 47: Check totals.

Schedule 3, Page 2 of 3:

Line RR1: The levelized annual revenue requirements of the items reflected in the columns below.

Line RR2: The percent of original investment cost for the levelized revenue requirements shown on RR1.

Lines 1 - 46, Columns A - G: Annual present value of each revenue requirement component shown. The nominal amounts are from Schedule 3, Page 2 of 3, Columns E - J.

Lines 1 - 46, Column E: Annual present value of total revenue requirements. Matches Column L on Schedule 3, Page 1 of 3.

Line 47, Columns A - G: Total of annual present value amounts for each column. These amounts are then discounted to arrive at the amounts shown on Line RR1.

Columns H and I: Summary of Levelized Annual Revenue Requirements. Column H describes each component. Column I shows the LARR rate by component and the total. The LARR rate shown on Line 5, Column I is applied to the original cost of the pipeline shown on Line 8, Column I to arrive at the levelized annual revenue requirements shown on Line 10, Column G. This amount is carried forward to Schedule 2 to determine the pipeline rate used to serve HTI (4.5" lateral).

Northern States Power Company - South Dakota **Schedule 4**
Gas Operations
Plant Investment - 4.5" Lateral HTI Line

	Pipeline Costs, As Classified (A)	Amounts (B)
	Major Source Codes - Alpha Summary	
(1)	General, including transportation	$274,601
(2)	Overhead	46,058
(3)	Labor	22,611
(4)	Material	92,849
(5)	Interest	18,734
(6)	Total Pipeline Project Costs	$454,853
(7)	Customer meter at HTI	$8,521
(8)	Additional meter at HTI in 1999	10,500
(9)	Total Meter Costs at HTI	$19,021

Sources and Notes:

Lines 1 - 5: Actual pipeline original cost investment. SDPUC Staff Data Request No. 4 - 4

Line 6: Total actual pipeline original cost investment.

Lines 7 - 8: Meter Costs Phase I and II.

Line 9: Total Meter Costs. Used for Customer Charge.

Northern States Power Company - South Dakota **Schedule 5**
Gas Operations
Operating Expenses (O&M)
Statement H (Revised)

All of the O&M on this Schedule pertains to the NSP-SD 4.5" lateral pipeline that iwll serve HTI.	Amount (A)	Annual Escalator (B)	1 Year Escalated Amount (C)
(1) NSP - Operating and Maintenance Training, readings, patrolling of line by Angus Anson Plant personnel	$8,154	3.0%	$8,399
(2) NWPS contract service Support and emergency services by NWPS	$2,130	3.0%	$2,194
(3) Services - NSP-SD Management and support	$7,200	3.0%	$7,416
(4) Insurance Estimated Annual Fee	$100	0.0%	$100
(5) OPS Assessment Estimate of Office of Pipeline Safety Assessments	$330	0.0%	$330
(6) Regulatory Fees Gross Receipts Tax Estimate	$250	0.0%	$250
(7) Total	$18,164	2.9%	$18,688

Sources and Notes:

Line 1, Column A: Direct costs of pipeline operations per NSP-SD Gas Operations budget. Consists of 12 hours per month at loaded labor of $37.56/hour and $20/hour for vehicle usage.

Line 2, Column A: Supplemental emergency service from Northwestern Public Service Company, $2,100 annually. One call per month @ $30 per call

Line 3, Column A: Services received from NSP-South Dakota personnel. Ten hours/month @ $60/hour

Line 4, Column A: Insurance costs @ $0.03/$100 of investment per NSP's Risk Mgmt. Dept.

Line 5, Column A: Office of Pipeline Safety assessment as adjusted by SDPUC Staff

Line 6, Column A: Annual regulatory fees based on Gross Receipts Tax. Calculation based on SDPUC Staff adjustment.

Column B: Annual escalators based on expectations of price inflation.

Column C: One-year escalations of amounts in Column A.

Line 7: Columns A and C are summarized and used to derive the overall escalator in Column B.

Northern States Power Company - South Dakota **Schedule 6**
Gas Operations
Cost of Capital - Statement G
1996 Historical Year

	Capitalization Amounts ($thousands) (A)	Ratio (B)	Rate (C)	Weighted Costs (D)	Net of Tax Return (E)
(1) Long Term Debt	$1,497,303	40.9736%	7.0953%	2.9072%	1.8897%
(2) Short Term Debt	264,064	7.2261%	5.5173%	0.3987%	0.2591%
(3) Preferred Stock	240,469	6.5804%	5.1408%	0.3383%	0.3383%
(4) Common Equity	1,652,477	45.2199%	11.2500%	5.0872%	5.0872%
(5) Total Capitalization	$3,654,313				
(6) **Required Rate of Return**				**8.7314%**	
(7) **Net of Tax Return**					**7.5744%**

Sources and Notes:

1996 actual capitalization and costs for NSP-Minnesota Company.

Column A: per NSP books and records.

Column B: Column A amounts for Lines 1 - 4 compared to the total shown in Column A, Line 5.

Column C: per NSP books and records.

Column D: Product of Column B times Column C. These weighted costs are used to determine the financing costs on a year-by-year basis.

Column E: Net of tax rates. Long and short term debt returns absent the tax effect due to their deductibility on NSP's federal income tax return. Tax rate @ 35%. Rates in Lines 1 and 2 consist of the rates in Column D multiplied times 1 minus the tax rate, or 0.65. The net of tax rate if used to discount the 45 year annual amounts to the present value.

Northern States Power Company - South Dakota **Schedule 7**

Gas Operations

Cost Support for Transfer Price Between South Dakota Gas Operations & NSP Generation for Use of the Angus Anson Supply Line

The calculations below are for illustrative purposes to support the amount per Mcf to be transferred between NSP-SD Gas Operations and NSP-Generation for NSP-SD's use of the Angus Anson supply pipeline. A rate of $0.045 per Mcf will be passed on by NSP-SD to HTI as part of their total distribution rate. NSP-SD does not seek SDPUC jurisdiction over that line, nor approval of the negotiated rate. This Schedule is included as information only.

12" NSP-Generation Line (Angus Anson Supply)	Amounts (A)	Unit Rate (B)
(1) Investment	$3,139,426	
(2) Annualized Fixed Charge Rate	20.51%	
(3) Annualized Revenue Requirements	$643,896	
(4) Pipeline MCF Capacity per Hour	4,900	
(5) Hours Per Year @ Capacity	3,200	$0.0411

Sources and Notes:

- Line 1: NSP-Generation recorded investment in Angus Anson pipeline.
- Line 2: Fixed charge rate developed for NSP line. Used as a proxy for a specific Angus Anson pipeline rate.
- Line 3: Line 4 times Line 5.
- Line 4: Capacity of Angus Anson 12" line.
- Line 5: Hours per Year equivalent at capacity. Amount is twice the NSP-SD HTI lateral based on significantly greater utilization of the larger "transmission" pipeline vs. a smaller distribution pipeline. This relationship is typical within the industry.
- Line 5: Col. B: Line 3/(Line 4 times Line 5)

Schedule 8

Northern States Power Company (Minn)
NSP-SD Gas Operations
Before the South Dakota PUC
Docket NG97-021
Fourth Set - SDPUC Staff Data Requests
Response to: No. 4

☐ **Proprietary**

X Non-Proprietary

Question:
NSP witness Winter's Schedule 4 lists project costs and meter costs. NSP's response to DR-1, question 18, provided an incomplete list of invoices and other support for those costs. Update the response to DR-1, question 18, and provide support for all rate based amounts, including easements.

Response:
Attached is a detailed listing of capitalized amounts for the steel and plastic portions of the pipeline. Invoice backup is not readily available in the form requested. However, the attached detail, extracted from NSP's capital asset books and records, supports NSP's recorded amounts for this project, and summarizes to $454,853.12.

Unlike the somewhat similar AMPIP project, it is difficult to reconstruct the recorded amounts with specific invoices. In contrast, the pipeline project is much more like an NSP distribution project which includes NSP labor, warehoused material, and supplies and services purchased under various purchase orders. In this way, reviewing and substantiating the amounts is similar to that used by the Staff in reviewing electric rate base amounts within previous cases.

Response By John Winter
Title: Sr. Regulatory Consultant
Company: NSP

Rebuttal Testimony and Schedules
Jamie C. Seitz

RECEIVED
DEC 23 1998
SOUTH DAKOTA PUBLIC UTILITIES COMMISSION

Before the South Dakota Public Utilities Commission
State of South Dakota

In the Matter of the Application for An Order Establishing
A Natural Gas Utility, and To Establish Initial
Natural Gas Transportation Rates for
Northern States Power Company

Docket No. NG97-021

RATE DESIGN AND TARIFF CONDITIONS

December 1998

EXHIBIT
9

TARIFF TERMS AND CONDITIONS
REBUTTAL TESTIMONY
JAMIE C. SEITZ
Docket No. NG97-021

Q. Please state your name, position and business address with Northern States Power Company ("NSP" or the Company").

A. My name is Jamie Seitz. I am the Manager of Gas Rates and Planning. My business address is 825 Rice Street, St. Paul, Minnesota 55117.

Q. What are your current responsibilities?

A. I am responsible for the management of the Company's gas rate design activities in the Minnesota, North Dakota and Arizona jurisdictions. In addition to having supervisory responsibilities for the Gas Rates area, I am responsible for the development of class cost of service studies, special rate studies, the administration and preparation of purchased gas adjustment ("PGA") filings, and the overall design of gas rate tariffs for the Company.

Q. What is your educational and professional background?

A. Schedule 1 is a summary of my educational and professional background.

Q. What is the purpose of your testimony?

A. Mr. Robert L. Knadle of the South Dakota Public Utilities Commission Staff ("Staff") filed testimony recommending various corrections or changes to the proposed gas Transportation Service Tariff ("Tariff") and the Transportation Service Agreement ("TSA") filed by NSP-SD. I will respond to this aspect of Mr. Knadle's testimony, and one recommendation by Mr. Rislov of Staff. Mr. Jim Smith will respond on various cost adjustments proposed by Mr. Knadle. I will also file testimony regarding additional tariff changes now proposed by NSP-SD.

Q. Please describe the purpose of the Tariff.

R. When NSP-SD originally filed its application in December of 1997, NSP-SD only specifically contemplated serving the Hutchinson Technology, Inc. ("HTI") plant in a newly annexed area of Sioux Falls. However, the proposal was filed as a "generally available" tariff so NSP-SD could also serve other customers, as we do under our South Dakota Electric Rate Book. Since the Commission accepted the Tariff, NSP-SD has in fact begun serving two other customers (the Minnehaha County Highway Department and the Jans Corporation). NSP-SD is now negotiating with the City of Sioux Falls to finalize a gas franchise. So NSP-SD is progressing toward growth in its natural gas operations in South Dakota, and is providing a competitive energy alternative for customers like HTI.

Q. Please respond to the Tariff revisions proposed by Mr. Knadle.

A. Many of the suggestions are minor corrections, which NSP-SD accepts. The revised Tariff supported by NSP-SD is included as Schedule 2 to my rebuttal testimony.

However, there are a few more substantive recommendations where NSP-SD would like to respond.

1. In Section 1.6, Staff seeks clarification on the use of the phrase "pro rata share" of Lost and Unaccounted For ("LAUF") gas. LAUF is the difference between the amount of gas received into the distribution system and the amount of gas delivered to its customers.

For example, assume a transporter received 20,100 Dth during one month for two customers. Metered deliveries to Customer #1 were 19,000 Dth, and metered deliveries to Customer #2 were 1,000 Dth, the LAUF was (20,100 - 20,000) or 100 Dth. The pro rata shares would be 95 Dth and 5 Dth, respectively. This allows the transporter full cost recovery from the customer. The tariff has been revised to explain that the customer's share of LAUF is calculated as a percentage of the customer's throughput on NSP-SD's system.

2. In Section 3.6, Mr. Knadle suggests NSP-SD add language to clarify whether the transporter or the customer is responsible for telemetering costs. Language has been included to indicate the customer is responsible for the telemetering expense. Similar changes are included in Section 7.0 of the TSA.

3. Mr. Knadle questions a phrase in Section 6.4 regarding disposition of excess gas. This provision was copied from a tariff of our affiliated interstate pipeline (Viking Gas), and basically refers to wholesale sales occurring before the NSP-SD receipt point, so this paragraph can be removed.

4. Mr. Knadle proposes extensive changes to Section 8.2, 8.4 and 8.5 regarding billing. NSP-SD believes we have addressed his concerns by revising these sections to be more consistent with the South Dakota Electric Rate Book.

5. NSP-SD has included the interruption of the Angus Anson line to the emergency conditions granting the use of fuel other than natural gas in response to Mr. Knadle's question regarding the character of service conditions.

6. With regards to Mr. Knadle's request for clarification on Daily Nomination and Balancing procedures, NSP-SD will revise these

sections of the TSA to be consistent with Article V, Paragraph 5.1 of the Transportation Tariff. When the tariff was originally filed, Northern's tariff was at (+/-) five percent. However, Northern's standards do change from time to time (i.e. the percent changed to 3% on 11/1/98 as part of their rate case) and the requirements for transportation customers should always be consistent with the rules that the system is operating under.

7. Mr. Knadle questions a sentence in Section 1 of the Firm Transportation Service rate schedule, which limits service to retail customers. The purpose of this provision is to recognize the nature of the facilities installed by NSP-SD, and to make the Company's South Dakota Gas Tariff consistent with its Minnesota and North Dakota gas rate books, which both contain a similar provision. See Schedule 3.

Basically, NSP-SD wants to contract with end-users such as HTI, and does not want to be obligated to provide transportation for resale. If the Commission were to order gas service restructuring, so a supplier like Enron could contract directly with NSP-SD for transportation service, NSP-SD would remove this provision at that time.

8. Mr. Knadle suggests that NSP-SD update its index of customers. The revised Tariff does include current customers. NSP-SD proposes to update this page annually.

9. Mr. Knadle requests additional support for the term "gross" negligence in Section 1.2 of the TSA. Gross Negligence is defined as the intentional failure to perform a manifest duty in reckless disregard of the consequences as affecting the life, health or property of another. SDCL 36-4B-1 (13); Black's Law Dictionary. NSP-SD will maintain the reference to "gross" negligence in this section as it is standard legal contract terminology.

10. In paragraph 2.0 of the TSA, Mr. Knadle proposes NSP-SD file a tariff to provide back-up service. NSP-SD agrees to do so if customers request this service.

11. In paragraph 2.9, Mr. Knadle requests a sample calculation of the monthly cashout mechanism. Schedule 4 provides such a calculation. This example also defines the monthly imbalance percentages as the usage volumes compared to the volumes nominated. This is consistent with most pipeline tariff language.

12. In paragraph 2.9 of the TSA, the reference to the Angus C. Anson pipeline surcharge has been eliminated because this charge is

recovered in the transportation commodity rate and thus should not be recovered as a fuel cost.

13. Mr. Knadle asks for clarification on the use of the phrase "fixed rate" in Section 3.2 of the TSA. There is no fixed rate in the Tariff, only a range between a minimum rate and a maximum rate. However, there would be a defined rate in each TSA with a customer. NSP-SD has removed the phrase "fixed rate" from Section 3.2 of the TSA.

14. Mr. Knadle asks that NSP-SD revise the Tariff to delete references to requirements "as provided in Northern's tariff." NSP-SD opposes this requirement. Northern's tariff is several hundred pages, and tariff terms and conditions can change almost monthly. In addition, operational provisions can change whenever the Gas Industry Standards Board ("GISB") amends its standards.

NSP-SD's pipeline operations must comply with any changes on Northern's tariff, and NSP-SD's tariff administration would be extremely burdensome under Mr. Knadle's proposal. If a customer wants to view Northern's tariff, it is available on the Internet at www.ets.enron.com\nngtariff\et_tf_vol1_frame.html, or NSP-SD could provide a copy of Northern's changes upon customer's request.

15. Mr. Knadle also requests clarification of the System Exit Charges in Appendix A to the TSA. As noted by Mr. Rislov, NSP-SD calculated the rates for the pipeline using a LARR approach, with a 45 year service life. However, the service contract with HTI is for a much shorter term. If the HTI plant were to close for some unanticipated reason, NSP-SD could be left with unrecovered costs. This provision would basically require a customer to pay NSP for its share of the unrecovered net investment of the line if the customer discontinued gas service and NSP-SD did not have an alternative market for this facility.

16. The Contract Year has been changed to Contract Period in Appendix A, Appendix B and in the General Terms and Conditions of the Tariff since contracts can be for a period longer than any twelve month period as originally stated. This should address Mr. Knadle's concern about contract term consistency.

17. The definition of Receipt Point is accurate since both Angus Anson and transportation customers receive gas at the same point (the Harrisburg TBS). The transportation customers then provide compensation for the use of the Angus Anson line.

18. Mr. Knadle is correct in stating that the transportation rates NSP-SD established were based on a specific customer ("HTI"), but it is the

intent of NSP-SD to use this established range of rates when offering service to similarly sized customers. As discussed later, NSP-SD is proposing a similar rate structure for smaller transportation customers.

Q. Do you have any other changes based on Mr. Knadle's testimony?

A. Yes. Mr. Knadle recommends that the floor of the transportation rate be raised to minimally recover variable costs for the customer and to provide for some contribution toward NSP's distribution system fixed costs. Schedule 5 has been provided to identify the new minimum rate of $0.12 per Dth to recover $0.04 as a contribution to the Angus Anson pipeline, $0.06 in incremental O&M costs and $0.02 as a contribution to system fixed costs.

Mr. Knadle also recommends providing specific language on the determination of the customer charge for prospective customers. NSP-SD would like to establish a $12 Customer Charge for Small Volume Customers (peak day requirements of less than 500 therms) and a $50 Customer Charge for Medium Volume Customers (peak day requirements of 500 therms to 1,999 therms) in response to his request. Since customers with similar usage patterns will have the same metering requirements, it will be more practical to establish a customer charge based on typical meter costs for a particular class of customer. Schedule 6 contains the calculation of these charges.

Q. If these new customer charges are established, what corresponding transportation charges are you proposing?

A. NSP-SD is providing gas service to two smaller customers in the adjacent Industrial Park. Based on the rate methodology and the revised LARR factor established for HTI, plus the estimated project costs for these two customers, the maximum rate would be $1.03 per Dth (or $0.103 per therm). Schedule 7 supports this calculation. Since NSP-SD is not currently serving any Medium Volume Transportation customers and does not have any estimated projects costs, we suggest using a market based rate of $0.50 per Dth for any prospective customers of this size. Schedule 8 compares typical bills under the confines of the currently established rate and under the new rate scenarios. The goal is to provide pricing flexibility to smaller customers.

Q. Mr. Rislov proposes a review of NSP-SD's gas rates in 2000, since there is little history regarding operation of the pipeline, total ongoing costs and volumes. Does NSP-SD agree?

R. NSP-SD would not support a requirement for a general rate case, since the NSP-SD gas operation is so small, but NSP-SD would be willing to work informally with the Staff to provide 1998 and 1999 actual data so the Staff can review the results of ongoing operations. As noted by Mr. Smith, NSP-SD would propose to provide this information by May 1, 2000, concurrent with NSP's gas utility jurisdictional reports to the Minnesota and North

Dakota Commissions. We believe this review could provide useful information.

S. Does this conclude your rebuttal testimony?

A. Yes.

AFFIDAVIT

STATE OF MINNESOTA)
)
COUNTY OF HENNEPIN)

Affiant, having been first sworn, on oath deposes and says:

That has read the foregoing testimony and if asked the questions therein his answers in response would be sworn as shown;

That the facts contained in said answers are true to the best of his knowledge and belief.

Jamie C. Seitz

SUBSCRIBED AND SWORN to me before this 23th day of December, 1998

Notary Public

[illegible]

Northern States Power Company – South Dakota
Gas Operations

Docket No. NG97-021
JCS – 1 Schedule 1

Ms. Jamie C. Seitz
Manager – Gas Rates and Planning
825 Rice Street, St. Paul, Minnesota

CURRENT RESPONSIBILITIES (January 1992 – Present)

I am responsible for the management of the Company's gas rate design activities in the Minnesota, North Dakota and Arizona jurisdictions. In addition to having supervisory responsibilities for the Gas Regulatory Analysis section, I am responsible for the development of class cost of service studies, special rate studies, the administration and preparation of the purchased gas adjustment (PGA) filings, and the overall design of gas rate tariffs for the Company.

PREVIOUS EMPLOYMENT (Northern States Power Company)

Manager, Gas Rates and Planning	1992 – Present
Principal Rate Analyst, Revenue Requirements	1990 - 1991
Senior Rate Analyst, Revenue Requirements	1995 – 1990
Rate Analyst, Revenue Requirements	1983 – 1985
Load Research Analyst, Load and Market Research	1980 – 1983

EDUCATION

University of Wisconsin, Bachelor of Science – Mathematics/Business Administration

PREVIOUS TESTIMONY

North Dakota – Gas Rate Design	PU-400-95-559
Minnesota – Rate Design and Cost Allocation	G002/GR-92-1186
South Dakota – Electric Rate Base	EL-90-13
South Dakota – Electric Rate Base	F-3764

NORTHERN STATES POWER COMPANY - SOUTH DAKOTA

GAS TRANSPORTATION SERVICE TARIFF

ORIGINAL VOLUME NO. 1

TABLE OF CONTENTS

PRELIMINARY STATEMENT

Northern States Power Company - South Dakota (hereafter "NSP-SD" or "Transporter") is an electric utility and prospectively a natural gas utility company planning to engage in the business of transporting and distributing natural gas in intrastate commerce to end users in the State of South Dakota. NSP's system consists of approximately ~~three~~ four miles of distribution lateral pipeline in Minnehaha County, South Dakota. NSP-SD will take delivery of natural gas at the compressor station located on the Angus C. Anson site east of Sioux Falls and deliver it to end-use customers along or at the terminus of the NSP distribution lateral line in Sioux Falls, South Dakota.

GENERAL TERMS AND CONDITIONS

ARTICLE 1
DEFINITIONS

1.1 "Btu" shall mean one British Thermal Unit.

1.2 "Contract Demand" shall mean the aggregate of the maximum daily quantities of gas, expressed in dkt per day, which Transporter is obligated to accept for transportation for the account of Shipper from the points of receipt as set forth in the Transportation Service Agreement ("TSA") between Transporter and Shipper.

1.3 "Contract ~~Year~~Period" shall mean the ~~twelve month~~ period ~~commencing~~ specified in Appendix A~~November 1 and terminating on October 31 of each year~~, until ~~this Agreement shall have~~the TSA has expired or otherwise been terminated in accordance with its terms.

1.4 "Day" shall mean the period of 24 consecutive hours, starting at 9:00 a.m. Central Clock Time, or such other 24 hour gas day period as established in Northern's Tariff.

1.5 "Dkt" shall mean the quantity of heat energy which is equivalent to 1,000,000 British Thermal Units (BTU). One "dkt" of gas means the quantity of gas which contains one dekatherm of heat energy. The total dekatherms are calculated by multiplying the gas volume in Mcf by its total gross heating value, divided by 1,000.

1.6 "Equivalent Quantities" shall mean the sum of quantities of gas measured in dkt received by Transporter and delivered for the account of Shipper at the points of receipt and delivery during any given period of time reduced by the sum of Shipper's Pro Rata Share of Lost and Unaccounted For Gas, calculated as a percentage of Shipper's throughput on Transporter's system, resulting from the operations of the System during the same period of time. In the event the ownership of gas lost as a result of an event of force majeure can be reasonably identified, the quantity thereof shall be charged to the Shipper or Shippers so identified.

1.7 "Gas" shall mean natural gas, unmixed or any mixture of natural and artificial gas.

1.8 "Gross Heating Value" shall mean the number of BTU's produced by the complete combustion, at a constant pressure, of the amount of gas which would occupy a volume of one (1) cubic foot at a temperature of 60 degrees Fahrenheit on a dry basis and at a pressure of 14.73 psia with air of the same temperature and pressure as the gas, when the products of combustion are cooled to the initial temperature of the gas and air, and when the water formed by combustion has been condensed to the liquid state.

1.9 "Maximum Daily Quantity" shall mean the maximum quantity expressed in dkt per day that the Transporter is obligated to receive for the account of Shipper at the point of receipt, as established in Exhibit A to Shipper's TSA.

1.10 "Mcf" shall mean 1,000 cubic feet of gas determined in accordance with the measurement base described in Paragraph 3.1 hereof.

1.11 "Month" shall mean the period beginning at 9:00 a.m. Central Clock Time on the first day of the calendar month and ending at the same hour on the first day of the next succeeding month.

1.12 "Northern" shall mean Northern Natural Gas Company, its successors and assigns.

1.13 "Northern's Tariff" shall mean the Northern's FERC Gas Tariff as it may be in effect from time to time.

1.14 "Pro Rata Share" shall mean the ratio that the quantity of gas delivered to Transporter for the account of Shipper to the total quantity of gas delivered to Transporter by all shippers for transportation in the System during any given period of time.

1.15 "SDPUC" shall mean the South Dakota Public Utilities Commission or any commission, agency or other state governmental body succeeding to the powers of such commission.

1.16 "Shipper" shall mean any party to a TSA providing for transportation of natural gas on Transporter's System. For purposes of Articles V and VI, "Shipper" shall also mean Shipper's Agent designated to provide day-to-day transportation management for Shipper. Shipper may change such designation from time to time upon written notice to Transporter.

1.17 "System" shall mean the pipeline and related pipeline facilities at the time owned by Transporter.

1.18 "TSA" shall mean the Transportation Service Agreement between Transporter and Shipper in the form set forth in this Tariff.

1.19 "Unaccounted For Gas" shall mean the difference between the sum of all input quantities of gas to the System and the sum of all output of gas from the System, which difference shall include but shall not be limited to gas used and accounted for in System operations, meter errors (subject to Section 3.8) and gas lost as a result of an event for force majeure, the ownership of which cannot be reasonably identified.

ARTICLE II
QUALITY

2.1 Quality Standards of Gas Received by Transporter. The gas to be delivered by Transporter shall be of merchantable quality and shall meet the minimum quality standards, as may be established or revised from time to time in Northern's Tariff.

2.2 Quality Tests. At the point of receipt, Transporter may cause tests to be made, by approved standard methods in general use in the gas industry, to determine whether the gas conforms to the quality specifications set out in Paragraph 2.1 hereof. Such tests shall be made at such intervals as Transporter may deem reasonable, and at other times, but not more often than once per day, or at the request of Shipper.

2.3 Failure to Conform. If gas delivered by Shipper does not comply with the quality specifications set out in Paragraph 2.1 hereof, Transporter shall have the right, in addition to all other remedies available to it by law, to refuse to accept any such gas. Transporter may, at its option and upon notice to Shipper, accept receipt of gas not complying with the quality specifications set out in Paragraph 2.1 herein provided. Transporter, at the expense of Shipper, may make all changes necessary to bring such gas into compliance with such specifications.

2.4 Quality Standards of Gas Transported By Transporter. Transporter shall use reasonable diligence to deliver gas for Shipper which shall meet the quality specifications set out in Paragraph 2.1 hereof, but shall only be obligated to deliver gas of the quality which results from the commingling of gas received by Transporter from Shipper and other shippers.

ARTICLE III
MEASUREMENT

3.1 Unit of Measurement and Metering Base. The volumetric measurement base shall be one cubic foot of gas at a pressure base of 14.73 pounds per square inch absolute, at a temperature base of 60 degrees Fahrenheit, and without adjustment for water vapor content.

3.2 Atmosphere Pressure. For the purpose of measurement, the absolute atmospheric (barometric) pressure at each measuring station shall be the atmospheric pressure determined by calculations based on the actual elevation above sea level of the meter at the place of measurement, and shall be stated in pounds per square inch.

3.3 Temperature. If determined to be necessary in the sole discretion of Transporter, the temperature of the gas shall be determined at each point of measurement by means of a properly installed recording thermometer, an indicating thermometer, an electronic temperature measuring device, or a temperature compensating meter of standard manufacture acceptable to Transporter.

3.4 Specific Gravity. If determined to be necessary in the sole discretion of Transporter, the specific gravity of the gas shall be determined at each point of receipt by one of the following methods:

(a) By means of a properly installed recording gravitometer of standard manufacture acceptable to Transporter.

(b) If (a) is not considered feasible, then by use of a portable specific gravity to balance of standard manufacture, or other standard device acceptable of Transporter and designed for such purpose or use in conjunction with a continuous sampler.

(c) Other methods acceptable to Transporter.

3.5 Measurement Procedures. Quantities of gas received and delivered hereunder shall be measured in accordance with Procedures contained in ANSI-API 2530, First Edition, AGA Committee Report No. 5, AGA Committee Report No. 7, and AGA Committee Report No. 8, or revisions or amendments thereto.

3.6 Measuring Equipment. Unless otherwise agreed, Transporter will provide, maintain, and operate necessary measuring and regulating stations equipped with flow meters and other necessary measuring equipment by which ~~its~~ quantities of gas delivered from Transporter hereunder shall be determined. Such measuring and regulating stations shall be so installed at the receipt point of the System and at other agreeable points. All flow, measuring, testing, and related equipment shall be of standard manufacture and type acceptable to Transporter.

Transporter and Shipper shall cause the recording chart on all gas measurement equipment to be changed, or mechanical or electronic indices read, by either Transporter or by Shipper's representative (where economical) on a daily basis. If telemetering is not installed, Shipper shall change recording charts on Transporter's Delivery point metering facilities or otherwise read Transporter's meter on a daily basis at a time specified by Transporter. Shipper may install check measuring equipment, provided that such equipment shall be so installed as not to interfere with operation of Transporter.

When Transporter deems it necessary, telemetering equipment shall be installed on Shipper's delivery point meter(s), at Customer's expense. Transporter will install and maintain the telemetering facilities. Shipper shall provide, install and maintain a weatherproof phone service and electrical service outlet with appropriate grounding for telemetering equipment. Shipper and Transporter, in the presence of each other, shall have access to all measuring equipment at all reasonable times, but the reading, calibrating, and adjusting thereof shall be done by the Transporter, unless otherwise agreed. Shipper and Transporter shall have the right to be present at the time of any installing, reading, cleaning, changing, repairing, inspecting, testing, calibrating, or adjusting done in connection with all measuring equipment. The records from such measuring equipment shall remain the property of Transporter. Reasonable care shall be exercised in the installation, maintenance and operation of measuring equipment so as to avoid any inaccuracy in the determination of the quantity of gas received and delivered.

3.7 Calibration and Test of Meters. The accuracy of all measuring equipment shall be verified by the Transporter at reasonable intervals, and if requested, in the presence of representatives of Shipper. Transporter shall not be required to verify the accuracy of such equipment more frequently than once in Contract Year. If either party at any time desires a special test of any measuring equipment, it will promptly notify the other, and the parties shall then cooperate to secure a prompt verification of the accuracy of such equipment. Transportation and related expenses incurred by Shipper or Transporter involved in the testing of meters shall be ~~done~~ borne by the party incurring such expense.

3.8 Correction of Metering Errors. If, upon any test, any measuring equipment is found to be in error, such errors shall be treated in the following manner: If the resultant aggregate error in the computed receipts or deliveries is not more than 2%, then previous receipts orf deliveries shall be considered accurate. All equipment shall, in any case, be adjusted at the time of test to record to zero error. If, however, the resultant aggregate error in computed receipt or deliveries exceeds 2% at a recording corresponding to the average hourly rate of gas flow for the period since the last preceding test, the previous recordings of such equipment shall be corrected to zero error for any period which is known definitely or agreed upon. In case the period is not known definitely or agreed upon, such correction shall be for a period extending

over one-half of the time elapsed since the date of the last test, not exceeding a correction period of 180 days.

3.9 Failure of Measuring Equipment. In the event any measuring equipment is out of service, or is found registering inaccurately and the error is not determinable by test, or by previous recording, receipts or deliveries through such equipment shall be estimated:

(a) By using the registration of any check meter or meters, if installed and accurately registering, or in the absence of (a);

(b) By correcting the error if the percentage of error is ascertainable by calibration, special test, or mathematical calculation, orf in the absence of both (a) and (b) then;

(c) By estimating the quantity of receipt or delivery based on receipts or deliveries during preceding periods under similar conditions when the measuring equipment was registering accurately.

3.10 Preservation of Records. Shipper and Transporter shall preserve all test data, charts, and other similar records for a period of at least one year, or such longer period as may be required by the SDPUC or other jurisdictional public authority.

ARTICLE IV
RECEIPT AND DELIVERY POINTS

4.1 Point of Receipt. The initial point of receipt hereunder shall be the point of interconnection between the facilities of Transporter and the facilities of Northern States Power Company - Generation located in Minnehaha County, South Dakota. Shipper shall deliver, or cause to be delivered, gas to Transporter at the point or receipt for transportation service, set forth in Exhibit A attached to Shipper's TSA.

4.2 Points of Delivery. The point(s) of delivery hereunder shall be the point(s) of connection between the facilities of Transporter and the facilities of Shipper, where Transporter shall deliver gas for the account of Shipper. Such point(s) of delivery are set forth in Exhibit A attached to Shipper's TSA. Unless otherwise agreed, the establishment of any additional point(s) of delivery at the request of Shipper shall be at the expense of Shipper.

ARTICLE V
SCHEDULES

5.1 Schedules. Prior to the first day of each month, Shipper shall furnish Transporter with a schedule showing the estimated daily quantities of gas Shipper desires Transporter to transport during such month. Such monthly schedule shall be provided at least one hour before the deadline for monthly nominations in Northern's Tariff. Thereafter Shipper shall on a daily basis advise Transporter of the volumes Shipper will deliver during the following day at least one hour prior to the time Transporter must submit daily nominations to Northern pursuant to Northern's Tariff. However, Shipper may establish a standing schedule of daily volumes, notifying Transporter prior to any day when Shipper's daily deliveries will differ from the standing schedule by more than the daily delivery variance (+/-) established in Northern's Tariff.

5.2 Departures from Schedules. Departures from the scheduled deliveries at the point of receipt shall be kept to the minimum permitted by operating conditions, and shall be balanced as soon as practicable. Shipper shall use its best efforts to give Transporter notice prior to proposed change of a daily quantity from that set forth in the schedule provided for in Paragraph 5.1 hereof. Such notice shall be provided at times consistent with the notice period for intra-day nomination changes set forth in Northern's Tariff. Transporter may waive such notice upon request if, in its judgment, operating conditions permit such waiver. Transporter and Shipper shall inform each other of any other changes of deliveries immediately upon knowledge thereof.

5.3 Hourly Variation. Deliveries shall be made at uniform hourly rates to the extent practicable. Transporter's obligation to deliver shall not exceed 1/16th of Shipper's Maximum Daily Quantity in any given hour.

ARTICLE VI
DAILY AND MONTHLY BALANCING

6.1 Scheduling and Balancing Tolerances. It is recognized that the parties will be unable to control exactly the quantities of gas delivered and accepted hereunder on any day, and that deliveries by Shipper and redeliveries by Transporter may vary above or below the quantities scheduled on any day. However, nothing in this ~~paragraph~~ article shall affect Shipper's obligation to pay for gas actually transported.

6.2 Daily Variance. The daily variance for a receipt point shall be the difference between the total quantities scheduled for receipt and the actual quantity delivered into Transporter's System. The daily variance for a delivery point shall be the difference between the total quantities scheduled and the actual quantity delivered by Transporter at such point on any day. Shipper shall take action to correct any daily variance between scheduled and actual receipts and deliveries occurring during the

month by making adjustments to schedules, receipts or deliveries. In no event shall the daily excess or deficiency variance exceed the allowable daily point of delivery variation set forth in Northern's Tariff.

6.3 Monthly Imbalances. Shipper's monthly imbalance shall be the net total of daily variance from all receipts and delivery point(s). Such monthly imbalance shall be corrected in-kind through adjustments to Shipper's schedules, receipts or deliveries in order for Shipper to receive Equivalent Quantities, or by such other method as is then mutually agreed upon by the parties hereto. The cumulative daily variances during any month above or below the quantities scheduled shall not exceed the monthly point of delivery ~~monthly~~ variance set forth in Northern's tariff.

~~6.4 Disposition of Excess Gas. In order to alleviate conditions that threaten the integrity of its System, Transporter may periodically acquire quantities of gas that are in excess of System needs. Transporter may make interruptible sales of such gas form time to time at the point of receipt pursuant to 18 CFR 284.402. Such sales shall be made under rates, terms and conditions mutually agreed upon between Transporter and the purchaser, provided that all such sales shall be fully interruptible.~~

ARTICLE VII
PRESSURE

7.1 Pressure at the Points of Receipt. Shipper shall cause the gas to be delivered at the points of receipt at a pressure sufficient to allow the gas to enter the System; however, Shipper shall not be required to deliver gas to the Transporter at any point of receipt at a pressure in excess of the minimum pressure specified with respect to each receipt point in Exhibit A of Shipper's TSA.

7.2 Pressure at Points of Delivery. Transporter shall deliver gas to Shipper's delivery points at the pressure existing in the Transporter's pipeline; however, Transporter must deliver gas to each point at a pressure not less than the minimum pressure specified with respect to each delivery point in Exhibit A to Shipper's TSA. Transporter, however, shall not be required or permitted to deliver gas at a pressure in excess of the maximum pressure specified for each point of delivery set forth in Exhibit A attached to Shipper's TSA.

ARTICLE VIII
BILLING AND PAYMENT

8.1 Billing. Unless otherwise agreed, on or before the 10th day of each month, Transporter shall render to Shipper a statement of the total amount of gas delivered by Transporter to Shipper at the point(s) of ~~receipt~~ delivery hereunder during the preceding month and the amount due. When information necessary for billing

purposes is in the control of Shipper, Shipper shall furnish such information to Transporter on or before the 10th day of the month.

Shipper and Transporter shall have the right to examine at reasonable times, books, records, and recording charts of the other to the extent necessary to verify the accuracy of any statement, charge, or computation made under or pursuant to any of the provisions hereof.

8.2 Payment. Unless otherwise agreed, Shipper shall pay Transporter at its general office or at such other address as Transporter shall designate ~~on or before the 28th day of the month, the amount due for the preceding month. If presentation of a bill by Transporter is delayed after the 20th day of the month, then the time of payment shall be extended accordingly unless shipper is responsible for such delay~~within 20 days after the filing transmittal date.

8.3 Remedies for Failure to Pay. Should Shipper fail to pay all or any portion of any bill as herein provided when such amount is due, interest on the unpaid portion of the bill shall occur at a rate of one percent (1%) per month. If such failure to pay continues for 30 days after payment is due, Transporter may, in addition to any other remedy it may have hereunder, suspend further delivery of gas until such amount is paid, if authorized pursuant to the rules of the SDPUC.

~~8.4 Disputed Bills. If Shipper in good faith shall dispute the amount of any such bill or part thereof and shall pay to Transporter such amounts as it concedes to be correct and, at any time thereafter within 30 days of a demand made by Transporter, shall furnish a good and sufficient surety bond in an amount and with surety satisfactory to Transporter, guaranteeing payment to Transporter of the amount ultimately found due upon such bills after a final determination which may be reached either by agreement or judgment of the courts, as may be the case, then Transporter shall not be entitled to suspend further delivery of gas unless and until default be made in the conditions of such bond.~~

8.4~~5~~ Adjustment of Billing Errors. In the event of a meter or billing error, as defined by the Public Utilities Commission, the Company shall recalculate the bills for service during the period of the error and make adjustments of bills in accordance with the rules prescribed by the Commission. If a customer has been overcharged as a result of the error, the recalculated amount will be refunded or, where applicable, a credit on a bill shall be made. If a customer has been undercharged as a result of the error, the Company may bill the customer if the amount due exceeds $10.00. The first billing of the recalculated amount due will be separately billed on a form different from the normal bill form and include a complete explanation of the billing. ~~If it shall be found that at any time or times Shipper has been overcharged or undercharged in any form whatsoever under the provisions hereof and, in the case of an overcharge, Shipper shall have actually paid the bill containing such overcharge, then within 30 days after the final determination of such overcharge or undercharge, the appropriate party shall pay to the other party the amount of said overcharge or undercharge, net of any other~~

~~amounts then payable hereunder. In the event an error is discovered in the amount billed in any statement rendered by Transporter, such error shall be adjusted within 30 days of the determination thereof provided that claim therefor shall have been made within one (1) year from the date of such statement. If the parties are unable to agree on the adjustment of any claimed error, any resort by either of the parties to legal procedure, either by law, in equity, or otherwise, shall be commenced within 12 months after the supposed cause of action is alleged to have arisen, or shall thereafter be forever barred.~~

ARTICLE IX
CONTROL OF GAS

9.1 Responsibility for Gas. As between the Shipper and Transporter hereto, Shipper shall be in exclusive control and possession of the gas until such has been delivered to Transporter at the point of receipt, and after such gas has been redelivered to or for the account of Shipper by Transporter at the point(s) of delivery. Transporter shall be in exclusive control and possession of such gas while same is in the System between the point of receipt and the point(s) of delivery. The party which shall be in exclusive control and possession of such gas shall be responsible for all injury or damage caused thereby.

ARTICLE X
FORCE MAJEURE

10.1 Force Majeure. Neither party shall be responsible or held liable for any loss or damage resulting from failure to perform its obligations due to any cause beyond its reasonable control; provided, however, that such force majeure affecting the performance hereunder by either Shipper or Transporter shall not relieve such party of liability in the event of its own concurring negligence or in the event of its own failure to use due diligence to remedy the situation and to remove the cause in an adequate manner and with all reasonable dispatch; provided further, that no such causes affecting such performance shall relieve either party from its obligation to make payments as determined hereunder or entitle either party to exercise any right to offset against any such payment obligation.

10.2 Definition. The term "force majeure" as used herein shall mean acts of God, strikes, lockouts, or other industrial disturbances; acts of a public enemy, wars, blockades, insurrection, riots, epidemics, landslides, lightning, earthquakes, fires, storms, floods, washouts; arrests and restraints of the government, either federal or state, civil or military, civil disturbances; shutdowns for purposes of necessary repairs, relocation, or construction of facilities; breakage or accident to machinery or lines of pipe; the necessity for testing (as required by governmental authority or as deemed necessary by repairs or alteration to machinery or lines of pipe); failure of surface equipment or pipelines; accidents, breakdowns, inability of either party hereto to obtain necessary material, supplies, or permits, or labor to perform or comply with an obligation or condition of this Agreement, rights of way, and any other causes, whether of the kind herein enumerated or otherwise, which are not reasonably in the control of the party claiming suspension. It is understood and agreed that the settlement of strikes or lockouts shall be entirely within the discretion of the party having the difficulty and that the above requirement that any force majeure shall be remedied with all reasonable dispatch shall not require the settlement of strikes or lockouts by acceding to the demands of an opposing party when such course is inadvisable in the discretion of the party having the difficulty.

ARTICLE XI
INTERRUPTIONS

11.1 Notice of Interruption. Transporter shall at all times attempt to operate, or cause to be operated, its System in a manner designed to make possible, as nearly as practicable, continuous receipt of gas from, and delivery of gas to, Shipper in the respective quantities provided for in Shipper's TSA. If an interruption or curtailment of such receipt and/or delivery shall become necessary, Transporter shall at once attempt to notify Shipper by facsimile or telephone or other prompt means of communication of the nature, extent and probable duration of such interruption or curtailment and of the quantity of gas which Transporter estimates it will be able to receive from and deliver to Shipper during the period of interruption or curtailment, and shall give like notice of the cessation of such interruption or curtailment.

11.2 Allocation of Reduced Capacity. If the effective capacity of all or a portion of Transporter's System is reduced as a result of force majeure, repairs, maintenance or any other cause, whether similar or dissimilar, and some curtailment of the quantity of gas to be received from shippers under their transportation agreements is required as a result, the reduced capacity shall, during the period of curtailment, be allocated proportionately, according to their respective Maximum Daily Quantities, among those shippers whose gas must be received or delivered at or transported through, the affected facilities.

11.3 Scheduling of Receipts and Deliveries. Transporter shall schedule all quantities tendered under all services performed by Transporter in sequence as follows: First to Transporter's firm transportation shippers, and second to other Rate Schedules that may be approved, in the order of priority as may be approved by the SDPUC or other regulatory bodies with jurisdiction.

ARTICLE XII
INCORPORATION IN RATE SCHEDULES AND TRANSPORTATION AGREEMENTS

12.1 These General Terms and Conditions as incorporated in and are part of Transporter's Rate Schedules and Transportation Service Agreements. In the event of a conflict between these General Terms and Conditions and terms in Transporter's Rate Schedules or TSA's, these General Terms and Conditions shall govern.

RATE SCHEDULE - FIRM TRANSPORTATION SERVICE

1.0 Availability. This Rate Schedule is available for the transportation of natural gas on a firm basis for any end user Shipper where (i) Transporter has determined that sufficient System capacity exists to provide the service requested by Shipper, and (ii) Shipper has executed a Transportation Service Agreement ("TSA") wherein Transporter agrees to transport gas for Shipper's account up to a specific maximum daily quantity. Transporter is not obligated to provide transportation service for resale.

2.0 Gas Supply; Upstream Transportation, New Facilities. Shipper shall be responsible for arranging for all natural gas supplies and interstate transportation of shipper's gas on Northern to the point of receipt. Transporter will arrange for transportation on the NSP-Generation intrastate pipeline on behalf of Shipper. Unless otherwise agreed, Shipper must pay for all facilities required to physically connect to Transporter's pipeline.

3.0 Receipts and Deliveries. The Point of Receipt for all gas transported by Transporter under this Rate Schedule shall be at the interconnection of Transporter's System with Northern States Power Company - Generation located in Minnehaha County, South Dakota. The Point(s) of Delivery shall be at the point(s) designated in the Exhibit A attached to Shipper's TSA.

4.0 Rates and Charges. The rates for service under this Rate Schedule are included in the appendix of the Gas Transportation Agreement. However, Transporter has the right at any time to file with the SDPUC to adjust the rates applicable to service under this Rate Schedule.

5.0 Daily Tolerance; Penalty Provisions. The daily tolerance level (+/-) from Shipper's daily scheduled volume shall be the daily variance established in Northern's Tariff. Unless otherwise agreed, in the event the daily quantity of gas delivered by Shipper deviates above or below the daily scheduled volume in excess of the Northern's Tariff tolerance level, and Transporter is assessed charges or penalties by Northern, Shipper shall pay, in addition to the appropriate rates contained in this tariff, an amount equal to any payment Transporter is required to make to Northern.

6.0 General Terms and Conditions. Any terms ~~of~~ and conditions not specified in this Rate Schedule shall be determined consistent with Transporter's General Terms and Conditions, which are incorporated by reference into this Rate Schedule.

Sheet 16 reserved for future use.

INDEX OF SHIPPERS

Shipper	Rate Schedule	Effective Date	Expiration Date
Hutchinson Technology, Inc.	FT	12/01/97	2/28/2008
Minnehaha County Highway Department	FT	10/1/98	10/1/2003
Jans Corporation	FT	10/1/98	9/30/2003

NATURAL GAS TRANSPORTATION SERVICE AGREEMENT

This Gas Transportation Agreement ("Agreement") is made this ____ day of , 19 __, by and between NORTHERN STATES POWER COMPANY, a Minnesota corporation, (hereinafter called "NSP" or "Company"), and __________________ a ~~Minnesota corporation~~, (hereinafter called "Customer"). Customer will enter into agreement to purchase natural gas and have that gas delivered to a specified receipt point~~town border station of Company~~. Customer and Company desire to enter into this Agreement to have said gas transported by Company to Customer's plant facilities.

WITNESSETH: The parties hereto, each in consideration of the agreement of the other, agree as follows:

1.0 TERM. This Agreement shall commence on __________________, and continue until ________________, and, if not terminated by at least 180 days prior notice, shall continue further until so terminated.

1.1 CHARACTER OF SERVICE. The transportation and delivery of gas hereunder is on a firm basis. In consideration for NSP's agreement to provide firm transportation service at the rates set forth in Section 3.2, Customer agrees to utilize natural gas transported by NSP for all the non-electric energy requirements of the Plant equipment for the term of this Agreement. However, Customer may use a fuel other than natural gas in the case of (i) a force majeure or other emergency condition on the NSP distribution system, Angus Anson line or Transporter's pipeline system, as provided in this Agreement or Transporter's Tariff, or (ii) a failure of Customer's gas supply as defined in Section 2.0 for reasons beyond the control of Customer.

1.2 CONTINUITY OF SERVICE. The Company will endeavor to provide continuous service but does not guarantee an uninterrupted or undisturbed supply of gas. The Company shall not be responsible for any loss or damage resulting from the interruption or disturbance of service for any cause other than the gross negligence of the Company. The Company shall not be liable for any loss of profits or other consequential damages resulting from the use of service or any interruption or disturbance of service.

2.0 LIMITATION ON OBLIGATION TO DELIVER. This Transportation Agreement is expressly contingent upon Customer or Customer's Agent's procurement of natural gas supplies and interstate pipeline transportation to the Company receipt point in Minnehaha County, SD . If Customer or Customer's Agent fails to deliver gas to Company at the designated ~~town border station~~receipt point, Customer shall immediately cease using gas. Company is not obligated to provide backup sales service to Customer. However, Company may at its option, agree to provide backup gas service.

2.1 REQUIREMENTS AND DELIVERIES; POINT OF DELIVERY. Company agrees to accept delivery of Customer's gas at the inlet of Company's distribution system in Minnehaha County, SD and, on a firm basis, transport and deliver said gas to Customer's point(s) of delivery in volumes up to ____ MMBTU per day, or such other volumes as is mutually agreed. Customer's point(s) of delivery shall be the outlet of the meter installation(s) at ____________________________________.

2.2 DAILY NOMINATIONS. Customer or Customer's Agent shall on a daily basis advise Company's gas dispatcher in St. Paul of the volumes Customer will request to be delivered during the following Gas Day. Customer may alternatively elect to make a standing nomination with Company, notifying Company on any day when customer's daily deliveries will differ from the standing nomination by the daily delivery variance (+/-) established in Northern's tariffs. ~~more than five (5) percent.~~ Customer shall submit daily or corrected standing nominations to Company at one hour prior to the time Transporter must submit daily nominations to Northern pursuant to Northern's tariffs. ~~least 24 hours in advance of the start of the Gas Day.~~ Customer's daily or standing nomination shall be its best estimate of the expected utilization for the Gas Day. If Customer and Company mutually agree, Company will relay Customer's daily or standing nomination to Customer's Agent, gas supplier(s), and Transporter.

2.3 DISPATCHING. Customer will adhere to gas dispatching policies and procedures established by Company from time-to-time to facilitate service under this Agreement. Company will inform Customer of any changes in dispatching policies that may affect this Agreement as they occur.

2.4 RATE OF FLOW. The gas supply shall be transported to Customer at a rate of flow up to but not exceeding ________ cubic feet per hour at the point(s) of delivery. Gas shall be delivered at such pressures and temperatures as may exist under operating conditions at Customer's service location. Operating pressures at this location shall normally be _______ psi.

2.57 REFUSAL OR DISCONTINUANCE OF SERVICE (a) With reasonable notice, the Company may refuse or discontinue gas service for any of the following reasons: failure to pay amounts payable when due; breach of contract for service; failure to provide the Company with reasonable access to its property or equipment; when the Company is unable to furnish gas service to Customer because it cannot obtain permits or necessary right-of-way; when necessary to comply with any order or request of any governmental authority having jurisdiction.

(b) Upon such notice as is reasonable under the circumstances, the Company may temporarily discontinue gas service when necessary to make repairs, replacements, or changes in Company's equipment or facilities.

(c) Without notice the Company may disconnect gas service to Customer in the event of an unauthorized use of or tampering with Company's equipment or in the event of a condition determined to be hazardous to the Customer, to other customers of the Company, to the public, or to the Company's employees, equipment, or service.

Any discontinuance of service will not relieve Customer from Customer's obligations to the Company.

2.68 BALANCING. Customer and Company agree to balance daily delivery point nominations with actual deliveries (as defined in Paragraph 3.2) on an ongoing basis. Customer agrees to exert its best efforts to keep daily deliveries within daily delivery variance (+/-) established in Northern's tariff. ~~five (5) percent of daily nomination.~~ Customer and Company shall balance as operationally necessary, but no less than monthly. Customer or Customer's Agent shall be responsible for balancing receipt point nominations made to Transporter with receipt point deliveries made by Customer or Customer's Agent's gas supplier(s).

2.97 MONTHLY CASHOUT MECHANISM. Unless otherwise agreed, Customer's monthly imbalance will be corrected by a cashout mechanism. Customer's monthly imbalance is the difference between (1) the sum of Customer's daily nominations for the month and (2) Customer's actual metered use. Monthly volumetric imbalances will not be carried forward to the next calendar month.

Undertake Purchase Payment: If Customer utilizes less gas than the volume Customer nominated and delivered to NSP system, Customer shall sell the undertake gas to NSP. Customer shall be paid an Undertake Purchase Payment equal to the monthly imbalance times the Undertake Purchase Rate.

Monthly Imbalance %	Undertake Purchase Rate
100% to 98%	Index + Transporter's Firm Transportation (TF) Commodity rate(s)
Less than 98% to 90%	[Index + Transporter's TF Commodity rate(s)] x 0.75
Less than 90%	[Index + Transporter's TF Commodity rate(s)] x 0.50

Overtake Charge: If Customer utilizes more gas than the volume Customer nominated and delivered to the NSP system, Customer shall purchase the overtake gas from NSP. Customer shall be assessed an Overtake Charge equal to the monthly imbalance times the Overtake Rate.

Monthly Imbalance %	Overtake Purchase Rate
100% to 102%	Index + Transporter's Interruptible Transportation (IT) Commodity rate(s)
Greater than 102% to 110%	[Index + Transporter's IT Commodity rate(s)] x 1.25
Greater than 110%	[Index + Transporter's IT Commodity rate(s)] x 1.50

Index for Monthly Cashout. The Index being used is Inside FERC Gas Market Report's first of the month "Prices of Spot Gas Delivered to Pipelines" for Northern Natural (Demarcation). Applicable pipeline commodity rate consists of all interstate pipeline charges including: GRI surcharge, Angus C. Anson fuel supply pipeline surcharge, fuel costs and commodity rate(s). All conditions of the monthly cashout mechanism apply unless Customer and NSP agree otherwise. However, NSP will treat similarly situated customers on a non-discriminatory basis.

3.02.8 CHARGES. Commencing with the date of initial deliveries of gas by Company, the charges for this transportation service shall be according to Appendix A.

2.93.1 MONTHLY CUSTOMER CHARGE. As established in Appendix A. The customer charge shall not exceed the maximum charge on file with the South Dakota Public Utilities Commission.

3.02 VOLUME CHARGE. A Volume Charge equal to the product of (i) the actual deliveries made by Company to Customer during the billing period, and the ~~fixed~~ rate per MMBtu stated in Appendix A. The volume metered by NSP will be considered the actual volume delivered by Company to Customer. All volumes will be adjusted for Btu content and supercompressibility. The volume charge per MMBTU shall not exceed the maximum charge on file with the South Dakota Public Utilities Commission.

3.13 TAXES. In addition to the rates specified above, NSP shall collect any federal, state or local sales, use, excise, or other such taxes and fees that are legally effective and applicable to the service provided hereunder.

3.24 PENALTY PROVISION. Customer shall be liable for any balancing or other penalties imposed on NSP by Transporter and caused by Customer's actions. Customer shall also be liable for any incremental costs incurred by Company, if any, caused by Customer's failure to stay within the +/- 5 percent daily tolerance zone.

3.35 ADDITIONAL CHARGE FOR USE DURING CURTAILMENT. If Customer fails to curtail use of gas hereunder when requested by Company, Customer shall pay, in addition to the appropriate above rates, either an amount equal to any payment Company is required to make to Transporter as a result of Customer's failure to curtail, or $10.00 per MMBtu of gas used in excess of the volume of gas to which customer is requested to curtail, whichever amount is greater. Such payments, however, shall not preclude Company from shutting off Customer's gas supply in the event of Customer's failure to curtail gas use thereof when requested by Company to do so.

4.0 PAYMENT OF BILLS. All bills are payable at Company's office on or before the ~~tenth~~ 20th day succeeding the date bill is rendered for service supplied by Company in the preceding month. Should Customer fail to remit the full amount when due, Customer shall pay a Late Payment Charge of 1% to be added to the next month's bill after the date due.

4.1 DISPUTED BILLS. If Customer in good faith disputes the amount of any monthly billing or part thereof, Customer shall pay Company the amount Customer believes to be correct and notify Company in writing of the basis for disputing the bill. Company shall promptly investigate the matter and submit a corrected bill to Customer. If Customer has underpaid the amount actually due, Customer shall within five (5) days remit the additional amount due. If Customer has overpaid the amount actually due, Company shall refund the overpayment by a credit to Customer's next bill. Company agrees to waive the late payment charge for the disputed portion of any bill if Customer disputed the bill in good faith.

5.0 BILLING ADDRESSES, CURTAILMENT NOTICES, OTHER NOTICES. The applicable addresses and/or telephone numbers for billing, curtailment notices, and other notices under this Agreement are provided in the Appendix C to this Agreement.

6.0 TITLE TO GAS. Unless otherwise agreed, Customer shall possess title to Customer's gas while being transported by Company. However, Company may, if the parties mutually agree, take title to Customer's gas to arrange interstate or intrastate pipeline transportation from Transporter to Company's receipt point.

6.1 WAIVER OF LIABILITY. Customer shall hold Company blameless for any termination of gas service caused by failure of Customer, Customer's Agent, Customer's gas supplier(s) or Transporter to deliver gas to Company's designated receipt point.

7.0 TELEMETERING. When transporter deems it necessary, t~~T~~elemetering equipment shall be installed on Customer's premises, at Customer's expense, in order to measure daily and monthly deliveries to Customer. Company will install and maintain the telemetering facilities. Customer shall provide, install and maintain a weatherproof phone service and electrical service outlet with appropriate grounding for telemetering equipment at Customer's ~~cost~~expense.

8.0 REGULATORY AUTHORITY. This agreement is subject to all valid laws, orders, rules and regulations of any and all duly constituted authorities having jurisdiction over the subject matter herein and is subject to the receipt of any necessary authorization for the transportation service contemplated herein.

9.0 REPORTING REQUIREMENTS. Customer shall furnish to NSP all information as may be required or appropriate to comply with reporting requirements of duly constituted authorities having jurisdiction over the subject matter herein.

10.0 CONFIDENTIALITY. The terms of this contract, including but not limited to Customer's delivered price of gas, NSP's customer charge and volume charge, the volume of gas transported, and all other material terms of this contract shall be kept confidential by NSP and Customer, except to the extent that any information must be disclosed to a third party as required by law or for the purpose of effectuating transportation of the subject gas pursuant to this Agreement.

11.0 <u>SUCCESSION, ASSIGNMENT</u>. This Agreement shall inure to and be equally binding on the respective parties, their successors and assigns. Neither party shall assign this Agreement and rights hereunder without the written approval of the other party. Such approval shall not be unreasonably withheld.

12.0 <u>ENTIRE AGREEMENT; MODIFICATION AND WAIVER</u>. This Agreement, together with all documents attached hereto which NSP has signed or initialed intending to make them a part hereof, constitutes the entire agreement between the parties relating to the transaction described herein and supersedes any and all prior oral or written understandings. No addition to or modification of any provision hereof shall be binding upon NSP, and NSP shall not be deemed to have waived any provision hereof or any remedy available to it unless such addition, modification or waiver is in writing and signed by a duly authorized employee of NSP.

13.0 <u>SEVERABILITY</u>. If any provision hereof is held to be unenforceable by final order of any regulatory authority or court of competent jurisdiction, such provision shall be severed herefrom and shall not affect the interpretation or enforceability of the remaining provisions hereof.

<u>IN WITNESS WHEREOF</u>, the parties have duly executed this Agreement effective the date and year first written above.

<u>NORTHERN STATES POWER COMPANY</u>	______________________________
	Customer
By ______________________________	By ______________________________
Title ______________________________	Title ______________________________
Date ______________________________	Date ______________________________

APPENDIX A
GAS TRANSPORTATION AGREEMENT
DATED ______________
FOR
(Customer name)

I. Delivery Period

The Agreement and the rates, terms and conditions contained herein, will be in effect for a term commencing ________________, and continuing through _____________, and then shall be renegotiated.

II. Delivery Point(s) and Charges

(a) Delivery Point(s)

NSP will transport the Customer's gas supplies to customer's facility, located at ___________________________ under this Agreement at the following rate:

(b) NSP Transportation Service Charges

The ~~maximum~~ Customer Charge is $~~287.00~~_____ per month.
Transportation local delivery volume charge of $_______ ~~will not exceed $0.213 per MMBtu transported and not be less than $0.044~~ per MMBtu transported, before applicable taxes and fees.

(c) Annual Minimum Local Delivery Charge

Customer agrees to an Annual Minimum Local Delivery Charge of ___________ as determined by the Company.

System Exit Charges will also apply as determined by the Company.

III. Contract Quantity

Customer nominates a maximum daily Contract Quantity of ______ MMBtu.

NSP is not obligated to provide firm transportation service in excess of Customer's maximum daily Contract Quantity unless NSP agrees to amend this Agreement in writing. However, NSP may at its option provide daily overrun transportation service to Customer on an interruptible basis if Customer so requests. The interruptible overrun local delivery charge per MMBtu shall be the same as the firm local delivery charge set forth above.

APPENDIX B
DEFINITIONS

"Btu" shall mean British Thermal Unit and shall be the quantity of heat required to raise the temperature of one (1) pound of water one degree Fahrenheit at sixty (60) degrees Fahrenheit.

"Contract Quantity" shall mean the daily quantity of natural gas which NSP is obligated to deliver on a firm basis to Customer pursuant to this Agreement.

"Contract ~~Year~~Period" shall mean the ~~twelve month calendar~~ period set forth in Appendix A.

"Customer" shall mean Hutchinson Technology Inc. For purposes of this Agreement, the term Customer also includes Customer's Agent.

"Customer's Agent" shall mean (if applicable) the party or entity designated by Customer in the Nomination Statement to perform day-to-day supply and/or delivery management functions for Customer. Subject to NSP's approval, Customer may change such designation from time to time upon written notice to NSP.

"Delivery Point" shall mean the outlet side of the NSP meter located on NSP's natural gas distribution system at Customer's Plant service locations.

"FERC" means the Federal Energy Regulatory Commission or successor agency.

"Firm Transportation" shall mean transportation service which is not subject to interruption except for emergencies or for failure of Customer to deliver gas to NSP at the Receipt Point for transportation to Customer.

"Gas" shall mean natural gas, manufactured gas, or other forms of gaseous energy which conform to the quality specifications in Transporter's Tariff.

"Gas Day" shall mean the 24 hour period determined in accordance with Transporter's Tariff.

"Interruptible Transportation" shall mean transportation service which is subject to interruption at Company's option.

"MMBtu" shall mean one million (1,000,000) BTUs. One MMBtu is equal to one (1) "Dekatherm" or ten (10) "Therms."

"Receipt Point" shall mean the inlet point of the NSP gas distribution system where NSP takes receipt of gas from Transporter.

"Transporter" shall mean Northern Natural Gas Company.

"Transporter's Tariff" shall mean Northern's FERC Gas Tariff on file with the FERC from time to time.

APPENDIX C
NOTICES AND CONTACT LIST

C-1 Notices to NSP:

Northern States Power Company
Attn: SD Gas Operations
P. O. Box 988
500 West Russell St.
Sioux Falls, SD 57101-0988

Notices and Bills to Customer:

C-2 Day to day communications

Wm. Duff Robinson
Senior Engineer
phone 605-339-8345
fax 605-339-8204

Jerry Peterson
Coordinator New Business Dev.
phone 605-339-8310
fax 605-339-8204

Day to day communications to Customer

C-3 Gas Transportation Communications

NSP Gas Control (24 Hours/day):

Northern States Power Company
Gas Control
825 Rice Street
St. Paul, MN 55117
phone: 612-229-5527
fax 612-229-2370

Customer's Agent

Docket No. NG97-021
JCS-1 Schedule 3
Page 1 of 2

NSP Northern States Power Company
Minneapolis, Minnesota 55401
MINNESOTA GAS RATE BOOK - MPUC NO. 2

GENERAL RULES AND REGULATIONS (Continued)

Section No. 6
1st Revised Sheet No. 8
Cancels Original Sheet No. 6-8

2.2 AVAILABILITY OF SERVICE UNDER RATE SCHEDULES

Availability of a rate schedule with respect to the purpose for which service thereunder may be used and the class or classes of customers to which the schedule applies shall be as specified in the rate schedule.

Availability of service under a rate schedule at any particular location in a community or territory where the schedule is shown to be effective, depends upon the proximity of the particular location to the Company facilities of adequate delivery capacity at suitable pressure and the limitations of the Company's extension rules and regulations, ~~and Town Border Purchase Contract.~~ The extent to which the Company will extend, enlarge, or change its facilities to supply service is determined by Section 5, EXTENSION RULES.

2.3 CHOICE OF OPTIONAL RATES

Where more than one rate schedule is available or the same class of service, as indicated by the complete copy of the Company's rates open to public inspection in the Company's office, the Company will assist the customers in making their selection of the rate schedule or schedules which will result in the lowest cost for estimated consumption, based on 12 months' service and on the information at hand. New customers may change to another rate schedule after a reasonable trial of the rate schedule originally selected. The Company is not required to change a customer from one rate schedule to another more often than once in 12 months unless there is a material change in the customer's load, or unless a change, becomes necessary as a result of an order issued by the Public Utilities Commission or a court having jurisdiction. The Company will not be required to make any change in a fixed term contract except as provided therein.

2.4 STANDBY SERVICE

Standby Service is service provided to a customer through a permanent connection solely for use in the event of failure or curtailment of another thermal energy source. Standby Service will be provided only under those rate schedules which specifically allow such service or by individual contract.

2.5 RESALE, BREAKDOWN, SUPPLEMENTARY OR AUXILIARY SERVICE

Unless specifically provided for in the rate schedule, service will not be supplied for resale, breakdown, supplementary or auxiliary purposes.

Date Filed:	By: Cynthia L. Lesher President, NSP Gas	Effective Date:
Docket No. G002/GR-97-1606		Order Date:

J:\RATES\PROPOSED\MN_GAS\RCASE97\INITIAL\MG_6_08.R01

2.2 AVAILABILITY OF SERVICE UNDER RATE SCHEDULES

Availability of a rate schedule with respect to the purpose for which service thereunder may be used and the class or classes of customers to which the schedule applies shall be as specified in the rate schedule.

Availability of service under a rate schedule at any particular location in a community or territory where the schedule is shown to be effective, depends upon the proximity of the particular location to the Company facilities of adequate capacity at suitable pressure and the limitations of the Company's extension rules and regulations and Town Border Purchase Contract. The extent to which the Company will extend, enlarge, or change its facilities to supply service is determined by Section 5, EXTENSION RULES. Subject to the extension rules, the Company may provide service to customers using 500 Therms or more per day at the available pressures in excess of 10 PSIG (pounds per square inch gauge); customers using less than this amount will be served at available pressures of 10 PSIG or less. Total requirements of a customer supplied at 10 PSIG or less shall not exceed 2,000 Therms per day.

2.3 CHOICE OF OPTIONAL RATES

Where more than one rate schedule is available for the same class of service, as indicated by the complete copy of the Company's rates open to public inspection in the Company's office, the Company will assist the customers in making their selection of the rate schedule or schedules which will result in the lowest cost for estimated consumption, based on 12 months' service and on the information at hand. New customers may change to another rate schedule after a reasonable trial of the rate schedule originally selected. The Company is not required to change a customer from one rate schedule to another more often than once in 12 months unless there is a material change in the customer's load, or unless a change, becomes necessary as a result of an order issued by the Public Service Commission or a court having jurisdiction. The Company will not be required to make any change in a fixed term contract except as provided therein.

2.4 RESALE, BREAKDOWN, SUPPLEMENTARY, STANDBY, OR AUXILIARY SERVICE

Unless specifically provided otherwise in the rate schedule, or sufficient financial consideration is provided for supplemental or standby service pursuant to Section 5.5, service will not be supplied for resale, breakdown, supplementary, standby, or auxiliary purposes. The Company is authorized to enter into agreements to waive the provisions of the rule and related rules so as to facilitate experimental use of alternative sources of energy by customers on terms that are agreeable to the Company.

Docket No. NG97-021
JCS - 1 Schedule 4

Examples of Monthly Cashout Mechanisms

1) Undertakes: Customer takes too little gas and must sell gas to NSP-SD's system.

Assumptions:

Index = $2.00/Dkt
TF Commodity Rate = $0.20 per Dkt
Customer nominates 100 Dkt

Percent of Nomination Taken	Volume Taken (Dkt)	Under Nomination	Amount Paid to Customer to Purchase Gas Customer Did Not Use	
98%	98	-2	($2.00 + $0.20) * 2 Dkt =	$4.40
90%	90	-10	($2.00 + $0.20) * 0.75 * 10 Dkt =	$16.50
85%	85	-15	($2.00 + $0.20) * 0.5 * 15 Dkt =	$16.50

2) Overtakes: Customer takes too much gas and must purchase gas from NSP-SD's system.

Assumptions:

Index = $2.00/Dkt
TF Commodity Rate = $0.20 per Dkt
Customer nominates 100 Dkt

Percent of Nomination Taken	Volume Taken (Dkt)	Over Nomination	Amount Customer Pays to Buy Gas	
102%	102	2	($2.00 + $0.20) * 2 Dkt =	$4.40
110%	110	10	($2.00 + $0.20) * 1.25 * 10 Dkt =	$27.50
115%	115	15	($2.00 + $0.20) * 1.5* 15 Dkt =	$49.50

Docket No. NG97-021
JCS-1 Schedule 5

Northern States Power Company - South Dakota
Gas Operations
Minimum Transportation Service Rate

Variable Operating Costs:

(1) Investment in HTI	$454,853
(2) Revised O&M LARR	6.02%
(3) Annual O&M Costs	$27,382.15
(4) HTI Annual Usage (MCF's)	480,726
(5) O&M Recovery Rate	$0.06
(6) Angus Anson Pipeline Rate	$0.04
(7) Contribution to System Fixed Costs	$0.02
(8) Revised Minimum Transportation Rate	$0.12

(1) Actual Plant in Service per JAS-1, Schedule 3, page 1 of 3
(2) Revised O&M LARR factor per JAS-1, Schedule 3, page 2 of 3
(3) Revised O&M LARR * Investment in HTI
(4) Pipeline MCF Capacity per Hour (306) * Hours per Year equivalent for HTI @ Capacity (1,571)
(5) Annual O&M Costs / HTI Annual Usage
(6) Revised Angus Anson Pipeline Rate
(7) Contribution to System Fixed Costs
(8) O&M Recovery plus Angus Anson Pipeline Contribution plus Contribution to System Fixed Costs

Docket No. NG-97-021
JCS-1 Schedule 6

Northern States Power Company - South Dakota
Gas Operations
Customer Charge Calculations

Small Volume Transportation	Medium Volume Transportation
$1,082.00 (1)	$4,417.00 (2)
14.49% (3)	14.49% (3)
$156.78 (4)	$640.02 (4)
12 (5)	12 (5)
$13.07 (6)	$53.34 (6)

(1) Typical Meter Cost for Small Volume Transportation Customer (Model Sprague 675 TC) (includes meter, regulator, labor, sales tax, P&W and 1% A&G)
(2) Typical Meter Cost for Medium Volume Transportation Customer (Model Roots 7M-175 TC) (includes meter, regulator, labor, sales tax, P&W and 1% A&G)
(3) Annualized Fixed Charge Rate less O&M per JAS-1, Schedule 2
(4) Line 1 * Line 2
(5) Number of Months in a Year
(6) Line 3 / Line 4

Docket No. NG97-021
JCS-1 Schedule 7

Northern State Power Company - South Dakota
Gas Operations
Small Volume Transportation Commodity Rate

(1) Estimated Plant in Service	$14,300.00
(2) Revised LARR	20.51%
(3) Annual Revenue Requirement	$2,932.93
(4) Estimated Annual Usage (MCF's)	2,979
(5) Commodity Rate	$0.985
(6) Angus Anson Rate	$0.045
(7) Total Transportation Rate	$1.030

(1) Estimated Pipeline Project Costs
(2) Revised LARR per JAS-1, Schedule 3, Page 2 of 3
(3) Estimated Plant in Service * Revised LARR
(4) Estimated Annual Usage of Minnehaha County Highway Department and Jans Corportation
(5) Annual Revenue Requirement / Estimate Annual Usage
(6) Angus Anson Rate per JAS-1, Schedule 7
(7) Commodity Rate plus Angus Anson Contribution

NSP

Northern States Power Company
Gas Utility

825 Rice Street
Saint Paul, Minnesota 55117-5485

December 29, 1998

William Bullard, Jr.
Executive Director
South Dakota Public Utilities Commission
500 East Capitol Avenue
Pierre, SD 57501

RECEIVED

DEC 30 1998

SOUTH DAKOTA PUBLIC
UTILITIES COMMISSION

Re: Northern States Power Company – South Dakota
Docket No. NG97-021
Errata Corrections to NSP Rebuttal Testimony and Schedules

FAX Received DEC 29 1998

Dear Mr. Bullard:

In discussions with the South Dakota Public Utilities Commission Staff ("Staff"), Northern States Power Company – South Dakota (NSP-SD) realized several errata changes are needed to correct errors in the pre-filed rebuttal testimony filed by NSP - SD on December 23, 1998. All errata corrections are attached and shown in legislative format. The errata corrections should expedite the hearing procedures scheduled for January 4, 1998.

First, Page 9, Line 8 of the rebuttal testimony of Ms. Jamie Seitz should state $0.045 instead of $0.04. This change should be repeated on Schedule 5, Line 6 of Ms. Seitz's testimony.

Second, JCS – 1, Schedule 4 has been corrected to include an Interruptible Transportation commodity rate in the overtake purchase example.

Next, several minor typographical errors to JCS –1, Schedule 2 have been corrected, and are summarized as follows:

- Original Sheet No. 7, Section 3.4 (b)
  The word "of" was replaced with "to" and the misplaced "to" was deleted.

- Original Sheet No. 11, Section 7.2
  The references to "delivery point" now state "delivery point(s)".

- Original Sheet No. 12, Section 8.2
  The term "filing transmittal date" was replaced with "billing date".

- Original Sheet No. 20, Section 2.2
  The word "least" was added before the phrase "one hour prior to the time Transporter must submit daily nominations to Northern pursuant to Northern's tariffs".

- Original Sheet No. 21, Section 2.7
  The margins were corrected to clarify the undertake/overtake purchase rates. In addition, the abbreviation of Firm Transportation was left as TF because the official designation in Northern's tariff is to "TF" service. Therefore, to address Mr. Knadle's concerns about consistency, the abbreviation of Interruptible Transportation was changed to "TI" on Original Sheet No. 22.

- Original Sheet No. 22, Section 2.7
  The reference to the Angus C. Anson fuel supply pipeline surcharge was eliminated, consistent with Page 6, Lines 20-23 of Ms. Seitz's testimony.

- Original Sheet No. 22, Section 3.2
  The reference to +/- 5 percent daily tolerance zone was replaced with "daily delivery variance (+/-) established in Northern's tariff" to be consistent with other sections of the tariff.

Also, Staff had raised a question through Mr. Knadle's direct testimony regarding nomination procedures which NSP – SD inadvertently did not address in rebuttal testimony. Mr. Knadle requested the accuracy of the nomination procedures (described in section 2.2 of JCS-1 – Schedule 2, Original Sheet No. 20) be confirmed. NSP-SD has confirmed the section is accurate.

In addition, to provide further clarification, NSP has provided a summary of the proposed rates by class in Schedule 2, Original Sheet No. 17 of Ms. Seitz's testimony. This sheet was previously reserved for future use. The values shown on this summary would provide the upper and lower limits which would be used in the service charge section of the gas transportation agreement (JCS -1, Schedule 2), signed with individual customers.

Service

NSP will serve a copy of this letter and attachments on the parties indicated on the official service list for this proceeding. A certificate of service and service list is attached.

Conclusion

Thank you for your prompt attention to this matter. Please feel free to call Amy Liberkowski (651-229-2367) with any questions.

Sincerely,

James P. Johnson

James P. Johnson
Senior Attorney

cc: Service List

Q. Do you have any other changes based on Mr. Knadle's testimony?

A. Yes. Mr. Knadle recommends that the floor of the transportation rate be raised to minimally recover variable costs for the customer and to provide for some contribution toward NSP's distribution system fixed costs. Schedule 5 has been provided to identify the new minimum rate of $0.12 per Dth to recover $0.045 as a contribution to the Angus Anson pipeline, $0.06 in incremental O&M costs and $0.02 as a contribution to system fixed costs.

Mr. Knadle also recommends providing specific language on the determination of the customer charge for prospective customers. NSP-SD would like to establish a $12 Customer Charge for Small Volume Customers (peak day requirements of less than 500 therms) and a $50 Customer Charge for Medium Volume Customers (peak day requirements of 500 therms to 1,999 therms) in response to his request. Since customers with similar usage patterns will have the same metering requirements, it will be more practical to establish a customer charge based on typical meter costs for a particular class of customer. Schedule 6 contains the calculation of these charges.

Q. If these new customer charges are established, what corresponding transportation charges are you proposing?

Northern Staates Power Company - South Dakota
Gas Operations
Minimum Transportation Service Rate

Docket No. NG97-021
JCS-1 Schedule 5
Errata Corrected

Variable Operating Costs:

(1) Investment in HTI	$454,853
(2) Revised O&M LARR	6.02%
(3) Annual O&M Costs	$27,382.15
(4) HTI Annual Usage (MCF's)	480,726
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(7) Contribution to System Fixed Costs	$0.02
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(1) Actual Plant in Service per JAS-1, Schedule 3, page 1 of 3
(2) Revised O&M LARR factor per JAS-1, Schedule 3, page 2 of 3
(3) Revised O&M LARR * Investment in HTI
(4) Pipeline MCF Capacity per Hour (306) * Hour per Year equivalent for HTI @ Capacity (1,571)
(5) Annual O&M Costs / HTI Annual Usage
(6) Angus Anson Pipeline Rate per JAS, Schedule 2
(7) Contribution to System Fixed Costs
(8) O&M Recovery plus Angus Anson Pipeline Contribution plus Contribution to System Fixed Costs

Docket No. NG97-021
JCS - 1 Schedule 4
Errata Corrected

Examples of Monthly Cashout Mechanisms

1) Undertakes: Customer takes too little gas and must sell gas to NSP-SD's system.

Assumptions:

Index = $2.00/Dkt
TF Commodity Rate = $0.20 per Dkt^
Customer nominates 100 Dkt

Percent of Nomination Taken	Volume Taken (Dkt)	Under Nomination	Amount Paid to Customer to Purchase Gas Customer Did Not Use	
98%	98	-2	($2.00 + $0.20) * 2 Dkt =	$4.40
90%	90	-10	($2.00 + $0.20) * 0.75 * 10 Dkt =	$16.50
85%	85	-15	($2.00 + $0.20) * 0.5 * 15 Dkt =	$16.50

2) Overtakes: Customer takes too much gas and must purchase gas from NSP-SD's system.

Assumptions:

Index = $2.00/Dkt
TI Commodity Rate = $0.25 per Dkt^
Customer nominates 100 Dkt

Percent of Nomination Taken	Volume Taken (Dkt)	Over Nomination	Amount Customer Pays to Buy Gas	
102%	102	2	($2.00 + $0.25) * 2 Dkt =	$4.50
110%	110	10	($2.00 + $0.25) * 1.25 * 10 Dkt =	$28.13
115%	115	15	($2.00 + $0.25) * 1.5* 15 Dkt =	$50.63

^ The TF and TI commodity rates are for illustrative purposes only. However, the rates reflect the general structure of firm and interruptible transportation commodity rates where firm commodity rates are lower than interruptible commodity rates.

ARTICLE III
MEASUREMENT

3.1 Unit of Measurement and Metering Base. The volumetric measurement base shall be one cubic foot of gas at a pressure base of 14.73 pounds per square inch absolute, at a temperature base of 60 degrees Fahrenheit, and without adjustment for water vapor content.

3.2 Atmosphere Pressure. For the purpose of measurement, the absolute atmospheric (barometric) pressure at each measuring station shall be the atmospheric pressure determined by calculations based on the actual elevation above sea level of the meter at the place of measurement, and shall be stated in pounds per square inch.

3.3 Temperature. If determined to be necessary in the sole discretion of Transporter, the temperature of the gas shall be determined at each point of measurement by means of a properly installed recording thermometer, an indicating thermometer, an electronic temperature measuring device, or a temperature compensating meter of standard manufacture acceptable to Transporter.

3.4 Specific Gravity. If determined to be necessary in the sole discretion of Transporter, the specific gravity of the gas shall be determined at each point of receipt by one of the following methods:

(a) By means of a properly installed recording gravitometer of standard manufacture acceptable to Transporter.

(b) If (a) is not considered feasible, then by use of a portable specific gravity balance of standard manufacture, or other standard device acceptable to~~of~~ Transporter and designed for such purpose or use in conjunction with a continuous sampler.

(c) Other methods acceptable to Transporter.

3.5 Measurement Procedures. Quantities of gas received and delivered hereunder shall be measured in accordance with Procedures contained in ANSI-API 2530, First Edition, AGA Committee Report No. 5, AGA Committee Report No. 7, and AGA Committee Report No. 8, or revisions or amendments thereto.

3.6 Measuring Equipment. Unless otherwise agreed, Transporter will provide, maintain, and operate necessary measuring and regulating stations equipped with flow meters and other necessary measuring equipment by which ~~its~~ quantities of gas delivered from Transporter hereunder shall be determined. Such measuring and regulating stations shall be so installed at the receipt point of the System and at other agreeable points. All flow, measuring, testing, and related equipment shall be of standard manufacture and type acceptable to Transporter.

month by making adjustments to schedules, receipts or deliveries. In no event shall the daily excess or deficiency variance exceed the allowable daily point of delivery variation set forth in Northern's Tariff.

6.3 Monthly Imbalances. Shipper's monthly imbalance shall be the net total of daily variance from all receipts and delivery point(s). Such monthly imbalance shall be corrected in-kind through adjustments to Shipper's schedules, receipts or deliveries in order for Shipper to receive Equivalent Quantities, or by such other method as is then mutually agreed upon by the parties hereto. The cumulative daily variances during any month above or below the quantities scheduled shall not exceed the monthly point of delivery ~~monthly~~ variance set forth in Northern's tariff.

~~6.4 Disposition of Excess Gas. In order to alleviate conditions that threaten the integrity of its System, Transporter may periodically acquire quantities of gas that are in excess of System needs. Transporter may make interruptible sales of such gas form time to time at the point of receipt pursuant to 18 CFR 284.402. Such sales shall be made under rates, terms and conditions mutually agreed upon between Transporter and the purchaser, provided that all such sales shall be fully interruptible.~~

ARTICLE VII
PRESSURE

7.1 Pressure at the Points of Receipt. Shipper shall cause the gas to be delivered at the points of receipt at a pressure sufficient to allow the gas to enter the System; however, Shipper shall not be required to deliver gas to the Transporter at any point of receipt at a pressure in excess of the minimum pressure specified with respect to each receipt point in Exhibit A of Shipper's TSA.

7.2 Pressure at Points(s) of Delivery. Transporter shall deliver gas to Shipper's delivery point(s) at the pressure existing in the Transporter's pipeline; however, Transporter must deliver gas to each point at a pressure not less than the minimum pressure specified with respect to each delivery point in Exhibit A to Shipper's TSA. Transporter, however, shall not be required or permitted to deliver gas at a pressure in excess of the maximum pressure specified for each point of delivery set forth in Exhibit A attached to Shipper's TSA.

ARTICLE VIII
BILLING AND PAYMENT

8.1 Billing. Unless otherwise agreed, on or before the 10th day of each month, Transporter shall render to Shipper a statement of the total amount of gas delivered by Transporter to Shipper at the point(s) of ~~receipt~~ delivery hereunder during the preceding month and the amount due. When information necessary for billing purposes is in the control of Shipper, Shipper shall furnish such information to Transporter on or before the 10th day of the month.

Shipper and Transporter shall have the right to examine at reasonable times, books, records, and recording charts of the other to the extent necessary to verify the accuracy of any statement, charge, or computation made under or pursuant to any of the provisions hereof.

8.2 Payment. Unless otherwise agreed, Shipper shall pay Transporter at its general office or at such other address as Transporter shall designate ~~on or before the 28th day of the month, the amount due for the preceding month. If presentation of a bill by Transporter is delayed after the 20th day of the month, then the time of payment shall be extended accordingly unless shipper is responsible for such delay~~within 20 days after the billing date.

8.3 Remedies for Failure to Pay. Should Shipper fail to pay all or any portion of any bill as herein provided when such amount is due, interest on the unpaid portion of the bill shall occur at a rate of one percent (1%) per month. If such failure to pay continues for 30 days after payment is due, Transporter may, in addition to any other remedy it may have hereunder, suspend further delivery of gas until such amount is paid, if authorized pursuant to the rules of the SDPUC.

~~8.4 Disputed Bills. If Shipper in good faith shall dispute the amount of any such bill or part thereof and shall pay to Transporter such amounts as it concedes to be correct and, at any time thereafter within 30 days of a demand made by Transporter, shall furnish a good and sufficient surety bond in an amount and with surety satisfactory to Transporter, guaranteeing payment to Transporter of the amount ultimately found due upon such bills after a final determination which may be reached either by agreement or judgment of the courts, as may be the case, then Transporter shall not be entitled to suspend further delivery of gas unless and until default be made in the conditions of such bond.~~

8.4~~5~~ Adjustment of Billing Errors. In the event of a meter or billing error, as defined by the Public Utilities Commission, the Company shall recalculate the bills for service during the period of the error and make adjustments of bills in accordance with the rules prescribed by the Commission. If a customer has been overcharged as a result of the error, the recalculated amount will be refunded or, where applicable, a credit on a bill shall be made. If a customer has been undercharged as a result of the error, the Company may bill the customer if the amount due exceeds $10.00. The first billing of the recalculated amount due will be separately billed on a form different from the normal bill form and include a complete explanation of the billing. ~~If it shall be found that at any time or times Shipper has been overcharged or undercharged in any form~~

service to Customer. However, Company may at its option, agree to provide backup gas service.

2.1 REQUIREMENTS AND DELIVERIES; POINT OF DELIVERY. Company agrees to accept delivery of Customer's gas at the inlet of Company's distribution system in Minnehaha County, SD and, on a firm basis, transport and deliver said gas to Customer's point(s) of delivery in volumes up to ___ MMBTU per day, or such other volumes as is mutually agreed. Customer's point(s) of delivery shall be the outlet of the meter installation(s) at ____________________.

2.2 DAILY NOMINATIONS. Customer or Customer's Agent shall on a daily basis advise Company's gas dispatcher in St. Paul of the volumes Customer will request to be delivered during the following Gas Day. Customer may alternatively elect to make a standing nomination with Company, notifying Company on any day when customer's daily deliveries will differ from the standing nomination by the daily delivery variance (+/-) established in Northern's tariffs. ~~more than five (5) percent.~~ Customer shall submit daily or corrected standing nominations to Company at least one hour prior to the time Transporter must submit daily nominations to Northern pursuant to Northern's tariffs. ~~least 24 hours in advance of the start of the Gas Day.~~ Customer's daily or standing nomination shall be its best estimate of the expected utilization for the Gas Day. If Customer and Company mutually agree, Company will relay Customer's daily or standing nomination to Customer's Agent, gas supplier(s), and Transporter.

2.3 DISPATCHING. Customer will adhere to gas dispatching policies and procedures established by Company from time-to-time to facilitate service under this Agreement. Company will inform Customer of any changes in dispatching policies that may affect this Agreement as they occur.

2.4 RATE OF FLOW. The gas supply shall be transported to Customer at a rate of flow up to but not exceeding ________ cubic feet per hour at the point(s) of delivery. Gas shall be delivered at such pressures and temperatures as may exist under operating conditions at Customer's service location. Operating pressures at this location shall normally be _______ psi.

2.5~~7~~ REFUSAL OR DISCONTINUANCE OF SERVICE (a) With reasonable notice, the Company may refuse or discontinue gas service for any of the following reasons: failure to pay amounts payable when due; breach of contract for service; failure to provide the Company with reasonable access to its property or equipment; when the Company is unable to furnish gas service to Customer because it cannot obtain permits or necessary right-of-way; when necessary to comply with any order or request of any governmental authority having jurisdiction.

(b) Upon such notice as is reasonable under the circumstances, the Company may temporarily discontinue gas service when necessary to make repairs, replacements, or changes in Company's equipment or facilities.

(c) Without notice the Company may disconnect gas service to Customer in the event of an unauthorized use of or tampering with Company's equipment or in the event of a condition determined to be hazardous to the Customer, to other customers of the Company, to the public, or to the Company's employees, equipment, or service.

Any discontinuance of service will not relieve Customer from Customer's obligations to the Company.

2.68 BALANCING. Customer and Company agree to balance daily delivery point nominations with actual deliveries (as defined in Paragraph 3.2) on an ongoing basis. Customer agrees to exert its best efforts to keep daily deliveries within daily delivery variance (+/-) established in Northern's tariff. ~~five (5) percent of daily nomination.~~ Customer and Company shall balance as operationally necessary, but no less than monthly. Customer or Customer's Agent shall be responsible for balancing receipt point nominations made to Transporter with receipt point deliveries made by Customer or Customer's Agent's gas supplier(s).

2.97 MONTHLY CASHOUT MECHANISM. Unless otherwise agreed, Customer's monthly imbalance will be corrected by a cashout mechanism. Customer's monthly imbalance is the difference between (1) the sum of Customer's daily nominations for the month and (2) Customer's actual metered use. Monthly volumetric imbalances will not be carried forward to the next calendar month.

Undertake Purchase Payment: If Customer utilizes less gas than the volume Customer nominated and delivered to NSP system, Customer shall sell the undertake gas to NSP. Customer shall be paid an Undertake Purchase Payment equal to the monthly imbalance times the Undertake Purchase Rate.

Monthly Imbalance %	Undertake Purchase Rate
100% to 98%	Index + Transporter's Firm Transportation (TF) Commodity rate(s)
Less than 98% to 90%	[Index + Transporter's TF Commodity rate(s)] x 0.75
Less than 90%	[Index + Transporter's TF Commodity rate(s)] x 0.50

Overtake Charge: If Customer utilizes more gas than the volume Customer nominated and delivered to the NSP system, Customer shall purchase the overtake gas from NSP. Customer shall be assessed an Overtake Charge equal to the monthly imbalance times the Overtake Rate.

Monthly Imbalance %	Overtake Purchase Rate
100% to 102%	Index + Transporter's Interruptible Transportation ~~(IT)~~ (TI) Commodity rate(s)
Greater than 102% to 110%	[Index + Transporter's ~~IT~~ TI Commodity rate(s)] x 1.25
Greater than 110%	[Index + Transporter's ~~IT~~ TI Commodity rate(s)] x 1.50

Index for Monthly Cashout. The Index being used is Inside FERC Gas Market Report's first of the month "Prices of Spot Gas Delivered to Pipelines" for Northern Natural (Demarcation). Applicable pipeline commodity rate consists of all interstate pipeline charges including: GRI surcharge, ~~Angus C. Anson fuel supply pipeline surcharge,~~ fuel costs and commodity rate(s). All conditions of the monthly cashout mechanism apply unless Customer and NSP agree otherwise. However, NSP will treat similarly situated customers on a non-discriminatory basis.

3.~~02~~.8 CHARGES. Commencing with the date of initial deliveries of gas by Company, the charges for this transportation service shall be according to Appendix A.

2.9~~3.1~~ MONTHLY CUSTOMER CHARGE. As established in Appendix A. The customer charge shall not exceed the maximum charge on file with the South Dakota Public Utilities Commission.

3.0~~2~~ VOLUME CHARGE. A Volume Charge equal to the product of (i) the actual deliveries made by Company to Customer during the billing period, and the ~~fixed~~ rate per MMBtu stated in Appendix A. The volume metered by NSP will be considered the actual volume delivered by Company to Customer. All volumes will be adjusted for Btu content and supercompressibility. The volume charge per MMBTU shall not exceed the maximum charge on file with the South Dakota Public Utilities Commission.

3.1~~3~~ TAXES. In addition to the rates specified above, NSP shall collect any federal, state or local sales, use, excise, or other such taxes and fees that are legally effective and applicable to the service provided hereunder.

3.2~~4~~ PENALTY PROVISION. Customer shall be liable for any balancing or other penalties imposed on NSP by Transporter and caused by Customer's actions. Customer shall also be liable for any incremental costs incurred by Company, if any, caused by Customer's failure to stay within ~~the +/- 5 percent daily tolerance zone.~~ the daily delivery variance (+/-) established in Northern's tariff.

3.3~~5~~ ADDITIONAL CHARGE FOR USE DURING CURTAILMENT. If Customer fails to curtail use of gas hereunder when requested by Company, Customer shall pay, in addition to the appropriate above rates, either an amount equal to any payment Company is required to make to Transporter as a result of Customer's failure to curtail, or $10.00 per MMBtu of gas used in excess of the volume of gas to which customer is requested to curtail, whichever amount is greater. Such payments, however, shall not

Northern States Power Company
Sioux Falls, South Dakota
Gas Transportation Service Tariff SDPUC NO. 1

Docket No. NG97-021
JCS – 1 Schedule 2

Original Sheet No. 17

Transportation Rate Summary

Availability

Small Volume	Peak day requirements of less than 500 therms
Medium Volume	Peak day requirements of 500 therms to 1,999 therms
Large Volume	Peak day requirements of at least 2,000 therms

Maximum Customer Charge per Month

Small Volume	$12.00
Medium Volume	$50.00
Large Volume	$290.00

Distribution Charge per Therm

	Minimum	Maximum
Small Volume	$0.012	$0.1030
Medium Volume	$0.012	$0.0500
Large Volume	$0.012	$0.0239

Date Filed: Dec 16, 1997
SDPUC Docket No.:

Issued by: Kent T. Larson
Chief Executive & General Manager

Effective:
Order Date:

CERTIFICATE OF SERVICE

I, Mary E. Lewis, hereby certify that I on this day served copies of the foregoing document or summary on the attached service list by placing the document in the First Class U.S. Mail at St. Paul, Minnesota, or by having the document delivered by hand.

Dated this 29th day of December, 1998.

Mary E. Lewis

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BEFORE THE
PUBLIC UTILITIES COMMISSION
STATE OF SOUTH DAKOTA

IN THE MATTER OF THE APPLICATION FOR
AN ORDER ESTABLISHING
A NATURAL GAS [redacted] UTILITY,
AND TO ESTABLISH INITIAL TRANSPORTATION RATES
FOR NORTHERN STATES POWER COMPANY

Docket No. NG97-021
Surrebuttal Testimony of Gregory A. Rislov
On Behalf of the Commission Staff
December 1998

Q. Are you the same Gregory A. Rislov who earlier in this docket filed testimony and exhibits on behalf of Commission Staff?

A. Yes, I am.

Q. What is the purpose of this additional testimony?

A. Northern States Power Company - South Dakota Gas (NSP) filed rebuttal testimony and exhibits in response to Staff's filing. NSP's rebuttal indicated several fundamental changes in circumstances that were not reflected in Staff's case.

Q. What are the fundamental changes?

A. Two new small volume customers have been added to the system. The original filing included only one large volume customer. There has been a large increase in plant. Perhaps the chief difference has been the way NSP proposes to assign costs to the customers.

Q. Is NSP's assignment different than what was proposed in the original filing?

A. The original filing related to only one customer. There were costs both directly assigned and allocated, and NSP used an acceptable method to determine which costs should be assigned and which should be allocated. The method NSP offers in its rebuttal for assignment and allocation of costs to the two new customers is different, however.

Q. Would you please explain?

A. Yes. It is helpful to visualize four separate components which generate the total costs. They are:

1. Angus Anson pipeline charge.
2. Customer charge costs related to meter costs, meter installation costs, meter reading and service costs, and billing costs.
3. Costs related to the NSP-gas steel main and the regulating equipment at the end of the steel main.
4. The costs of extending service from the steel main to the customer. This includes the costs of the plastic pipe extension and the meterset.

NSP's original filing had three categories as NSP combined the above categories (3) and (4) into one category for billing purposes.

Q. Is that necessarily wrong?

A. No, it's not. The problem came with the rebuttal filing. The two new customers were directly assigned the costs in categories (1), (2) and (4), and were allocated a portion of category (3). Hutchinson Technologies (HTI) was not directly assigned its category (4) costs. HTI's category (4) costs were still being treated as average system costs as they were still combined with category (3). The net of all this is fairness requires category (4) costs to either be: 1. averaged; or 2. directly assigned. Mixing and matching means that some customers will pay too much and others will pay too little.

Q. What is Staff recommending to resolve this?

A. We are recommending that the costs of HTI's extension and meterset be removed from the general cost of service and assigned directly to HTI.

Q. How will NSP recover these costs?

A. There are options. NSP could ask the customer to pay them. NSP could pay the initial costs and then develop a repayment arrangement much like the method used to recover meter costs. NSP could pay them and then assess a volumetric surcharge until the cost is fully repaid. NSP needs to tariff the method(s) it chooses, and the decision could be made after consultation with the prospective customer.

Q. Are there any other changes you wish to mention?

A. I have prepared an updated Exhibit _(GAR-1) to reflect both updated costs and the costs moved out of rate base and assigned directly to HTI. The customer charge applicable to HTI has also changed due to updates. These changes should be self-explanatory.

Q. I have no further questions.

NORTHERN STATES POWER COMPANY
Docket NG97-021 - South Dakota -Gas

Revised Exhibit_(GAR-1)

Time Period (a)	Year (b)	Plant in Service Additions (c)	Net Investment Rate Base (d)	Equity Return (e)	Taxes on Equity Return (f)	Debt Return (g)	Book Depr. (h)	Operating Expenses (i)	Property Taxes (j)	Total Revenue Requirement (k)	Levelized Requirement (L)
0	1997	413,871	407,881	11,086	5,988	6,742	5,980	3,031	1,814	34,391	80,655
1	1998	0	395,935	21,809	11,742	13,267	11,960	18,713	9,979	87,483	80,655
2	1999	0	383,979	21,187	11,382	12,882	11,960	19,250	10,279	88,031	80,655
3	2000	0	372,023	20,588	11,043	12,489	11,960	19,814	10,587	86,405	80,655
4	2001	0	360,067	19,880	10,684	12,101	11,960	20,380	10,905	85,804	80,655
5	2002	0	348,111	19,211	10,344	11,708	11,960	20,980	11,232	85,429	80,655
6	2003	0	336,155	18,582	9,985	11,311	11,960	21,588	11,569	84,981	80,655
7	2004	0	324,199	17,914	9,646	10,915	11,960	22,214	11,916	84,581	80,655
8	2005	0	312,243	17,286	9,297	10,520	11,960	22,858	12,273	84,170	80,655
9	2006	0	300,287	16,616	8,947	10,125	11,960	23,522	12,642	83,806	80,655
10	2007	0	288,331	15,988	8,588	9,730	11,960	24,204	13,021	83,476	80,655
11	2008	0	276,375	15,319	8,249	9,334	11,960	24,908	13,411	83,175	80,655
12	2009	0	264,419	14,670	7,899	8,939	11,960	25,629	13,814	82,907	80,655
13	2010	0	252,463	14,022	7,550	8,544	11,960	26,371	14,228	82,671	80,655
14	2011	0	240,507	13,373	7,201	8,149	11,960	27,138	14,658	82,469	80,655
15	2012	0	228,551	12,724	6,852	7,753	11,960	27,923	15,096	82,300	80,655
16	2013	0	216,595	12,076	6,502	7,358	11,960	28,733	15,549	82,172	80,655
17	2014	0	204,639	11,427	6,153	6,963	11,960	29,566	16,014	82,079	80,655
18	2015	0	192,683	10,779	5,804	6,568	11,960	30,423	16,494	82,023	80,655
19	2016	0	180,727	10,130	5,454	6,172	11,960	31,305	16,989	82,007	80,655
20	2017	0	168,771	9,481	5,105	5,777	11,960	32,213	17,499	82,031	80,655
21	2018	0	156,815	8,832	4,756	5,382	11,960	33,146	18,024	82,097	80,655
22	2019	0	144,859	8,184	4,407	4,987	11,960	34,109	18,565	82,208	80,655
23	2020	0	132,903	7,535	4,057	4,591	11,960	35,098	19,122	82,359	80,655
24	2021	0	120,947	6,886	3,708	4,196	11,960	36,116	19,696	82,557	80,655
25	2022	0	108,991	6,238	3,359	3,801	11,960	37,163	20,286	82,802	80,655
26	2023	0	97,035	5,589	3,009	3,406	11,960	38,241	20,895	83,096	80,655
27	2024	0	85,079	4,940	2,660	3,010	11,960	39,350	21,521	83,438	80,655
28	2025	0	73,123	4,292	2,311	2,615	11,960	40,491	22,167	83,832	80,655
29	2026	0	61,167	3,643	1,962	2,220	11,960	41,665	22,832	84,279	80,655
30	2027	0	49,211	2,994	1,612	1,824	11,960	42,874	23,517	84,779	80,655
31	2028	0	37,255	2,346	1,263	1,429	11,960	44,117	24,223	85,333	80,655
32	2029	0	25,299	1,697	914	1,034	11,960	45,396	24,949	85,946	80,655
33	2030	0	13,343	1,048	564	639	11,960	46,713	25,698	86,618	80,655
34	2031	0	1,387	400	215	243	11,960	48,067	26,469	87,350	80,655
35	2032	0	(10,569)	(249)	(134)	(152)	11,960	49,461	27,263	88,145	80,655
36	2033	0	(22,525)	(898)	(483)	(547)	11,960	50,896	28,081	89,004	80,655
37	2034	0	(34,481)	(1,546)	(833)	(942)	11,960	52,372	28,923	89,929	80,655
38	2035	0	(46,437)	(2,195)	(1,182)	(1,338)	11,960	53,891	29,791	90,923	80,655
39	2036	0	(58,393)	(2,844)	(1,531)	(1,733)	11,960	55,453	30,684	91,986	80,655
40	2037	0	(70,349)	(3,492)	(1,881)	(2,128)	11,960	57,061	31,605	93,121	80,655
41	2038	0	(82,305)	(4,141)	(2,230)	(2,523)	11,960	58,716	32,553	94,331	80,655
42	2039	0	(94,261)	(4,790)	(2,579)	(2,918)	11,960	60,419	33,530	95,617	80,655
43	2040	0	(106,217)	(5,438)	(2,928)	(3,314)	11,960	62,171	34,536	96,982	80,655
44	2041	0	(118,173)	(6,087)	(3,278)	(3,709)	11,960	63,974	35,572	98,428	80,655
45	2042	0	(124,154)	(6,374)	(3,540)	(4,008)	5,980	65,829	36,639	94,330	80,655
Totals		413,871		350,301	188,823	213,447	538,025	1,663,564	828,801	3,610,881	3,710,130
Net present value				165,219	88,884	100,873	128,388	273,217	147,918	804,088	804,092

Time Period (a)	Present Value of Equity Return (m)	Present Value of Taxes-Equity (n)	Present Value of Debt Return (o)	Present Value of Depr. (p)	Present Value of O & M (q)	Present Value of Prop. Tax (r)	Sum of Present Values (s)
0	14,739	7,938	8,981	11,454	24,374	13,169	80,653
1	14,739	7,938	8,981	11,454	24,374	13,169	
2	14,739	7,938	8,981	11,454	24,374	13,169	
3	14,739	7,938	8,981	11,454	24,374	13,169	
4	14,739	7,938	8,981	11,454	24,374	13,169	
5	14,739	7,938	8,981	11,454	24,374	13,169	
6	14,739	7,938	8,981	11,454	24,374	13,169	
7	14,739	7,938	8,981	11,454	24,374	13,169	
8	14,739	7,938	8,981	11,454	24,374	13,169	
9	14,739	7,938	8,981	11,454	24,374	13,169	
10	14,739	7,938	8,981	11,454	24,374	13,169	
11	14,739	7,938	8,981	11,454	24,374	13,169	
12	14,739	7,938	8,981	11,454	24,374	13,169	
13	14,739	7,938	8,981	11,454	24,374	13,169	
14	14,739	7,938	8,981	11,454	24,374	13,169	
15	14,739	7,938	8,981	11,454	24,374	13,169	
16	14,739	7,938	8,981	11,454	24,374	13,169	
17	14,739	7,938	8,981	11,454	24,374	13,169	
18	14,739	7,938	8,981	11,454	24,374	13,169	
19	14,739	7,938	8,981	11,454	24,374	13,169	
20	14,739	7,938	8,981	11,454	24,374	13,169	
21	14,739	7,938	8,981	11,454	24,374	13,169	
22	14,739	7,938	8,981	11,454	24,374	13,169	
23	14,739	7,938	8,981	11,454	24,374	13,169	
24	14,739	7,938	8,981	11,454	24,374	13,169	
25	14,739	7,938	8,981	11,454	24,374	13,169	
26	14,739	7,938	8,981	11,454	24,374	13,169	
27	14,739	7,938	8,981	11,454	24,374	13,169	
28	14,739	7,938	8,981	11,454	24,374	13,169	
29	14,739	7,938	8,981	11,454	24,374	13,169	
30	14,739	7,938	8,981	11,454	24,374	13,169	
31	14,739	7,938	8,981	11,454	24,374	13,169	
32	14,739	7,938	8,981	11,454	24,374	13,169	
33	14,739	7,938	8,981	11,454	24,374	13,169	
34	14,739	7,938	8,981	11,454	24,374	13,169	
35	14,739	7,938	8,981	11,454	24,374	13,169	
36	14,739	7,938	8,981	11,454	24,374	13,169	
37	14,739	7,938	8,981	11,454	24,374	13,169	
38	14,739	7,938	8,981	11,454	24,374	13,169	
39	14,739	7,938	8,981	11,454	24,374	13,169	
40	14,739	7,938	8,981	11,454	24,374	13,169	
41	14,739	7,938	8,981	11,454	24,374	13,169	
42	14,739	7,938	8,981	11,454	24,374	13,169	
43	14,739	7,938	8,981	11,454	24,374	13,169	
44	14,739	7,938	8,981	11,454	24,374	13,169	
45	14,739	7,938	8,981	11,454	24,374	13,169	
Net present value	165,215	88,959	100,871	128,362	273,217	147,918	804,089
Levelized Annual Revenue Requirement	3.56%	1.92%	2.17%	2.77%	5.89%	3.18%	19.49%

Rebutted Exhibit — (RLK-1)
Page 1 of 6

Northern States Power Company
Sioux Falls, South Dakota
Gas Transportation Service Tariff SDPUC NO. 1

~~Docket No. NG97-021~~
~~JCS-1 Schedule 2~~
~~Original Sheet No. 17~~

Transportation Rate Summary

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SOUTH DAKOTA PUBLIC
UTILITIES COMMISSION

Availability

Small Volume	Peak day requirements of less than 500 therms
Medium Volume	Peak day requirements of 500 therms to 1,999 therms
Large Volume	Peak day requirements of at least 2,000 therms

Maximum Customer Charge per Month

Small Volume	$12.00
Medium Volume	$50.00
Large Volume	~~$290.00~~ $ 270.00

Distribution Charge per Therm

	Minimum	Maximum
Small Volume	~~$0.012~~ $ .0116	~~$0.1030~~ $ .1005
Medium Volume	~~$0.012~~ $ .0116	~~$0.0500~~
Large Volume	~~$0.012~~ $ .0116	~~$0.0239~~ $ .0238

EXHIBIT
12

Date Filed: Dec 16, 1997
SDPUC Docket No.:

Issued by: Kent T. Larson
Chief Executive & General Manager

Effective:
Order Date:

Northern States Power Company - South Dakota
Gas Operations
Customer Charge Calculations

Small Volume Transportation	Medium Volume Transportation
$1,082.00 (1)	$4,417.00 (2)
13.60% ~~14.49%~~ (3)	13.60% ~~14.49%~~ (3)
$ 147.15 ~~$156.78~~ (4)	$ 600.71 ~~$640.02~~ (4)
12 (5)	12 (5)
$ 12.26 ~~$13.07~~ (6)	$ 50.06 ~~$53.34~~ (6)

(1) Typical Meter Cost for Small Volume Transportation Customer (Model Sprague 675 TC) (includes meter, regulator, labor, sales tax, P&W and 1% A&G)
(2) Typical Meter Cost for Medium Volume Transportation Customer (Model Roots 7M-175 TC) (includes meter, regulator, labor, sales tax, P&W and 1% A&G)
(3) Annualized Fixed Charge Rate less O&M per JAS-1, Schedule 2
(4) Line 1 * Line 2
(5) Number of Months in a Year
(6) Line 3 / Line 4

Rebuttal Exhibit ___ (RLK-1)
Page 3 of 6

Schedule 4

Northern States Power Company - South Dakota
Gas Operations
Development of Rates
Maximum and Proposed Large Volume Transportation
Customer Charge

The natural gas maximum transportation rate developed below pertains to NSP's newly installed 4.5" lateral pipeline extending from the Angus Anson Supply line to the Sioux Empire Development Park 5, which will serve HTI. The proposed maximum rate in Column B of $0.239 per Mcf includes $0.045 per Mcf for use of the Angus Anson line (Line 4). That rate is a pass-through to HTI. NSP-SD is not seeking approval of the Angus Anson portion of the rate. For information, Schedule 7 of Exhibit 4 shows a calculation supporting the $0.045 per Mcf charge for use of the Angus Anson line.

	Amounts (A)			Maximum Rates (B)	
4.5" NSP-SD Lateral Pipeline Rate					
(1) Annualized Revenue Requirements	~~$93,290~~	$80,655			
(2) Pipeline MCF Capacity per Hour	306				
(3) Hours Per Year @ Capacity	1,571		480,726 Mcf	~~$0.194~~	$.168
(4) Angus Anson Pipeline Rate				$0.045	
(5) Total Transportation Rate				~~$0.239~~	$.213
Customer Charge					
(6) Investment in Metering at HTI	$19,021				
(7) Annualized Fixed Charge Rate less O&M	~~14.40%~~	13.60%			
(8) Annualized Metering Revenue Requirements	~~$2,736~~	$2,587			
(9) Annual Meter Reading and Billing Costs	$720				
(10) Total Customer Costs Supporting Customer Charge	~~$3,426~~	$3,307	Monthly	~~$290~~	$276

Sources and Notes:

Line 1: Revenue Requirements per Schedule 3, Page 2 of 3.
Line 2: 90% of Pipeline capacity of 340 Mcf/Hr.
Line 3, Col A: Hours per Year equivalent for HTI @ capacity.
Line 3, Col. B: Line 1/(Line 2 times Line 3), Col. A.
Line 4, Column B: Negotiated rate for Angus C. Anson pipeline. See text for further discussion.
Line 5, Column B: Total maximum natural gas transportation supported by cost evidence.
Line 6: Meter investment at HTI per Schedule 5.
Line 7: Fixed charge rate from Schedule 3, Page 2 of 3, less O&M component.
Line 8: Line 6 times Line 7.
Line 9: Meter reading, billing, and service costs (O&M) at $60 per month.
Line 10: Total customer costs in Col. A. Monthly maximum customer charge in Col. B.

Rebuttal Exhibit __ (RLK-1)
Page 4 of 6

Northern States Power Company - South Dakota
Gas Operations
Minimum Transportation Service Rate

Docket No. NG97-021
~~JCS-1 Schedule 5~~
Errata ~~Corrected~~

Variable Operating Costs:

(1) Investment in HTI	~~$454,855~~	$ 413,871
(2) Revised O&M LARR	~~6.02%~~	5.89 %
(3) Annual O&M Costs	~~$27,382.13~~	$ 24,377
(4) HTI Annual Usage (MCF's)	480,726	
(5) O&M Recovery Rate	~~0.06~~	$ .051
(6) Angus Anson Pipeline Rate	$0.045	
(7) Contribution to System Fixed Costs	$0.02	
(8) Revised Minimum Transportation Rate	~~$0.12~~	$ .116

(1) Actual Plant in Service per JAS-1, Schedule 3, page 1 of 3
(2) Revised O&M LARR factor per JAS-1, Schedule 3, page 2 of 3
(3) Revised O&M LARR * Investment in HTI
(4) Pipeline MCF Capacity per Hour (306) * Hour per Year equivalent for HTI @ Capacity (1,571)
(5) Annual O&M Costs / HTI Annual Usage
(6) Angus Anson Pipeline Rate per JAS, Schedule 2
(7) Contribution to System Fixed Costs
(8) O&M Recovery plus Angus Anson Pipeline Contribution plus Contribution to System Fixed Costs

Rebuttal Exhibit — (RLK-1)
Page 5 of 6
~~Docket No. NG97-021~~
~~JCS-1 Schedule 7~~

Northern State Power Company - South Dakota
Gas Operations
Small Volume Transportation Commodity Rate

(1) Estimated Plant in Service	~~$14,300.00~~	$ 12,107
(2) Revised LARR	~~20.51%~~	19.49 %
(3) Annual Revenue Requirement	$2,932.93 •	$ 2,359.65
(4) Estimated Annual Usage (MCF's)	2,979	
(5) Commodity Rate	~~$0.985~~ •	$ .792
(6) Angus Anson Rate	$0.045	
(7) NSP - Gas Transportation rate		$ .168
(8) ~~(7)~~ Total Transportation Rate	~~$1.030~~	$ 1.005

(1) Estimated Pipeline Project Costs
(2) Revised LARR per JAS-1, Schedule 3, Page 2 of 3
(3) Estimated Plant in Service * Revised LARR
(4) Estimated Annual Usage of Minnehaha County Highway Department and Jans Corporation
(5) Annual Revenue Requirement / Estimate Annual Usage
(6) Angus Anson Rate per JAS-1, Schedule 7
(7) Commodity Rate plus Angus Anson Contribution

Northern State Power Company - South Dakota
Gas Operations
Large ~~Small~~ Volume Transportation Commodity Rate

(1) Estimated Plant in Service	~~$14,300.00~~	$ 40,982
(2) Revised LARR	~~20.51%~~	19.49%
(3) Annual Revenue Requirement	$2,932.93 *	$ 7,987
(4) Estimated Annual Usage (MCF's)	~~2,979~~	317,342
(5) Commodity Rate	~~$0.985~~ *	$ .025
(6) Angus Anson Rate	$0.045	
(7) NSP - Gas transportation rate		$ .168
(8) ~~(7)~~ Total Transportation Rate	~~$1.030~~	$ .238

(1) Estimated Pipeline Project Costs
(2) Revised LARR per JAS-1, Schedule 3, Page 2 of 3
(3) Estimated Plant in Service * Revised LARR
(4) Estimated Annual Usage of Minnehaha County Highway Department and Jans Corporation
(5) Annual Revenue Requirement / Estimate Annual Usage
(6) Angus Anson Rate per JAS-1, Schedule 7
(7) Commodity Rate plus Angus Anson Contribution

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February 2, 1999

Rolayne Ailts Wiest
Public Utilities Commission
State Capitol
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Pierre, South Dakota 57501-5070

RECEIVED
FEB 03 1999
SOUTH DAKOTA PUBLIC
UTILITIES COMMISSION

RE: **NSP GAS**
Docket NG97-021
Our file: 0185.01

Dear Rolayne:

I have visited with Bob Riter, Jr., and he has indicated no opposition to a short extension of time for NSP's initial brief. I have completed an initial draft of the brief, but my lobbying responsibilities make it difficult to communicate with my client. I would appreciate having a little extra time to do so.

I would appreciate an extension of time of two weeks beyond February 8 to file the brief. Thank you very much.

Yours truly,

MAY, ADAM, GERDES & THOMPSON LLP

BY [signature]

DAG:mw

cc: Bob Riter, Jr.
Karen Cremer

RECEIVED

FEB 08 1999

SOUTH DAKOTA PUBLIC UTILITIES COMMISSION

LAW OFFICES

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February 8, 1999

<u>HAND DELIVERED</u>

Mr. William Bullard, Jr.
Executive Director
Public Utilities Commission
State Capitol
500 East Capitol Avenue
Pierre, South Dakota 57501-5070

RE: **NSP NATURAL GAS**
Docket NG97-021
Our file: 0185

Dear Bill:

Enclosed are original and 11 copies of NSP's opening brief in this docket, to which is attached its revised tariff. Please file the enclosure.

I am also enclosing an additional face page of the brief. Please date stamp it and return it to me in enclosed self-addressed stamped envelope.

With a copy of this letter, I am sending a copy of the brief and tariff to the service list.

Yours truly,

MAY, ADAM, GERDES & THOMPSON LLP

BY:

DAG:mw

Enclosures

cc/enc: Bob Riter, Jr.
Karen Cremer
Jim Wilcox
J.P. Johnson
Denny Fulton

RECEIVED

FEB 08 1999

SOUTH DAKOTA PUBLIC
UTILITIES COMMISSION

BEFORE THE PUBLIC UTILITIES COMMISSION
STATE OF SOUTH DAKOTA

IN THE MATTER OF THE APPLICATION FOR AN ORDER ESTABLISHING A NATURAL GAS UTILITY, AND TO ESTABLISH INITIAL NATURAL GAS TRANSPORTATION RATES FOR NORTHERN STATES POWER COMPANY.	)))))	NG97-021 **APPLICANT'S OPENING BRIEF**

Pursuant to the briefing schedule established by the Commission, Northern States Power Company - South Dakota operations ("NSP-SD") submits its opening brief in this matter. Intervenor MidAmerican Energy Company will be called "MidAmerican," and Commission Staff will be "Staff."

On December 16, 1997, NSP-SD filed with the Commission an application for an order establishing a natural gas local distribution utility, and to establish initial gas transportation rates. On January 28, 1998, the Commission entered its order allowing NSP to flow gas, subject to refund, to accommodate its initial customer, Hutchinson Technology, Inc. ("HTI"). On April 7, 1998, NSP-SD filed an amended application seeking to be regulated as a gas utility, as distinguished from a gas distribution utility. On May 6, 1998, the Commission entered its order taking jurisdiction over NSP-SD as a gas utility and approving the intervention of MidAmerican and PAM Natural Gas. PAM Natural Gas did not appear at the hearing in this matter.

As stated by Chairman Burg at the outset of the hearing in this matter, the issues for determination by the Commission are whether the Commission will grant NSP's request to establish natural gas transportation tariffs and whether the Commission will grant NSP's request for a waiver of ARSD 20:10:13:04 and 20:10:13:05.[1] The record demonstrates the Commission should accept the NSP-SD rates and tariff (as revised) and grant the waiver request.

FACTS

NSP's Angus C. Anson Generating Site ("Anson Plant") is served by a 13-mile, 12-inch high pressure pipeline ("Anson Line") that interconnects with the Northern Natural Gas Company pipeline just east of Harrisburg and proceeds to the Angus Anson site.[2] The Anson Line was initially constructed to serve the fuel needs of the combustion turbines ("Cts") at the Anson Plant, plus serve anticipated Cts in the future. In 1997, NSP-SD constructed a 3.5-mile, 4.5-inch steel lateral ("Hutchinson Lateral") from the Anson Pipeline to the Sioux Empire Development Park #5 in northeastern Sioux Falls. The Company initially constructed the Hutchinson Lateral in order to meet the natural gas service requirements of HTI, and to provide a competitive gas delivery alternative to HTI and other potential gas users in the industrial park.[3]

[1]TR 3.

[2]Wilcox prefiled testimony 4.

[3]Wilcox prefiled testimony 5, TR 10.

The NSP-SD application, as amended, only seeks approval of the rates and tariffs for the Hutchinson Lateral. NSP-SD has the right to use the Anson Line for a fee, and this expense is included in the proposed rate. While this application is not intended to determine the rates and tariffs for the Anson Line, it does provide a means for NSP-SD to market the unused capacity of the Anson Line. The unused firm capacity available is 325 mcf per hour.[4]

Presently, NSP-SD provides retail gas transportation service to three customers: Hutchinson Technology, Inc., Minnehaha County and Jans Corporation. Additional facts will be recited in discussion of the specific issues presented by the docket.

ISSUES

1. Does NSP-SD propose a just and reasonable rate in its proposed tariff?
2. Are the conditions of service proposed by NSP-SD adequate, efficient and reasonable?

DISCUSSION

1. NSP-SD proposes a just and reasonable rate.

This Commission has sole and exclusive jurisdiction over rates charged and conditions of service employed by gas and electric utilities in this state, including intrastate gas pipeline

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[4]Wilcox prefiled testimony 4, TR 9.

facilities such as the Hutchinson Lateral. SDCL §§ 49-34A-5, 49-34A-6 and 49-34A-39. As provided by SDCL § 49-34A-6:

> Every rate made, demanded or received by any public utility shall be just and reasonable. Every unjust or unreasonable rate shall be prohibited. The Public Utilities Commission is hereby authorized, empowered and directed to regulate all rates, fees and charges for the public utility service of all public utilities, including penalty for late payments, to the end that the public shall pay only just and reasonable rates for service rendered.

In this docket, there is substantial agreement between NSP-SD and Staff on all fundamental points necessary to achieve a just and reasonable rate. No countervailing evidence has been offered by any party. MidAmerican offered no testimony whatsoever, and simply cross examined NSP and staff witnesses. PAM Natural Gas did not participate in the hearing.

NSP's rate testimony came from James A. Smith, who adopted the direct schedules and testimony of John Winter and filed his own rebuttal testimony.[5] Mr. Smith adopted Staff's methodology set forth in Gregory Rislov's surrebuttal testimony, Exhibit 11, and his rebuttal exhibit, Exhibit 12, prepared by Robert Knadle.[6] While MidAmerican cross examined both Mr. Smith and Mr. Rislov at length concerning their conclusions, it remains clear that:

- NSP-SD's current status is that of a start-up operation, and it is not unusual initially for costs to not be fully recov-

[5]TR 29 and 30.

[6]TR 67.

ered through calculated rates during the start-up period. The rates must be based upon a proportionate allocation of the capacity of the system. Otherwise, subsequent sales would exceed the volume used to establish the rate, resulting in a situation where the utility could over recover its cost of service.[7]

- Substantial unused firm capacity does not exist on the Anson Line. HTI is projected to eventually require more than half the capacity of the Hutchinson Lateral, 202 mcf per hour from a total allowed capacity of 325 mcf per hour.[8] Minnehaha County and Jans Corporation require additional capacity and the remaining load will eventually be allocated to additional customers.[9]
- The purpose of the computations of both Mr. Smith and Mr. Rislov is to determine a transportation rate for the entire Hutchinson Lateral line, which then can be applied to the prorated capacity needed to serve any particular customer.[10] NSP-SD has accepted the rate structures suggested by Staff in Exhibits 11 and 12. In so doing, this represents an agreement on total investment, cost of service, initial

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[7]TR 68, 113.

[8]TR 38, 39.

[9]TR 43.

[10]TR 48, Rislov surrebuttal testimony, Exhibit 11, p. 2.

projected volumes and the minimum and maximum transportation commodity rates by class. Additionally, NSP-SD has agreed to a separation of customer specific costs, individual customer facility extension costs and metering, thus establishing a rate separate from the Hutchinson Lateral transport rate. This permits a fairer allocation of customer specific costs.[11]

Mr. Rislov has suggested in his initial testimony on pages 8 and 9 that NSP-SD file its cost of service in 2000. At transcript page 114, line 18, Mr. Rislov refers to "rate case type data" as comprising the year 2000 filing. Ms. Wiest then asks whether a "new rate case" should be filed by May 1 of 2000, and Mr. Rislov responds in the affirmative. NSP-SD agrees to that which is reasonable to verify the accuracy of cost estimates being used to establish the cost of service. However, there seems to be some misunderstanding as to terminology. NSP-SD agrees to provide such information a South Dakota jurisdictional gas financial summary would show on May 1, 2000, similar to NSP-SD's annual jurisdictional electric financial report. Presently, it would be premature to require a full blown rate case in advance. The Commission has the authority to investigate NSP-SD's gas rates and services. SDCL § 49-34A-26. NSP-SD would suggest that the Commission order the filing of cost data as of May 1, 2000. Thereafter, if Commission

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[11] TR 67, Exhibit 11, p. 2.

or staff believe that further proceedings are necessary, they can be ordered.

NSP-SD's concern about conditioning present approval of its tariff on filing a full rate case is practical. The test year cost of service is $93,000 annually. This compares to 1997 NSP-SD electric revenues of $80.3 million (see NSP-SD's May 1, 1998, jurisdiction report, on file with the Commission). A tripling of NSP-SD gas revenues would not cause a material change in overall NSP-SD financial results. Also, the annual costs are fairly fixed on categories such as depreciation, return and contracted O & M. The Hutchinson Lateral is a fixed asset, and customer connections will be direct charged. The only factor which may change is sales volume. If NSP-SD's sales volume were to increase above the level used to design the proposed rate, it would be a fairly simple task to adjust the rate prospectively. However, the Commission does not need a full rate case to make such a finding.

Based upon the substantial agreement of Staff and NSP-SD concerning the cost of service calculation, it is submitted that the Commission should approve NSP-SD's proposed rates as just and reasonable.

At page 46, of the transcript NSP-SD agreed to provide any feasibility study which might have been part of the basis of the decision to market the unused firm capacity of the Anson Line. None was conducted, so there is nothing to produce. The decision was a management decision based upon the existence of unused firm capacity and an opportunity to market that capacity in a cost effective manner to the Sioux Empire Development Park #5.

2. NSP-SD proposes conditions of service which are adequate, efficient and just.

Under SDCL § 49-34A-2, public utilities are required to provide conditions of service which are adequate, efficient and reasonable. The uncontested evidence supports this conclusion.

a. System exit charges.

Only after negotiations occurred between HTI and NSP-SD did the Hutchinson Lateral project come to fruition. It is speculative at this point to suggest that exit charges would be applied against HTI, or any customer. Any utility contemplates that its customer will remain in business and continue to perform under the contract as negotiated in good faith. So long as the customer remains in business, any issue of application of exit charges is inapplicable.

The agreement to install the lateral line, as mentioned, was subject to negotiation. HTI was provided a copy of the draft South Dakota tariff which included exit fee provisions. It should also be remembered that NSP has an obligation to both its ratepayers and to its stockholders to be prudent in new market entry. It is a reasonable protection for NSP's ratepayers to require that business commitments be honored. HTI made an economic choice to select NSP-SD as its gas transporter, and accepted the arrangement knowing the requirement of potential exit fees. This is simply a prudent arrangement for both businesses.

Likewise, both Minnehaha County and Jans Corporation were aware (or should have been aware) of the exit charge provisions before the transactions were entered into. The Commission should approve reasonable exit charge language in NSP-SD's revised tariff, which is submitted with this brief. See, Exhibit A, attached hereto.

b. Backup gas service.

NSP-SD has agreed to remove this provision from the tariff at Staff's suggestion. It therefore is not an issue for Commission determination.

c. Transportation service for resale.

The issue of providing transportation services to others for resale was injected into the proceeding through the cross examination of MidAmerican. It is the position of NSP-SD that it is well within its entrepreneurial discretion under present South Dakota law to determine whether or not it will permit transport of gas for resale over its facilities. NSP's gas tariffs in other states do not allow transportation for resale, and NSP-SD is seeking to be consistent. For the Commission to require transportation of gas for resale would be to effectively impose restructuring of the gas utility business in this state, contrary to both custom and statute.

Gas service is defined alternatively as the retail sale of natural gas through a distribution pipeline to 50 or more customers, or as the sale of transportation services by an intrastate natural gas pipeline. SDCL § 49-34A-1(8). An intrastate natural gas pipeline is defined as one located entirely within this state transporting gas from a receipt point to one or more locations for customers other than the pipeline operator. SDCL § 49-34A-1(9A). This definitional section is silent as to whether an intrastate pipeline operator is required, as distinguished from permitted, to allow the transport of wholesale gas for resale. Here, NSP-SD proposes to provide service under the tariff only to retail end users, just as it provides electric services under its South Dakota Electric Rate Book only to retail customers. (Wholesale electric sales and transmission-only service is regulated by FERC, not the Commission.)

Moreover, other statutes support the conclusion that such a decision is for the utility to make. Under South Dakota law, gas utilities are rate regulated. SDCL § 49-34A-6. Typically, "deregulation" contemplates that rates are set in the marketplace. A fundamental component of mandatory deregulation injects competition as the necessary alternative to rate regulation. Not only does the state presently provide for rate regulation of gas utilities like NSP-SD, but it specifically prohibits rate increases to prevent competition. SDCL § 49-34A-20. If the Commission sought to require NSP to deregulate, the principle of equal protection of laws would require the Commission to do so for all gas utilities. South Dakota Const., Art. VI, § 18; State vs. Scougal, 3 SD 55, 51 NW 858 (1892) (state could not prohibit individual citizens from conducting banking business except in towns of less than 500 population).

CONCLUSION

NSP-SD has proposed a just and reasonable rate, as evidenced by the agreement of the only witnesses testifying on the subject. NSP-SD has provided adequate, efficient and reasonable conditions of service in its tariff. The Commission should approve the tariff and cost of service as agreed upon.

Dated this 8th day of February, 1999.

MAY, ADAM, GERDES & THOMPSON LLP

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CERTIFICATE OF SERVICE

David A. Gerdes of May, Adam, Gerdes & Thompson LLP hereby certifies that on the 8th day of February, 1998, he mailed by United States mail, first class postage thereon prepaid, a true and correct copy of the foregoing in the above-captioned action to the following at their last known addresses, to-wit:

Karen Cremer
Public Utilities Commission
State Capitol
500 East Capitol Avenue
Pierre, South Dakota 57501-5070

Bob Riter
Attorney at Law
P.O. Box 280
Pierre, South Dakota 57501

David A. Gerdes

NORTHERN STATES POWER COMPANY - SOUTH DAKOTA

GAS TRANSPORTATION SERVICE TARIFF

ORIGINAL VOLUME NO. 1

TABLE OF CONTENTS

PRELIMINARY STATEMENT

Northern States Power Company - South Dakota (hereafter "NSP-SD" or "Transporter") is an electric utility and prospectively a natural gas utility company planning to engage in the business of transporting and distributing natural gas in intrastate commerce to end users in the State of South Dakota. NSP's system consists of approximately ~~three~~ four miles of distribution lateral pipeline in Minnehaha County, South Dakota. NSP-SD will take delivery of natural gas at the compressor station located on the Angus C. Anson site east of Sioux Falls and deliver it to end-use customers along or at the terminus of the NSP distribution lateral line in Sioux Falls, South Dakota.

GENERAL TERMS AND CONDITIONS

ARTICLE 1
DEFINITIONS

1.1 "Btu" shall mean one British Thermal Unit.

1.2 "Contract Demand" shall mean the aggregate of the maximum daily quantities of gas, expressed in dkt per day, which Transporter is obligated to accept for transportation for the account of Shipper from the points of receipt as set forth in the Transportation Service Agreement ("TSA") between Transporter and Shipper.

1.3 "Contract ~~Year~~Period" shall mean the ~~twelve month~~ period ~~commencing~~ specified in Appendix A~~November 1 and terminating on October 31 of each year~~, until ~~this Agreement shall have~~the TSA has expired or otherwise been terminated in accordance with its terms.

1.4 "Day" shall mean the period of 24 consecutive hours, starting at 9:00 a.m. Central Clock Time, or such other 24 hour gas day period as established in Northern's Tariff.

1.5 "Dkt" shall mean the quantity of heat energy which is equivalent to 1,000,000 British Thermal Units (BTU). One "dkt" of gas means the quantity of gas which contains one dekatherm of heat energy. The total dekatherms are calculated by multiplying the gas volume in Mcf by its total gross heating value, divided by 1,000.

1.6 "Equivalent Quantities" shall mean the sum of quantities of gas measured in dkt received by Transporter and delivered for the account of Shipper at the points of receipt and delivery during any given period of time reduced by the sum of Shipper's Pro Rata Share of Lost and Unaccounted For Gas, calculated as a percentage of Shipper's throughput on Transporter's system -resulting from the operations of the System during the same period of time. In the event the ownership of gas lost as a result of an event of force majeure can be reasonably identified, the quantity thereof shall be charged to the Shipper or Shippers so identified.

1.7 "Gas" shall mean natural gas, unmixed or any mixture of natural and artificial gas.

1.8 "Gross Heating Value" shall mean the number of BTU's produced by the complete combustion, at a constant pressure, of the amount of gas which would occupy a volume of one (1) cubic foot at a temperature of 60 degrees Fahrenheit on a dry basis and at a pressure of 14.73 psia with air of the same temperature and pressure as the gas, when the products of combustion are cooled to the initial temperature of the gas and air, and when the water formed by combustion has been condensed to the liquid state.

1.9 "Maximum Daily Quantity" shall mean the maximum quantity expressed in dkt per day that the Transporter is obligated to receive for the account of Shipper at the point of receipt, as established in Exhibit A to Shipper's TSA.

1.10 "Mcf" shall mean 1,000 cubic feet of gas determined in accordance with the measurement base described in Paragraph 3.1 hereof.

1.11 "Month" shall mean the period beginning at 9:00 a.m. Central Clock Time on the first day of the calendar month and ending at the same hour on the first day of the next succeeding month.

1.12 "Northern" shall mean Northern Natural Gas Company, its successors and assigns.

1.13 "Northern's Tariff" shall mean the Northern's FERC Gas Tariff as it may be in effect from time to time.

1.14 "Pro Rata Share" shall mean the ratio that the quantity of gas delivered to Transporter for the account of Shipper to the total quantity of gas delivered to Transporter by all shippers for transportation in the System during any given period of time.

1.15 "SDPUC" shall mean the South Dakota Public Utilities Commission or any commission, agency or other state governmental body succeeding to the powers of such commission.

1.16 "Shipper" shall mean any party to a TSA providing for transportation of natural gas on Transporter's System. For purposes of Articles V and VI, "Shipper" shall also mean Shipper's Agent designated to provide day-to-day transportation management for Shipper. Shipper may change such designation from time to time upon written notice to Transporter.

1.17 "System" shall mean the pipeline and related pipeline facilities at the time owned by Transporter.

1.18 "TSA" shall mean the Transportation Service Agreement between Transporter and Shipper in the form set forth in this Tariff.

1.19 "Unaccounted For Gas" shall mean the difference between the sum of all input quantities of gas to the System and the sum of all output of gas from the System, which difference shall include but shall not be limited to gas used and accounted for in System operations, meter errors (subject to Section 3.8) and gas lost as a result of an event for force majeure, the ownership of which cannot be reasonably identified.

ARTICLE II
QUALITY

2.1 Quality Standards of Gas Received by Transporter. The gas to be delivered by Transporter shall be of merchantable quality and shall meet the minimum quality standards, as may be established or revised from time to time in Northern's Tariff.

2.2 Quality Tests. At the point of receipt, Transporter may cause tests to be made, by approved standard methods in general use in the gas industry, to determine whether the gas conforms to the quality specifications set out in Paragraph 2.1 hereof. Such tests shall be made at such intervals as Transporter may deem reasonable, and at other times, but not more often than once per day, or at the request of Shipper.

2.3 Failure to Conform. If gas delivered by Shipper does not comply with the quality specifications set out in Paragraph 2.1 hereof, Transporter shall have the right, in addition to all other remedies available to it by law, to refuse to accept any such gas. Transporter may, at its option and upon notice to Shipper, accept receipt of gas not complying with the quality specifications set out in Paragraph 2.1 herein provided. Transporter, at the expense of Shipper, may make all changes necessary to bring such gas into compliance with such specifications.

2.4 Quality Standards of Gas Transported By Transporter. Transporter shall use reasonable diligence to deliver gas for Shipper which shall meet the quality specifications set out in Paragraph 2.1 hereof, but shall only be obligated to deliver gas of the quality which results from the commingling of gas received by Transporter from Shipper and other shippers.

ARTICLE III
MEASUREMENT

3.1 Unit of Measurement and Metering Base. The volumetric measurement base shall be one cubic foot of gas at a pressure base of 14.73 pounds per square inch absolute, at a temperature base of 60 degrees Fahrenheit, and without adjustment for water vapor content.

3.2 Atmosphere Pressure. For the purpose of measurement, the absolute atmospheric (barometric) pressure at each measuring station shall be the atmospheric pressure determined by calculations based on the actual elevation above sea level of the meter at the place of measurement, and shall be stated in pounds per square inch.

3.3 Temperature. If determined to be necessary in the sole discretion of Transporter, the temperature of the gas shall be determined at each point of measurement by means of a properly installed recording thermometer, an indicating thermometer, an electronic temperature measuring device, or a temperature compensating meter of standard manufacture acceptable to Transporter.

3.4 Specific Gravity. If determined to be necessary in the sole discretion of Transporter, the specific gravity of the gas shall be determined at each point of receipt by one of the following methods:

(a) By means of a properly installed recording gravitometer of standard manufacture acceptable to Transporter.

(b) If (a) is not considered feasible, then by use of a portable specific gravity to balance of standard manufacture, or other standard device acceptable ~~of~~ to Transporter and designed for such purpose or use in conjunction with a continuous sampler.

(c) Other methods acceptable to Transporter.

3.5 Measurement Procedures. Quantities of gas received and delivered hereunder shall be measured in accordance with Procedures contained in ANSI-API 2530, First Edition, AGA Committee Report No. 5, AGA Committee Report No. 7, and AGA Committee Report No. 8, or revisions or amendments thereto.

3.6 Measuring Equipment. Unless otherwise agreed, Transporter will provide, maintain, and operate necessary measuring and regulating stations equipped with flow meters and other necessary measuring equipment by which ~~its~~ quantities of gas delivered from Transporter hereunder shall be determined. Such measuring and regulating stations shall be so installed at the receipt point of the System and at other agreeable points. All flow, measuring, testing, and related equipment shall be of standard manufacture and type acceptable to Transporter.

Transporter and Shipper shall cause the recording chart on all gas measurement equipment to be changed, or mechanical or electronic indices read, by either Transporter or by Shipper's representative (where economical) on a daily basis. If telemetering is not installed, Shipper shall change recording charts on Transporter's Delivery point metering facilities or otherwise read Transporter's meter on a daily basis at a time specified by Transporter. Shipper may install check measuring equipment, provided that such equipment shall be so installed as not to interfere with operation of Transporter.

When Transporter deems it necessary, telemetering equipment shall be installed on Shipper's delivery point meter(s), at Customer's expense. - Transporter will install and maintain the telemetering facilities. Shipper shall provide, install and maintain a weatherproof phone service and electrical service outlet with appropriate grounding for telemetering equipment. Shipper and Transporter, in the presence of each other, shall have access to all measuring equipment at all reasonable times, but the reading, calibrating, and adjusting thereof shall be done by the Transporter, unless otherwise agreed. Shipper and Transporter shall have the right to be present at the time of any installing, reading, cleaning, changing, repairing, inspecting, testing, calibrating, or adjusting done in connection with all measuring equipment. The records from such measuring equipment shall remain the property of Transporter. Reasonable care shall be exercised in the installation, maintenance and operation of measuring equipment so as to avoid any inaccuracy in the determination of the quantity of gas received and delivered.

3.7 Calibration and Test of Meters. The accuracy of all measuring equipment shall be verified by the Transporter at reasonable intervals, and if requested, in the presence of representatives of Shipper. Transporter shall not be required to verify the accuracy of such equipment more frequently than once in Contract Year. If either party at any time desires a special test of any measuring equipment, it will promptly notify the other, and the parties shall then cooperate to secure a prompt verification of the accuracy of such equipment. Transportation and related expenses incurred by Shipper or Transporter involved in the testing of meters shall be ~~done~~ borne by the party incurring such expense.

3.8 Correction of Metering Errors. If, upon any test, any measuring equipment is found to be in error, such errors shall be treated in the following manner: If the resultant aggregate error in the computed receipts or deliveries is not more than 2%, then previous receipts orf deliveries shall be considered accurate. All equipment shall, in any case, be adjusted at the time of test to record to zero error. If, however, the resultant aggregate error in computed receipt or deliveries exceeds 2% at a recording corresponding to the average hourly rate of gas flow for the period since the last preceding test, the previous recordings of such equipment shall be corrected to zero error for any period which is known definitely or agreed upon. In case the period is not known definitely or agreed upon, such correction shall be for a period extending

over one-half of the time elapsed since the date of the last test, not exceeding a correction period of 180 days.

3.9 Failure of Measuring Equipment. In the event any measuring equipment is out of service, or is found registering inaccurately and the error is not determinable by test, or by previous recording, receipts or deliveries through such equipment shall be estimated:

(a) By using the registration of any check meter or meters, if installed and accurately registering, or in the absence of (a);

(b) By correcting the error if the percentage of error is ascertainable by calibration, special test, or mathematical calculation, or, if in the absence of both (a) and (b) then;

(c) By estimating the quantity of receipt or delivery based on receipts or deliveries during preceding periods under similar conditions when the measuring equipment was registering accurately.

3.10 Preservation of Records. Shipper and Transporter shall preserve all test data, charts, and other similar records for a period of at least one year, or such longer period as may be required by the SDPUC or other jurisdictional public authority.

ARTICLE IV
RECEIPT AND DELIVERY POINTS

4.1 Point of Receipt. The initial point of receipt hereunder shall be the point of interconnection between the facilities of Transporter and the facilities of Northern States Power Company - Generation located in Minnehaha County, South Dakota. Shipper shall deliver, or cause to be delivered, gas to Transporter at the point or receipt for transportation service, set forth in Exhibit A attached to Shipper's TSA.

4.2 Points of Delivery. The point(s) of delivery hereunder shall be the point(s) of connection between the facilities of Transporter and the facilities of Shipper, where Transporter shall deliver gas for the account of Shipper. Such point(s) of delivery are set forth in Exhibit A attached to Shipper's TSA. Unless otherwise agreed, the establishment of any additional point(s) of delivery at the request of Shipper shall be at the expense of Shipper.

ARTICLE V
SCHEDULES

5.1 Schedules. Prior to the first day of each month, Shipper shall furnish Transporter with a schedule showing the estimated daily quantities of gas Shipper desires Transporter to transport during such month. Such monthly schedule shall be provided at least one hour before ~~the deadline for monthly nominations in Northern's Tariff~~11:30 a.m. central clock time (cct). Thereafter Shipper shall on a daily basis advise Transporter of the volumes Shipper will deliver during the following day at least one hour prior to ~~the time~~11:30 a.m. cct~~ Transporter must submit daily nominations to Northern pursuant to Northern's Tariff~~. However, Shipper may establish a standing schedule of daily volumes, notifying Transporter prior to any day when Shipper's daily deliveries will differ from the standing schedule by more than ~~the daily delivery variance (+/-) established in Northern's Tariff~~five (5) percent.

5.2 Departures from Schedules. Departures from the scheduled deliveries at the point of receipt shall be kept to the minimum permitted by operating conditions, and shall be balanced as soon as practicable. Shipper shall use its best efforts to give Transporter notice prior to proposed change of a daily quantity from that set forth in the schedule provided for in Paragraph 5.1 hereof. Such notice shall be provided by ~~at times consistent with the notice period for intra-day nomination changes set forth in Northern's Tariff~~10:00 a.m. cct for nominations effective at 5:00 p.m. cct on gas day or 5:00 p.m. cct for nominations effective at 9:00 p.m. cct on gas day. Transporter may waive such notice upon request if, in its judgment, operating conditions permit such waiver. Transporter and Shipper shall inform each other of any other changes of deliveries immediately upon knowledge thereof.

5.3 Hourly Variation. Deliveries shall be made at uniform hourly rates to the extent practicable. Transporter's obligation to deliver shall not exceed 1/16th of Shipper's Maximum Daily Quantity in any given hour.

ARTICLE VI
DAILY AND MONTHLY BALANCING

6.1 Scheduling and Balancing Tolerances. It is recognized that the parties will be unable to control exactly the quantities of gas delivered and accepted hereunder on any day, and that deliveries by Shipper and redeliveries by Transporter may vary above or below the quantities scheduled on any day. However, nothing in this ~~paragraph~~ article shall affect Shipper's obligation to pay for gas actually transported.

6.2 Daily Variance. The daily variance for a receipt point shall be the difference between the total quantities scheduled for receipt and the actual quantity delivered into Transporter's System. The daily variance for a delivery point shall be the difference between the total quantities scheduled and the actual quantity delivered by Transporter at such point on any day. Shipper shall take action to correct any daily variance between scheduled and actual receipts and deliveries occurring during the

month by making adjustments to schedules, receipts or deliveries. In no event shall the daily excess or deficiency variance exceed ~~the allowable daily point of delivery variation set forth in Northern's Tariff~~five(5) percent.

6.3 Monthly Imbalances. Shipper's monthly imbalance shall be the net total of daily variance from all receipts and delivery point(s). Such monthly imbalance shall be corrected in-kind through adjustments to Shipper's schedules, receipts or deliveries in order for Shipper to receive Equivalent Quantities, or by such other method as is then mutually agreed upon by the parties hereto. The cumulative daily variances during any month above or below the quantities scheduled shall not exceed ~~the monthly point of delivery monthly variance set forth in Northern's tariff~~five (5) percent.

~~6.4 Disposition of Excess Gas. In order to alleviate conditions that threaten the integrity of its System, Transporter may periodically acquire quantities of gas that are in excess of System needs. Transporter may make interruptible sales of such gas form time to time at the point of receipt pursuant to 18 CFR 284.402. Such sales shall be made under rates, terms and conditions mutually agreed upon between Transporter and the purchaser, provided that all such sales shall be fully interruptible.~~

ARTICLE VII
PRESSURE

7.1 Pressure at the Points of Receipt. Shipper shall cause the gas to be delivered at the points of receipt at a pressure sufficient to allow the gas to enter the System; however, Shipper shall not be required to deliver gas to the Transporter at any point of receipt at a pressure in excess of the minimum pressure specified with respect to each receipt point in Exhibit A of Shipper's TSA.

7.2 Pressure at Point(s)s of Delivery. Transporter shall deliver gas to Shipper's delivery points at the pressure existing in the Transporter's pipeline; however, Transporter must deliver gas to each point at a pressure not less than the minimum pressure specified with respect to each delivery point in Exhibit A to Shipper's TSA. Transporter, however, shall not be required or permitted to deliver gas at a pressure in excess of the maximum pressure specified for each point of delivery set forth in Exhibit A attached to Shipper's TSA.

ARTICLE VIII
BILLING AND PAYMENT

8.1 Billing. Unless otherwise agreed, on or before the 10th day of each month, Transporter shall render to Shipper a statement of the total amount of gas delivered by Transporter to Shipper at the point(s) of ~~receipt~~ delivery hereunder during the preceding month and the amount due. When information necessary for billing

purposes is in the control of Shipper, Shipper shall furnish such information to Transporter on or before the 10th day of the month.

Shipper and Transporter shall have the right to examine at reasonable times, books, records, and recording charts of the other to the extent necessary to verify the accuracy of any statement, charge, or computation made under or pursuant to any of the provisions hereof.

8.2 Payment. Unless otherwise agreed, Shipper shall pay Transporter at its general office or at such other address as Transporter shall designate ~~on or before the 28th day of the month, the amount due for the preceding month. If presentation of a bill by Transporter is delayed after the 20th day of the month, then the time of payment shall be extended accordingly unless shipper is responsible for such delay~~within 20 days after the billing date.

8.3 Remedies for Failure to Pay. Should Shipper fail to pay all or any portion of any bill as herein provided when such amount is due, interest on the unpaid portion of the bill shall occur at a rate of one percent (1%) per month. If such failure to pay continues for 30 days after payment is due, Transporter may, in addition to any other remedy it may have hereunder, suspend further delivery of gas until such amount is paid, if authorized pursuant to the rules of the SDPUC.

~~8.4 Disputed Bills. If Shipper in good faith shall dispute the amount of any such bill or part thereof and shall pay to Transporter such amounts as it concedes to be correct and, at any time thereafter within 30 days of a demand made by Transporter, shall furnish a good and sufficient surety bond in an amount and with surety satisfactory to Transporter, guaranteeing payment to Transporter of the amount ultimately found due upon such bills after a final determination which may be reached either by agreement or judgment of the courts, as may be the case, then Transporter shall not be entitled to suspend further delivery of gas unless and until default be made in the conditions of such bond.~~

8.4~~5~~ Adjustment of Billing Errors. In the event of a meter or billing error, as defined by the Public Utilities Commission, the Company shall recalculate the bills for service during the period of the error and make adjustments of bills in accordance with the rules prescribed by the Commission. If a customer has been overcharged as a result of the error, the recalculated amount will be refunded or, where applicable, a credit on a bill shall be made. If a customer has been undercharged as a result of the error, the Company may bill the customer if the amount due exceeds $10.00. The first billing of the recalculated amount due will be separately billed on a form different from the normal bill form and include a complete explanation of the billing.

Previous Section 8.5 deleted.

ARTICLE IX
CONTROL OF GAS

9.1 Responsibility for Gas. As between the Shipper and Transporter hereto, Shipper shall be in exclusive control and possession of the gas until such has been delivered to Transporter at the point of receipt, and after such gas has been redelivered to or for the account of Shipper by Transporter at the point(s) of delivery. Transporter shall be in exclusive control and possession of such gas while same is in the System between the point ofs receipt and the point(s) of delivery. The party which shall be in exclusive control and possession of such gas shall be responsible for all injury or damage caused thereby.

ARTICLE X
FORCE MAJEURE

10.1 Force Majeure. Neither party shall be responsible or held liable for any loss or damage resulting from failure to perform its obligations due to any cause beyond its reasonable control; provided, however, that such force majeure affecting the performance hereunder by either Shipper or Transporter shall not relieve such party of liability in the event of its own concurring negligence or in the event ofs its own failure to use due diligence to remedy the situation and to remove the cause in an adequate manner and with all reasonable dispatch; provided further, that no such causes affecting such performance shall relieve either party from its obligation to make payments as determined hereunder or entitle either party to exercise any right to offset against any such payment obligation.

10.2 Definition. The term "force majeure" as used herein shall mean acts of God, strikes, lockouts, or other industrial disturbances; acts of a public enemy, wars, blockades, insurrection, riots, epidemics, landslides, lightning, earthquakes, fires, storms, floods, washouts; arrests and restraints of the government, either federal or state, civil or military, civil disturbances; shutdowns for purposes of necessary repairs, relocation, or construction of facilities; breakage or accident to machinery or lines of pipe; the necessity for testing (as required by governmental authority or as deemed necessary by repairs or alteration to machinery or lines of pipe); failure of surface equipment or pipelines; accidents, breakdowns, inability of either party hereto to obtain necessary material, supplies, or permits, or labor to perform or comply with an obligation or condition of this Agreement, rights of way, and any other causes, whether of the kind herein enumerated or otherwise, which are not reasonably in the control of the party claiming suspension. It is understood and agreed that the settlement of strikes or lockouts shall be entirely within the discretion of the party having the difficulty and that the above requirement that any force majeure shall be remedied with all reasonable dispatch shall not require the settlement of strikes or lockouts by acceding to the demands of an opposing party when such course is inadvisable in the discretion of the party having the difficulty.

ARTICLE XI
INTERRUPTIONS

11.1 Notice of Interruption. Transporter shall at all times attempt to operate, or cause to be operated, its System in a manner designed to make possible, as nearly as practicable, continuous receipt of gas from, and delivery of gas to, Shipper in the respective quantities provided for in Shipper's TSA. If an interruption or curtailment of such receipt and/or delivery shall become necessary, Transporter shall at once attempt to notify Shipper by facsimile or telephone or other prompt means of communication of the nature, extent and probable duration of such interruption or curtailment and of the quantity of gas which Transporter estimates it will be able to receive from and deliver to Shipper during the period of interruption or curtailment, and shall give like notice of the cessation of such interruption or curtailment.

11.2 Allocation of Reduced Capacity. If the effective capacity of all or a portion of Transporter's System is reduced as a result of force majeure, repairs, maintenance or any other cause, whether similar or dissimilar, and some curtailment of the quantity of gas to be received from shippers under their transportation agreements is required as a result, the reduced capacity shall, during the period of curtailment, be allocated proportionately, according to their respective Maximum Daily Quantities, among those shippers whose gas must be received or delivered at or transported through, the affected facilities.

11.3 Scheduling of Receipts and Deliveries. Transporter shall schedule all quantities tendered under all services performed by Transporter in sequence as follows: First to Transporter's firm transportation shippers, and second to other Rate Schedules that may be approved, in the order of priority as may be approved by the SDPUC or other regulatory bodies with jurisdiction.

ARTICLE XII
INCORPORATION IN RATE SCHEDULES AND TRANSPORTATION AGREEMENTS

12.1 These General Terms and Conditions as incorporated in and are part of Transporter's Rate Schedules and Transportation Service Agreements. In the event of a conflict between these General Terms and Conditions and terms in Transporter's Rate Schedules or TSA's, these General Terms and Conditions shall govern.

RATE SCHEDULE - FIRM TRANSPORTATION SERVICE

1.0 Availability. This Rate Schedule is available for the transportation of natural gas on a firm basis for any end user Shipper where (i) Transporter has determined that sufficient System capacity exists to provide the service requested by Shipper, and (ii) Shipper has executed a Transportation Service Agreement ("TSA") wherein Transporter agrees to transport gas for Shipper's account up to a specific maximum daily quantity. Transporter is not obligated to provide transportation service for resale.

2.0 Gas Supply; Upstream Transportation, New Facilities. Shipper shall be responsible for arranging for all natural gas supplies and interstate transportation of shipper's gas on Northern to the point of receipt. Transporter will arrange for transportation on the NSP-Generation intrastate pipeline on behalf of Shipper. Unless otherwise agreed, Shipper must pay for all facilities required to physically connect to Transporter's pipeline.

3.0 Receipts and Deliveries. The Point of Receipt for all gas transported by Transporter under this Rate Schedule shall be at the interconnection of Transporter's System with Northern States Power Company - Generation located in Minnehaha County, South Dakota. The Point(s) of Delivery shall be at the point(s) designated in the Exhibit A attached to Shipper's TSA.

4.0 Rates and Charges. The rates for service under this Rate Schedule are included in ~~the appendix of the Gas Transportation Agreement~~Original Sheet No. 16. However, Transporter has the right at any time to file with the SDPUC to adjust the rates applicable to service under this Rate Schedule.

5.0 Daily Tolerance; Penalty Provisions. The daily tolerance level (+/-) from Shipper's daily scheduled volume shall be the five (5) percent daily variance established in Northern's Tariff. Unless otherwise agreed, in the event the daily quantity of gas delivered by Shipper deviates above or below the daily scheduled volume in excess of the Northern's Tariff tolerance level, and Transporter is assessed charges or penalties by Northern, Shipper shall pay, in addition to the appropriate rates contained in this tariff, an amount equal to any payment Transporter is required to make to Northern.

6.0 General Terms and Conditions. Any terms ~~of~~ and conditions not specified in this Rate Schedule shall be determined consistent with Transporter's General Terms and Conditions, which are incorporated by reference into this Rate Schedule.

Northern States Power Company
Sioux Falls, South Dakota
Gas Transportation Service Tariff SDPUC NO. 1

Docket No. NG97-021
JCS – 1 Schedule 2

Original Sheet No. 16

~~Sheet 16 reserved for future use.~~
Transportation Rate Summary

Availability

Small Volume	Peak day requirements of less than 500 therms
~~Medium Volume~~	~~Peak day requirements of 500 therms to 1,999 therms~~
Large Volume	Peak day requirements of at least 2,000 therms

Maximum Customer Charge per Month

Small Volume	$12.00
~~Medium Volume~~	~~$50.00~~
Large Volume	~~$290~~$276.00

Distribution Charge per Therm

	Minimum	Maximum
Small Volume	~~$0.012~~$0.0116	~~$0.1030~~$0.1005
~~Medium Volume~~	~~$0.012~~	~~$0.0500~~
Large Volume	~~$0.012~~$0.0116	~~$0.0230~~$0.0238

Date Filed: Dec 16, 1997
Effective:
SDPUC Docket No.:

Issued by: ~~Michael J. Hanson~~Kent T. Larson
Chief Executive & General Manager

Order Date:

- Northern States Power Company
Sioux Falls, South Dakota
Gas Transportation Service Tariff SDPUC NO. 1

Docket No. NG97-021
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INDEX OF SHIPPERS

Shipper	Rate Schedule	Effective Date	Expiration Date
Hutchinson Technology, Inc.	FT	12/01/97	2/28/2008
Minnehaha County Highway Department	FT	10/1/98	10/1/2003
Jans Corporation	FT	10/1/98	9/30/2003

Date Filed: Dec 16, 1997
Effective:
SDPUC Docket No.:

Issued by: ~~Michael J. Hanson~~Kent T. Larson
Chief Executive & General Manager

Order Date:

NATURAL GAS TRANSPORTATION SERVICE AGREEMENT

This Gas Transportation Agreement ("Agreement") is made this ___ day of _____, 19__, by and between NORTHERN STATES POWER COMPANY, a Minnesota corporation, (hereinafter called "NSP" or "Company"), and ________________ ~~, a Minnesota corporation,~~ (hereinafter called "Customer"). Customer will enter into agreement to purchase natural gas and have that gas delivered to a specified receipt point~~town border station of Company~~. Customer and Company desire to enter into this Agreement to have said gas transported by Company to Customer's plant facilities.

WITNESSETH: The parties hereto, each in consideration of the agreement of the other, agree as follows:

1.0 TERM. This Agreement shall commence on ________________, and continue until ______________, and, if not terminated by at least 180 days prior notice, shall continue further until so terminated.

1.1 CHARACTER OF SERVICE. The transportation and delivery of gas hereunder is on a firm basis. In consideration for NSP's agreement to provide firm transportation service at the rates set forth in Sections ~~3.2~~2.9 and 3.0, Customer agrees to utilize natural gas transported by NSP for all the non-electric energy requirements of the Plant equipment for the term of this Agreement. However, Customer may use a fuel other than natural gas in the case of (i) a force majeure or other emergency condition on the NSP distribution system, Angus Anson line or Transporter's pipeline system, as provided in this Agreement or Transporter's Tariff, or (ii) a failure of Customer's gas supply as defined in Section 2.0 for reasons beyond the control of Customer.

1.2 CONTINUITY OF SERVICE. The Company will endeavor to provide continuous service but does not guarantee an uninterrupted or undisturbed supply of gas. The Company shall not be responsible for any loss or damage resulting from the interruption or disturbance of service for any cause other than the gross negligence of the Company. The Company shall not be liable for any loss of profits or other consequential damages resulting from the use of service or any interruption or disturbance of service.

2.0 LIMITATION ON OBLIGATION TO DELIVER. This Transportation Agreement is expressly contingent upon Customer or Customer's Agent's procurement of natural gas supplies and interstate pipeline transportation to the Company receipt point in Minnehaha County, SD. If Customer or Customer's Agent fails to deliver gas to Company at the designated ~~town border station~~receipt point, Customer shall immediately cease using gas. Company is not obligated to provide backup sales service to Customer. ~~However, Company may at its option, agree to provide backup gas service.~~

2.1 REQUIREMENTS AND DELIVERIES; POINT OF DELIVERY. Company agrees to accept delivery of Customer's gas at the inlet of Company's distribution system in Minnehaha County, SD and, on a firm basis, transport and deliver said gas to Customer's point(s) of delivery in volumes up to ___ MMBTU per day, or such other volumes as is mutually agreed. Customer's point(s) of delivery shall be the outlet of the meter installation(s) at ______________________________.

2.2 DAILY NOMINATIONS. Customer or Customer's Agent shall on a daily basis advise Company's gas dispatcher in St. Paul of the volumes Customer will request to be delivered during the following Gas Day. Customer may alternatively elect to make a standing nomination with Company, notifying Company on any day when customer's daily deliveries will differ from the standing nomination by ~~the daily delivery variance (+/-) established in Northern's tariffs~~ more than five (5) percent~~.~~ Customer shall submit daily or corrected standing nominations to Company at least one hour prior to ~~the time Transporter must submit daily nominations to Northern pursuant to Northern's tariffs~~11:30 a.m. cct. ~~least 24 hours in advance of the start of the Gas Day.~~ Customer's daily or standing nomination shall be its best estimate of the expected utilization for the Gas Day. If Customer and Company mutually agree, Company will relay Customer's daily or standing nomination to Customer's Agent, gas supplier(s), and Transporter.

2.3 DISPATCHING. Customer will adhere to gas dispatching policies and procedures established by Company from time-to-time to facilitate service under this Agreement. Company will inform Customer of any changes in dispatching policies that may affect this Agreement as they occur.

2.4 RATE OF FLOW. The gas supply shall be transported to Customer at a rate of flow up to but not exceeding _______ cubic feet per hour at the point(s)of delivery. Gas shall be delivered at such pressures and temperatures as may exist under operating conditions at Customer's service location. Operating pressures at this location shall normally be _____ psi.

2.5~~7~~ REFUSAL OR DISCONTINUANCE OF SERVICE (a) With reasonable notice, the Company may refuse or discontinue gas service for any of the following reasons: failure to pay amounts payable when due; breach of contract for service; failure to provide the Company with reasonable access to its property or equipment; when the Company is unable to furnish gas service to Customer because it cannot obtain permits or necessary right-of-way; when necessary to comply with any order or request of any governmental authority having jurisdiction.

(b) Upon such notice as is reasonable under the circumstances, the Company may temporarily discontinue gas service when necessary to make repairs, replacements, or changes in Company's equipment or facilities.

(c) Without notice the Company may disconnect gas service to Customer in the event of an unauthorized use of or tampering with Company's equipment or in the event of a condition determined to be hazardous to the Customer, to other customers of the Company, to the public, or to the Company's employees, equipment, or service.

Any discontinuance of service will not relieve Customer from Customer's obligations to the Company.

2.68 BALANCING. Customer and Company agree to balance daily delivery point nominations with actual deliveries (as defined in Paragraph 3.02) on an ongoing basis. Customer agrees to exert its best efforts to keep daily deliveries within five (5) percent of daily nomination. ~~daily delivery variance (+/-) established in Northern's tariff.~~ Customer and Company shall balance as operationally necessary, but no less than monthly. Customer or Customer's Agent shall be responsible for balancing receipt point nominations made to Transporter with receipt point deliveries made by Customer or Customer's Agent's gas supplier(s).

2.97 MONTHLY CASHOUT MECHANISM. Unless otherwise agreed, Customer's monthly imbalance will be corrected by a cashout mechanism. Customer's monthly imbalance is the difference between (1) the sum of Customer's daily nominations for the month and (2) Customer's actual metered use. Monthly volumetric imbalances will not be carried forward to the next calendar month.

Undertake Purchase Payment: If Customer utilizes less gas than the volume Customer nominated and delivered to NSP system, Customer shall sell the undertake gas to NSP. Customer shall be paid an Undertake Purchase Payment equal to the monthly imbalance times the Undertake Purchase Rate.

Monthly Imbalance %	Undertake Purchase Rate
0% to 2%	Index + Transporter's Firm Transportation (TF) Commodity Rate(s)
Greater than 2% up to 10%	[Index + Transporter's TF Commodity Rate(s)] x 0.75
Greater than 10%	[Index + Transporter's TF Commodity Rate(s)] x 0.50

Overtake Charge: If Customer utilizes more gas than the volume Customer nominated and delivered to the NSP system, Customer shall purchase the overtake gas from NSP. Customer shall be assessed an Overtake Charge equal to the monthly imbalance times the Overtake Rate.

Monthly Imbalance %	Overtake Rate
0% to 2%	Index + Transporter's Interruptible Transportation (IT) Commodity Rate(s)
Greater than 2% up to 10%	[Index + Transporter's IT Commodity Rate(s)] x 1.25
Greater than 10%	[Index + Transporter's IT Commodity Rate(s)] x 1.50

Index for Monthly Cashout. The Index being used is Inside FERC Gas Market Report's first of the month "Prices of Spot Gas Delivered to Pipelines" for Northern Natural (Demarcation). Applicable pipeline commodity rate consists of all interstate pipeline charges including: GRI surcharge, ~~Angus C. Anson fuel supply pipeline surcharge,~~ fuel costs and commodity rate(s). All conditions of the monthly cashout mechanism apply

unless Customer and NSP agree otherwise. However, NSP will treat similarly situated customers on a non-discriminatory basis.

~~3.0~~2.8 CHARGES. Commencing with the date of initial deliveries of gas by Company, the charges for this transportation service shall be according to Appendix A.

2.9~~3.1~~ MONTHLY CUSTOMER CHARGE. As established in Appendix A. The customer charge shall not exceed the maximum charge on file with the South Dakota Public Utilities Commission.

3.0~~2~~ VOLUME CHARGE. A Volume Charge equal to the product of (i) the actual deliveries made by Company to Customer during the billing period, and the ~~fixed~~ rate per MMBtu stated in Appendix A. The volume metered by NSP will be considered the actual volume delivered by Company to Customer. All volumes will be adjusted for Btu content and supercompressibility. The volume charge per MMBTU shall not exceed the maximum charge on file with the South Dakota Public Utilities Commission.

3.1~~3~~ TAXES. In addition to the rates specified above, NSP shall collect any federal, state or local sales, use, excise, or other such taxes and fees that are legally effective and applicable to the service provided hereunder.

3.2~~4~~ PENALTY PROVISION. Customer shall be liable for any balancing or other penalties imposed on NSP by Transporter and caused by Customer's actions. Customer shall also be liable for any incremental costs incurred by Company, if any, caused by Customer's failure to stay within the +/- five (5) percent daily tolerance zone.

3.3~~5~~ ADDITIONAL CHARGE FOR USE DURING CURTAILMENT. If Customer fails to curtail use of gas hereunder when requested by Company, Customer shall pay, in addition to the appropriate above rates, either an amount equal to any payment Company is required to make to Transporter as a result of Customer's failure to curtail, or $10.00 per MMBtu of gas used in excess of the volume of gas to which customer is requested to curtail, whichever amount is greater. Such payments, however, shall not preclude Company from shutting off Customer's gas supply in the event of Customer's failure to curtail gas use thereof when requested by Company to do so.

4.0 PAYMENT OF BILLS. All bills are payable at Company's office on or before the ~~tenth~~ 20th day succeeding the date bill is rendered for service supplied by Company in the preceding month. Should Customer fail to remit the full amount when due, Customer shall pay a Late Payment Charge of 1% to be added to the next month's bill after the date due.

4.1 DISPUTED BILLS. If Customer in good faith disputes the amount of any monthly billing or part thereof, Customer shall pay Company the amount Customer believes to be correct and notify Company in writing of the basis for disputing the bill. Company shall promptly investigate the matter and submit a corrected bill to Customer.

If Customer has underpaid the amount actually due, Customer shall within five (5) days remit the additional amount due. If Customer has overpaid the amount actually due, Company shall refund the overpayment by a credit to Customer's next bill. Company agrees to waive the late payment charge for the disputed portion of any bill if Customer disputed the bill in good faith.

5.0 BILLING ADDRESSES, CURTAILMENT NOTICES, OTHER NOTICES. The applicable addresses and/or telephone numbers for billing, curtailment notices, and other notices under this Agreement are provided in the Appendix C to this Agreement.

6.0 TITLE TO GAS. Unless otherwise agreed, Customer shall possess title to Customer's gas while being transported by Company. However, Company may, if the parties mutually agree, take title to Customer's gas to arrange interstate or intrastate pipeline transportation from Transporter to Company's receipt point.

6.1 WAIVER OF LIABILITY. Customer shall hold Company blameless for any termination of gas service caused by failure of Customer, Customer's Agent, Customer's gas supplier(s) or Transporter to deliver gas to Company's designated receipt point.

7.0 TELEMETERING. - When transporter deems it necessary, t~~T~~elemetering equipment shall be installed on Customer's premises, at Customer's expense, in order to measure daily and monthly deliveries to Customer. Company will install and maintain the telemetering facilities. Customer shall provide, install and maintain a weatherproof phone service and electrical service outlet with appropriate grounding for telemetering equipment at Customer's ~~cost~~expense.

8.0 REGULATORY AUTHORITY. This agreement is subject to all valid laws, orders, rules and regulations of any and all duly constituted authorities having jurisdiction over the subject matter herein and is subject to the receipt of any necessary authorization for the transportation service contemplated herein.

9.0 REPORTING REQUIREMENTS. Customer shall furnish to NSP all information as may be required or appropriate to comply with reporting requirements of duly constituted authorities having jurisdiction over the subject matter herein.

10.0 CONFIDENTIALITY. The terms of this contract, including but not limited to Customer's delivered price of gas, NSP's customer charge and volume charge, the volume of gas transported, and all other material terms of this contract shall be kept confidential by NSP and Customer, except to the extent that any information must be disclosed to a third party as required by law or for the purpose of effectuating transportation of the subject gas pursuant to this Agreement.

11.0 SUCCESSION, ASSIGNMENT. This Agreement shall inure to and be equally binding on the respective parties, their successors and assigns. Neither party

shall assign this Agreement and rights hereunder without the written approval of the other party. Such approval shall not be unreasonably withheld.

12.0 ENTIRE AGREEMENT; MODIFICATION AND WAIVER. This Agreement, together with all documents attached hereto which NSP has signed or initialed intending to make them a part hereof, constitutes the entire agreement between the parties relating to the transaction described herein and supersedes any and all prior oral or written understandings. No addition to or modification of any provision hereof shall be binding upon NSP, and NSP shall not be deemed to have waived any provision hereof or any remedy available to it unless such addition, modification or waiver is in writing and signed by a duly authorized employee of NSP.

13.0 SEVERABILITY. If any provision hereof is held to be unenforceable by final order of any regulatory authority or court of competent jurisdiction, such provision shall be severed herefrom and shall not affect the interpretation or enforceability of the remaining provisions hereof.

IN WITNESS WHEREOF, the parties have duly executed this Agreement effective the date and year first written above.

NORTHERN STATES POWER COMPANY	______________________
	Customer
By ______________________	By ______________________
Title ______________________	Title ______________________
Date ______________________	Date ______________________

APPENDIX A
GAS TRANSPORTATION AGREEMENT
DATED ______________
FOR
(Customer name)

I. Delivery Period

The Agreement and the rates, terms and conditions contained herein, will be in effect for a term commencing ______________, and continuing through ____________, and then shall be renegotiated.

II. Delivery Point(s) and Charges

(a) Delivery Point(s)

NSP will transport the Customer's gas supplies to customer's facility, located at ________________________ under this Agreement at the following rate:

(b) NSP Transportation Service Charges

The ~~maximum~~ Customer Charge is ~~$287.00~~_____ per month.
Transportation local delivery volume charge of $______ ~~will not exceed $0.213 per MMBtu transported and not be less than $0.044~~ per MMBtu transported, before applicable taxes and fees.

(c) Annual Minimum Local Delivery Charge

Customer agrees to an Annual Minimum Local Delivery Charge of __________ as determined by the Company.

System Exit Charges will also apply as determined by the Company. If service under the Transportation Agreement (or Successor Agreement) terminates prior to the end of the contract period, customer agrees to pay Company the unrecovered facility extension cost (investment minus accumulated book depreciation) applicable for the month in which the Transportation Agreement is terminated.

III. Contract Quantity

Customer nominates a maximum daily Contract Quantity of ______ MMBtu.

NSP is not obligated to provide firm transportation service in excess of Customer's maximum daily Contract Quantity unless NSP agrees to amend this Agreement in writing. However, NSP may at its option provide daily overrun transportation service to Customer on an interruptible basis if Customer so requests. The interruptible overrun local delivery charge per MMBtu shall be the same as the firm local delivery charge set forth above.

APPENDIX B
DEFINITIONS

"Btu" shall mean British Thermal Unit and shall be the quantity of heat required to raise the temperature of one (1) pound of water one degree Fahrenheit at sixty (60) degrees Fahrenheit.

"Contract Quantity" shall mean the daily quantity of natural gas which NSP is obligated to deliver on a firm basis to Customer pursuant to this Agreement.

"Contract ~~Year~~Period" shall mean the ~~twelve-month calendar~~ period set forth in Appendix A.

"Customer" shall mean Hutchinson Technology Inc. For purposes of this Agreement, the term Customer also includes Customer's Agent.

"Customer's Agent" shall mean (if applicable) the party or entity designated by Customer in the Nomination Statement to perform day-to-day supply and/or delivery management functions for Customer. Subject to NSP's approval, Customer may change such designation from time to time upon written notice to NSP.

"Delivery Point" shall mean the outlet side of the NSP meter located on NSP's natural gas distribution system at Customer's Plant service locations.

"FERC" means the Federal Energy Regulatory Commission or successor agency.

"Firm Transportation" shall mean transportation service which is not subject to interruption except for emergencies or for failure of Customer to deliver gas to NSP at the Receipt Point for transportation to Customer.

"Gas" shall mean natural gas, manufactured gas, or other forms of gaseous energy which conform to the quality specifications in Transporter's Tariff.

"Gas Day" shall mean the 24 hour period determined in accordance with Transporter's Tariff.

"Interruptible Transportation" shall mean transportation service which is subject to interruption at Company's option.

"MMBtu" shall mean one million (1,000,000) BTUs. One MMBtu is equal to one (1) "Dekatherm" or ten (10) "Therms."

"Receipt Point" shall mean the inlet point of the NSP gas distribution system where NSP takes receipt of gas from Transporter.

"Transporter" shall mean Northern Natural Gas Company.

"Transporter's Tariff" shall mean Northern's FERC Gas Tariff on file with the FERC from time to time.

APPENDIX C
NOTICES AND CONTACT LIST

C-1 Notices to NSP:

Northern States Power Company
Attn: SD Gas Operations
P. O. Box 988
500 West Russell St.
Sioux Falls, SD 57101-0988

Notices and Bills to Customer:

C-2 Day to day communications

Wm Duff Robinson
Senior Engineer
phone 605-339-8345
fax 605-339-8204

Jerry Peterson
Coordinator New Business Dev.
phone 605-339-8310
fax 605-339-8204

Day to day communications to Customer

C-3 Gas Transportation Communications

NSP Gas Control (24 Hours/day):

Northern States Power Company
Gas Control
825 Rice Street
St. Paul, MN 55117
phone: 612-229-5527
fax 612-229-2370

Customer's Agent

South Dakota

Public Utilities Commission

State Capitol Building, 500 East Capitol Avenue, Pierre, South Dakota 57501-5070

Capitol Office
Telephone (605)773-3201
FAX (605)773-3809

Transportation/
Warehouse Division
Telephone (605)773-5280
FAX (605)773-3225

Consumer Hotline
1-800-332-1782

TTY Through
Relay South Dakota
1-800-877-1113

Internet Website
www.puc.state.sd.us/puc/

March 8, 1999

Mr. David A. Gerdes
Attorney at Law
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P. O. Box 160
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Mr. Michael J. Hanson
Chief Executive and General Manager
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Ms. Jennifer Erickson
Chief Operating Officer
PAM Natural Gas
P. O. Box 5200
Sioux Falls, SD 57117-5200

Mr. Robert C. Riter, Jr.
Attorney at Law
Riter, Mayer, Hofer, Wattier & Brown
P. O. Box 280
Pierre, SD 57501-0280

Re: In the Matter of the Application for an Order Establishing a Natural Gas Utility, and to Establish Initial Natural Gas Transportation Rates for Northern States Power Company
Docket NG97-021

Dear Folks:

Enclosed each of you will find copies of Staff's Brief in the above captioned matter. This is intended as service upon you by mail.

Sincerely,

Karen E. Cremer
Staff Attorney

Enc.

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF SOUTH DAKOTA

IN THE MATTER OF THE APPLICATION FOR AN ORDER ESTABLISHING A NATURAL GAS UTILITY, AND TO ESTABLISH INITIAL NATURAL GAS TRANSPORTATION RATES FOR NORTHERN STATES POWER COMPANY	)))))	**STAFF'S BRIEF** **NG97-021**

Pursuant to the briefing schedule established in the above-captioned matter, the South Dakota Public Utilities Commission Staff (Staff) submits its brief on the following issues:

I. Whether Northern States Power should provide transportation services to others for resale over its facilities.

II. Whether Northern States Power should file updated cost of service data, and if so, when, and at what level of detail.

ARGUMENT

I.

WHETHER NORTHERN STATES POWER SHOULD PROVIDE TRANSPORTATION SERVICES TO OTHERS FOR RESALE OVER ITS FACILITIES.

Northern States Power Company - South Dakota Operations (NSP-SD) is requesting that it be granted authority to operate as a gas utility. At the hearing, MidAmerican Energy Company (MidAmerican) questioned NSP-SD if it would be willing to change its tariff so that resellers and not just end users could be customers of NSP-SD. NSP-SD stated that it was not willing to do so unless mandated by the Commission.

To the best of Staff's knowledge no resellers have requested to become customers of NSP-SD. Due to this, it appears that this issue is not ripe and need not be determined at this time. Neither the South Dakota statutes nor the Federal Energy Regulatory Commission Regulations Subpart B--Certain Transportation by Interstate Pipelines, § 284.101 et seq., or Subpart C--Certain Transportation by Intrastate Pipelines, § 284.121

et seq., speak to this issue. It is Staff's position that while nothing prohibits the Commission from addressing this issue, there is nothing requiring the Commission to address it at this time. Staff recommends this issue be addressed when a potential reseller makes a bona fide service request, and specific details can be thoroughly examined and ruled upon.

II.

WHETHER NORTHERN STATES POWER SHOULD FILE UPDATED COST OF SERVICE DATA, AND IF SO, WHEN, AND AT WHAT LEVEL OF DETAIL.

Staff's position regarding this issue is that NSP-SD should be ordered to update its cost of service numbers in May 2000 with calendar year 1999 numbers. Exhibit 6, pgs. 8-9 Transcript pg. 114. This information should be rate case quality but does not require the filing of testimony. If Staff has any questions after this information is filed, data requests can be issued. Should the need arise following the filing of this information, Staff, pursuant to SDCL 49-34A-26, could petition the Commission to substantiate the rate if it appeared to be unreasonable, insufficient, or unjustly discriminatory.

Staff's recommendation that NSP-SD file its actual numbers from 1999 also includes a recommendation that NSP-SD file its annual operations report. Finally Staff would recommend that the tariff language filed as an attachment to NSP-SD's brief be approved, subject to the Commission's decision on the resale language of the tariff.

Dated this 8th day of March, 1999.

Karen E. Cremer

Karen E. Cremer
Staff Attorney
South Dakota Public Utilities Commission
500 East Capitol
Pierre, SD 57501
Telephone (605) 773-3201

CERTIFICATE OF SERVICE

I hereby certify that copies of Staff's Brief were served on the following by mailing the same to them by United States Post Office First Class Mail, postage thereon prepaid, at the address shown below on this the 8th day of March, 1999.

Mr. David A. Gerdes
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Chief Operating Officer
PAM Natural Gas
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Sioux Falls, SD 57117-5200

Mr. Robert C. Riter, Jr.
Attorney at Law
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Pierre, SD 57501-0280

Karen E. Cremer

Karen E. Cremer
Staff Attorney
South Dakota Public Utilities Commission
500 East Capitol
Pierre, SD 57501

MidAmerican
ENERGY
OBSESSIVELY, RELENTLESSLY AT YOUR SERVICE™

MidAmerican Energy
401 Douglas Street
Sioux City, Iowa 51101

RECEIVED
MAR 12 1999
SOUTH DAKOTA PUBLIC
UTILITIES COMMISSION

FAX Received MAR 10 1999

Suzan M. Stewart
Managing Attorney

March 10, 1999

BY TELEFAX & U.S. MAIL DELIVERY

Mr. William Bullard, Jr.
Executive Secretary
South Dakota Public Utilities Commission
500 East Capitol Avenue
Pierre, SD 57501

In Re: In the Matter of the Application for an Order
Establishing a Natural Gas Local Distribution
Utility, and to Establish Initial Natural Gas
Transportation Rates for Northern States Power
Company
Docket No. NG97-021

Dear Mr. Bullard:

Enclosed please find the original and four copies of the Brief of Intervenor MidAmerican Energy Company for filing in the above-captioned matter. Please file stamp the extra copy and return in the self-addressed stamped envelope enclosed.

Very truly yours,

Suzan M. Stewart

Enc.
CC: Certificate of Service List

RECEIVED

MAR 12 1999

SOUTH DAKOTA PUBLIC
UTILITIES COMMISSION

BEFORE THE
PUBLIC UTILITIES COMMISSION
STATE OF SOUTH DAKOTA

IN THE MATTER OF THE APPLICATION FOR AN ORDER ESTABLISHING A NATURAL GAS UTILITY, AND TO ESTABLISH INITIAL NATURAL GAS TRANSPORTATION RATES FOR NORTHERN STATES POWER COMPANY	)))))	NG97-021

FAX Received MAR 10 1999

BRIEF OF INTERVENOR MIDAMERICAN ENERGY COMPANY

Intervenor MidAmerican Energy Company ("MidAmerican") is the largest natural gas distribution company serving the State of South Dakota. The distribution pipeline that has been constructed by Applicant Northern States Power Company – South Dakota ("NSP-SD") was specifically constructed to provide a competitive gas delivery alternative to MidAmerican natural gas delivery service in the Sioux Empire Development Park number 5. (Tr. 10-11, 68). In determining whether to authorize NSP-SD to provide natural gas transportation service in South Dakota and to approve the tariffs proposed by NSP-SD, the South Dakota Public Utilities Commission ("Commission") should strive to create a level playing field for this competition. Furthermore, MidAmerican should be permitted to use the Angus Anson 12-inch gas transmission pipeline ("Anson Pipeline") to transport natural gas to its local distribution service area.

STATEMENT OF FACTS

MidAmerican concurs with the statement of facts presented in Applicant's Opening Brief with one exception. NSP-SD claims an extremely limited amount of unused capacity exists in the Anson Pipeline – about 325 MCF per hour. (Tr. 9, Exh. 3,

p. 4, l. 18-21). It is only this amount of capacity that NSP-SD proposes to make available to transportation customers in the industrial park. This calculation is based on peak usage of the two combustion turbines at the Angus Anson generating plant of 2,450 MCF per hour, peak usage of the Pathfinder Unit at the rate of 900 MCF per hour and 1,225 MCF per hour usage of a possible third combustion turbine unit that has yet to be constructed. (Tr. 9-10; Exh. 3, p. 4, l. 2-21). The probability that all of these units will all be operated at capacity at the same time is remote or unlikely. The Anson generating plant only operates at capacity 300 hours of the year. (Tr. 65). Furthermore, the third unit is not yet built. The Commission should determine the true amount of available capacity at this location.

In addition, it is not clear what amount of this excess capacity will be used to supply the requirements of Hutchinson Technologies, Inc. ("HTI"). HTI has unspecified expansion plans. (Tr. 23). MidAmerican believes that complete information regarding the current and future use by HTI of this facility is required in order to determine whether the proposed rate is reasonable, as well as whether there may be any capacity remaining for resale purposes.

ARGUMENT

I. NSP-SD MEETS THE STATUTORY CRITERIA FOR CERTIFICATION AS A GAS UTILITY.

NSP-SD seeks to become a gas utility, providing transportation service on a limited basis only. Under SDCL 49-34A-1(9), a "gas utility" is a person "...operating, maintaining, or controlling ...equipment or facilities for providing *gas service* to or for the public." (Emphasis supplied). "Gas service" is defined by SDCL 49-34A-1(8) to include "the sale of transportation services by an intrastate natural gas pipeline." The designation as a public utility is accompanied by a bundle of obligations to the public, including the obligation to charge only rates approved by a public service commission as well as the obligation to deliver gas. NSP-SD has acknowledged that its local distribution operations ("LDC") operations in South Dakota will have a limited purpose and are intended only to be a method for NSP-SD to market the unused capacity of the Anson Line. (NSP-SD Br. p. 3).

NSP-SD does not propose to accept the obligations to serve and deliver which are key to the designation as a "public utility" under the law and regulations of South Dakota. The Commission should only grant it the limited status of a gas utility offering exclusively transportation service on a discretionary basis.

II. THE RATE CHARGED NSP-SD's LARGEST CUSTOMER DOES NOT RECOVER THE COSTS OF SERVICE. IF THE COMMISSION APPROVES NSP-SD's PROFFERED RATES, IT SHOULD ADOPT COMMISSION STAFF'S PROPOSAL TO REVIEW THE RATES IN 2000 IN ORDER TO ANALYZE THE ACTUAL COSTS OF SERVICE.

NSP-SD has proposed a ratemaking scheme that is unique among South Dakota natural gas utilities. NSP uses a levelized annual revenue requirement methodology to develop a maximum transportation rate of $0.194 per dekatherm, applicable to large customers. (Exh. 8, p. 2, l. 17, Sch. 5; Exh. 9, p. 9). The maximum rate recovers the estimated cost of service calculated on a levelized basis. (Tr. 35-36; Exh. 8, Sch.3). However, HTI will not be charged to maximum rate. The minimum rate recovers only the variable operating costs of annual O & M of the 4 ½ inch system, an internally negotiated transfer price for the use the Anson pipeline, plus a $0.02 cents contribution to system fixed costs. (Exh. 9, Sch. 5). HTI, the largest customer served by NSP-SD, is paying something less than the maximum rate, so not all of its costs of service are being recovered. (Tr. 35-36, 63). The rates are also unique because they recover only a very nominal amount of regulatory and administrative costs. (Tr. 69; Exh. 7, p. 3, l. 2-16; Exh. 8, p. 4, l. 1-9).

For small and medium transportation customers, the costing methodology becomes even less precise. For small transportation customers, the maximum rate is $1.03 per dekatherm. (Exh. 9, Sch. 7). The rate for medium volume customers is labeled as "market based" and is $0.50 per dekatherm. (Exh. 9., p. 10, l. 8-11). This is identical to the floor of MidAmerican's comparable rate.

NSP's witness Smith claims that this methodology is typical of projects where expansion is expected. However, NSP-SD's witnesses have testified that the opportunities for expansion of this system are nominal - service will only be provided until the small amount of excess capacity in the line is exhausted. (Tr. 11).

NSP justifies the imprecision of its ratemaking methodology on the fact that its customers are not paying the costs of the Anson Pipeline in gas or electric utility rates. (Tr. 52-53). While this may be comforting to NSP customers, NSP's proposed ratemaking methodology places MidAmerican at a competitive disadvantage. MidAmerican, in comparison to NSP-SD, bases its rates on a fully allocated class cost of service study. These rates include administrative and overhead costs, such as the costs of gas supply personnel purchasing gas for purposes of system integrity. MidAmerican is at a particular disadvantage in the case of service to smaller transportation customers. MidAmerican requires all of its transportation customers to telemeter at their expense. NSP-SD has indicated that it may not require customers to pay for costly daily metering devices. (Tr. 85). At this time, MidAmerican's tariff s do not provide that flexibility. If the Commission should approve NSP-SD's proposed tariffs. MidAmerican anticipates that it may file an optional tariff with the Commission authorizing the reduction of its rates on a selected basis to meet competitive threats. Part of this request may be to eliminate the requirement that customers pay for telemetry.

Part of any Commission approval of the NSP-SD tariff should be review of the scheme in 2000, as proposed by Commission Staff Witness Rislov. (Tr. 114). NSP-SD rates are based on a number of assumptions that may not be supported by actual operating experience. Annual review of this rate will minimize the possibility of inadvertent Commission approval of a price that is below short-run marginal cost to serve the customers.

III. PIPELINE FACILITIES TO THE ANGUS ANSON GENERATING STATION SHOULD BE USED IN THE PUBLIC INTEREST. THIS INCLUDES AUTHORIZING NSP-SD TO RESELL PIPELINE CAPACITY TO THIRD PARTIES.

NSP-SD's proposed tariffs do not permit transportation service to be resold. (Exh. 9, p. 5, l. 9-21, Sch. 3). NSP-SD argues that this provision is necessary to make the South Dakota tariffs consistent with NSP tariffs in other jurisdictions. (Tr. 75-78). This is not a compelling argument. The Commission should determine whether requiring NSP-SD to resell transportation service is in the public interest.[1] NSP- SD states that it would eliminate the provision if the Commission ordered gas restructuring. (Tr. 77). MidAmerican believes that transportation resales may additionally promote efficient use of pipeline facilities in South Dakota.

[1] SDCL 49-34A-1(8) extends the scope of the Commission's jurisdiction to resales of transportation service. The definition of "gas service" contained therein is limited to *retail* sales of natural gas but does not contain the same limitation in its reference to transportation service.

MidAmerican's primary interest in the purchase of distribution service for resale does not relate to NSP-SD's 4-½ inch lateral system. MidAmerican anticipates that it may, at some time in the future, seek to interconnect its distribution system with the Anson Pipeline. MidAmerican could use the Anson Pipeline to move gas to move gas to its local distribution area instead of constructing new, duplicate distribution facilities. If MidAmerican determines that interconnection is appropriate, it will make a request to NSP-SD for service under the Commission-approved tariff.

In its brief, NSP-SD raises the possibility that the principle of equal protection of law might require MidAmerican to resell transportation service if NSP-SD is so ordered. MidAmerican's transportation tariffs on file with Commission do not prevent the sale of transportation service for resale. MidAmerican would be required to resell its transportation service to other distribution system users at its filed rates.

CONCLUSION

NSP-SD has proposed a unique ratemaking scheme for its gas transportation service. This scheme may place MidAmerican at a competitive disadvantage and should be reviewed by the South Dakota Public Utilities Commission in 2000. Furthermore, NSP-SD tariffs should be modified to permit resale of transportation service.

DATED this 10th day of March 1999.

Respectfully submitted,

MIDAMERICAN ENERGY COMPANY

BY Suzan M. Stewart

Suzan M. Stewart
Managing Attorney
401 Douglas Street
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CERTIFICATE OF SERVICE

I hereby certify that a true and correct copy of the attached Brief of Intervenor MidAmerican Energy Company in Docket No. NG97-021 was sent by first class, postage pre-paid, to the following:

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May, Adam, Gerdes & Thompson
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Robert C. Riter, Jr.
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P.O. Box 280
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Dated this 10th day of March, 1999.

Sherry Wenzel

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March 11, 1999

Rolayne Ailts Wiest
Public Utilities Commission
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REC
MAR 12, 1999
SOUTH DAKOTA PUBLIC
UTILITIES COMMISSION

RE: **NSP GAS**
Docket NG97-021
Our file: 0185.01

Dear Rolayne:

Enclosed is a copy of a letter from Bob Riter, Jr., representing MidAmerican, which I believe is self-explanatory. Unfortunately, I need some extra time to work on whatever reply brief is necessary because Judge Kornmann has scheduled a federal trial which will take up my time during the week of March 22. I hope this will be agreeable with the Commission and staff.

Yours truly,

MAY, ADAM, GERDES & THOMPSON LLP

David A. Gerdes

BY:

DAG:mw

Enclosure

cc: Bob Riter, Jr.
cc/enc: Karen Cremer
Jim Wilcox
Jim Johnson

LAW OFFICES
RITER, MAYER, HOFER, WATTIER & BROWN, LLP
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R.C. RITER (1912-1994)
E. D. MAYER
ROBERT D. HOFER
ROBERT C. RITER, JR.
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March 9, 1999

Mr. David A. Gerdes
Attorney at Law
P. O. Box 160
Pierre, SD 57501

Re: In the Matter of the Application for an Order Establishing a Natural Gas Local Distribution Utility, and to Establish Initial Natural Gas Transportation Rates for Northern States Power Company

Dear Dave:

Per our visit of earlier this week, this merely confirms that we are agreeable to you having until April 2, 1999 to submit your Reply Brief in this matter. I trust you will advise the Public Utilities Commission accordingly.

Thank you.

Very truly yours,

RITER, MAYER, HOFER, WATTIER
& BROWN, LLP

By: [signature]
Robert C. Riter, Jr.

RCR Jr-wb

cc: Suzan Stewart

LAW OFFICES
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April 1, 1999

HAND DELIVERED

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SOUTH DAKOTA PUBLIC
UTILITIES COMMISSION

Mr. William Bullard, Jr.
Executive Director
Public Utilities Commission
State Capitol
500 East Capitol Avenue
Pierre, South Dakota 57501-5070

RE: **NORTHERN STATES POWER COMPANY; SIOUX FALLS GAS**
Docket NG97-021
Our file: 0185

Dear Bill:

Enclosed are original and 11 copies of NSP-SD's reply brief in this docket. Please file the enclosure.

I am enclosing an additional face page of the brief. Please date stamp it and return it to me in the enclosed self-addressed stamped envelope.

With a copy of this letter, I am forwarding a copy of the reply brief to the service list.

Yours truly,

MAY, ADAM, GERDES & THOMPSON LLP

BY: Dave Gerdes

DAG:mw

Enclosures

cc/enc: Karen Cremer
Robert C. Riter, Jr.
Suzanne Stewart
Jim Wilcox
J.P. Johnson
Denny Fulton

RECEIVED

APR 01 1999

SOUTH DAKOTA PUBLIC
UTILITIES COMMISSION

BEFORE THE PUBLIC UTILITIES COMMISSION
STATE OF SOUTH DAKOTA

IN THE MATTER OF THE APPLICATION FOR AN ORDER ESTABLISHING A NATURAL GAS UTILITY, AND TO ESTABLISH INITIAL NATURAL GAS TRANSPORTATION RATES FOR NORTHERN STATES POWER COMPANY.	)	NG97-021 **APPLICANT'S REPLY BRIEF**

Northern States Power Company-South Dakota ("NSP-SD") submits this brief pursuant to the briefing schedule established by the Commission and the extension of time within which to file the reply brief granted by MidAmerican Energy Company ("MidAmerican").

Nothing stated in the answering briefs of MidAmerican or Commission Staff ("Staff") prevents the Commission from granting NSP-SD's request to establish natural gas transportation tariffs and for a waiver of ARSD 20:10:13:04 and 20:10:13:05.

ARGUMENT

In its statement of facts, MidAmerican agrees with NSP-SD's statement of facts, but claims one exception, arguing that the limited unused capacity existing in the Anson Line proven by the evidence is in fact not accurate. This argument does not withstand scrutiny for several reasons:

- MidAmerican offered no countervailing direct evidence. The uncontested evidence in the record discloses that only 325 mcf per hour of capacity is available, notwithstanding MidAmerican's arguments to the contrary.
- The rate and tariff proposed by NSP-SD apply solely to service on the 3.5-mile lateral pipeline ("Hutchinson Lateral")

constructed and operated by NSP-SD. While it is indeed true that a component of the rate includes the cost of using the Anson Line owned and operated by NSP-Generation, the proposed tariff only pertains to the Hutchinson Lateral. MidAmerican's speculation as to the possibility of all three gas-fired generating units operating simultaneously has no relevance because this proceeding will not set rates or terms and conditions of service for the Anson Line. It impermissibly seeks to expand the scope of the Commission's inquiry to facilities and services not properly in the case.

- NSP-Generation and NSP-SD are separate business units of the company.[1] NSP-SD's ability to deliver gas on the Hutchinson Lateral is subject to the available capacity on the Anson Line determined by NSP-Generation.[2] The Anson Line is in the NSP electric rate base, was constructed to fire combustion turbines to generate electricity and must have its firm capacity preserved for the benefit of NSP's electric customers (who are paying for it). Thus, notwithstanding MidAmerican's arguments, the capacity available for transport by NSP-SD is limited by the requirements of NSP-Generation for the Anson plant. Again, MidAmerican offered no countervailing evidence.

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[1]Exhibit 3; Jim Wilcox prefiled testimony, p. 8.

[2]Hearing transcript; James A. Smith, pp. 65 and 66.

- MidAmerican argues that the amount of excess capacity to be used by Hutchinson Technologies, Inc., ("HTI") is unclear, but again offers no supporting evidence. The uncontradicted evidence at the hearing proved that HTI will eventually require more than half the capacity of the Hutchinson Lateral, specifically, 202 mcf per hour.[3]

On page two of its brief, MidAmerican states that NSP-SD meets the statutory criteria for certification as a gas utility. With that conclusion, NSP-SD agrees. By entering its order regarding jurisdiction and approving intervention dated May 6, 1998, the Commission recognized NSP-SD's status as a gas utility. As stated at the outset of the hearing by Chairman Burg, the issues presented at the hearing on this docket involve only approving NSP's natural gas transportation tariffs and NSP's request for waiver, as previously stated. NSP-SD does not at this time propose to be regulated as a gas utility offering "gas service" as defined by SDCL § 49-34A-1(8). In other words, NSP is not presently seeking

[3]Hearing transcript; James A. Smith, pp. 38 and 39. Moreover, MidAmerican's arguments regarding HTI's future expansion plans are inconsistent with its arguments regarding the proposed rate. MidAmerican basically argues (p.3) that the rates, which are derived by dividing test year costs by billing units, do not recover the full cost of service; however, MidAmerican also argues (p.2) HTI consumption may increase, thereby contributing to greater cost recovery. There is no record evidence the test year cost of service or billing unit levels are unreasonable. As discussed herein, if costs or units change, the impact will be reflected in the 2000 financial review.

certification as a local distribution company. This is the point made by MidAmerican.

At page 3 of its brief, MidAmerican argues that NSP-SD's proposed rates do not presently recover all of the fully allocated costs of service. Because of NSP-SD's startup situation, this is an appropriate way to address the proposed rate, as fully elaborated in NSP-SD's initial brief. NSP-SD has adopted the methodology suggested by Staff. It provides the flexibility to add customers up to the maximum unused capacity of the Hutchinson Lateral without the unnecessary design of individual rates for each additional customer. As advocated by Staff, this rate structure makes sense, considering the present and proposed size of NSP-SD's operation.

MidAmerican claims a competitive disadvantage because NSP-SD's proposed rate will require customers to pay customer specific costs, such as daily metering. This technique was suggested by Staff because the rather unique character of NSP-SD's present operation and the addition of future customers made this approach the most practical alternative. Secondly, it takes into consideration NSP-SD's status as a gas transporter, rather than a local distribution company. MidAmerican itself agreed with this distinction in its brief, and cannot now pick and choose which side of the issue it wishes to embrace. If MidAmerican accepts NSP-SD's status as a gas utility offering transportation service on a discretionary basis, it should also accept those necessary distinctions in rate structure between NSP-SD as a retail transporter and MidAmerican as a local distribution company making bundled retail sales.

In any event, Staff has suggested that a review of NSP-SD's experience be conducted in 2000 to test the assumptions made by Staff and NSP-SD in constructing the rate which both suggested to the Commission. This review, to which NSP-SD has agreed, disposes of any objection from MidAmerican. On a related subject, NSP-SD notes that Staff has agreed with its position that the information to be filed for review should be of rate case quality, but short of an actual proceeding. NSP agrees to cooperate with Staff in making such a filing.

Finally, MidAmerican suggests that NSP-SD transportation service be resold. As NSP-SD argued in its initial brief, neither South Dakota law nor South Dakota custom in the gas business presently contemplates restructuring of retail transportation services in South Dakota. For the Commission to so radically expand the filed service obligations of retail utilities, it would require a separate docket permitting all gas companies doing business in South Dakota to participate. Stated another way, if the Commission considered it appropriate to take up the question of whether it is in the public interest for NSP-SD, or any other company, to offer transportation service for resale, the Commission must give all companies and interested parties an opportunity to participate in such a decision. Such a policy decision must apply to all entities providing retail gas delivery service, including MidAmerican, just as FERC applied its restructuring policies in Orders 436 and 636 to all interstate gas pipelines.

CONCLUSION

NSP-SD respectfully requests that the Commission grant its request for approval of natural gas transportation tariffs and its request for a waiver of ARSD 20:10:13:04 and 20:10:13:05. Mid-American's arguments to the contrary are totally unsupported by evidence in the record or are misdirected toward the Anson Line, which is not an issue in this proceeding. The evidence offered by NSP-SD and Staff support the approvals requested.

Dated this 1st day of April, 1999.

MAY, ADAM, GERDES & THOMPSON LLP

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CERTIFICATE OF SERVICE

David A. Gerdes of May, Adam, Gerdes & Thompson LLP hereby certifies that on the 1st day of April, 1999, he mailed by United States mail, first class postage thereon prepaid, a true and correct copy of the foregoing in the above-captioned action to the following at their last known addresses, to-wit:

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David A. Gerdes

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF SOUTH DAKOTA

IN THE MATTER OF THE APPLICATION FOR AN ORDER ESTABLISHING A NATURAL GAS UTILITY, AND TO ESTABLISH INITIAL NATURAL GAS TRANSPORTATION RATES FOR NORTHERN STATES POWER COMPANY	)))))	FINDINGS OF FACT AND CONCLUSIONS OF LAW; NOTICE OF ENTRY OF ORDER NG97-021

On December 16, 1997, Northern States Power Company - South Dakota (NSP-SD), filed with the Public Utilities Commission (Commission) an application for an order establishing a natural gas local distribution utility, and to establish initial natural gas transportation rates. The initial rate will allow NSP-SD to serve the new Hutchinson Technology, Inc. (HTI) facility in the Sioux Empire Development Park Number 5 in eastern Sioux Falls, South Dakota, through a new lateral pipeline. HTI had contacted NSP-SD and requested the proposed service. The proposed tariff, rate schedule, and form of service agreement would establish NSP-SD as a regulated utility in the state of South Dakota, subject to Commission jurisdiction. The proposed maximum rate is a volumetric rate per Mcf with a per month fixed customer service charge. At the time of filing, only HTI was affected by the proposed rate and tariff. The HTI plant was expected to be in commercial operation in February of 1998. NSP-SD also requested that the Commission waive the tariff schedule arrangement and form of tariff rules found at ARSD 20:10:13:04 and 20:10:13:05. NSP-SD further requested waiver of any other Commission rules necessary to allow the tariff and rate to be effective on the date requested. NSP-SD has further requested the Commission to approve the proposed initial rate, subject to refund and subject to hearing, within 30 days following the date of the filing.

At its regularly scheduled meeting of January 8, 1998, the Commission ordered that, pursuant to SDCL 49-1A-8, NSP-SD shall be assessed a filing fee as requested by the executive director up to the statutory limit of $100,000 and February 9, 1998, was established as the deadline for intervention. The Commission took under advisement the request by NSP-SD to permit it to flow gas to its one customer, HTI. On January 12, 1998, at a duly noticed ad hoc meeting, the Commission unanimously voted to allow NSP-SD to flow gas through its pipeline, subject to refund, in order to accommodate its customer, HTI. Commissioner Schoenfelder also asked for clarification as to whether the Commission has jurisdiction to regulate NSP-SD as a gas utility. Intervention was granted to MidAmerican Energy. An intervention request was also received from PAM Natural Gas (PAM). The Commission requested that PAM refile its request for intervention to clarify the filing. On February 23, 1998, PAM filed another request for intervention.

On April 7, 1998, NSP-SD filed an amended application requesting that the title of the application be amended to allow it to seek to be regulated as a gas utility. On April 15, 1998, MidAmerican Energy filed an amended motion to intervene based on NSP-SD's amended application. On April 22, 1998, at its regularly scheduled meeting, the Commission found it had jurisdiction. It also granted intervention to MidAmerican Energy and PAM.

By order dated November 18, 1999, a procedural schedule was set and a hearing was scheduled for 1:30 p.m., on Monday, January 4, 1999, in Room 412, State Capitol Building, 500 East Capitol, Pierre, South Dakota. The hearing was held as scheduled and briefs were filed following the hearing.

At its April 26, 1999, meeting, the Commission unanimously voted to grant the application and the request to waive ARSD 20:10:13:04 and 20:10:13:05. Based on the evidence of record, the Commission makes the following findings of fact and conclusions of law:

FINDINGS OF FACT

1. On December 16, 1997, NSP-SD filed with the Commission an application for an order establishing a natural gas local distribution utility and initial natural gas transportation rates. Exhibit 1. NSP-SD also requested that the Commission waive the tariff schedule arrangement and form of tariff rules found at ARSD 20:10:13:04 and 20:10:13:05. Id.

2. On April 7, 1998, NSP-SD filed an amended application requesting that the title of the application be amended to allow it to seek to be regulated as a gas utility. Exhibit 2.

3. In 1994, a natural gas pipeline was constructed by NSP's Generation Business Unit to provide fuel delivery for the new combustion turbines being installed at the Angus C. Anson Generating Site. Exhibit 2 at 3. The pipeline consists of a 12 inch pipe and is 13 miles long. Id. at 3-4.

4. In 1997, NSP-SD constructed a 3.5 mile long, 4.5 inch diameter steel lateral pipeline from the Angus C. Anson natural gas fuel supply pipeline to the Hutchinson Technologies, Inc. facility in the Sioux Empire Development Park located in Sioux Falls, South Dakota. Id. at 4. This pipeline will be referred to as the Hutchinson Lateral. Subsequently, NSP-SD began to serve two other customers, the Minnehaha County Highway Department and the Jans Corporation. Exhibit 9 at 2.

5. In its application, NSP-SD proposed a Gas Transportation Service Tariff containing the rates and conditions of service. Exhibit 1. NSP-SD proposed maximum rates with a levelized annual revenue requirement. Exhibit 5 at 2.

6. Commission staff proposed changes to the rates, terms, and conditions of service in its prefiled testimony. Exhibits 6 and 7. In response to Commission staff's proposed changes contained in its prefiled testimony, NSP-SD made a number of changes to its proposed tariff. Exhibit 9.

7. At the hearing, James Smith, a witness for NSP-SD stated that NSP-SD adopted the methodology for rates as proposed by Commission staff. Tr. at 67. Robert Knadle, Commission staff analyst, stated that NSP-SD had agreed to the changes he proposed in his rebuttal testimony. Tr. at 124. Mr. Knadle also revised his testimony based on updates

provided to Commission staff after staff had filed its testimony. Tr. at 116-122. Following the hearing, NSP-SD submitted another proposed tariff which contained additional changes. See Gas Transportation Service Tariff SDPUC NO. 1, Original Sheet No. 1 through Original Sheet No. 27, inclusive (attached to Applicant's Opening Brief, dated February 8, 1999).

8. Following the filing of the updated tariff, Commission staff recommended approval of the tariff. Commission Staff Brief at 2.

9. The Commission finds that the rates in the proposed tariff are just and reasonable. However, because this is a start-up facility where estimates were used to set the rates, the Commission finds that NSP-SD shall update its cost of service numbers in May of 2000 with calendar year 1999 numbers. Commission staff shall review the filing and, based on its analysis, may petition the Commission to determine whether the tariffed rate is unreasonable, insufficient, or unjustly discriminatory. See SDCL 49-34A-26.

10. The Commission finds that the terms and conditions in the proposed tariff are just and reasonable. With respect to the issue of whether NSP-SD should provide transportation services to others for resale over its facilities, the Commission finds that it will decide this issue when a reseller actually requests to become a customer of NSP-SD or in a separate proceeding in order to allow other interested parties an opportunity to comment.

11. The Commission also finds that on the issue of system exit charges, the reference to the "facility extension" contained in the Gas Transportation Agreement means only that portion of the facility that is built from the Hutchinson Lateral to the customer-owned facility. See Gas Transportation Service Tariff SDPUC NO. 1, Original Sheet No. 24 (attached to Applicant's Opening Brief, dated February 8, 1999).

12. The Commission therefore approves the following tariff sheets: Gas Transportation Service Tariff SDPUC NO. 1, Original Sheet No. 1 through Original Sheet No. 27, inclusive (attached to Applicant's Opening Brief, dated February 8, 1999).

13. The Commission further finds that NSP-SD is an intrastate natural gas pipeline utility providing gas service through the sale of transportation services. See SDCL 49-34A-1(8), (9), and (9A).

14. The Commission finds good cause to waive the tariff schedule arrangement and form of tariff rules found at ARSD 20:10:13:04 and 20:10:13:05.

CONCLUSIONS OF LAW

1. The Commission has jurisdiction in this matter pursuant to SDCL Chapters 1-26 and 49-34A, specifically 1-26-17.1, 49-34A-4, 49-34A-6, 49-34A-8, 49-34A-10, 49-34A-11, 49-34A-12, 49-34A-13, 49-34A-13.1, 49-34A-17, 49-34A-19, and 49-34A-21.

2. The Commission finds that NSP-SD is an intrastate natural gas pipeline utility providing gas service through the sale of transportation services. See SDCL 49-34A-1(8), (9), and (9A).

3. The Commission finds that NSP-SD's proposed tariff sheets are fair and reasonable and are approved. See Gas Transportation Service Tariff SDPUC NO. 1, Original Sheet No. 1 through Original Sheet No. 27, inclusive (attached to Applicant's Opening Brief, dated February 8, 1999).

4. The Commission finds good cause to waive the tariff schedule arrangement and form of tariff rules found at ARSD 20:10:13:04 and 20:10:13:05.

It is therefore

ORDERED, that NSP-SD's proposed tariff sheets filed as Gas Transportation Service Tariff SDPUC NO. 1, Original Sheet No. 1 through Original Sheet No. 27, inclusive (attached to Applicant's Opening Brief, dated February 8, 1999) are fair and reasonable and are approved and that ARSD 20:10:13:04 and 20:10:13:05 are hereby waived.

NOTICE OF ENTRY OF ORDER

PLEASE TAKE NOTICE that this Order was duly entered on the 12th day of May, 1999. Pursuant to SDCL 1-26-32, this Order will take effect 10 days after the date of receipt or failure to accept delivery of the decision by the parties.

Dated at Pierre, South Dakota, this 12th day of May, 1999.

CERTIFICATE OF SERVICE

The undersigned hereby certifies that this document has been served today upon all parties of record in this docket, as listed on the docket service list, by facsimile or by first class mail, in properly addressed envelopes, with charges prepaid thereon.

By: Delaine Kolbo

Date: 5/12/99

(OFFICIAL SEAL)

BY ORDER OF THE COMMISSION:

James A. Burg
JAMES A. BURG, Chairman

Pam Nelson
PAM NELSON, Commissioner

Laska Schoenfelder
LASKA SCHOENFELDER, Commissioner