

1 **I. Introduction**

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

3 **A.** My name is Dante Mugrace. I am a Senior Consultant with the regulatory
4 consultant firm of PCMG and Associates, LLC. My business address is 22
5 Brookes Avenue, Gaithersburg, MD 20877.

6 **Q. Are you the same Dante Mugrace who previously filed Direct Testimony in
7 this Proceeding?**

8 **A.** Yes. I submitted Direct Testimony on March 1, 2022. My qualifications and
9 experiences are attached to my Direct Testimony.

10 **II. Purpose of Testimony**

11
12 **Q. What is the purposed of your rebuttal testimony?**

13 **A.** The purpose of my Surrebuttal Testimony is to address the Rebuttal Testimony of
14 Northern States Power Company (NSPC or Company) Gas witnesses Halama,
15 Krug and Zich. I am also making certain adjustments to the proposals in my Direct
16 Testimony and a revised calculation of the Company's revenue requirement that
17 incorporates the effects of my adjustments. To the extent that I do not respond to
18 a particular issue or argument contained within my Surrebuttal Testimony, I defer
19 to my Direct Testimony on those issues.

20 **Q. With your adjustments to your Direct Testimony, what is your revised
21 Company revenue requirement?**

22 **A.** With my adjustments, which include updated adjustments from the Company on
23 certain revenue requirement issues, and Dr. Griffing's recommended overall rate
24 of return I have calculated a revised revenue requirement of \$3,958,994 or a
25 5.882% increase over current rates. My recommended revenue requirement
26 includes an overall rate of return of 6.91% with a common equity component of
27 9.54% as recommended by Dr. Marlon Griffing.

28 **Q. Has the Company updated its revenue requirement?**

1 **A.** The Company is now proposing a revenue requirement increase of \$5.993 million,
2 a reduction of \$1.966 million from its initial filing. (Exhibit BCH-2 at 1).

3 **Q. Did Mr. Halama concur with you updated revenue requirement adjustment?**

4 **A.** No. Mr. Halama stated that there was difference of \$7,000 and Mr. Halama stated
5 that my revenue requirement should be \$3.869 million.

6 **Q. What is your response?**

7 **A.** The difference of \$7,000 is >1% between my recommended revenue requirement
8 increase and the way Mr. Halama's calculated my revenue requirement increase;
9 this could be due to rounding issues and the flow-throughs of various taxes. It is
10 de minimis in nature.

11 **Q. What issues are you accepting from the Company with respect to the
12 Company's rebuttal testimony?**

13 **A.** I am accepting the following issues and adjustments from the Company in its
14 rebuttal testimony through Company witness Mr. Halama:

- 15 • Fargo Capacity Project and related cost adjustments
- 16 • AGIS Removal and related cost adjustments
- 17 • Depreciation Study - TD&G Update
- 18 • Damage Prevention Program (DPP) – duplicative adjustment
- 19 • Net Operating Loss
- 20 • Cash Working Capital – The final adjustment to Cash Working Capital is
21 a function of the Commission's determination in the final revenue
22 requirement – Schedule S- DM-8
- 23 • Federal and State Income Taxes – Tax Depreciation balance –
24 Schedule S-DM-23.

25
26
27 **Q. What are the revenue requirement issues that you are not accepting from the
28 Company but are otherwise accepting the adjustment to your recommended
29 balances?**

30 **A.** The following are the revenue requirement issues that I am not fully accepting or
31 agreeing to, but am accepting certain adjustments that the Company has proposed
32 in its rebuttal testimony:

33

1 **III. Revenue Requirement Issues**

2 A. O&M Expense Adjustment

3 **Q. What Company adjustments are you addressing that you do not agree**
4 **with?**

5 **A.** Mr. Halama did not agree with my historical averages of certain O&M expenses
6 and stated that my adjustments are not appropriate. (Exhibit BCH-2 at 7).

7
8 **Q. What did Mr. Halama state regarding your historical normalization of certain**
9 **O&M expenses?**

10 **A.** Mr. Halama stated that the Company selected a future test year of calendar year
11 2022 and utilized its forecasted 2022 budget of revenues and expenses as the
12 basis of its 2022 test year. Use of a forecasted budget is consistent with the
13 Company's long-standing practice and is consistent with North Dakota statute and
14 Commission precedent. (Exhibit BCH-2 at 8). Mr. Halama stated that my use of
15 a three-year historical average to determine a significant portion of expenses
16 resulted in a removal of \$1.698 million in total O&M expenses from the Company's
17 cost of service. (Exhibit BCH-2 at 9). Mr. Halama stated that my use of a three-
18 year average was not sufficient enough to justify my approach. Mr. Halama stated
19 that my adjustment to certain O&M expenses rather than all O&M expenses along
20 with the use of a 2019-2021 three-year average seems wholly arbitrary and
21 provides no support and calls into question the analytical rigor of my adjustment
22 (Exhibit BCH-2 at 12). Mr. Halama stated that my adjustments were to only non-
23 labor expenses and not to total labor and non-labor O&M expenses. (Exhibit BCH-
24 2 at 13). Mr. Halama stated that my adjustment could eliminate the opportunity for
25 the Company to earn its authorized rate of return due to the rates reflecting O&M
26 expenses significantly below historical actuals, the test year budgeted amount and
27 any discernable trend in O&M costs. (Exhibit BCH-2 at 13). Mr. Halama stated
28 that my methodology results in an outcome that is not credible. (Exhibit BCH-2 at
29 14). Mr. Halama stated that unlike the Company's electric utility operations where
30 allocation factors can and do change annually and can and do impact overall cost

1 of service, the North Dakota gas jurisdictional costs are primarily direct assigned
2 or allocated based on the design day demand and customer allocation, which do
3 not significantly fluctuate from year to year. (Exhibit BCH-2 at 15).

4
5 **Q. What is your argument for the use of a three-year average for certain O&M**
6 **Expenses?**

7 **A.** I believe the use of a three-year average to set certain O&M expense is an
8 appropriate approach for setting rates for service. I chose the historic years 2018,
9 9, 2020 and 2021 as these expenses are the most recent expense levels and going
10 further back to include a five-year or an eight-year average would result in stale
11 data and some of the expenses might have changed, been eliminated or are non-
12 recurring. Costs change from year to year, and one of the goals in setting rates
13 for service is to provide for gradualism in the rate setting arena so as to not put
14 stress on ratepayers when costs change from year to year due to sudden
15 increases/decreases incurred by the Company from outside vendors, or in the way
16 the Company allocates its costs from year to year. These types of costs do
17 fluctuate from year to year. Prices do change over time, but not always
18 proportionately. Some costs may be expected to decrease but other costs may be
19 expected to increase. One-time costs or an abnormal cost distribution may reduce
20 costs in a particular year and is a good reason for spreading out one-time costs
21 over time to provide rate stability for customers. As I indicated previously in my
22 testimony, the Company should not expect to recover all of its costs during the test
23 year, the Company is given the opportunity to do so. As Mr. Halama stated,
24 historical averages can be appropriate if certain expenses were generally
25 increasing or decreasing at unusually high or low rates, providing the historical
26 actuals could be shown to demonstrate an appropriate forecasting trend for the
27 future year. (Exhibit BCH-2 at 12). There is no expectation that the Company
28 recover all of its expected future costs in the rate year.

29 **Q. Did you ask the Company to provide the reasoning for the variability related**
30 **to Gas Production, Gas Distribution and Customer Accounting?**

1 **A.** Yes. In response to 4-12, 4-13 and 4-14, for Gas Production, Gas Distribution and
2 Customer Accounting, respectively, I asked the Company for reasonings on the
3 fluctuations from year to year in response to 1-34 Attachment A. The responses
4 were not fully descriptive of the reasoning for the variability of certain expenses. In
5 response to 4-13, the Company stated the variability of distribution expenses was
6 due to many different factors which causes volatility in actual expenses, including
7 weather and weather related incidences, damage prevention locate volumes,
8 contractor prices and compliance requirements. This is the reason for the expense
9 swing of approximately \$900,000, and why it is appropriate to normalize these
10 costs.

11 **Q. What did Mr. Halama state as the reason for the Customer Accounting**
12 **expenses?**

13 **A.** Mr. Halama stated that the increase in O&M expenses between 2021 and 2022
14 was due to higher meter reading costs and meter reading management software,
15 driven by the need to upgrade existing meter reading software to integrate with
16 new technologies. (Exhibit BCH-2 at 15). Mr. Halama stated that the Company's
17 investment in technologies through the Company's MyAccount smartphone
18 application and new user experience into the Company's other systems is driving
19 a slight increase in operations and maintenance expenses in the 2022 test year.
20 (Exhibit BCH-2 at 15).

21 **Q. What is your response with regard to Mr. Halama's response related to**
22 **Customer Accounting and your use of a normalized 3-year average of certain**
23 **O&M expenses?**

24 **A.** Historical trends (actual) are a reliable indicator of future costs. I did review all of
25 the Company's O&M Expense categories and found that the majority of these
26 costs have been stable and consistent in prior years ((Purchased Gas, Gas
27 Production, Sales, Economic and Other, and A&G). My adjustments reflect those
28 O&M expenses that vary from year to year, mainly limited to Gas Distribution and
29 Customer Accounting. With respect to the cost changes in the Customer
30 Accounting expense, I did ask for a description of these costs (4-14) but did not
31 get the detailed response that Mr. Halama indicated in his rebuttal testimony

1 (Exhibit BCH-2) page 15. In addition, given the presence of the COVID-19
2 pandemic, it is even more appropriate to average out costs so that customers are
3 not greatly impacted by increased expenses, all the more reason that it is
4 appropriate to smooth out costs in times of uncertainty (2020 and 2021 COVID-19
5 period). Even in 2022, the COVID-19 pandemic is still present, and further
6 uncertainty continues. I am of the opinion that inflationary cost increases and
7 pressures placed upon the Company should not be included as the reason to
8 assert changes in expenses. The Company has not provided any specific areas
9 where such costs have impacted the Company. Inflationary costs are typically
10 blanket type increases used for economic data that are applied to all goods and
11 services that may not be directly related to the Company's operations. It is simply
12 a forecast or prediction of cost adjustments. The Company should not assume
13 that all of its costs will be affected by inflation and are going to be recovered when
14 rates are set for service, even in the case of inflationary pressures. The Company
15 is given the opportunity to recover costs, not a guarantee of full recovery.

16
17 **B. Labor Adjustment**

18 **Q. What has Mr. Halama stated regarding your Labor Normalization?**

19 **A.** Mr. Halama did not agree with my inclusion of a vacancy rate removal from the
20 Company's 2022 COSS since the Company has not conducted a formal vacancy
21 rate analysis. Mr. Halama stated that the Company has included a negative labor
22 loading rate to account for attrition in workforce, in response to regulatory concerns
23 in other jurisdictions. (Exhibit BCH-2 at 19). Mr. Halama stated that the Company's
24 budgets already include an offset to labor in the 2022 COSS using an attrition rate
25 of 4% on productive labor which was based upon historical attrition and other
26 vacancy rates. Mr. Halama stated that my adjustment is duplicative. (Exhibit BCH-
27 2 at 19).

28 **Q. What is your response?**

1 **A.** I am still recommending a labor vacancy adjustment. The Company does not have
2 to formally perform such an adjustment in order for one to implement such an
3 adjustment. The Company has not provided any analysis to show that it has
4 incorporated an attrition rate into its COSS for 2022. In response to 1-19, the
5 Company stated that opening positions are filled as soon as possible and that
6 specific dates are unknown, and the list will change throughout the year. The
7 Company cannot determine the anticipated hire date for specific openings. In
8 response to 1-34, the information shows that labor costs are on the decline with
9 an expense total of \$6.962 million in 2019 to \$3.993 million in 2021, with a slight
10 uptick of \$99,865 in the 2022 test year for a total of \$4.093 million. In response to
11 1-17, the information shows that in each year beginning in 2016 and through 2021,
12 on average approximately 153 employees in the NSPM total company have left in
13 each year. I believe this trend will continue through 2022, and it is reasonable to
14 conclude that the labor vacancy will exceed the replacement of employees.
15 Attachment A to 1-19 shows approximately 106 vacancy openings in 2022, far
16 below the 153 average employees leaving the NSPM total company. The
17 Company should provide a list of employee hires that occurred in 2022, and
18 whether any candidates have been identified and will be expected to be hired by
19 the Company.

20

21 C. Meter Installation Costs

22 **Q. What did Mr. Halama state regarding my adjustment to the Company's Meter**
23 **Installation costs?**

24 **A.** Mr. Halama stated that I used a composite book depreciation rate as opposed to
25 using the actual book lives for the asset and that I assumed the forecasted dollars
26 not having a corresponding impact to tax depreciation and deferred income taxes,
27 which amounts to >\$500. (Exhibit BCH-2 at 20).

28 **Q. What is your response?**

1 **A.** Although the use of composite rates of depreciation to adjust changes in plant is a
2 reasonable and appropriate approach for ratemaking purposes and the setting of
3 rates for service, I am accepting Mr. Halama's use of the actual book lives to
4 calculate the adjustment, since the differences are minimal.

5 **Q. What did Ms. Zich state regarding your adjustment to remove meter
6 installation costs from the 2022 test year COSS?**

7 **A.** Ms. Zich stated that my 2 percent adjustment escalation was related to the 2019
8 costs rather than the 2022 cost, which if accepted, would reduce the forecasted
9 2022 costs below 2019 actual costs. (Exhibit JHZ-2 at 3). Ms. Zich stated that the
10 2022 cost was \$396,270 rather than what I calculated of \$388,500 to be 2022
11 costs.

12 **Q. What is your response?**

13 **A.** In response to 1-46 the Company provided the cost of an individual meter at \$3,500
14 per meter with no specific calculation for costs proposed in 2022. If the \$396,270
15 is now the actual costs proposed by the Company, the adjustment for removal of
16 the 2 percent becomes \$7,770 instead of my proposed \$7,617, a difference of
17 \$153. I am accepting this increased removal adjustment cost.

18 **Q. What else did Ms. Zich state regarding your removal of the 2 percent
19 escalation cost?**

20 **A.** Ms. Zich stated that the 2 percent is appropriate because costs for both materials
21 and labor are increasing. Given the passage of time and the general inflationary
22 pressures that affect both material and labor costs, escalating costs by 2 percent
23 to arrive at cost expected to be incurred in 2022 was appropriate and conservative.
24 (Exhibit JHZ-2 at 3-4).

25 **Q. What is your response?**

26 **A.** The 2 percent cost escalation is not appropriate as these costs are not justified by
27 actual costs incurred by the Company but rather a blanket increase of overall costs
28 for goods and services. As I indicated previously on the inclusion of inflationary

1 costs, the Company has not provided any specific areas where such costs have
2 impacted the Company.

3
4 D. Donations and Chamber of Commerce Dues

5 **Q. What did Mr. Halama state regarding your adjustment to the Company's**
6 **Donations and Chamber of Commerce Dues?**

7 **A.** Mr. Halama stated that these dues and donations are normal and expected
8 business expenses that provide benefits to North Dakota ratepayers. Mr. Halama
9 stated that these costs are important mechanisms for supporting the communities
10 and organizations in the area the Company serves. (Exhibit BCH-2 at 21).

11 **Q. What is your recommendation?**

12 **A.** I see no benefit to the ratepayers of North Dakota. These types of costs do not
13 benefit the ratepayers in the Company's North Dakota service territory but rather
14 are regional in nature. The Company should not be in the business of financially
15 supporting causes that are not customer specific and organizations with non-
16 ratepayer service. I see no nexus of benefits between these types of costs and
17 the provision of safe and reliable utility service. If the Company wants to be good
18 corporate citizens, then the shareholders of the Company can provide the dollars
19 to support these causes and not burden ratepayers with them. The Company
20 should not have unfettered access to ratepayer money for which ratepayers
21 receive no benefit, and do not have a say of where their ratepayer monies are
22 going to or providing support for.

23 **Q. What did Mr. Krug state regarding your removal of these costs?**

24 **A.** Mr. Krug stated that the expenses in question are appropriate and provide benefits
25 for North Dakota, including the North Dakota customers. The Chamber of
26 Commerce dues facilitate communications with an important category of
27 customers, and charitable contributions are a normal and expected expense for a
28 business, particularly for a corporation of Xcel's Energy size and prominence in
29 the community. (Exhibit ADK-1 at 16). Mr. Krug stands by the Company's request

1 for recovery of 50 percent of these costs which the Company believes is
2 reasonable given the Commission's historic resistance to allowing full recovery of
3 these types of costs. (Exhibit ADK-1 at 16).

4 **Q. What is your response?**

5 **A.** As I indicated previously, these costs should not be funded by ratepayer money,
6 but rather through state, local, federal and civic and municipal organizations. The
7 Company should not be using ratepayer money to show that it is a good corporate
8 citizen and believes in these causes. While I commend the Company for
9 contributing to these causes, the shareholders should be funding these costs and
10 not ratepayers.

11
12 E. Economic Development Donations

13 **Q. What did Mr. Halama state regarding your removal of the Company's**
14 **Economic Development Donations?**

15 **A.** Mr. Halama stated that the economic development in question provides benefits
16 for North Dakota, including Xcel Energy customers. Mr. Halama requested that
17 the Commission continue to support economic development efforts on behalf of
18 the communities the Company serves.

19 **Q. What is your recommendation?**

20 **A.** As I stated in my direct testimony, I do not believe these types of costs should be
21 recovered from ratepayers. These are considered non-regulatory utility expenses
22 that support regional and local economic development and do not provide any
23 utility related benefits to the ratepayers of North Dakota. The ratepayers do not
24 have a say as to which type of donations their ratepayer dollars support. It is not
25 the responsibility of the Company to be the savior of economic development issues
26 and regional and local problems. The Company has not shown or provided what
27 benefits utility ratepayers in North Dakota receive or how these ratepayers are
28 benefitting from these contributions. If the Company wants to participate in giving

1 back to the community, the Shareholders of the Company should fund these
2 causes and receive a tax benefit through the corporate entity.

3
4
5 F. Incentive Compensation

6 **Q. What did Mr. Halama state regarding your removal of the increase to the**
7 **Company's Incentive Compensation adjustment?**

8 **A.** Mr. Halama stated that the Company's scorecard is used to determine the level of
9 incentive compensation that will be paid in the subsequent year. The incentive
10 compensation associated with the applicable scorecard, are accrued in the year
11 the incentive is earned. The 2021 Corporate Scorecard determined the level of
12 incentive to be paid in 2022, which was accrued in 2021. The 2021 Corporate
13 Scorecard results have no impact on the 2022 test year. (Exhibit BCH-2 at 22).

14 **Q. What did Mr. Halama state regarding the 2022 Corporate Scorecard?**

15 **A.** Mr. Halama stated that the incentive compensation included in the 2022 test year
16 will be based on the 2022 Corporate Scorecard. The actual payment of the
17 incentive expense included in the 2022 test year COSS will be paid in March 2023,
18 based upon the 2022 Corporate Scorecard. (Exhibit BCH-2 at 22).

19 **Q. What is your recommendation?**

20 **A.** Any type of incentive compensation included in the Company's test year COSS
21 should not be included and recovered by ratepayers. As I stated in my direct
22 testimony, the Company has not provided any evidence that these costs benefit
23 ratepayers, but rather these costs are used to retain and maintain employees at
24 the senior and executive level. The Company can provide any level of incentive
25 type pay to its employees with the shareholders paying for or funding these costs.
26 In addition, Mr. Halama stated that the 2022 Corporate Scorecard costs will be
27 paid in March 2023, which is beyond the test year period (out of period adjustment)
28 and should not be included in the revenue requirement.

1 **Q. What did Mr. Krug state regarding your Incentive Compensation removal?**

2 **A.** Mr. Krug stated that these costs are known and measurable because they
3 represent the Company's forecasted LTI costs in the 2022 future test year. (Exhibit
4 ADK-1 at 15). These costs are no different than other test year costs that the
5 Company has forecasted which Mr. Mugrace agreed are known and measurable.
6 Mr. Krug stated that the LTI program is an important tool that allows the Company
7 to attract and retain key, senior leaders and ensure they effectively manage the
8 Company consistent with the customer focused goals of environmental excellence
9 and efficient management. (Exhibit ADK-1 at 15).

10 **Q. What is your argument?**

11 **A.** As I indicated previously in my testimony, the Company has not provided any
12 support nor evidence that shows the Incentive Compensation benefits customers.
13 These costs predominately are for retain and maintaining key executives from not
14 leaving the Company. Given that the Company's Scorecard results have not
15 occurred, there is no way to determine if these key executives have met the goals
16 of the program, not whether the goals of the program are beneficial to ratepayers.
17 Finally, these payouts will occur in 2023, well beyond the 2022 test year period,
18 and thus are considered an out of period adjustment.

19

20 G. Income Tax Tracker

21 **Q. What did Mr. Halama state regarding the costs related to the recovery of the**
22 **Income Tax Tracker?**

23 **A.** Mr. Halama stated that he did not agree with my 5 year amortization period related
24 to the Company's recovery of its Income Tax Tracker. Mr. Halama stated that the
25 Company proposed a three-year amortization period to match the period the
26 Company expects rates to remain in effect as a result of this rate case. (Exhibit
27 BCH-2 at 23).

28 **Q. What is your recommendation?**

1 **A.** My adjustment to the amortization period of 5 years was based upon the
2 Company's prior rate case proceedings filed with the Commission. The Company
3 has filed rate case proceedings with the Commission, on average every five-years.
4 It is appropriate to use that time period to amortize the associated expenses
5 related to the Income Tax Tracker. There is no assurance that the Company will
6 actually file its next base rate case proceeding within a three-year period.

7 H. Rate Case Expenses

8 **Q. What did Mr. Halama state regarding the costs associated with Rate Case**
9 **Expenses?**

10 **A.** In the same manner as Mr. Halama proposed to amortize the Company's Income
11 Tax Tracker, he proposed the same 3 year recovery period for Rate Case
12 Expenses. (Exhibit BCH-2 at 24).

13 **Q. What is your response to Mr. Halama?**

14 **A.** In the same manner as I recommended the Income Tax Tracker to be amortized
15 over a 5 year period, I am utilizing the same 5 year period for Rate Case Expenses.
16 There is no assurance that the Company will file its next base rate case proceeding
17 within a three-year period.

18

19 I. Property Taxes

20 **Q. What did Mr. Halama state regarding your historical three-year average of**
21 **Property Taxes?**

22 **A.** Mr. Halama did not agree with my use of an historical three-year average as he
23 stated that this does not consider the investments the Company has made in the
24 system over the last three years and is not consistent with how Property Tax
25 valuations and assessments are prepared by the North Dakota Office of the State
26 Tax Commissioner. (Exhibit BCH-2 at 25).

27 **Q. What is your response?**

1 **A.** My adjustment to Property Taxes is based upon the Company's response to 1-24.
2 The 2019-2021 Property Taxes have fluctuated from \$1.301 million in 2019, a
3 reduction to \$1.190 million in 2020 or 8.5%, and an increase to \$1.283 million in
4 2021, or 7.8%. The Company then adjusted its Property Taxes to \$1.587 million,
5 an increase of \$0.304 million or 24%. The Company's Plant in Service balance
6 grew from \$164 million in 2020, an increase of 17%, to \$192.5 million in 2021; and
7 \$222.6 million in 2022, an increase of 15.7%. Given that Company allocations do
8 change from year to year, it may not appear that the Company's tax bill of \$1.587
9 million will be realized or whether the allocation from NSPM to the North Dakota
10 jurisdictional service will adjusted and allocated accordingly. As indicated in
11 response to 1-24 the Company stated that these valuations do not reflect the full
12 amount of Property Taxes included in rates. The Company should provide an
13 update with respect to the level of Property Taxes associated with the North
14 Dakota jurisdictional service area.

15

16 J. Payroll Taxes

17 **Q. What did Mr. Halama state regarding your adjustment to the Company's**
18 **Payroll Taxes?**

19 **A.** Mr. Halama stated that my adjustment is not appropriate as it relates to labor and
20 incentive, and if the Commission accepts the Company's position on the recovery
21 of these adjustments, the adjustment becomes unnecessary. (Exhibit BCH-2 at
22 25).

23 **Q. What is your response?**

24 **A.** If the Commission agrees with the Company with respect to adjustments made by
25 me for labor and incentive, I am in agreement with Mr. Halama that my payroll
26 adjustment becomes unnecessary.

27

28

1 K. Federal and State Income Taxes

2 **Q. What did Mr. Halama state regarding your adjustment to the Company's**
3 **Federal and State Income Taxes?**

4 **A.** Mr. Halama stated that the Company reviewed my calculations and identified
5 errors in my schedules related to operating income adjustments, plant additions
6 related to changes in tax depreciation and deferred tax expense and interest
7 synchronization to reflect the weighted cost of debt and rate base. (Exhibit BCH-
8 2 at 27). Mr. Halama stated that these errors resulted in about \$710,000 of
9 underestimated revenue requirement for the test year. (Exhibit BCH-2 at 27-28).

10 **Q. What is your response?**

11 **A.** I corrected my errors through my surrebuttal testimony and exhibits. My
12 recommended Federal and State Income Taxes represent the flow-throughs of my
13 adjustments to Rate Base and Operating Income. While these flow-throughs may
14 not be exact, they are correctly calculated. The differences are due to rounding of
15 certain expenses, and the use of composite rates for various tax expense
16 adjustments. As Mr. Halama stated, the final calculations of Federal and State
17 Income Taxes to be included in the test year will be a function of the final approved
18 levels of revenues, expenses and rate base as well as weighted cost of capital
19 approved by the Commission. (Exhibit BCH-2 at 28).

20
21 **Q. Does this conclude your Surrebuttal Testimony?**

22 **A.** Yes. I reserve the right to update my surrebuttal testimony in the event the
23 Company revises its rebuttal filing.

24

25

REVENUE REQUIREMENT

	(1) Company Proposed	Adjustments	ND PSC Advocacy Staff	References
1 Average Rate Base	\$ 124,227,000	\$ (1,642,969)	\$ 122,584,031	
2 Present Rate Income	\$ 3,919,000	\$ 1,558,758	\$ 5,477,758	
3 AFUDC	\$ -		\$ -	
4 Total Available for Return	\$ 3,919,000	\$ 1,558,758	\$ 5,477,758	
5 Present Rate of Return	3.155%		4.469%	
6 Required Return	7.450%		6.91%	
7 Operating Income Requirement	\$ 9,254,912	\$ (784,355)	\$ 8,470,557	
	\$ -	\$ -	\$ -	
8 Income Deficiency	\$ 5,335,912	\$ (2,343,113)	\$ 2,992,799	
9 Gross Revenue Conversion Factor	1.322840		1.322840	(2)
10 Revenue Deficiency	\$ 7,058,557	\$ (3,099,563)	\$ 3,958,994	
				\$ 966,195 To Schedule DM-23
11 Present Rate Revenues	\$ 67,303,000		\$ 67,302,687	
12 Percentage Increase	10.488%		5.882%	

Total Revenue Requirement \$ 71,261,681

- (1) Company Exhibit BCH-1 Schedule 7
- (2) Company Exhibit BCH-1 Schedule 3A

State Income Tax Rate	4.310000%
Federal Income Tax Rate	21.000000%
Effective Tax Rate	20.090000%
Composite Tax Rate	24.400000%
Revenue Conversion Factor	1.322837

Differences due to rounding

WEIGHTED AVERAGE COST OF CAPITAL

(1) Company Proposed

		Ratios	Cost of Capital	Weighted Average
1	LT Debt	47.03000%	4.09550%	1.92611%
2	ST Debt	0.43000%	1.09000%	0.00469%
3	Common Equity	52.54000%	10.50000%	5.51670%
4	Total Capital	100.00000%		7.44750%
5	rounded			7.45000%

(2) ND PSC Advocacy Staff

6	LT Debt	47.570%	4.100%	1.950%
7	ST Debt	0.430%	1.090%	0.005%
8	Common Equity	52.000%	9.540%	4.961%
9	Total Capital	100.000%		6.91%

(1) Company WP C1

(2) Exhibit MFG-16

AVERAGE RATE BASE

		(1)			
		Company		ND PSC	
		Proposed	Adjustments	Advocacy Staff	References
<u>Gas Plant in Service</u>					
1	Production	\$ 5,340,000	\$ -	\$ 5,340,000	
2	Transmission	\$ 3,909,000	\$ -	\$ 3,909,000	
3	Distribution	\$ 181,046,000	\$ (607,617)	\$ 180,438,383	
4	Gas Storage	\$ 9,341,000	\$ -	\$ 9,341,000	
5	General	\$ 14,757,000	\$ -	\$ 14,757,000	
6	Common	\$ 8,463,000	\$ -	\$ 8,463,000	
7	Total Gas Plant In Service	\$ 222,856,000		\$ 222,248,383	
8	Depreciation Reserve	\$ 82,973,000	\$ (71,337)	\$ 82,901,663	
9	Net Gas Plant In Service	\$ 139,883,000	\$ (536,280)	\$ 139,346,720	
10	Gas Plant Held for Future Use	\$ -	\$ -	\$ -	
11	Construction Work in Progress	\$ 188,000	\$ -	\$ 188,000	
12	Accumulated Deferred Income Taxes	\$ 19,783,000	\$ (15,981)	\$ 19,767,019	
13	Cash Working Capital	\$ 648,000	\$ (1,100,670)	\$ (452,670)	
14	Subtotal	\$ 120,936,000	\$ (1,620,969)	\$ 119,315,031	
<u>Other Rate Base Items</u>					
15	Materials and Supplies	\$ 150,000	\$ -	\$ 150,000	
16	Fuel Inventory	\$ 2,098,000	\$ -	\$ 2,098,000	
17	Non-Plant Assets & Liabilities	\$ 1,463,000	\$ -	\$ 1,463,000	
18	Customer Advances	\$ (1,340,000)	\$ -	\$ (1,340,000)	
19	Customer Deposits	\$ (42,000)	\$ -	\$ (42,000)	
20	Prepays and Other	\$ 523,000	\$ -	\$ 523,000	
21	Regulatory Amortization - ITT/ADIT ARAM	\$ 440,000	\$ (23,000)	\$ 417,000	WP A15
22	Total Other Rate Base Items	\$ 3,292,000	\$ (23,000)	\$ 3,269,000	NDPSC 1-32
23	Total Average Rate Base	\$ 124,228,000	\$ (1,643,969)	\$ 122,584,031	

(1) Company Exhibit BCH-1 Schedule 15

differences due to rounding

OPERATING INCOME STATEMENT

		(1)				Present Rates	
		Company		Company		ND PSC	
		Present Rates	Adjustments	Proposed Rates	Adjustments	Advocacy Staff	References
Operating Revenues							
1	Retail Revenues	\$ 67,303,000	\$ 7,059,000	\$ 74,362,000	\$ -	\$ 67,302,687	
2	Interdepartmental	\$ -		\$ -	\$ -	\$ -	
3	Other Operating	\$ 550,000	\$ -	\$ 550,000	\$ -	\$ 550,384	
4	Total Operating Revenues	\$ 67,853,000	\$ 7,059,000	\$ 74,912,000	\$ -	\$ 67,853,071	DM-9
Operating Expenses							
5	Purchased Gas	\$ 43,934,000		\$ 43,934,000	\$ -	\$ 43,934,429	DM-12
6	Gas Production & Storage	\$ 635,000		\$ 635,000	\$ -	\$ 635,473	DM-13
7	Gas Transmission	\$ 387,000		\$ 387,000	\$ (44,477)	\$ 342,523	DM-14
8	Gas Distribution	\$ 5,129,000		\$ 5,129,000	\$ (923,211)	\$ 4,205,789	DM-15
9	Customer Accounting	\$ 1,613,000		\$ 1,613,000		\$ 1,311,454	DM-16
10	Customer Service & Other	\$ 149,000		\$ 149,000	\$ 10,771	\$ 159,771	DM-17
11	Sales, Econ Development & Other	\$ 10,000		\$ 10,000	\$ (7,645)	\$ 2,355	DM-18
12	Administrative & General	\$ 2,508,000		\$ 2,508,000		\$ 2,471,170	DM-19
	Vacancy Rate Adjustment				\$ (173,413)	\$ (173,413)	1-34/20/17
13	Total Operating Expenses	\$ 54,365,000	\$ -	\$ 54,365,000	\$ (1,475,449)	\$ 52,889,551	
14	Depreciation Expense	\$ 6,892,000	\$ -	\$ 6,892,000	\$ (72,132)	\$ 6,819,868	DM-20
15	Amortization Expense	\$ 440,000	\$ -	\$ 440,000	\$ (166,994)	\$ 273,006	DM-21
16	Taxes Other Than Income	\$ 2,401,000		\$ 2,401,000	\$ (346,090)	\$ 2,054,910	DM-22
17	State Income Taxes	\$ (29,000)	\$ 304,243	\$ 275,243	\$ 88,688	\$ 59,688	DM-23
18	Federal Income Taxes	\$ (135,000)	\$ 1,418,499	\$ 1,283,499	\$ 413,289	\$ 278,289	DM-23
19	Total Taxes	\$ 2,237,000	\$ 1,722,742	\$ 3,959,742	\$ 155,887	\$ 2,392,887	
20	Total Expenses	\$ 63,934,000	\$ 1,722,742	\$ 65,656,742	\$ (1,558,687)	\$ 62,375,313	
21	AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -	
22	Total Operating Income	\$ 3,919,000	\$ 5,336,258	\$ 9,255,258	\$ 1,558,758	\$ 5,477,758	
						\$ 2,992,799	
23	Rate Base	\$ 124,228,000		\$ 124,228,000		\$ 122,584,031	
24	Rate of Return	3.155%		7.4502%		6.91%	
				\$ 9,255,258		\$ 8,470,557	

(1) Company Exhibit BCH-1 Schedule 11

differences due to rounding

GAS PLANT IN SERVICE

		(1)						
		Company		Company		ND PSC		
		Proposed Unadj.	Adjustments	Proposed Adj.	Adjustments	Advocacy Staff	References	
1	Gas Manufactured Plant	\$ 5,340,000	\$ -	\$ 5,340,000		\$ 5,340,000		
2	Gas Storage	\$ 9,341,000	\$ -	\$ 9,341,000		\$ 9,341,000		
3	Gas Transmission	\$ 3,909,000	\$ -	\$ 3,909,000		\$ 3,909,000		
4	Gas Distribution	\$ 181,046,000	\$ -	\$ 181,046,000	\$ (607,617)	\$ 180,438,383	ND PSC 1-46/49	
5	General	\$ 11,871,000	\$ -	\$ 11,871,000		\$ 11,871,000	ND PSC 4-7/4-9	
6	Common	\$ 11,348,000	\$ -	\$ 11,348,000		\$ 11,348,000		
7	Total Gas Plant In Service	\$ 222,855,000	\$ -	\$ 222,855,000	\$ (607,617)	\$ 222,247,383		ND PSC 1-44/45

(1) Company Exhibit BCH-1 Schedule 5

Meter Installation costs - outside \$3,500 x 111 - \$388,500 1-46 (relocation) 1-46
 Meter exchange costs \$453 X 12,525 = \$5,673,825 1-47
 Cost to exchange a module \$72 x 12,525 = \$901,800 commencing in 2023 1-48
 Fargo Project located in Gas Distribution
 Capital Additions 1-55 and 1-56
 AGIS adjustment 1-62
 Wescott - Spring of 2022, Sibley - Maplewood and Delta V

ACCUMULATED DEPRECIATION

	(1)		Company Proposed	Adjustments	ND PSC Advocacy Staff	References
	Company Unadjusted	Adjustments				
Gas Manufactured Plant	\$ 2,420,000	\$ (45,000)	\$ 2,375,000	\$ -	\$ 2,375,000	WP A8
Gas Storage	\$ 8,010,000	\$ 29,000	\$ 8,039,000	\$ -	\$ 8,039,000	WP A8
Gas Transmission	\$ 1,683,000	\$ 3,000	\$ 1,686,000	\$ -	\$ 1,686,000	WP A9
Gas Distribution	\$ 59,581,000	\$ 50,000	\$ 59,631,000	\$ (71,337)	\$ 59,559,663	WP A9
General	\$ 5,559,000	\$ 47,000	\$ 5,606,000	\$ -	\$ 5,606,000	WP A9
Common	\$ 5,619,000	\$ 17,000	\$ 5,636,000	\$ -	\$ 5,636,000	WP A9
Total Accumulated Depreciation	\$ 82,872,000	\$ 101,000	\$ 82,973,000	\$ (71,337)	\$ 82,901,663	

(1) Company Exhibit BCH-1 Schedule 5

ACCUMULATED DEFERRED INCOME TAXES

		(1)						
		Company		Company		ND PSC		
		Unadjusted	Adjustments	Proposed	Adjustments	Advocacy Staff	References	
1	Production	\$ (77,000)	\$ 12,000	\$ (65,000)	\$ -	\$ (65,000)	WP A8	
2	Transmission	\$ 718,000	\$ (1,000)	\$ 717,000	\$ -	\$ 717,000	WP A9	
3	Distribution	\$ 17,469,000	\$ (14,000)	\$ 17,455,000	\$ -	\$ 17,455,000	WP A9	
4	Gas Storage	\$ (416,000)	\$ (8,000)	\$ (424,000)	\$ (14,981)	\$ (438,981)	WP A8	
5	General	\$ 1,266,000	\$ (19,000)	\$ 1,247,000	\$ -	\$ 1,247,000	WP A9	
6	Common	\$ 625,000	\$ 1,000	\$ 626,000	\$ -	\$ 626,000	WP A9	
7	Net Operating Loss	\$ (93,000)	\$ -	\$ (93,000)	\$ -	\$ (93,000)		
8	Non-Plant Related	\$ 319,000	\$ -	\$ 319,000	\$ -	\$ 319,000		
9	Total Accumulated Deferred Income Taxes	\$ 19,811,000	\$ (29,000)	\$ 19,782,000	\$ (14,981)	\$ 19,767,019		

(1) Company Exhibit BCH-1 Schedule 15

CASH WORKING CAPITAL		(1)					
	Lead/Lag Days	Company Dollars	Dollar x Days	Adjustments	ND PSC Advocacy Staff	References	
1	Fuel Expenses	39.09119	\$ 14,442,000	\$ 564,554,966	\$ 1,152,877,375	\$ 1,717,432,341	4-3
	Labor						
2	Regular Payroll	11.890587	\$ 3,409,000	\$ 40,535,011	\$ (173,413)	\$ 38,473,031	DM-4
3	Incentive	248.81	\$ 37,000	\$ 9,205,970	\$ (28,039)	\$ 2,229,586	
4	Pension & Benefits	37.23	\$ 647,000	\$ 24,087,810	\$ -	\$ 24,087,810	
			\$ 4,093,000	\$ 73,828,791	\$ (9,038,364)	\$ 64,790,427	
5	All Other Operating Expenses	22.73988	\$ 37,080,000	\$ 843,194,750		\$ 207,581,798	4-3
6	Property Taxes	357.9199	\$ 1,587,000	\$ 568,018,881		\$ 450,486,576	
7	Employer's Payroll Taxes	31.6197	\$ 263,000	\$ 8,315,981		\$ 7,902,041	
8	Gross Earnings Tax	38.8962	\$ 1,214,000	\$ 47,219,987		\$ 47,219,987	
9	Federal Income Taxes	37.005	\$ (386,000)	\$ (14,283,930)		\$ (4,995,675)	
10	State Income Taxes	36.9156	\$ (83,000)	\$ (3,063,995)		\$ (1,070,552)	
			\$ 39,675,000	\$ 1,449,401,675		\$ 707,124,174	
11	Total		\$ 58,210,000	\$ 2,087,785,432		\$ 2,489,346,943	
12	Net Annual Expense (365)			\$ 5,719,960		\$ 6,820,129	
13	Revenues	40.2998	\$ 67,303,000	\$ 2,712,297,439		\$ 2,712,284,826	
14	Late Payment		\$ 155,000	\$ -		\$ -	
15	Miscellaneous Services	40.389	\$ 118,000	\$ 4,765,902		\$ 4,765,902	
16	Rentals	-50.009	\$ 211,000	\$ (10,551,899)		\$ (10,551,899)	
17	Total		\$ 67,787,000	\$ 2,706,511,442		\$ 2,706,498,829	
18	Net Annual Amount (365)			\$ 7,415,100		\$ 7,415,065	
19	Expense/Revenue Factor			85.87%		85.87%	
20	Allocated Revenue			\$ 6,367,489		\$ 6,367,459	
21	Net Cash Working Capital			\$ 647,529		\$ (452,670)	

(1) Company Exhibit BCH-1 Schedule 8

OPERATING REVENUES

		(1)		ND PSC		
		Company	Adjustments	Advocacy Staff	References	
		Proposed				
1	Residential Service	\$ 26,797,199	\$ -	\$ 26,797,199		
2	Commerical/Industrial	\$ 31,901,891	\$ -	\$ 31,901,891		
3	Small Interruptible Service	\$ 2,194,889	\$ -	\$ 2,194,889		
4	Large Interruptible Service	\$ 6,408,708	\$ -	\$ 6,408,708		
5	Interruptible	\$ -	\$ -	\$ -		
6	Firm Transportation Service	\$ -	\$ -	\$ -		
7	Total Present Rate Revenues	\$ 67,302,687	\$ -	\$ 67,302,687		
8	Other Gas Revenues	\$ 550,384	\$ -	\$ 550,384		1-33
9	Total Operating Revenues	\$ 67,853,071	\$ -	\$ 67,853,071		

(1) Company WP R2 Present Revenues
 Differences due to rounding

**OPERATION & MAINTENANCE
 EXPENSES - WORKSHEET**

Three-Year Normalize Non-Labor		(1) Company		ND PSC		
		Proposed	Adjustments	Advocacy Staff	References	
1	Purchased Gas Expense	\$ 43,934,429	\$ -	\$ 43,934,429		DM-12
2	Gas Production & Storage	\$ 289,489	\$ -	\$ 289,489		DM-13
3	Gas Transmission	\$ 304,359	\$ (44,169)	\$ 260,190		DM-14
4	Gas Distribution	\$ 3,278,109	\$ (901,253)	\$ 2,376,856		DM-15
5	Customer Accounting	\$ 1,217,726	\$ (301,166)	\$ 916,560		DM-16
6	Customer Service & Information	\$ 140,217	\$ 11,853	\$ 152,070		DM-17
7	Sales, Econ Develop & Other	\$ 8,872	\$ -	\$ 8,872		DM-18
8	Administrative & General	\$ 1,099,071	\$ -	\$ 1,099,071		DM-19
9	Total	\$ 50,272,272	\$ (1,234,735)	\$ 49,037,537		

(1) Company WP O2-3 Jurisdictional Alloc.
 Differences due to rounding

check for vacancy rate - 1-17 and 1-15
 check for hires in 1-19 - trade secret for salaries
 review 1-34 without labor

PURCHASED GAS

	(1) Company Proposed	Adjustments	ND PSC Advocacy Staff	References
1 Unadjusted Balance	\$ 43,934,429		\$ 43,934,429	
2 Adjustments	\$ -		\$ -	
3 Precedential Adjustments	\$ -		\$ -	
4 Adjusted Balance	\$ 43,934,429	\$ -	\$ 43,934,429	

(1) Company Schedule BCH-1 Schedule 6
 Company WP O2-3 Jurisdictional Allocation

GAS PRODUCTION & STORAGE

	(1) Company Proposed	Adjustments	ND PSC Advocacy Staff	References
1 Unadjusted Balance	\$ 635,473		\$ 635,473	
2 Adjustments	\$ -	\$ -	\$ -	ND PSC 4-12
3 Precedential Adjustments	\$ -	\$ -	\$ -	
4 Adjusted Balance	\$ 635,473		\$ 635,473	ND PSC 1-51

(1) Company Exhibit BCH-1 Schedule 6
 Company WP O2-3 Jurisdictional Allocation
 Wescott, Maplewood & Sibley Plants

GAS TRANSMISSION

		(1)			
		Company		ND PSC	
		Proposed	Adjustments	Advocacy Staff	References
1	Unadjusted Balance	\$ 386,692		\$ 386,692	
2	Adjustments - three year average	\$ -	\$ (44,169)	\$ (44,169)	ND PSC 1-34
	Damage Prevention Program	\$ -	\$ -	\$ -	ND PSC 1-53
3	Precedential Adjustments	\$ -	\$ -	\$ -	
4	Adjusted Balance	\$ 386,692	\$ (44,169)	\$ 342,523	

- (1) Company Exhibit BCH-1 Schedule 6
 Company WP O2-3 Jurisdictional Allocation

GAS DISTRIBUTION

		(1)		ND PSC		
		Company	Adjustments	Advocacy Staff	References	
		Proposed				
Unadjusted Balance						
1	G Customer MNND Border	\$ 2,258,174	\$ (775,305)	\$ 1,482,869	ND PSC 4-13	
2	G Customers	\$ 947,014	\$ 168,496	\$ 1,115,510		
3	G Direct MN	\$ -	\$ -	\$ -		
4	G Direct ND	\$ 1,924,193	\$ (294,443)	\$ 1,629,750		
5	Total Balance	\$ 5,129,381	\$ (901,252)	\$ 4,228,129	ND PSC 1-50	
6	Damage Prevention Program	\$ -	\$ (22,340)	\$ (22,340)	ND PSC 1-53	
7	Precedential Adjustments	\$ -	\$ -	\$ -		
8	Adjusted Balance	\$ 5,129,381	\$ (923,592)	\$ 4,205,789		

- (1) Company Exhibit BCH-1 Schedule 6
 Company WP O2-3 Jurisdictional Allocation
 Fargo Capacity Cost - O&M \$18,000 plus \$4,600

CUSTOMER ACCOUNTING

		(1)		ND PSC		
		Company	Adjustments	Advocacy Staff	References	
		Proposed				
Unadjusted Balance						
1	G Bad Debts	\$ 280,729	\$ 4,204	\$ 284,933	ND PSC 4-14	
2	G Customers	\$ 932,545	\$ (191,159)	\$ 741,386		
3	G Direct MN	\$ -	\$ -	\$ -		
4	G Direct ND	\$ 399,447	\$ (114,312)	\$ 285,135		
5	Total Balance	\$ 1,612,721	\$ (301,267)	\$ 1,311,454		
6	Adjustments	\$ -	\$ -	\$ -		
7	Precedential Adjustments	\$ -	\$ -	\$ -		
8	Adjusted Balance	\$ 1,612,721	\$ (301,267)	\$ 1,311,454		

- (1) Company Exhibit BCH-1 Schedule 6
 Company WP O2-3 Jurisdictional Allocation
 Meter reading costs - 1-48

CUSTOMER SERVICE & INFORMATION

		(1)		ND PSC		
		Company		Advocacy Staff		References
		Proposed	Adjustments			
Unadjusted Balance						
1	G Customers	\$ 51,713		\$ 51,713		ND PSC 1-34
2	G Direct ND	\$ 97,676		\$ 97,676		
3	Advertising	\$ 40,000		\$ 40,000		
4	Total Unadjusted Balance	\$ 189,389	\$ -	\$ 189,389		
Adjustments						
5	Precedential Adjustments	\$ (40,000)	\$ 11,853	\$ (41,471)	\$ 11,853	DM-10 WP A1 Adv
6	Adjusted Balance	\$ 149,389	\$ 10,382	\$ 159,771		ND-PSC 1-39

(1) Company Exhibit BCH-1 Schedule 6
 Company WP O2-3 Jurisdictional Allocation

SALES & ECONOMIC DEVELOPMENT

	(1)		ND PSC		
	Company	Adjustments	Advocacy Staff	References	
	Proposed				
Unadjusted Balance					
G Customers	\$ 2,355		\$ 2,355		
Total Unadjusted Balance	\$ 2,355	\$ -	\$ 2,355		
Adjustments	\$ -	\$ -	\$ -		ND PSC 1-34 WP A11 Econ.
Precedential Adjustments	\$ 7,382	\$ (7,382)	\$ -		Donations 1-41
Adjusted Balance	\$ 9,737	\$ (7,382)	\$ 2,355		

- (1) Company Exhibit BCH-1 Schedule 6
 Company WP O2-3 Jurisdictional Allocation

ADMINISTRATIVE & GENERAL

		(1)		ND PSC		
		Company		Advocacy Staff		References
		Proposed	Adjustments			
Unadjusted Balance						
1	G Customers MNND Border	\$ 226,813	\$ -	\$ 226,813		ND PSC 1-34
2	G Customers MNND Border	\$ 2,222,388	\$ -	\$ 2,222,388		
3	G Direct ND	\$ 58,455	\$ -	\$ 58,455		
4	Other	\$ 130,846	\$ -	\$ 130,846		
5	Total Unadjusted Balance	\$ 2,638,502	\$ -	\$ 2,638,502		
6	Adjustments - Other	\$ -	\$ -	\$ -		ND PSC 1-34 1-25/26
Precedential Adjustments:						
7	Advertising	\$ (28,856)	\$ -	\$ (28,856)		WP A1 Adv. 1-39
8	Customer Deposits	\$ 676	\$ -	\$ 676		WP A3
9	Incentive Pay	\$ (17,013)	\$ -	\$ (17,013)		WP A4
10	Incentive Pay LT	\$ (97,348)	\$ -	\$ (97,348)		WP A5
11	SERP	\$ (3,027)	\$ -	\$ (3,027)		WP A6
12	Total Precedential Adjustments	\$ (145,568)	\$ -	\$ (145,568)		
RM Adjustments						
13	Aviation (100%)	\$ (22,003)	\$ -	\$ (22,003)		WP A7
14	Chamber of Commerce	\$ 2,221	\$ (2,221)	\$ -		WP A10 - 1-40
15	Economic Develop Donations	\$ 6,226	\$ (6,226)	\$ -		WP A12 1-42
16	Incentive Pay - Environmental LTI	\$ 17,060	\$ (17,060)	\$ -		WP A13
17	Incentive Pay - Time Based LTI	\$ 10,979	\$ (10,979)	\$ -		WP A14
18	Total RM Adjustments	\$ 14,483	\$ (36,486)	\$ (22,003)		
19	Adjusted Balance	\$ 2,507,417		\$ 2,470,931		
20	rounding	\$ 239		\$ 239		
21	Total	\$ 2,507,656	\$ (36,486)	\$ 2,471,170		

- (1) Company Exhibit BCH-1 Schedule 6
 Company O2-3 Jurisdictional Allocation
 Company Exhibit BCH-1 Schedule 4

Review data responses to 1-6, 1-13, 1-14, 1-15, 1-16, 1-17
 Confirm total Gas Employees and the allocate employees who left

DEPRECIATION EXPENSE

		(1)			
		Company		ND PSC	
		Proposed	Adjustments	Advocacy Staff	References
1	Unadjusted Balance	\$ 6,845,000	\$ (16,078)	\$ 6,828,922	1-43/4-9
Remaining Life					
2	Gas Manufactured Production Plant	\$ (90,872)	\$ -	\$ (90,872)	WP A8
3	Gas Other Storage Plant	\$ 58,954	\$ -	\$ 58,954	WP A8
4	Total Remaining Life	\$ (31,918)	\$ -	\$ (31,918)	
Depreciation Study					
5	Gas Distribution - Composite 2.646%	\$ 33,481	\$ -	\$ 33,481	WP A9
6	Gas Transmission - Composite 1.76%	\$ 1,767	\$ -	\$ 1,767	WP A9
7	Common-General - AGIS - 21.68%	\$ 17,742	\$ -	\$ 17,742	WP A9
8	General	\$ 27,897	\$ -	\$ 27,897	WP A9
9	Common-Intangible	\$ (6,212)	\$ -	\$ (6,212)	WP A9
10	Intangible	\$ 3,448	\$ -	\$ 3,448	WP A9
11	Total Depreciation Study	\$ 78,123	\$ -	\$ 78,123	
	Updated Depreciation adjustment		\$ (55,259)	\$ (55,259)	1-43
12	Adjusted Balance	\$ 6,891,205	\$ (71,337)	\$ 6,819,868	

(1) Company Exhibit BCH-1 Schedule 6
 Fargo Project located in Gas Distribution
 refer to 1-43, updated in Company
 rebuttal
 Refer to 1-61/63

AMORTIZATION EXPENSE

	(1)		ND PSC		
	Company	Adjustments	Advocacy Staff	References	
	Proposed				
Unadjusted Balance	\$	-			
(2) Income Tax Tracker	\$ 9,317	\$ (3,727)	\$ 5,590		WP A15
NOL Tax Reform ADIT ARAM	\$ 22,547	\$ -	\$ 22,547		WP A16
(3) Rate Case Expense Amortization	\$ 408,115	\$ (163,246)	\$ 244,869		WP A17
Adjusted Balance	\$ 439,979	\$ (166,973)	\$ 273,006		

(1) Company Exhibit BCH-1 Schedule 6

Refer to 1-43 - updated in Company Rebuttal

- (2) Income Tax Tracker amortized over 5 years
- (3) Rate Case Expense amortized over 5 years

TAXES OTHER THAN INCOME				
	(1)		ND PSC	
	Company	Adjustments	Advocacy Staff	References
	Proposed			
Property Taxes	\$ 1,587,442	\$ (328,818)	\$ 1,258,624	1-24
Payroll Taxes	\$ 262,844	\$ (12,935)	\$ 249,909	1-34
Unadjusted Deferred Income Taxes / ITC	\$ 564,000	\$ -	\$ 564,000	
Depreciation Study - Remaining Life				
Gas Manufactured Plant	\$ 25,543	\$ -	\$ 25,543	
Gas Other Storage Plant	\$ (16,571)	\$ -	\$ (16,571)	
Total	\$ 8,972	\$ -	\$ 8,972	WP A8
Depreciation Study - TD&G - 28.11%				
Gas Distribution	\$ (9,410)	\$ -	\$ (9,410)	
Gas Transmission	\$ (497)	\$ -	\$ (497)	
Common-General	\$ (4,987)	\$ -	\$ (4,987)	
General	\$ (7,841)	\$ -	\$ (7,841)	
Common-Intangible	\$ 1,746	\$ -	\$ 1,746	
Intangible Plant	\$ (969)	\$ -	\$ (969)	
Total	\$ (21,958)	\$ -	\$ (21,958)	WP A9
Adjusted Deferred Income Taxes/ITC	\$ 551,014	\$ (4,637)	\$ 546,377	
Total Taxes Other Than Income	\$ 2,401,300	\$ (346,390)	\$ 2,054,910	

(1) Company Exhibit BCH-1 Schedule 6

STATE INCOME TAXES
FEDERAL INCOME TAXES

	(1)					
	Company		ND PSC			Update
	Proposed	Adjustments	Advocacy Staff	References		
State Income Taxes						
Current - 4.31%	\$ (29,000)	\$ -	\$ (29,000)	NDPSC 1-38	\$ 59,688	To Schedule DM-4
Proposed Revenue Requirement	\$ 7,059,000		\$ 2,929,911	\$ 3,958,994		
Proposed State Income Taxes	\$ 304,243		\$ 126,279	\$ 170,633		
Proposed Balance	\$ 275,243		\$ 97,279	\$ 230,321		
Federal Income Taxes						
Current - 21%	\$ (135,000)	\$ -	\$ (135,000)	NDPSC 1-38	\$ 278,289	To Schedule DM-4
Proposed Revenue Requirement	\$ 7,059,000		\$ 2,929,911	\$ 3,788,361		
Proposed Federal Income Taxes	\$ 1,418,499		\$ 588,763	\$ 795,556		
Proposed Balance	\$ 1,283,499		\$ 453,763	\$ 1,073,845	\$ 337,977	Total Present
Check total	\$ 1,558,742		\$ 551,042	\$ 1,304,166	\$ 337,977	\$ 966,189 To Schedule DM-1

(1) Company Exhibit BCH-1 Schedule 3A
 Differences due to rounding

Company Present	\$ (671,153)
O&M Adjustments	\$ 2,056,027
	\$ 1,384,874
SIT at Present Rates	4.31%
	\$ 59,688
FIT at Present Rates	\$ 1,325,186
	21.00%
	\$ 278,289

