State of North Dakota
Before the North Dakota Public Service Commission

In the Matter of
Application and Notice of Change in Natural Gas Rates of
MONTANA-DAKOTA UTILITIES CO.
Case No. PU-17-295

Direct Testimony of
Scott J. Rubin

on Behalf of
AARP

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72 PU-17-295 Filed 12/18/2017 Pages: 161
Prefiled Direct Testimony of Scott J. Robin
AARP, Intervenors
David A. Tschider, Attorney

Contents

Introduction

Q. Please state your name and business address.

A. My name is Scott J. Rubin. My business address is 333 Oak Lane, Bloomsburg, PA.

Q. By whom are you employed and in what capacity?

A. I am an independent consultant and an attorney. My practice is limited to matters affecting the public utility industry.

Q. What is the purpose of your testimony in this case?

A. I have been asked by AARP to review the Application for an increase in natural gas rates filed by Montana-Dakota Utilities Company ("MDU" or "Company"). AARP has more than 50,000 members in North Dakota many of whom are natural gas customers of MDU.

Q. What are your qualifications to provide this testimony in this case?

A. I have testified as an expert witness before utility commissions or courts in the District of Columbia; the province of Nova Scotia; and the states of Alaska, Arizona, California, Connecticut, Delaware, Illinois, Kentucky, Maine, Maryland, Massachusetts, Minnesota, Mississippi, New Hampshire, New Jersey, New York, Ohio, Pennsylvania, and West Virginia. I also have testified as an expert witness before various federal, state, and local legislative committees. I have served as a consultant to the staffs of three state utility commissions, as well as to several national utility trade associations, and state and local governments throughout the country. Prior to establishing my own consulting and law practice, I was employed by the Pennsylvania Office of Consumer Advocate from 1983 through January 1994 in increasingly responsible positions. From 1990 until I left state government, I was one of two senior attorneys in that office. Among my other responsibilities in that position, I had a major role in setting its policy positions on water and electric matters. In addition, I was responsible for supervising the technical staff of the office. I also testified as an expert witness for that office on rate design and cost of service issues.

Throughout my career, I developed substantial expertise in matters relating to the economic regulation of public utilities. I have published articles, contributed to books, written speeches, and delivered numerous presentations, on both the national and state level, relating to regulatory issues. I have attended numerous continuing education courses involving the utility industry. I also have participated as a faculty member in utility-related educational programs for the Institute for Public Utilities at Michigan State University, the American Water Works Association, and the Pennsylvania Bar Institute.

Q. Do you have any experience that is particularly relevant to the issues in this case?

A. Yes, I do. I have testified on numerous occasions as a rate design and cost of service expert. For example, since 2013, I have testified as an expert witness on issues related to cost-of-service studies, rate design, and other tariff issues in natural gas distribution utility rate cases in Illinois (Ameren, North Shore Gas, and Peoples Gas), Maine (Maine Natural Gas), Nova Scotia (Heritage Gas), Ohio (Duke Energy), and Pennsylvania (Pike County Light & Power).

Q. Have you prepared an exhibit summarizing your experience?

A. Yes. My curriculum vitae is attached to my testimony as Appendix A.

Summary

Q. What is the primary focus of your direct testimony?

A. My review focuses on a few issues, including (1) the cost-of-service study ("COSS") prepared by MDU, (2) the allocation of any increase among the customer classes, (3) the design of residential rates, (4) the Company's proposed System Safety & Integrity Program Adjustment Mechanism ("SIA") surcharge, and (5) MDU's proposed increase in the returned check charge.

Q. Please summarize your recommendations.

A. My recommendations are summarized as follows:

- I recommend the use of the Basic Customer method for classifying distribution-system costs. Under that approach, all costs associated with meters, meter reading, service line, billing, and customer service are classified as 100% customer-related. All other distribution-system costs, including mains, are classified as 100% demand-related.

- The Company's class revenue allocation proposal is reasonable under any of the COSS methodologies, and I recommend its adoption by the Commission.

- If the Commission finds that the revenue requirement is lower than that proposed by MDU, I recommend that the increases to the Residential and Firm General classes should be scaled back proportionately. The other classes should continue to see no change in their distribution rates, as the Company proposed.

- The residential customer charge should not be increased in this case. Any rate increase allocated to the residential class should be collected solely through a consumption charge.

- The Commission should reject the Company's proposed SIA tariff. There is no reason to have special, miniature rate cases that look at only one aspect of the Company's operations.

- If the Commission disagrees with me and approves any type of surcharge for safety-related expenditures, the costs should be recovered as a percentage adder on the base-rate portion of each customer's bill (that is, excluding the cost of gas). In that way, customer classes with much larger per-customer costs (including, for example, significant demand-related costs, as well as more expensive regulators and service lines) would pay their fair share of costs.

- Finally, I recommend that the Commission reject the Company's proposal to increase its returned check fee to $40. MDU's returned check fee should remain at $15.

Background

Principles of Utility Rate Design

Q. Are there basic principles that should guide the design of utility rates?

A. Yes. A reasonable rate design should be developed to meet several goals. More than 50 years ago, Professor James Bonbright outlined those goals and they remain valid today. Professor Bonbright posited that there were eight attributes of a sound rate design which could be grouped together into the following "primary criteria": (a) collection of the revenue requirement, (b) fairly apportioning the revenue requirement among different types of customers, and (c) encouraging the efficient use of the utility service (or, conversely, discouraging inefficient consumption).[1]

Q. What are the fairness and efficiency principles?

A. Professor Bonbright described fairness as follows: "the principle that the burden of meeting total revenue requirements must be distributed fairly among the beneficiaries of the service."[2] He described efficiency as rates being designed to "discourage the

[1] James C. Bonbright, *Principles of Public Utility Rates* (Columbia Univ. Press, 1961), pp. 290-292.
[2] *Id.*, p. 292.

wasteful use of public utility services while promoting all use that is economically justified in view of the relationships between costs incurred and benefits received."[3]

Also included within the fairness principle is the attribute that the rates themselves should be stable, "with a minimum of unexpected changes seriously adverse to existing customers."[4] Regulators and witnesses often refer to this as the principle of gradualism or rate continuity. That is, changes in the rate design should be made slowly so that customers' expectations about utility pricing are not violated. This is important because customers make decisions about energy consumption that cannot be reversed for many years. For example, if an MDU customer needs a new water heater or clothes dryer, the customer will need to make decisions that are directly or indirectly influenced by the utility rate design. These may include whether to purchase a gas or electric appliance and whether the customer is willing to pay more money for a more efficient appliance.

As Professor Bonbright cautioned: "Indeed, unless rate-making policies are sufficiently stable to permit a consumer to predict with some confidence what his charges will be *if he decides* to equip his home or his factory to take the contemplated service and then to buy the service, the cost-price system of rate making will be self-defeating when viewed as a means of securing a rational control of demand."[5] In other words, it is important for the structure of utility rates to exhibit both a strong relationship to the cost of providing service (to encourage efficiency and fairness) and to remain stable (to avoid

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[3] *Id.*
[4] *Id.*, p. 291.
[5] *Id.*, p. 297 (emphasis in original).

unintended consequences to customers who have made expensive decisions based on the rate design).

Obviously, some of these goals compete with one another. For example, if the only purpose of the rate design was to collect the revenue requirement, each customer could be charged the same amount every month, regardless of energy usage or any other factor. The utility would be assured of receiving almost exactly the same amount of money each month, and that amount would recover the revenue requirement. But that would ignore other important goals, including encouraging the efficient use of the resource and being fair to all customers. A reasonable rate design, therefore, must achieve a balance of these goals.

Q. Is there a way to quantitatively evaluate the ability of a rate design to be fair to customers and encourage efficiency?

A. Yes. The most direct way to evaluate the fairness and efficiency of a rate design is to compare the revenues that would be collected from each customer to the cost to serve the customer. When differences in customers' bills are primarily based on differences in the cost to serve the customers, the rate design can be considered fair to all customers. Similarly, when bills increase roughly in proportion to changes in the cost to provide service to customers, the rate design encourages the efficient use of utility service, as the incremental charge to the customer is approximately equal to the incremental cost to the utility. When the charge to the customer is approximately equal to the cost to the utility to provide the service, then the customer will make economically efficient decisions about using the service (increased consumption will cause an increased bill that is approximately equal to the increased cost of providing the service). Thus, determining the cost of serving a customer is an important component of evaluating both the fairness and efficiency of a rate design.

Q. In your experience, are similar rate design principles commonly used throughout the United States and Canada in designing utility rates?

A. Yes. While different jurisdictions may emphasize certain principles over others, similar rate design principles are commonly used in designing utility rates in nearly every jurisdiction in which I have appeared.

Q. To the best of your knowledge, are these types of principles used by this Commission?

A. I have not conducted exhaustive research into this, but I did locate a 2002 decision in an MDU natural gas case where the Commission discussed the principle of rate continuity. Based on that principle and other factors, the Commission concluded that increases in residential and small commercial customer charges should be moderated even if it resulted in the charges being less than the cost of service.[6]

Other Preliminary Matters

Q. Do you have any other preliminary matters to address?

A. Yes. My review of the Company's cost-of-service studies, cost allocations, and rate design are all based on the use of the Company's proposed revenue requirement. I do this so that my recommendations can be compared on an apples-to-apples basis with the Company's proposals. This should not be taken as an endorsement by me or AARP of the Company's revenue requirement claims.

[6] *Montana-Dakota Utilities Co.*, 222 P.U.R.4th 36, (ND PSC 2002).

In addition, a portion of my testimony discusses regulatory policy issues. Given the nature of public utility regulation, much of the public policy in this field is contained in decisions by regulatory agencies and courts; or in statutes, ordinances, or regulations. If I cite to these types of sources, it should not be taken as a legal opinion, but rather as sources supporting my expert opinion concerning appropriate public policy and regulatory practice.

Cost-of-Service Study ("COSS")

Q. Has MDU prepared a COSS reflecting its revenue requirement claims?

A. Yes. Statement M of the Company's filing contains an embedded class COSS for the projected 2018 test year.

Q. Please summarize your understanding of the results of the Company's COSS.

A. I have prepared Table 1, below, to summarize the results of the Company's COSS. The table shows the cost to serve each customer class excluding the cost of gas, which I will refer to as the distribution costs. It also shows revenues under present rates, excluding the gas commodity revenues but including each class's share of miscellaneous revenues, which I will refer to as distribution revenues. Finally, it shows the difference between distribution costs and revenues. This column is calculated as revenues minus costs so that a negative number means that an increase in distribution revenues would be required to have a class's revenues precisely equal the cost of serving the class.

Table 1: Cost of Service (Company Filed) Compared to Class Distribution Revenues (Including Allocated Other Revenues) Under Present Rates

Class	Cost of Service (Company Filed)	Distribution Revenues	Difference
Residential	$28,382,000	$24,603,000	$ (3,779,000)
Small Firm General	4,756,000	4,503,000	(253,000)
Large Firm General	8,032,000	8,313,000	281,000
Air Force Delivery	104,000	121,000	17,000
Small Interruptible	1,306,000	1,835,000	529,000
Large Interruptible	989,000	1,386,000	397,000
Minot AFB Distrib.	446,000	463,000	17,000
Total	**$44,015,000**	**$41,224,000**	**$ (2,791,000)**

Source: MDU Statement M, pp. 1-4 (Net Distribution Cost of Service; Projected Revenue Before Increase - Projected Cost of Gas)

Q. Before you continue, what rates did the Company use to determine distribution revenues?

A. The distribution revenues under present rates, or what the Company terms "projected revenue before increase" represents the existing permanent distribution rates multiplied by projected billing determinants for the 2018 test year. When I use the phrase "present rates" or "existing rates" I also will be referring to the permanent rates that were in effect when the Company filed this case. As the Commission knows, interim rates are subject to modification and do not have the same legal force and effect as Commission-made rates determined after a rate case.

Q. Other than the cost to serve each customer class, does the Company's COSS provide any other useful information?

A. Yes. The Company's COSS also calculates the unit costs of service for each customer class. The calculation of unit costs takes the three primary categories of cost causation -- demand-related costs, energy-related costs, and customer-related costs -- and divides them by the number of relevant units. For the residential class, those units are energy consumption for demand- and energy-related costs and the number of customers for customer-related costs. For example, the Company's COSS concludes that the residential class has demand-related costs of $7,101,000. MDU Statement M, p. 1. This figure is then divided by the residential class's energy consumption of 8,826,214 dekatherms ("Dk") to calculate a unit demand cost per Dk of $0.800, as shown at the bottom of MDU Statement M, p. 1. The unit costs of service are important pieces of information to consider when designing rates, and I will discuss them in the rate design portion of my testimony.

Q. Do you agree with the Company's COSS?

A. No, I do not. While there are various assumptions and methodologies in the COSS with which I disagree, most of them do not have a significant effect on the results of the study. There is, however, one issue where the Company's COSS contains a significant error that does affect the study's results.

Q. What is that issue?

A. The Company's allocation of distribution mains must be corrected. The issue is significant because distribution mains represent almost 50% of the Company's rate base: $66,985,000 in net plant out of a total rate base of $135,451,000.[7] In addition, the allocation of distribution mains affects the allocation of other types of plant and expenses that are based on plant or rate base allocators.

[7] MDU Statement M, pp. 1 (total rate base), 5 (gross plant), and 8 (accrued depreciation). Distribution mains: gross plant of $103,231,000 less $36,246,000 of accrued depreciation equals $66,985,000 of net plant.

Q. How did the Company classify distribution mains?

A. MDU classified distribution mains as being 25% customer-related and 75% demand-related.

Q. Is that classification consistent with standard practice in the natural gas utility industry?

A. No. The classification of distribution mains is one of the most controversial aspects of a cost-of-service study and different jurisdictions handle the costs differently. Some jurisdictions use a "basic customer" or "basic system" approach that treats as customer-related only costs associated with metering, the service line, billing, and customer service. AARP and I generally support this method. Utilities in some parts of the country, however, are moving to adopt a different method which purports to support a higher customer charge. This is known as the minimum system method. This method estimates a portion of distribution mains that are theoretically incurred to connect each customer to the distribution system regardless of the customer's demand. I am not aware of any jurisdiction, or any practice in the industry, that simply estimates the customer-related portion as being a stated percentage without a supporting analysis.

Further, the use of any type of minimum system analysis is controversial. In 1989, the National Association of Regulatory Utility Commissioners ("NARUC") published the most recent version of its rate design manual for natural gas utilities.[8] Even then, almost 30 years ago, NARUC recognized: "A portion of customer costs associated with the distribution system may be included as customer costs. However, the inclusion

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[8] NARUC, *Gas Distribution Rate Design Manual* (June 1989) (cited as "*NARUC Gas Manual*").

of such costs can be controversial."[9] The manual also noted that although a minimum-size analysis could estimate a customer-related portion of the distribution system, "[t]he contra argument to the inclusion of certain distribution costs as customer costs is that mains and services are installed to serve demands of the consumers and should be allocated to that function."[10]

Q. Has MDU prepared any analysis supporting its 25% / 75% classification of distribution mains?

A. MDU provided a workpaper that it calls a minimum system analysis. That workpaper, however, does not meet the requirements of a minimum system analysis and has no value in estimating the appropriate customer- and demand-related percentages.

Q. Can you be more specific?

A. Yes. I have attached as Exhibit ___ (SJR-1) the Company's response to PSC 5.1 which is the Company's purported minimum-system workpaper. It can be seen from this workpaper that the Company tallied the feet of distribution main of various diameters and then multiplied each sized main by the current cost of a main of each size. The result is a total cost of mains of $256,278,752. The Company then priced out all mains at the current cost of a 2-inch main (the smallest size main it currently installs), which totals $176,599,631. The Company divided the two numbers and concluded that 68.91% of the cost of mains is customer-related.

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[9] *NARUC Gas Manual*, p. 22.
[10] *Id.*, p. 23.

Q. Are there errors in the Company's approach?

A. Yes. The first error is rather obvious. The Company's analysis is based on the current cost of installing gas mains, not the actual cost of its system. MDU's actual system, not some hypothetical brand-new system, is the cost we're trying to classify. In particular, the Company's analysis shows a total cost of $256,278,752, but the Company's records show that the total gross plant value of its gas mains (that is, the original construction cost before depreciation) is only $103,231,000.[11]

Q. Does the use of a current replacement cost comply with the requirements for a minimum-system analysis?

A. No. The *NARUC Gas Manual* describes the minimum size analysis as follows: "Under the minimum size main theory, all distribution mains are priced out at the historic unit cost of the smallest main installed in the system, and assigned as customer costs. The remaining book cost of distribution mains is assigned to demand."[12]

That is, the industry-standard approach to a minimum size analysis is to use the <u>historic unit cost</u> of the <u>smallest size main</u> actually installed in the system and treat that as the customer-related cost. MDU's analysis deviates from this standard. It does not use the historic unit cost; instead it uses a much higher current cost.

[11] MDU Statement M, p. 5.
[12] *NARUC Gas Manual*, p. 22.

Q. Does MDU's analysis comply with the second requirement set out in the NARUC Gas Manual: that the analysis determine the cost of the smallest size main in service?

A. No. MDU's workpaper does not use the cost of the smallest size main installed in the system. SJR-1 shows that MDU actually has mains as small as 0.75-inches installed in the system. In fact, I calculate from the Company's workpaper that in total MDU has approximately 792,000 feet of main with a diameter smaller than 2 inches, representing almost 6% of all distribution mains installed in the system.

Q. Is it reasonable to use a 0.75-inch main as the minimum when the Company currently does not install mains smaller than 2 inches?

A. Yes, there are at least two reasons why it is reasonable to use a 0.75-inch main as the minimum system size. First, the purpose of the minimum-system analysis is to classify the costs of the system as it exists. The Company actually has several miles of 0.75-inch main in service today.

Second, a system comprised of 2-inch mains would be sufficient to serve nearly the entire demand of the residential class, except for a few very large gas users. That is, 2-inch mains have a significant demand-serving capability. For instance, a recent analysis I performed for another gas distribution utility showed that more than 90% of its residential demand would be met by a system consisting of only 2-inch mains. If a minimum-system analysis were to be performed using 2-inch mains, then there would be little or no residual residential demand to be allocated. In other words, a 2-inch main is much too large to be considered a "minimum" essentially demand-free main.

Q. What is the combined effect of these two errors in the Company's analysis?

A. The combined effect of these two errors is to greatly overstate the cost of a minimum-sized system. The smallest-size mains (the 0.75-inch mains) are likely to be some of the oldest and least expensive mains in the system. While MDU did not include such information as part of its minimum-size workpaper, earlier this year I obtained similar information from an Illinois utility, Northern Illinois Gas Co. (also known as Nicor). That utility filed a rate case earlier in 2017 and its minimum-size analysis includes data on the historic cost of mains of different sizes. Data for that utility show that the historic installed cost of a 0.75-inch gas distribution main was $1.38 per foot.

Q. Are the Nicor and MDU systems of a similar age?

A. Yes. According to the most recent depreciation study filed by Nicor, its oldest distribution mains were installed in 1900. I have attached as Exhibit ___ (SJR-2) an excerpt from Nicor's depreciation study filed with the Illinois Commerce Commission in 2013 at Docket No. 13-0500. The depreciation study filed by MDU in this case shows that MDU's oldest mains were installed in 1916.[13] Further, for both systems less than 10% of the cost of mains was incurred prior to 1960. Essentially, both systems still have some very old distribution mains (100 years or older) in place, but most of the system (in terms of cost) was installed during the past 50 to 60 years. Thus, it appears reasonable to conclude that the Nicor and MDU gas distribution systems are of a similar vintage. As I stated above, plant records for both utilities also show that the smallest mains still in service are 0.75-inches in diameter. From this information, I conclude that it is

[13] MDU Exhibit EMR-1, pp. 6-7 to 6-10.

reasonable to use a unit-cost figure for Nicor's smallest mains as a proxy for the unit cost of MDU's smallest mains.

Q. What would be the effect on MDU's minimum-size analysis for distribution mains if you used $1.38 per foot as the "historic unit cost of the smallest main installed in the system," as specified in the *NARUC Gas Manual*?

A. I have prepared Exhibit ___ (SJR-3) to perform this calculation. As I show in that schedule, using Nicor's historic cost of a 0.75-inch main as a proxy for MDU's historic cost of a main of that size would result in a customer-related distribution main cost of $18,746,730, which represents 18.16% of the cost of distribution mains. This is a much more reasonable estimate of the customer-related portion of the cost of distribution mains.

Q. What do you recommend?

A. I support the use of the basic customer method for classifying distribution-system costs. Under that approach, as explained in the *NARUC Gas Manual*, all costs associated with meters, meter reading, service line, billing, and customer service are classified as 100% customer-related. All other distribution-system costs, including mains, are classified as 100% demand-related. In my opinion, and based on my more than 30 years of experience in the field of utility regulation, the basic customer method is the only method that appropriately recognizes that even the smallest size utility facility has a demand-carrying capability and is sized based on demand considerations. This is true for distribution mains, meters, regulators, and customer service lines. Rather than pretending that some of these facilities have no demand component, the basic customer method represents a reasonable compromise that classifies all facilities from the right of way to the customer's premises as being customer-related (service line, meter, regulator) and all facilities upstream of the customer as being demand-related. This avoids the need to try to artificially determine the customer- and demand-related portions of service lines, meters, regulators, and distribution mains, while fairly allocating costs among all customers.

Q. How does your recommendation differ from the Company's approach?

A. The Company's approach is really a hybrid that is not recognized in the *NARUC Gas Manual*. The Company did not recognize a demand-related portion of service lines, meters, or regulators; that is, this part of MDU's classification is consistent with the basic customer approach. But it then deviated from the basic customer approach by classifying as demand-related a significant portion of distribution mains.

Q. Have you calculated the effect of using the basic customer methodology on the COSS?

A. Yes. Exhibit ___ (SJR-4) contains the results of using the basic customer methodology on the COSS. In preparing this schedule, I used the electronic version of the COSS that MDU provided in response to PSC interim request 1.2. Table 2, below, compares the results of my preferred COSS and the Company's COSS. Using the basic customer methodology results in reducing the revenue responsibility for the residential class from $28,382,000 to $26,511,000. Most of that difference is allocated to the classes with large demands and relatively few customers, the Large Firm General and Interruptible classes.

Table 2: Class Cost of Service Under Company COSS and Basic Customer Methodology

Class	Company	Basic Customer	Difference
Residential	$28,382,000	$26,511,000	$ (1,871,000)
Small Firm General	4,756,000	4,894,000	138,000
Large Firm General	8,032,000	9,341,000	1,309,000
Air Force Delivery	104,000	104,000	-
Small Interruptible	1,306,000	1,627,000	321,000
Large Interruptible	989,000	1,093,000	104,000
Minot AFB Distrib.	446,000	445,000	(1,000)
Total	**$44,015,000**	**$44,015,000**	-

Source: MDU Statement M, pp. 1-4 (Net Distribution Cost of Service; Exhibit ___ (SJR-4), pp. 1-4 (Net Distribution Cost of Service)

Q. How does each class's cost of service under the Basic Customer methodology compare to revenues from each class under present rates?

A. I show this comparison in Table 3, below. The table shows the revenue deficiency, or required rate increase, for each customer class when comparing present-rate revenues to the class cost of service using the Basic Customer methodology.

Table 3: Cost of Service (Basic Customer Methodology) Compared to Class Distribution Revenues Under Present Rates

Class	Cost of Service (Basic Customer)	Distribution Revenues	Difference
Residential	$26,511,000	$24,603,000	$ (1,908,000)
Small Firm General	4,894,000	4,503,000	(391,000)
Large Firm General	9,341,000	8,313,000	(1,028,000)
Air Force Delivery	104,000	121,000	17,000
Small Interruptible	1,627,000	1,835,000	208,000
Large Interruptible	1,093,000	1,386,000	293,000
Minot AFB Distrib.	445,000	463,000	18,000
Total	**$44,015,000**	**$41,224,000**	**$ (2,791,000)**

Source: Exhibit ___ (SJR-4), pp. 1-4 (Net Distribution Cost of Service; Projected Revenue Before Increase - Projected Cost of Gas)

From Table 3, it can be seen that the Residential, Small Firm General, and Large Firm General classes each require revenue increases to have revenues completely cover the class cost of service. The increases for the Residential and Small Firm General classes, however, are considerably smaller under this approach than they are under the Company's COSS, as I will describe in greater detail in the Class Revenue Allocation section of my testimony.

Q. In the alternative, have you calculated the effect of using a more accurate minimum-system estimate of the customer-related portion of distribution mains in the COSS?

A. Yes. While I do not support the use of a minimum-size analysis, if the Commission determines that the minimum-size approach is appropriate, then the analysis must be performed properly. As I showed in Exhibit ___ (SJR-3), a proper analysis would conclude that no more than 18.16% of the cost of distribution mains is customer-related, with the remainder being demand-related. Even this understates the demand-related costs because even a system composed entirely of 0.75-inch mains would have some demand-carrying capability.

I recognize, of course, that while a system built entirely of 0.75-inch mains would be able to deliver some gas to customers, it would not be able to provide sufficient pressures and quantities to meet all customer needs. That is precisely the point of a minimum system analysis. Any gas required in excess of that which could be delivered by such a small system would require the Company to incur costs for larger-sized mains and other facilities, the costs of which are demand-related.

To be conservative, however, I have included the entire 18.16% as being customer-related and I have not reflected a demand component in the costs of service lines, meters, and regulators, even though we know that customers who use more gas require larger meters, regulators, and service lines because of their increased demands.

The results of the COSS using 18.16% of distribution mains as being customer-related are shown in Exhibit ___ (SJR-5). Table 4, below, compares the results of a COSS using the corrected minimum system analysis and the Company's COSS. Correcting the minimum system analysis results in reducing the revenue responsibility for the residential class from $28,382,000 to $27,879,000.

Table 4: Class Cost of Service Under Company COSS and Corrected Minimum System Methodology

Class	Company	Corrected Minimum System	Difference
Residential	$28,382,000	$27,879,000	$ (503,000)
Small Firm General	4,756,000	4,789,000	33,000
Large Firm General	8,032,000	8,383,000	351,000
Air Force Delivery	104,000	104,000	-
Small Interruptible	1,306,000	1,403,000	97,000
Large Interruptible	989,000	1,011,000	22,000
Minot AFB Distrib.	446,000	446,000	-
Total	**$44,015,000**	**$44,015,000**	**-**

Source: MDU Statement M, pp. 1-4 (Net Distribution Cost of Service; Exhibit ___ (SJR-5), pp. 1-4 (Net Distribution Cost of Service)

Q. Did you also calculate how each class's cost of service under the corrected minimum system analysis compares to revenues from each class under present rates?

A. Yes. I show this comparison in Table 5, below. The table shows the revenue deficiency, or required rate increase, for each customer class when comparing present-rate revenues to the class cost of service using the corrected minimum system methodology.

Table 5: Cost of Service (Corrected Minimum System Methodology) Compared to Class Distribution Revenues Under Present Rates

Class	**Cost of Service (Corrected Min. Sys.)**	**Distribution Revenues**	**Difference**
Residential	$27,879,000	$24,603,000	$ (3,276,000)
Small Firm General	4,789,000	4,503,000	(286,000)
Large Firm General	8,383,000	8,313,000	(70,000)
Air Force Delivery	104,000	121,000	17,000
Small Interruptible	1,403,000	1,835,000	432,000
Large Interruptible	1,011,000	1,386,000	375,000
Minot AFB Distrib.	446,000	463,000	17,000
Total	**$44,015,000**	**$41,224,000**	**$ (2,791,000)**

Source: Exhibit ___ (SJR-5), pp. 1-4 (Net Distribution Cost of Service; Projected Revenue Before Increase - Projected Cost of Gas)

From Table 5, it can be seen that the Residential, Small Firm General, and Large Firm General classes each require revenue increases to have revenues completely cover the class cost of service.

Class Revenue Allocation

Q. How did the Company propose allocating its proposed rate increase among the customer classes?

A. The Company proposed allocating the entire rate increase to the Residential and Firm General customer classes, as I summarize in Table 6, below.

Table 6: MDU Proposed Class Revenue Allocation			
Class	**Present Distribution Revenues (Excluding Other Revenues)**	**MDU Proposed**	
		$ Increase	**% Increase**
Residential	$22,762,526	$ 3,458,717	15.2%
Firm General	11,785,787	2,409,704	20.4%
Air Force Delivery	119,891	0	0.0%
Small Interruptible	1,700,349	(171)	-0.0%
Large Interruptible	1,327,781	139	0.0%
Total	**$37,696,334**	**$5,868,389**	**15.6%**
Source: MDU Statement N, pp. 1-2			

Q. Assuming, for the sake of this question, that the Company's COSS is accurate, are these class increases reasonable?

A. If I were to make the assumption that the Company's proposed revenue increase is reasonable and that its COSS is reasonable -- assumptions with which I do not agree -- then the Company's proposed class revenue allocation would be reasonable. Under the Company's COSS, and excluding consideration of Other Revenues, the Residential and Firm General classes are providing revenues that are below the cost of service, while the remaining classes are providing revenues under present rates that exceed the class cost of service under proposed rates.

Q. You have explained why you did not consider the Company's COSS to be reasonable or accurate. If the Commission adopts your recommended COSS using the Basic Customer methodology, or your alternative that corrects the minimum system analysis, would it change the class revenue allocation?

A. No, the Company's class revenue allocation proposal was not based strictly on cost-of-service considerations. On Exhibit ___ (SJR-6) I provide a comparison of the class revenue deficiencies under the three different COSS methodologies, and I also show the

Company's proposed revenue allocation. The Company's allocation is actually quite close to the cost-based revenue deficiency under the Basic Customer methodology that I prefer. As a result, I consider the Company's class revenue allocation proposal to be reasonable under any of the COSS methodologies, and I recommend its adoption by the Commission, as adjusted for the ultimate revenue requirement determination made by the Commission.

Q. How do you recommend the Commission should adjust the revenue allocation to reflect a different revenue requirement?

A. If the Commission finds that the revenue requirement is lower than that proposed by MDU, I recommend that the increases to the Residential and Firm General classes should be scaled back proportionately. The other classes should continue to see no change in their distribution rates, as the Company proposed.

Residential Rate Design

Q. Did you review the Company's proposed design of residential rates?

A. Yes.

Q. Please summarize your understanding of the Company's residential rate design proposals.

A. MDU's existing (permanent) residential rate is a flat charge of $0.6443 per day. There is no element of the distribution rate that is based on the amount of gas consumed or demanded by the customer. Under proposed rates, MDU proposes to increase the flat charge to $0.7422 per day, an increase of 15.2%. MDU proposes to continue the practice of having no consumption-based distribution charge.

Q. Do you agree with the Company's proposed design of residential rates?

A. No. The Company's proposed residential rate design is not consistent with the results of its cost-of-service study, does not reflect a fair allocation of costs among residential customers with different demand and consumption characteristics, and does nothing to encourage the efficient use of natural gas (or to discourage the inefficient use of gas). As such, the proposed rate design violates two of Bonbright's fundamental principles of rate design: the fairness and efficiency principles.

Q. What is the effect of the Company's proposed rate design on different types of residential customers?

A. The Company's COSS calculates that the customer-related cost is $18.13 per month, demand-related costs are $0.800 per Dk, and energy-related costs are $0.030 per Dk.[14] Yet the Company proposes a customer charge that would average $22.58 per month.[15] This charge is $4.45 per month, or $53.40 per year, more than the customer-related cost. The proposed rates, therefore, would result in charging lower-usage customers (such as customers in small dwelling units or those who do not use natural gas for both space heating and water heating) significantly more than the cost of service, while higher-use residential customers would pay significantly less than the cost to serve them.

Q. Do these figures change under your preferred COSS methodology or your alternative that corrects the minimum system calculation?

A. Yes, they do. Table 7 show the unit costs for the residential class under the different COSS options.

[14] MDU Statement M, p. 1.
[15] Proposed charge of $0.7442 per day x 365 days ÷ 12 billing periods per year = $22.575 per bill.

Table 7: Unit Costs for Residential Class Under Different COSS Options

COSS Option	Customer Cost per Bill	Demand Cost per Dk	Energy Cost per Dk
MDU	$18.13	$0.800	$0.030
Basic Customer	$14.33	$1.090	$0.030
Correct Min. Sys.	$17.09	$0.880	$0.030

Sources: MDU Statement M, p. 1; Exhibit ___(SJR-4), p. 1; Exhibit ___(SJR-5), p. 1.

Q. You stated that the Company's proposal would result in charging lower-use residential customers more than the cost to serve them, and higher-use residential customers less than the cost of service. Did you conduct any analysis to attempt to quantify this concern?

A. Yes. As I described earlier, the Company's COSS calculates a unit energy-related cost of $0.030 per Dk and a unit demand-related cost of $0.800 per Dk, or a total of 83 cents per Dk incurred by the Company to serve customers, in addition to customer-related costs. The average residential customer uses approximately 91 Dk per year.[16]

That average, however, does not represent most of the Company's residential customers. In response to AARP request 1.12, MDU provided actual billing data for each residential customer for calendar year 2016. I analyzed those data by first removing from the data set all customer accounts that did not have at least 10 months (300 days) of billing data, and also removing a few accounts that had more than about 14 months (410 days) of data. The resulting data set has information for more than 75,000 customers who were customers for essentially all of 2016. I then annualized the billing data for a

[16] Average residential customer usage: 8,826,214 Dk ÷ 96,792 customers = 91.19 Dk per year; figures from MDU Statement M, p. 1.

non-leap-year by determining average consumption per day for each customer and multiplying that by 365 days. I also separated customers who received LIHEAP benefits (approximately 1,900 of the full-year customers) from those who did not receive such benefits, to see if low-income heating customers were significantly different from other customers.

Next, I calculated the consumption level breakpoints for the groups of customers. Specifically, I determined decile distributions; that is, the lowest 10% of gas users, the next 10%, and so on. Exhibit ___ (SJR-7) shows the results of this analysis. Simply stated, while the overall data suggests that the average residential customer uses 91 Dk per year, the actual distribution of consumption is quite diverse. Fully 70% of full-year residential customers use less than the average. At the lowest usage levels, 10% of customers use less than 39 Dk per year. At the other extreme, the largest 10% of residential gas users consume more than 123 Dk per year.

Q. Why is it important to understand the diversity of consumption within the residential class?

A. If all customers were roughly the same, then the specific rate design selected would not make much difference in customers' bill on an annual basis. While a rate design could shift revenues among seasons (higher consumption charges would result in higher winter bills and lower summer bills, for example), on an annual basis an average customer will come out about the same.

Where there is significant diversity within the class, however, the rate design will have very real consequences for customers. As the Company's data demonstrate, in the real world, residential customers differ significantly from the class average. Customers who use much less than the class-average amount of gas would pay higher bills if revenues are collected through fixed charges and lower bills if revenues are collected through a combination of fixed charges and consumption charges; and the reverse is true for higher-use customers.

Q. Can you provide an example?

A. Yes. For my example, I will use the results of my preferred COSS (using the Basic Customer method) because the residential class's cost of service is very close to the Company's proposed level of revenues for the class. This means that the unit costs calculated in the COSS will be comparable to the Company's proposed rates for the class.

For purposes of this example, I will compare the annual bills for four customers: a low-use customer with usage of 40 Dk per year (about 10% of customers use less gas), a typical customer using 72 Dk per year (about 50% of customers use less gas and 50% use more gas annually), a customer with average usage of 90 Dk per year (about 30% of customers use this amount of gas or more), and a high-use customer using 120 Dk per year (only about 10% of customers use more gas than this). Table 8 compares the annual bills for these customers under present rates, MDU's proposed rates, and rates based on the unit costs from the COSS.

Table 8: Example of Rate Design Impacts on Different Types of Residential Customers (Annual Bill Excluding Cost of Gas)			
Customer Type	**Present Rates**	**MDU Proposed Rates**	**Cost-Based Rates**
Low use (40 Dk/yr)	$ 235.17	$ 270.90	$ 216.75
Typical (72 Dk/yr)	$ 235.17	$ 270.90	$ 252.59
Average (90 Dk/yr)	$ 235.17	$ 270.90	$ 272.75
High use (120 Dk/yr)	$ 235.17	$ 270.90	$ 306.35

Q. What do you conclude from these examples?

A. I conclude that there is significant diversity in gas consumption within the residential class, and that diversity results in real differences in the cost of serving customers. The cost studies show that between 25% and 36% of the residential class's costs are related to the class's peak demand. Thus, under the Company's proposed residential rate structure, low-use customers would pay more than $50 per year in excess of the cost of serving them and higher-use customers would receive a subsidy of $30 per year or more.

Q. In the Company's last rate case, a "straight fixed variable" rate design was adopted for the residential class that recovers all costs through a fixed charge. Was that decision in error?

A. I did not participate in the last case and I do not know what evidence the Commission had before it at that time, so I cannot draw any conclusions about the reasonableness of the Commission's last decision. All I can do is offer my opinions, recommendations, and conclusions based on the evidence available in this case. That evidence demonstrates that the Company has significant demand-related costs that vary with the amount of gas a customer uses during peak periods. In addition, the COSS shows that approximately 1%

of the residential class's costs (excluding the cost of gas) are energy-related. Under no circumstances should energy-related costs be recovered through a fixed charge.

Q. How should demand-related costs be collected from customers who do not have demand meters, like residential customers?

A. When demand meters are not present, it is necessary to use a proxy that bears a reasonable relationship to demand. From the Company's billing data, there is no question that each residential customer does not cause the same level of demand during peak periods. Specifically, using the data for full-year customers, there were 109 customers who used more than 365 Dk per year; that is, an average of more than 1 Dk per day. In contrast, there were 999 customers who used less than 12 Dk per year; that is, an average of less than 1 Dk per month. Collectively, those 109 largest customers used more than 56,000 Dk of gas, while the 999 smallest customers used a total of approximately 5,400 Dk of gas. That is, the 109 largest customers used 10 times more gas than the 999 smallest customers combined. Stated differently, each of those large customers used more gas in two weeks than one of the smallest customers used in an entire year. There is no way that the peak-period demands are the same for these customers.

Q. Did you perform any analysis to estimate the peak-period demands for these largest and smallest customers?

A. Yes. I selected the largest and smallest customers from the data set and calculated the single month in which each group (large and small) had the highest monthly gas usage. For both groups, the peak month was January. The 109 largest customers used a total of 9,075 Dk during the month (an average of 83 Dk per customer), while the 999 smallest customers used a total of 1,037 Dk during the same month (an average of 1 Dk per customer). That is, during the peak month, each of the large customers used <u>more gas in 10 hours</u> than one of the small customers used during the <u>entire month</u>. It is mathematically and practically impossible for the largest and smallest customers to have the same peak-period demand for natural gas.

Q. One of the arguments behind straight fixed-variable pricing is that the cost of distribution infrastructure is the same to serve large and small customers. Is that correct?

A. No, it is not correct. Customers who use larger amounts of gas require larger meters and regulators. For example, I have attached as Exhibit ___ (SJR-8) printouts provided by one gas meter vendor, Tristate Meter, showing the capacities for different types of meters and regulators. In essence, the standard residential installation can handle a gas flow rate of 275 cubic feet per hour ("cfh"). If the flow rate is expected to be greater than that during any hour, then a larger meter and regulator are required.

Q. During 2016, did any of MDU's residential customers exhibit an average monthly flow rate that exceeded 275 cfh?

A. Yes. There are 1,000 cubic feet in a Dk and 744 hours in a 31-day month (like the peak month of January). So if a customer's total monthly consumption exceeds 204.6 Dk, the average hourly flow rate during the month would exceed 275 cfh.[17] MDU had two residential customers who exceeded 204.6 Dk of usage during a single month in 2016. Of course, it is highly unlikely for a customer to use exactly the same amount of gas each hour, so in reality a lower level of monthly peak consumption would be likely to require a larger (more expensive) meter and regulator. If, for example, MDU exercised a margin

[17] 275 cu. ft. per hour x 744 hours/month x 1 Dk per 1,000 cu. ft. = 204.6 Dk per month.

of safety given hour-by-hour variability and required a larger meter for any customer using more than 100 Dk in a month, then at least 29 residential customers would require a larger meter and regulator.

The precise number is not critically important. What matters is that MDU has some residential customers who use large amounts of gas and are demonstrably more expensive to serve than smaller users of gas. As an example, attached as Exhibit ___ (SJR-9) is a pricing sheet from one meter distributor showing that a typical residential-sized meter (rated at 250 cph) costs about $80, while the next larger meter (rated at 425 cph) costs about $440. Thus, the cost to serve the largest residential customers -- just for the larger meter -- would be substantially more than the cost to serve a typical residential customer. This means that there is a real cost associated with increased demand for residential customers. Thus, based on MDU's actual billing data for the test year, the underlying premise of straight fixed-variable pricing (that the cost of serving each residential customers is approximately the same) is incorrect. The diversity within the residential class is such that some customers are significantly more expensive to serve than other customers, and those cost differences are related to the amount of gas used by customers.

Q. Are there other reasons why it is important to charge demand-related costs based on a measure of gas usage rather than assuming that they are the same for all customers?

A. Yes. In the cost-of-service study, certain costs are allocated among customer classes based on each class's contribution to demand. If a customer's demand increases, then costs allocated to the customer's class will increase (all else being equal); and if a customer decreases its demand, then costs allocated to the class will decrease. Thus, charging demand-related costs to customers based on their consumption of gas sends an important price signal to customers: if you increase your demand it will reduce the level of costs allocated to the class. As a matter of fairness and efficiency, the customer who causes those increased costs to be allocated to the class (the customer with higher demand) should be charged for those costs.

Q. Are low-use residential customers of particular concern to AARP?

A. Yes. While I am certain that there are AARP members in MDU's service territory of all income levels and gas usage levels, the smallest users of natural gas who do not qualify for low-income assistance are likely to include retirees on fixed incomes with only one person in the household. Attached as Exhibit ___(SJR-10) is my analysis of data from the 2009 Residential Energy Consumption Survey (RECS) conducted by the U.S. Department of Energy. The data show that one-person households that are not living in poverty are likely to use far less natural gas than other residential households. According to the data for this region of the country (Iowa, Minnesota, North Dakota, and South Dakota), a retired person living alone with an income above 150% of the poverty level is likely to use only 68,400 cubic feet (or approximately 68 Dk) per year. This compares to residential gas users with two or more people in the household and incomes above 150% of the poverty level who average 90,000 cubic feet (90 Dk) per year, which is nearly identical to MDU's average residential usage of 91 Dk. That is, the one-person retiree's average gas usage is only about 3/4 of the gas usage of an average residential household. Yet, MDU's rate design would charge those two customers exactly the same amount for gas distribution service.

Q. Did you conduct any analysis to determine whether MDU's service territory includes one-person households with retirees?

A. Yes. I reviewed U.S. Census data to determine the likely presence of one-person retiree households in MDU's service area. Exhibit ___(SJR-11) shows the results for each county served by MDU (in whole or in part). I would caution that while the numbers appear to be precise, several of them have large margins of error due to the sampling methods used by the Census Bureau and the small populations of several counties. Thus, while I do not give much weight to the specific numbers shown for smaller counties, it is reasonable to conclude that MDU is likely to serve hundreds, if not thousands, of one-person households dependent on retirement income. This is corroborated by MDU's billing data which shows MDU has more than 33,000 residential customers who use less than 70 Dk per year.

Q. What do you recommend?

A. I recommend that the residential customer charge should not be increased in this case. Any rate increase allocated to the residential class should be collected solely through a consumption charge. Given the COSS results, I actually would prefer to see the Commission reduce the customer charge, but that could result in significant bill increases for higher-use residential customers, especially customers with large families.

Q. What COSS results are you referring to when you suggest that the existing customer charge is too high and should be reduced?

A. I am relying on the unit costs for the residential class that are calculated in all three of the COSS that I discussed above, and that I summarized earlier in Table 7. Briefly, the Company's COSS shows that the customer-related cost is $18.13 per customer per month.

My preferred COSS using the Basic Customer methodology results in customer-related costs of $14.33 per month, and my corrected version of the Company's COSS (using a corrected minimum system analysis) has customer-related costs of $17.09 per month. The Company's existing residential rate consists of a customer charge $0.6443 per day, or approximately $19.60 per month. Thus, the ***existing*** customer charge exceeds the customer-related unit cost of service under ***proposed*** rates under any of the cost studies presented in this case.

I explained above the importance of collecting demand- and energy-related costs in proportion to customers' energy consumption. This is important both as a matter of fairness and efficiency. As I explained at the outset, fairness requires that customers who cause more costs to be incurred and/or allocated to their class should pay more than customers whose usage patterns result in lower costs for the class.

Moreover, efficiency requires that customers should pay rates that reflect the increased costs associated with increased consumption. In the case of the residential class, those increased costs occur for at least two reasons. First, very large customers require more expensive meters and regulators and their rates should reflect those increased costs. Second, each customer's demand influences the class's overall peak demand, which in turn is a direct input into the COSS allocation of costs among the customer classes. That is, higher demands result in higher costs for the class and the principle of efficiency suggests that the rate design should reflect that fact.

Q. Do the Company's other rates contain distribution charges that vary with demand and/or consumption?

A. Yes. The Company's distribution rates for commercial and industrial customers contain charges that are based on gas demand and/or consumption, in addition to a fixed-charge component. Given the diversity within the residential class, the same type of rate structure should be used for the residential class.

Q. Why do you recommend no increase in the customer charge instead of a reduction in the charge?

A. I am concerned about the potential to shift revenues significantly onto higher-use residential customers, such as customers with large families or those living in older homes that might not be well insulated. Keeping the existing customer charge, even though it exceeds the customer-related costs in the COSS, has the effect of providing a gradual transition to cost-based rates. Lower-use residential customers would pay more than the cost of service and higher-use customers would pay less than cost, but all customers in the class would be moving closer to paying their costs.

This type of gradual movement toward cost-based rates is consistent with the regulatory principles of fairness and rate continuity that I discuss at the outset of my testimony. Moving toward cost-based rates also moves the rate design toward encouraging the efficient use of the utility service, as I discussed above.

Q. Have you designed rates to implement your recommendation?

A. Yes. Attached as Exhibit ___(SJR-12) are the specific rates that would implement my recommendation under MDU's proposed revenue requirement and revenue allocation, and the bill impacts on customers at different consumption levels. This analysis is prepared using the Company's proposed revenue requirement, so that the rates can be compared on an "apples-to-apples" basis with the Company's proposal.

Proposed System Safety & Integrity Program Adjustment Mechanism ("SIA")

Q. Have you reviewed the Company's SIA tariff proposal?

A. Yes, I have reviewed the Company's proposed SIA tariff, identified as proposed Rate 94, appearing on Original Sheet Nos. 37 and 37.1 of the proposed tariff.

Q. What is your understanding of the purpose of the proposed SIA tariff?

A. The Company's proposed tariff states that the purpose of the SIA is to "recover the revenue requirement associated with the Company's additions and/or replacement of natural gas distribution facilities in compliance with operational, state, or federal pipeline safety programs deemed prudent by the Commission and not currently recovered through the Company's retail rates."

Q. Do you know what that means?

A. No, I do not fully understand the scope of the Company's proposal. If the tariff did not include the term "operational," it would be fairly straightforward to understand the meaning and purpose of the SIA. The federal government, through the Pipeline and Hazardous Materials Safety Administration (part of the U.S. Department of Transportation), has pipeline safety standards, including inspection, maintenance, and repair standards. This Commission is responsible for enforcing the federal pipeline safety requirements within the state. Thus, costs associated with making additions and replacements of facilities to remain in compliance with federal and state safety programs would be relatively easy to identify and would be fairly limited in scope.

My concern is that the proposed tariff also includes the term "operational" and, frankly, it is included in a way that leads me to question its intent and purpose. The proposed tariff language uses the phrase, "operational, state, or federal pipeline safety programs." The word operational is an adjective and must modify a noun. It appears that "operational" is modifying either "programs" or "pipeline safety programs," but I do not know if that makes any sense for MDU. Does the Company have an "operational" pipeline safety program that is somehow different from the state and federal pipeline safety programs? Are there specific expenditures associated with its "operational" pipeline safety program that are not associated with a federal or state program? Are "operational" safety expenditures separately budgeted or accounted for in a particular way that makes it possible to track and audit them? Or is the term meant to refer to "operational programs" which would be so broad as to encompass nearly everything the Company does to operate and maintain its system.

Q. Do you oppose the idea of a special rate adjustment mechanism for expenditures needed to comply with federal or state safety requirements?

A. Generally, I oppose the use of special rate adjustment mechanisms. Under very limited circumstances, however, I do not oppose the use of a special rate adjustment for expenditures required to comply with <u>new</u> federal or state safety requirements. In particular, if a new federal or state safety requirement is implemented between rate cases, and where the new requirement has a significant cost, then it may be reasonable to either recover such costs through a special rate adjustment or permit the utility to defer such expenditures until its next rate case. It is absolutely critical for utilities to provide safe facilities and if significant new safety standards are imposed, the ratemaking process must not impede a utility's ability to comply with those standards.

That is a far cry, however, from the Company's proposal in this case. Here, MDU is proposing a rather open-ended and undefined category of expenditures -- those associated with all pipeline safety programs (and perhaps "operational" programs as well), whether new or existing. That is, rather than being limited to expenditures that could not be anticipated or included in the test-year budget, the Company is suggesting that costs should be recoverable as long as the specific costs are "not currently recovered" in rates. The Company does not explain the meaning of "not currently recovered." The proposed tariff provision is much too broad.

Q. Do you have any other concerns with the Company's proposal?

A. Yes. First, through the discovery process the Company identified some changes that should be made in its proposed tariff language. I am attaching the relevant discovery responses (AARP 1.2 and 1.3) as Exhibit ___ (SJR-13).

Second, additional discovery responses provided further clarification about the meaning and intention of the proposed SIA tariff. I am attaching those responses (AARP 1.4 and PSC 2.55) as Exhibit ___ (SJR-14). From my reading of those responses, it appears that the Company is suggesting an annual miniature rate case in which all of its expenditures (capital investment, operations and maintenance expenses, taxes, and so on) would be examined, but only for SIA projects. In addition, MDU would ask the Commission to pre-approve the SIA projects for the following year and true-up SIA revenues from the previous year. This is an extremely cumbersome process that is not consistent with the manner in which rates are set.

Specifically, according to well-established ratemaking principles, utility rates are set based on a synchronized examination of all aspects of the utility's cost of service and sources of revenue, as well other considerations such as the quality of service and efficiency of management. That synchronization is the reason why we use a test year when a rate case is filed. One treatise on utility regulation discusses this synchronization, or the matching principle, as follows:

> If the utility proposes a change, particularly a major change, in the test year rate base, it is required also to consider the related changes in other costs or in revenue. Additional investments may result in efficiencies that reduce operating costs or quality improvements that will increase sales. Unless the utility shows that it has taken such matters into account, its revenue requirement is likely to be out of balance or overstated.[18]

The proposed SIA would be an exception to the matching principle because it would permit MDU to reflect increases in one element of its costs without also reflecting other associated changes that may occur. While the Company has clarified in discovery that it intends to include changes in operations and maintenance expenses that result from SIA programs (something that is not apparent from its proposed tariff), that still ignores all other changes that occur between rate cases.

Many things change between cases. Some costs increase, others decrease or are eliminated entirely. Capital budgets can change, resulting in a reallocation of capital to meet different priorities or exigencies. Interest rates may increase or decrease, the number of employees may change, and so on. MDU's proposal is designed to focus

[18] Leonard Saul Goodman, *The Process of Ratemaking* (1998), vol. II, p. 735.

solely on one area where it expects costs to increase; ignoring all of those other aspects of its operations where costs may decrease.

Q. Can you provide an example?

A. Yes. One example would be postage expense. For many years, we experienced regular increases in postage expense with rates increasing by a penny or two every couple of years. Using MDU's logic, it would be reasonable to have a "postage cost adjustment" so that if postage increased by a penny, then the impact of that would be flowed through customers' rates. If that had been implemented, however, it would have ignored the significant changes that occurred in electronic billing for utility companies. Electronic billing has completely eliminated postage expense for many customers. Of course, a separate rate mechanism also could have been implemented for electronic billing costs -- a brand new project for many utilities 10 or 15 years ago. But, again, focusing solely on the increased cost without identifying offsetting savings (such as lower postage and printing costs) would be improper. It also might not be possible to measure the indirect cost impacts, such as changes in customer-service operations or changes in working capital requirements if customers respond to electronic bills differently from paper ones.

This is just one example. Every year utilities make numerous changes in their operations. Some of those save money and some of them cost more. The standard ratemaking process considers all of those changes in a synchronized examination of the utility's operations. It is only through that process that the cost of serving customers, expressed as a unit cost (so much per month as a customer charge; so much per unit of gas consumed, and so on), can be determined. Whatever may change between cases, we have a high level of confidence that the actual rates being charged to customers reflect the entirety of the utility's operations.

This is the underlying reason for the matching principle -- to ensure that the rates stated in the tariff are based on the entire operation of the utility. Just because one particular thing changes between cases does not mean that the tariffed rates no longer reflect the utility's entire cost of providing safe and reliable service. If the utility believes that the tariffs are no longer adequate, then the utility can file a new rate case. Similarly, if customers believe that costs have declined (or revenues increased) so much that the rates are too high to be just and reasonable, then customers can seek to reduce the rates. In either event, however, in order to adjust rates, there should be a synchronized examination of the utility's entire business.

Q. What do you recommend?

A. I recommend that the Commission reject the Company's proposed SIA tariff. There is no reason to have special, miniature rate cases that look at only one aspect of the Company's operations. Indeed, there are very sound reasons, that go back many decades, for refusing to engage in such single-issue ratemaking that violates the matching principle.

Q. Do you have any other concerns with the Company's proposed SIA tariff?

A. Yes. The Company proposes to recover the costs included in the SIA tariff as a supplement to the customer charge; that is, as an equal amount per customer. As I discussed above, however, the Company's COSS recognizes that much of the cost of distributing natural gas is related to customers' demand for gas, and that demand is not the same for each customer within a customer class, and is definitely not the same for customers in different classes.

Q. Can you be more specific?

A. Yes. According to the Company's COSS, the residential class has approximately 86% of the Company's customers. Thus, under the Company's proposed SIA tariff, the residential class would pay 86% of SIA-related costs.[19] Such a charge, however, would greatly exceed the residential class's expected share of such costs.

If an SIA project involved the replacement of a portion of a gas main, the cost would be included in the distribution mains account. Only 57.5% of costs in that account, however, are allocated to the residential class under the Company's COSS.[20] An even smaller amount would be allocated to the residential class under my preferred COSS and the corrected Company COSS. Thus, collecting the cost of a main from each customer equally would require residential customers to bear 86% of the costs when the Company's own COSS shows that the class should pay only two-thirds of that amount (2/3 of 86% is 57.3%).

Similarly, if the SIA project involved replacing service lines, the COSS calculates that the residential class's share should be 80.6%.[21] If the project involves new service regulators, the residential share should be only 62.6%.[22] And if the project involves

[19] Allocation factor 4 found on MDU Statement M, p. 23.
[20] Allocation factor 13, MDU Statement M, p. 23.
[21] Allocation factor 17, MDU Statement M, p. 23.
[22] Allocation factor 20, MDU Statement M, p. 27.

maintenance expenditures for mains and services, the residential share according to MDU's uncorrected COSS should be only 64.4%.[23]

Based on my review of the COSS, there is no category of infrastructure cost -- whether for plant or maintenance -- where the residential class's allocated share of the cost is as high as 86%. Thus, there is absolutely no justification for recovering such costs as an equal amount from each customer.

Q. If, despite your recommendation, the Commission approves any type of SIA surcharge, how should such costs be recovered?

A. If the Commission disagrees with me and approves any type of surcharge for safety-related expenditures, the costs should be recovered as a percentage adder on the base-rate portion of each customer's bill (that is, excluding the cost of gas). In that way, customer classes with much larger per-customer costs (including, for example, significant demand-related costs, as well as more expensive regulators and service lines) would pay their fair share of costs.

Proposed Increase in Returned Check Charge

Q. Has the Company proposed any other tariff changes that concern you?

A. Yes, the Company proposes to increase the fee for a returned check. At the present time, the fee in the Company's tariff is $15 if a check or electronic payment is returned. The Company proposes to increase this fee to $40.

[23] Allocation factor 22, MDU Statement M, p. 27.

Q. Has the Company provided any testimony or evidence showing that it incurs a cost of $40 to process a returned payment?

A. No. The Company did, however, respond to discovery requests from AARP and Staff concerning this issue. Those responses (AARP 1.5, PSC 1.45, and PSC 2.9) are attached as Exhibit ___ (SJR-15). The Company's responses do not support any increase in the returned check charge, let alone the proposal to nearly triple the charge.

In particular, the response to PSC 2.9 shows that the Company's actual cost to its banks is only $2.80 per returned item. In that response, the Company states that its proposed $40 charge is meant to be a "deterrent to customers." The Company, however, does not provide any evidence that customers need such a deterrent, particularly because of fees charged by a customer's bank to the customer when a check is dishonored. I am also concerned that an investor-owned utility should not be in the business of attempting to penalize customers for behavior the utility thinks is improper, unless of course it affects the utility's business (such as theft of service).

A utility is not a police officer or other moral authority; it is a private company providing an essential public service. Its rates and charges should allow the utility an opportunity to recover its costs. A utility should not be receiving penalty payments from customers that are wholly unrelated to the utility's costs of providing services to the public.

Q. Based on your experience, is a returned check fee of $40 consistent with standard practice in the utility industry?

A. No. I have testified in four cases recently in which the returned check charge was at issue. The results of those cases were fees of $5.60 (Massachusetts Electric Co.), $14.58 (Commonwealth Edison Co. in Illinois), $11.00 (Eversource in Massachusetts), and $25.89 (United Illuminating Co. in Connecticut). In addition, as part of my work in the United Illuminating case, I reviewed the returned check fees charged by several other energy utilities in Northeastern states and found that the charges ranged from $8.00 (Southern Connecticut Gas Co.) to $20.00 (New York State Electric & Gas Co.). In addition, I have recently started work on a rate case filed by Eversource in Connecticut where the utility is proposing to reduce its returned check fee from $22.00 to $20.00. I am awaiting further information to determine whether the $20.00 fee is consistent with the cost of processing a returned payment, particularly since the same utility recently adopted a cost-based fee of $11.00 in Massachusetts.

For this case, I have broadened my search for information on returned check fees charged by natural gas distribution utilities to include the Upper Midwest. I present the results in Table 9.

Table 9: Returned Check Fees Charged by Natural Gas Distribution Utilities in the Upper Midwest		
State	**Utility**	**Returned Check Fee**
Iowa	Alliant	$15.00
Iowa	Black Hills	$20.00
Iowa	Liberty	$10.00
Iowa	MidAmerican	$15.00
Minnesota	CenterPoint	$10.00
Minnesota	Minnesota Energy	$15.00
Minnesota	Xcel	$15.00
Montana	MDU	$20.00
Montana	NorthWestern	$10.00
Nebraska	MidAmerican	$11.00
North Dakota	Xcel	$15.00
South Dakota	MidAmerican	$30.00
South Dakota	MDU	$40.00
South Dakota	NorthWestern	$15.00
Wyoming	MDU	$30.00
Wyoming	Questar	$20.00

Thus, not only is a fee of $40.00 greatly in excess of MDU's cost of processing a returned check, it also is inconsistent with standard practice in the utility industry, and it would greatly exceed the highest charge levied in any state bordering the Dakotas (except for MDU's fee in South Dakota).

Q. What do you recommend?

A. As I discussed above, my work with, and research into, numerous other utilities shows that the cost of processing a returned payment usually ranges between $10 and $15. Keeping MDU's charge at its existing level of $15 would provide MDU with more than $12 to process the return (entering the information in the customer's account and notifying the customer), in addition to the $2.80 bank fee. The Company has not provided any evidence to show that its processing costs are any higher than this amount, and indeed other utilities are able to process returned payments for much less than $12. I recommend, therefore, that MDU's returned check fee should remain at $15.

Conclusion

Q. Does this conclude your direct testimony?

A. Yes.

Appendix A

Scott J. Rubin
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Current Position

Public Utility Attorney and Consultant. 1994 to present. I provide legal, consulting, and expert witness services to various organizations interested in the regulation of public utilities.

Previous Positions

Lecturer in Computer Science, Susquehanna University, Selinsgrove, PA. 1993 to 2000.

Senior Assistant Consumer Advocate, Office of Consumer Advocate, Harrisburg, PA. 1990 to 1994. I supervised the administrative and technical staff and shared with one other senior attorney the supervision of a legal staff of 14 attorneys.

Assistant Consumer Advocate, Office of Consumer Advocate, Harrisburg, PA. 1983 to 1990.

Associate, Laws and Staruch, Harrisburg, PA. 1981 to 1983.

Law Clerk, U.S. Environmental Protection Agency, Washington, DC. 1980 to 1981.

Research Assistant, Rockville Consulting Group, Washington, DC. 1979.

Current Professional Activities

Member, American Bar Association, Infrastructure and Regulated Industries Section.

Member, American Water Works Association.

Admitted to practice law before the Supreme Court of Pennsylvania, the New York State Court of Appeals, the United States District Court for the Middle District of Pennsylvania, the United States Court of Appeals for the Third Circuit, and the Supreme Court of the United States.

Previous Professional Activities

Member, American Water Works Association, Rates and Charges Subcommittee, 1998-2001.

Member, Federal Advisory Committee on Disinfectants and Disinfection By-Products in Drinking Water, U.S. Environmental Protection Agency, Washington, DC. 1992 to 1994.

Chair, Water Committee, National Association of State Utility Consumer Advocates, Washington, DC. 1990 to 1994; member of committee from 1988 to 1990.

Member, Board of Directors, Pennsylvania Energy Development Authority, Harrisburg, PA. 1990 to 1994.

Member, Small Water Systems Advisory Committee, Pennsylvania Department of Environmental Resources, Harrisburg, PA. 1990 to 1992.

Member, Ad Hoc Committee on Emissions Control and Acid Rain Compliance, National Association of State Utility Consumer Advocates, 1991.

Member, Nitrogen Oxides Subcommittee of the Acid Rain Advisory Committee, U.S. Environmental Protection Agency, Washington DC. 1991.

Education

J.D. with Honors, George Washington University, Washington, DC. 1981.

B.A. with Distinction in Political Science, Pennsylvania State University, University Park, PA. 1978.

Publications and Presentations (* denotes peer-reviewed publications)

1. "Quality of Service Issues," a speech to the Pennsylvania Public Utility Commission Consumer Conference, State College, PA. 1988.

2. K.L. Pape and S.J. Rubin, "Current Developments in Water Utility Law," in *Pennsylvania Public Utility Law* (Pennsylvania Bar Institute). 1990.

3. Presentation on Water Utility Holding Companies to the Annual Meeting of the National Association of State Utility Consumer Advocates, Orlando, FL. 1990.

4. "How the OCA Approaches Quality of Service Issues," a speech to the Pennsylvania Chapter of the National Association of Water Companies. 1991.

5. Presentation on the Safe Drinking Water Act to the Mid-Year Meeting of the National Association of State Utility Consumer Advocates, Seattle, WA. 1991.

6. "A Consumer Advocate's View of Federal Pre-emption in Electric Utility Cases," a speech to the Pennsylvania Public Utility Commission Electricity Conference. 1991.

7. Workshop on Safe Drinking Water Act Compliance Issues at the Mid-Year Meeting of the National Association of State Utility Consumer Advocates, Washington, DC. 1992.

8. Formal Discussant, Regional Acid Rain Workshop, U.S. Environmental Protection Agency and National Regulatory Research Institute, Charlotte, NC. 1992.

9. S.J. Rubin and S.P. O'Neal, "A Quantitative Assessment of the Viability of Small Water Systems in Pennsylvania," *Proceedings of the Eighth NARUC Biennial Regulatory Information Conference*, National Regulatory Research Institute (Columbus, OH 1992), IV:79-97.

10. "The OCA's Concerns About Drinking Water," a speech to the Pennsylvania Public Utility Commission Water Conference. 1992.

11. Member, Technical Horizons Panel, Annual Meeting of the National Association of Water Companies, Hilton Head, SC. 1992.

12. M.D. Klein and S.J. Rubin, "Water and Sewer -- Update on Clean Streams, Safe Drinking Water, Waste Disposal and Pennvest," *Pennsylvania Public Utility Law Conference* (Pennsylvania Bar Institute). 1992.

13. Presentation on Small Water System Viability to the Technical Assistance Center for Small Water Companies, Pa. Department of Environmental Resources, Harrisburg, PA. 1993

14. "The Results Through a Public Service Commission Lens," speaker and participant in panel discussion at Symposium: "Impact of EPA's Allowance Auction," Washington, DC, sponsored by AER*X. 1993.

15. "The Hottest Legislative Issue of Today -- Reauthorization of the Safe Drinking Water Act," speaker and participant in panel discussion at the Annual Conference of the American Water Works Association, San Antonio, TX. 1993.

16. "Water Service in the Year 2000," a speech to the Conference: "Utilities and Public Policy III: The Challenges of Change," sponsored by the Pennsylvania Public Utility Commission and the Pennsylvania State University, University Park, PA. 1993.

17. "Government Regulation of the Drinking Water Supply: Is it Properly Focused?," speaker and participant in panel discussion at the National Consumers League's Forum on Drinking Water Safety and Quality, Washington, DC. 1993. Reprinted in *Rural Water*, Vol. 15 No. 1 (Spring 1994), pages 13-16.

18. "Telephone Penetration Rates for Renters in Pennsylvania," a study prepared for the Pennsylvania Office of Consumer Advocate. 1993.

19. "Zealous Advocacy, Ethical Limitations and Considerations," participant in panel discussion at "Continuing Legal Education in Ethics for Pennsylvania Lawyers," sponsored by the Office of General Counsel, Commonwealth of Pennsylvania, State College, PA. 1993.

20. "Serving the Customer," participant in panel discussion at the Annual Conference of the National Association of Water Companies, Williamsburg, VA. 1993.

21. "A Simple, Inexpensive, Quantitative Method to Assess the Viability of Small Water Systems," a speech to the Water Supply Symposium, New York Section of the American Water Works Association, Syracuse, NY. 1993.

22. * S.J. Rubin, "Are Water Rates Becoming Unaffordable?," *Journal American Water Works Association*, Vol. 86, No. 2 (February 1994), pages 79-86.

23. "Why Water Rates Will Double (If We're Lucky): Federal Drinking Water Policy and Its Effect on New England," a briefing for the New England Conference of Public Utilities Commissioners, Andover, MA. 1994.

24. "Are Water Rates Becoming Unaffordable?," a speech to the Legislative and Regulatory Conference, Association of Metropolitan Water Agencies, Washington, DC. 1994.

25. "Relationships: Drinking Water, Health, Risk and Affordability," speaker and participant in panel discussion at the Annual Meeting of the Southeastern Association of Regulatory Commissioners, Charleston, SC. 1994.

26. "Small System Viability: Assessment Methods and Implementation Issues," speaker and participant in panel discussion at the Annual Conference of the American Water Works Association, New York, NY. 1994.

27. S.J. Rubin, "How much should we spend to save a life?," *Seattle Journal of Commerce*, August 18, 1994 (Protecting the Environment Supplement), pages B-4 to B-5.

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30. "Surviving the Safe Drinking Water Act," speaker at the Annual Meeting of the National Association of State Utility Consumer Advocates, Reno, NV. 1994.

31. "Safe Drinking Water Act Compliance -- Ratemaking Implications," speaker at the National Conference of Regulatory Attorneys, Scottsdale, AZ. 1995. Reprinted in *Water*, Vol. 36, No. 2 (Summer 1995), pages 28-29.

32. S.J. Rubin, "Water: Why Isn't it Free? The Case of Small Utilities in Pennsylvania," *Utilities, Consumers & Public Policy: Issues of Quality, Affordability, and Competition, Proceedings of the Fourth Utilities, Consumers and Public Policy Conference* (Pennsylvania State University 1995), pages 177-183.

33. S.J. Rubin, "Water Rates: An Affordable Housing Issue?," *Home Energy*, Vol. 12 No. 4 (July/August 1995), page 37.

34. Speaker and participant in the Water Policy Forum, sponsored by the National Association of Water Companies, Naples, FL. 1995.

35. Participant in panel discussion on "The Efficient and Effective Maintenance and Delivery of Potable Water at Affordable Rates to the People of New Jersey," at The New Advocacy: Protecting Consumers in the Emerging Era of Utility Competition, a conference sponsored by the New Jersey Division of the Ratepayer Advocate, Newark, NJ. 1995.

36. J.E. Cromwell III, and S.J. Rubin, *Development of Benchmark Measures for Viability Assessment* (Pa. Department of Environmental Protection 1995).

37. S. Rubin, "A Nationwide Practice from a Small Town in Pa.," *Lawyers & the Internet – a Supplement to the Legal Intelligencer and Pa. Law Weekly* (February 12, 1996), page S6.

38. "Changing Customers' Expectations in the Water Industry," speaker at the Mid-America Regulatory Commissioners Conference, Chicago, IL. 1996, reprinted in *Water* Vol. 37 No. 3 (Winter 1997), pages 12-14.

39. "Recent Federal Legislation Affecting Drinking Water Utilities," speaker at Pennsylvania Public Utility Law Conference, Pennsylvania Bar Institute, Hershey, PA. 1996.

40. "Clean Water at Affordable Rates: A Ratepayers Conference," moderator at symposium sponsored by the New Jersey Division of Ratepayer Advocate, Trenton, NJ. 1996.

41. "Water Workshop: How New Laws Will Affect the Economic Regulation of the Water Industry," speaker at the Annual Meeting of the National Association of State Utility Consumer Advocates, San Francisco, CA. 1996.

42. * E.T. Castillo, S.J. Rubin, S.K. Keefe, and R.S. Raucher, "Restructuring Small Systems," *Journal American Water Works Association*, Vol. 89, No. 1 (January 1997), pages 65-74.

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47. Briefing on Issues Affecting the Water Utility Industry, Annual Meeting of the National Association of State Utility Consumer Advocates, Boston, MA. 1997.

48. "Capacity Development in the Water Industry," speaker at the Annual Meeting of the National Association of Regulatory Utility Commissioners, Boston, MA. 1997.

49. "The Ticking Bomb: Competitive Electric Metering, Billing, and Collection," speaker at the Annual Meeting of the National Association of State Utility Consumer Advocates, Boston, MA. 1997.

50. Scott J. Rubin, "A Nationwide Look at the Affordability of Water Service," *Proceedings of the 1998 Annual Conference of the American Water Works Association*, Water Research, Vol. C, No. 3, pages 113-129 (American Water Works Association, 1998).

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54. "Consumer Advocacy for the Future," speaker at the Age of Awareness Conference, Changes and Choices: Utilities in the New Millennium, Carlisle, PA. 1999.

55. Keynote Address, $1 Energy Fund, Inc., Annual Membership Meeting, Monroeville, PA. 1999.

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59. Janice A. Beecher and Scott J. Rubin, presentation on "Special Topics in Rate Design: Affordability" at the Annual Conference and Exhibition of the American Water Works Association, Denver, CO. 2000.

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65. Scott J. Rubin, Consumer Issues in the Water Industry, NARUC Annual Regulatory Studies Program, East Lansing, MI. 2000.

66. "Be Utility Wise in a Restructured Utility Industry," Keynote Address at Be UtilityWise Conference, Pittsburgh, PA. 2000.

67. Scott J. Rubin, Jason D. Sharp, and Todd S. Stewart, "The Wired Administrative Lawyer," *5th Annual Administrative Law Symposium*, Pennsylvania Bar Institute, Harrisburg, PA. 2000.

68. Scott J. Rubin, "Current Developments in the Water Industry," *Pennsylvania Public Utility Law Conference*, Pennsylvania Bar Institute, Harrisburg, PA. 2000.

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102. * Scott J. Rubin, How Should We Regulate Small Water Utilities?, National Regulatory Research Institute. 2009.

103. * John Cromwell III, et al., *Best Practices in Customer Payment Assistance Programs*, Water Research Foundation, Denver, CO. 2010.

104.* Scott J. Rubin, What Does Water Really Cost? Rate Design Principles for an Era of Supply Shortages, Infrastructure Upgrades, and Enhanced Water Conservation, , National Regulatory Research Institute. 2010.

105. Scott J. Rubin and Christopher P.N. Woodcock, Teleseminar: Water Rate Design, National Regulatory Research Institute. 2010.

106. David Monie and Scott J. Rubin, Cost of Service Studies and Water Rate Design: A Debate on the Utility and Regulatory Perspectives, Meeting of New England Chapter of National Association of Water Companies, Newport, RI. 2010.

107. * Scott J. Rubin, A Call for Water Utility Reliability Standards: Regulating Water Utilities' Infrastructure Programs to Achieve a Balance of Safety, Risk, and Cost, National Regulatory Research Institute. 2010.

108.* Raucher, Robert S.; Rubin, Scott J.; Crawford-Brown, Douglas; and Lawson, Megan M. "Benefit-Cost Analysis for Drinking Water Standards: Efficiency, Equity, and Affordability Considerations in Small Communities," *Journal of Benefit-Cost Analysis*: Vol. 2: Issue 1, Article 4. 2011.

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110. Scott J. Rubin, Current Topics in Water: Rate Design and Reliability. Presentation to the Water Committee of the National Association of Regulatory Utility Commissioners, Washington, DC. 2011.

111. Scott J. Rubin, Water Reliability and Resilience Standards, *Pennsylvania Public Utility Law Conference* (Pennsylvania Bar Institute). 2011.

112. Member of Expert Panel, Leadership Forum: Business Management for the Future, Annual Conference and Exposition of the American Water Works Association, Washington, DC. 2011.

113. Scott J. Rubin, Evaluating Community Affordability in Storm Water Control Plans, *Flowing into the Future: Evolving Water Issues* (Pennsylvania Bar Institute). 2011.

114. Invited Participant, Summit on Declining Water Demand and Revenues, sponsored by The Alliance for Water Efficiency, Racine, WI. 2012.

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15. *Winter Harbor Water Company, Proposed Schedule Revisions to Introduce a Readiness-to-Serve Charge*, Maine Public Utilities Commission, Docket No. 95-271. 1995 and 1996. Concerning standards for, and the reasonableness of, imposing a readiness to serve charge and/or exit fee on the customers of a small investor-owned water utility, on behalf of the Maine Public Advocate.

16. *In the Matter of the 1995 Long-Term Electric Forecast Report of the Cincinnati Gas & Electric Company*, Public Utilities Commission of Ohio, Case No. 95-203-EL-FOR, and *In the Matter of the Two-Year Review of the Cincinnati Gas & Electric Company's Environmental Compliance Plan Pursuant to Section 4913.05, Revised Cost*, Case No. 95-747-EL-ECP. 1996. Concerning the reasonableness of the utility's long-range supply and demand-management plans, the reasonableness of its plan for complying with the Clean Air Act Amendments of 1990, and discussing methods to ensure the provision of utility service to low-income customers, on behalf of the Office of the Ohio Consumers' Counsel..

17. *In the Matter of Notice of the Adjustment of the Rates of Kentucky-American Water Company*, Kentucky Public Service Commission, Case No. 95-554. 1996. Concerning rate design, cost of service, and sales forecast issues, on behalf of the Kentucky Office of Attorney General.

18. *In the Matter of the Application of Citizens Utilities Company for a Hearing to Determine the Fair Value of its Properties for Ratemaking Purposes, to Fix a Just and Reasonable Rate of Return Thereon, and to Approve Rate Schedules Designed to Provide such Rate of Return*, Arizona Corporation Commission, Docket Nos. E-1032-95-417, *et al.* 1996. Concerning rate design, cost of service, and the price elasticity of water demand, on behalf of the Arizona Residential Utility Consumer Office.

19. *Cochrane v. Bangor Hydro-Electric Company*, Maine Public Utilities Commission, Docket No. 96-053. 1996. Concerning regulatory requirements for an electric utility to engage in unregulated business enterprises, on behalf of the Maine Public Advocate.

20. *In the Matter of the Regulation of the Electric Fuel Component Contained within the Rate Schedules of Monongahela Power Company and Related Matters*, Public Utilities Commission of Ohio, Case No. 96-106-EL-EFC. 1996. Concerning the costs and procedures associated with the implementation of the Clean Air Act Amendments of 1990, on behalf of the Ohio Consumers' Counsel.

21. *In the Matter of the Regulation of the Electric Fuel Component Contained within the Rate Schedules of Cleveland Electric Illuminating Company and Toledo Edison Company and Related Matters*, Public Utilities Commission of Ohio, Case Nos. 96-107-EL-EFC and 96-108-EL-EFC. 1996. Concerning the

costs and procedures associated with the implementation of the Clean Air Act Amendments of 1990, on behalf of the Ohio Consumers' Counsel.

22. *In the Matter of the Regulation of the Electric Fuel Component Contained within the Rate Schedules of Ohio Power Company and Columbus Southern Power Company and Related Matters*, Public Utilities Commission of Ohio, Case Nos. 96-101-EL-EFC and 96-102-EL-EFC. 1997. Concerning the costs and procedures associated with the implementation of the Clean Air Act Amendments of 1990, on behalf of the Ohio Consumers' Counsel.

23. *An Investigation of the Sources of Supply and Future Demand of Kentucky-American Water Company (Phase II)*, Kentucky Public Service Commission, Docket No. 93-434. 1997. Concerning supply and demand planning, on behalf of the Kentucky Office of Attorney General, Public Service Litigation Branch.

24. *In the Matter of the Regulation of the Electric Fuel Component Contained within the Rate Schedules of Cincinnati Gas and Electric Co. and Related Matters*, Public Utilities Commission of Ohio, Case No. 96-103-EL-EFC. 1997. Concerning the costs and procedures associated with the implementation of the Clean Air Act Amendments of 1990, on behalf of the Ohio Consumers' Counsel.

25. *Bangor Hydro-Electric Company Petition for Temporary Rate Increase*, Maine Public Utilities Commission, Docket No. 97-201. 1997. Concerning the reasonableness of granting an electric utility's request for emergency rate relief, and related issues, on behalf of the Maine Public Advocate.

26. *Testimony concerning H.B. 1068 Relating to Restructuring of the Natural Gas Utility Industry*, Consumer Affairs Committee, Pennsylvania House of Representatives. 1997. Concerning the provisions of proposed legislation to restructure the natural gas utility industry in Pennsylvania, on behalf of the Pennsylvania AFL-CIO Gas Utility Caucus.

27. *In the Matter of the Regulation of the Electric Fuel Component Contained within the Rate Schedules of Cleveland Electric Illuminating Company and Toledo Edison Company and Related Matters*, Public Utilities Commission of Ohio, Case Nos. 97-107-EL-EFC and 97-108-EL-EFC. 1997. Concerning the costs and procedures associated with the implementation of the Clean Air Act Amendments of 1990, on behalf of the Ohio Consumers' Counsel.

28. *In the Matter of the Petition of Valley Road Sewerage Company for a Revision in Rates and Charges for Water Service*, New Jersey Board of Public Utilities, Docket No. WR92080846J. 1997. Concerning the revenue requirements and rate design for a wastewater treatment utility, on behalf of the New Jersey Division of Ratepayer Advocate.

29. *Bangor Gas Company, L.L.C., Petition for Approval to Furnish Gas Service in the State of Maine*, Maine Public Utilities Commission, Docket No. 97-795. 1998. Concerning the standards and public policy concerns involved in issuing a certificate of public convenience and necessity for a new natural gas utility, and related ratemaking issues, on behalf of the Maine Public Advocate.

30. *In the Matter of the Investigation on Motion of the Commission into the Adequacy of the Public Utility Water Service Provided by Tidewater Utilities, Inc., in Areas in Southern New Castle County, Delaware*, Delaware Public Service Commission, Docket No. 309-97. 1998. Concerning the standards for the provision of efficient, sufficient, and adequate water service, and the application of those standards to a water utility, on behalf of the Delaware Division of the Public Advocate.

31. *In the Matter of the Regulation of the Electric Fuel Component Contained within the Rate Schedules of Cincinnati Gas and Electric Co. and Related Matters*, Public Utilities Commission of Ohio, Case No. 97-103-EL-EFC. 1998. Concerning fuel-related transactions with affiliated companies and the appropriate ratemaking treatment and regulatory safeguards involving such transactions, on behalf of the Ohio Consumers' Counsel.

32. *Olde Port Mariner Fleet, Inc. Complaint Regarding Casco Bay Island Transit District's Tour and Charter Service*, Maine Public Utilities Commission, Docket No. 98-161. 1998. Concerning the standards and requirements for allocating costs and separating operations between regulated and unregulated operations of a transportation utility, on behalf of the Maine Public Advocate and Olde Port Mariner Fleet, Inc.

33. *Central Maine Power Company Investigation of Stranded Costs, Transmission and Distribution Utility Revenue Requirements, and Rate Design*, Maine Public Utilities Commission, Docket No. 97-580. 1998. Concerning the treatment of existing rate discounts when designing rates for a transmission and distribution electric utility, on behalf of the Maine Public Advocate.

34. *Pa. Public Utility Commission v. Manufacturers Water Company*, Pennsylvania Public Utility Commission, Docket No. R-00984275. 1998. Concerning rate design on behalf of the Manufacturers Water Industrial Users.

35. *In the Matter of Petition of Pennsgrove Water Supply Company for an Increase in Rates for Water Service*, New Jersey Board of Public Utilities, Docket No. WR98030147. 1998. Concerning the revenue requirements, level of affiliated charges, and rate design for a water utility, on behalf of the New Jersey Division of Ratepayer Advocate.

36. *In the Matter of Petition of Seaview Water Company for an Increase in Rates for Water Service*, New Jersey Board of Public Utilities, Docket No. WR98040193. 1999. Concerning the revenue requirements and rate design for a water utility, on behalf of the New Jersey Division of Ratepayer Advocate.

37. *In the Matter of the Regulation of the Electric Fuel Component Contained within the Rate Schedules of Ohio Power Company and Columbus Southern Power Company and Related Matters*, Public Utilities Commission of Ohio, Case Nos. 98-101-EL-EFC and 98-102-EL-EFC. 1999. Concerning the costs and procedures associated with the implementation of the Clean Air Act Amendments of 1990, on behalf of the Ohio Consumers' Counsel.

38. *In the Matter of the Regulation of the Electric Fuel Component Contained within the Rate Schedules of Dayton Power and Light Company and Related Matters*, Public Utilities Commission of Ohio, Case No. 98-105-EL-EFC. 1999. Concerning the costs and procedures associated with the implementation of the Clean Air Act Amendments of 1990, on behalf of the Ohio Consumers' Counsel.

39. *In the Matter of the Regulation of the Electric Fuel Component Contained within the Rate Schedules of Monongahela Power Company and Related Matters*, Public Utilities Commission of Ohio, Case No. 99-106-EL-EFC. 1999. Concerning the costs and procedures associated with the implementation of the Clean Air Act Amendments of 1990, on behalf of the Ohio Consumers' Counsel.

40. *County of Suffolk, et al. v. Long Island Lighting Company, et al.*, U.S. District Court for the Eastern District of New York, Case No. 87-CV-0646. 2000. Submitted two affidavits concerning the calculation and collection of court-ordered refunds to utility customers, on behalf of counsel for the plaintiffs.

41. *Northern Utilities, Inc., Petition for Waivers from Chapter 820*, Maine Public Utilities Commission, Docket No. 99-254. 2000. Concerning the standards and requirements for defining and separating a natural gas utility's core and non-core business functions, on behalf of the Maine Public Advocate.

42. *Notice of Adjustment of the Rates of Kentucky-American Water Company*, Kentucky Public Service Commission, Case No. 2000-120. 2000. Concerning the appropriate methods for allocating costs and designing rates, on behalf of the Kentucky Office of Attorney General.

43. *In the Matter of the Petition of Gordon's Corner Water Company for an Increase in Rates and Charges for Water Service*, New Jersey Board of Public Utilities, Docket No. WR00050304. 2000. Concerning the revenue requirements and rate design for a water utility, on behalf of the New Jersey Division of Ratepayer Advocate.

44. *Testimony concerning Arsenic in Drinking Water: An Update on the Science, Benefits, and Costs*, Committee on Science, United States House of Representatives. 2001. Concerning the effects on low-income households and small communities from a more stringent regulation of arsenic in drinking water.

45. *In the Matter of the Application of The Cincinnati Gas & Electric Company for an Increase in Gas Rates in its Service Territory*, Public Utilities Commission of Ohio, Case No. 01-1228-GA-AIR, *et al.* 2002. Concerning the need for and structure of a special rider and alternative form of regulation for an accelerated main replacement program, on behalf of the Ohio Consumers' Counsel.

46. *Pennsylvania State Treasurer's Hearing on Enron and Corporate Governance Issues*. 2002. Concerning Enron's role in Pennsylvania's electricity market and related issues, on behalf of the Pennsylvania AFL-CIO.

47. *An Investigation into the Feasibility and Advisability of Kentucky-American Water Company's Proposed Solution to its Water Supply Deficit*, Kentucky Public Service Commission, Case No. 2001-00117. 2002. Concerning water supply planning, regulatory oversight, and related issue, on behalf of the Kentucky Office of Attorney General.

48. *Joint Application of Pennsylvania-American Water Company and Thames Water Aqua Holdings GmbH*, Pennsylvania Public Utility Commission, Docket Nos. A-212285F0096 and A-230073F0004. 2002. Concerning the risks and benefits associated with the proposed acquisition of a water utility, on behalf of the Pennsylvania Office of Consumer Advocate.

49. *Application for Approval of the Transfer of Control of Kentucky-American Water Company to RWE AG and Thames Water Aqua Holdings GmbH*, Kentucky Public Service Commission, Case No. 2002-00018. 2002. Concerning the risks and benefits associated with the proposed acquisition of a water utility, on behalf of the Kentucky Office of Attorney General.

50. *Joint Petition for the Consent and Approval of the Acquisition of the Outstanding Common Stock of American Water Works Company, Inc., the Parent Company and Controlling Shareholder of West Virginia-American Water Company*, West Virginia Public Service Commission, Case No. 01-1691-W-PC. 2002. Concerning the risks and benefits associated with the proposed acquisition of a water utility, on behalf of the Consumer Advocate Division of the West Virginia Public Service Commission.

51. *Joint Petition of New Jersey-American Water Company, Inc. and Thames Water Aqua Holdings GmbH for Approval of Change in Control of New Jersey-American Water Company, Inc.*, New Jersey Board of Public

Utilities, Docket No. WM01120833. 2002. Concerning the risks and benefits associated with the proposed acquisition of a water utility, on behalf of the New Jersey Division of Ratepayer Advocate.

52. *Illinois-American Water Company, Proposed General Increase in Water Rates*, Illinois Commerce Commission, Docket No. 02-0690. 2003. Concerning rate design and cost of service issues, on behalf of the Illinois Office of the Attorney General.

53. *Pennsylvania Public Utility Commission v. Pennsylvania-American Water Company,* Pennsylvania Public Utility Commission, Docket No. R-00038304. 2003. Concerning rate design and cost of service issues, on behalf of the Pennsylvania Office of Consumer Advocate.

54. *West Virginia-American Water Company,* West Virginia Public Service Commission, Case No. 03-0353-W-42T. 2003. Concerning affordability, rate design, and cost of service issues, on behalf of the West Virginia Consumer Advocate Division.

55. *Petition of Seabrook Water Corp. for an Increase in Rates and Charges for Water Service*, New Jersey Board of Public Utilities, Docket No. WR3010054. 2003. Concerning revenue requirements, rate design, prudence, and regulatory policy, on behalf of the New Jersey Division of Ratepayer Advocate.

56. *Chesapeake Ranch Water Co. v. Board of Commissioners of Calvert County*, U.S. District Court for Southern District of Maryland, Civil Action No. 8:03-cv-02527-AW. 2004. Submitted expert report concerning the expected level of rates under various options for serving new commercial development, on behalf of the plaintiff.

57. *Testimony concerning Lead in Drinking Water*, Committee on Government Reform, United States House of Representatives. 2004. Concerning the trade-offs faced by low-income households when drinking water costs increase, including an analysis of H.R. 4268.

58. *West Virginia-American Water Company,* West Virginia Public Service Commission, Case No. 04-0373-W-42T. 2004. Concerning affordability and rate comparisons, on behalf of the West Virginia Consumer Advocate Division.

59. *West Virginia-American Water Company,* West Virginia Public Service Commission, Case No. 04-0358-W-PC. 2004. Concerning costs, benefits, and risks associated with a wholesale water sales contract, on behalf of the West Virginia Consumer Advocate Division.

60. *Kentucky-American Water Company,* Kentucky Public Service Commission, Case No. 2004-00103. 2004. Concerning rate design and tariff issues, on behalf of the Kentucky Office of Attorney General.

61. *New Landing Utility, Inc.,* Illinois Commerce Commission, Docket No. 04-0610. 2005. Concerning the adequacy of service provided by, and standards of performance for, a water and wastewater utility, on behalf of the Illinois Office of Attorney General.

62. *People of the State of Illinois v. New Landing Utility, Inc.,* Circuit Court of the 15th Judicial District, Ogle County, Illinois, No. 00-CH-97. 2005. Concerning the standards of performance for a water and wastewater utility, including whether a receiver should be appointed to manage the utility's operations, on behalf of the Illinois Office of Attorney General.

63. *Hope Gas, Inc. d/b/a Dominion Hope*, West Virginia Public Service Commission, Case No. 05-0304-G-42T. 2005. Concerning the utility's relationships with affiliated companies, including an appropriate level of revenues and expenses associated with services provided to and received from affiliates, on behalf of the West Virginia Consumer Advocate Division.

64. *Monongahela Power Co. and The Potomac Edison Co.*, West Virginia Public Service Commission, Case Nos. 05-0402-E-CN and 05-0750-E-PC. 2005. Concerning review of a plan to finance the construction of pollution control facilities and related issues, on behalf of the West Virginia Consumer Advocate Division.

65. *Joint Application of Duke Energy Corp., et al., for Approval of a Transfer and Acquisition of Control*, Case Kentucky Public Service Commission, No. 2005-00228. 2005. Concerning the risks and benefits associated with the proposed acquisition of an energy utility, on behalf of the Kentucky Office of the Attorney General.

66. *Commonwealth Edison Company proposed general revision of rates, restructuring and price unbundling of bundled service rates, and revision of other terms and conditions of service,* Illinois Commerce Commission, Docket No. 05-0597. 2005. Concerning rate design and cost of service, on behalf of the Illinois Office of Attorney General.

67. *Pennsylvania Public Utility Commission v. Aqua Pennsylvania, Inc.*, Pennsylvania Public Utility Commission, Docket No. R-00051030. 2006. Concerning rate design and cost of service, on behalf of the Pennsylvania Office of Consumer Advocate.

68. *Central Illinois Light Company d/b/a AmerenCILCO, Central Illinois Public Service Company d/b/a AmerenCIPS, and Illinois Power Company d/b/a AmerenIP, proposed general increases in rates for delivery service*, Illinois Commerce Commission, Docket Nos. 06-0070, et al. 2006. Concerning rate design and cost of service, on behalf of the Illinois Office of Attorney General.

69. *Grens, et al., v. Illinois-American Water Co.*, Illinois Commerce Commission, Docket Nos. 5-0681, et al. 2006. Concerning utility billing, metering, meter reading, and customer service practices, on behalf of the Illinois Office of Attorney General and the Village of Homer Glen, Illinois.

70. *Commonwealth Edison Company Petition for Approval of Tariffs Implementing ComEd's Proposed Residential Rate Stabilization Program*, Illinois Commerce Commission, Docket No. 06-0411. 2006. Concerning a utility's proposed purchased power phase-in proposal, in behalf of the Illinois Office of Attorney General.

71. *Illinois-American Water Company, Application for Approval of its Annual Reconciliation of Purchased Water and Purchased Sewage Treatment Surcharges Pursuant to 83 Ill. Adm. Code 655*, Illinois Commerce Commission, Docket No. 06-0196. 2006. Concerning the reconciliation of purchased water and sewer charges, on behalf of the Illinois Office of Attorney General and the Village of Homer Glen, Illinois.

72. *Illinois-American Water Company, et al.*, Illinois Commerce Commission, Docket No. 06-0336. 2006. Concerning the risks and benefits associated with the proposed divestiture of a water utility, on behalf of the Illinois Office of Attorney General.

73. *Joint Petition of Kentucky-American Water Company, et al.*, Kentucky Public Service Commission, Docket No. 2006-00197. 2006. Concerning the risks and benefits associated with the proposed divestiture of a water utility, on behalf of the Kentucky Office of Attorney General.

74. *Aqua Illinois, Inc. Proposed Increase in Water Rates for the Kankakee Division*, Illinois Commerce Commission, Docket No. 06-0285. 2006. Concerning various revenue requirement, rate design, and tariff issues, on behalf of the County of Kankakee.

75. *Housing Authority for the City of Pottsville v. Schuylkill County Municipal Authority*, Court of Common Pleas of Schuylkill County, Pennsylvania, No. S-789-2000. 2006. Concerning the reasonableness and uniformity of rates charged by a municipal water authority, on behalf of the Pottsville Housing Authority.

76. *Application of Pennsylvania-American Water Company for Approval of a Change in Control*, Pennsylvania Public Utility Commission, Docket No. A-212285F0136. 2006. Concerning the risks and benefits associated with the proposed divestiture of a water utility, on behalf of the Pennsylvania Office of Consumer Advocate.

77. *Application of Artesian Water Company, Inc., for an Increase in Water Rates*, Delaware Public Service Commission, Docket No. 06-158. 2006. Concerning rate design and cost of service, on behalf of the Staff of the Delaware Public Service Commission.

78. *Central Illinois Light Company, Central Illinois Public Service Company, and Illinois Power Company: Petition Requesting Approval of Deferral and Securitization of Power Costs*, Illinois Commerce Commission, Docket No. 06-0448. 2006. Concerning a utility's proposed purchased power phase-in proposal, in behalf of the Illinois Office of Attorney General.

79. *Petition of Pennsylvania-American Water Company for Approval to Implement a Tariff Supplement Revising the Distribution System Improvement Charge*, Pennsylvania Public Utility Commission, Docket No. P-00062241. 2007. Concerning the reasonableness of a water utility's proposal to increase the cap on a statutorily authorized distribution system surcharge, on behalf of the Pennsylvania Office of Consumer Advocate.

80. *Adjustment of the Rates of Kentucky-American Water Company*, Kentucky Public Service Commission, Case No. 2007-00143. 2007. Concerning rate design and cost of service, on behalf of the Kentucky Office of Attorney General.

81. *Application of Kentucky-American Water Company for a Certificate of Convenience and Necessity Authorizing the Construction of Kentucky River Station II, Associated Facilities and Transmission Main*, Kentucky Public Service Commission, Case No. 2007-00134. 2007. Concerning the life-cycle costs of a planned water supply source and the imposition of conditions on the construction of that project, on behalf of the Kentucky Office of Attorney General.

82. *Pa. Public Utility Commission v. Pennsylvania-American Water Company*, Pennsylvania Public Utility Commission, Docket No. R-00072229. 2007. Concerning rate design and cost of service, on behalf of the Pennsylvania Office of Consumer Advocate.

83. *Illinois-American Water Company Application for Approval of its Annual Reconciliation of Purchased Water and Purchased Sewage Treatment Surcharges*, Illinois Commerce Commission, Docket No. 07-0195. 2007. Concerning the reconciliation of purchased water and sewer charges, on behalf of the Illinois Office of Attorney General.

84. *In the Matter of the Application of Aqua Ohio, Inc. to Increase Its Rates for Water Service Provided In the Lake Erie Division*, Public Utilities Commission of Ohio, Case No.07-0564-WW-AIR. 2007. Concerning rate design and cost of service, on behalf of the Office of the Ohio Consumers' Counsel.

85. *Pa. Public Utility Commission v. Aqua Pennsylvania Inc.,* Pennsylvania Public Utility Commission, Docket No. R-00072711. 2008. Concerning rate design, on behalf of the Masthope Property Owners Council.

86. *Illinois-American Water Company Proposed increase in water and sewer rates*, Illinois Commerce Commission, Docket No. 07-0507. 2008. Concerning rate design and demand studies, on behalf of the Illinois Office of Attorney General.

87. *Central Illinois Light Company, d/b/a AmerenCILCO; Central Illinois Public Service Company, d/b/a AmerenCIPS; Illinois Power Company, d/b/a AmerenIP: Proposed general increase in rates for electric delivery service*, Illinois Commerce Commission Docket Nos. 07-0585, 07-0586, 07-0587. 2008. Concerning rate design and cost of service studies, on behalf of the Illinois Office of Attorney General.

88. *Commonwealth Edison Company: Proposed general increase in electric rates*, Illinois Commerce Commission Docket No. 07-0566. 2008. Concerning rate design and cost of service studies, on behalf of the Illinois Office of Attorney General.

89. *In the Matter of Application of Ohio American Water Co. to Increase Its Rates*, Public Utilities Commission of Ohio, Case No. 07-1112-WS-AIR. 2008. Concerning rate design and cost of service, on behalf of the Office of the Ohio Consumers' Counsel.

90. *In the Matter of the Application of The East Ohio Gas Company d/b/a Dominion East Ohio for Authority to Increase Rates for its Gas Service*, Public Utilities Commission of Ohio, Case Nos. 07-829-GA-AIR, et al. 2008. Concerning the need for, and structure of, an accelerated infrastructure replacement program and rate surcharge, on behalf of the Office of the Ohio Consumers' Counsel.

91. *Pa. Public Utility Commission v. Pennsylvania American Water Company*, Pennsylvania Public Utility Commission, Docket No. R-2008-2032689. 2008. Concerning rate design, cost of service study, and other tariff issues, on behalf of the Pennsylvania Office of Consumer Advocate.

92. *Pa. Public Utility Commission v. York Water Company*, Pennsylvania Public Utility Commission, Docket No. R-2008-2023067. 2008. Concerning rate design, cost of service study, and other tariff issues, on behalf of the Pennsylvania Office of Consumer Advocate.

93. *Northern Illinois Gas Company d/b/a Nicor Gas Company,* Illinois Commerce Commission, Docket No. 08-0363. 2008. Concerning rate design, cost of service, and automatic rate adjustments, on behalf of the Illinois Office of Attorney General.

94. *West Virginia American Water Company,* West Virginia Public Service Commission, Case No. 08-0900-W-42T. 2008. Concerning affiliated interest charges and relationships, on behalf of the Consumer Advocate Division of the Public Service Commission of West Virginia.

95. *Illinois-American Water Company Application for Approval of its Annual Reconciliation of Purchased Water and Purchased Sewage Treatment Surcharges*, Illinois Commerce Commission, Docket No. 08-

0218. 2008. Concerning the reconciliation of purchased water and sewer charges, on behalf of the Illinois Office of Attorney General.

96. *In the Matter of Application of Duke Energy Ohio, Inc. for an Increase in Electric Rates*, Public Utilities Commission of Ohio, Case No. 08-0709-EL-AIR. 2009. Concerning rate design and cost of service, on behalf of the Office of the Ohio Consumers' Counsel.

97. *The Peoples Gas Light and Coke Company and North Shore Gas Company Proposed General Increase in Rates for Gas Service*, Illinois Commerce Commission, Docket Nos. 09-0166 and 09-0167. 2009. Concerning rate design and automatic rate adjustments on behalf of the Illinois Office of Attorney General, Citizens Utility Board, and City of Chicago.

98. *Illinois-American Water Company Proposed Increase in Water and Sewer Rates*, Illinois Commerce Commission, Docket No. 09-0319. 2009. Concerning rate design and cost of service on behalf of the Illinois Office of Attorney General and Citizens Utility Board.

99. *Pa. Public Utility Commission v. Aqua Pennsylvania Inc.*, Pennsylvania Public Utility Commission, Docket No. R-2009-2132019. 2010. Concerning rate design, cost of service, and automatic adjustment tariffs, on behalf of the Pennsylvania Office of Consumer Advocate.

100. *Apple Canyon Utility Company and Lake Wildwood Utilities Corporation Proposed General Increases in Water Rates*, Illinois Commerce Commission, Docket Nos. 09-0548 and 09-0549. 2010. Concerning parent-company charges, quality of service, and other matters, on behalf of Apple Canyon Lake Property Owners' Association and Lake Wildwood Association, Inc.

101. *Application of Aquarion Water Company of Connecticut to Amend its Rate Schedules*, Connecticut Department of Public Utility Control, Docket No. 10-02-13. 2010. Concerning rate design, proof of revenues, and other tariff issues, on behalf of the Connecticut Office of Consumer Counsel.

102. *Illinois-American Water Company Annual Reconciliation Of Purchased Water and Sewage Treatment Surcharges*, Illinois Commerce Commission, Docket No. 09-0151. 2010. Concerning the reconciliation of purchased water and sewer charges, on behalf of the Illinois Office of Attorney General.

103. *Pa. Public Utility Commission v. Pennsylvania-American Water Co.*, Pennsylvania Public Utility Commission, Docket Nos. R-2010-2166212, et al. 2010. Concerning rate design and cost of service study for four wastewater utility districts, on behalf of the Pennsylvania Office of Consumer Advocate.

104. *Central Illinois Light Company d/b/a AmerenCILCO, Central Illinois Public Service Company d/b/a AmerenCIPS, Illinois Power Company d/b/a AmerenIP Petition for accounting order*, Illinois Commerce Commission, Docket No. 10-0517. 2010. Concerning ratemaking procedures for a multi-district electric and natural gas utility, on behalf of the Illinois Office of Attorney General.

105. *Commonwealth Edison Company Petition for General Increase in Delivery Service Rates*, Illinois Commerce Commission Docket No. 10-0467. 2010. Concerning rate design and cost of service study, on behalf of the Illinois Office of Attorney General.

106. *Pa. Public Utility Commission v. City of Lancaster Bureau of Water*, Pennsylvania Public Utility Commission, Docket No. R-2010-2179103. 2010. Concerning rate design, cost of service, and cost

allocation, on behalf of the Pennsylvania Office of Consumer Advocate.

107.*Application of Yankee Gas Services Company for Amended Rate Schedules*, Connecticut Department of Public Utility Control, Docket No. 10-12-02. 2011. Concerning rate design and cost of service for a natural gas utility, on behalf of the Connecticut Office of Consumers' Counsel.

108.*California-American Water Company*, California Public Utilities Commission, Application 10-07-007. 2011. Concerning rate design and cost of service for multiple water-utility service areas, on behalf of The Utility Reform Network.

109.*Little Washington Wastewater Company, Inc., Masthope Wastewater Division*, Pennsylvania Public Utility Commission Docket No. R-2010-2207833. 2011. Concerning rate design and various revenue requirements issues, on behalf of the Masthope Property Owners Council.

110.*In the matter of Pittsfield Aqueduct Company, Inc.*, New Hampshire Public Utilities Commission Case No. DW 10-090. 2011. Concerning rate design and cost of service on behalf of the New Hampshire Office of the Consumer Advocate.

111.*In the matters of Pennichuck Water Works, Inc. Permanent Rate Case and Petition for Approval of Special Contract with Anheuser-Busch, Inc.*, New Hampshire Public Utilities Commission Case Nos. DW 10-091 and DW 11-014. 2011. Concerning rate design, cost of service, and contract interpretation on behalf of the New Hampshire Office of the Consumer Advocate.

112.*Artesian Water Co., Inc. v. Chester Water Authority*, U.S. District Court for the Eastern District of Pennsylvania Case No. 10-CV-07453-JP. 2011. Concerning cost of service, ratemaking methods, and contract interpretation on behalf of Chester Water Authority.

113.*North Shore Gas Company and The Peoples Gas Light and Coke Company Proposed General Increases in Rates for Gas Service*, Illinois Commerce Commission, Docket Nos. 11-0280 and 11-0281. 2011. Concerning rate design and cost of service on behalf of the Illinois Office of Attorney General, the Citizens Utility Board, and the City of Chicago.

114.*Ameren Illinois Company: Proposed general increase in electric delivery service rates and gas delivery service rates*, Illinois Commerce Commission, Docket Nos. 11-0279 and 11-0282. 2011. Concerning rate design and cost of service for natural gas and electric distribution service, on behalf of the Illinois Office of Attorney General and the Citizens Utility Board.

115.*Pa. Public Utility Commission v. Pennsylvania-American Water Co.*, Pennsylvania Public Utility Commission, Docket No. R-2011-2232243. 2011. Concerning rate design, cost of service, sales forecast, and automatic rate adjustments on behalf of the Pennsylvania Office of Consumer Advocate.

116.*Aqua Illinois, Inc. Proposed General Increase in Water and Sewer Rates*, Illinois Commerce Commission, Docket No. 11-0436. 2011. Concerning rate design and cost of service on behalf of the Illinois Office of Attorney General.

117.*City of Nashua Acquisition of Pennichuck Corporation*, New Hampshire Public Utilities Commission, Docket No. DW 11-026. 2011. Concerning the proposed acquisition of an investor-owned utility holding company by a municipality, including appropriate ratemaking methodologies, on behalf of the

New Hampshire Office of Consumer Advocate.

118. *An Application by Heritage Gas Limited for the Approval of a Schedule of Rates, Tolls and Charges*, Nova Scotia Utility and Review Board, Case NSUARB-NG-HG-R-11. 2011. Concerning rate design and cost of service, on behalf of the Nova Scotia Consumer Advocate.

119. *An Application of Halifax Regional Water Commission for Approval of a Cost of Service and Rate Design Methodology,* Nova Scotia Utility and Review Board , Case NSUARB-W-HRWC-R-11. 2011. Concerning rate design and cost of service, on behalf of the Nova Scotia Consumer Advocate.

120. *National Grid USA and Liberty Energy Utilities Corp.*, New Hampshire Public Utilities Commission, Docket No. DG 11-040. 2011. Concerning the costs and benefits of a proposed merger and related conditions, on behalf of the New Hampshire Office of Consumer Advocate.

121. *Great Northern Utilities, Inc., et al.*, Illinois Commerce Commission, Docket Nos. 11-0059, et al. 2012. Concerning options for mitigating rate impacts and consolidating small water and wastewater utilities for ratemaking purposes, on behalf of the Illinois Office of Attorney General.

122. *Pa. Public Utility Commission v. Aqua Pennsylvania, Inc.,* Pennsylvania Public Utility Commission, Docket No. R-2011-2267958. 2012. Concerning rate design, cost of service, and automatic rate adjustment mechanisms, on behalf of the Pennsylvania Office of Consumer Advocate.

123. *Golden State Water Company*, California Public Utilities Commission, Application 11-07-017. 2012. Concerning rate design and quality of service, on behalf of The Utility Reform Network.

124. *Golden Heart Utilities, Inc. and College Utilities Corporation*, Regulatory Commission of Alaska, Case Nos. U-11-77 and U-11-78. 2012. Concerning rate design and cost of service, on behalf of the Alaska Office of the Attorney General.

125. *Illinois-American Water Company*, Illinois Commerce Commission, Docket No. 11-0767. 2012. Concerning rate design, cost of service, and automatic rate adjustment mechanisms, on behalf of the Illinois Office of Attorney General.

126. *Application of Tidewater Utilities, Inc., for a General Rate Increase in Water Base Rates and Tariff Revisions*, Delaware Public Service Commission, Docket No. 11-397. 2012. Concerning rate design and cost of service study, on behalf of the Staff of the Delaware Public Service Commission.

127. *In the Matter of the Philadelphia Water Department's Proposed Increase in Rates for Water and Wastewater Utility Services*, Philadelphia Water Commissioner, FY 2013-2016. 2012. Concerning rate design and related issues for storm water service, on behalf of Citizens for Pennsylvania's Future.

128. *Corix Utilities (Illinois) LLC, Hydro Star LLC, and Utilities Inc. Joint Application for Approval of a Proposed Reorganization*, Illinois Commerce Commission, Docket No. 12-0279. 2012. Concerning merger-related synergy savings and appropriate ratemaking treatment of the same, on behalf of the Illinois Office of Attorney General.

129. *North Shore Gas Company and The Peoples Gas Light and Coke Company*, Illinois Commerce Commission, Docket Nos. 12-0511 and 12-0512. 2012. Concerning rate design, cost of service study,

and automatic rate adjustment tariff on behalf of the Illinois Office of Attorney General.

130. *Pa. Public Utility Commission v. City of Lancaster Sewer Fund*, Pennsylvania Public Utility Commission, Docket No. R-2012-2310366. 2012. Concerning rate design, cost of service, and cost allocation, on behalf of the Pennsylvania Office of Consumer Advocate.

131. *Aquarion Water Company of New Hampshire*, New Hampshire Public Utilities Commission, Docket No. DW 12-085. 2013. Concerning tariff issues, including an automatic adjustment clause for infrastructure improvement, on behalf of the New Hampshire Office of Consumer Advocate.

132. *In the Matter of the Application of Duke Energy Ohio, Inc., for an Increase in Electric Distribution Rates*, Public Utilities Commission of Ohio, Case No. 12-1682-EL-AIR, et al. 2013. Concerning rate design and tariff issues, on behalf of the Office of the Ohio Consumers' Counsel.

133. *In the Matter of the Application of Duke Energy Ohio, Inc., for an Increase in Natural Gas Distribution Rates*, Public Utilities Commission of Ohio, Case No. 12-1685-GA-AIR, et al. 2013. Concerning cost-of-service study, rate design, and tariff issues, on behalf of the Office of the Ohio Consumers' Counsel.

134. *In the Matter of the Application of The Dayton Power and Light Company to Establish a Standard Service Offer in the Form of an Electric Security Plan*, Public Utilities Commission of Ohio, Case No. 12-426-EL-SSO, et al. 2013. Concerning rate design, on behalf of the Office of the Ohio Consumers' Counsel.

135. *Application of the Halifax Regional Water Commission, for Approval of Amendments to its Schedule of Rates and Charges and Schedule of Rules and Regulations for the delivery of water, public and private fire protection, wastewater and stormwater services*, Nova Scotia Utility and Review Board, Matter No. M05463, 2013. Concerning rate design, cost-of-service study, and miscellaneous tariff provisions, on behalf of the Consumer Advocate of Nova Scotia.

136. *California Water Service Co. General Rate Case Application* , California Public Utilities Commission, Docket No. A.12-07-007. 2013. Concerning rate design, phase-in plans, low-income programs, and other tariff issues, on behalf of The Utility Reform Network.

137. *Application of The United Illuminating Company to Amend its Rate Schedules*, Connecticut Public Utility Regulatory Authority, Docket No. 13-01-19. 2013. Concerning sales forecast, rate design, and other tariff issues, on behalf of the Connecticut Office of Consumer Counsel.

138. *Application of Aquarion Water Company of Connecticut to Amend its Rate Schedules*, Connecticut Public Utility Regulatory Authority, Docket No. 13-02-20. 2013. Concerning sales forecast and rate design on behalf of the Connecticut Office of Consumer Counsel.

139. *Ameren Illinois Company, Proposed General Increase in Natural Gas Delivery Service Rates*, Illinois Commerce Commission, Docket No. 13-0192. 2013. Concerning rate design and revenue allocation, on behalf of the Illinois Office of Attorney General and Citizens Utility Board.

140. *Commonwealth Edison Company, Tariff filing to present the Illinois Commerce Commission with an opportunity to consider revenue neutral tariff changes related to rate design*, Docket No. 13-0387. 2013. Concerning rate design and cost of service study issues, on behalf of the Illinois Office of Attorney

General.

141.*In the Matter of the Potomac Electric Power Company for Authority to Increase Existing Retail Rates and Charges for Electric Distribution Service*, District of Columbia Public Service Commission, Formal Case No. 1103. 2013. Concerning rate design, revenue allocation, and cost-of-service study issues, on behalf of the District of Columbia Office of Peoples' Counsel.

142.*Pa. Public Utility Commission v. Pennsylvania-American Water Co.*, Pennsylvania Public Utility Commission, Docket No. R-2013-2355276. 2013. Concerning rate design, revenue allocation, and regulatory policy, on behalf of the Pennsylvania Office of Consumer Advocate.

143.*In the Matter of the Revenue Requirement and Transmission Tariff Designated as TA364-8 filed by Chugach Electric Association, Inc.*, Regulatory Commission of Alaska, U-13-007. 2013. Concerning rate design and cost-of-service study issues, on behalf of the Alaska Office of the Attorney General.

144.*Ameren Illinois Company: Tariff filing to present the Illinois Commerce Commission with an opportunity to consider revenue neutral tariff changes related to rate design*, Docket No. 13-0476. 2013. Concerning rate design and cost of service study issues, on behalf of the Illinois Office of Attorney General.

145.*Pa. Public Utility Commission v. City of Bethlehem Bureau of Water*, Pennsylvania Public Utility Commission, Docket No. R-2013-2390244. 2014. Concerning rate design, cost of service study, and revenue allocation on behalf of the Pennsylvania Office of Consumer Advocate.

146.*In the Matter of the Tariff Revision Designated as TA332-121 filed by the Municipality of Anchorage d/b/a Municipal Light and Power Department*, Regulatory Commission of Alaska, U-13-184. 2014. Concerning rate design and cost-of-service study issues, on behalf of the Alaska Office of the Attorney General.

147.*Pa. Public Utility Commission v. Pike County Light and Power Co. - Gas*, Pennsylvania Public Utility Commission, Docket No. R-2013-2397353. 2014. Concerning rate design and revenue allocation on behalf of the Pennsylvania Office of Consumer Advocate.

148.*Pa. Public Utility Commission v. Pike County Light and Power Co. - Electric*, Pennsylvania Public Utility Commission, Docket No. R-2013-2397237. 2014. Concerning rate design, cost of service study, and revenue allocation on behalf of the Pennsylvania Office of Consumer Advocate.

149.*The Peoples Gas Light and Coke Company North Shore Gas Company Proposed General Increase In Rates for Gas Service,* Illinois Commerce Commission, Docket Nos. 14-0224 and 14-0225. 2014. Concerning rate design on behalf of the Illinois Office of the Attorney General and the Environmental Law and Policy Center.

150.*Apple Valley Ranchos Water Company*, California Public Utilities Commission, Docket No. A.14-01-002. 2014. Concerning rate design and automatic rate adjustment mechanisms on behalf of the Town of Apple Valley.

151.*Application by Heritage Gas Limited for Approval to Amend its Franchise Area*, Nova Scotia Utility and Review Board, Matter No. M06271. 2014. Concerning criteria, terms, and conditions for expanding a utility's service area and using transported compressed natural gas to serve small retail customers, on behalf of the Nova Scotia Consumer Advocate.

152.*Notice of Intent of Entergy Mississippi, Inc. to Modernize Rates to Support Economic Development, Power Procurement, and Continued Investment*, Mississippi Public Service Commission Docket No. 2014-UN-132. 2014. Concerning rate design and tariff issues, on behalf of the Mississippi Public Utilities Staff.

153.*Pa. Public Utility Commission v. City of Lancaster Bureau of Water*, Pennsylvania Public Utility Commission, Docket No. R-2014-2418872. 2014. Concerning rate design, cost of service study, and revenue allocation on behalf of the Pennsylvania Office of Consumer Advocate.

154.*Pa. Public Utility Commission v. Borough of Hanover Municipal Water Works*, Pennsylvania Public Utility Commission, Docket No. R-2014-2428304. 2014. Concerning rate design, cost of service study, and revenue allocation on behalf of the Pennsylvania Office of Consumer Advocate.

155.*Investigation of Commonwealth Edison Company's Cost of Service for Low-Use Customers In Each Residential Class*, Illinois Commerce Commission, Docket No. 14-0384. 2014. Concerning rate design on behalf of the Illinois Office of Attorney General.

156.*Application of the Halifax Regional Water Commission, for Approval of its Schedule of Rates and Charges and Schedule of Rules and Regulations for the Provision of Water, Public and Private Fire Protection, Wastewater and Stormwater Services*, Nova Scotia Utility and Review Board, Matter No. M06540. 2015. Concerning rate design, cost of service study, and tariff issues on behalf of the Nova Scotia Consumer Advocate.

157.*Testimony concerning organization and regulation of Philadelphia Gas Works*, Philadelphia City Council's Special Committee on Energy Opportunities. 2015.

158.*Testimony concerning proposed telecommunications legislation*, Maine Joint Standing Committee on Energy, Utilities, and Technology. 2015.

159.*Pa. Public Utility Commission v. United Water Pennsylvania, Inc.*, Pennsylvania Public Utility Commission, Docket No. R-2015-2462723. 2015. Concerning rate design, cost of service study, and revenue allocation on behalf of the Pennsylvania Office of Consumer Advocate.

160.*Ameren Illinois Company Proposed General Increase in Gas Delivery Service Rates*, Illinois Commerce Commission, Docket No. 15-0142. 2015. Concerning rate design on behalf of the Illinois Office of Attorney General.

161.*Maine Natural Gas Company Request for Multi-Year Rate Plan*, Maine Public Utilities Commission, Docket No. 2015-00005. 2015. Concerning rate design and automatic rate adjustment tariffs on behalf of the Maine Office of the Public Advocate.

162.*Application of Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company for Authority to Provide for a Standard Service Offer*, Public Utilities Commission of Ohio, Case No. 14-1297-EL-SSO. 2015. Concerning rate design and proposed rate discounts on behalf of the Office of the Ohio Consumers' Counsel.

163. *An Application of the Halifax Regional Water Commission, for approval of revisions to its Cost of Service Manual and Rate Design for Stormwater Service*, Nova Scotia Utility and Review Board, Matter No. M07147. 2016. Concerning stormwater rate design and cost of service, on behalf of the Nova Scotia Consumer Advocate.

164. *In The Matter Of An Application By Heritage Gas Limited For Enhancement To Its Existing Residential Retro-Fit Assistance Fund*, Nova Scotia Utility and Review Board, Matter No. M07146. 2016. Concerning costs and benefits associated with utility system expansion, on behalf of the Nova Scotia Consumer Advocate.

165. *In the Matter of the Application of UNS Electric, Inc. for the Establishment of Just and Reasonable Rates and Charges*, Arizona Corporation Commission, Docket No. E-04204A-15-0142. 2016. Concerning rate design and residential demand charges on behalf of Arizona Utility Ratepayer Alliance.

166. *In the Matter of Application of Water Service Corporation of Kentucky for a General Adjustment in Existing Rates*, Kentucky Public Service Commission, Case No. 2015-00382. 2016. Concerning rate design and service area consolidation on behalf of the Kentucky Office of the Attorney General.

167. *Massachusetts Electric Company And Nantucket Electric Company*, Massachusetts Department of Public Utilities, Docket No. DPU 15-155. 2016. Concerning rate design and cost-of-service studies on behalf of the Massachusetts Office of Attorney General.

168. *In the Matter of Abenaki Water Company*, New Hampshire Public Utilities Commission, Docket No. DW 15-199. 2016. Concerning rate design on behalf of the New Hampshire Office of the Consumer Advocate.

169. *In the Matter of an Application by Heritage Gas Limited for Approval of its Customer Retention Program*, Nova Scotia Utility and Review Board Matter No. M07346. 2016. Concerning a regulatory response to competition and potential business failure on behalf of the Nova Scotia Consumer Advocate.

170. *Joint Application of Pennsylvania-American Water Company and the Sewer Authority of the City of Scranton*, Pennsylvania Public Utility Commission Docket No. A-2016-2537209. 2016. Concerning the lawfulness, costs and benefits, and ratemaking treatment of a proposed acquisition of a combined wastewater and storm water utility on behalf of the Pennsylvania Office of Consumer Advocate.

171. *Application of The United Illuminating Company to Amend its Rate Schedules*, Connecticut Public Utility Regulatory Authority Docket No. 16-06-04. 2016. Concerning rate design, cost-of-service study, and other tariff issues on behalf of the Connecticut Office of Consumer Counsel.

172. *Ameren Illinois Company Tariff filing to present the Illinois Commerce Commission with an opportunity to consider revenue neutral tariff changes related to rate design*, Illinois Commerce Commission Docket No. 16-0387. 2016. Concerning rate design and cost-of-service study on behalf of the Illinois Office of the Attorney General.

173. *Unitil Energy Systems, Inc.*, New Hampshire Public Utilities Commission Docket No. 16-384. 2016. Concerning rate design and cost-of-service study on behalf of the New Hampshire Office of Consumer Advocate.

174. *Liberty Utilities (Granite State Electric) Corp.*, New Hampshire Public Utilities Commission Docket No. 16-383. 2016. Concerning rate design and cost-of-service study on behalf of the New Hampshire Office of Consumer Advocate.

175. *Arizona Public Service Co.*, Arizona Corporation Commission Docket No. E-01345A-16-0123. 2017. Concerning rate design and cost-of-service study on behalf of the Arizona Utility Ratepayer Alliance.

176. *Commonwealth Edison Company, Tariff filing to present the Illinois Commerce Commission with an opportunity to consider revenue neutral tariff changes related to rate design*, Illinois Commerce Commission Docket No. 17-0049. 2017. Concerning rate design and cost of service study issues, on behalf of the Illinois Office of Attorney General.

177. *NSTAR Electric Company and Western Massachusetts Electric Company*, Massachusetts Department of Public Utilities Docket No. D.P.U. 17-05. 2017. Concerning rate design and cost of service study issues, on behalf of the Massachusetts Office of Attorney General.

178. *In the Matter of the Tariff Revision Designated as TA857-2 Filed by Alaska Power Company*, Regulatory Commission of Alaska No. U-16-078. 2017. Concerning rate design and cost of service study issues on behalf of the Alaska Office of the Attorney General.

179. *In the Matter of the Application of Minnesota Power For Authority to Increase Rates for Electric Utility Service in Minnesota*, Minnesota Public Utilities Commission Docket No. E015/GR-16-664. 2017. Concerning rate design and cost of service study issues on behalf of AARP.

180. *Pennsylvania Public Utility Commission v. Pennsylvania-American Water Company,* Pennsylvania Public Utility Commission, Docket No. R-2017-2595853. 2017. Concerning rate design, cost of service, and policy issues, on behalf of the Pennsylvania Office of Consumer Advocate.

181. *Aqua Illinois, Inc. Proposed Rate Increases for Water and Sewer Services*, Illinois Commerce Commission, Docket No. 17-0259. 2017. Concerning rate design and single-tariff pricing, on behalf of the Illinois Office of Attorney General.

182. *Petition of Pennsylvania-American Water Company for Approval of Tariff Changes and Accounting and Rate Treatment Related to Replacement of Lead Customer-Owned Service Pipes*, Pennsylvania Public Utility Commission, Docket No. P-2017-2606100. 2017. Concerning public policy and ratemaking issues associated with the replacement of customer-owned lead service lines, on behalf of the Pennsylvania Office of Consumer Advocate.

MONTANA-DAKOTA UTILITIES CO.
NORTH DAKOTA PUBLIC SERVICE COMMISSION
SET 5 - DATA REQUESTS
ISSUED OCTOBER 25, 2017
CASE NO. PU-17-295

5.1 Please refer to MDU's response to PSC Data Request 3.9, Attachment A. Please provide (A) Attachment A in live Excel spreadsheet format with all formulae and macros intact and functioning and (B) complete work papers showing the development of the amounts shown in the column labeled "Cost for Minimum System," including base inputs and all intermediate calculations. Please provide calculation work papers in live Excel spreadsheet format with all formulae and macros intact and functioning.

Response:

Please see Response No. 5.1 Attachment A.

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
MILES OF MAIN - YEAR END
DECEMBER 31, 2016

	Total Footage	Cost Per Foot	Total	Cost for Minimum Sysetm	
2" and less	8,578,122	$13	$111,515,586	$111,515,586	
4" Equivalent	3,599,188	$20	$71,983,760	$46,789,444	
6" Equivalent	839,338	$30	$25,180,140	$10,911,394	
8" Equivalent	176,406	$39	$6,879,834	$2,293,278	
10" - 16"	391,533	$104	$40,719,432	$5,089,929	
	13,584,587		$256,278,752	$176,599,631	68.91%

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
MILES OF MAIN - YEAR END
DECEMBER 31, 2016

STEEL MAIN	MILES OF MAIN	TOTAL FOOTAGE
0.50	0.000	0
0.75	3.890	20,537
1.00	7.500	39,601
1.25	46.752	246,853
1.50	0.000	0
2.00	430.082	2,270,835
2.50	0.000	0
3.00	65.195	344,228
4.00	247.402	1,306,282
5.00	0.044	230
6.00	81.842	432,128
7.00	0.000	0
8.00	28.408	149,993
10.00	8.536	45,069
12.00	31.170	164,575
14.00	0.000	0
16.00	0.000	0
	950.820	5,020,331

PLASTIC MAIN	MILES OF MAIN	TOTAL FOOTAGE
0.50	-	0
0.75	11.829	62,456
1.00	11.804	62,326
1.25	68.219	360,194
1.50	-	0
2.00	1,044.568	5,515,320
2.50	-	0
3.00	46.168	243,767
4.00	322.900	1,704,911
6.00	77.080	406,980
8.00	5.002	26,413
10.00	-	0
12.00	34.449	181,889
	1,622.018	8,564,256
	2,572.838	**13,584,587**

NICOR GAS COMPANY
Naperville, Illinois

DEPRECIATION STUDY

RELATED TO GAS PLANT

AS OF DECEMBER 31, 2012

GANNETT FLEMING, INC. - VALUATION AND RATE DIVISION

Harrisburg, Pennsylvania

NICOR GAS COMPANY

ACCOUNT 376 MAINS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2012

SURVIVOR CURVE.. IOWA 65-R3
NET SALVAGE PERCENT.. -20

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1900	196,051.83	235,262	235,262			
1901	18,654.00	22,385	22,385			
1902	17,785.00	21,342	21,342			
1903	7,281.00	8,714	8,737			
1904	11,471.00	13,672	13,765			
1905	11,572.00	13,758	13,886			
1906	36,974.00	43,809	44,369			
1907	11,588.00	13,683	13,906			
1908	17,902.00	21,063	21,482			
1909	25,300.00	29,655	30,360			
1910	44,690.00	52,192	53,628			
1911	18,120.00	21,078	21,744			
1912	50,350.00	58,347	60,420			
1913	52,813.00	60,958	63,376			
1914	41,883.00	48,149	50,260			
1915	14,676.00	16,804	17,611			
1916	39,088.00	44,575	46,906			
1917	27,366.00	31,076	32,839			
1918	24,012.00	27,156	28,814			
1919	16,580.00	18,672	19,896			
1920	5,459.13	6,122	6,551			
1921	45,924.00	51,277	55,109			
1922	30,104.00	33,468	36,125			
1923	208,280.00	230,596	249,936			
1924	191,899.00	211,539	230,279			
1925	72,070.09	79,100	86,484			
1926	760,549.00	831,085	912,659			
1927	512,126.00	557,164	614,551			
1928	387,755.00	419,995	465,306			
1929	243,300.00	262,314	291,960			
1930	14,645.05	15,717	17,574			
1931	284,609.23	304,014	341,531			
1932	414,816.99	440,879	497,780			
1933	104,736.02	110,775	125,683			
1934	249,427.75	262,429	299,313			
1935	6,811.11	7,128	8,173			
1936	230,481.11	239,856	276,577			
1937	384,876.15	398,259	461,851			
1938	404,773.51	416,308	485,728			
1939	296,844.93	303,441	356,214			
1940	75,892.03	77,074	91,070			
1941	686,378.67	692,380	823,654			

NICOR GAS COMPANY

ACCOUNT 376 MAINS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2012

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 65-R3						
NET SALVAGE PERCENT.. -20						
1942	480,073.68	480,815	576,088			
1943	239,879.00	238,476	287,855			
1944	369,299.00	364,343	443,159			
1945	372,123.23	364,178	446,548			
1946	2,234,489.32	2,168,626	2,681,387			
1947	1,882,100.00	1,810,994	2,258,520			
1948	2,840,688.86	2,708,722	3,408,827			
1949	6,012,992.00	5,679,247	7,215,590			
1950	3,333,448.37	3,118,268	4,000,138			
1951	5,319,783.25	4,925,311	6,383,740			
1952	6,800,131.23	6,229,301	8,160,157			
1953	3,399,874.01	3,080,612	4,079,849			
1954	5,022,473.61	4,498,891	6,026,968			
1955	6,239,592.87	5,523,462	7,487,511			
1956	6,830,995.07	5,973,869	8,197,194			
1957	7,355,230.52	6,350,859	8,826,277			
1958	7,228,527.12	6,160,006	8,674,233			
1959	19,511,641.73	16,404,296	23,413,970			
1960	25,150,041.67	20,847,473	30,180,050			
1961	15,066,739.07	12,308,381	18,080,087			
1962	13,775,936.21	11,086,102	16,531,123			
1963	17,437,646.94	13,817,103	20,925,176			
1964	18,175,672.19	14,173,753	21,810,807			
1965	22,685,963.25	17,401,858	27,223,156			
1966	24,724,384.97	18,641,494	29,669,262			
1967	13,829,517.30	10,245,681	16,595,421			
1968	17,543,168.86	12,763,918	21,051,803			
1969	14,161,610.26	10,110,030	16,993,932			
1970	24,787,495.65	17,357,394	29,744,995			
1971	13,511,483.58	9,274,282	16,213,780			
1972	13,635,339.60	9,168,021	16,362,408			
1973	21,919,713.88	14,426,504	26,303,657			
1974	16,733,543.67	10,772,252	20,080,252			
1975	18,832,675.74	11,852,382	22,599,211			
1976	19,558,083.90	12,020,007	23,418,759	50,942	31.71	1,606
1977	41,554,679.78	24,925,328	48,562,389	1,303,227	32.51	40,087
1978	28,152,211.50	16,464,990	32,078,986	1,703,668	33.32	51,130
1979	23,928,038.88	13,632,378	26,560,166	2,153,481	34.14	63,078
1980	39,971,020.84	22,167,129	43,188,548	4,776,677	34.96	136,633
1981	28,025,246.22	15,107,738	29,434,631	4,195,664	35.80	117,197
1982	26,086,339.16	13,658,077	26,610,235	4,693,372	36.64	128,094
1983	25,967,861.57	13,188,454	25,695,262	5,466,172	37.49	145,803

NICOR GAS COMPANY

ACCOUNT 376 MAINS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2012

SURVIVOR CURVE.. IOWA 65-R3
NET SALVAGE PERCENT.. -20

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1984	25,455,261.25	12,528,570	24,409,600	6,136,714	38.34	160,060
1985	30,779,278.87	14,654,753	28,552,074	8,383,061	39.21	213,799
1986	35,179,074.16	16,184,344	31,532,199	10,682,690	40.08	266,534
1987	44,102,327.65	19,581,433	38,150,798	14,771,995	40.95	360,732
1988	53,599,681.83	22,927,371	44,669,739	19,649,879	41.83	469,756
1989	46,035,728.41	18,935,600	36,892,512	18,350,362	42.72	429,550
1990	45,105,725.34	17,803,410	34,686,649	19,440,221	43.62	445,672
1991	38,779,650.35	14,662,431	28,567,033	17,968,547	44.52	403,606
1992	35,399,522.53	12,789,706	24,918,375	17,561,052	45.43	386,552
1993	40,725,448.00	14,029,754	27,334,379	21,536,159	46.34	464,742
1994	69,594,616.55	22,792,515	44,406,997	39,106,543	47.26	827,477
1995	79,240,382.02	24,606,040	47,940,315	47,148,143	48.18	978,583
1996	45,508,192.21	13,349,919	26,009,847	28,599,984	49.11	582,366
1997	20,714,503.80	5,717,203	11,138,912	13,718,493	50.05	274,096
1998	24,749,141.23	6,401,316	12,471,780	17,227,189	50.99	337,854
1999	16,432,514.96	3,965,100	7,725,264	11,993,754	51.93	230,960
2000	42,592,643.51	9,530,189	18,567,809	32,543,363	52.88	615,419
2001	50,880,416.15	10,492,559	20,442,809	40,613,690	53.83	754,481
2002	46,776,251.19	8,825,556	17,194,963	38,936,538	54.78	710,780
2003	54,851,030.35	9,376,893	18,269,141	47,552,095	55.74	853,105
2004	55,983,219.12	8,568,120	16,693,396	50,486,467	56.71	890,257
2005	68,440,448.92	9,261,635	18,044,582	64,083,957	57.67	1,111,218
2006	58,135,138.74	6,826,228	13,299,642	56,462,524	58.64	962,867
2007	61,473,257.00	6,116,835	11,917,521	61,850,387	59.61	1,037,584
2008	53,743,866.09	4,375,826	8,525,487	55,967,152	60.59	923,703
2009	50,529,735.96	3,208,840	6,251,831	54,383,852	61.56	883,428
2010	68,996,954.72	3,133,842	6,105,711	76,690,635	62.54	1,226,265
2011	119,419,611.43	3,263,021	6,357,392	136,946,142	63.52	2,155,953
2012	74,848,571.80	677,230	1,319,457	88,498,829	64.51	1,371,862
	2,075,055,867.30	752,830,514	1,348,433,417	1,141,633,624		21,012,889

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 54.3 1.01

Montana Dakota Utilities Co.
ND PSC Case No. PU-17-295

Exhibit ___ (SJR-3)

Corrected Calculation of Minimum Size Analysis for Distribution Mains

Line				
1	Feet of distribution main		13,584,587	
2	Estimated historic cost of 0.75-inch main	$	1.38	per foot
3	Historic customer-related cost	$	18,746,730	
4	Historic cost of distribution mains	$	103,229,687	
5	Customer-related cost		**18.16%**	

Sources

Line 1: Exhibit ___ (SJR-1)

Line 2: Northern Illinois Gas Co., Ill. Commerce Comm'n Docket No. 17-0124, AG Exhibit 2.01

Line 3: line 1 x line 2

Line 4: MDU electronic COSS (provided in response to PSC Interim 1.2), Plant tab, cell O16

Line 5: line 3 ÷ line 4

Montana-Dakota Utilities Co.
ND PSC Case No. PU-17-295

Cost-of-Service Study Using Basic Customer Methodology

Exhibit ___ (SJR-4)
Page 1 of 28

	Total North Dakota	Residential Demand	Residential Energy	Residential Customer	Total Residential
Projected Rate Base	135,451	40,576	40	36,976	77,592
Operating Income for Proposed Return	10,216	3,060	3	2,790	5,853
Projected Operating Income	6,569	(2,942)	(137)	6,599	3,520
Increase in Operating Income	3,647	6,002	140	(3,809)	2,333
Related Taxes for Increase					
Federal Income	2,216	3,646	85	(2,315)	1,416
Total Increase in Revenue	5,863	9,648	225	(6,124)	3,749
Projected Revenue Before Increase	112,137	12,882	23,600	23,527	60,009
Total Cost of Service Required from Rates:	114,928	21,489	23,822	16,639	61,950
Less Projected Cost of Gas	70,913	11,841	23,598	0	35,439
Net Distribution Cost of Service	43,911	9,648	224	16,639	26,511
Return on Rate Base Before Increase	4.850%				4.537%
Projected Billing Units	112,516			96,792	
Bills	1,350,192			1,161,504	
Dk	23,351,305	8,826,214	8,826,214		
Unit Cost of Service					
Energy cost per Dk			$0.03		
Demand cost per Dk		$1.090			
Customer Cost Per Month				$14.33	
Cust and Demand cost per month				$22.63	

Montana-Dakota Utilities Co.
ND PSC Case No. PU-17-295

Cost-of-Service Study Using Basic Customer Methodology

	Small Firm General			Total	Large Firm General			Total
	Demand	Energy	Customer	Small Firm General	Demand	Energy	Customer	Large Firm General
Projected Rate Base	11,040	26	5,210	16,276	24,870	29	7,175	32,074
Operating Income for Proposed Return	833	2	393	1,228	1,876	2	541	2,419
Projected Operating Income	(737)	(26)	1,528	765	(1,767)	(98)	3,223	1,358
Increase in Operating Income	1,570	28	(1,135)	463	3,643	100	(2,682)	1,061
Related Taxes for Increase								
Federal Income	954	17	(690)	281	2,214	61	(1,630)	645
Total Increase in Revenue	2,524	45	(1,825)	744	5,857	161	(4,312)	1,706
Projected Revenue Before Increase	3,244	5,214	4,231	12,689	7,689	17,027	7,722	32,438
Total Cost of Service Required from Rates:	5,505	5,258	2,315	13,078	12,924	17,186	3,334	33,444
Less Projected Cost of Gas	2,981	5,203	0	8,184	7,067	17,036	0	24,103
Net Distribution Cost of Service	2,524	55	2,315	4,894	5,857	150	3,334	9,341
Return on Rate Base Before Increase				4.700%				4.234%
Projected Billing Units			10,850				4,710	
Bills			130,200				56,520	
Dk	2,036,838	2,036,838			5,998,825	5,998,825		
Unit Cost of Service								
Energy cost per Dk		$0.03				$0.03		
Demand cost per Dk	$1.240				$0.980			
Customer Cost Per Month			$17.78				$58.99	
Cust and Demand cost per month								

Montana-Dakota Utilities Co.
ND PSC Case No. PU-17-295

Cost-of-Service Study Using Basic Customer Methodology

	Air Force Delivery			Total	Small Interruptible			Total
	Demand	Energy	Customer	Air Force Delivery	Demand	Energy	Customer	Small Interruptible
Projected Rate Base	86	0	69	155	3,841	0	219	4,060
Operating Income for Proposed Return	6	0	5	11	290	0	17	307
Projected Operating Income	(28)	(6)	56	22	(488)	(11)	852	353
Increase in Operating Income	34	6	(51)	(11)	778	11	(835)	(46)
Related Taxes for Increase								
Federal Income	21	4	(31)	(6)	473	7	(507)	(27)
Total Increase in Revenue	55	10	(82)	(17)	1,251	18	(1,342)	(73)
Projected Revenue Before Increase	166	1,319	120	1,605	329	1,508	1,707	3,544
Total Cost of Service Required from Rates:	221	1,329	38	1,588	1,446	1,526	358	3,330
Less Projected Cost of Gas	166	1,318	0	1,484	195	1,508	0	1,703
Net Distribution Cost of Service	55	11	38	104	1,251	18	358	1,627
Return on Rate Base Before Increase				14.194%				8.695%
Projected Billing Units			3				155	
Bills			36				1,860	
Dk	490,100	490,100			1,677,385	1,677,385		
Unit Cost of Service								
Energy cost per Dk		$0.02				$0.01		
Demand cost per Dk	$0.110				$0.750			
Customer Cost Per Month			$1,055.56				$192.47	
Cust and Demand cost per month								

Cost-of-Service Study Using Basic Customer Methodology

	Large Interruptible			Total Large Interruptible	Minot Air Force Base Distribution			Total MAFB Distribution
	Demand	Energy	Customer		Demand	Energy	Customer	
Projected Rate Base	3,917	0	110	4,027	823	0	444	1,267
Operating Income for Proposed Return	295	0	8	303	62	0	33	95
Projected Operating Income	(319)	(9)	777	449	(173)	0	275	102
Increase in Operating Income	614	9	(769)	(146)	235	0	(242)	(7)
Related Taxes for Increase								
Federal Income	373	5	(467)	(89)	143	0	(147)	(4)
Total Increase in Revenue	987	14	(1,236)	(235)	378	0	(389)	(11)
Projected Revenue Before Increase	58	0	1,331	1,389	6	0	457	463
Total Cost of Service Required from Rates:	987	14	92	1,093	378	0	67	445
Less Projected Cost of Gas	0	0	0	0	0	0	0	0
Net Distribution Cost of Service	987	14	92	1,093	378	0	67	445
Return on Rate Base Before Increase				11.150%				8.051%
Projected Billing Units			6					0
Bills			72					12
Dk	4,321,943	4,321,943						
Unit Cost of Service								
Energy cost per Dk		$0.00						
Demand cost per Dk	$0.230							
Customer Cost Per Month			$1,277.78					$37,083.33
Cust and Demand cost per month								

Montana-Dakota Utilities Co.
ND PSC Case No. PU-17-295

Cost-of-Service Study Using Basic Customer Methodology

	Allocation Factor	Total North Dakota	Residential Demand	Residential Energy	Residential Customer	Total Residential	Firm General-Meter < 500 cubic feet Demand	Firm General-Meter < 500 cubic feet Energy	Firm General-Meter < 500 cubic feet Customer	Total Small Firm General
Rate Base-Projected										
Gas Plant in Service										
Production Plant	3	0	0	0	0	0	0	0	0	0
Land	13	913	444	0	0	444	112	0	0	112
Rights of Way	13	498	243	0	0	243	61	0	0	61
Structures & Improvements	40	423	210	0	0	210	53	0	0	53
Direct	Direct	81	0	0	0	0	0	0	0	0
Mains - $103,231-Directly Assigned $2,639										
Demand Related 75%	2	100,592	49,892	0	0	49,892	12,563	0	0	12,563
Customer Related 25%	8	0	0	0	0	0	0	0	0	0
Directly Assigned Demand Related 75%	Direct	2,639	0	0	0	0	0	0	0	0
Directly Assigned Customer Related 25%	Direct	0	0	0	0	0	0	0	0	0
Heskett Pipeline - $22,181										
Demand Related 75%	2	16,636	8,251	0	0	8,251	2,078	0	0	2,078
Customer Related 25%	8	5,545	0	0	4,770	4,770	0	0	535	535
Meas. & Reg. Equip. - General	40	1,754	869	0	0	869	219	0	0	219
Direct	Direct	208	0	0	0	0	0	0	0	0
Meas. & Reg. Equip. - City Gate	13	5,288	2,575	0	0	2,575	648	0	0	648
Direct	Direct	72	0	0	0	0	0	0	0	0
Services	37	46,810	0	0	37,188	37,188	0	0	5,961	5,961
Direct	Direct	405	0	0	0	0	0	0	0	0
Meters	9	31,618	0	0	19,850	19,850	0	0	2,670	2,670
Direct	Direct	55	0	0	0	0	0	0	0	0
Service Regulators	9	4,479	0	0	2,812	2,812	0	0	378	378
Direct	Direct	15	0	0	0	0	0	0	0	0
Ind. Meas. & Reg. Station Equipment	40	376	187	0	0	187	47	0	0	47
Direct	Direct	593	0	0	0	0	0	0	0	0
Property on Customer Premise	13	115	57	0	0	57	14	0	0	14
Cathodic Protection & Other Equipment	40	1,712	848	0	0	848	214	0	0	214
Direct	Direct	4	0	0	0	0	0	0	0	0
Distribution Plant - includes Heskett		220,831	63,576	0	64,620	128,196	16,009	0	9,544	25,553
Distribution Plant Excluding Direct Assignments		216,759	63,576	0	64,620	128,196	16,009	0	9,544	25,553
General Plant	38	14,138	4,145	0	4,217	8,362	1,044	0	623	1,667
Direct	Direct	286	0	0	0	0	0	0	0	0
Intangible Plant - General	15	3,464	965	0	1,043	2,008	243	0	157	400
Direct	Direct	2,193								
Common Plant	15	13,249	3,688	0	3,993	7,681	929	0	601	1,530
Intangible Common (Excluding CC&B)	15	5,236	1,460	0	1,576	3,036	367	0	237	604
Intangible Common (CC&B)	4	9,061	0	0	7,796	7,796	0	0	874	874
Acquisition Adjustment	15	97	28	0	29	57	7	0	4	11
Total Gas Plant in Service including Heskett		268,555	73,862	0	83,274	157,137	18,599	0	12,040	30,639

Montana-Dakota Utilities Co.
ND PSC Case No. PU-17-295

Cost-of-Service Study Using Basic Customer Methodology

	Allocation Factor	Total North Dakota	Firm General > 500 cubic feet: Demand	Firm General > 500 cubic feet: Energy	Firm General > 500 cubic feet: Customer	Total Large Firm General	Air Force Delivery: Demand	Air Force Delivery: Energy	Air Force Delivery: Customer	Total Air Force Delivery	Small Interruptible: Demand	Small Interruptible: Energy	Small Interruptible: Customer	Total Small Interruptible
Rate Base-Projected														
Gas Plant in Service														
Production Plant	3	0	0	0	0	0	0	0	0	0	0	0	0	0
Land	13	913	266	0	0	266	0	0	0	0	56	0	0	56
Rights of Way	13	498	145	0	0	145	0	0	0	0	30	0	0	30
Structures & Improvements	40	423	125	0	0	125	0	0	0	0	26	0	0	26
Direct	Direct	81	22	0	7	29	13	0	4	17	0	0	0	0
Mains - $103,231-Directly Assigned $2,639														
Demand Related 75%	2	100,592	29,777	0	0	29,777	0	0	0	0	6,248	0	0	6,248
Customer Related 25%	8	0	0	0	0	0	0	0	0	0	0	0	0	0
Directly Assigned Demand Related 75%	Direct	2,639	69	0	0	69	0	0	0	0	0	0	0	0
Directly Assigned Customer Related 25%	Direct	0	0	0	0	0	0	0	0	0	0	0	0	0
Heskett Pipeline - $22,181														
Demand Related 75%	2	16,636	4,925	0	0	4,925	0	0	0	0	1,033	0	0	1,033
Customer Related 25%	8	5,545	0	0	232	232	0	0	0	0	0	0	8	8
Meas. & Reg. Equip. - General	40	1,754	520	0	0	520	0	0	0	0	109	0	0	109
Direct	Direct	208	34	0	11	45	0	0	0	0	8	0	3	11
Meas. & Reg. Equip. - City Gate	13	5,288	1,540	0	0	1,540	0	0	0	0	322	0	0	322
Direct	Direct	72	0	0	0	0	54	0	18	72	0	0	0	0
Services	37	46,810	0	0	3,420	3,420	0	0	0	0	0	0	233	233
Direct	Direct	405	0	0	0	0	0	0	0	0	0	0	0	0
Meters	9	31,618	0	0	8,017	8,017	0	0	49	49	0	0	954	954
Direct	Direct	55	0	0	0	0	0	0	0	0	0	0	0	0
Service Regulators	9	4,479	0	0	1,136	1,136	0	0	7	7	0	0	135	135
Direct	Direct	15	0	0	0	0	0	0	0	0	0	0	0	0
Ind. Meas. & Reg. Station Equipment	40	376	111	0	0	111	0	0	0	0	23	0	0	23
Direct	Direct	593	0	0	0	0	53	0	18	71	248	0	83	331
Property on Customer Premise	13	115	33	0	0	33	0	0	0	0	7	0	0	7
Cathodic Protection & Other Equipment	40	1,712	508	0	0	508	0	0	0	0	106	0	0	106
Direct	Direct	4	0	0	0	0	0	0	0	0	0	0	0	0
Distribution Plant - includes Heskett		220,831	38,075	0	12,823	50,898	120	0	96	216	8,216	0	1,416	9,632
Distribution Plant Excluding Direct Assignments		216,759	37,950	0	12,805	50,755	0	0	56	56	7,960	0	1,330	9,290
General Plant	38	14,138	2,475	0	835	3,310	0	0	4	4	519	0	87	606
Direct	Direct	286	0	0	0	0	0	0	0	0	0	0	0	0
Intangible Plant - General	15	3,464	578	0	220	798	2	0	2	4	125	0	25	150
Direct	Direct	2,193												
Common Plant	15	13,249	2,211	0	840	3,051	8	0	6	14	479	0	94	573
Intangible Common (Excluding CC&B)	15	5,236	874	0	332	1,206	3	0	3	6	189	0	37	226
Intangible Common (CC&B)	4	9,061	0	0	379	379	0	0	0	0	0	0	12	12
Acquisition Adjustment	15	97	16	0	6	22	0	0	0	0	4	0	1	5
Total Gas Plant in Service including Heskett		268,555	44,229	0	15,435	59,664	133	0	111	244	9,532	0	1,672	11,204

Montana-Dakota Utilities Co.
ND PSC Case No. PU-17-295

Cost-of-Service Study Using Basic Customer Methodology

	Allocation Factor	Total North Dakota	Large Interruptible Demand	Large Interruptible Energy	Large Interruptible Customer	Total Large Interruptible	Minot Air Force Base Distribution Demand	Minot Air Force Base Distribution Energy	Minot Air Force Base Distribution Customer	Total Minot Air Force
Rate Base-Projected										
Gas Plant in Service										
Production Plant	3	0	0	0	0	0	0	0	0	0
Land	13	913	35	0	0	35	0	0	0	0
Rights of Way	13	498	19	0	0	19	0	0	0	0
Structures & Improvements	40	423	9	0	0	9	0	0	0	0
Direct	Direct	81	26	0	9	35	0	0	0	0
Mains - $103,231-Directly Assigned $2,639										
Demand Related 75%	2	100,592	2,112	0	0	2,112	0	0	0	0
Customer Related 25%	8	0	0	0	0	0	0	0	0	0
Directly Assigned Demand Related 75%	Direct	2,639	1.814	0	0	1,814	756	0	0	756
Directly Assigned Customer Related 25%	Direct	0	0	0	0	0	0	0	0	0
Heskett Pipeline - $22,181										
Demand Related 75%	2	16,636	349	0	0	349	0	0	0	0
Customer Related 25%	8	5,545	0	0	0	0	0	0	0	0
Meas. & Reg. Equip. - General	40	1,754	37	0	0	37	0	0	0	0
Direct	Direct	208	114	0	38	152	0	0	0	0
Meas. & Reg. Equip. - City Gate	13	5,288	203	0	0	203	0	0	0	0
Direct	Direct	72	0	0	0	0	0	0	0	0
Services	37	46,810	0	0	8	8	0	0	0	0
Direct	Direct	405	0	0	0	0	0	0	405	405
Meters	9	31,618	0	0	78	78	0	0	0	0
Direct	Direct	55	0	0	0	0	0	0	55	55
Service Regulators	9	4,479	0	0	11	11	0	0	0	0
Direct	Direct	15	0	0	0	0	0	0	15	15
Ind. Meas. & Reg. Station Equipment	40	376	8	0	0	8	0	0	0	0
Direct	Direct	593	143	0	48	191	0	0	0	0
Property on Customer Premise	13	115	4	0	0	4	0	0	0	0
Cathodic Protection & Other Equipment	40	1,712	36	0	0	36	0	0	0	0
Direct	Direct	4	0	0	0	0	3	0	1	4
Distribution Plant - includes Heskett		220,831	4,909	0	192	5,101	759	0	476	1,235
Distribution Plant Excluding Direct Assignments		216,759	2,812	0	97	2,909	0	0	0	0
General Plant	38	14,138	183	0	6	189	0	0	0	0
Direct	Direct	286	0	0	0	0	214	0	72	286
Intangible Plant - General	15	3,464	80	0	3	83	13	0	8	21
Direct	Direct	2,193	1,645		548	2,193				
Common Plant	15	13,249	304	0	13	317	51	0	32	83
Intangible Common (Excluding CC&B)	15	5,236	120	0	5	125	20	0	13	33
Intangible Common (CC&B)	4	9,061	0	0	0	0	0	0	0	0
Acquisition Adjustment	15	97	2	0	0	2	0	0	0	0
Total Gas Plant in Service including Heskett		268,555	7,243	0	767	8,010	1,057	0	601	1,658

Montana-Dakota Utilities Co.
ND PSC Case No. PU-17-295

Cost-of-Service Study Using Basic Customer Methodology

	Allocation Factor	Total North Dakota	Residential Demand	Residential Energy	Residential Customer	Total Residential	Firm General-Meter < 500 cubic feet Demand	Firm General-Meter < 500 cubic feet Energy	Firm General-Meter < 500 cubic feet Customer	Total Small Firm General
Less: Accumulated Depreciation										
Production Plant	3	0	0	0	0	0	0	0	0	0
Distribution Plant										
Rights of Way	13	79	38	0	0	38	10	0	0	10
Structures & Improvements	23	187	77	0	0	77	20	0	0	20
Mains	40	36,213	17,949	0	(1)	17,948	4,520	0	0	4,520
Direct	Direct	33	0	0	0	0	0	0	0	0
Heskett - $787										
Demand Related 75%	2	590	292	0	0	292	74	0	0	74
Customer Related 25%	8	197	0	0	170	170	0	0	19	19
Meas. & Reg. Equip. - General	18	660	292	0	0	292	74	0	0	74
Meas. & Reg. Equip. - City Gate	19	708	340	0	0	340	86	0	0	86
Services	37	32,686	0	0	25,967	25,967	0	0	4,163	4,163
Direct	Direct	35	0	0	0	0	0	0	0	0
Meters	5	11,577	0	0	7,265	7,265	0	0	977	977
Direct	Direct	12	0	0	0	0	0	0	0	0
Service Regulators	9	1,416	0	0	889	889	0	0	120	120
Direct	Direct	2	0	0	0	0	0	0	0	0
Ind. Meas. & Reg. Station Equipment	21	331	64	0	0	64	16	0	0	16
Property on Customer Premise	13	125	61	0	0	61	15	0	0	15
Cathodic Protection & Other Equipment	13	862	419	0	0	419	106	0	0	106
Distribution Plant		85,713	19,532	0	34,290	53,822	4,921	0	5,279	10,200
General Plant	38	1,497	440	0	446	886	111	0	66	177
Direct	Direct	102	0	0	0	0	0	0	0	0
Intangible Plant - General	15	888	249	0	268	517	62	0	40	102
Intangible Plant - General - Direct	Direct	554	0	0	0	0	0	0	0	0
Common Plant	15	4,165	1.158	0	1,255	2,413	292	0	189	481
Intangible Plant - Common	15	3,524	983	0	1,062	2,045	247	0	160	407
Intangible Plant - Common-CC&B	4	2,961	0	0	2,547	2,547	0	0	286	286
Acquisition Adjustment	15	71	19	0	21	40	5	0	3	8
Less: Total Accumulated Reserve for Depreciation		99,475	22,381	0	39,889	62,270	5,638	0	6,023	11,661
Net Gas Plant in Service including Heskett		169,080	51,481	0	43,385	94,867	12,961	0	6,017	18,978
Additions										
Materials & Supplies	15	2,070	576	0	624	1,200	145	0	94	239
Fuel Stocks	10	95	0	40	0	40	0	26	0	26
Prepayments	25	249	68	0	77	145	17	0	11	28
Loss on Sale of Employee Housing	24	775	236	0	201	437	59	0	28	87
Unamortized Loss on Debt	24	470	143	0	120	263	36	0	17	53
Unamortized Redumption Cost of Preferred Stock	24	60	20	0	15	35	5	0	2	7
Gain on Sale of Williston Office	24	(281)	(85)	0	(72)	(157)	(22)	0	(10)	(32)
Total Additions		3,438	958	40	965	1,963	240	26	142	408
Total Before Deductions		172,518	52,439	40	44,350	96,829	13,201	26	6,159	19,386
Deductions										
Accumulated Deferred Income Tax	24	(21,052)	(6,411)	0	(5,401)	(11,812)	(1,614)	0	(749)	(2,363)
Accumulated Investment Tax Credit	24	0	0	0	0	0	0	0	0	0
Customer Advances For Construction	Direct	(16,015)	(5,452)	0	(1,973)	(7,425)	(547)	0	(200)	(747)
Total Deductions		(37,067)	(11,863)	0	(7,374)	(19,237)	(2,161)	0	(949)	(3,110)
Total Rate Base		135,451	40,576	40	36,976	77,592	11,040	26	5,210	16,276

Montana-Dakota Utilities Co.
ND PSC Case No. PU-17-295

Cost-of-Service Study Using Basic Customer Methodology

	Allocation Factor	Total North Dakota	Firm General > 500 cubic feet Demand	Firm General > 500 cubic feet Energy	Firm General > 500 cubic feet Customer	Total Large Firm General	Air Force Delivery Demand	Air Force Delivery Energy	Air Force Delivery Customer	Total Air Force Delivery	Small Interruptible Demand	Small Interruptible Energy	Small Interruptible Customer	Total Small Interruptible
Less: Accumulated Depreciation														
Production Plant	3	0	0	0	0	0	0	0	0	0	0	0	0	0
Distribution Plant														
Rights of Way	13	79	23	0	0	23	0	0	0	0	5	0	0	5
Structures & Improvements	23	187	55	0	3	58	5	0	1	6	10	0	0	10
Mains	40	36,213	10,737	0	0	10,737	0	0	0	0	2,248	0	0	2,248
Direct	Direct	33	0	0	0	0	0	0	0	0	0	0	0	0
Heskett - $787														
Demand Related 75%	2	590	175	0	0	175	0	0	0	0	37	0	0	37
Customer Related 25%	8	197	0	0	8	8	0	0	0	0	0	0	0	0
Meas. & Reg. Equip. - General	18	660	186	0	4	190	0	0	0	0	39	0	1	40
Meas. & Reg. Equip. - City Gate	19	708	203	0	0	203	7	0	2	9	43	0	0	43
Services	37	32,686	0	0	2,388	2,388	0	0	0	0	0	0	163	163
Direct	Direct	35	0	0	0	0	0	0	0	0	0	0	0	0
Meters	5	11,577	0	0	2,934	2,934	0	0	18	18	0	0	349	349
Direct	Direct	12	0	0	0	0	0	0	0	0	0	0	0	0
Service Regulators	9	1,416	0	0	359	359	0	0	2	2	0	0	43	43
Direct	Direct	2	0	0	0	0	0	0	0	0	0	0	0	0
Ind. Meas. & Reg. Station Equipment	21	331	38	0	0	38	18	0	6	24	93	0	28	121
Property on Customer Premise	13	125	36	0	0	36	0	0	0	0	8	0	0	8
Cathodic Protection & Other Equipment	13	862	251	0	0	251	0	0	0	0	53	0	0	53
Distribution Plant		85,713	11,704	0	5,696	17,400	30	0	29	59	2,536	0	584	3,120
General Plant	38	1,497	262	0	88	350	0	0	0	0	55	0	9	64
Direct	Direct	102	0	0	0	0	0	0	0	0	0	0	0	0
Intangible Plant - General	15	888	148	0	56	204	1	0	0	1	32	0	6	38
Intangible Plant - General - Direct	Direct	554	0	0	0	0	0	0	0	0	0	0	0	0
Common Plant	15	4,165	695	0	264	959	3	0	2	5	151	0	30	181
Intangible Plant - Common	15	3,524	588	0	223	811	2	0	2	4	127	0	25	152
Intangible Plant - Common-CC&B	4	2,961	0	0	124	124	0	0	0	0	0	0	4	4
Acquisition Adjustment	15	71	12	0	5	17	0	0	0	0	3	0	1	4
Less: Total Accumulated Reserve for Depreciation		99,475	13,409	0	6,456	19,865	36	0	33	69	2,904	0	659	3,563
Net Gas Plant in Service including Heskett		169,080	30,820	0	8,979	39,799	97	0	78	175	6,628	0	1,013	7,641
Additions														
Materials & Supplies	15	2,070	345	0	131	476	1	0	1	2	75	0	15	90
Fuel Stocks	10	95	0	29	0	29	0	0	0	0	0	0	0	0
Prepayments	25	249	41	0	14	55	0	0	0	0	9	0	2	11
Loss on Sale of Employee Housing	24	775	141	0	41	182	0	0	0	0	30	0	5	35
Unamortized Loss on Debt	24	470	86	0	25	111	0	0	0	0	18	0	3	21
Unamortized Redumption Cost of Preferred Stock	24	60	11	0	3	14	0	0	0	0	2	0	0	2
Gain on Sale of Williston Office	24	(281)	(51)	0	(15)	(66)	0	0	0	0	(11)	0	(2)	(13)
Total Additions		3,438	573	29	199	801	1	0	1	2	123	0	23	146
Total Before Deductions		172,518	31,393	29	9,178	40,600	98	0	79	177	6,751	0	1,036	7,787
Deductions														
Accumulated Deferred Income Tax	24	(21,052)	(3,837)	0	(1,118)	(4,955)	(12)	0	(10)	(22)	(825)	0	(126)	(951)
Accumulated Investment Tax Credit	24	0	0	0	0	0	0	0	0	0	0	0	0	0
Customer Advances For Construction	Direct	(16,015)	(2,686)	0	(885)	(3,571)	0	0	0	0	(2,085)		(691)	(2,776)
Total Deductions		(37,067)	(6,523)	0	(2,003)	(8,526)	(12)	0	(10)	(22)	(2,910)	0	(817)	(3,727)
Total Rate Base		135,451	24,870	29	7,175	32,074	86	0	69	155	3,841	0	219	4,060

Cost-of-Service Study Using Basic Customer Methodology

	Allocation Factor	Total North Dakota	Large Interruptible Demand	Large Interruptible Energy	Large Interruptible Customer	Total Large Interruptible	Minot Air Force Base Distribution Demand	Minot Air Force Base Distribution Energy	Minot Air Force Base Distribution Customer	Total Minot Air Force
Less: Accumulated Depreciation										
Production Plant	3	0	0	0	0	0	0	0	0	0
Distribution Plant										
Rights of Way	13	79	3	0	0	3	0	0	0	0
Structures & Improvements	23	187	13	0	3	16	0	0	0	0
Mains	40	36,213	760	0	0	760	0	0	0	0
Direct	Direct	33	0	0	0	0	25	0	8	33
Heskett - $787										
Demand Related 75%	2	590	12	0	0	12	0	0	0	0
Customer Related 25%	8	197	0	0	0	0	0	0	0	0
Meas. & Reg. Equip. - General	18	660	51	0	13	64	0	0	0	0
Meas. & Reg. Equip. - City Gate	19	708	27	0	0	27	0	0	0	0
Services	37	32,686	0	0	5	5	0	0	0	0
Direct	Direct	35	0	0	0	0	0	0	35	35
Meters	5	11,577	0	0	34	34	0	0	0	0
Direct	Direct	12	0	0	0	0	0	0	12	12
Service Regulators	9	1,416	0	0	3	3	0	0	0	0
Direct	Direct	2	0	0	0	0	0	0	2	2
Ind. Meas. & Reg. Station Equipment	21	331	52	0	16	68	0	0	0	0
Property on Customer Premise	13	125	5	0	0	5	0	0	0	0
Cathodic Protection & Other Equipment	13	862	33	0	0	33	0	0	0	0
Distribution Plant		85,713	956	0	74	1,030	25	0	57	82
General Plant	38	1,497	19	0	1	20	0	0	0	0
Direct	Direct	102	0	0	0	0	76	0	26	102
Intangible Plant - General	15	888	20	0	1	21	3	0	2	5
Intangible Plant - General - Direct	Direct	554	415	0	139	554	0	0	0	0
Common Plant	15	4,165	96	0	4	100	16	0	10	26
Intangible Plant - Common	15	3,524	81	0	3	84	13	0	8	21
Intangible Plant - Common-CC&B	4	2,961	0	0	0	0	0	0	0	0
Acquisition Adjustment	15	71	2	0	0	2	0	0	0	0
Less: Total Accumulated Reserve for Depreciation		99,475	1,589	0	222	1,811	133	0	103	236
Net Gas Plant in Service including Heskett		169,080	5,654	0	545	6,199	924	0	498	1,422
Additions										
Materials & Supplies	15	2,070	48	0	2	50	8	0	5	13
Fuel Stocks	10	95	0	0	0	0	0	0	0	0
Prepayments	25	249	7	0	1	8	1	0	1	2
Loss on Sale of Employee Housing	24	775	26	0	2	28	4	0	2	6
Unamortized Loss on Debt	24	470	16	0	2	18	3	0	1	4
Unamortized Redumption Cost of Preferred Stock	24	60	2	0	0	2	0	0	0	0
Gain on Sale of Williston Office	24	(281)	(9)	0	(1)	(10)	(2)	0	(1)	(3)
Total Additions		3,438	90	0	6	96	14	0	8	22
Total Before Deductions		172,518	5,744	0	551	6,295	938	0	506	1,444
Deductions										
Accumulated Deferred Income Tax	24	(21,052)	(704)	0	(68)	(772)	(115)	0	(62)	(177)
Accumulated Investment Tax Credit	24	0	0	0	0	0	0	0	0	0
Customer Advances For Construction	Direct	(16,015)	(1,123)	0	(373)	(1,496)	0	0	0	0
Total Deductions		(37,067)	(1,827)	0	(441)	(2,268)	(115)	0	(62)	(177)
Total Rate Base		135,451	3,917	0	110	4,027	823	0	444	1,267

Montana-Dakota Utilities Co.
ND PSC Case No. PU-17-295

Cost-of-Service Study Using Basic Customer Methodology

	Allocation Factor	Total North Dakota	Residential Demand	Residential Energy	Residential Customer	Total Residential	Firm General-Meter < 500 cubic feet Demand	Firm General-Meter < 500 cubic feet Energy	Firm General-Meter < 500 cubic feet Customer	Total Small Firm General
Income Statement										
Gas Operating Revenues										
Retail Sales & Transportation										
Residential	Direct	58,201	11,841	23,597	22,763	58,201	0	0	0	0
Firm General	Direct	44,072	0	0	0	0	2,981	5,213	4,140	12,334
Air Force Delivery	Direct	1,605	0	0	0	0	0	0	0	0
Small Interruptible	Direct	3,403	0	0	0	0	0	0	0	0
Large Interruptible	Direct	1,328	0	0	0	0	0	0	0	0
Total Sales & Transportation Revenues		108,609	11,841	23,597	22,763	58,201	2,981	5,213	4,140	12,334
Other Operating Revenue										
Miscellaneous										
Reconnect Fees	6	31	0	0	27	27	0	0	3	3
Minot Maintenance Fee Rate 65	Direct	456	0	0	0	0	0	0	0	0
NSF Check Fees & Other	6	19	0	0	16	16	0	0	2	2
Miscellaneous	24	1	0	0	1	1	0	0	0	0
Rent From Gas Property	24	466	139	0	121	260	36	0	17	53
Other Gas Revenues										
Miscellaneous	31	267	51	3	107	161	13	1	14	28
Heskett Pipeline Revenue - $2,275										
Demand Related 75%	2	1,706	846	0	0	846	213	0	0	213
Customer Related 25%	8	569	0	0	489	489	0	0	55	55
Transport and Penalty Revenue - Net	24	13	5	0	3	8	1	0	0	1
Total Other Operating Revenue		3,528	1,041	3	764	1,808	263	1	91	355
		3,072	1,041	3	764	1,808	263	1	91	355
Unbilled Revenue	26	0	0	0	0	0	0	0	0	0
Total Operating Revenues		112,137	12,882	23,600	23,527	60,009	3,244	5,214	4,231	12,689
Operation & Maintenance Expenses										
Cost of Purchased Gas	Direct	70,913	11,841	23,598	0	35,439	2,981	5,203	0	8,184
Other Gas Supply Expenses	3	372	0	184	0	184	0	42	0	42
Distribution Expenses										
Operation										
Load Dispatch	1	20	0	8	0	8	0	2	0	2
Mains and Services	22	2,326	779	0	578	1,357	196	0	93	289
Measuring Stations - General	18	119	53	0	0	53	13	0	0	13
Measuring Stations - Industrial	21	151	29	0	1	30	7	0	0	7
Measuring Stations - City Gate	19	40	21	0	0	21	5	0	0	5
Meters & House Regulators	16	488	0	0	306	306	0	0	41	41
Customer Installations	5	667	0	0	419	419	0	0	56	56
Other Gas Distribution	27	2,182	503	5	746	1,254	127	1	109	237
Rents	27	75	17	0	27	44	4	0	4	8
Supervision & Engineering	27	1,371	317	3	468	788	80	1	68	149
Direct -Minot AFB Distribution System	Direct	78	0	0	0	0	0	0	0	0
Total Operation Expense		7,517	1,719	16	2,545	4,280	432	4	371	807

Montana-Dakota Utilities Co.
ND PSC Case No. PU-17-295

Cost-of-Service Study Using Basic Customer Methodology

	Allocation Factor	Total North Dakota	Firm General > 500 cubic feet Demand	Firm General > 500 cubic feet Energy	Firm General > 500 cubic feet Customer	Total Large Firm General	Air Force Delivery Demand	Air Force Delivery Energy	Air Force Delivery Customer	Total Air Force Delivery	Small Interruptible Demand	Small Interruptible Energy	Small Interruptible Customer	Total Small Interruptible
Income Statement														
Gas Operating Revenues														
Retail Sales & Transportation														
Residential	Direct	58,201	0	0	0	0	0	0	0	0	0	0	0	0
Firm General	Direct	44,072	7,067	17,025	7,646	31,738				0	0	0	0	0
Air Force Delivery	Direct	1,605	0	0	0	0	166	1,319	120	1,605	0	0	0	0
Small Interruptible	Direct	3,403	0	0	0	0	0	0	0	0	195	1,508	1,700	3,403
Large Interruptible	Direct	1,328	0	0	0	0	0	0	0	0	0	0	0	0
Total Sales & Transportation Revenues		108,609	7,067	17,025	7,646	31,738	166	1,319	120	1,605	195	1,508	1,700	3,403
Other Operating Revenue														
Miscellaneous														
Reconnect Fees	6	31	0	0	1	1	0	0	0	0	0	0	0	0
Minot Maintenance Fee Rate 65	Direct	456	0	0	0	0	0	0	0	0	0	0	0	0
NSF Check Fees & Other	6	19	0	0	1	1	0	0	0	0	0	0	0	0
Miscellaneous	24	1	0	0	0	0	0	0	0	0	0	0	0	0
Rent From Gas Property	24	466	85	0	25	110	0	0	0	0	18	0	3	21
Other Gas Revenues														
Miscellaneous	31	267	30	2	24	56	0	0	0	0	9	0	3	12
Heskett Pipeline Revenue - $2,275														
Demand Related 75%	2	1,706	505	0	0	505	0	0	0	0	106	0	0	106
Customer Related 25%	8	569	0	0	24	24	0	0	0	0	0	0	1	1
Transport and Penalty Revenue - Net	24	13	2	0	1	3	0	0	0	0	1	0	0	1
Total Other Operating Revenue		3,528	622	2	76	700	0	0	0	0	134	0	7	141
		3,072	622	2	76	700	0	0	0	0	134	0	7	141
Unbilled Revenue	26	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Operating Revenues		112,137	7,689	17,027	7,722	32,438	166	1,319	120	1,605	329	1,508	1,707	3,544
Operation & Maintenance Expenses														
Cost of Purchased Gas	Direct	70,913	7,067	17,036	0	24,103	166	1,318	0	1,484	195	1,508	0	1,703
Other Gas Supply Expenses	3	372	0	124	0	124	0	10	0	10	0	12	0	12
Distribution Expenses														
Operation														
Load Dispatch	1	20	0	5	0	5	0	0	0	0	0	1	0	1
Mains and Services	22	2,326	465	0	53	518	0	0	0	0	97	0	4	101
Measuring Stations - General	18	119	34	0	1	35	0	0	0	0	7	0	0	7
Measuring Stations - Industrial	21	151	17	0	0	17	8	0	3	11	42	0	13	55
Measuring Stations - City Gate	19	40	11	0	0	11	0	0	0	0	1	0	0	1
Meters & House Regulators	16	488	0	0	124	124	0	0	1	1	0	0	15	15
Customer Installations	5	667	0	0	169	169	0	0	1	1	0	0	20	20
Other Gas Distribution	27	2,182	302	3	199	504	5	0	3	8	84	1	30	115
Rents	27	75	10	0	7	17	0	0	0	0	3	0	1	4
Supervision & Engineering	27	1,371	190	2	125	317	3	0	2	5	53	0	19	72
Direct -Minot AFB Distribution System	Direct	78	0	0	0	0	0	0	0	0	0	0	0	0
Total Operation Expense		7,517	1,029	10	678	1,717	16	0	10	26	287	2	102	391

Montana-Dakota Utilities Co.
ND PSC Case No. PU-17-295

Cost-of-Service Study Using Basic Customer Methodology

	Allocation Factor	Total North Dakota	Large Interruptible Demand	Large Interruptible Energy	Large Interruptible Customer	Total Large Interruptible	Minot Air Force Base Distribution Demand	Minot Air Force Base Distribution Energy	Minot Air Force Base Distribution Customer	Total Minot Air Force
Income Statement										
Gas Operating Revenues										
Retail Sales & Transportation										
Residential	Direct	58,201	0	0	0	0	0	0	0	0
Firm General	Direct	44,072	0	0	0	0	0	0	0	0
Air Force Delivery	Direct	1,605	0	0	0	0	0	0	0	0
Small Interruptible	Direct	3,403	0	0	0	0	0	0	0	0
Large Interruptible	Direct	1,328	0	0	1,328	1,328	0	0	0	0
Total Sales & Transportation Revenues		108,609	0	0	1,328	1,328	0	0	0	0
Other Operating Revenue										
Miscellaneous										
Reconnect Fees	6	31	0	0	0	0	0	0	0	0
Minot Maintenance Fee Rate 65	Direct	456	0	0	0	0	0	0	456	456
NSF Check Fees & Other	6	19	0	0	0	0	0	0	0	0
Miscellaneous	24	1	0	0	0	0	0	0	0	0
Rent From Gas Property	24	466	16	0	2	18	3	0	1	4
Other Gas Revenues										
Miscellaneous	31	267	6	0	1	7	3	0	0	3
Heskett Pipeline Revenue - $2,275										
Demand Related 75%	2	1,706	36	0	0	36	0	0	0	0
Customer Related 25%	8	569	0	0	0	0	0	0	0	0
Transport and Penalty Revenue - Net	24	13	0	0	0	0	0	0	0	0
Total Other Operating Revenue		3,528	58	0	3	61	6	0	457	463
		3,072	58	0	3	61	6	0	1	7
Unbilled Revenue	26	0	0	0	0	0	0	0	0	0
Total Operating Revenues		112,137	58	0	1,331	1,389	6	0	457	463
Operation & Maintenance Expenses										
Cost of Purchased Gas	Direct	70,913	0	0	0	0	0	0	0	0
Other Gas Supply Expenses	3	372	0	0	0	0	0	0	0	0
Distribution Expenses										
Operation										
Load Dispatch	1	20	0	4	0	4	0	0	0	0
Mains and Services	22	2,326	61	0	0	61	0	0	0	0
Measuring Stations - General	18	119	9	0	2	11	0	0	0	0
Measuring Stations - Industrial	21	151	24	0	7	31	0	0	0	0
Measuring Stations - City Gate	19	40	2	0	0	2	0	0	0	0
Meters & House Regulators	16	488	0	0	1	1	0	0	0	0
Customer Installations	5	667	0	0	2	2	0	0	0	0
Other Gas Distribution	27	2,182	55	2	7	64	0	0	0	0
Rents	27	75	2	0	0	2	0	0	0	0
Supervision & Engineering	27	1,371	35	1	4	40	0	0	0	0
Direct -Minot AFB Distribution System	Direct	78	0	0	0	0	78	0	0	78
Total Operation Expense		7,517	188	7	23	218	78	0	0	78

Cost-of-Service Study Using Basic Customer Methodology

	Allocation Factor	Total North Dakota	Residential Demand	Residential Energy	Residential Customer	Total Residential	Firm General-Meter < 500 cubic feet Demand	Firm General-Meter < 500 cubic feet Energy	Firm General-Meter < 500 cubic feet Customer	Total Small Firm General
Maintenance										
Structures & Improvements	13	10	5	0	0	5	1	0	0	1
Mains	13	371	181	0	0	181	45	0	0	45
Measuring Stations - General	18	118	53	0	0	53	13	0	0	13
Measuring Stations - Industrial	21	50	10	0	0	10	2	0	0	2
Measuring Stations - City Gate	19	30	14	0	0	14	4	0	0	4
Services	5	250	0	0	157	157	0	0	21	21
Meters & House Regulators	16	323	0	0	202	202	0	0	27	27
Other Equipment	28	433	99	0	135	234	24	0	18	42
Supervision & Engineering	28	367	83	0	114	197	21	0	15	36
Direct -Minot AFB Distribution System	Direct	55	0	0	0	0	0	0	0	0
Total Maintenance Expense		2,007	445	0	608	1,053	110	0	81	191
Total Distribution Expenses		9,524	2,164	16	3,153	5,333	542	4	452	998
Customer Accounts	4	95	0	0	82	82	0	0	9	9
Meter Reading	5	232	0	0	145	145	0	0	20	20
Customer Records & Collection	4	2,206	0	0	1,898	1,898	0	0	213	213
Uncollectible Accounts	6	283	0	0	244	244	0	0	27	27
Miscellaneous Customer Accounts	4	125	0	0	108	108	0	0	12	12
Customer Service & Information	4	254	0	0	219	219	0	0	24	24
Sales Expenses	4	94	0	0	81	81	0	0	9	9
Administration & General Expenses	30	8,347	1.896	14	2,763	4,673	475	4	396	875
Total Gas O&M Expenses		92,445	15,901	23,812	8,693	48,406	3,998	5,253	1,162	10,413
O&M Excl. Cost of Gas and A&G		13,185	2,164	200	5,930	8,294	542	46	766	1,354
O&M Excl. Cost of Gas		21,532	4,060	214	8,693	12,967	1,017	50	1,162	2,229
Depreciation Expense										
Production Plant	3	0	0	0	0	0	0	0	0	0
Distribution Plant										
Rights of Way	13	7	4	0	0	4	1	0	0	1
Structures & Improvements	23	13	5	0	0	5	1	0	0	1
Mains	40	2,618	1,298	0	0	1,298	327	0	0	327
Direct -Minot AFB Distribution System	Direct	14	0	0	0	0	0	0	0	0
Heskett Pipeline - $461	Direct									
Demand Related 75%	2	346	173	0	0	173	43	0	0	43
Customer Related 25%	8	115	0	0	99	99	0	0	11	11
Meas. & Reg. Equip. - General	18	47	21	0	0	21	5	0	0	5
Meas. & Reg. Equip. - City Gate	19	134	65	0	0	65	16	0	0	16
Services	17	2,983	0	0	2,403	2,403	0	0	375	375
Direct -Minot AFB Distribution System	Direct	6	0	0	0	0	0	0	0	0
Meters	5	1,078	0	0	677	677	0	0	91	91
Direct -Minot AFB Distribution System	Direct	2	0	0	0	0	0	0	0	0
Service Regulators	20	66	0	0	41	41	0	0	6	6
Ind. Meas. & Reg. Station Equipment	21	29	5	0	0	5	1	0	0	1
Cathodic Protection & Other Equipment	13	28	14	0	0	14	3	0	0	3
Total Distribution Plant		7,486	1,585	0	3,220	4,805	397	0	483	880

Montana-Dakota Utilities Co.
ND PSC Case No. PU-17-295

Exhibit___ (SJR-4)
Page 15 of 28

Cost-of-Service Study Using Basic Customer Methodology

	Allocation Factor	Total North Dakota	Firm General > 500 cubic feet: Demand	Firm General > 500 cubic feet: Energy	Firm General > 500 cubic feet: Customer	Total Large Firm General	Air Force Delivery: Demand	Air Force Delivery: Energy	Air Force Delivery: Customer	Total Air Force Delivery	Small Interruptible: Demand	Small Interruptible: Energy	Small Interruptible: Customer	Total Small Interruptible
Maintenance														
Structures & Improvements	13	10	3	0	0	3	0	0	0	0	1	0	0	1
Mains	13	371	108	0	0	108	0	0	0	0	23	0	0	23
Measuring Stations - General	18	118	33	0	1	34	0	0	0	0	7	0	0	7
Measuring Stations - Industrial	21	50	6	0	0	6	3	0	1	4	14	0	4	18
Measuring Stations - City Gate	19	30	9	0	0	9	0	0	0	0	2	0	0	2
Services	5	250	0	0	63	63	0	0	0	0	0	0	8	8
Meters & House Regulators	16	323	0	0	82	82	0	0	1	1	0	0	10	10
Other Equipment	28	433	60	0	55	115	1	0	1	2	18	0	8	26
Supervision & Engineering	28	367	51	0	47	98	1	0	1	2	15	0	7	22
Direct -Minot AFB Distribution System	Direct	55	0	0	0	0	0	0	0	0	0	0	0	0
Total Maintenance Expense		2,007	270	0	248	518	5	0	4	9	80	0	37	117
Total Distribution Expenses		9,524	1,299	10	926	2,235	21	0	14	35	367	2	139	508
Customer Accounts	4	95	0	0	4	4	0	0	0	0	0	0	0	0
Meter Reading	5	232	0	0	59	59	0	0	0	0	0	0	7	7
Customer Records & Collection	4	2,206	0	0	92	92	0	0	0	0	0	0	3	3
Uncollectible Accounts	6	283	0	0	12	12	0	0	0	0	0	0	0	0
Miscellaneous Customer Accounts	4	125	0	0	5	5	0	0	0	0	0	0	0	0
Customer Service & Information	4	254	0	0	11	11	0	0	0	0	0	0	0	0
Sales Expenses	4	94	0	0	4	4	0	0	0	0	0	0	0	0
Administration & General Expenses	30	8,347	1,138	9	812	1,959	18	0	12	30	322	2	122	446
Total Gas O&M Expenses		92,445	9,504	17,179	1,925	28,608	205	1,328	26	1,559	884	1,524	271	2,679
O&M Excl. Cost of Gas and A&G		13,185	1,299	134	1,113	2,546	21	10	14	45	367	14	149	530
O&M Excl. Cost of Gas		21,532	2,437	143	1,925	4,505	39	10	26	75	689	16	271	976
Depreciation Expense														
Production Plant	3	0	0	0	0	0	0	0	0	0	0	0	0	0
Distribution Plant														
Rights of Way	13	7	2	0	0	2	0	0	0	0	0	0	0	0
Structures & Improvements	23	13	4	0	1	5	0	0	0	0	1	0	0	1
Mains	40	2,618	776	0	0	776	0	0	0	0	162	0	0	162
Direct -Minot AFB Distribution System	Direct	14	0	0	0	0	0	0	0	0	0	0	0	0
Heskett Pipeline - $461	Direct													
Demand Related 75%	2	346	102	0	0	102	0	0	0	0	21	0	0	21
Customer Related 25%	8	115	0	0	5	5	0	0	0	0	0	0	0	0
Meas. & Reg. Equip. - General	18	47	13	0	0	13	0	0	0	0	3	0	0	3
Meas. & Reg. Equip. - City Gate	19	134	39	0	0	39	1	0	0	1	8	0	0	8
Services	17	2,983	0	0	189	189	0	0	0	0	0	0	15	15
Direct -Minot AFB Distribution System	Direct	6	0	0	0	0	0	0	0	0	0	0	0	0
Meters	5	1,078	0	0	273	273	0	0	2	2	0	0	32	32
Direct -Minot AFB Distribution System	Direct	2	0	0	0	0	0	0	0	0	0	0	0	0
Service Regulators	20	66	0	0	17	17	0	0	0	0	0	0	2	2
Ind. Meas. & Reg. Station Equipment	21	29	3	0	0	3	2	0	1	3	8	0	2	10
Cathodic Protection & Other Equipment	13	28	8	0	0	8	0	0	0	0	2	0	0	2
Total Distribution Plant		7,486	947	0	485	1,432	3	0	3	6	205	0	51	256

Montana-Dakota Utilities Co.
ND PSC Case No. PU-17-295

Cost-of-Service Study Using Basic Customer Methodology

	Allocation Factor	Total North Dakota	Large Interruptible Demand	Large Interruptible Energy	Large Interruptible Customer	Total Large Interruptible	Minot Air Force Base Distribution Demand	Minot Air Force Base Distribution Energy	Minot Air Force Base Distribution Customer	Total Minot Air Force
Maintenance										
Structures & Improvements	13	10	0	0	0	0	0	0	0	0
Mains	13	371	14	0	0	14	0	0	0	0
Measuring Stations - General	18	118	9	0	2	11	0	0	0	0
Measuring Stations - Industrial	21	50	8	0	2	10	0	0	0	0
Measuring Stations - City Gate	19	30	1	0	0	1	0	0	0	0
Services	5	250	0	0	1	1	0	0	0	0
Meters & House Regulators	16	323	0	0	1	1	0	0	0	0
Other Equipment	28	433	12	0	2	14	0	0	0	0
Supervision & Engineering	28	367	10	0	2	12	0	0	0	0
Direct -Minot AFB Distribution System	Direct	55	0	0	0	0	55	0	0	55
Total Maintenance Expense		2,007	54	0	10	64	55	0	0	55
Total Distribution Expenses		9,524	242	7	33	282	133	0	0	133
Customer Accounts	4	95	0	0	0	0	0	0	0	0
Meter Reading	5	232	0	0	1	1	0	0	0	0
Customer Records & Collection	4	2,206	0	0	0	0	0	0	0	0
Uncollectible Accounts	6	283	0	0	0	0	0	0	0	0
Miscellaneous Customer Accounts	4	125	0	0	0	0	0	0	0	0
Customer Service & Information	4	254	0	0	0	0	0	0	0	0
Sales Expenses	4	94	0	0	0	0	0	0	0	0
Administration & General Expenses	30	8,347	212	6	29	247	117	0	0	117
Total Gas O&M Expenses		92,445	454	13	63	530	250	0	0	250
O&M Excl. Cost of Gas and A&G		13,185	242	7	34	283	133	0	0	133
O&M Excl. Cost of Gas		21,532	454	13	63	530	250	0	0	250
Depreciation Expense										
Production Plant	3	0	0	0	0	0	0	0	0	0
Distribution Plant										
Rights of Way	13	7	0	0	0	0	0	0	0	0
Structures & Improvements	23	13	1	0	0	1	0	0	0	0
Mains	40	2,618	55	0	0	55	0	0	0	0
Direct -Minot AFB Distribution System	Direct	14	0	0	0	0	14	0	0	14
Heskett Pipeline - $461	Direct									
Demand Related 75%	2	346	7	0	0	7	0	0	0	0
Customer Related 25%	8	115	0	0	0	0	0	0	0	0
Meas. & Reg. Equip. - General	18	47	4	0	1	5	0	0	0	0
Meas. & Reg. Equip. - City Gate	19	134	5	0	0	5	0	0	0	0
Services	17	2,983	0	0	1	1	0	0	0	0
Direct -Minot AFB Distribution System	Direct	6	0	0	0	0	0	0	6	6
Meters	5	1,078	0	0	3	3	0	0	0	0
Direct -Minot AFB Distribution System	Direct	2	0	0	0	0	0	0	2	2
Service Regulators	20	66	0	0	0	0	0	0	0	0
Ind. Meas. & Reg. Station Equipment	21	29	5	0	2	7	0	0	0	0
Cathodic Protection & Other Equipment	13	28	1	0	0	1	0	0	0	0
Total Distribution Plant		7,486	78	0	7	85	14	0	8	22

Cost-of-Service Study Using Basic Customer Methodology

	Allocation Factor	Total North Dakota	Residential Demand	Residential Energy	Residential Customer	Total Residential	Firm General-Meter < 500 cubic feet Demand	Firm General-Meter < 500 cubic feet Energy	Firm General-Meter < 500 cubic feet Customer	Total Small Firm General
General Plant	38	160	47	0	48	95	12	0	7	19
Direct -Minot AFB Distribution System	Direct	5	0	0	0	0	0	0	0	0
Amort. of Intangible Plant - General	15	226	63	0	68	131	16	0	10	26
Direct	Direct	56	0	0	0	0	0	0	0	0
Common Plant	15	354	99	0	107	206	25	0	16	41
Intangible Plant - Common (Excluding CC&B)	15	265	73	0	80	153	19	0	12	31
Intangible Plant - Common (CC&B)	4	625	0	0	538	538	0	0	60	60
Amortization of Gain	15	26	6	0	9	15	2	0	1	3
Acquisition Adjustment	15	3	0	0	1	1	0	0	0	0
Total Depreciation Expense		9,206	1,873	0	4,071	5,944	471	0	589	1,060
Taxes Other Than Income										
Ad Valorem Taxes-Production	3	0	0	0	0	0	0	0	0	0
Ad Valorem Taxes-Other	15	1,180	326	0	356	682	83	0	54	137
Other Taxes - Payroll, Franchise, Other	31	860	161	9	346	516	41	2	46	89
Other Taxes - Minot AFB Distribution- Direct	Direct	0	0	0	0	0	0	0	0	0
Other Taxes - Revenue	26	0	0	0	0	0	0	0	0	0
Total Taxes Other Than Income Taxes		2,040	487	9	702	1,198	124	2	100	226
Total Operating Expense		103,691	18,261	23,821	13,466	55,548	4,593	5,255	1,851	11,699
Interest Expense/AFUDC Equity Add Back	36	3,214	987	0	834	1,821	248	0	115	363
Direct -Minot AFB Distribution System	Direct	0	0	0	0	0	0	0	0	0
Taxable Income		5,232	(6,366)	(221)	9,227	2,640	(1,597)	(41)	2,265	627
Income Taxes	37.8015%	1,979	(2,406)	(84)	3,488	998	(604)	(15)	856	237
Full Normalization	24	(102)	(31)	0	(26)	(57)	(8)	0	(4)	(12)
Total Income Taxes		1,877	(2,437)	(84)	3,462	941	(612)	(15)	852	225
Total Operating Expense		105,568	15,824	23,737	16,928	56,489	3,981	5,240	2,703	11,924
Operating Income:		6,569	(2,942)	(137)	6,599	3,520	(737)	(26)	1,528	765

Montana-Dakota Utilities Co.
ND PSC Case No. PU-17-295

Cost-of-Service Study Using Basic Customer Methodology

	Allocation Factor	Total North Dakota	Firm General > 500 cubic feet Demand	Energy	Customer	Total Large Firm General	Air Force Delivery Demand	Energy	Customer	Total Air Force Delivery	Small Interruptible Demand	Energy	Customer	Total Small Interruptible
General Plant	38	160	28	0	9	37	0	0	0	0	6	0	1	7
Direct -Minot AFB Distribution System	Direct	5	0	0	0	0	0	0	0	0	0	0	0	0
Amort. of Intangible Plant - General	15	226	38	0	14	52	0	0	0	0	8	0	2	10
Direct	Direct	56	0	0	0	0	0	0	0	0	0	0	0	0
Common Plant	15	354	59	0	22	81	0	0	0	0	13	0	3	16
Intangible Plant - Common (Excluding CC&B)	15	265	44	0	17	61	0	0	0	0	10	0	2	12
Intangible Plant - Common (CC&B)	4	625	0	0	26	26	0	0	0	0	0	0	1	1
Amortization of Gain	15	26	4	0	2	6	0	0	0	0	1	0	0	1
Acquisition Adjustment	15	3	1	0	0	1	1	0	0	1	0	0	0	0
Total Depreciation Expense		9,206	1,121	0	575	1,696	4	0	3	7	243	0	60	303
Taxes Other Than Income														
Ad Valorem Taxes-Production	3	0	0	0	0	0	0	0	0	0	0	0	0	0
Ad Valorem Taxes-Other	15	1,180	197	0	75	272	1	0	1	2	43	0	8	51
Other Taxes - Payroll, Franchise, Other	31	860	97	6	77	180	2	0	1	3	28	1	11	40
Other Taxes - Minot AFB Distribution- Direct	Direct	0	0	0	0	0	0	0	0	0	0	0	0	0
Other Taxes - Revenue	26	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Taxes Other Than Income Taxes		2,040	294	6	152	452	3	0	2	5	71	1	19	91
Total Operating Expense		103,691	10,919	17,185	2,652	30,756	212	1,328	31	1,571	1,198	1,525	350	3,073
Interest Expense/AFUDC Equity Add Back	36	3,214	591	0	172	763	2	0	1	3	127	0	19	146
Direct -Minot AFB Distribution System	Direct	0	0	0	0	0	0	0	0	0	0	0	0	0
Taxable Income		5,232	(3,821)	(158)	4,898	919	(48)	(9)	88	31	(996)	(17)	1,338	325
Income Taxes	37.8015%	1,979	(1,444)	(60)	1,852	348	(18)	(3)	33	12	(377)	(6)	506	123
Full Normalization	24	(102)	(19)	0	(5)	(24)	0	0	0	0	(4)	0	(1)	(5)
Total Income Taxes		1,877	(1,463)	(60)	1,847	324	(18)	(3)	33	12	(381)	(6)	505	118
Total Operating Expense		105,568	9,456	17,125	4,499	31,080	194	1,325	64	1,583	817	1,519	855	3,191
Operating Income:		6,569	(1,767)	(98)	3,223	1,358	(28)	(6)	56	22	(488)	(11)	852	353

Montana-Dakota Utilities Co.
ND PSC Case No. PU-17-295

Cost-of-Service Study Using Basic Customer Methodology

	Allocation Factor	Total North Dakota	Large Interruptible Demand	Large Interruptible Energy	Large Interruptible Customer	Total Large Interruptible	Minot Air Force Base Distribution Demand	Minot Air Force Base Distribution Energy	Minot Air Force Base Distribution Customer	Total Minot Air Force
General Plant	38	160	2	0	0	2	0	0	0	0
Direct -Minot AFB Distribution System	Direct	5	0	0	0	0	4	0	1	5
Amort. of Intangible Plant - General	15	226	5	0	0	5	1	0	1	2
Direct	Direct	56	42	0	14	56	0	0	0	0
Common Plant	15	354	8	0	0	8	1	0	1	2
Intangible Plant - Common (Excluding CC&B)	15	265	6	0	0	6	1	0	1	2
Intangible Plant - Common (CC&B)	4	625	0	0	0	0	0	0	0	0
Amortization of Gain	15	26	1	0	0	1	0	0	0	0
Acquisition Adjustment	15	3	0	0	0	0	0	0	0	0
Total Depreciation Expense		9,206	142	0	21	163	21	0	12	33
Taxes Other Than Income										
Ad Valorem Taxes-Production	3	0	0	0	0	0	0	0	0	0
Ad Valorem Taxes-Other	15	1,180	27	0	1	28	5	0	3	8
Other Taxes - Payroll, Franchise, Other	31	860	18	1	3	22	10	0	0	10
Other Taxes - Minot AFB Distribution- Direct	Direct	0	0	0	0	0	0	0	0	0
Other Taxes - Revenue	26	0	0	0	0	0	0	0	0	0
Total Taxes Other Than Income Taxes		2,040	45	1	4	50	15	0	3	18
Total Operating Expense		103,691	641	14	88	743	286	0	15	301
Interest Expense/AFUDC Equity Add Back	36	3,214	108	0	10	118	0	0	0	0
Direct -Minot AFB Distribution System	Direct	0	0	0	0	0	0	0	0	0
Taxable Income		5,232	(691)	(14)	1,233	528	(280)	0	442	162
Income Taxes	37.8015%	1,979	(261)	(5)	466	200	(106)	0	167	61
Full Normalization	24	(102)	(3)	0	0	(3)	(1)	0	0	(1)
Total Income Taxes		1,877	(264)	(5)	466	197	(107)	0	167	60
Total Operating Expense		105,568	377	9	554	940	179	0	182	361
Operating Income:		6,569	(319)	(9)	777	449	(173)	0	275	102

Montana-Dakota Utilities Co.
ND PSC Case No. PU-17-295

Cost-of-Service Study Using Basic Customer Methodology

		Total	Residential			Small Firm General		
		North Dakota	Demand	Energy	Customer	Demand	Energy	Customer
		23,351,305	0	8,826,214	0	0	2,036,838	0
1	Dk Throughput Projected	100.000000%	0.000000%	37.797520%	0.000000%	0.000000%	8.722587%	0.000000%
		192,668	95,561	0	0	24,062	0	0
2	Peak Design Day @ Distribution	100.000000%	49.598792%	0.000000%	0.000000%	12.488841%	0.000000%	0.000000%
		17,924,849	0	8,826,214	0	0	2,036,838	0
3	Dk Sales Projected	100.000000%	0.000000%	49.240102%	0.000000%	0.000000%	11.363209%	0.000000%
		112,516	0	0	96,792	0	0	10,850
4	Average Customers	100.000000%	0.000000%	0.000000%	86.025099%	0.000000%	0.000000%	9.643073%
		154,248	0	0	96,792	0	0	13,020
5	Total Weighted Customers	100.000000%	0.000000%	0.000000%	62.750894%	0.000000%	0.000000%	8.440952%
		112,352	0	0	96,792	0	0	10,850
6	Average Res. & Firm General Cust.	100.000000%	0.000000%	0.000000%	86.150669%	0.000000%	0.000000%	9.657149%
		112,512	0	0	96,792	0	0	10,850
8	Average Customers @ Distribution	100.000000%	0.000000%	0.000000%	86.028157%	0.000000%	0.000000%	9.643416%
	Total Weighted Customers Excluding	154,172	0	0	96,792	0	0	13,020
9	Large IT - Transmission Customers	100.000000%	0.000000%	0.000000%	62.781829%	0.000000%	0.000000%	8.445113%
		50,826	0	21,374	0	0	13,787	0
10	Residential & Firm General Propane Sales	100.000000%	0.000000%	42.053280%	0.000000%	0.000000%	27.125880%	0.000000%
		102,475	49,892	0	0	12,563	0	0
13	Distribution Mains (000's) excluding Heskett & AF Dist	99.999998%	48.686995%	0.000000%	0.000000%	12.259576%	0.000000%	0.000000%
		198,650	55,325	0	59,850	13,931	0	9,009
15	Distribution Plant (000's) excluding Heskett	100.000000%	27.850536%	0.000000%	30.128415%	7.012848%	0.000000%	4.535119%
		36,097	0	0	22,662	0	0	3,048
16	Meters & Regulators (000's) Excl AF Distribution	100.000000%	0.000000%	0.000000%	62.780840%	0.000000%	0.000000%	8.443915%
		120,124	0	0	96,792	0	0	15,082
17	Weighted Services	100.000000%	0.000000%	0.000000%	80.576737%	0.000000%	0.000000%	12.555359%
		1,962	869	0	0	219	0	0
18	Meas. & Reg. Sta. Eqpt.- General (000's)	99.999998%	44.291538%	0.000000%	0.000000%	11.162080%	0.000000%	0.000000%
		5,360	2,575	0	0	648	0	0
19	Meas. & Reg. Eqpt.- City Gate (000's)	99.999999%	48.043912%	0.000000%	0.000000%	12.090274%	0.000000%	0.000000%
		4,494	0	0	2,812	0	0	378
20	Service Regulators (000's)	100.000000%	0.000000%	0.000000%	62.572319%	0.000000%	0.000000%	8.411215%
		969	187	0	0	47	0	0
21	Ind. Meas. & Reg. Sta. Eqpt. (000's)	99.999999%	19.298246%	0.000000%	0.000001%	4.850361%	0.000000%	0.000000%
		149,285	49,892	0	37,188	12,563	0	5,961
22	Mains & Services (000's) Excl AF Distribution	99.999999%	33.420638%	0.000000%	24.910741%	8.415447%	0.000000%	3.993033%
		504	210	0	0	53	0	0
23	Structures and Improvements	100.000002%	41.666668%	0.000000%	0.000000%	10.515873%	0.000000%	0.000000%
		169,080	51,481	0	43,385	12,961	0	6,017
24	Net Gas Plant in Service (000's)	100.000000%	30.447775%	0.000000%	25.659500%	7.665617%	0.000000%	3.558677%
		268,555	73,862	0	83,274	18,599	0	12,040
25	Total Gas Plant in Service (000's)	99.999999%	27.503524%	0.000000%	31.008209%	6.925591%	0.000000%	4.483258%
		108,609	11,841	23,597	22,763	2,981	5,213	4,140
26	Projected Operating Revenue (000's)	100.000000%	10.902411%	21.726561%	20.958668%	2.744708%	4.799786%	3.811839%
		3,811	882	8	1,304	221	2	190

Montana-Dakota Utilities Co.
ND PSC Case No. PU-17-295

Cost-of-Service Study Using Basic Customer Methodology

		Total	Large Firm General			Air Force Delivery		
		North Dakota	Demand	Energy	Customer	Demand	Energy	Customer
		23,351,305	0	5,998,825	0	0	490,100	0
1	Dk Throughput Projected	100.000000%	0.000000%	25.689464%	0.000000%	0.000000%	2.098812%	0.000000%
		192,668	57,033	0	0	0	0	0
2	Peak Design Day @ Distribution	100.000000%	29.601698%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
		17,924,849	0	5,998,825	0	0	490,100	0
3	Dk Sales Projected	100.000000%	0.000000%	33.466530%	0.000000%	0.000000%	2.734193%	0.000000%
		112,516	0	0	4,710	0	0	3
4	Average Customers	100.000000%	0.000000%	0.000000%	4.186071%	0.000000%	0.000000%	0.002666%
		154,248	0	0	39,093	0	0	237
5	Total Weighted Customers	100.000000%	0.000000%	0.000000%	25.344251%	0.000000%	0.000000%	0.153649%
		112,352	0	0	4,710	0	0	0
6	Average Res. & Firm General Cust.	100.000000%	0.000000%	0.000000%	4.192182%	0.000000%	0.000000%	0.000000%
		112,512	0	0	4,710	0	0	0
8	Average Customers @ Distribution	100.000000%	0.000000%	0.000000%	4.186220%	0.000000%	0.000000%	0.000000%
	Total Weighted Customers Excluding	154,172	0	0	39,093	0	0	237
9	Large IT - Transmission Customers	100.000000%	0.000000%	0.000000%	25.356744%	0.000000%	0.000000%	0.153724%
		50,826	0	15,665	0	0	0	0
10	Residential & Firm General Propane Sales	100.000000%	0.000000%	30.820840%	0.000000%	0.000000%	0.000000%	0.000000%
		102,475	29,846	0	0	0	0	0
13	Distribution Mains (000's) excluding Heskett & AF Dist	99.999998%	29.125152%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
		198,650	33,150	0	12,591	120	0	96
15	Distribution Plant (000's) excluding Heskett	100.000000%	16.687668%	0.000000%	6.338294%	0.060287%	0.000000%	0.048286%
		36,097	0	0	9,153	0	0	56
16	Meters & Regulators (000's) Excl AF Distribution	100.000000%	0.000000%	0.000000%	25.356678%	0.000000%	0.000000%	0.155138%
		120,124	0	0	7,630	0	0	0
17	Weighted Services	100.000000%	0.000000%	0.000000%	6.351770%	0.000000%	0.000000%	0.000000%
		1,962	554	0	11	0	0	0
18	Meas. & Reg. Sta. Eqpt.- General (000's)	99.999998%	28.236493%	0.000000%	0.560652%	0.000000%	0.000000%	0.000000%
		5,360	1,540	0	0	54	0	18
19	Meas. & Reg. Eqpt.- City Gate (000's)	99.999999%	28.733059%	0.000000%	0.000000%	1.003045%	0.000000%	0.334348%
		4,494	0	0	1,136	0	0	7
20	Service Regulators (000's)	100.000000%	0.000000%	0.000000%	25.278149%	0.000000%	0.000000%	0.155763%
		969	111	0	0	53	0	18
21	Ind. Meas. & Reg. Sta. Eqpt. (000's)	99.999999%	11.455108%	0.000000%	0.000000%	5.469556%	0.000000%	1.857585%
		149,285	29,846	0	3,420	0	0	0
22	Mains & Services (000's) Excl AF Distribution	99.999999%	19.992632%	0.000000%	2.290920%	0.000000%	0.000000%	0.000000%
		504	147	0	7	13	0	4
23	Structures and Improvements	100.000002%	29.166667%	0.000000%	1.388889%	2.579365%	0.000000%	0.793651%
		169,080	30,820	0	8,979	97	0	78
24	Net Gas Plant in Service (000's)	100.000000%	18.228092%	0.000000%	5.310514%	0.057227%	0.000000%	0.046085%
		268,555	44,229	0	15,435	133	0	111
25	Total Gas Plant in Service (000's)	99.999999%	16.469272%	0.000000%	5.747433%	0.049435%	0.000000%	0.041303%
		108,609	7,067	17,025	7,646	166	1,319	120
26	Projected Operating Revenue (000's)	100.000000%	6.506827%	15.675497%	7.039932%	0.152842%	1.214448%	0.110488%
		3,811	527	5	347	8	0	5

Montana-Dakota Utilities Co.
ND PSC Case No. PU-17-295

Cost-of-Service Study Using Basic Customer Methodology

		Total	Small Interruptible			Large Interruptible		
		North Dakota	Demand	Energy	Customer	Demand	Energy	Customer
1	Dk Throughput Projected	23,351,305 100.000000%	0 0.000000%	1,677,385 7.183260%	0 0.000000%	0 0.000000%	4,321,943 18.508357%	0 0.000000%
2	Peak Design Day @ Distribution	192,668 100.000000%	11,967 6.211203%	0 0.000000%	0 0.000000%	4,045 2.099466%	0 0.000000%	0 0.000000%
3	Dk Sales Projected	17,924,849 100.000000%	0 0.000000%	572,872 3.195966%	0 0.000000%	0 0.000000%	0 0.000000%	0 0.000000%
4	Average Customers	112,516 100.000000%	0 0.000000%	0 0.000000%	155 0.137758%	0 0.000000%	0 0.000000%	6 0.005333%
5	Total Weighted Customers	154,248 100.000000%	0 0.000000%	0 0.000000%	4,650 3.014626%	0 0.000000%	0 0.000000%	456 0.295628%
6	Average Res. & Firm General Cust.	112,352 100.000000%	0 0.000000%	0 0.000000%	0 0.000000%	0 0.000000%	0 0.000000%	0 0.000000%
8	Average Customers @ Distribution	112,512 100.000000%	0 0.000000%	0 0.000000%	155 0.137763%	0 0.000000%	0 0.000000%	5 0.004444%
9	Total Weighted Customers Excluding Large IT - Transmission Customers	154,172 100.000000%	0 0.000000%	0 0.000000%	4,650 3.016112%	0 0.000000%	0 0.000000%	380 0.246478%
10	Residential & Firm General Propane Sales	50,826 100.000000%	0 0.000000%	0 0.000000%	0 0.000000%	0 0.000000%	0 0.000000%	0 0.000000%
13	Distribution Mains (000's) excluding Heskett & AF Dist	102,475 99.999998%	6,248 6.097097%	0 0.000000%	0 0.000000%	3,926 3.831178%	0 0.000000%	0 0.000000%
15	Distribution Plant (000's) excluding Heskett	198,650 100.000000%	7,183 3.615913%	0 0.000000%	1,408 0.708785%	4,560 2.295624%	0 0.000000%	192 0.096527%
16	Meters & Regulators (000's) Excl AF Distribution	36,097 100.000000%	0 0.000000%	0 0.000000%	1,089 3.016871%	0 0.000000%	0 0.000000%	89 0.246558%
17	Weighted Services	120,124 100.000000%	0 0.000000%	0 0.000000%	593 0.493657%	0 0.000000%	0 0.000000%	23 0.019147%
18	Meas. & Reg. Sta. Eqpt.- General (000's)	1,962 99.999998%	117 5.963303%	0 0.000000%	3 0.152905%	151 7.696228%	0 0.000000%	38 1.936799%
19	Meas. & Reg. Eqpt.- City Gate (000's)	5,360 99.999999%	322 6.007821%	0 0.000000%	0 0.000000%	203 3.787540%	0 0.000000%	0 0.000000%
20	Service Regulators (000's)	4,494 100.000000%	0 0.000000%	0 0.000000%	135 3.004005%	0 0.000000%	0 0.000000%	11 0.244771%
21	Ind. Meas. & Reg. Sta. Eqpt. (000's)	969 99.999999%	271 27.966976%	0 0.000000%	83 8.565531%	151 15.583075%	0 0.000000%	48 4.953560%
22	Mains & Services (000's) Excl AF Distribution	149,285 99.999999%	6,248 4.185283%	0 0.000000%	233 0.156077%	3,926 2.629869%	0 0.000000%	8 0.005359%
23	Structures and Improvements	504 100.000002%	26 5.158730%	0 0.000000%	0 0.000000%	35 6.994048%	0 0.000000%	9 1.736111%
24	Net Gas Plant in Service (000's)	169,080 100.000000%	6,628 3.920045%	0 0.000000%	1,013 0.599126%	5,654 3.344133%	0 0.000000%	545 0.322185%
25	Total Gas Plant in Service (000's)	268,555 99.999999%	9,532 3.549370%	0 0.000000%	1,672 0.622592%	7,243 2.697123%	0 0.000000%	767 0.285510%
26	Projected Operating Revenue (000's)	108,609 100.000000%	195 0.179543%	1,508 1.388467%	1,700 1.565248%	0 0.000000%	0 0.000000%	1,328 1.222735%
		3,811	147	1	52	96	4	12

Montana-Dakota Utilities Co.
ND PSC Case No. PU-17-295

Cost-of-Service Study Using Basic Customer Methodology

		Total	Minot Air Force Base Distribution		
		North Dakota	Demand	Energy	Customer
		23,351,305	0	0	0
1	Dk Throughput Projected	100.000000%	0.000000%	0.000000%	0.000000%
		192,668	0	0	0
2	Peak Design Day @ Distribution	100.000000%	0.000000%	0.000000%	0.000000%
		17,924,849	0	0	0
3	Dk Sales Projected	100.000000%	0.000000%	0.000000%	0.000000%
		112,516	0	0	0
4	Average Customers	100.000000%	0.000000%	0.000000%	0.000000%
		154,248	0	0	0
5	Total Weighted Customers	100.000000%	0.000000%	0.000000%	0.000000%
		112,352	0	0	0
6	Average Res. & Firm General Cust.	100.000000%	0.000000%	0.000000%	0.000000%
		112,512	0	0	0
8	Average Customers @ Distribution	100.000000%	0.000000%	0.000000%	0.000000%
	Total Weighted Customers Excluding	154,172	0	0	0
9	Large IT - Transmission Customers	100.000000%	0.000000%	0.000000%	0.000000%
		50,826	0	0	0
10	Residential & Firm General Propane Sales	100.000000%	0.000000%	0.000000%	0.000000%
		102,475	0	0	0
13	Distribution Mains (000's) excluding Heskett & AF Dist	99.999998%	0.000000%	0.000000%	0.000000%
		198,650	759	0	476
15	Distribution Plant (000's) excluding Heskett	100.000000%	0.382080%	0.000000%	0.239618%
		36,097	0	0	0
16	Meters & Regulators (000's) Excl AF Distribution	100.000000%	0.000000%	0.000000%	0.000000%
		120,124	0	0	4
17	Weighted Services	100.000000%	0.000000%	0.000000%	0.003330%
		1,962	0	0	0
18	Meas. & Reg. Sta. Eqpt.- General (000's)	99.999998%	0.000000%	0.000000%	0.000000%
		5,360	0	0	0
19	Meas. & Reg. Eqpt.- City Gate (000's)	99.999999%	0.000000%	0.000000%	0.000000%
		4,494	0	0	15
20	Service Regulators (000's)	100.000000%	0.000000%	0.000000%	0.333778%
		969	0	0	0
21	Ind. Meas. & Reg. Sta. Eqpt. (000's)	99.999999%	0.000000%	0.000000%	0.000000%
		149,285	0	0	0
22	Mains & Services (000's) Excl AF Distribution	99.999999%	0.000000%	0.000000%	0.000000%
		504	0	0	0
23	Structures and Improvements	100.000002%	0.000000%	0.000000%	0.000000%
		169,080	924	0	498
24	Net Gas Plant in Service (000's)	100.000000%	0.546488%	0.000000%	0.294536%
		268,555	1,057	0	601
25	Total Gas Plant in Service (000's)	99.999999%	0.393588%	0.000000%	0.223791%
		108,609	0	0	0
26	Projected Operating Revenue (000's)	100.000000%	0.000000%	0.000000%	0.000000%
		3,811	0	0	0

Cost-of-Service Study Using Basic Customer Methodology

		Total	Residential			Small Firm General		
		North Dakota	Demand	Energy	Customer	Demand	Energy	Cu
27	All Other Dist. Operation Exp. (000's) Excl AF Dist	99.999999%	23.143532%	0.209919%	34.216740%	5.799003%	0.052480%	4.985568%
		1,152	263	0	359	65	0	48
28	All Other Dist. Maintenance Exp. (000's) Excl AF Dist	99.999999%	22.829861%	0.000000%	31.163194%	5.642361%	0.000000%	4.166667%
		9,524	2,164	16	3,153	542	4	452
30	Distribution O&M (000's)	100.000001%	22.721546%	0.167997%	33.105837%	5.690886%	0.041999%	4.745905%
		21,532	4,060	214	8,693	1,017	50	1,162
31	O&M Excl. Cost of Gas (000's)	100.000002%	18.855657%	0.993870%	40.372467%	4.723203%	0.232213%	5.396619%
		167,658	51,481	0	43,385	12,961	0	6,017
36	Net Gas Plant in Service (000's) Excluding Minot AFB	99.999997%	30.706020%	0.000000%	25.877130%	7.730633%	0.000000%	3.588860%
		121,836	0	0	96,792	0	0	15,516
37	Weighted Services Excluding Transmission Level Customers	100.000000%	0.000000%	0.000000%	79.444499%	0.000000%	0.000000%	12.735152%
		216,759	63,576	0	64,620	16,009	0	9,544
38	Distribution Plant Less Direct Assignment (000's)	100.000000%	29.330270%	0.000000%	29.811910%	7.385622%	0.000000%	4.403047%
		100,661	49,892	0	0	12,563	0	0
40	Distribution Mains (000) Excluding Transmission Level Customer-Direct Assigned	99.999998%	49.564378%	0.000000%	0.000000%	12.480504%	0.000000%	0.000000%

		Total	Large Firm General			Air Force Delivery		
		North Dakota	Demand	Energy	Customer	Demand	Energy	Customer
27	All Other Dist. Operation Exp. (000's) Excl AF Dist	99.999999%	13.828391%	0.131199%	9.105222%	0.209919%	0.000000%	0.131199%
		1,152	159	0	146	3	0	2
28	All Other Dist. Maintenance Exp. (000's) Excl AF Dist	99.999999%	13.802083%	0.000000%	12.673611%	0.260417%	0.000000%	0.173611%
		9,524	1,299	10	926	21	0	14
30	Distribution O&M (000's)	100.000001%	13.639227%	0.104998%	9.722806%	0.220496%	0.000000%	0.146997%
		21,532	2,437	143	1,925	39	10	26
31	O&M Excl. Cost of Gas (000's)	100.000002%	11.318038%	0.664128%	8.940182%	0.181126%	0.046443%	0.120751%
		167,658	30,820	0	8,979	97	0	78
36	Net Gas Plant in Service (000's) Excluding Minot AFB	99.999997%	18.382695%	0.000000%	5.355555%	0.057713%	0.000000%	0.046476%
		121,836	0	0	8,902	0	0	0
37	Weighted Services Excluding Transmission Level Customers	100.000000%	0.000000%	0.000000%	7.306543%	0.000000%	0.000000%	0.000000%
		216,759	37,950	0	12,805	0	0	56
38	Distribution Plant Less Direct Assignment (000's)	100.000000%	17.507924%	0.000000%	5.907483%	0.000000%	0.000000%	0.025835%
		100,661	29,846	0	0	0	0	0
40	Distribution Mains (000) Excluding Transmission Level Customer-Direct Assigned	99.999998%	29.650013%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%

Montana-Dakota Utilities Co.
ND PSC Case No. PU-17-295

Cost-of-Service Study Using Basic Customer Methodology

		Total	Small Interruptible			Large Interruptible		
		North Dakota	Demand	Energy	Customer	Demand	Energy	Customer
27	All Other Dist. Operation Exp. (000's) Excl AF Dist	99.999999%	3.857255%	0.026240%	1.364471%	2.519024%	0.104959%	0.314878%
		1,152	47	0	22	32	0	6
28	All Other Dist. Maintenance Exp. (000's) Excl AF Dist	99.999999%	4.079861%	0.000000%	1.909722%	2.777778%	0.000000%	0.520833%
		9,524	367	2	139	242	7	33
30	Distribution O&M (000's)	100.000001%	3.853423%	0.021000%	1.459471%	2.540949%	0.073499%	0.346493%
		21,532	689	16	271	454	13	63
31	O&M Excl. Cost of Gas (000's)	100.000002%	3.199889%	0.074308%	1.258592%	2.108490%	0.060375%	0.292588%
		167,658	6,628	0	1,013	5,654	0	545
36	Net Gas Plant in Service (000's) Excluding Minot AFB	99.999997%	3.953293%	0.000000%	0.604207%	3.372497%	0.000000%	0.324918%
		121,836	0	0	606	0	0	20
37	Weighted Services Excluding Transmission Level Customers	100.000000%	0.000000%	0.000000%	0.497390%	0.000000%	0.000000%	0.016416%
		216,759	7,960	0	1,330	2,812	0	97
38	Distribution Plant Less Direct Assignment (000's)	100.000000%	3.672281%	0.000000%	0.613585%	1.297293%	0.000000%	0.044750%
		100,661	6,248	0	0	2,112	0	0
40	Distribution Mains (000) Excluding Transmission Level Customer-Direct Assigned	99.999998%	6.206972%	0.000000%	0.000000%	2.098131%	0.000000%	0.000000%

Montana-Dakota Utilities Co.
ND PSC Case No. PU-17-295

Cost-of-Service Study Using Basic Customer Methodology

		Total	Minot Air Force Base Distribution		
		North Dakota	Demand	Energy	Customer
27	All Other Dist. Operation Exp. (000's) Excl AF Dist	99.999999%	0.000000%	0.000000%	0.000000%
		1,152	0	0	0
28	All Other Dist. Maintenance Exp. (000's) Excl AF Dist	99.999999%	0.000000%	0.000000%	0.000000%
		9,524	133	0	0
30	Distribution O&M (000's)	100.000001%	1.396472%	0.000000%	0.000000%
		21,532	250	0	0
31	O&M Excl. Cost of Gas (000's)	100.000002%	1.161063%	0.000000%	0.000000%
		167,658	0	0	0
36	Net Gas Plant in Service (000's) Excluding Minot AFB	99.999997%	0.000000%	0.000000%	0.000000%
		121,836	0	0	0
37	Weighted Services Excluding Transmission Level Customers	100.000000%	0.000000%	0.000000%	0.000000%
		216,759	0	0	0
38	Distribution Plant Less Direct Assignment (000's)	100.000000%	0.000000%	0.000000%	0.000000%
		100,661	0	0	0
40	Distribution Mains (000) Excluding Transmission Level Customer-Direct Assigned	99.999998%	0.000000%	0.000000%	0.000000%

Montana-Dakota Utilities Co.
ND PSC Case No. PU-17-295

Cost-of-Service Study Using Basic Customer Methodology

Rate	Customer Class	Factor No. 1 Projected DK Throughput	Factor No. 2 Design Day Peak	Factor No. 3 DK Sales Projected	Factor No. 4 Average Customers	Factor No. 5 Total Weighted Customers	Factor No. 6 Average Res & Firm Gen Customers	Factor No. 8 Average Customers at Distribution	Factor No. 9 Total Weighted Customers Ex. LG IT Trans.	Factor No. 17 Weighted Services Distribution
60	Residential Gas Service	8,826,214	95,561	8,826,214	96,792	96,792	96,792	96,792	96,792	96,792
64	Minot Air Force Base	415,925	0	415,925	1		0			4
64	Air Force-Distribution PAR Site	31,858	0	31,858	1					
64	Air Force-Distribution PAR Site	42,317	0	42,317	1					
		490,100	0	490,100	3	237	0	0	237	4
70	Firm General Service									
	Firm General-Small	2,036,838	24,062	2,036,838	10,850	13,020	10,850	10,850	13,020	15,082
	Firm General-Large	5,998,825	57,033	5,998,825	4,710	39,093	4,710	4,710	39,093	7,630
	Subtotal Firm	8,035,663	81,095	8,035,663	15,560	52,113	15,560	15,560	52,113	22,712
71	Small Interruptible Sales	572,872	4,665	572,872	92	2,760		92	2,760	352
81	Small Interruptible Transport	1,104,513	7,302		63	1,890		63	1,890	241
	Subtotal Small IT	1,677,385	11,967	572,872	155	4,650	0	155	4,650	593
85	Large Interruptible Sales	0	0	0	0	0		0	0	0
82	Large Interruptible Transport	4,321,943	4,045		6	456		5	380	23
	Subtotal Large IT	4,321,943	4,045	0	6	456	0	5	380	23
	Total North Dakota Gas	23,351,305	192,668	17,924,849	112,516	154,248	112,352	112,512	154,172	120,124

Montana-Dakota Utilities Co.
ND PSC Case No. PU-17-295

Exhibit ___ (SJR-5)
Page 1 of 28

Cost-of-Service Study Using Corrected Minimum-Size Analysis

	Total North Dakota	Residential Demand	Residential Energy	Residential Customer	Total Residential
Projected Rate Base	135,451	33,562	40	49,127	82,729
Operating Income for Proposed Return	10,216	2,532	3	3,706	6,241
Projected Operating Income	6,569	(2,322)	(137)	5,516	3,057
Increase in Operating Income	3,647	4,854	140	(1,810)	3,184
Related Taxes for Increase					
Federal Income	2,216	2,948	85	(1,100)	1,933
Total Increase in Revenue	5,863	7,802	225	(2,910)	5,117
Projected Revenue Before Increase	112,137	12,852	23,600	23,581	60,033
Total Cost of Service Required from Rates:	114,928	19,643	23,822	19,853	63,318
Less Projected Cost of Gas	70,913	11,841	23,598	0	35,439
Net Distribution Cost of Service	43,911	7,802	224	19,853	27,879
Return on Rate Base Before Increase	4.850%				3.695%
Projected Billing Units	112,516			96,792	
Bills	1,350,192			1,161,504	
Dk	23,351,305	8,826,214	8,826,214		
Unit Cost of Service					
Energy cost per Dk			$0.03		
Demand cost per Dk		$0.880			
Customer Cost Per Month				$17.09	
Cust and Demand cost per month				$23.81	

Montana-Dakota Utilities Co.
ND PSC Case No. PU-17-295

Cost-of-Service Study Using Corrected Minimum-Size Analysis

	Small Firm General			Total	Large Firm General			Total
	Demand	Energy	Customer	Small Firm General	Demand	Energy	Customer	Large Firm General
Projected Rate Base	9,279	26	6,573	15,878	20,679	29	7,776	28,484
Operating Income for Proposed Return	700	2	496	1,198	1,560	2	586	2,148
Projected Operating Income	(581)	(26)	1,408	801	(1,393)	(98)	3,174	1,683
Increase in Operating Income	1,281	28	(912)	397	2,953	100	(2,588)	465
Related Taxes for Increase								
Federal Income	779	17	(554)	242	1,795	61	(1,573)	283
Total Increase in Revenue	2,060	45	(1,466)	639	4,748	161	(4,161)	748
Projected Revenue Before Increase	3,235	5,214	4,238	12,687	7,671	17,027	7,725	32,423
Total Cost of Service Required from Rates:	5,041	5,258	2,674	12,973	11,815	17,186	3,485	32,486
Less Projected Cost of Gas	2,981	5,203	0	8,184	7,067	17,036	0	24,103
Net Distribution Cost of Service	2,060	55	2,674	4,789	4,748	150	3,485	8,383
Return on Rate Base Before Increase				5.045%				5.909%
Projected Billing Units			10,850				4,710	
Bills			130,200				56,520	
Dk	2,036,838	2,036,838			5,998,825	5,998,825		
Unit Cost of Service								
Energy cost per Dk		$0.03				$0.03		
Demand cost per Dk	$1.010				$0.790			
Customer Cost Per Month			$20.54				$61.66	
Cust and Demand cost per month								

Montana-Dakota Utilities Co.
ND PSC Case No. PU-17-295

Cost-of-Service Study Using Corrected Minimum-Size Analysis

	Air Force Delivery			Total	Small Interruptible			Total
	Demand	Energy	Customer	Air Force Delivery	Demand	Energy	Customer	Small Interruptible
Projected Rate Base	86	0	69	155	2,969	0	237	3,206
Operating Income for Proposed Return	6	0	5	11	224	0	18	242
Projected Operating Income	(28)	(6)	56	22	(413)	(11)	851	427
Increase in Operating Income	34	6	(51)	(11)	637	11	(833)	(185)
Related Taxes for Increase								
Federal Income	21	4	(31)	(6)	387	7	(506)	(112)
Total Increase in Revenue	55	10	(82)	(17)	1,024	18	(1,339)	(297)
Projected Revenue Before Increase	166	1,319	120	1,605	324	1,508	1,707	3,539
Total Cost of Service Required from Rates:	221	1,329	38	1,588	1,219	1,526	361	3,106
Less Projected Cost of Gas	166	1,318	0	1,484	195	1,508	0	1,703
Net Distribution Cost of Service	55	11	38	104	1,024	18	361	1,403
Return on Rate Base Before Increase				14.194%				13.319%
Projected Billing Units			3				155	
Bills			36				1,860	
Dk	490,100	490,100			1,677,385	1,677,385		
Unit Cost of Service								
Energy cost per Dk		$0.02				$0.01		
Demand cost per Dk	$0.110				$0.610			
Customer Cost Per Month			$1,055.56				$194.09	
Cust and Demand cost per month								

Montana-Dakota Utilities Co.
ND PSC Case No. PU-17-295

Cost-of-Service Study Using Corrected Minimum-Size Analysis

	Large Interruptible			Total	Minot Air Force Base Distribution			Total
	Demand	Energy	Customer	Large Interruptible	Demand	Energy	Customer	MAFB Distribution
Projected Rate Base	3,292	0	442	3,734	691	0	574	1,265
Operating Income for Proposed Return	248	0	33	281	52	0	43	95
Projected Operating Income	(278)	(9)	765	478	(174)	0	275	101
Increase in Operating Income	526	9	(732)	(197)	226	0	(232)	(6)
Related Taxes for Increase								
Federal Income	320	5	(445)	(120)	137	0	(141)	(4)
Total Increase in Revenue	846	14	(1,177)	(317)	363	0	(373)	(10)
Projected Revenue Before Increase	55	0	1,332	1,387	5	0	458	463
Total Cost of Service Required from Rates:	846	14	151	1,011	363	0	83	446
Less Projected Cost of Gas	0	0	0	0	0	0	0	0
Net Distribution Cost of Service	846	14	151	1,011	363	0	83	446
Return on Rate Base Before Increase				12.801%				7.984%
Projected Billing Units			6					0
Bills			72					12
Dk	4,321,943	4,321,943						
Unit Cost of Service								
Energy cost per Dk		$0.00						
Demand cost per Dk	$0.200							
Customer Cost Per Month			$2,097.22					$37,166.67
Cust and Demand cost per month								

Montana-Dakota Utilities Co.
ND PSC Case No. PU-17-295

Cost-of-Service Study Using Corrected Minimum-Size Analysis

	Allocation Factor	Total North Dakota	Residential Demand	Residential Energy	Residential Customer	Total Residential	Firm General-Meter < 500 cubic feet Demand	Firm General-Meter < 500 cubic feet Energy	Firm General-Meter < 500 cubic feet Customer	Total Small Firm General
Rate Base-Projected										
Gas Plant in Service										
Production Plant	3	0	0	0	0	0	0	0	0	0
Land	13	913	362	0	140	502	92	0	16	108
Rights of Way	13	498	197	0	76	273	50	0	9	59
Structures & Improvements	40	423	173	0	66	239	43	0	7	50
Direct	Direct	81	0	0	0	0	0	0	0	0
Mains - $103,231-Directly Assigned $2,639										
Demand Related 75%	2	82,324	40,833	0	0	40,833	10,281	0	0	10,281
Customer Related 25%	8	18,267	0	0	15,714	15,714	0	0	1,762	1,762
Directly Assigned Demand Related 75%	Direct	2,160	0	0	0	0	0	0	0	0
Directly Assigned Customer Related 25%	Direct	479	0	0	0	0	0	0	0	0
Heskett Pipeline - $22,181										
Demand Related 75%	2	16,636	8,251	0	0	8,251	2,078	0	0	2,078
Customer Related 25%	8	5,545	0	0	4,770	4,770	0	0	535	535
Meas. & Reg. Equip. - General	40	1,754	711	0	274	985	179	0	31	210
Direct	Direct	208	0	0	0	0	0	0	0	0
Meas. & Reg. Equip. - City Gate	13	5,288	2,107	0	811	2,918	531	0	91	622
Direct	Direct	72	0	0	0	0	0	0	0	0
Services	37	46,810	0	0	37,188	37,188	0	0	5,961	5,961
Direct	Direct	405	0	0	0	0	0	0	0	0
Meters	9	31,618	0	0	19,850	19,850	0	0	2,670	2,670
Direct	Direct	55	0	0	0	0	0	0	0	0
Service Regulators	9	4,479	0	0	2,812	2,812	0	0	378	378
Direct	Direct	15	0	0	0	0	0	0	0	0
Ind. Meas. & Reg. Station Equipment	40	376	153	0	59	212	38	0	7	45
Direct	Direct	593	0	0	0	0	0	0	0	0
Property on Customer Premise	13	115	45	0	18	63	12	0	2	14
Cathodic Protection & Other Equipment	40	1,712	696	0	267	963	175	0	30	205
Direct	Direct	4	0	0	0	0	0	0	0	0
Distribution Plant - includes Heskett		220,830	53,528	0	82,045	135,573	13,479	0	11,499	24,978
Distribution Plant Excluding Direct Assignments		216,758	53,528	0	82,045	135,573	13,479	0	11,499	24,978
General Plant	38	14,138	3,490	0	5,353	8,843	879	0	750	1,629
Direct	Direct	286	0	0	0	0	0	0	0	0
Intangible Plant - General	15	3,464	790	0	1,347	2,137	199	0	191	390
Direct	Direct	2,193								
Common Plant	15	13,249	3,021	0	5,155	8,176	760	0	731	1,491
Intangible Common (Excluding CC&B)	15	5,236	1,195	0	2,036	3,231	300	0	289	589
Intangible Common (CC&B)	4	9,061	0	0	7,796	7,796	0	0	874	874
Acquisition Adjustment	15	97	22	0	38	60	6	0	5	11
Total Gas Plant in Service including Heskett		268,554	62,046	0	103,770	165,817	15,623	0	14,339	29,962

Montana-Dakota Utilities Co.
ND PSC Case No. PU-17-295

Cost-of-Service Study Using Corrected Minimum-Size Analysis

	Allocation Factor	Total North Dakota	Firm General > 500 cubic feet: Demand	Energy	Customer	Total Large Firm General	Air Force Delivery: Demand	Energy	Customer	Total Air Force Delivery	Small Interruptible: Demand	Energy	Customer	Total Small Interruptible
Rate Base-Projected														
Gas Plant in Service														
Production Plant	3	0	0	0	0	0	0	0	0	0	0	0	0	0
Land	13	913	218	0	7	225	0	0	0	0	46	0	0	46
Rights of Way	13	498	119	0	4	123	0	0	0	0	25	0	0	25
Structures & Improvements	40	423	103	0	3	106	0	0	0	0	21	0	0	21
Direct	Direct	81	22	0	7	29	13	0	4	17	0	0	0	0
Mains - $103,231-Directly Assigned $2,639														
Demand Related 75%	2	82,324	24,369	0	0	24,369	0	0	0	0	5,113	0	0	5,113
Customer Related 25%	8	18,267	0	0	765	765	0	0	0	0	0	0	25	25
Directly Assigned Demand Related 75%	Direct	2,160	56	0	0	56	0	0	0	0	0	0	0	0
Directly Assigned Customer Related 25%	Direct	479	0	0	13	13	0	0	0	0	0	0	0	0
Heskett Pipeline - $22,181														
Demand Related 75%	2	16,636	4,925	0	0	4,925	0	0	0	0	1,033	0	0	1,033
Customer Related 25%	8	5,545	0	0	232	232	0	0	0	0	0	0	8	8
Meas. & Reg. Equip. - General	40	1,754	426	0	14	440	0	0	0	0	89	0	0	89
Direct	Direct	208	34	0	11	45	0	0	0	0	8	0	3	11
Meas. & Reg. Equip. - City Gate	13	5,288	1,260	0	40	1,300	0	0	0	0	264	0	1	265
Direct	Direct	72	0	0	0	0	54	0	18	72	0	0	0	0
Services	37	46,810	0	0	3,420	3,420	0	0	0	0	0	0	233	233
Direct	Direct	405	0	0	0	0	0	0	0	0	0	0	0	0
Meters	9	31,618	0	0	8,017	8,017	0	0	49	49	0	0	954	954
Direct	Direct	55	0	0	0	0	0	0	0	0	0	0	0	0
Service Regulators	9	4,479	0	0	1,136	1,136	0	0	7	7	0	0	135	135
Direct	Direct	15	0	0	0	0	0	0	0	0	0	0	0	0
Ind. Meas. & Reg. Station Equipment	40	376	91	0	3	94	0	0	0	0	19	0	0	19
Direct	Direct	593	0	0	0	0	53	0	18	71	248	0	83	331
Property on Customer Premise	13	115	27	0	1	28	0	0	0	0	6	0	0	6
Cathodic Protection & Other Equipment	40	1,712	415	0	13	428	0	0	0	0	87	0	0	87
Direct	Direct	4	0	0	0	0	0	0	0	0	0	0	0	0
Distribution Plant - includes Heskett		220,830	32,065	0	13,686	45,751	120	0	96	216	6,959	0	1,442	8,401
Distribution Plant Excluding Direct Assignments		216,758	31,953	0	13,655	45,608	0	0	56	56	6,703	0	1,356	8,059
General Plant	38	14,138	2,084	0	891	2,975	0	0	4	4	437	0	88	525
Direct	Direct	286	0	0	0	0	0	0	0	0	0	0	0	0
Intangible Plant - General	15	3,464	473	0	235	708	2	0	2	4	103	0	25	128
Direct	Direct	2,193												
Common Plant	15	13,249	1,810	0	897	2,707	8	0	6	14	395	0	96	491
Intangible Common (Excluding CC&B)	15	5,236	715	0	355	1,070	3	0	3	6	156	0	38	194
Intangible Common (CC&B)	4	9,061	0	0	379	379	0	0	0	0	0	0	12	12
Acquisition Adjustment	15	97	13	0	7	20	0	0	0	0	3	0	1	4
Total Gas Plant in Service including Heskett		268,554	37,160	0	16,450	53,610	133	0	111	244	8,053	0	1,702	9,755

Montana-Dakota Utilities Co.
ND PSC Case No. PU-17-295

Cost-of-Service Study Using Corrected Minimum-Size Analysis

	Allocation Factor	Total North Dakota	Large Interruptible Demand	Large Interruptible Energy	Large Interruptible Customer	Total Large Interruptible	Minot Air Force Base Distribution Demand	Minot Air Force Base Distribution Energy	Minot Air Force Base Distribution Customer	Total Minot Air Force
Rate Base-Projected										
Gas Plant in Service										
Production Plant	3	0	0	0	0	0	0	0	0	0
Land	13	913	29	0	3	32	0	0	0	0
Rights of Way	13	498	16	0	2	18	0	0	0	0
Structures & Improvements	40	423	7	0	0	7	0	0	0	0
Direct	Direct	81	26	0	9	35	0	0	0	0
Mains - $103,231-Directly Assigned $2,639										
Demand Related 75%	2	82,324	1,728	0	0	1,728	0	0	0	0
Customer Related 25%	8	18,267	0	0	1	1	0	0	0	0
Directly Assigned Demand Related 75%	Direct	2,160	1,485	0	0	1,485	619	0	0	619
Directly Assigned Customer Related 25%	Direct	479	0	0	329	329	0	0	137	137
Heskett Pipeline - $22,181										
Demand Related 75%	2	16,636	349	0	0	349	0	0	0	0
Customer Related 25%	8	5,545	0	0	0	0	0	0	0	0
Meas. & Reg. Equip. - General	40	1,754	30	0	0	30	0	0	0	0
Direct	Direct	208	114	0	38	152	0	0	0	0
Meas. & Reg. Equip. - City Gate	13	5,288	166	0	17	183	0	0	0	0
Direct	Direct	72	0	0	0	0	0	0	0	0
Services	37	46,810	0	0	8	8	0	0	0	0
Direct	Direct	405	0	0	0	0	0	0	405	405
Meters	9	31,618	0	0	78	78	0	0	0	0
Direct	Direct	55	0	0	0	0	0	0	55	55
Service Regulators	9	4,479	0	0	11	11	0	0	0	0
Direct	Direct	15	0	0	0	0	0	0	15	15
Ind. Meas. & Reg. Station Equipment	40	376	6	0	0	6	0	0	0	0
Direct	Direct	593	143	0	48	191	0	0	0	0
Property on Customer Premise	13	115	4	0	0	4	0	0	0	0
Cathodic Protection & Other Equipment	40	1,712	29	0	0	29	0	0	0	0
Direct	Direct	4	0	0	0	0	3	0	1	4
Distribution Plant - includes Heskett		220,830	4,132	0	544	4,676	622	0	613	1,235
Distribution Plant Excluding Direct Assignments		216,758	2,364	0	120	2,484	0	0	0	0
General Plant	38	14,138	154	0	8	162	0	0	0	0
Direct	Direct	286	0	0	0	0	214	0	72	286
Intangible Plant - General	15	3,464	66	0	9	75	11	0	11	22
Direct	Direct	2,193	1,645		548	2,193				
Common Plant	15	13,249	252	0	36	288	41	0	41	82
Intangible Common (Excluding CC&B)	15	5,236	100	0	14	114	16	0	16	32
Intangible Common (CC&B)	4	9,061	0	0	0	0	0	0	0	0
Acquisition Adjustment	15	97	2	0	0	2	0	0	0	0
Total Gas Plant in Service including Heskett		268,554	6,351	0	1,159	7,510	904	0	753	1,657

Montana-Dakota Utilities Co.
ND PSC Case No. PU-17-295

Cost-of-Service Study Using Corrected Minimum-Size Analysis

	Allocation Factor	Total North Dakota	Residential Demand	Residential Energy	Residential Customer	Total Residential	Firm General-Meter < 500 cubic feet Demand	Firm General-Meter < 500 cubic feet Energy	Firm General-Meter < 500 cubic feet Customer	Total Small Firm General
Less: Accumulated Depreciation										
Production Plant	3	0	0	0	0	0	0	0	0	0
Distribution Plant										
Rights of Way	13	79	32	0	12	44	8	0	1	9
Structures & Improvements	23	187	65	0	24	89	16	0	3	19
Mains	40	36,213	14,691	0	5,652	20,343	3,699	0	634	4,333
Direct	Direct	33	0	0	0	0	0	0	0	0
Heskett - $787										
Demand Related 75%	2	590	292	0	0	292	74	0	0	74
Customer Related 25%	8	197	0	0	170	170	0	0	19	19
Meas. & Reg. Equip. - General	18	660	240	0	92	332	60	0	10	70
Meas. & Reg. Equip. - City Gate	19	708	280	0	107	387	70	0	12	82
Services	37	32,686	0	0	25,967	25,967	0	0	4,163	4,163
Direct	Direct	35	0	0	0	0	0	0	0	0
Meters	5	11,577	0	0	7,265	7,265	0	0	977	977
Direct	Direct	12	0	0	0	0	0	0	0	0
Service Regulators	9	1,416	0	0	889	889	0	0	120	120
Direct	Direct	2	0	0	0	0	0	0	0	0
Ind. Meas. & Reg. Station Equipment	21	331	54	0	20	74	13	0	2	15
Property on Customer Premise	13	125	50	0	19	69	13	0	2	15
Cathodic Protection & Other Equipment	13	862	344	0	132	476	86	0	15	101
Distribution Plant		85,713	16,048	0	40,349	56,397	4,039	0	5,958	9,997
General Plant	38	1,497	371	0	567	938	93	0	79	172
Direct	Direct	102	0	0	0	0	0	0	0	0
Intangible Plant - General	15	888	204	0	345	549	51	0	49	100
Intangible Plant - General - Direct	Direct	554	0	0	0	0	0	0	0	0
Common Plant	15	4,165	950	0	1,620	2,570	239	0	230	469
Intangible Plant - Common	15	3,524	804	0	1,371	2,175	202	0	194	396
Intangible Plant - Common-CC&B	4	2,961	0	0	2,547	2,547	0	0	286	286
Acquisition Adjustment	15	71	16	0	28	44	4	0	4	8
Less: Total Accumulated Reserve for Depreciation		99,475	18,393	0	46,827	65,220	4,628	0	6,800	11,428
Net Gas Plant in Service including Heskett		169,079	43,653	0	56,943	100,597	10,995	0	7,539	18,534
Additions										
Materials & Supplies	15	2,070	473	0	805	1,278	119	0	114	233
Fuel Stocks	10	95	0	40	0	40	0	26	0	26
Prepayments	25	249	59	0	96	155	14	0	13	27
Loss on Sale of Employee Housing	24	775	198	0	263	461	50	0	35	85
Unamortized Loss on Debt	24	470	121	0	157	278	31	0	21	52
Unamortized Redumption Cost of Preferred Stock	24	60	17	0	20	37	4	0	3	7
Gain on Sale of Williston Office	24	(281)	(73)	0	(95)	(168)	(18)	0	(13)	(31)
Total Additions		3,438	795	40	1,246	2,081	200	26	173	399
Total Before Deductions		172,517	44,448	40	58,189	102,677	11,195	26	7,712	18,933
Deductions										
Accumulated Deferred Income Tax	24	(21,052)	(5,435)	0	(7,089)	(12,524)	(1,369)	0	(939)	(2,308)
Accumulated Investment Tax Credit	24	0	0	0	0	0	0	0	0	0
Customer Advances For Construction	Direct	(16,015)	(5,452)	0	(1,973)	(7,425)	(547)	0	(200)	(747)
Total Deductions		(37,067)	(10,887)	0	(9,062)	(19,949)	(1,916)	0	(1,139)	(3,055)
Total Rate Base		135,450	33,561	40	49,127	82,728	9,279	26	6,573	15,878

Montana-Dakota Utilities Co.
ND PSC Case No. PU-17-295

Cost-of-Service Study Using Corrected Minimum-Size Analysis

	Allocation Factor	Total North Dakota	Firm General > 500 cubic feet Demand	Firm General > 500 cubic feet Energy	Firm General > 500 cubic feet Customer	Total Large Firm General	Air Force Delivery Demand	Air Force Delivery Energy	Air Force Delivery Customer	Total Air Force Delivery	Small Interruptible Demand	Small Interruptible Energy	Small Interruptible Customer	Total Small Interruptible
Less: Accumulated Depreciation														
Production Plant	3	0	0	0	0	0	0	0	0	0	0	0	0	0
Distribution Plant														
Rights of Way	13	79	19	0	1	20	0	0	0	0	4	0	0	4
Structures & Improvements	23	187	46	0	4	50	5	0	1	6	8	0	0	8
Mains	40	36,213	8,787	0	280	9,067	0	0	0	0	1,839	0	9	1,848
Direct	Direct	33	0	0	0	0	0	0	0	0	0	0	0	0
Heskett - $787														
Demand Related 75%	2	590	175	0	0	175	0	0	0	0	37	0	0	37
Customer Related 25%	8	197	0	0	8	8	0	0	0	0	0	0	0	0
Meas. & Reg. Equip. - General	18	660	155	0	8	163	0	0	0	0	33	0	1	34
Meas. & Reg. Equip. - City Gate	19	708	166	0	5	171	7	0	2	9	35	0	0	35
Services	37	32,686	0	0	2,388	2,388	0	0	0	0	0	0	163	163
Direct	Direct	35	0	0	0	0	0	0	0	0	0	0	0	0
Meters	5	11,577	0	0	2,934	2,934	0	0	18	18	0	0	349	349
Direct	Direct	12	0	0	0	0	0	0	0	0	0	0	0	0
Service Regulators	9	1,416	0	0	359	359	0	0	2	2	0	0	43	43
Direct	Direct	2	0	0	0	0	0	0	0	0	0	0	0	0
Ind. Meas. & Reg. Station Equipment	21	331	31	0	1	32	18	0	6	24	91	0	28	119
Property on Customer Premise	13	125	30	0	1	31	0	0	0	0	6	0	0	6
Cathodic Protection & Other Equipment	13	862	205	0	7	212	0	0	0	0	43	0	0	43
Distribution Plant		85,713	9,614	0	5,996	15,610	30	0	29	59	2,096	0	593	2,689
General Plant	38	1,497	221	0	94	315	0	0	0	0	46	0	9	55
Direct	Direct	102	0	0	0	0	0	0	0	0	0	0	0	0
Intangible Plant - General	15	888	121	0	60	181	1	0	0	1	26	0	6	32
Intangible Plant - General - Direct	Direct	554	0	0	0	0	0	0	0	0	0	0	0	0
Common Plant	15	4,165	569	0	282	851	3	0	2	5	124	0	30	154
Intangible Plant - Common	15	3,524	481	0	239	720	2	0	2	4	105	0	25	130
Intangible Plant - Common-CC&B	4	2,961	0	0	124	124	0	0	0	0	0	0	4	4
Acquisition Adjustment	15	71	10	0	5	15	0	0	0	0	2	0	1	3
Less: Total Accumulated Reserve for Depreciation		99,475	11,016	0	6,800	17,816	36	0	33	69	2,399	0	668	3,067
Net Gas Plant in Service including Heskett		169,079	26,144	0	9,650	35,794	97	0	78	175	5,654	0	1,034	6,688
Additions														
Materials & Supplies	15	2,070	283	0	140	423	1	0	1	2	62	0	15	77
Fuel Stocks	10	95	0	29	0	29	0	0	0	0	0	0	0	0
Prepayments	25	249	34	0	15	49	0	0	0	0	7	0	2	9
Loss on Sale of Employee Housing	24	775	120	0	44	164	0	0	0	0	26	0	5	31
Unamortized Loss on Debt	24	470	73	0	27	100	0	0	0	0	16	0	3	19
Unamortized Redumption Cost of Preferred Stock	24	60	9	0	3	12	0	0	0	0	2	0	0	2
Gain on Sale of Williston Office	24	(281)	(43)	0	(16)	(59)	0	0	0	0	(9)	0	(2)	(11)
Total Additions		3,438	476	29	213	718	1	0	1	2	104	0	23	127
Total Before Deductions		172,517	26,620	29	9,863	36,512	98	0	79	177	5,758	0	1,057	6,815
Deductions														
Accumulated Deferred Income Tax	24	(21,052)	(3,255)	0	(1,202)	(4,457)	(12)	0	(10)	(22)	(704)	0	(129)	(833)
Accumulated Investment Tax Credit	24	0	0	0	0	0	0	0	0	0	0	0	0	0
Customer Advances For Construction	Direct	(16,015)	(2,686)	0	(885)	(3,571)	0	0	0	0	(2,085)		(691)	(2,776)
Total Deductions		(37,067)	(5,941)	0	(2,087)	(8,028)	(12)	0	(10)	(22)	(2,789)	0	(820)	(3,609)
Total Rate Base		135,450	20,679	29	7,776	28,484	86	0	69	155	2,969	0	237	3,206

Montana-Dakota Utilities Co.
ND PSC Case No. PU-17-295

Cost-of-Service Study Using Corrected Minimum-Size Analysis

	Allocation Factor	Total North Dakota	Large Interruptible Demand	Large Interruptible Energy	Large Interruptible Customer	Total Large Interruptible	Minot Air Force Base Distribution Demand	Minot Air Force Base Distribution Energy	Minot Air Force Base Distribution Customer	Total Minot Air Force
Less: Accumulated Depreciation										
Production Plant	3	0	0	0	0	0	0	0	0	0
Distribution Plant										
Rights of Way	13	79	2	0	0	2	0	0	0	0
Structures & Improvements	23	187	12	0	3	15	0	0	0	0
Mains	40	36,213	622	0	0	622	0	0	0	0
Direct	Direct	33	0	0	0	0	25	0	8	33
Heskett - $787										
Demand Related 75%	2	590	12	0	0	12	0	0	0	0
Customer Related 25%	8	197	0	0	0	0	0	0	0	0
Meas. & Reg. Equip. - General	18	660	48	0	13	61	0	0	0	0
Meas. & Reg. Equip. - City Gate	19	708	22	0	2	24	0	0	0	0
Services	37	32,686	0	0	5	5	0	0	0	0
Direct	Direct	35	0	0	0	0	0	0	35	35
Meters	5	11,577	0	0	34	34	0	0	0	0
Direct	Direct	12	0	0	0	0	0	0	12	12
Service Regulators	9	1,416	0	0	3	3	0	0	0	0
Direct	Direct	2	0	0	0	0	0	0	2	2
Ind. Meas. & Reg. Station Equipment	21	331	51	0	16	67	0	0	0	0
Property on Customer Premise	13	125	4	0	0	4	0	0	0	0
Cathodic Protection & Other Equipment	13	862	27	0	3	30	0	0	0	0
Distribution Plant		85,713	800	0	79	879	25	0	57	82
General Plant	38	1,497	16	0	1	17	0	0	0	0
Direct	Direct	102	0	0	0	0	76	0	26	102
Intangible Plant - General	15	888	17	0	2	19	3	0	3	6
Intangible Plant - General - Direct	Direct	554	415	0	139	554	0	0	0	0
Common Plant	15	4,165	79	0	11	90	13	0	13	26
Intangible Plant - Common	15	3,524	67	0	10	77	11	0	11	22
Intangible Plant - Common-CC&B	4	2,961	0	0	0	0	0	0	0	0
Acquisition Adjustment	15	71	1	0	0	1	0	0	0	0
Less: Total Accumulated Reserve for Depreciation		99,475	1,395	0	242	1,637	128	0	110	238
Net Gas Plant in Service including Heskett		169,079	4,956	0	917	5,873	776	0	643	1,419
Additions										
Materials & Supplies	15	2,070	39	0	6	45	6	0	6	12
Fuel Stocks	10	95	0	0	0	0	0	0	0	0
Prepayments	25	249	6	0	1	7	1	0	1	2
Loss on Sale of Employee Housing	24	775	23	0	4	27	4	0	3	7
Unamortized Loss on Debt	24	470	14	0	3	17	2	0	2	4
Unamortized Redumption Cost of Preferred Stock	24	60	2	0	0	2	0	0	0	0
Gain on Sale of Williston Office	24	(281)	(8)	0	(2)	(10)	(1)	0	(1)	(2)
Total Additions		3,438	76	0	12	88	12	0	11	23
Total Before Deductions		172,517	5,032	0	929	5,961	788	0	654	1,442
Deductions										
Accumulated Deferred Income Tax	24	(21,052)	(617)	0	(114)	(731)	(97)	0	(80)	(177)
Accumulated Investment Tax Credit	24	0	0	0	0	0	0	0	0	0
Customer Advances For Construction	Direct	(16,015)	(1,123)	0	(373)	(1,496)	0	0	0	0
Total Deductions		(37,067)	(1,740)	0	(487)	(2,227)	(97)	0	(80)	(177)
Total Rate Base		135,450	3,292	0	442	3,734	691	0	574	1,265

Cost-of-Service Study Using Corrected Minimum-Size Analysis

	Allocation Factor	Total North Dakota	Residential Demand	Residential Energy	Residential Customer	Total Residential	Firm General-Meter < 500 cubic feet Demand	Firm General-Meter < 500 cubic feet Energy	Firm General-Meter < 500 cubic feet Customer	Total Small Firm General
Income Statement										
Gas Operating Revenues										
Retail Sales & Transportation										
Residential	Direct	58,201	11,841	23,597	22,763	58,201	0	0	0	0
Firm General	Direct	44,072	0	0	0	0	2,981	5,213	4,140	12,334
Air Force Delivery	Direct	1,605	0	0	0	0	0	0	0	0
Small Interruptible	Direct	3,403	0	0	0	0	0	0	0	0
Large Interruptible	Direct	1,328	0	0	0	0	0	0	0	0
Total Sales & Transportation Revenues		108,609	11,841	23,597	22,763	58,201	2,981	5,213	4,140	12,334
Other Operating Revenue										
Miscellaneous										
Reconnect Fees	6	31	0	0	27	27	0	0	3	3
Minot Maintenance Fee Rate 65	Direct	456	0	0	0	0	0	0	0	0
NSF Check Fees & Other	6	19	0	0	16	16	0	0	2	2
Miscellaneous	24	1	0	0	1	1	0	0	0	0
Rent From Gas Property	24	466	118	0	158	276	30	0	21	51
Other Gas Revenues										
Miscellaneous	31	267	43	3	123	169	10	1	16	27
Heskett Pipeline Revenue - $2,275										
Demand Related 75%	2	1,706	846	0	0	846	213	0	0	213
Customer Related 25%	8	569	0	0	489	489	0	0	55	55
Transport and Penalty Revenue - Net	24	13	4	0	4	8	1	0	1	2
Total Other Operating Revenue		3,528	1,011	3	818	1,832	254	1	98	353
		3,072	1,011	3	818	1,832	254	1	98	353
Unbilled Revenue	26	0	0	0	0	0	0	0	0	0
Total Operating Revenues		112,137	12,852	23,600	23,581	60,033	3,235	5,214	4,238	12,687
Operation & Maintenance Expenses										
Cost of Purchased Gas	Direct	70,913	11,841	23,598	0	35,439	2,981	5,203	0	8,184
Other Gas Supply Expenses	3	372	0	184	0	184	0	42	0	42
Distribution Expenses										
Operation										
Load Dispatch	1	20	0	8	0	8	0	2	0	2
Mains and Services	22	2,326	638	0	823	1,461	160	0	120	280
Measuring Stations - General	18	119	42	0	17	59	11	0	2	13
Measuring Stations - Industrial	21	151	24	0	10	34	6	0	1	7
Measuring Stations - City Gate	19	40	18	0	6	24	4	0	1	5
Meters & House Regulators	16	488	0	0	306	306	0	0	41	41
Customer Installations	5	667	0	0	419	419	0	0	56	56
Other Gas Distribution	27	2,182	412	5	904	1,321	104	1	127	232
Rents	27	75	13	0	32	45	4	0	4	8
Supervision & Engineering	27	1,371	260	3	568	831	65	1	80	146
Direct -Minot AFB Distribution System	Direct	78	0	0	0	0	0	0	0	0
Total Operation Expense		7,517	1,407	16	3,085	4,508	354	4	432	790

Montana-Dakota Utilities Co.
ND PSC Case No. PU-17-295

Cost-of-Service Study Using Corrected Minimum-Size Analysis

	Allocation Factor	Total North Dakota	Firm General > 500 cubic feet Demand	Energy	Customer	Total Large Firm General	Air Force Delivery Demand	Energy	Customer	Total Air Force Delivery	Small Interruptible Demand	Energy	Customer	Total Small Interruptible
Income Statement														
Gas Operating Revenues														
Retail Sales & Transportation														
Residential	Direct	58,201	0	0	0	0	0	0	0	0	0	0	0	0
Firm General	Direct	44,072	7,067	17,025	7,646	31,738				0	0	0	0	0
Air Force Delivery	Direct	1,605	0	0	0	0	166	1,319	120	1,605	0	0	0	0
Small Interruptible	Direct	3,403	0	0	0	0	0	0	0	0	195	1,508	1,700	3,403
Large Interruptible	Direct	1,328	0	0	0	0	0	0	0	0	0	0	0	0
Total Sales & Transportation Revenues		108,609	7,067	17,025	7,646	31,738	166	1,319	120	1,605	195	1,508	1,700	3,403
Other Operating Revenue														
Miscellaneous														
Reconnect Fees	6	31	0	0	1	1	0	0	0	0	0	0	0	0
Minot Maintenance Fee Rate 65	Direct	456	0	0	0	0	0	0	0	0	0	0	0	0
NSF Check Fees & Other	6	19	0	0	1	1	0	0	0	0	0	0	0	0
Miscellaneous	24	1	0	0	0	0	0	0	0	0	0	0	0	0
Rent From Gas Property	24	466	72	0	27	99	0	0	0	0	16	0	3	19
Other Gas Revenues														
Miscellaneous	31	267	25	2	25	52	0	0	0	0	7	0	3	10
Heskett Pipeline Revenue - $2,275														
Demand Related 75%	2	1,706	505	0	0	505	0	0	0	0	106	0	0	106
Customer Related 25%	8	569	0	0	24	24	0	0	0	0	0	0	1	1
Transport and Penalty Revenue - Net	24	13	2	0	1	3	0	0	0	0	0	0	0	0
Total Other Operating Revenue		3,528	604	2	79	685	0	0	0	0	129	0	7	136
		3,072	604	2	79	685	0	0	0	0	129	0	7	136
Unbilled Revenue	26	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Operating Revenues		112,137	7,671	17,027	7,725	32,423	166	1,319	120	1,605	324	1,508	1,707	3,539
Operation & Maintenance Expenses														
Cost of Purchased Gas	Direct	70,913	7,067	17,036	0	24,103	166	1,318	0	1,484	195	1,508	0	1,703
Other Gas Supply Expenses	3	372	0	124	0	124	0	10	0	10	0	12	0	12
Distribution Expenses														
Operation														
Load Dispatch	1	20	0	5	0	5	0	0	0	0	0	1	0	1
Mains and Services	22	2,326	381	0	65	446	0	0	0	0	80	0	4	84
Measuring Stations - General	18	119	28	0	2	30	0	0	0	0	6	0	0	6
Measuring Stations - Industrial	21	151	14	0	0	14	8	0	3	11	42	0	13	55
Measuring Stations - City Gate	19	40	9	0	0	9	0	0	0	0	1	0	0	1
Meters & House Regulators	16	488	0	0	124	124	0	0	1	1	0	0	15	15
Customer Installations	5	667	0	0	169	169	0	0	1	1	0	0	20	20
Other Gas Distribution	27	2,182	247	3	206	456	5	0	3	8	74	1	30	105
Rents	27	75	9	0	7	16	0	0	0	0	3	0	1	4
Supervision & Engineering	27	1,371	155	2	130	287	3	0	2	5	46	0	19	65
Direct -Minot AFB Distribution System	Direct	78	0	0	0	0	0	0	0	0	0	0	0	0
Total Operation Expense		7,517	843	10	703	1,556	16	0	10	26	252	2	102	356

Montana-Dakota Utilities Co.
ND PSC Case No. PU-17-295

Cost-of-Service Study Using Corrected Minimum-Size Analysis

	Allocation Factor	Total North Dakota	Large Interruptible Demand	Large Interruptible Energy	Large Interruptible Customer	Total Large Interruptible	Minot Air Force Base Distribution Demand	Minot Air Force Base Distribution Energy	Minot Air Force Base Distribution Customer	Total Minot Air Force
Income Statement										
Gas Operating Revenues										
Retail Sales & Transportation										
Residential	Direct	58,201	0	0	0	0	0	0	0	0
Firm General	Direct	44,072	0	0	0	0	0	0	0	0
Air Force Delivery	Direct	1,605	0	0	0	0	0	0	0	0
Small Interruptible	Direct	3,403	0	0	0	0	0	0	0	0
Large Interruptible	Direct	1,328	0	0	1,328	1,328	0	0	0	0
Total Sales & Transportation Revenues		108,609	0	0	1,328	1,328	0	0	0	0
Other Operating Revenue										
Miscellaneous										
Reconnect Fees	6	31	0	0	0	0	0	0	0	0
Minot Maintenance Fee Rate 65	Direct	456	0	0	0	0	0	0	456	456
NSF Check Fees & Other	6	19	0	0	0	0	0	0	0	0
Miscellaneous	24	1	0	0	0	0	0	0	0	0
Rent From Gas Property	24	466	14	0	3	17	2	0	2	4
Other Gas Revenues										
Miscellaneous	31	267	5	0	1	6	3	0	0	3
Heskett Pipeline Revenue - $2,275										
Demand Related 75%	2	1,706	36	0	0	36	0	0	0	0
Customer Related 25%	8	569	0	0	0	0	0	0	0	0
Transport and Penalty Revenue - Net	24	13	0	0	0	0	0	0	0	0
Total Other Operating Revenue		3,528	55	0	4	59	5	0	458	463
		3,072	55	0	4	59	5	0	2	7
Unbilled Revenue	26	0	0	0	0	0	0	0	0	0
Total Operating Revenues		112,137	55	0	1,332	1,387	5	0	458	463
Operation & Maintenance Expenses										
Cost of Purchased Gas	Direct	70,913	0	0	0	0	0	0	0	0
Other Gas Supply Expenses	3	372	0	0	0	0	0	0	0	0
Distribution Expenses										
Operation										
Load Dispatch	1	20	0	4	0	4	0	0	0	0
Mains and Services	22	2,326	50	0	5	55	0	0	0	0
Measuring Stations - General	18	119	9	0	2	11	0	0	0	0
Measuring Stations - Industrial	21	151	23	0	7	30	0	0	0	0
Measuring Stations - City Gate	19	40	1	0	0	1	0	0	0	0
Meters & House Regulators	16	488	0	0	1	1	0	0	0	0
Customer Installations	5	667	0	0	2	2	0	0	0	0
Other Gas Distribution	27	2,182	48	2	10	60	0	0	0	0
Rents	27	75	2	0	0	2	0	0	0	0
Supervision & Engineering	27	1,371	30	1	6	37	0	0	0	0
Direct -Minot AFB Distribution System	Direct	78	0	0	0	0	78	0	0	78
Total Operation Expense		7,517	163	7	33	203	78	0	0	78

Montana-Dakota Utilities Co.
ND PSC Case No. PU-17-295

Cost-of-Service Study Using Corrected Minimum-Size Analysis

	Allocation Factor	Total North Dakota	Residential Demand	Residential Energy	Residential Customer	Total Residential	Firm General-Meter < 500 cubic feet Demand	Firm General-Meter < 500 cubic feet Energy	Firm General-Meter < 500 cubic feet Customer	Total Small Firm General
Maintenance										
Structures & Improvements	13	10	5	0	2	7	1	0	0	1
Mains	13	371	148	0	57	205	37	0	6	43
Measuring Stations - General	18	118	42	0	16	58	11	0	2	13
Measuring Stations - Industrial	21	50	8	0	3	11	2	0	0	2
Measuring Stations - City Gate	19	30	12	0	5	17	3	0	1	4
Services	5	250	0	0	157	157	0	0	21	21
Meters & House Regulators	16	323	0	0	202	202	0	0	27	27
Other Equipment	28	433	82	0	166	248	20	0	21	41
Supervision & Engineering	28	367	68	0	141	209	17	0	18	35
Direct -Minot AFB Distribution System	Direct	55	0	0	0	0	0	0	0	0
Total Maintenance Expense		2,007	365	0	749	1,114	91	0	96	187
Total Distribution Expenses		9,524	1,772	16	3,834	5,622	445	4	528	977
Customer Accounts	4	95	0	0	82	82	0	0	9	9
Meter Reading	5	232	0	0	145	145	0	0	20	20
Customer Records & Collection	4	2,206	0	0	1,898	1,898	0	0	213	213
Uncollectible Accounts	6	283	0	0	244	244	0	0	27	27
Miscellaneous Customer Accounts	4	125	0	0	108	108	0	0	12	12
Customer Service & Information	4	254	0	0	219	219	0	0	24	24
Sales Expenses	4	94	0	0	81	81	0	0	9	9
Administration & General Expenses	30	8,347	1,552	14	3,360	4,926	390	4	463	857
Total Gas O&M Expenses		92,445	15,165	23,812	9,971	48,948	3,816	5,253	1,305	10,374
O&M Excl. Cost of Gas and A&G		13,185	1,772	200	6,611	8,583	445	46	842	1,333
O&M Excl. Cost of Gas		21,532	3,324	214	9,971	13,509	835	50	1,305	2,190
Depreciation Expense										
Production Plant	3	0	0	0	0	0	0	0	0	0
Distribution Plant										
Rights of Way	13	7	3	0	1	4	1	0	0	1
Structures & Improvements	23	13	4	0	2	6	1	0	0	1
Mains	40	2,618	1,062	0	409	1,471	267	0	46	313
Direct -Minot AFB Distribution System	Direct	14	0	0	0	0	0	0	0	0
Heskett Pipeline - $461	Direct									
Demand Related 75%	2	346	173	0	0	173	43	0	0	43
Customer Related 25%	8	115	0	0	99	99	0	0	11	11
Meas. & Reg. Equip. - General	18	47	17	0	7	24	4	0	1	5
Meas. & Reg. Equip. - City Gate	19	134	54	0	20	74	13	0	2	15
Services	17	2,983	0	0	2,403	2,403	0	0	375	375
Direct -Minot AFB Distribution System	Direct	6	0	0	0	0	0	0	0	0
Meters	5	1,078	0	0	677	677	0	0	91	91
Direct -Minot AFB Distribution System	Direct	2	0	0	0	0	0	0	0	0
Service Regulators	20	66	0	0	41	41	0	0	6	6
Ind. Meas. & Reg. Station Equipment	21	29	4	0	2	6	1	0	0	1
Cathodic Protection & Other Equipment	13	28	12	0	4	16	3	0	0	3
Total Distribution Plant		7,486	1,329	0	3,665	4,994	333	0	532	865

Montana-Dakota Utilities Co.
ND PSC Case No. PU-17-295

Cost-of-Service Study Using Corrected Minimum-Size Analysis

	Allocation Factor	Total North Dakota	Firm General > 500 cubic feet: Demand	Firm General > 500 cubic feet: Energy	Firm General > 500 cubic feet: Customer	Total Large Firm General	Air Force Delivery: Demand	Air Force Delivery: Energy	Air Force Delivery: Customer	Total Air Force Delivery	Small Interruptible: Demand	Small Interruptible: Energy	Small Interruptible: Customer	Total Small Interruptible
Maintenance														
Structures & Improvements	13	10	2	0	0	2	0	0	0	0	0	0	0	0
Mains	13	371	88	0	3	91	0	0	0	0	19	0	0	19
Measuring Stations - General	18	118	28	0	2	30	0	0	0	0	6	0	0	6
Measuring Stations - Industrial	21	50	5	0	0	5	3	0	1	4	14	0	4	18
Measuring Stations - City Gate	19	30	7	0	0	7	0	0	0	0	1	0	0	1
Services	5	250	0	0	63	63	0	0	0	0	0	0	8	8
Meters & House Regulators	16	323	0	0	82	82	0	0	1	1	0	0	10	10
Other Equipment	28	433	49	0	56	105	1	0	1	2	15	0	8	23
Supervision & Engineering	28	367	41	0	48	89	1	0	1	2	13	0	7	20
Direct -Minot AFB Distribution System	Direct	55	0	0	0	0	0	0	0	0	0	0	0	0
Total Maintenance Expense		2,007	220	0	254	474	5	0	4	9	68	0	37	105
Total Distribution Expenses		9,524	1,063	10	957	2,030	21	0	14	35	320	2	139	461
Customer Accounts	4	95	0	0	4	4	0	0	0	0	0	0	0	0
Meter Reading	5	232	0	0	59	59	0	0	0	0	0	0	7	7
Customer Records & Collection	4	2,206	0	0	92	92	0	0	0	0	0	0	3	3
Uncollectible Accounts	6	283	0	0	12	12	0	0	0	0	0	0	0	0
Miscellaneous Customer Accounts	4	125	0	0	5	5	0	0	0	0	0	0	0	0
Customer Service & Information	4	254	0	0	11	11	0	0	0	0	0	0	0	0
Sales Expenses	4	94	0	0	4	4	0	0	0	0	0	0	0	0
Administration & General Expenses	30	8,347	932	9	839	1,780	18	0	12	30	280	2	122	404
Total Gas O&M Expenses		92,445	9,062	17,179	1,983	28,224	205	1,328	26	1,559	795	1,524	271	2,590
O&M Excl. Cost of Gas and A&G		13,185	1,063	134	1,144	2,341	21	10	14	45	320	14	149	483
O&M Excl. Cost of Gas		21,532	1,995	143	1,983	4,121	39	10	26	75	600	16	271	887
Depreciation Expense														
Production Plant	3	0	0	0	0	0	0	0	0	0	0	0	0	0
Distribution Plant														
Rights of Way	13	7	2	0	0	2	0	0	0	0	0	0	0	0
Structures & Improvements	23	13	3	0	1	4	0	0	0	0	1	0	0	1
Mains	40	2,618	635	0	20	655	0	0	0	0	133	0	1	134
Direct -Minot AFB Distribution System	Direct	14	0	0	0	0	0	0	0	0	0	0	0	0
Heskett Pipeline - $461	Direct													
Demand Related 75%	2	346	102	0	0	102	0	0	0	0	21	0	0	21
Customer Related 25%	8	115	0	0	5	5	0	0	0	0	0	0	0	0
Meas. & Reg. Equip. - General	18	47	11	0	1	12	0	0	0	0	2	0	0	2
Meas. & Reg. Equip. - City Gate	19	134	32	0	1	33	1	0	0	1	7	0	0	7
Services	17	2,983	0	0	189	189	0	0	0	0	0	0	15	15
Direct -Minot AFB Distribution System	Direct	6	0	0	0	0	0	0	0	0	0	0	0	0
Meters	5	1,078	0	0	273	273	0	0	2	2	0	0	32	32
Direct -Minot AFB Distribution System	Direct	2	0	0	0	0	0	0	0	0	0	0	0	0
Service Regulators	20	66	0	0	17	17	0	0	0	0	0	0	2	2
Ind. Meas. & Reg. Station Equipment	21	29	3	0	0	3	2	0	1	3	8	0	2	10
Cathodic Protection & Other Equipment	13	28	7	0	0	7	0	0	0	0	1	0	0	1
Total Distribution Plant		7,486	795	0	507	1,302	3	0	3	6	173	0	52	225

Montana-Dakota Utilities Co.
ND PSC Case No. PU-17-295

Cost-of-Service Study Using Corrected Minimum-Size Analysis

	Allocation Factor	Total North Dakota	Large Interruptible Demand	Large Interruptible Energy	Large Interruptible Customer	Total Large Interruptible	Minot Air Force Base Distribution Demand	Minot Air Force Base Distribution Energy	Minot Air Force Base Distribution Customer	Total Minot Air Force
Maintenance										
Structures & Improvements	13	10	0	0	0	0	0	0	0	0
Mains	13	371	12	0	1	13	0	0	0	0
Measuring Stations - General	18	118	9	0	2	11	0	0	0	0
Measuring Stations - Industrial	21	50	8	0	2	10	0	0	0	0
Measuring Stations - City Gate	19	30	1	0	0	1	0	0	0	0
Services	5	250	0	0	1	1	0	0	0	0
Meters & House Regulators	16	323	0	0	1	1	0	0	0	0
Other Equipment	28	433	11	0	3	14	0	0	0	0
Supervision & Engineering	28	367	10	0	2	12	0	0	0	0
Direct -Minot AFB Distribution System	Direct	55	0	0	0	0	55	0	0	55
Total Maintenance Expense		2,007	51	0	12	63	55	0	0	55
Total Distribution Expenses		9,524	214	7	45	266	133	0	0	133
Customer Accounts	4	95	0	0	0	0	0	0	0	0
Meter Reading	5	232	0	0	1	1	0	0	0	0
Customer Records & Collection	4	2,206	0	0	0	0	0	0	0	0
Uncollectible Accounts	6	283	0	0	0	0	0	0	0	0
Miscellaneous Customer Accounts	4	125	0	0	0	0	0	0	0	0
Customer Service & Information	4	254	0	0	0	0	0	0	0	0
Sales Expenses	4	94	0	0	0	0	0	0	0	0
Administration & General Expenses	30	8,347	188	6	39	233	117	0	0	117
Total Gas O&M Expenses		92,445	402	13	85	500	250	0	0	250
O&M Excl. Cost of Gas and A&G		13,185	214	7	46	267	133	0	0	133
O&M Excl. Cost of Gas		21,532	402	13	85	500	250	0	0	250
Depreciation Expense										
Production Plant	3	0	0	0	0	0	0	0	0	0
Distribution Plant										
Rights of Way	13	7	0	0	0	0	0	0	0	0
Structures & Improvements	23	13	1	0	0	1	0	0	0	0
Mains	40	2,618	45	0	0	45	0	0	0	0
Direct -Minot AFB Distribution System	Direct	14	0	0	0	0	14	0	0	14
Heskett Pipeline - $461	Direct									
Demand Related 75%	2	346	7	0	0	7	0	0	0	0
Customer Related 25%	8	115	0	0	0	0	0	0	0	0
Meas. & Reg. Equip. - General	18	47	3	0	1	4	0	0	0	0
Meas. & Reg. Equip. - City Gate	19	134	4	0	0	4	0	0	0	0
Services	17	2,983	0	0	1	1	0	0	0	0
Direct -Minot AFB Distribution System	Direct	6	0	0	0	0	0	0	6	6
Meters	5	1,078	0	0	3	3	0	0	0	0
Direct -Minot AFB Distribution System	Direct	2	0	0	0	0	0	0	2	2
Service Regulators	20	66	0	0	0	0	0	0	0	0
Ind. Meas. & Reg. Station Equipment	21	29	4	0	2	6	0	0	0	0
Cathodic Protection & Other Equipment	13	28	1	0	0	1	0	0	0	0
Total Distribution Plant		7,486	65	0	7	72	14	0	8	22

Montana-Dakota Utilities Co.
ND PSC Case No. PU-17-295

Cost-of-Service Study Using Corrected Minimum-Size Analysis

	Allocation Factor	Total North Dakota	Residential Demand	Residential Energy	Residential Customer	Total Residential	Firm General-Meter < 500 cubic feet Demand	Firm General-Meter < 500 cubic feet Energy	Firm General-Meter < 500 cubic feet Customer	Total Small Firm General
General Plant	38	160	39	0	61	100	10	0	8	18
Direct -Minot AFB Distribution System	Direct	5	0	0	0	0	0	0	0	0
Amort. of Intangible Plant - General	15	226	51	0	88	139	13	0	12	25
Direct	Direct	56	0	0	0	0	0	0	0	0
Common Plant	15	354	80	0	138	218	20	0	20	40
Intangible Plant - Common (Excluding CC&B)	15	265	60	0	103	163	15	0	15	30
Intangible Plant - Common (CC&B)	4	625	0	0	538	538	0	0	60	60
Amortization of Gain	15	26	6	0	11	17	1	0	1	2
Acquisition Adjustment	15	3	1	0	1	2	0	0	0	0
Total Depreciation Expense		9,206	1,566	0	4,605	6,171	392	0	648	1,040
Taxes Other Than Income										
Ad Valorem Taxes-Production	3	0	0	0	0	0	0	0	0	0
Ad Valorem Taxes-Other	15	1,180	268	0	459	727	68	0	65	133
Other Taxes - Payroll, Franchise, Other	31	860	133	9	397	539	33	2	52	87
Other Taxes - Minot AFB Distribution- Direct	Direct	0	0	0	0	0	0	0	0	0
Other Taxes - Revenue	26	0	0	0	0	0	0	0	0	0
Total Taxes Other Than Income Taxes		2,040	401	9	856	1,266	101	2	117	220
Total Operating Expense		103,691	17,132	23,821	15,432	56,385	4,309	5,255	2,070	11,634
Interest Expense/AFUDC Equity Add Back	36	3,214	834	0	1,094	1,928	211	0	145	356
Direct -Minot AFB Distribution System	Direct	0	0	0	0	0	0	0	0	0
Taxable Income		5,232	(5,114)	(221)	7,055	1,720	(1,285)	(41)	2,023	697
Income Taxes	37.8015%	1,978	(1,933)	(84)	2,667	650	(486)	(15)	765	264
Full Normalization	24	(102)	(26)	0	(34)	(60)	(7)	0	(5)	(12)
Total Income Taxes		1,876	(1,959)	(84)	2,633	590	(493)	(15)	760	252
Total Operating Expense		105,567	15,173	23,737	18,065	56,975	3,816	5,240	2,830	11,886
Operating Income:		6,570	(2,321)	(137)	5,516	3,058	(581)	(26)	1,408	801

Montana-Dakota Utilities Co.
ND PSC Case No. PU-17-295

Cost-of-Service Study Using Corrected Minimum-Size Analysis

	Allocation Factor	Total North Dakota	Firm General > 500 cubic feet Demand	Energy	Customer	Total Large Firm General	Air Force Delivery Demand	Energy	Customer	Total Air Force Delivery	Small Interruptible Demand	Energy	Customer	Total Small Interruptible
General Plant	38	160	24	0	10	34	0	0	0	0	5	0	1	6
Direct -Minot AFB Distribution System	Direct	5	0	0	0	0	0	0	0	0	0	0	0	0
Amort. of Intangible Plant - General	15	226	31	0	15	46	0	0	0	0	7	0	2	9
Direct	Direct	56	0	0	0	0	0	0	0	0	0	0	0	0
Common Plant	15	354	48	0	24	72	0	0	0	0	11	0	3	14
Intangible Plant - Common (Excluding CC&B)	15	265	36	0	18	54	0	0	0	0	8	0	2	10
Intangible Plant - Common (CC&B)	4	625	0	0	26	26	0	0	0	0	0	0	1	1
Amortization of Gain	15	26	4	0	2	6	0	0	0	0	1	0	0	1
Acquisition Adjustment	15	3	0	0	0	0	1	0	0	1	0	0	0	0
Total Depreciation Expense		9,206	938	0	602	1,540	4	0	3	7	205	0	61	266
Taxes Other Than Income														
Ad Valorem Taxes-Production	3	0	0	0	0	0	0	0	0	0	0	0	0	0
Ad Valorem Taxes-Other	15	1,180	161	0	80	241	1	0	1	2	35	0	9	44
Other Taxes - Payroll, Franchise, Other	31	860	80	6	79	165	2	0	1	3	24	1	11	36
Other Taxes - Minot AFB Distribution- Direct	Direct	0	0	0	0	0	0	0	0	0	0	0	0	0
Other Taxes - Revenue	26	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Taxes Other Than Income Taxes		2,040	241	6	159	406	3	0	2	5	59	1	20	80
Total Operating Expense		103,691	10,241	17,185	2,744	30,170	212	1,328	31	1,571	1,059	1,525	352	2,936
Interest Expense/AFUDC Equity Add Back	36	3,214	501	0	185	686	2	0	1	3	108	0	20	128
Direct -Minot AFB Distribution System	Direct	0	0	0	0	0	0	0	0	0	0	0	0	0
Taxable Income		5,232	(3,071)	(158)	4,796	1,567	(48)	(9)	88	31	(843)	(17)	1,335	475
Income Taxes	37.8015%	1,978	(1,161)	(60)	1,813	592	(18)	(3)	33	12	(319)	(6)	505	180
Full Normalization	24	(102)	(16)	0	(6)	(22)	0	0	0	0	(3)	0	(1)	(4)
Total Income Taxes		1,876	(1,177)	(60)	1,807	570	(18)	(3)	33	12	(322)	(6)	504	176
Total Operating Expense		105,567	9,064	17,125	4,551	30,740	194	1,325	64	1,583	737	1,519	856	3,112
Operating Income:		6,570	(1,393)	(98)	3,174	1,683	(28)	(6)	56	22	(413)	(11)	851	427

Montana-Dakota Utilities Co.
ND PSC Case No. PU-17-295

Cost-of-Service Study Using Corrected Minimum-Size Analysis

	Allocation Factor	Total North Dakota	Large Interruptible Demand	Large Interruptible Energy	Large Interruptible Customer	Total Large Interruptible	Minot Air Force Base Distribution Demand	Minot Air Force Base Distribution Energy	Minot Air Force Base Distribution Customer	Total Minot Air Force
General Plant	38	160	2	0	0	2	0	0	0	0
Direct -Minot AFB Distribution System	Direct	5	0	0	0	0	4	0	1	5
Amort. of Intangible Plant - General	15	226	4	0	1	5	1	0	1	2
Direct	Direct	56	42	0	14	56	0	0	0	0
Common Plant	15	354	7	0	1	8	1	0	1	2
Intangible Plant - Common (Excluding CC&B)	15	265	5	0	1	6	1	0	1	2
Intangible Plant - Common (CC&B)	4	625	0	0	0	0	0	0	0	0
Amortization of Gain	15	26	0	0	0	0	0	0	0	0
Acquisition Adjustment	15	3	0	0	0	0	0	0	0	0
Total Depreciation Expense		9,206	125	0	24	149	21	0	12	33
Taxes Other Than Income										
Ad Valorem Taxes-Production	3	0	0	0	0	0	0	0	0	0
Ad Valorem Taxes-Other	15	1,180	22	0	3	25	4	0	4	8
Other Taxes - Payroll, Franchise, Other	31	860	16	1	3	20	10	0	0	10
Other Taxes - Minot AFB Distribution- Direct	Direct	0	0	0	0	0	0	0	0	0
Other Taxes - Revenue	26	0	0	0	0	0	0	0	0	0
Total Taxes Other Than Income Taxes		2,040	38	1	6	45	14	0	4	18
Total Operating Expense		103,691	565	14	115	694	285	0	16	301
Interest Expense/AFUDC Equity Add Back	36	3,214	95	0	18	113	0	0	0	0
Direct -Minot AFB Distribution System	Direct	0	0	0	0	0	0	0	0	0
Taxable Income		5,232	(605)	(14)	1,199	580	(280)	0	442	162
Income Taxes	37.8015%	1,978	(229)	(5)	453	219	(106)	0	167	61
Full Normalization	24	(102)	(3)	0	(1)	(4)	0	0	0	0
Total Income Taxes		1,876	(232)	(5)	452	215	(106)	0	167	61
Total Operating Expense		105,567	333	9	567	909	179	0	183	362
Operating Income:		6,570	(278)	(9)	765	478	(174)	0	275	101

Montana-Dakota Utilities Co.
ND PSC Case No. PU-17-295

Cost-of-Service Study Using Corrected Minimum-Size Analysis

		Total	Residential			Small Firm General		
		North Dakota	Demand	Energy	Customer	Demand	Energy	Customer
1	Dk Throughput Projected	23,351,305 100.000000%	0 0.000000%	8,826,214 37.797520%	0 0.000000%	0 0.000000%	2,036,838 8.722587%	0 0.000000%
2	Peak Design Day @ Distribution	192,668 100.000000%	95,561 49.598792%	0 0.000000%	0 0.000000%	24,062 12.488841%	0 0.000000%	0 0.000000%
3	Dk Sales Projected	17,924,849 100.000000%	0 0.000000%	8,826,214 49.240102%	0 0.000000%	0 0.000000%	2,036,838 11.363209%	0 0.000000%
4	Average Customers	112,516 100.000000%	0 0.000000%	0 0.000000%	96,792 86.025099%	0 0.000000%	0 0.000000%	10,850 9.643073%
5	Total Weighted Customers	154,248 100.000000%	0 0.000000%	0 0.000000%	96,792 62.750894%	0 0.000000%	0 0.000000%	13,020 8.440952%
6	Average Res. & Firm General Cust.	112,352 100.000000%	0 0.000000%	0 0.000000%	96,792 86.150669%	0 0.000000%	0 0.000000%	10,850 9.657149%
8	Average Customers @ Distribution	112,512 100.000000%	0 0.000000%	0 0.000000%	96,792 86.028157%	0 0.000000%	0 0.000000%	10,850 9.643416%
9	Total Weighted Customers Excluding Large IT - Transmission Customers	154,172 100.000000%	0 0.000000%	0 0.000000%	96,792 62.781829%	0 0.000000%	0 0.000000%	13,020 8.445113%
10	Residential & Firm General Propane Sales	50,826 100.000000%	0 0.000000%	21,374 42.053280%	0 0.000000%	0 0.000000%	13,787 27.125880%	0 0.000000%
13	Distribution Mains (000's) excluding Heskett & AF Dist	102,474 99.999997%	40,833 39.847179%	0 0.000000%	15,714 15.334621%	10,281 10.032789%	0 0.000000%	1,762 1.719461%
15	Distribution Plant (000's) excluding Heskett	198,649 100.000000%	45,277 22.792500%	0 0.000000%	77,275 38.900334%	11,401 5.739278%	0 0.000000%	10,964 5.519292%
16	Meters & Regulators (000's) Excl AF Distribution	36,097 100.000000%	0 0.000000%	0 0.000000%	22,662 62.780840%	0 0.000000%	0 0.000000%	3,048 8.443915%
17	Weighted Services	120,124 100.000000%	0 0.000000%	0 0.000000%	96,792 80.576737%	0 0.000000%	0 0.000000%	15,082 12.555359%
18	Meas. & Reg. Sta. Eqpt.- General (000's)	1,962 99.999999%	711 36.238531%	0 0.000000%	274 13.965341%	179 9.123344%	0 0.000000%	31 1.580020%
19	Meas. & Reg. Eqpt.- City Gate (000's)	5,360 99.999998%	2,107 39.312047%	0 0.000000%	811 15.131500%	531 9.907308%	0 0.000000%	91 1.697863%
20	Service Regulators (000's)	4,494 100.000000%	0 0.000000%	0 0.000000%	2,812 62.572319%	0 0.000000%	0 0.000000%	378 8.411215%
21	Ind. Meas. & Reg. Sta. Eqpt. (000's)	969 100.000001%	153 15.789474%	0 0.000000%	59 6.088752%	38 3.921569%	0 0.000000%	7 0.722394%
22	Mains & Services (000's) Excl AF Distribution	149,284 100.000000%	40,833 27.352563%	0 0.000000%	52,902 35.437153%	10,281 6.886873%	0 0.000000%	7,723 5.173361%
23	Structures and Improvements	504 100.000001%	173 34.325398%	0 0.000000%	66 13.095238%	43 8.531746%	0 0.000000%	7 1.388889%
24	Net Gas Plant in Service (000's)	169,079 100.000001%	43,653 25.818158%	0 0.000000%	56,943 33.678403%	10,995 6.502890%	0 0.000000%	7,539 4.458871%
25	Total Gas Plant in Service (000's)	268,554 100.000000%	62,046 23.103761%	0 0.000000%	103,770 38.640319%	15,623 5.817459%	0 0.000000%	14,339 5.339342%
26	Projected Operating Revenue (000's)	108,609 100.000000%	11,841 10.902411%	23,597 21.726561%	22,763 20.958668%	2,981 2.744708%	5,213 4.799786%	4,140 3.811839%
		3,811	722	8	1,581	181	2	221

Montana-Dakota Utilities Co.
ND PSC Case No. PU-17-295

Cost-of-Service Study Using Corrected Minimum-Size Analysis

		Total	Large Firm General			Air Force Delivery		
		North Dakota	Demand	Energy	Customer	Demand	Energy	Customer
		23,351,305	0	5,998,825	0	0	490,100	0
1	Dk Throughput Projected	100.000000%	0.000000%	25.689464%	0.000000%	0.000000%	2.098812%	0.000000%
		192,668	57,033	0	0	0	0	0
2	Peak Design Day @ Distribution	100.000000%	29.601698%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
		17,924,849	0	5,998,825	0	0	490,100	0
3	Dk Sales Projected	100.000000%	0.000000%	33.466530%	0.000000%	0.000000%	2.734193%	0.000000%
		112,516	0	0	4,710	0	0	3
4	Average Customers	100.000000%	0.000000%	0.000000%	4.186071%	0.000000%	0.000000%	0.002666%
		154,248	0	0	39,093	0	0	237
5	Total Weighted Customers	100.000000%	0.000000%	0.000000%	25.344251%	0.000000%	0.000000%	0.153649%
		112,352	0	0	4,710	0	0	0
6	Average Res. & Firm General Cust.	100.000000%	0.000000%	0.000000%	4.192182%	0.000000%	0.000000%	0.000000%
		112,512	0	0	4,710	0	0	0
8	Average Customers @ Distribution	100.000000%	0.000000%	0.000000%	4.186220%	0.000000%	0.000000%	0.000000%
	Total Weighted Customers Excluding	154,172	0	0	39,093	0	0	237
9	Large IT - Transmission Customers	100.000000%	0.000000%	0.000000%	25.356744%	0.000000%	0.000000%	0.153724%
		50,826	0	15,665	0	0	0	0
10	Residential & Firm General Propane Sales	100.000000%	0.000000%	30.820840%	0.000000%	0.000000%	0.000000%	0.000000%
		102,474	24,425	0	778	0	0	0
13	Distribution Mains (000's) excluding Heskett & AF Dist	99.999997%	23.835314%	0.000000%	0.759217%	0.000000%	0.000000%	0.000000%
		198,649	27,140	0	13,454	120	0	96
15	Distribution Plant (000's) excluding Heskett	100.000000%	13.662311%	0.000000%	6.772761%	0.060287%	0.000000%	0.048286%
		36,097	0	0	9,153	0	0	56
16	Meters & Regulators (000's) Excl AF Distribution	100.000000%	0.000000%	0.000000%	25.356678%	0.000000%	0.000000%	0.155138%
		120,124	0	0	7,630	0	0	0
17	Weighted Services	100.000000%	0.000000%	0.000000%	6.351770%	0.000000%	0.000000%	0.000000%
		1,962	460	0	25	0	0	0
18	Meas. & Reg. Sta. Eqpt.- General (000's)	99.999999%	23.445464%	0.000000%	1.274210%	0.000000%	0.000000%	0.000000%
		5,360	1,260	0	40	54	0	18
19	Meas. & Reg. Eqpt.- City Gate (000's)	99.999998%	23.508866%	0.000000%	0.746313%	1.003045%	0.000000%	0.334348%
		4,494	0	0	1,136	0	0	7
20	Service Regulators (000's)	100.000000%	0.000000%	0.000000%	25.278149%	0.000000%	0.000000%	0.155763%
		969	91	0	3	53	0	18
21	Ind. Meas. & Reg. Sta. Eqpt. (000's)	100.000001%	9.391125%	0.000000%	0.309598%	5.469556%	0.000000%	1.857585%
		149,284	24,425	0	4,198	0	0	0
22	Mains & Services (000's) Excl AF Distribution	100.000000%	16.361432%	0.000000%	2.812090%	0.000000%	0.000000%	0.000000%
		504	125	0	10	13	0	4
23	Structures and Improvements	100.000001%	24.801587%	0.000000%	1.984127%	2.579365%	0.000000%	0.793651%
		169,079	26,144	0	9,650	97	0	78
24	Net Gas Plant in Service (000's)	100.000001%	15.462624%	0.000000%	5.707402%	0.057228%	0.000000%	0.046085%
		268,554	37,160	0	16,450	133	0	111
25	Total Gas Plant in Service (000's)	100.000000%	13.837085%	0.000000%	6.125405%	0.049435%	0.000000%	0.041303%
		108,609	7,067	17,025	7,646	166	1,319	120
26	Projected Operating Revenue (000's)	100.000000%	6.506827%	15.675497%	7.039932%	0.152842%	1.214448%	0.110488%
		3,811	432	5	360	8	0	5

Montana-Dakota Utilities Co.
ND PSC Case No. PU-17-295

Cost-of-Service Study Using Corrected Minimum-Size Analysis

		Total	Small Interruptible			Large Interruptible		
		North Dakota	Demand	Energy	Customer	Demand	Energy	Customer
		23,351,305	0	1,677,385	0	0	4,321,943	0
1	Dk Throughput Projected	100.000000%	0.000000%	7.183260%	0.000000%	0.000000%	18.508357%	0.000000%
		192,668	11,967	0	0	4,045	0	0
2	Peak Design Day @ Distribution	100.000000%	6.211203%	0.000000%	0.000000%	2.099466%	0.000000%	0.000000%
		17,924,849	0	572,872	0	0	0	0
3	Dk Sales Projected	100.000000%	0.000000%	3.195966%	0.000000%	0.000000%	0.000000%	0.000000%
		112,516	0	0	155	0	0	6
4	Average Customers	100.000000%	0.000000%	0.000000%	0.137758%	0.000000%	0.000000%	0.005333%
		154,248	0	0	4,650	0	0	456
5	Total Weighted Customers	100.000000%	0.000000%	0.000000%	3.014626%	0.000000%	0.000000%	0.295628%
		112,352	0	0	0	0	0	0
6	Average Res. & Firm General Cust.	100.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
		112,512	0	0	155	0	0	5
8	Average Customers @ Distribution	100.000000%	0.000000%	0.000000%	0.137763%	0.000000%	0.000000%	0.004444%
	Total Weighted Customers Excluding	154,172	0	0	4,650	0	0	380
9	Large IT - Transmission Customers	100.000000%	0.000000%	0.000000%	3.016112%	0.000000%	0.000000%	0.246478%
		50,826	0	0	0	0	0	0
10	Residential & Firm General Propane Sales	100.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
		102,474	5,113	0	25	3,213	0	330
13	Distribution Mains (000's) excluding Heskett & AF Dist	99.999997%	4.989558%	0.000000%	0.024396%	3.135429%	0.000000%	0.322033%
		198,649	5,926	0	1,434	3,783	0	544
15	Distribution Plant (000's) excluding Heskett	100.000000%	2.983156%	0.000000%	0.721877%	1.904493%	0.000000%	0.273724%
		36,097	0	0	1,089	0	0	89
16	Meters & Regulators (000's) Excl AF Distribution	100.000000%	0.000000%	0.000000%	3.016871%	0.000000%	0.000000%	0.246558%
		120,124	0	0	593	0	0	23
17	Weighted Services	100.000000%	0.000000%	0.000000%	0.493657%	0.000000%	0.000000%	0.019147%
		1,962	97	0	3	144	0	38
18	Meas. & Reg. Sta. Eqpt.- General (000's)	99.999999%	4.943935%	0.000000%	0.152905%	7.339450%	0.000000%	1.936799%
		5,360	264	0	1	166	0	17
19	Meas. & Reg. Eqpt.- City Gate (000's)	99.999998%	4.925667%	0.000000%	0.018658%	3.097200%	0.000000%	0.317183%
		4,494	0	0	135	0	0	11
20	Service Regulators (000's)	100.000000%	0.000000%	0.000000%	3.004005%	0.000000%	0.000000%	0.244771%
		969	267	0	83	149	0	48
21	Ind. Meas. & Reg. Sta. Eqpt. (000's)	100.000001%	27.554180%	0.000000%	8.565531%	15.376677%	0.000000%	4.953560%
		149,284	5,113	0	258	3,213	0	338
22	Mains & Services (000's) Excl AF Distribution	100.000000%	3.425015%	0.000000%	0.172825%	2.152274%	0.000000%	0.226414%
		504	21	0	0	33	0	9
23	Structures and Improvements	100.000001%	4.166667%	0.000000%	0.000000%	6.597222%	0.000000%	1.736111%
		169,079	5,654	0	1,034	4,956	0	917
24	Net Gas Plant in Service (000's)	100.000001%	3.344005%	0.000000%	0.611550%	2.931328%	0.000000%	0.542203%
		268,554	8,053	0	1,702	6,351	0	1,159
25	Total Gas Plant in Service (000's)	100.000000%	2.998656%	0.000000%	0.633765%	2.364983%	0.000000%	0.431478%
		108,609	195	1,508	1,700	0	0	1,328
26	Projected Operating Revenue (000's)	100.000000%	0.179543%	1.388467%	1.565248%	0.000000%	0.000000%	1.222735%
		3,811	129	1	52	83	4	17

Montana-Dakota Utilities Co.
ND PSC Case No. PU-17-295

Cost-of-Service Study Using Corrected Minimum-Size Analysis

		Total	Minot Air Force Base Distribution		
		North Dakota	Demand	Energy	Customer
		23,351,305	0	0	0
1	Dk Throughput Projected	100.000000%	0.000000%	0.000000%	0.000000%
		192,668	0	0	0
2	Peak Design Day @ Distribution	100.000000%	0.000000%	0.000000%	0.000000%
		17,924,849	0	0	0
3	Dk Sales Projected	100.000000%	0.000000%	0.000000%	0.000000%
		112,516	0	0	0
4	Average Customers	100.000000%	0.000000%	0.000000%	0.000000%
		154,248	0	0	0
5	Total Weighted Customers	100.000000%	0.000000%	0.000000%	0.000000%
		112,352	0	0	0
6	Average Res. & Firm General Cust.	100.000000%	0.000000%	0.000000%	0.000000%
		112,512	0	0	0
8	Average Customers @ Distribution	100.000000%	0.000000%	0.000000%	0.000000%
	Total Weighted Customers Excluding	154,172	0	0	0
9	Large IT - Transmission Customers	100.000000%	0.000000%	0.000000%	0.000000%
		50,826	0	0	0
10	Residential & Firm General Propane Sales	100.000000%	0.000000%	0.000000%	0.000000%
		102,474	0	0	0
13	Distribution Mains (000's) excluding Heskett & AF Dist	99.999997%	0.000000%	0.000000%	0.000000%
		198,649	622	0	613
15	Distribution Plant (000's) excluding Heskett	100.000000%	0.313116%	0.000000%	0.308585%
		36,097	0	0	0
16	Meters & Regulators (000's) Excl AF Distribution	100.000000%	0.000000%	0.000000%	0.000000%
		120,124	0	0	4
17	Weighted Services	100.000000%	0.000000%	0.000000%	0.003330%
		1,962	0	0	0
18	Meas. & Reg. Sta. Eqpt.- General (000's)	99.999999%	0.000000%	0.000000%	0.000000%
		5,360	0	0	0
19	Meas. & Reg. Eqpt.- City Gate (000's)	99.999998%	0.000000%	0.000000%	0.000000%
		4,494	0	0	15
20	Service Regulators (000's)	100.000000%	0.000000%	0.000000%	0.333778%
		969	0	0	0
21	Ind. Meas. & Reg. Sta. Eqpt. (000's)	100.000001%	0.000000%	0.000000%	0.000000%
		149,284	0	0	0
22	Mains & Services (000's) Excl AF Distribution	100.000000%	0.000000%	0.000000%	0.000000%
		504	0	0	0
23	Structures and Improvements	100.000001%	0.000000%	0.000000%	0.000000%
		169,079	776	0	643
24	Net Gas Plant in Service (000's)	100.000001%	0.458958%	0.000000%	0.380296%
		268,554	904	0	753
25	Total Gas Plant in Service (000's)	100.000000%	0.336618%	0.000000%	0.280391%
		108,609	0	0	0
26	Projected Operating Revenue (000's)	100.000000%	0.000000%	0.000000%	0.000000%
		3,811	0	0	0

Cost-of-Service Study Using Corrected Minimum-Size Analysis

		Total	Residential			Small Firm General		
		North Dakota	Demand	Energy	Customer	Demand	Energy	Customer
27	All Other Dist. Operation Exp. (000's) Excl AF Dist	99.999999%	18.945159%	0.209919%	41.485173%	4.749410%	0.052480%	5.799003%
		1,152	215	0	442	54	0	57
28	All Other Dist. Maintenance Exp. (000's) Excl AF Dist	100.000000%	18.663194%	0.000000%	38.368056%	4.687500%	0.000000%	4.947917%
		9,524	1,772	16	3,834	445	4	528
30	Distribution O&M (000's)	100.000002%	18.605628%	0.167997%	40.256194%	4.672407%	0.041999%	5.543889%
		21,532	3,324	214	9,971	835	50	1,305
31	O&M Excl. Cost of Gas (000's)	100.000001%	15.437488%	0.993870%	46.307819%	3.877949%	0.232213%	6.060747%
		167,660	43,653	0	56,943	10,995	0	7,539
36	Net Gas Plant in Service (000's) Excluding Minot AFB	99.999998%	26.036671%	0.000000%	33.963441%	6.557927%	0.000000%	4.496609%
		121,836	0	0	96,792	0	0	15,516
37	Weighted Services Excluding Transmission Level Customers	100.000000%	0.000000%	0.000000%	79.444499%	0.000000%	0.000000%	12.735152%
		216,758	53,528	0	82,045	13,479	0	11,499
38	Distribution Plant Less Direct Assignment (000's)	99.999998%	24.694821%	0.000000%	37.850966%	6.218456%	0.000000%	5.304995%
		100,660	40,833	0	15,714	10,281	0	1,762
40	Distribution Mains (000) Excluding Transmission Level Customer-Direct Assigned	99.999998%	40.565268%	0.000000%	15.610968%	10.213590%	0.000000%	1.750447%

Montana-Dakota Utilities Co.
ND PSC Case No. PU-17-295

Cost-of-Service Study Using Corrected Minimum-Size Analysis

		Total	Large Firm General			Air Force Delivery		
		North Dakota	Demand	Energy	Customer	Demand	Energy	Customer
27	All Other Dist. Operation Exp. (000's) Excl AF Dist	99.999999%	11.335607%	0.131199%	9.446340%	0.209919%	0.000000%	0.131199%
		1,152	130	0	150	3	0	2
28	All Other Dist. Maintenance Exp. (000's) Excl AF Dist	100.000000%	11.284722%	0.000000%	13.020833%	0.260417%	0.000000%	0.173611%
		9,524	1,063	10	957	21	0	14
30	Distribution O&M (000's)	100.000002%	11.161277%	0.104998%	10.048299%	0.220496%	0.000000%	0.146997%
		21,532	1,995	143	1,983	39	10	26
31	O&M Excl. Cost of Gas (000's)	100.000001%	9.265280%	0.664128%	9.209549%	0.181126%	0.046443%	0.120751%
		167,660	26,144	0	9,650	97	0	78
36	Net Gas Plant in Service (000's) Excluding Minot AFB	99.999998%	15.593493%	0.000000%	5.755707%	0.057712%	0.000000%	0.046475%
		121,836	0	0	8,902	0	0	0
37	Weighted Services Excluding Transmission Level Customers	100.000000%	0.000000%	0.000000%	7.306543%	0.000000%	0.000000%	0.000000%
		216,758	31,953	0	13,655	0	0	56
38	Distribution Plant Less Direct Assignment (000's)	99.999998%	14.741324%	0.000000%	6.299652%	0.000000%	0.000000%	0.025835%
		100,660	24,425	0	778	0	0	0
40	Distribution Mains (000) Excluding Transmission Level Customer-Direct Assigned	99.999998%	24.264852%	0.000000%	0.772899%	0.000000%	0.000000%	0.000000%

Montana-Dakota Utilities Co.
ND PSC Case No. PU-17-295

Cost-of-Service Study Using Corrected Minimum-Size Analysis

		Total	Small Interruptible			Large Interruptible		
		North Dakota	Demand	Energy	Customer	Demand	Energy	Customer
27	All Other Dist. Operation Exp. (000's) Excl AF Dist	99.999999%	3.384938%	0.026240%	1.364471%	2.177906%	0.104959%	0.446077%
		1,152	40	0	22	30	0	7
28	All Other Dist. Maintenance Exp. (000's) Excl AF Dist	100.000000%	3.472222%	0.000000%	1.909722%	2.604167%	0.000000%	0.607639%
		9,524	320	2	139	214	7	45
30	Distribution O&M (000's)	100.000002%	3.359933%	0.021000%	1.459471%	2.246955%	0.073499%	0.472491%
		21,532	600	16	271	402	13	85
31	O&M Excl. Cost of Gas (000's)	100.000001%	2.786550%	0.074308%	1.258592%	1.866989%	0.060375%	0.394761%
		167,660	5,654	0	1,034	4,956	0	917
36	Net Gas Plant in Service (000's) Excluding Minot AFB	99.999998%	3.372308%	0.000000%	0.616726%	2.956137%	0.000000%	0.546792%
		121,836	0	0	606	0	0	20
37	Weighted Services Excluding Transmission Level Customers	100.000000%	0.000000%	0.000000%	0.497390%	0.000000%	0.000000%	0.016416%
		216,758	6,703	0	1,356	2,364	0	120
38	Distribution Plant Less Direct Assignment (000's)	99.999998%	3.092389%	0.000000%	0.625582%	1.090617%	0.000000%	0.055361%
		100,660	5,113	0	25	1,728	0	1
40	Distribution Mains (000) Excluding Transmission Level Customer-Direct Assigned	99.999998%	5.079475%	0.000000%	0.024836%	1.716670%	0.000000%	0.000993%

Montana-Dakota Utilities Co.
ND PSC Case No. PU-17-295

Cost-of-Service Study Using Corrected Minimum-Size Analysis

		Total North Dakota	Minot Air Force Base Distribution Demand	Energy	Customer
27	All Other Dist. Operation Exp. (000's) Excl AF Dist	99.999999%	0.000000%	0.000000%	0.000000%
		1,152	0	0	0
28	All Other Dist. Maintenance Exp. (000's) Excl AF Dist	100.000000%	0.000000%	0.000000%	0.000000%
		9,524	133	0	0
30	Distribution O&M (000's)	100.000002%	1.396472%	0.000000%	0.000000%
		21,532	250	0	0
31	O&M Excl. Cost of Gas (000's)	100.000001%	1.161063%	0.000000%	0.000000%
		167,660	0	0	0
36	Net Gas Plant in Service (000's) Excluding Minot AFB	99.999998%	0.000000%	0.000000%	0.000000%
		121,836	0	0	0
37	Weighted Services Excluding Transmission Level Customers	100.000000%	0.000000%	0.000000%	0.000000%
		216,758	0	0	0
38	Distribution Plant Less Direct Assignment (000's)	99.999998%	0.000000%	0.000000%	0.000000%
		100,660	0	0	0
40	Distribution Mains (000) Excluding Transmission Level Customer-Direct Assigned	99.999998%	0.000000%	0.000000%	0.000000%

Montana-Dakota Utilities Co.
ND PSC Case No. PU-17-295

Cost-of-Service Study Using Corrected Minimum-Size Analysis

Rate	Customer Class	Factor No. 1 Projected DK Throughput	Factor No. 2 Design Day Peak	Factor No. 3 DK Sales Projected	Factor No. 4 Average Customers	Factor No. 5 Total Weighted Customers	Factor No. 6 Average Res & Firm Gen Customers	Factor No. 8 Average Customers at Distribution	Factor No. 9 Total Weighted Customers Ex. LG IT Trans.	Factor No. 17 Weighted Services Distribution
60	Residential Gas Service	8,826,214	95,561	8,826,214	96,792	96,792	96,792	96,792	96,792	96,792
64	Minot Air Force Base	415,925	0	415,925	1		0			4
64	Air Force-Distribution PAR Site	31,858	0	31,858	1					
64	Air Force-Distribution PAR Site	42,317	0	42,317	1					
		490,100	0	490,100	3	237	0	0	237	4
70	Firm General Service									
	Firm General-Small	2,036,838	24,062	2,036,838	10,850	13,020	10,850	10,850	13,020	15,082
	Firm General-Large	5,998,825	57,033	5,998,825	4,710	39,093	4,710	4,710	39,093	7,630
	Subtotal Firm	8,035,663	81,095	8,035,663	15,560	52,113	15,560	15,560	52,113	22,712
71	Small Interruptible Sales	572,872	4,665	572,872	92	2,760		92	2,760	352
81	Small Interruptible Transport	1,104,513	7,302		63	1,890		63	1,890	241
	Subtotal Small IT	1,677,385	11,967	572,872	155	4,650	0	155	4,650	593
85	Large Interruptible Sales	0	0	0	0	0		0	0	0
82	Large Interruptible Transport	4,321,943	4,045		6	456		5	380	23
	Subtotal Large IT	4,321,943	4,045	0	6	456	0	5	380	23
	Total North Dakota Gas	23,351,305	192,668	17,924,849	112,516	154,248	112,352	112,512	154,172	120,124

Montana Dakota Utilities Co.
ND PSC Case No. PU-17-295

Exhibit ___ (SJR-6)

Comparison of Class Revenue Deficiencies Under Each COSS with MDU's Proposed Class Revenue Allocation

MDU as Filed: Minimum System Using Current Cost of 2-Inch Main

	Cost of Service	Less Other Revenue	Base Cost	Present Base Revenues	Revenue Deficiency	MDU Proposed Increase
Residential	$ 28,382,000	$ 1,808,000	$ 26,574,000	$ 22,762,526	$ 5,619,474	$ 3,458,717
Firm General	12,788,000	1,055,000	11,733,000	11,785,787	1,002,213	2,409,704
Air Force Delivery	104,000	-	104,000	119,891	(15,891)	-
Small Interruptible	1,306,000	141,000	1,165,000	1,700,349	(394,349)	(171)
Large Interruptible	989,000	61,000	928,000	1,327,781	(338,781)	139
Minot AFB Distribution	446,000	463,000	(17,000)	-	(4,277)	-
Total	$ 44,015,000	$ 3,528,000	$ 40,487,000	$ 37,696,334	$ 5,868,389	$ 5,868,389

AARP Recommended: Basic Customer Method

	Cost of Service	Less Other Revenue	Base Cost	Present Base Revenues	Revenue Deficiency	MDU Proposed Increase
Residential	$ 26,511,000	$ 1,808,000	$ 24,703,000	$ 22,762,526	$ 3,748,474	$ 3,458,717
Firm General	14,235,000	1,055,000	13,180,000	11,785,787	2,449,213	2,409,704
Air Force Delivery	104,000	-	104,000	119,891	(15,891)	-
Small Interruptible	1,627,000	141,000	1,486,000	1,700,349	(73,349)	(171)
Large Interruptible	1,093,000	61,000	1,032,000	1,327,781	(234,781)	139
Minot AFB Distribution	445,000	463,000	(18,000)	-	(5,277)	-
Total	$ 44,015,000	$ 3,528,000	$ 40,487,000	$ 37,696,334	$ 5,868,389	$ 5,868,389

Montana Dakota Utilities Co.
ND PSC Case No. PU-17-295

Exhibit ___ (SJR-6)
Page 2 of 2

Alternate: Minimum System Corrected to Use Historic Cost of 0.75-Inch Main

	Cost of Service	Less Other Revenue	Base Cost	Present Base Revenues	Revenue Deficiency	MDU Proposed Increase
Residential	$ 27,879,000	$ 1,808,000	$ 26,071,000	$ 22,762,526	$ 5,116,474	$ 3,458,717
Firm General	13,172,000	1,055,000	12,117,000	11,785,787	1,386,213	2,409,704
Air Force Delivery	104,000	-	104,000	119,891	(15,891)	-
Small Interruptible	1,403,000	141,000	1,262,000	1,700,349	(297,349)	(171)
Large Interruptible	1,011,000	61,000	950,000	1,327,781	(316,781)	139
Minot AFB Distribution	446,000	463,000	(17,000)	-	(4,277)	-
Total	$ 44,015,000	$ 3,528,000	$ 40,487,000	$ 37,696,334	$ 5,868,389	$ 5,868,389

Montana Dakota Utilities Co.
ND PSC Case No. PU-17-295

Exhibit ___ (SJR-7)

Decile Distribution of Annual Usage for Full-Year Residential Customers

Data provided in response to AARP 1.12

Full-year defined as between 300 and 410 days of billed usage, annualized to 365 days.

	Dekatherms per year		
Decile	All Customers	LIHEAP Recipients	All Other Customers
10%	39.16	44.43	38.99
20%	50.86	54.12	50.80
30%	58.80	61.90	58.72
40%	65.94	69.09	65.86
50%	72.90	75.42	72.80
60%	80.48	82.60	80.40
70%	89.84	91.88	89.80
80%	102.22	101.83	102.24
90%	123.10	122.12	123.12
No. of accounts in sample	75,634	1,892	73,742

Each decile represents 1/10 of customers in sample

Exhibit ___ (SJR-8)
Page 1 of 3

TRI-STATE

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*Be advised this table is used as a guideline for selecting a gas meter for your natural gas measurement application.
If have questions or need additional information please call our office at (901) 363-0377

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ProductNumber	Manufacturer	Description	Pressure	Capacity	Differential	Connections
R275	SENSUS	RESIDENTIAL GAS METER (DIAPHRAGM)	7"	275 CFH	.5"	3/4 or 1 NPT
415	SENSUS	RESIDENTIAL GAS METER (DIAPHRAGM)	7"	415 CFH	.5"	1 or 1-1/4 or 1-1/2 NPT
750-STD	SENSUS	INDUSTRIAL GAS METER (DIAPHRAGM) (REFURBISHED ONLY)	7"	750 CFH	.5"	1-1/4 or 1-1/2 NPT
B3-8C175	DRESSER	INDUSTRIAL GAS METER (ROTARY)	7"	800 CFH	.5"	2 Flange
1600-STD	SENSUS	INDUSTRIAL GAS METER (DIAPHRAGM) (REFURBISHED ONLY)	7"	800 CFH	.5"	1-1/4 or 1-1/2 NPT
1000-STD	SENSUS	INDUSTRIAL GAS METER (DIAPHRAGM) (REFURBISHED ONLY)	7"	1000 CFH	.5"	1-1/4 or 1-1/2 NPT
B3-11C175	DRESSER	INDUSTRIAL GAS METER (ROTARY)	7"	1100 CFH	.5"	2 Flange
SONIX-600	SENSUS	ULTRASONIC SONIX 600	7"	1130 CFH		3/4 OR 1 OR 1-1/4 OR 1-1/2
3000-STD	SENSUS	INDUSTRIAL GAS METER (DIAPHRAGM) (REFURBISHED ONLY)	7"	1450 CFH	2"	2 or 3 NPT
B3-15C175	DRESSER	INDUSTRIAL GAS METER (ROTARY)	7"	1500 CFH	.5"	2 Flange
SONIX-880	SENSUS	ULTRASONIC SONIX 880	7"	1625 CFH		1 OR 1-1/4 OR 1-1/2-2 NPT
B3-2M175	DRESSER	INDUSTRIAL GAS METER (ROTARY)	7"	2000 CFH	.5"	2 Flange
SONIX-2000	SENSUS	ULTRASONIC SONIX 2000	7"	2000 CFH		2-IN FLANGE
5000-STD	SENSUS	INDUSTRIAL GAS METER (DIAPHRAGM) (REFURBISHED ONLY)	7"	2500 CFH	2"	4 NPT or FLG
FVP-750	NICE	FLANGED VORTEX PLATE 3/4-INCH BORE	7"	2664 CFH		3/4 Flange
FVP-1750	NICE	FLANGED VORTEX PLATE 3/4-INCH BORE	7"	2664 CFH		1 Flange
B3-3M175	DRESSER	INDUSTRIAL GAS METER (ROTARY)	7"	3000 CFH	.5"	2 Flange
FVP-1000	NICE	FLANGED VORTEX PLATE 1-INCH BORE	7"	4428 CFH		1 Flange
FVP-1510	NICE	FLANGED VORTEX PLATE 1-INCH BORE	7"	4428 CFH		1-1/2 Flange
FVP-2100	NICE	FLANGED VORTEX PLATE 1 INCH BORE	7"	4428 CFH		2 Flange
10000-STD	SENSUS	INDUSTRIAL GAS METER (DIAPHRAGM) (REFURBISHED ONLY)	7"	5000 CFH	.5"	4 NPT or FLG
B3-5M175	DRESSER	INDUSTRIAL GAS METER (ROTARY)	7"	5000 CFH	.5"	3 Flange
B3-7M175	DRESSER	INDUSTRIAL GAS METER (ROTARY)	7"	7000 CFH	.5"	3 Flange
TPL-9	SENSUS	INDUSTRIAL GAS METER (TURBINE)	7"	9000 CFH		2 or 3 Flange

Exhibit ___ (SJR-8)
Page 2 of 3

T-10	SENSUS	INDUSTRIAL GAS METER (TURBINE)	7"	10000 CFH		2 or 3 Waffer Flange
FVP-1500	NICE	FLANGED VORTEX PLATE 1-1/2 BORE	7"	10878 CFH		1-1/2 Flange
FVP-2150	NICE	FLANGED VORTEX PLATE 1-1/2 INCH BORE	7"	10878 CFH		2 Flange
B3-11M175	DRESSER	INDUSTRIAL GAS METER (ROTARY)	7"	11000 CFH	.5"	4 Flange
B3-16M175	DRESSER	INDUSTRIAL GAS METER (ROTARY)	7"	16000 CFH	.5"	4 Flange
T18-STD	SENSUS	INDUSTRIAL GAS METER (TURBINE)	7"	18000 CFH		4 Flange
FVP-2000	NICE	FLANGED VORTEX PLATE 2-INCH BORE	7"	18300 CFH		2 Flange
FVP-3200	NICE	FLANGED VORTEX PLATE 2-INCH BORE	7"	18300 CFH		3 Flange
T27-STD	SENSUS	INDUSTRIAL GAS METER (TURBINE)	7"	27000 CFH		4 Flange
T35-STD	SENSUS	INDUSTRIAL GAS METER (TURBINE)	7"	35000 CFH		6 Flange
FVP-3000	NICE	FLANGED VORTEX PLATE 3 INCH BORE	7"	40680 CFH		3 Flange
FVP-4300	NICE	FLANGED VORTEX PLATE 3 INCH BORE	7"	40680 CFH		4 Flange
T57-STD	SENSUS	INDUSTRIAL GAS METER (TURBINE)	7"	57000 CFH		6 Flange
FVP-4000	NICE	FLANGED VORTEX PLATE 4-INCH BORE	7"	70800 CFH		4 Flange
FVP-6400	NICE	FLANGED VORTEX PLATE 4-INCH BORE	7"	70800 CFH		6 Flange
FVP-6000	NICE	FLANGED VORTEX PLATE 6-INCH BORE	7"	160500 CFH		6 Flange
FVP-8600	NICE	FLANGED VORTEX PLATE 6-INCH BORE	7"	160500 CFH		8 Flange
FVP-8000	NICE	FLANGED VORTEX PLATE 8-INCH BORE	7"	378000 CFH		8 Flange

Return to sizing: Click

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*Be advised this table is used as a guideline for selecting a gas regulators for your natural gas application.
If have questions or need additional information please call our office at (901) 363-0377

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MfgName	ProductNo	BodySize	Droop	InternalRelief	OutletPressPsig	InletPress	MinCapacity	MaxCapacity
BRYAN DONKIN	260R	1/2; 3/4; 1	5	yes	1 psig	2 psig	130 CFH	299 CFH
SENSUS TECHNOLOGIES	243-8-2	1-1/4	5.6	yes	1 psig	2 psig	450 CFH	1850 CFH
SENSUS TECHNOLOGIES	243-8-2	1-1/2 OR 2	5.6	yes	1 psig	2 psig	450 CFH	2100 CFH

Return to sizing: Click

Exhibit ___ (SJR-9)
Page 1 of 4

Measurement Control Systems

Call us Toll-Free 1 (844) 263-7582 for any assistance or questions.

Gas Meters

Elster Meter is a worldwide market leader for state-of-the art high accuracy down-stream gas measurement and regulation. Elster Meter supplies you worldwide with Meter and SMART meter systems, communication modules to the head end system and many more. Furthermore, Elster Perfection offers a complete line of gas distribution products that allow installers to make fast easy and safe connections from "main to meter" and from "tank to house".

We're the largest distributor of Elster Gas Meters in the US.

Call us Toll-Free 1(844)263-7582 for any assistance or questions.

Brand New! American Meter: BK-250

A small 3/4" residential gas sub-meter cable of gas loads up to 250

American Meter: BK-250 With Pulser

A 3/4" residential gas meter with pulse interface. Perfect for large scale sub-metering projects ...

MBH (0.6 SG N.G. @ 7" WC). LA...

$79.95

$109.95

American Meter: Diaphragm Gas Meter AC-250

A 3/4" or 1" multipurpose diaphragm gas meter cable of gas loads up to 250 MBH (0.6 SG N.G. @ 7" ...

From $134.95 On Sale from $149.95

American Meter-Diaphragm Gas Sub-meter AM250

A 3/4" side inlet & outlet diaphragm gas sub-meter available with temp. comp. and pulse outpu...

From $135.95 On Sale from $159.00

Exhibit ___ (SJR-9)
Page 3 of 4

American Meter- Natural Gas Flow Meter AL425

A 1-1/4" multipurpose diaphragm gas meter cable of gas loads up to 425 MBH (0.6 SG Gas @ 7" WC). ...

From $439.00

American Meter- Gas Meter AC630

Product Description Diaphragm gas meter with odometer. C/F index & temperature compensation....

$899.00

Exhibit ___ (SJR-9)
Page 4 of 4

Honeywell American Quantometer Turbine Gas Meter

Product Description: The QA meter offers the ultimate in compactnessand accuracy to continuously ...

From $999.00

American Meter- AC800 Diaphragm Meter

Features • Die-cast aluminum case • High-performance ball bearing crank frame for excellent sust...

$1,099.00

Montana Dakota Utilities Co.
ND PSC Case No. PU-17-295

Exhibit ___ (SJR-10)

Residential Energy Consumption Survey (RECS) 2009: Average Gas Usage (100 cu. ft.) of Households that Use Natural Gas
Reportable Domain 10 (Iowa, Minnesota, North Dakota, South Dakota)
Source: Analysis using RECS 2009 Public use microdata

	All Households		No Retiree		Retiree*	
	Households	Avg Gas	Households	Avg Gas	Households	Avg Gas
All households in IA, MN, ND, SD	2,556,666	838	1,720,666	857	836,001	798
All one-person households	712,926	700	376,274	704	336,652	695
One-person HH and ≤ 150% poverty	198,602	742	67,633	799	130,969	713
One-person HH and > 150% poverty	514,324	684	308,641	683	205,683	684
All households with 2 or more people	1,843,740	891	1,344,392	900	499,348	867
2 or more people and ≤ 150% poverty	281,912	843	229,606	825	52,305	923
2 or more and > 150% poverty	1,561,828	900	1,114,785	915	447,043	861

*Retiree defined as one or more household member receiving retirement income

Number of One-Person Households Age 65 or Older in Counties Served by MDU

Source: U.S. Census, American Community Survey

County	One-Person Households Age 65 or Older
Barnes	99
Benson	45
Bowman	79
Burke	27
Burleigh	563
Cavalier	67
Dunn	24
Eddy	30
Emmons	96
Foster	64
Golden Valley	20
Hettinger	44
Kidder	32
McKenzie	48
McLean	128
Morton	287
Mountrail	93
Pembina	80
Ramsey	181
Richland	147
Slope	19
Stark	352
Stutsman	329
Walsh	159
Ward	401
Williams	120
MDU Total	3,534

Montana Dakota Utilities Co.
ND PSC Case No. PU-17-295

Exhibit ___ (SJR-12)

AARP Proposed Residential Rate Design Under MDU's Proposed Revenue Requirement
Source: MDU Statement N

Proof of Revenues

			Present		AARP Proposed	
	Billing Units	Multiplier	Rate	Revenue	Rate	Revenue
Customer charge	96,792	365	$ 0.6443	$ 22,762,526	$ 0.6443	$ 22,762,526
Volumetric charge	8,826,214	1	$ -	-	$ 0.3917	3,457,228
Total				$ 22,762,526		$ 26,219,754
Revenue target under MDU proposed revenue requirement						$ 26,219,654
Difference from target						$ 100

Effect on Distribution Portion of Bills of Representative Residential Customers

			MDU Proposed		AARP Proposed	
Customer Type	Annual Use	Present Bill	Bill	% Change	Bill	% Change
Low use	40	$ 235.17	$ 270.90	15.2%	$ 250.84	6.7%
Typical	72	$ 235.17	$ 270.90	15.2%	$ 263.37	12.0%
Average	91	$ 235.17	$ 270.90	15.2%	$ 270.81	15.2%
High use	120	$ 235.17	$ 270.90	15.2%	$ 282.17	20.0%

Effect on Total Bills (Including Cost of Gas) of Representative Residential Customers
(Note: Cost of gas as of 5/1/2017 per MDU Statement N)

			MDU Proposed		AARP Proposed	
Customer Type	Annual Use	Present Bill	Bill	% Change	Bill	% Change
Low use	40	$ 395.61	$ 431.34	9.0%	$ 411.28	4.0%
Typical	72	$ 523.96	$ 559.70	6.8%	$ 552.16	5.4%
Average	91	$ 600.17	$ 635.90	6.0%	$ 635.82	5.9%
High use	120	$ 716.49	$ 752.22	5.0%	$ 763.49	6.6%

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SET 1 - DATA REQUESTS
ISSUED NOVEMBER 14, 2017
CASE NO. PU-17-295

1.2 Reference: Proposed tariff, Sheet No. 37. Please review the language in numbered paragraph 4 on this page and provide a correction, if necessary. It appears that there may be words or phrases missing in the first sentence, particularly where it states: "shall be allocated to each rate class, transmission level customers, based on ...".

Response:

The first sentence of Paragraph 4 should read: "The projected revenue requirement and true-up balance shall be allocated to each rate class, excluding transmission level customers, based on the respective rate class' percentage of distribution (or non-gas) revenues authorized in the Company's last general rate case."

MONTANA-DAKOTA UTILITIES CO.
AARP
SET 1 - DATA REQUESTS
ISSUED NOVEMBER 14, 2017
CASE NO. PU-17-295

1.3 Reference: Proposed tariff, Sheet No. 37. For each of the following cost components, please explain in detail why the Company believes it is appropriate to collect cost increases through an automatic adjustment mechanism, and how such cost increases will be measured:

- **a. operation and maintenance expenditures**
- **b. depreciation**
- **c. taxes**
- **d. current return on project costs during construction.**

Response:

Montana-Dakota has not proposed to collect System Safety and Integrity Program (SSIP) costs through an automatic adjustment mechanism. The proposed SSIP must be reviewed and approved by the Commission prior to implementing or updating SSIP rates.

a - c. All incremental costs or savings incurred that are specific to the SSIP should be included in the SSIP revenue requirement. This provides for a total SSIP revenue requirement reflecting both cost increases and decreases to be included in the Company's SSIP rates. Pursuant to the terms of the proposed Rate 94 tariff, the Company will file annually an application requesting Commission approval to update its SSIP rates to reflect the Company's most recent projected capital costs and related expenses, along with a true-up of the previous year's actuals costs.

d. The Company did not intend to propose to earn a return on project costs during construction. Please see the direct testimony of T. Jacobson, Exhibit No.___(TRJ-3), page 5 for an example of how the Company has proposed to calculate the return on projects once they have been placed in service. The language on proposed tariff Sheet No. 37 should be clarified from "current return on project costs during construction" to "return on project costs included in rate base".

MONTANA-DAKOTA UTILITIES CO.
AARP
SET 1 - DATA REQUESTS
ISSUED NOVEMBER 14, 2017
CASE NO. PU-17-295

1.4 Reference: Proposed tariff, Sheet No. 37.

a. Does the proposed System Safety and Integrity Program (SSIP) Adjustment Mechanism include a return on the capital costs of completed projects? If so, please indicate where in the proposed tariff such costs are identified and provide corrected language, if necessary.

b. Do the rate of return and capital structure for the SSIP Adjustment Mechanism include short-term debt, as would be the case in calculating an Allowance for Funds Used During Construction (AFUDC)? If not, why not?

c. Would projects eligible for inclusion in the SSIP Adjustment Mechanism also accrue AFUDC? Please explain why or why not.

d. Please explain in detail why the proposed SSIP Adjustment Mechanism would allocate costs among customer classes based on each class's percentage of distribution revenues, rather than a measure that more closely tracks the costs being collected through the mechanism.

e. Why is the Company not proposing any cap or limit on the amount of the SSIP Adjustment Mechanism?

f. Why is the Company proposing to include operations and maintenance expenses in the SSIP Adjustment Mechanism?

g. How will the Company measure incremental operations and maintenance expenses that are associated with the SSIP but not already recovered through base rates?

h. Will the automatic adjustment of SSIP-related return on investment include a reduction to rate base for additional accrued depreciation during the period since the conclusion of the test year in the most recent rate case? If not, why not?

i. Why is the Company proposing to update the capital structure but not the return on equity for purposes of the SSIP Adjustment Mechanism?

j. Will the calculation of the SSIP Adjustment Mechanism include a credit for reduced operations and maintenance expenditures associated with facilities that are repaired, replaced, or upgraded? If not, why not?

k. Will the calculation of the SSIP Adjustment Mechanism include a credit for the reduction in lost or unaccounted for gas as a result of the repair, replacement, or upgrade of facilities under the SSIP? If not, why not?

Response:

a. Please see AARP Response No. 1.3 d.

b. Yes. The Company has proposed to use the capital structure, including short term debt, consistent with the data presented in Statement D, page 1.

c. Yes. Typically all projects with a cost greater than $50,000 and a construction period longer than 30 days are eligible for AFUDC.

d. The Company chose the proposed allocation of costs to the various rate classes as it would maintain the rate design structure ultimately authorized in this rate case within the context of the SSIP mechanism, providing a consistency between the 2018 costs that will be recovered through the Company's base rates and those recovered through the SSIP mechanism.

e. Under the proposed tariff, Montana-Dakota would file annually with the Commission a portfolio of projects and costs that the Company would undertake in the upcoming year. The year following the Company would include in its next year's plan a true-up to actual costs from that projected, allowing the Commission to review the actual project costs incurred for those projects undertaken in the previous year. At that time it is the Company's obligation to show that any cost increases from those projected were prudently and reasonably incurred and should be recoverable through the SSIP mechanism. A cap or limit would prematurely assume any cost increases over and above the Company's projections is unreasonable, which in effect, would limit the Company's ability to recover prudently incurred project costs.

f. If there are O&M expenses incurred specific to the SSIP, the expenses should be included in the SSIP revenue requirement, no different than any other cost incurred that is specific to the SSIP.

g. Please see PSC Response No. 2.55.

h. Once again, the SSIP is not an automatic adjustment mechanism. The SSIP will include a reduction for accumulated depreciation and deferred income taxes, as applicable.

i. The Company has proposed to use the most recent Commission authorized rate of return on equity as the Company does not have a basis to update the rate used absent Commission approval.

j. If there are specific O&M savings that result from the SSIP program the Company does intend to include those savings as an offset to the revenue requirement.

k. The lost and unaccounted for gas costs are included in the Company's Cost of Gas - Natural Gas Rate 88 tariff and would not be included in the SSIP.

MONTANA-DAKOTA UTILITIES CO.
NORTH DAKOTA PUBLIC SERVICE COMMISSION
SET 2 - DATA REQUESTS
ISSUED OCTOBER 6, 2017
CASE NO. PU-17-295

2.55. Refer to page 32 of Mr. Darras' testimony.

a) How will the Company account for the avoidance of duplicative or overlapping of recoveries under the SSIP mechanism and under base capital spending?

b) How will the Company segregate out O&M expenses and Overheads related to replacement of its mains and services under the SSIP and under base capital spending?

Response:

a) All costs associated with the SSIP Mechanism will be identified and submitted to the Commission prior to recovery and the specific project costs will be tracked separately.

b) If there are O&M expenses and overheads specifically related to the SSIP, they too will be identified and tracked separately.

MONTANA-DAKOTA UTILITIES CO.
AARP
SET 1 - DATA REQUESTS
ISSUED NOVEMBER 14, 2017
CASE NO. PU-17-295

1.5 Reference: Proposed tariff, Sheet No. 42.13.

a. Please provide a workpaper showing the calculation of the proposed $40.00 returned check charge.

b. Please provide the Company's most recent statement from each of its banks or other payment processors showing the amount charged to the Company for each type of returned payment (paper check, ACH, credit card, etc.).

Response:

a. Please see PSC Response Nos. 1.45 and 2.9.

b. Please see PSC Response No. 2.9.

MONTANA-DAKOTA UTILITIES CO.
NORTH DAKOTA PUBLIC SERVICE COMMISSION
SET 1 - DATA REQUESTS
ISSUED AUGUST 14, 2017
CASE NO. PU-17-295

Witness: Stephanie Bosch

1.45: In General Provisions Rate 100, Page 14 of 19, the Company proposes to change its Returned Check Charge to $40. Please provide evidence that the costs for this are indeed $40.

Response:

The Company proposed to increase the returned check charge to $40,consistent with the charge recently approved in the Company's North Dakota electric rate case (Case No. PU-16-666) and the Company's most recent South Dakota gas (Docket No. NG15-005) and electric (Docket No. EL15-024) rate cases.

MONTANA-DAKOTA UTILITIES CO.
NORTH DAKOTA PUBLIC SERVICE COMMISSION
SET 2 - DATA REQUESTS
ISSUED OCTOBER 6, 2017
CASE NO. PU-17-295

2-9. In response to Data Request 1.45, the Company states that because the Commission previously approved the increase in returned check charges in Case No. PU-16-666, it should approve it in this case. That is not a response to the question asked. Each rate case needs to justify changes and Staff is asking for justification. This charge is detrimental to the most vulnerable customers, those who have issues with the ability to pay. In lieu of a $40 return check charge, a customer could contribute that towards the payment of their bill. Therefore, we repeat our question, please provide the costs that the Company incurs for a check that is returned for insufficient funds.

Response:

Please see the table below for the requested information.

The Company did not propose a cost-based Returned Check Charge. The level of the proposed charge is such that it's intent is to serve as a deterrent to customers to not write that check in which there are insufficient funds in the account to cover the amount of the check.

Charge	Cost/ Transaction	# 1/	Total Cost
Returned Check Charge	$4.00	458	$1,832
Returned Check - Special Instructions	$10.00	8	80
Redeposited Check	$2.00	615	1,230
ACH Return	$2.75	3,873	10,651
Unauthorized ACH Return	$6.00	29	174
		4,983	13,967
Average Cost/Returned Item			$2.80

1/ Reflects the total number of transactions for all Montana-Dakota for January through August 2017. The number of returned items specific to North Dakota is 2,842.

STATE OF NORTH DAKOTA
PUBLIC SERVICE COMMISSION

Montana-Dakota Utilities Co., a Division of	)	
MDU Resources Group, Inc.	)	**Case No. PU-I7-295**
2017 Natural Gas Rate Increase Application	)	

STATE OF NORTH DAKOTA)
) ss.
COUNTY OF BURLEIGH)

AFFIDAVIT OF SERVICE

I hereby certify that the eight (8) copies of the transcript of the testimony of Scott J. Rubin, were hand delivered to the Secretary of the North Dakota Public Service Commission on December 18, 2017, with a complete copy thereof e-mailed to **Daniel S. Kuntz**, MDU Resources Group, PO Box 5650, Bismarck, ND 58502-5650, on this 18th day of December, 2017.

David A. Tschider

Subscribed and sworn to before me this 18th day of December, 2017 by David A. Tschider.

VIRGINIA SWANSON
Notary Public
State of North Dakota
My Commission Expires September 12, 2018

Virginia Swanson

Virginia Swanson, Notary Public