DEPARTMENT OF PUBLIC SERVICE REGULATION
BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MONTANA

* * * * *

IN THE MATTER OF the Application of the	)	REGULATORY DIVISION
Application of Montana-Dakota Utilities Co.	)	
for Authority to Establish Increased Rates for	)	DOCKET NO. D2015.6.51
Electric Service in the State of Montana	)	

Direct Testimony
of
John W. Wilson
on Behalf
of
The Montana Consumer Counsel

November 20, 2015

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I. QUALIFICATIONS

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND ADDRESS.

A. My name is John W. Wilson. I am President of J.W. Wilson & Associates, Inc. Our offices are at 1601 North Kent Street, Suite 1104, Arlington, Virginia 22209.

Q. PLEASE OUTLINE YOUR EDUCATIONAL BACKGROUND.

A. I hold a B.S. degree with senior honors and a Masters Degree in Economics from the University of Wisconsin. I have also received a Ph.D. in Economics from Cornell University. My major fields of study were industrial organization and public regulation of business, and my doctoral dissertation was a study of utility pricing and regulation.

Q. HOW HAVE YOU BEEN EMPLOYED SINCE THAT TIME?

A. After completing my graduate education I was an assistant professor of economics at the United States Military Academy, West Point, New York. In that capacity, I taught courses in both economics and government. While at West Point, I also served as an economic consultant to the Antitrust Division of the United States Department of Justice.

After leaving West Point, I was employed by the Federal Power Commission, first as a staff economist and then as Chief of FPC's Division

of Economic Studies. In that capacity, I was involved in regulatory matters involving most phases of FPC regulation of electric utilities and the natural gas industry. Since 1973 I have been employed as an economic consultant by various clients, including federal, state, provincial and local governments, private enterprise and nonprofit organizations. This work has pertained to a wide range of issues concerning public utility regulation, insurance rate regulation, antitrust matters and economic and financial analysis. In 1975 I formed J.W. Wilson & Associates, Inc., a Washington, D.C. corporation.

Q. WOULD YOU PLEASE DESCRIBE SOME OF YOUR ADDITIONAL PROFESSIONAL ACTIVITIES?

A. I have authored a variety of articles and monographs, including a number of studies dealing with utility regulation and economic policy. I have consulted on regulatory, financial and competitive market matters with the Federal Communications Commission, the National Academy of Sciences, the Ford Foundation, the National Regulatory Research Institute, the Electric Power Research Institute, the U.S. Department of Justice Antitrust Division, the Federal Trade Commission Bureau of Competition, the Commerce Department, the Department of the Interior, the Department of Energy, the Small Business Administration, the Department of Defense, the Tennessee Valley Authority, the Federal Energy Administration, and

numerous state and provincial agencies and legislative bodies in the United States and Canada.

Previously, I was a member of the Economics Committee of the U.S. Water Resources Council, the FPC Coordinating Representative for the Task Force on Future Financial Requirements for the National Power Survey, the Advisory Committee to the National Association of Insurance Commissioners (NAIC) Task Force on Profitability and Investment Income, and the NAIC's Advisory Committee on Nuclear Risks.

In addition, I have testified as an expert witness in court proceedings dealing with competition in the electric power industry and on regulatory matters before more than 50 Federal and State regulatory bodies throughout the United States and Canada. I have also appeared on numerous occasions as an expert witness at the invitation of U.S. Senate and Congressional Committees dealing with antitrust and regulatory legislation. In addition, I have been retained as an expert on regulatory matters by more than 25 State and Federal regulatory agencies. I have also participated as a speaker, panelist, or moderator in many professional conferences and programs dealing with business regulation, financial issues, economic policy and antitrust matters. I am a member of the American Economic Association and an associate member of the American Bar Association and the ABA’s Antitrust, Insurance and Regulatory Law Sections.

Q. WHAT IS THE SUBJECT OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I have been asked by the Montana Consumer Counsel ("MCC") to review and address Montana Dakota Utilities Company's ("MDU" or "the Company") proposals in this case concerning rate of return, cost allocation and rate design.

II. RATE OF RETURN

Q. PLEASE SUMMARIZE YOUR RATE OF RETURN TESTIMONY?

A. My rate of return testimony in this case deals with MDU's requested return on equity ("ROE") allowance and the resulting allowed rate of return on rate base. This analysis focuses primarily on the Company's cost of common equity capital.

While MDU is requesting a common equity return allowance of 10.0 percent, the evidence that I present shows that a more reasonable equity return allowance, under present financial circumstances, would be in the 7.5 to 9.0 percent range. Especially in view of the decline in interest rates and other money costs that has occurred during the past seven years, a 10.0 percent equity return allowance would not be just and reasonable in this case.

Q. WHAT IS RATE OF RETURN?

A. Rate of return is often described as the profit, expressed as a percentage of the utility's invested capital (measured as rate base), that the utility is allowed to include in its rates. From an economist's perspective it is not quite right to call this allowed "profit" because it includes both the cost of debt capital (interest expense) as well as the allowed return on equity investment. If a utility has $100 million invested in rate base and this is funded with $50 million of debt, with an average interest rate of 4 percent, and $50 million of equity, which the Commission has determined requires an after tax return of 8 percent (cost of equity or "ROE"), the allowed after tax rate of return on rate base would be 6 percent or $6 million annually. This amount, along with all expenses and taxes, would be the revenue requirement reflected in the utility's rates.

Q. IS THE DETERMINATION OF A UTILITY'S RATE OF RETURN ALLOWANCE A CONTROVERSIAL ASPECT IN MOST RATE CASES?

A. Yes. Rate of return accounts for a substantial portion of a utility's rates. While the debt component of rate of return is usually a straightforward measure of a Company's actual interest costs as reflected on its books, the

equity return component is largely a matter of judgment and is typically hotly contested.

While rate of return analysts may be able to offer the Commission facts, analyses and insights that will help to inform a reasonable range within which that essential judgment can be exercised, it is ultimately a determination that must depend on the Commission's priorities, objectives and exercise of discretion.

A. THE DCF MODEL

Q. DO YOU DISAGREE WITH THE DESCRIPTION OF THE DISCOUNTED CASH FLOW (DCF) MODEL THAT DR. GASKE HAS PRESENTED IN HIS DIRECT TESTIMONY?

A. No. While I am in agreement with Dr. Gaske's basic description of the model, as explained below, I do not agree with his flotation cost adjustment and with several of his other procedures.

Q. ARE DCF MODELS FREQUENTLY USED AS A METHOD FOR MEASURING THE COST OF, OR REQUIRED RETURN ON, A PUBLIC UTILITY'S COMMON EQUITY CAPITAL?

A. Yes. Discounted cash flow models are frequently used as a method for estimating the cost of, or required return on, a public utility's common

equity capital.

Q. PLEASE PROVIDE A BRIEF EXPLANATION OF THE MODEL.

A. The DCF model is based upon two fundamental principles. First, it is based on the principle that rational investors evaluate the risks and expected returns of securities in capital markets and establish a price for a particular security which adequately compensates them for the risks they perceive. Second, the model is based on the proposition that the total return received by shareholders consists of dividends and capital gains, and these are measured in terms of the current dividend yield plus the expected rate of dividend growth. The DCF model, which combines yield and growth information to produce the total return expected by investors, is the following:

$$\begin{array}{c}\text{Total Return}\\ \text{to Investor}\end{array} = \begin{array}{c}\text{Current}\\ \text{Dividend Yield}\end{array} + \begin{array}{c}\text{Expected Dividend}\\ \text{Growth Rate}\end{array}$$

The model makes no separate provision for capital gains because they are fully accounted for in the growth component. That is, capital gains are a consequence of price appreciation which, in turn, is a consequence of rising dividends and expected dividend growth.

Since an individual investor cannot control either the current dividend rate or the dividend growth rate, his decision about the adequacy of returns is

reflected by his buy, sell, and hold decisions. If the expected return exceeds the required return, the price of common stock will be greater than the stock's book value. If the expected return is lower than investor requirements, the market price will fall below book value. If investor expectations and requirements are the same, the stock will trade at a price equal to book value.

In other words, the DCF procedure for estimating the cost of equity capital reflects the fact that the maximum price a logical investor will pay for a security is an amount equal to the present value of the dividends that he or she expects to receive over the years during which the security is held plus its resale price, including capital gains, when the security is sold. Algebraically, this observation can be represented by the following equation:

$$Po = \frac{D_1}{1 + R} + \frac{D_2}{(1+R)^2} + \ldots + \frac{D_t}{(1+R)^t} + \frac{P_t}{(1+R)^t}$$

where Po is the price of a company's common stock today; D_1, D_2 ... D_t are expected dividends in subsequent periods; P_t is the expected resale price of the stock at some time in the future; and R is the discount rate or required return (sometimes referred to as the opportunity cost of capital). This algebraic statement, becomes an infinite geometric progression (because P_t

and all subsequent resale values depend on expected dividends and resale prices at that point in the future, and dividends are assumed to grow at a constant annual rate) which reduces algebraically to the familiar DCF formula:

$$R = D/P + g$$

where g is the expected annual rate of dividend growth.

The market price is the present value of all cash flows expected in the future, discounted at a rate equal to the rate of return investors require on the investment. Present value is the current worth of expected future returns – that is, what an investor would be willing to pay today in order to obtain the expected cash flows in the future. Today's price is the present value of these expected cash flows, discounted at a rate that reflects the cost of capital, including the risk perceived by investors that their expectations will not be met.

The most controversial aspect of DCF analysis is usually estimating the growth component of the model, rather than the underlying model or theory, itself.

Q. WHAT EXPECTATIONS ARE IMPORTANT IN DCF ANALYSIS?

A. Investors' collective expectations are central to the discounted cash flow

approach and are the key to establishing the cost of common equity capital. While analysts may opine on what they think investor expectations may be, the only way in which investors reveal their collective expectations is in the market prices that they establish for common stock. Investors establish prices for common stocks on the basis of their collective expectations of future income streams (dividends and capital gains) relative to their return requirements for the level of perceived risk. It is the consensus of investor expectations that establishes the price of common equities, and those expectations are ultimately concerned with investors' expected future income stream (i.e, dividends). This means that it is the expected future growth in dividends, which is most important.

Although dividend yields are easy to estimate with published data, the expected growth component is not as easy or free of controversy. Analysts often publish their expectations, which, overall, tend to be somewhat bullish, but there is no published consensus value for the generally more conservative expectations investors hold. That analysts' forecasts are somewhat more bullish than investors' actual expectations is evident from a number of observations, including stock market prices which are typically somewhat lower than analysts price forecasts. Really valuable analysts are those who know something that the market does not already know. In seeking an equity cost rate one must determine, on the basis of factual

information, what the most reasonable estimate of growth expectations held by investors is at any point in time.

In this regard, it is important to emphasize that the task of the rate of return analyst is to determine what growth rate investors are expecting, and not to forecast the actual growth rate the analyst expects. Nor does it matter whether investors' expectations turn out to be right or wrong. Today's common stock prices, which enter the DCF calculation through the dividend yield term, depend upon today's expectations for future growth. Of course, expectations and requirements may be different at different times, and therefore the cost of common equity is likely to change over time. For example, when interest rates are very high, it is likely that required equity returns will be higher than when, as now, interest rates are low. Similarly, when expected long-term inflation rates are high, it is likely that the cost of common equity will be higher than when long-term inflation expectations are low. A cost of common equity that exists at one point in time may be quite different from that which existed previously, or that may exist in the future. Also, while tomorrow's hindsight may prove that today's expectations were wrong, that does not and cannot possibly affect today's cost of capital. That is why it is necessary only for the rate of return analyst to estimate, as accurately as possible, what present investor expectations actually are, and not whether they are correct.

Q. DO YOU AGREE WITH DR. GASKE'S DCF CALCULATIONS?

A. I have some disagreements with his specific calculations.

Q. PLEASE EXPLAIN THOSE DISAGREEMENTS.

A. First, I disagree with his flotation cost adjustment. While it is true that actual flotation costs are part of the cost of capital, assuming a flotation cost of 3.5 percent for all of MDU's common equity capital, as Dr. Gaske does, greatly overstates MDU's actual common stock issuance costs.

In the case of debt, actual issuance or flotation costs are incorporated into the capital cost computation by relating the actual proceeds from debt issuances (e.g., the face amount of bonds less actual issuance costs) to interest payment obligations. Thus, if a company issues $100 million of debt at a 6 percent interest rate and has actual proceeds of $99 million (i.e., issuance costs are $1 million) the embedded cost of debt is 6.06 percent (6/99) and not 6.00 percent (6/100).

In the case of common equity, the great preponderance of equity growth for electric utilities (including MDU) is retained earnings - not new public stock issuances. Retained earnings (and other forms of raising common equity capital, such as dividend reinvestment plans and parent company equity infusions out of parent retained earnings), do not have the issuance costs that Dr. Gaske assumes.

Q. DO YOU HAVE ANY OTHER DISAGREEMENTS?

A. Yes. I disagree with Dr. Gaske's reliance on DCF results for the unregulated competitive companies that comprise the S&P 500, and I disagree with his conclusion that MDU's Montana electric operations are relatively risky compared with other comparable electric utilities, justifying an ROE allowance at the upper end of the zone of reasonableness. Actually realized ROEs will almost always turn out to be either somewhat higher or lower than the nominally allowed ROE. The point of estimating a zone of reasonableness as opposed to only a single point ROE estimate is to set an allowed return within the reasonable zone so that minor variations from the nominally allowed ROE will still produce an end result that remains just and reasonable. By going to the upper end of the zone of reasonableness, as Dr. Gaske does in recommending his allowed ROE, defeats this purpose, as minor upward variations in the actually realized ROE will produce end results that are excessive and unreasonable. For that reasons the allowed ROE should be set at or near the mid-point of the zone of reasonableness.

As regards the S&P 500, this group of companies is comprised of companies that are largely unregulated and operate in competitive markets that are far more risky and uncertain than a monopoly electric utility. Even if Dr. Gaske's ROE estimates for these companies were correct, they would not be applicable to a regulated electric utility monopoly like MDU.

Q. PLEASE DESCRIBE YOUR OWN DCF COST OF EQUITY ESTIMATES.

A. My DCF cost of equity estimates are presented in Exhibits___(JWW-1) and (JWW-2). Each of these exhibits is comprised of a part A and a part B. Part A presents results for the same selected sub-group of 12 electric utilities as used by Dr. Gaske, and Part B presents results for the more comprehensive group of all 45 of the Value Line electrics, without the eliminations imposed by Dr Gaske. Exhibit__(JWW-1) presents DCF results for the "earnings growth" model, which reflects earnings growth estimates based on security analysts' earnings projections, while Exhibit__(JWW-2) presents DCF results for the "fundamental" growth model, which reflects earnings growth estimates based on retained earnings. In my opinion Dr. Gaske's eliminations, which reduce the number of observations used in the DCF calculations from 45 to 12, do not result in a more representative group of electric utilities, but they do result in a somewhat higher end result for Dr. Gaske's earnings growth model.

Q. PLEASE SUMMARIZE EXHIBIT ___(JWW-1).

A. Exhibit___(JWW-1-A) provides DCF model results based on analysts' projected earnings growth forecasts for Dr. Gaske's group of 12 selected electric utility companies, whereas Exhibit___(JWW-1-B) provides

corresponding results reflecting all of the 45 electric utilities covered by Value Line. The average indicated ROE estimates are 9.55 percent for the group of 12 and 8.75 for the group of 45. The major difference between this exhibit and Dr. Gaske's analysis, in addition to reflecting results for all comparable electric utility companies rather than only a sample or a sub-set of the whole, is that it does not include Dr. Gaske's flotation cost adjustment. As discussed above that adjustment is highly inappropriate and would result in generally excessive rates because very little if any of the Company's common equity incurs flotation costs in any given year. Indeed, Statement F, Rule 38.5.149 in this case shows that MDU has not incurred any flotation cost on the issuance of new stock in the last four years.

Q. IS IT ALWAYS WRONG TO SELECT ONLY A SAMPLE OR SUB-SET OF A WHOLE GROUP AS DR. GASKE DOES IN THIS CASE?

A. While it is not necessarily wrong to select and focus only on a sub-set of the whole group, that always raises questions about "cherry picking" to achieve a desired end result. In this case, Dr. Gaske's "basic" DCF results for his limited group of 12 are subject to distortion by unrepresentative high growth estimates for only a few companies, such as TECO Energy and PNM Resources. In any event, I felt that it would be more informative and less subject to questions about manipulation to provide the Commission

with a full picture, which, of course, allows the Commission to pick and focus on sub-sets if it believes that is appropriate.

Q. HAVE YOU ALSO PERFORMED FUNDAMENTAL DCF ANALYSES?

A. Yes, I have.

Q. WHAT IS A FUNDAMENTAL DCF CALCULATION?

A. A fundamental DCF calculation uses retained earnings as the measure of expected growth. Because retained earnings provide for growth in equity and growth in equity provides for business growth, the rate of earnings plow-back (i.e., those earnings not paid out in dividends, but retained in the enterprise) serves as a basis for estimating future dividend growth. If the funds that are retained and reinvested earn the allowed return and the allowed return is equal to the cost of capital, retained earnings provide a good estimate of future growth.

For example, if a company with a stock price and book value of $50 per share earns $5.00 (10 percent) and pays out a dividend of $2.50, its dividend yield is 5 percent (i.e., 2.50/50). Expected growth will also be 5 percent because, if the 10 percent earnings rate is maintained, the $2.50 that is retained and invested in the enterprise will permit earnings to increase by that amount (i.e., $2.50 x 10 percent = $0.25, which is 5 percent of $5.00).

Likewise, the retention of $2.50 of earnings within the corporation will cause the book value of its stock to increase by 5 percent (i.e., $2.50 is 5 percent of $50.00). In this case, the dividend yield of 5 percent plus expected growth of 5 percent equals 10 percent, which is the cost of capital.

Q. PLEASE SUMMARIZE THE RESULTS OF YOUR FUNDAMENTAL DCF CALCULATION.

A. The results of my fundamental DCF calculations are presented in Exhibit___(JWW-2). As in the case of Exhibit___(JWW-1) I have again made DCF calculations using both Dr. Gaske's selected group of 12 utilities (JWW-2-A) and using the full Value Line population of 45 comparable electric utilities (JWW-2-B). The results are similar to Dr. Gaske's retained earnings growth calculations, except that I have not included his flotation cost adjustment for the reasons explained above. The fundamental DCF results reported in Exhibit___(JWW-2) indicate an ROE requirement of approximately 8.0 percent using either group of comparable utilities.

B. CAPITAL ASSET PRICING MODEL

Q. HAVE YOU ALSO PERFORMED CAPITAL ASSET PRICING MODEL CALCULATIONS TO ESTIMATE THE COST OF EQUITY CAPITAL?

A. Yes; I have.

Q. PLEASE DESCRIBE THE CAPITAL ASSET PRICING MODEL ("CAPM").

A. The CAPM is, like the DCF model, one of the most widely used techniques to estimate the cost of equity capital. The fundamental principle underlying the CAPM is that investors require compensation for risk when making an investment – that is, they require a higher return than is required for a riskless investment. In other words, while the DCF model estimates the cost of equity capital directly by examining expected dividend flows and market prices, the CAPM estimates required returns by evaluating the relative risk of alternative investments.

In comparison with the expected return on a risk-free investment, a risky investment must provide investors with a risk premium – an expected return higher than the riskless rate. The most commonly used measure of a risk-free asset is a short term (e.g., 90 day) U.S. Treasury security, which has little or no default or inflation price risk. It should be emphasized that

only very short term Treasury debt can be assumed to be risk-free. Long term treasury debt, which locks investors into U.S. dollar denominated assets for years, can be very risky as inflation or international currency fluctuations can significantly impair investment value. Only very short term treasury debt is substantially free of the risks of currency fluctuation and inflation.

CAPM separates the total risk of an investment into two parts: systematic and unsystematic risk. Systematic risk is unavoidable; it affects all assets to a greater or lesser degree. For example, a sharp rise in inflation would affect all stocks to a greater or lesser degree. The size of the risk premium for each stock is determined in proportion to the stock's co-movement with the market for all stocks. A stock that is twice as volatile as the average requires a risk premium that is double the average risk premium. A stock that is half as volatile as the average requires a risk premium that is half the average, etc. All systematic risk is rewarded with a risk premium, above the risk free rate of return that varies in direct proportion to the stock's relative volatility. The relative risk of each stock is measured by a value known as beta ("B"), which is a measure of the stock's relative volatility in comparison with the volatility of the entire market.

In contrast, unsystematic risk is that portion of total risk that can be avoided by diversifying. Unsystematic risk is not rewarded with a risk premium.

The CAPM defines the cost of equity for each company's stock as equaling the riskless rate plus an increment equal to the amount of systematic risk that goes with the investment:

$$K_n = R_f + B_n (R_m - R_f)$$

where,

K_n = the cost of equity for company n

R_f = the riskless rate of return

B_n = the beta for the stock of company n

$R_m - R_f$ = the expected market risk premium (i.e., the average difference between the expected returns on the diversified market portfolio and the riskless return).

Q. WHAT ARE THE APPROPRIATE VALUES FOR THESE VARIABLES IN THIS CASE?

A. At the present time, riskless treasury bills are yielding less than 1 percent, and the high value over the past decade has been about 5 percent. Within this range, R_f = 1.0 to 5.0 percent. With regard to risk premium, surveys and academic analyses indicate that the expected market risk premium R_m

is in the range of 3 percent to 7 percent.[1]

Among the people who have studied the equity premium closely, most think it is probably in the range of 3 to 5 percentage points above treasury bills. On the other hand, rank-and-file finance professors have often continued to peg the long-term premium at about 6 to 7 percent, according to a comprehensive survey published by Ivo Welch of Yale University.[2]

As shown in Exhibit___(JWW-5), average beta values for comparable electric utilities are about 0.75. Using 0.75 as the beta estimate and 5 percent as the market risk premium, the CAPM cost of equity estimate is:

$$K = 5.0\% + 0.75\ (5.0\%) = 8.75\%.$$

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[1] For example, according to Dinson, March and Staunton ("Risks and Returns in the 20th and 21st Centuries," Business Strategy Review, 2000, Volume 11, Issue 2):

> "It has become clear that the current level of the equity risk premium is unlikely to be as high as was considered reasonable in the mid-1990s. The arithmetic mean of 8½% recommended by Ross, Westerfield and Jaffe (1993), the 8-9% suggested (with caveats) by Bealey and Myers (2000), and the 7½% recommended by Wetson, Chung and Sui (1997), and a similar figure inferred from the Copeland, Koller and Murrin (1995) geometric mean of 5-6%, all look excessive. The market is almost certainly building lower risk premia than this into stock prices….The cost of capital has thus fallen substantially in recent years."

Also, according to Eugene F. Fama of the University of Chicago and Kenneth R. French of the Massachusetts Institute of Technology, the risk premium over the past half-century was about 4 percent. Their calculation is based on going back to the past and analyzing what kinds of returns investors had a reasonable right to expect for the future, given companies' dividend yields and expected growth rates. Risk premiums exceeding 4 percent were, they say, the result of a series of surprises, such as the end of the Cold War and the development of the computer – windfalls that investors do not count on to repeat themselves. Fama and French expect stocks to outperform risk-free securities by only 3 percent to 3.5 percent a year in the long term. (See E.F. Fama and K.R. French, "Dividend Yields and Expected Stock Returns," Journal of Financial Economics, 22 (1), 3-25 and "Business Conditions and Expected Returns on Stocks and Bonds," Journal of Financial Economics, 25 (1), 23-49.)

[2] Welch, himself, agrees with the 3-5 percent range. According to his analysis, a 3 percent geometric equity premium estimate and a 5 percent arithmetic estimate are more accurate than the 6 percent to 7 percent consensus of the profession. (See Ivo Welch, "Views of Financial Economists on the Equity Premium and on Professional Controversies" (University of California, Los Angeles and Yale University, 2001)).

The result is lower if today's lower risk free rate is used in the calculation. CAPM equity return calculations are summarized in Exhibit___(JWW-3). As in the case of the first two exhibits, part A pertains to Dr. Gaske's sub-set of 12 selected utilities, whereas part B pertains to all 45 of the Value Line electrics.

C. COMPARABLE EARNINGS

Q. HAVE YOU ALSO EXAMINED COMPARABLE EARNINGS FOR INVESTORS IN COMPARABLE ELECTRIC UTILITIES?

A. Yes. I have examined the rates of return that Value Line expects to be earned on common equity capital by comparable electric utilities as well as returns that are expected to be earned in relation to Value Line's expected market prices of those equity securities. This latter and most relevant comparison is essentially the return on book value divided by the market/book ratio for each company's stock.

Q. WHAT IS A MARKET/BOOK RATIO AND WHY IS IT RELEVANT IN DETERMINING A FAIR COMMON EQUITY RETURN ALLOWANCE?

A. A market/book ratio is the relationship that exists at any time between the market value that investors place on a firm's common stock and the stock's

book value.

If regulators allow firms to earn rates of return that equal the cost of obtaining capital in the marketplace, then market forces will tend to drive the prices of stocks toward their book values. If the expected return exceeds the required return, the price of common stock will be greater than the stock's book value. If the expected return is lower than investor requirements, the market price will tend to fall below book value. If investor expectations and requirements are the same, the stock will tend to trade at a price equal to book value.

Q. IS THIS AN IMPORTANT CONSIDERATION IN RATE REGULATION?

A. Yes. It is an important consideration in rate regulation. If the market price of common stock rises to and remains at a level that is substantially in excess of book value, that is a clear signal that investors' earnings expectations as a percentage of book value exceed the cost of capital, and that investors have capitalized these expected excess earnings by bidding up the price of common stock to a level greater than the stock's book value.

Thus, for example, if an investor purchases common shares at a market price equal to 1.5 times the stock's book value and the company earns a 15 percent rate of return on book value, the investor actually realizes a smaller

return (i.e., 10 percent) on the market value of his or her investment. Since 15 percent exceeds the return that is required in the marketplace (we know that because, in this example, with a 15 percent return investors bid the stock price up to 150 percent of its book value), the 15 percent return on book value is capitalized (i.e., built into the discounted present value of the security) by investors, thus inflating the market price of stock. While this may result in gains for original stockholders who paid book value for their holdings, the excess return is an unnecessary expense for ratepayers if it is reflected in allowed rates. Since it is both excessive and unnecessary, this condition should typically be avoided under effective rate regulation. Of course, temporary fluctuations and short-term cycles affect prices, and a stock price varies from its trend over time. This means that if common equity costs remain about the same over time, and if investors expect future returns equal to the market cost of equity, the price of stock will fluctuate within a reasonably narrow range of book value.

Q. IS THERE EVIDENCE AS TO WHAT RETURN ON EQUITY CAPITAL IS EXPECTED TO PRODUCE A MARKET-TO-BOOK RATIO OF 1.0 IN THE ELECTRIC UTILITY INDUSTRY IN THE FUTURE?

A. Yes. The Value Line Investment Survey, which is an excellent source of reported historical financial data, has published projected market-to-book

ratios for companies for the period 2018-2020 in recent issues. These are summarized for comparable electric utility companies in Exhibit___(JWW-4). Again, part A of the exhibit pertains to Dr. Gaske's selected sub-group of 12 companies and part B pertains to the entire Value Line group of 45 electric companies. As shown in this Exhibit, it is projected that an average 10.48 percent return on the book value for the entire group of comparable electric companies will produce a market-to-book ratio of 1.55. This, in turn, implies a cost of equity capital for these companies of about 6.91 percent. For the smaller selected sub-group of 12 companies, the corresponding cost of common equity result is 6.90 percent.

A market price equal to book value indicates that investors expect future earnings rates equal to their required return or cost of capital. To the extent that investors expect that the rate of return earned on book assets will exceed the required return or cost of capital, there will be a tendency to bid up the market value of stocks to the level at which the expected return in relation to market value equals the required return or cost of capital. Thus, if the required return or cost of capital is 8 percent, but investors expect that a 12 percent return will be earned on book value, market prices will be bid up to 1.5 times book value so that the realized return equals the cost of capital (i.e., 8 percent). The implication in this case is that an equity return of about 6.9 percent would be sufficient to sustain the stock price at book

value, i.e.,

$$10.53/1.55 = 6.93$$

Q. WHY HAVE YOU EXAMINED THESE EXPECTED COMPARABLE EARNINGS RATES?

A. Comparable rates of return from alternative investment opportunities determine the return level that investors can expect to obtain in competitive capital markets at any time. Moreover, comparable returns are generally considered by regulatory commissions and courts in determining "fair earnings" rates in rate proceedings. Indeed, regulatory standards demand that Commissions make an effort to allow similar profit rates to firms in similar risk circumstances. In examining comparable earnings data, it is, of course, important to remember that rates of return earned by other regulated companies are determined in some measure by previous regulatory decisions, and they may be either excessive or inadequate for certain firms at certain times. Therefore, while comparable earnings data do provide an essential reference point for any cost of capital decision (indeed, comparable earnings opportunities are the foundation on which investors make their capital commitment determinations and they are therefore the foundation of DCF and other cost of capital models), a simple mathematical extrapolation is not always sufficient.

Q. SHOULD MDU'S RATES INCLUDE A COMMON EQUITY RATE OF RETURN ALLOWANCE EQUAL TO THAT EARNED IN RECENT YEARS BY THESE COMPARABLE COMPANIES?

A. Not necessarily. Experienced returns may be an approximate benchmark for return authorizations, but there are several reasons why caution should be exercised in simply applying those average rates of return here. First, there is an obvious element of circularity in allowing a rate of return for a given regulated enterprise equivalent to the rate of return which other regulated enterprises have been allowed to earn.

Second, earned returns are not always the same as required returns. When market-to-book ratios exceed unity, it means that book return expectations are higher than current equity market return requirements.

D. COMPARATIVE RISK

Q. IS THERE EMPIRICAL EVIDENCE DEMONSTRATING THAT REGULATED ELECTRIC UTILITIES ARE LESS RISKY BUSINESSES THAN COMPETITIVE UNREGULATED ENTERPRISES?

A. Yes. Analyses of stock market indices reflect the comparatively stable and low-risk nature of common stock investments in regulated electric utilities.

Q. WHAT STOCK MARKET INDICES HAVE YOU REVIEWED?

A. In addition to the beta coefficients that I have used above in the CAPM cost of equity analyses discussed above, Value Line also publishes indices of safety, price stability and earnings predictability for a wide variety of firms in all sectors of the economy. As shown in Exhibit___(JWW-5), the full group of comparable electric companies have an average safety index of 2.00 on a scale from 1 to 5, where 1 is the highest safety rating. Also, price stability ranks at the upper end of the scale (95.67) from 5 to 100 where 100 is the highest stability rating. The average earnings predictability index for these companies is 79.00 on a scale from 5 to 100, and financial strength is rated at B++. Average rankings for Dr. Gaske's smaller selected sub-group are very similar. By all of these measures, electric utilities are indicated to be well below average risk for large publicly owned firms in the U.S. economy.

E. <u>CAPITAL STRUCTURE</u>

Q. WHAT CAPITAL STRUCTURE DOES MDU RECOMMEND FOR RATEMAKING PURPOSES IN THIS CASE?

A. MDU recommends establishing a rate of return on rate base reflecting its test year capital structure comprised of 41.14 percent long term debt at a cost of 5.95%, 8.11 percent short term debt at a cost of 1.63%, 1.24 percent

preferred stock at a cost of 4.58% and 49.52 percent common equity.

Q. IN YOUR OPINION ARE THESE REASONABLE CAPITAL STRUCTURE PERCENTAGES AND EMBEDDED COST RATES FOR RATEMAKING PURPOSES IN THIS CASE?

A. Yes; they are.

F. RATE OF RETURN RECOMMENDATION

Q. WHAT IS YOUR SPECIFIC RATE OF RETURN RECOMMENDATION IN THIS CASE?

A. As I said at the outset, within a zone of reasonableness, the determination of an appropriate ROE allowance is a matter of the Commission exercising its discretion in balancing the public interest objectives of consumer protection and incentives for adequate service and capital attraction. As summarized in Exhibit___(JWW-6), the empirical evidence and calculations that I have provided define an ROE zone of reasonableness within a range from about 7.5 percent to 9.0 percent. Within this zone of reasonableness, I use the 8.5 percent to calculate a recommended return on rate base. An ROE allowance of this amount acknowledges that MDU has provided and is expected to continue to provide adequate electric utility service to its Montana customers. It also recognizes MDU's comparatively

modest level of business risk for electric utility service and the Company's adequate common equity ratio. Based on an 8.5 percent ROE allowance, the Company's allowed return on its electric utility rate base would be 6.85 percent:

	Ratio	Cost	Allowed Return
Long Term Debt	41.14%	5.95%	2.45%
Short Term Debt	8.11%	1.63%	0.13%
Preferred Stock	1.24%	4.58%	0.06%
Common Equity	49.52%	8.500%	4.21%
	Overall Return on Rate Base		6.85%

III. COST OF SERVICE ALLOCATION

Q. PLEASE SUMMARIZE YOUR COST OF SERVICE TESTIMONY.

A. My cost of service testimony shows that, with reasonable cost allocation procedures reflecting energy consumption requirements as an important causal determinant of electric utility plant investment, residential and small business customers are being charged more than their fair share of MDU's revenue requirements. The Company's contention that these customers are paying less than the average rate of return is based on faulty cost allocation procedures that mistakenly attribute an exceedingly large portion of total costs among customer classes on a per-customer or non-coincident peak demand basis rather than on the basis of electric energy consumption and

monthly peak demands.

A. MDU'S COST OF SERVICE STUDY

Q. HAVE YOUR REVIEWED MDU'S COST OF SERVICE STUDY IN THIS CASE?

A. Yes, I have.

Q. WHAT ISSUES HAVE YOU IDENTIFIED WITH RESPECT TO MDU'S COST OF SERVICE STUDY?

A. There are several. First, MDU has chosen to allocate all of its generation and transmission plant costs using an average and excess ("A&E") demand allocator. Although this allocator gives some consideration to energy as a capacity cost determinant, it uses non-coincident demand rather than coincident demand to allocate the demand cost component. That is, "excess demand" is defined as the difference between average class demand (which is the same class allocation percentage as kwh) and the non-coincident class peak ("NCP"). Class NCPs do not occur at the time of the system peak. Therefore, this choice of allocators results in an allocation of generation and transmission costs that falls far short of conforming to the principles of cost causality.

The end result of MDU's approach is to attribute more generation and transmission costs to low load factor customers (i.e., residential and small commercial) and fewer costs to high load factor customers (i.e., industrial) than would result from a more reasonable energy and coincident demand allocator that recognizes the factors that cause the utility to invest in generation and transmission plant.

While an allocator based on non-coincident demand is often used to allocate local distribution plant costs, generation and transmission plant investment levels are related to energy consumption and monthly coincident peak demands rather than changes in customer class non-coincident peaks.

Q. PLEASE EXPLAIN WHY THAT IS THE CASE.

A. A utility invests in generating and transmission assets in order to meet energy demand requirements and to serve system peak loads, not the individual class non-coincident peak load. A non-coincident peak demand allocation method such as the average and excess method used by MDU assigns demand-related costs to customer classes in proportion to the excess, or departure, of each class's non-coincident peak ("NCP") from the average load of that class. However, that excess is likely to occur when the system load is not at its coincident peak level, and therefore is not imposing additional load requirements on the system. In contrast to a method that is

based on coincident peaks, the Company's procedure distributes the interclass diversity benefits so that classes that have peaks coincident with the system (such as high load factor industrials) are assigned a smaller share of total system costs, and classes with high diversity (such as the residential class) are assigned a larger portion of total costs.

The Company's choice to allocate generation and transmission capacity based on a non-coincident peak demand allocator is particularly harmful to low load factor residential and small commercial ratepayers whose non-coincident peaks are quite diverse, and it is beneficial to high load factor large industrials, whose non-coincident peaks are less diverse and similar to, or the same as, their peak demands.

Q. WHAT IS THE END RESULT OF THE COMPANY'S AVERAGE AND EXCESS ALLOCATION?

A. The end result of MDU's average and excess approach is a cost allocation that closely resembles an allocation based solely on monthly coincident peak demands, without giving any consideration to energy consumption as a cost-causing factor. The table below shows the percentage of costs allocated to each major class using MDU's average and excess allocator as compared to class coincident demand and energy.

Class	Average and Excess %	Coincident Demand %	Energy %
Residential	28.08%	29.68%	24.37%
Small Gen. Serv.	17.36%	20.01%	16.40%
Large Gen. Serv.	52.08%	48.35%	57.05%

Q. ARE THERE OTHER PROBLEMS WITH THE COMPANY'S ALLOCATION METHODOLOGY?

A. Yes. MDU has also assigned a large percentage (more than 70 percent) of its distribution plant costs to the customer category and none of these costs to energy. The Company's large assignment of distribution system costs to the customer category is the result of using a so called "minimum system" method that incorrectly uses actually used equipment as a proxy for minimum system design. As in the case of the A&E allocation method used by MDU for generation and transmission plant, assigning most distribution system costs on a flat per customer basis results in much greater cost responsibility for small residential and general service customers. In this case residential customers get 52.61 percent of the distribution plant cost allocation even though they account for only 37.96 percent of distribution voltage energy deliveries. This end result is the obvious outcome since small customers account for a much larger percentage of total customers than they do for total demand or energy.

As shown below, if MDU's plant costs are reallocated to more properly reflect energy responsibility for plant investment the calculated rates of return for customer classes change substantially. With these corrections, the end result indicates that residential customer rates produce returns that are well above the system average.

Indicated Rates of Return (Before adjustments)

Rate Class	MDU Study (JWW-7)	Corrected Study (JWW-8)
Total Company	3.528%	3.528%
Residential	2.201%	4.863%
Small General	3.983%	4.189%
Large General	4.291%	2.820%
Mun. Pumping	-0.024%	-9.804%
Lighting	3.651%	8.248%

B. GENERATION COSTS

Q. HOW SHOULD GENERATION PLANT COSTS BE ALLOCATED?

A. Rather than properly allocating generation plant costs on the basis of demand and energy, MDU's A&E allocation produces class assignments of generation plant costs that closely resemble a simple allocation based only on monthly coincident peak demand. In contrast to this end result, a substantial portion of generation plant costs are actually determined by

energy consumption. The Company's extreme methodology also hurts low load factor classes, such as residential and small business customers, as it ignores the benefit that the diversity of loads in these classes gives to the system as they occur at off-peak times.

In allocating generation plant costs it is increasingly recognized that hours other than the peak hour are critical from a system planning perspective, and regulators and utilities have moved toward multiple peak allocation methods as well as the division (classification) of generation plant costs between energy and demand responsibility. The FERC's application of the 12-CP method in its allocation of generation costs between jurisdictions based on the combination of the twelve monthly system coincident peaks, rather than on the basis of contribution to the single highest hourly demand during the year, is an attempt to at least capture some of the relevant cost-causative attributes of the monthly loads that the utility must serve. That is, although the monthly peaks in, say, the spring and fall months may be significantly below the winter and summer peaks, the probability of losing load and corresponding capacity needs may be similar in all seasons because most scheduled maintenance occurs during the spring and fall months. Thus, under FERC's 12-CP jurisdictional allocation method, which MDU has used for jurisdictional (but not class) cost allocation in this case, it is implied that there is little or no seasonal or monthly variation in

capacity cost responsibility. Thus, an average of all twelve monthly peaks is used as the measure of peak demand. This implies that generation and transmission capacity is not installed to meet only coincident peak demand, but rather to maintain system reliability during all months of the year. This approach, which I have used in modifying MDU's class cost allocations, attributes generation and transmission plant costs that are properly classified as demand-related to customer classes on the basis of 12-CP.

Q. WHAT OTHER METHODS MAY BE USED TO ALLOCATE GENERATION PLANT COSTS?

A. It is now generally recognized that energy loads are a major determinant of generation plant costs. Consequently, a number of methods have been developed to incorporate energy weighting into the allocation of production plant costs. Typically, this is done by classifying part of the utility's production plant costs as energy-related and allocating those costs to rate classes based on energy consumption. Two methods that follow this approach are: "Average and Peak" and "Equivalent Peaker."

Q. PLEASE EXPLAIN THESE METHODS.

A. Under the Average and Peak method, each class's average demand (load factor times CP) is combined with its peak demand to develop the class allocator. The end result is that the system load factor determines the

percentage of plant costs to be allocated as energy-related, and the remainder (1-load factor) is allocated in proportion to each class's CP demand.

Alternatively, the "Equivalent Peaker" method reflects generation expansion planning objectives as they relate to both peak loads and energy loads in determining the most cost-effective type of generation capacity to be added. The premise of the peaker method is that increases in peak demand require the addition of peaking capacity and that utilities incur costs for more expensive intermediate and base load units because of the energy loads they must serve. That is, in the system planning process, utilities first determine their need for additional capacity and then choose among the available generation options. These options may include low-cost combustion turbines ("CTs"), more expensive combined cycle or renewable (e.g., wind) units and even more expensive base load coal or nuclear units. The choice of unit depends on the duration of the load to be served. A peak load of brief duration would be most economically served by a CT, whereas a continuous load would be served most economically by a base load unit. Thus, the cost of a peaker is related to peak demand, but the additional cost of a combined cycle or base load unit is caused by energy needs. In other words, the ratio of the cost of peaking capacity per unit of load (kW) to the utility's total capacity cost per unit of load

determines the percentage of generation plant cost to be classified as demand, with the remainder being classified as energy.

Q. WHAT METHOD DO YOU RECOMMEND IN THIS CASE?

A. Because it is clear that a large portion of MDU's base load and renewable generation plant investment is driven by energy requirements, I would recommend that the Commission give consideration to allocation methods that incorporate a balanced energy and demand weighting into the allocation of production plant. In this case, MDU's cost allocation would have been more reasonable if its generation plant allocator had used 12-CP demand rather than excess demand to allocate the portion of generation and transmission plant that was not allocated based on energy. Below, I will present this alternative cost of service result to illustrate how the choice of methodology alters conclusions about the return levels that are attributable to each rate class.

Q. WHY SHOULD A PORTION OF THE COMPANY'S GENERATION PLANT COSTS BE ASSIGNED IN PROPORTION TO ENERGY CONSUMPTION INSTEAD OF ASSIGNING ALL OF THESE COSTS IN PROPORTION TO DEMAND?

A. Virtually all utilities, including MDU, install and maintain various types of generating units. Some plants are used to deliver energy practically around-

the-clock. Consequently, these investments are made with an aim to reducing energy costs, in addition to meeting peak demand. If a utility's goal for power plants were simply to meet peak demand rather than building expensive base load capacity, it would install only low capital cost peaking plants with much lower generation and transmission network capital requirements. Peakers and their associated transmission facilities have much lower capacity costs but are more expensive to run. But, if they only run during peak times, the higher running costs are justified in order to save on capital costs. Much more costly, but operationally efficient (i.e., low operating costs), base load generating plants and associated transmission grids are installed if they can be run long enough to generate enough fuel savings that more than offset their higher capital expenditures. Hence, these higher capital costs are incurred to serve year-round energy requirements at lower total costs. When a plant serves both base load and peak needs (as most base load plants and transmission systems do), its cost classification should reflect both functions.

Q. ARE THESE SAME CONSIDERATIONS RELEVANT TO TRANSMISSION PLANT INVESTMENTS?

A. Yes. As discussed below, these same principles are true for capital intensive, high voltage transmission grids that deliver power from generating plants and tie their output together in an integrated network.

Base load plants and their associated transmission grids are used to produce, coordinate and deliver energy around-the-clock as well as to satisfy the average level of demand of a company's customers, and a portion of their relatively high capital costs are justified by energy consumption and not by the coincident or non-coincident demands of the various classes.

C. <u>TRANSMISSION COSTS</u>

Q. HOW SHOULD TRANSMISSION COSTS BE CLASSIFIED AND ALLOCATED?

A. Utilities typically use transmission for three purposes: to reduce generating costs, to increase energy delivery reliability and to mitigate the need to add generating capacity. Transmission facilities reduce the cost of kwh output by permitting the development of efficient base load generating units and integrating generation resources. A cost-minimizing utility maintains a mix of generating resources in order to meet the varying demands placed on its system. This mix allows the utility to reduce overall production costs, thereby lowering the cost of both capacity and energy.

In order to be successful at this, the utility uses its transmission grid to achieve optimal dispatch. Hence, a capital-intensive transmission grid reduces energy costs, and this should be recognized in the classification of

transmission costs. Also in this way, the large energy consumers who benefit from the lower cost energy that these investments make possible will pay a fair share of the costs that reduce their energy charges.

Q. PLEASE EXPLAIN HOW TRANSMISSION INVESTMENT REDUCES ENERGY COSTS.

A. When utilities make capital intensive transmission (and generation) investments, they typically make their choice based on a variety of engineering considerations related to system loads and resources. Many of these considerations are energy related—such as decisions to build base load plants or wind generation. Base load plants, even though they are more capital intensive, are more economical to run for long periods of time. They are therefore cost-justified by energy requirements, not peak demand. Likewise, the location of such plants at sites remote from load centers (because those remote sites are close to fuel supplies or wind resources and/or because they minimize environmental or public safety impacts) is likely to involve more capital investment in transmission. But this does not mean that the cost of this energy-enabling transmission plant investment is the best, or even a good, measure of peak related transmission capacity costs. The reason is that a substantial portion of the actual transmission plant investment resulted from energy considerations and should not be counted as a demand-related cost of transmission capacity. If an efficient

utility were solely interested in adding capacity, and renewable or low cost energy were not issues, it would add the least costly plant to build and the cost of connecting this plant to the distribution grid would be the transmission cost caused by peak demand. Large transmission networks for load and resource integration and energy transport from remote base load or wind-powered plants would not be required or justified.

Q. IS THE TRANSMISSION SYSTEM FUNCTION OF TYING PLANTS TOGETHER IN A NETWORK DISTINCT FROM MEETING PEAK DEMAND?

A. Yes. The transmission system function of tying generation plants together in an integrated network for system reliability is quite different from the movement of additional peak capacity. Transmission capacity that permits interconnection for system reliability, or that is in lieu of constructing more generation capacity reserves, involves costs independent of the movement of additional capacity at peak times. Transmission costs incurred for such reasons are not primarily a cost of providing additional peak capacity. The same is also true for large transmission level substations. These are typically needed on integrated systems that efficiently tie remote base load and wind-powered plants to network load centers, but their costs are not primarily attributable to the cost of peak demand.

Q. ARE THERE OTHER WAYS TO RECOGNIZE THE IMPORTANCE OF ENERGY REQUIREMENTS AS A DETERMINANT OF TRANSMISSION PLANT COSTS?

A. Yes. Some utilities and regulators have attempted to recognize that transmission investment is undertaken for energy as well as demand purposes by categorizing each planned facility as related to growth in demand or as related to "non-demand" usage. There are some problems with such an approach, however. First, it is not economically possible to neatly pigeon-hole all facilities as demand versus non-demand because in the real world they actually serve a dual function. Second, the approach has the potential for costly and unproductive litigation over the appropriate designation of facilities. Third, a designation approach also provides an opportunity to inappropriately affect rates by biasing determinations of demand versus non-demand investments. For example, it may be profit-maximizing for a utility to shift costs away from those who are more able to turn to economical energy alternatives, like alternative fuels, self-generation or off-system suppliers.

If a generation plant is located near the source of fuel rather than near the load center, the cost of fuel is reduced but transmission costs are increased. Likewise, if a base load plant is sited at a remote location for water, environmental, fuel, wind or safety reasons, the power generated there must

be transmitted over high-voltage transmission to load centers and integrated on a transmission network with power production from other locations. The result is a savings on generating costs at the expense of greater transmission costs. Those who benefit from low cost energy consumption should be allocated an energy share of these costs. Transmission investment and expense is clearly related to both the transport and network integration of less costly energy from base load plants rather than to simply meet demand. The important network integration aspect of these facilities would be better recognized as in the case of generation plant, by assigning transmission plant to energy and coincident demand.

D. <u>DISTRIBUTION COSTS</u>

Q. DO YOU AGREE WITH THE WAY THAT MDU HAS ALLOCATED ITS DISTRIBUTION SYSTEM COSTS?

A. No. While I will recommend several alternatives to MDU's allocation methods for distribution system costs, the largest fault that I find with the Company's procedure is that it allocates nearly all of its distribution system cost (more than 70 percent) on a flat per customer basis. Only a small part of distribution system costs are allocated in proportion to demand and none are allocated in proportion to energy delivery requirements. Electricity delivery systems and the facilities that comprise them (poles, conductors,

transformers, etc.) are designed by their manufacturers and installed by utilities to meet demand and load requirements and should not be allocated so predominantly on a flat per customer basis. MDU's allocation method for distribution system costs results in a very large portion of these costs being allocated to residential customers because they account for 71 percent of MDU's Montana customers.

Q. IS THERE ALWAYS GENERAL AGREEMENT AMONG RATE ANALYSTS AS TO HOW CUSTOMER-RELATED COSTS SHOULD BE CLASSIFIED?

A. No. Most rate analysts do agree that a portion of total distribution facility costs should be classified on a customer-related basis. For example, billing and accounting costs, meters and meter reading can be reasonably considered customer-related. However, the customer component of distribution facilities can be exaggerated and that results in smaller customers being allocated a much greater portion of costs than their share of overall consumption. Such cost-shifting is often based on a motivation to recover more costs from those market sectors with the less competitive alternatives in order to bolster the prospect for economic success in more competitive market segments. To the extent that rate design follows cost allocation, this cost allocation also provides a stable (fixed charge) revenue stream that is unaffected by ups and downs in sales volume.

Q. IS MDU'S CHOICE OF AN NCP ALLOCATOR, RATHER THAN CP, FOR LOCAL DISTRIBUTION PLANT THAT IS PROPERLY ALLOCATED TO DEMAND A REASONABLE CHOICE?

A. While NCP is an appropriate cost allocator for distribution facilities that are installed and operated to meet local area service requirements, 12-CP is likely to be a more appropriate choice to allocate primary distribution network costs that are driven by more broadly based regional requirements. The coincident peak method basically allocates all costs classified as demand-related to customer classes in proportion to each class's contribution to the system coincident peak or peaks. The rationale for this approach is that the required capacity is determined by the maximum annual or monthly coincident demands to be placed on the system. However, this rationale may not hold where costs are not determined by system requirements but by local considerations. In the case of local distribution facilities, it is local loads, which often vary from the system coincident peak, that determine plant requirements. Therefore, a non-coincident demand allocator for local distribution facilities is generally thought to be more reasonable for the demand component of local plant.

Since each class may experience its own local peak at a different time than when the system peak occurs, the sum of the non-coincident class peaks typically will exceed the system coincident peak by a significant margin.

This inter-class diversity benefits the system in the sense that the utility need only install sufficient generation capacity to meet the diversified (i.e., coincident) peaks of the several classes.

Q. PLEASE SUMMARIZE MDU'S ALLOCATION OF DISTRIBUTION SYSTEM COSTS.

A. MDU has employed a constrained version of what is sometimes referred to as a "minimum distribution system" or "minimum-size" methodology in an effort to assign distribution plant and associated distribution costs on a flat per customer basis rather than in proportion to power demand or energy consumption.[3] The Company then uses this methodology to allocate most of its distribution system costs among customer classes on the basis of the number of customers in each rate class. Because the residential class has, by far, the largest number of customers, and, on average, residential customers typically use much less electricity than large commercial and industrial customers, the Company's minimum-system methodology assigns a very high percentage of distribution plant costs to the residential rate classes.

[3] The Company's constrained version of the minimum size method uses actual equipment sizes rather than theoretical minimum sizes.

Q. PLEASE DESCRIBE THE MINIMUM DISTRIBUTION SYSTEM METHODOLOGY.

A. The minimum distribution system methodology generally involves the estimation of costs associated with a theoretical minimum plant that would be required to serve a minimum (i.e., near zero) load. In contrast, the methodology employed by MDU in this case apparently involves the Company's estimated cost of constructing a normal system under normal industry circumstances but with relatively small sized (but high cost) facilities that are capable of carrying normal small loads. Because MDU has used actual, contemporary standard equipment and conventional system construction (such as triplex wire, pad-mounted transformers and underground conduit) designed to meet today's actual and anticipated loads in costing out its estimate of a minimum size system, the end result includes substantial costs that are clearly load related, and is not "minimum system" at all. Rather than a theoretical minimum system construct, the Company's approach reflects the cost of the smaller, but still highly costly, load carrying facilities that are actually installed and operating on its system. As such, the costs of this system reflect its demand and energy carrying capability rather than representing only fixed costs that would be incurred independent of demand and load levels. Consequently, the use of MDU's methodology to determine a fixed customer cost component for rates

severely tilts distribution cost allocation in a way that is costly to small customers with relatively small loads (e.g., MDU allocates 84 percent of poles conductors and conduits to customer count).

Q. WHAT EVIDENCE SHOWS THAT MDU'S MINIMUM SYSTEM COST ESTIMATE IMPROPERLY REFLECTS THE COSTS OF ACTUAL LOAD SERVING FACILITIES RATHER THAN THE THEORETICAL COST OF A NEAR-ZERO LOAD SYSTEM?

A. The Company has used nothing other than actual load-serving facilities costs to construct its estimated minimum system costs. These are estimated, as stated in the workpapers supplied in response to data request MCC-118. For example, the file MCC-118 Transformers states that, "Transformer & Capacitor - Installation Costs [are] for 2015". The same data response also shows that the Company has chosen the use of only expensive pad mounted transformer equipment to estimate minimum distribution system costs. The result of this approach is that the customer component of Account 368-Transformers is 79 percent. If less costly line transformers had been used, the customer component would have been 62 percent. Even more importantly the Company's approach does not take into account the energy contribution to distribution system costs.

Q. WHAT IS THE BASIC PREMISE WITH RESPECT TO THE COMPANY'S PROPOSED CUSTOMER COMPONENT OF DISTRIBUTION SYSTEM COSTS?

A. The basic premise underlying the Company's methodology is that these costs do not vary with demand levels or energy usage. Therefore, MDU does not allocate or charge for these costs on the basis for demand or energy. Rather than allocating or charging these costs on the basis of system usage or in proportion to the amount of service that is provided through these facilities, the Company's premise is that these costs should be recovered through fixed monthly customer charges.

Q. ARE DISTRIBUTION SYSTEM COSTS UNRELATED TO LOAD OR ENERGY REQUIREMENTS?

A. No; of course not. During the past half century the cost of electric utility distribution facilities has increased by far more than overall price levels in the economy. Over these years the standard quality and capability of electric distribution equipment has also been significantly enhanced. A half century ago average distribution line transformers in the industry were about one-third the size (measured in KVA capacity) of today's average transformer, and yet they served an average of 7-8 meters as compared with today's average of about 3-4 meters.

In short, distribution system equipment has been substantially redesigned and upgraded to meet load requirements as they have grown over time. For this reason, it would be a great pricing distortion to assume that the cost of today's actual distribution equipment and its installation is a reasonable basis for computing the cost of a minimum theoretical system designed to serve a near zero load.

Q. WHAT IS YOUR ESTIMATE OF THE COST OF A MINIMUM THEORETICAL SYSTEM DESIGNED TO SERVE A NEAR ZERO LOAD?

A. I would estimate that the cost of such a theoretical system would be no more than 10 to 25 percent of the actual distribution system costs. In contrast, MDU has estimated that the minimum system is nearly 85 percent of actual costs, but that estimate reflects the actual cost of state-of-the-art facilities designed, sized and installed to handle today's actual loads. This is inappropriate as we know that (1) today's actual distribution equipment has been substantially enhanced over time to meet increased load requirements, (2) more equipment per meter served has been required as load has grown, (3) about half of today's equipment cost level is attributable to load related upgrades that have occurred over time rather than to price inflation and (4) even the starting points for these comparisons were actual systems and equipment rather than a theoretically minimum

system designed to meet a near zero load level. It follows that the theoretical minimum cost would be in the range of 10 to 25 percent of MDU's actual cost rather than nearly 85 percent as the Company proposes.

Q. ARE THERE ADDITIONAL REASONS FOR REJECTING THE ALLOCATION OF DISTRIBUTION NETWORK COSTS ON A PER CUSTOMER BASIS?

A. Yes. Allocating these costs on a per customer basis ignores the basic fact that the costs associated with investments in distribution lines and related equipment are part of an integrated power delivery network; they are not customer-specific facilities that are causally attributable on the basis of customer counts.

Q. WHY IS THAT?

A. MDU's distribution facilities have been sized by manufacturers and installed to meet the expected loads placed upon them, and not to meet a specific number of customers to be served. It therefore makes little sense to allocate these distribution plant costs on the basis of the number of customers being served in each rate class. The fact that an electric utility's distribution lines are sized and installed to meet customer loads and not customer counts is demonstrated by the following hypothetical example: An area of a specific size may contain 20 individual commercial customers,

each with a 50 KW peak load, or 4 office buildings, each with a 250 KW peak load, or 5 apartment buildings, each with 40 individually metered apartments having a 5 KW peak load. While the number and type of service connections and meters will vary directly with the number of customers and there are likely to be some differences in transformer configuration, the local distribution facilities must be structured to handle a 1,000 KW peak load in each case, regardless of whether there are 4 or 20 or 200 customers. Thus, as Bonbright *et al.* have observed:

> The really controversial aspect of customer-cost imputation arises because of the cost analyst's frequent practice of including, not just those costs that can be definitely earmarked as incurred for the benefit of specific customers, but also a substantial fraction of the annual maintenance and capital costs of the secondary (low voltage) distribution system - a fraction equal to the estimated annual costs of a hypothetical system of minimum capacity. This minimum capacity is sometimes determined by the smallest sizes of conductors deemed adequate to maintain voltage while keeping them from falling of their own weight. In any case, the annual costs of this phantom, minimum-size distribution system are treated as customer costs and are deducted from the annual costs of the existing system, only the balance being included among those demand-related costs to be mentioned in the following section. Their inclusion among the customer costs is defended on the ground that, since they vary directly with the area of the distribution system (or else with the lengths of the distribution lines, depending on the type of distribution system), they therefore vary directly with the number of customers. Alternatively, they are calculated by the "zero-intercept" method whereby regression equations are run relating cost to various sizes of equipment and eventually solving for the cost of a zero-sized system (Sterzinger, 1981).

> What this last-named cost computation overlooks, of course, is the very weak correlation between the area (or the mileage) of a distribution system and the number of customers served by this system. For it makes no allowance for the density factor (customers per linear mile or per square mile). Our casual empiricism is supported by a more systematic regression analysis (in Lessels, 1980) where no statistical association was found between distribution costs and number of customers. Thus, if the company's entire service area stays fixed, an increase in number of customers does not necessarily betoken any increase whatever in the cost of a minimum-size distribution system.
>
> (James C. Bonbright, Albert L. Danielsen and David R. Kamerschen, Principles of Public Utility Rates, Public Utility Reports, Inc., Arlington, Virginia, 1988)

Q. ARE THERE FURTHER REASONS FOR QUESTIONING THE ALLOCATION OF MINIMUM DISTRIBUTION SYSTEM COSTS ON A PER CUSTOMER BASIS?

A. Yes. That approach over-allocates distribution costs to smaller customers whenever the minimum system is not a purely zero load system. That is clearly the case here. Consider the following hypothetical: assume that there are 100 small customers with a combined peak load of 1,000 and 10 large customers with a combined peak load of 3,000. Further, assume that 50 percent of distribution costs are asserted to be minimum system costs to be allocated on a per customer basis and only the remaining 50 percent of these costs are allocated in proportion to demand and energy. In this event, the small customers would be allocated 57.95 percent of the distribution

costs and the large customers would be allocated only 42.05 percent of the costs:

$$\text{Small Customers} = \frac{100}{110} \times .50 + \frac{1{,}000}{4{,}000} \times .50 = .5795$$

$$\text{Large Customers} = \frac{10}{110} \times .50 + \frac{3{,}000}{4{,}000} \times .50 = .4205$$

But if the so-called minimum system could actually handle loads, then an adjustment is necessary to reflect a credit for demand costs that are, in effect, actually covered by minimum system charges. For example, if the so-called minimum system could actually handle, say, 50 percent of demand, and distribution system costs were a linear function of demand, an adjusted result would be as follows:

$$\text{Small Customers} = \frac{100}{110} \times .25 + \frac{1{,}000}{4{,}000} \times .75 = .4148$$

$$\text{Large Customers} = \frac{10}{110} \times .25 + \frac{3{,}000}{4{,}000} \times .75 = .5852$$

If the minimum system could actually handle 80 percent of demand, an adjusted result would be:

$$\text{Small Customers} = \frac{100}{110} \times .10 + \frac{1{,}000}{4{,}000} \times .90 = .3159$$

$$\text{Large Customers} = \frac{10}{110} \times .10 + \frac{3{,}000}{4{,}000} \times .90 = .6841$$

Quite obviously, using the costs of actual load bearing facilities as a proxy for minimum system costs that are allocable on a per customer basis can severely overcharge small customers in relation to their true cost responsibility.

Q. IS IT REASONABLE TO CLASSIFY DISTRIBUTION FACILITIES AS BOTH DEMAND AND ENERGY RELATED?

A. Yes. Because these facilities are designed to meet both local peaks and energy requirements over time, distribution facilities are appropriately classified as both demand and energy related. These facilities may therefore be classified using a demand-energy split. The allocation of the energy-related portion should be done in accordance with each class's contribution to total energy consumption and the demand-related portion should be allocated in accordance with each class's share of non-coincident peak demands.

E. ALTERNATIVE COST OF SERVICE STUDY

Q. HAVE YOU PREPARED AN ALTERNATIVE COST OF SERVICE STUDY BASED ON MDU'S FILING IN THIS CASE THAT INCORPORATES THE RECOMMENDATIONS THAT YOU HAVE MADE?

A. Yes.

Q. PLEASE DESCRIBE THE COST OF SERVICE STUDY THAT YOU HAVE PREPARED.

A. The alternative cost of service study that I have prepared is summarized in Exhibit___ (JWW-8). This study follows the same format as presented in MDU's rate filing and, with the exception of the changes noted, it is based on the same cost of service data and allocation procedures presented in the Company's filing.

Q. PLEASE DESCRIBE EXHIBIT___(JWW-7).

A. Exhibit___(JWW-7) is simply a replication of the cost of service study filed by MDU. It is included here as a convenience for comparison purposes and also as a check that any alternative results start from the same place as the Company's filing.

Q. PLEASE DESCRIBE EXHIBIT___(JWW-8).

A. Exhibit___(JWW-8) addresses the concerns that have been raised in my testimony, including MDU's allocation of all generation and transmission plant costs in relation to the so-called average and excess methodology, which in this case turns out to be a cost allocation that closely resembles a monthly coincident peak demand allocation. Whereas MDU's filed cost of service study (replicated in Exhibit___(JWW-7)) used average and excess to allocate all generation and transmission plant costs, Exhibit___(JWW-8) allocates generation and transmission plant in relation to both 12-CP and energy. Under this approach, half of MDU's generation and transmission plant is allocated in proportion to class energy loads and the other half is allocated in proportion to monthly coincident peak demands. In addition, I have divided distribution network costs (poles, towers, fixtures, conduit and transformers) 50/50 between energy usage and NCP demand.

I have also reallocated revenue credits (sales for resale and margin sharing) and A&G expenses on the basis of retail revenues. This is a more comprehensive and appropriate allocator than the allocators (kwh and O&M costs, respectively) used by the Company. Likewise, I have allocated materials and supplies on the basis of total plant rather than on the narrower basis of only production, transmission and distribution plant used by the Company. As is shown in Exhibit___(JWW-8), when these

corrections are made to MDU's cost of service study, it is clear that residential customers are supporting far more than their fair share of total system costs.

IV. MDU'S RATE DESIGN

Q. PLEASE SUMMARIZE YOUR EVALUATION OF MDU'S RATE DESIGN.

A. As described above, MDU's rates are structured to recover a specific portion of the Company's total revenue requirement from each rate class. As a general proposition, the Company acknowledges that the revenue requirement for each rate class should equal that portion of MDU's total cost of service that is incurred to provide the electric service requirements of the rate class. If a cost of service study has correctly attributed the proper portion of total costs to each rate class, an appropriate rate structure would result in equal rates of return for each class.

As discussed above, the Company's cost of service study does not reasonably reflect rate class cost responsibility. If the Commission agrees that MDU has underallocated costs to high load factor customers and overallocated costs to smaller, lower load factor customers, rate

adjustments to achieve appropriate rate class parity would be quite different than MDU's cost of service study suggests.

Q. IN ADDITION TO ACHIEVING THE REQUIRED REVENUES AND FAIR COST APPORTIONMENT, DOES THE COMPANY'S RATE STRUCTURE RESULT IN EFFICIENT PRICE SIGNALS FOR ENERGY CONSUMPTION?

A. Substantial improvements can be made in this regard. One area for improvement would be to correct inconsistent price signals between various tariffs. For example, under the Company's proposal residential (Rate 10) and small general service (Rate 20) customers would be charged substantially higher energy rates in the summer months than in the winter months, but large general service (Rate 30) customers and contract customers (Rate 35) would be charged the same energy rates in all months. As a result, small general service subscribers taking service at primary voltage, and who also have high demand charges, would pay energy rates (including fuel and purchased power) of $0.082/kwh in the summer months (June-Sept.) while large general service subscribers, also taking service at primary voltage, would pay corresponding energy rates of $0.043/kwh in the same months. Residential customers, who do not have demand charges, would be charged $0.109/kwh in these same months. Obviously, the price

signals for summer energy consumption would vary substantially between customer classes.

Also, while per customer charges play no role in encouraging efficient energy consumption, the Company proposes to raise these flat monthly charges substantially for all customer classes. For residential customers MDU proposes a 39 percent increase in the customer charge (from $5.40 to $7.50 per month), while for small general service subscribers the customer charge increase would be 20 percent and for large general service subscribers the customer charge increase would be 29 percent (from $70 to $90 per month). At the same time, summer energy charges for large general service customers at primary voltage would be increased by 3.2 percent (from $0.04184 to $0.04318 per kwh). Summer energy rates for large general service customers at secondary voltage would also be increased by 5.2 percent. MDU's proposal to raise flat customer charges and increase peak season energy charges by a disproportionally small amount is certainly not a sensible rate design change for any electricity supplier concerned about improving price signals to promote efficient energy consumption.

Customers are also receiving highly inconsistent price signals for incremental energy consumption. For example, while residential customers are being told that the incremental cost or cost savings associated with one

kilowatt-hour more or less in the summer is 10.9¢, large contract service (Rate 35) customers are being told that it is less than half that amount - - 4.6¢. Likewise, while residential summer incremental energy rates will be 31 percent higher than winter incremental energy rates and small general service summer incremental energy rates will be 49 percent higher than corresponding winter rates, there will be no summer/winter incremental energy rate differential at all for large general service or contract rates. Also, while residential customers will receive a 23 percent increase in summer incremental energy rates, the corresponding change for large general service customers will be only an 8.2 percent rate increase. In fact, at the Company's marginal generating plants (i.e., the plants being dispatched to match total generation with load), at any particular time the incremental cost or cost savings of one kilowatt hour more or less ("system lambda") is exactly the same regardless of which customer's load is varying.

Q. WHAT DO YOU RECOMMEND REGARDING MDU'S RATE DESIGN?

A. Given the substantial misallocation of class cost responsibility identified in MDU's class cost of service study, the Company has not presented a credible case for revamping overall class revenue responsibilities. In addition to correcting this class cost of service misallocation it would be

desirable to at least restructure incremental energy charges and rationalize interclass rate comparisons in each season so as to better reflect incremental energy costs applicable to all customers. Incremental energy costs (primarily the fuel cost associated with one kilowatt-hour more or less at any time) are perhaps the least difficult and least controversial costs to quantify with reasonable accuracy. Marginal energy rates are also the strongest energy conservation tool available to utilities and the most important price signal to get right. Customers can respond to marginal energy costs much more readily than they can to estimates of any other functional marginal cost. For example, what response can be expected (or would be desired) from increasing the customer cost "price signal" from $5.40 to $7.50 per month as MDU proposes for residential customers in this case?

Q. WHY IS IT IMPORTANT FOR PRICES TO REFLECT INCREMENTAL ENERGY COSTS?

A. In a market economy, it is the price system that allocates resources, encourages producer and consumer efficiency, rations limited supplies of goods and services and, in general, serves as a disciplinary force in determining what is produced, in what volume, and how it is distributed. The prices of various goods and services in a market economy constitute a ranking of incentives affecting both producers and consumers. Through

their willingness to pay various prices for various goods, consumers signal their preferences to producers. By their willingness to sell various goods at various prices, the producers, in turn, signal costs to consumers. When certain conditions are present, especially those associated with the ideal of perfect competition, the price system forces each individual producer and consumer, while working purely in his or her own interest, to contribute to the welfare of society as a whole. Under these conditions, available resources are used in the most efficient way to produce the largest possible quantity of the most wanted goods and services, and these are distributed so as to maximize aggregate economic satisfaction. But this requires the price for incremental consumption to reflect the cost of incremental production.

In an efficient market producers will supply additional units as long as prices exceed the cost of producing additional units. At the same time consumers will demand and purchase additional units as long as prices are below the benefit of consuming additional units. The producer's cost of incremental production defines supply, and the consumer's benefit from incremental consumption defines demand. Efficiency is achieved in markets when cost and benefit of incremental production and consumption are equal. Prices that reflect the cost of incremental production are the key to achieving this efficiency.

In competitive markets prices also tend to reach an equilibrium at a level that covers the total costs of production (including a return to capital investment). Prices above such a level cannot prevail over long periods as that would attract competitive entry and expand production to capture the excess of price over costs, and at the same time, such a high price would discourage consumption to a level below what would have prevailed with cost-based rates. Conversely, prices below cost would encourage consumption and discourage production, as no firm can exist for long when price fails to cover the costs of production. Thus, in a competitive market, consumers cannot expect to buy goods at prices below the cost of production, and they cannot be forced to pay prices above that level.

Q. DO THESE PRINCIPLES APPLY EQUALLY TO PRICES REFLECTING MARGINAL ENERGY COSTS, MARGINAL CUSTOMER COSTS AND MARGINAL DEMAND COSTS?

A. No. They are, by far, much more important for marginal energy costs. Customers can respond directly to energy price signals telling them the incremental (fuel or purchased power) cost of an increase or decrease in kwh consumption. In contrast, they have little or no ability to alter demand in response to changes in per customer rates. In a similar sense, capacity costs (whether generation, transmission or distribution) are more or less fixed in the short run and it is therefore far more difficult to design and

implement efficiency inducing price signals for these cost components. In short, efficient (i.e., cost-reflective) electricity pricing should start with energy rates reflecting marginal energy costs for all classes.

Q. PLEASE SUMMARIZE YOUR COST ALLOCATION AND RATE DESIGN RECOMMENDATIONS.

A. As shown in Exhibit___ (JWW-8), MDU's residential rates should not be raised in relation to rates charged to other classes of customers. Residential rates are already recovering a more than proportionate share of costs associated with serving these customers and a rate of return far above the system average is already being recovered from the residential service class. Also, customer charges should not be raised for any customer. Customer charges do not contribute to efficient resource use or energy consumption decisions. To the extent any rate increases are required for non-residential classes, they should be imposed as part of the class energy charge. Also, to the extent that seasonal energy rate differentials are appropriate, they should be adopted for all customer classes, and disproportionally small increases in summer energy charges that MDU proposes for large general service customers should not be approved.

V. MDU'S PROPOSED NEW COST RECOVERY RIDERS

Q. PLEASE DESCRIBE MDU'S PROPOSED NEW COST RECOVERY RIDERS FOR TRANSMISSION AND ENVIRONMENTAL COSTS.

A. The Company's proposed new Riders for transmission and environmental cost recovery (Rate 98 and 99 tariffs) are somewhat unusual and troubling from a traditional regulatory perspective. These proposed new Riders would provide for transmission cost ("TCRR") and mandated environmental resource cost ("ECRR") increases without traditional general rate case consideration, allowing immediate rate adjustments for these costs, in isolation, without considering associated cost offsets and how these costs fit into the Company's overall revenue requirement. Mandated environmental resource cost increases, for example, would be passed on to consumers without considering how such mandated generation capacity additions may be offset by reductions in other generation costs. Likewise, transmission investment which is often closely integrated with and a substitute for generation costs, would be tracked through to consumers in rate adjustments without considering related generation cost offsets.

Q. IS THERE GENERAL AGREEMENT THAT COST TRACKERS LIKE THESE REPRESENT AN OPTIMAL RATEMAKING APPROACH?

A. No. There are often important incentive issues in optimizing a utility's performance that are not always well-served by this type of single cost tracker.

Q. HOW DO TRACKERS AND COST RECOVERY RIDERS FIT INTO THE OVERALL PROCESS OF ELECTRIC UTILITY RATE REGULATION?

A. The retail prices charged for electricity by rate regulated utilities like MDU must be approved by state commissions. When an electric utility wants to change its prices, it must file a set of rate schedules, showing the new prices that it proposes to charge, with its state regulatory commission. These rate schedules are price lists, showing the rates and charges for electric service, and also explaining any other terms and conditions under which electricity service is furnished by the utility.

Before approving a utility's request for a rate increase, the regulator, as here, generally institutes an investigation and hearing into the need for the higher rates. This process of investigation and hearing is called a general rate case. It involves, as here, the presentation of testimony and other

evidence by the utility company, arguing its need for the higher rates, as well as testimony by interveners, such as the MCC, large customers or other consumer groups, addressing the utility's request.

After all the parties to the rate case have been heard, the commission examines the complete record of its investigation and renders its decision. It may accept the proposed rates as filed; reject them entirely, thus continuing the old rates in effect; or, most typically, permit the utility to increase its rates by some part of the total amount originally requested.

Each general rate investigation is a major undertaking for a public utility commission, and it generally extends over a period of many months. The effort and time required for a general rate investigation are needed in part to satisfy the procedural requirement that the interested parties, including the company, all have adequate opportunity to prepare their cases and be heard. In addition to procedural requirements are the scope and complexity of the issues that may be considered in a general rate case investigation.

Because of the length of a complete rate investigation, the rate decision that results from it must necessarily be based only on the factual situation as it was seen at the time of the rate case. However, newly approved rates are almost certain to remain in effect for at least a year or more, before they can be superseded by rates that may result from the next succeeding rate

investigation.

In an effort to reduce the time and resource requirements of complete rate investigations, partial cost adjustment procedures, such as fuel and purchased power cost trackers, are sometimes used for changing electric utility rates between complete general rate investigations. The purpose of these adjustment procedures is to permit prompt changes in electric utility rate levels, to reflect changes in some of the utility's larger and more volatile cost elements, without the necessity of a complete rate investigation.

The specification of which cost elements may properly be the subject of rate adjustments between general rate proceedings is an important and difficult substantive issue. There is often not ready agreement about which cost elements require rate adjustment between general rate cases and which do not. Utility companies are likely to want rate adjustments for those factors most responsible for increasing total costs such as inflation in the prices of the inputs they purchase; whereas consumer groups are likely to want consideration of those offsetting factors that tend to reduce costs or inflation, such as improvements in productivity. To make the adjustment process work effectively, a regulatory commission must establish and enforce a firm policy defining the cost factors that may be considered in this process.

When a policy for rate adjustments is established, it must also specify the events that will trigger the adjustment process. This trigger may be simply the passage of time, as with a monthly review of fuel and purchased power costs; or it may be a specific cost event. When the triggering event occurs, the next step is to calculate the changes in the costs for which interim adjustment is allowed. As is proposed for Rider Rates 98 and 99, a uniform price change per kilowatt-hour is typically deemed the appropriate way to reflect the specified cost changes in rates, although this can become more complex if time-varying or other more complex rate forms are adopted.

Q. WHAT ARE THE ADVANTAGES OF TRACKERS AND COST ADJUSTMENT RIDERS?

A. These rate adjustment mechanisms offer only one advantage: because they focus on only some of the many elements in the total cost of service for an electric utility, and because they typically do not involve any consideration of rate structure, they permit prompt and more frequent adjustment of electric utility rate levels, in response to changes in the costs on which they are focused, than is possible in complete rate investigations. This advantage is an important one, with the following consequences:

- If the costs subject to the tracker or rider are moving in the same direction as the total costs of the utility, then the rate adjustment

process helps keep the overall rate level in touch with the total cost level of the utility, and therefore it reduces the needed frequency of complete rate investigations. If the costs subject to adjustment are not moving in the same direction as total costs, the tracker process will result in a greater separation of rates and costs and thus make matters worse.

- The tracker process can also permit regulatory resources to be concentrated on those cost elements that are large, volatile, or otherwise important. It conserves resources that would otherwise be used for repeated study, in complete rate investigations of other cost elements not requiring such frequent regulatory attention.

- Trackers also permit a prompt rate adjustment at times when extremely large changes in one cost of service element make an adjustment in the rate level most essential.

Q. ARE THERE ALSO DISADVANTAGES ASSOCIATED WITH SUCH TRACKERS AND RIDERS?

A. Yes. These piecemeal rate adjustment approaches also involve a number of disadvantages.

1. Since rate adjustments are based upon consideration of some, but not all, of the costs of an electric utility, it is possible for the rate adjustments to go in one direction while the utility's total costs are moving in the other direction. This result is obviously worse than no tracker or rider at all.

2. Even when not perverse, as in (1), partial cost adjustment procedures may be biased to register changes in those cost elements that are most subject to increase, without registering the offsetting factors, such as productivity improvements, that reduce total cost increases. In the case of MDU's proposed transmission and environmental cost Riders, there is no offset for likely reductions in other costs that are displaced by the costs that are tracked.

3. Trackers may also tend to weaken or distort incentives, and they can be subject to abuse. For example, by implementing a rate adjustment rider only for transmission investments, the

Commission would be favoring transmission plant expansion over potentially more efficient local generation development.

Q. WHAT ARE THE POTENTIAL INCENTIVE PROBLEMS OF COST TRACKERS AND RIDERS?

A. Trackers and Riders may tend to weaken the incentives for a utility to supply electricity at minimum cost. If the rate level is fixed, then it is the shareholders who stand to gain or lose the full amount of any cost savings or increases, at least until the next rate case, when the rate level is reset to the then-prevailing cost level. If, instead, there are cost tracker procedures to change the rate level quickly in response to certain cost changes between rate cases, then these gains and losses are shifted very quickly to the ratepayers, and management has less incentive to minimize costs than when the benefits or costs go to the shareholders.

In addition to weakening the incentive for a utility to minimize the outlay on items subject to rate adjustment, the existence of a tracker or selective rider may distort the incentive for a utility to choose the most efficient and least costly combination of inputs for supplying electricity. When all costs are rising, the utility may have an incentive to use relatively more of the inputs for which tracker adjustments are possible, and less of the inputs for which there is the greatest regulatory lag in recovering cost increases

through higher rates.

The key disadvantages of selective cost trackers and riders like those MDU proposes in this case is that they both weaken and distort the incentives for cost minimization and they fail to recognize offsets to the costs being tracked. With this type of rate adjustment procedure in effect, a utility has no direct financial incentive to either seek out the lowest cost resources or to economize on tracked investments, when to do so would require the expenditure of money on any other resource or investment that is not subject to a tracker.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS REGARDING THE COMPANY'S PROPOSED ENVIRONMENTAL COST AND TRANSPORTATION COST RECOVERY RIDERS IN THIS CASE.

A. The Company's proposed ECRR and TCRR tariffs are partial cost recovery mechanisms that could impose efficiency disincentives as well as potentially perverse rate adjustments that cause overall revenues to diverge from overall costs to a greater extent than would occur without these rate adjustment riders. These proposed riders represent piecemeal ratemaking which fails to recognize the likely cost offsets associated with the targeted cost changes. They would also bias investment and expenditure decisions,

as well as undermining management efficiency incentives. As such, they should be rejected by the Commission.

Q. DOES THIS CONCLUDE YOU PREPARED DIRECT TESTIMONY IN THIS CASE?

A. Yes; it does.

Exhibit JWW-1-A

D2015.6.51

Montana-Dakota Utilities

Direct Testimony of

John W. Wilson

on behalf of the

Montana Consumer Counsel

November 20, 2015

DCF Cost of Equity Indications

Earnings Growth Model

Selected Electric Companies from Exhibit No.___(JSG-2)

			(1)	(2)	(3)	(4)	(5)	(6)	(7)
				Div Yield x (1 + 0.625g)		g		D/P + g	
		Company	Dividend Yield	Zacks	Yahoo	Zacks Growth	Yahoo Growth	Zacks	Yahoo
1	ALE	ALLETE, Inc	4.1%	4.3%	4.3%	5.0%	5.5%	9.3%	9.8%
2	LNT	Alliant Energy Corp.	3.7%	3.8%	3.8%	5.3%	5.4%	9.1%	9.2%
3	AEE	Ameren Corp.	4.0%	4.2%	4.2%	6.8%	6.4%	11.0%	10.5%
4	AEP	American Elec Pwr Co.	3.8%	3.9%	3.9%	4.7%	4.6%	8.6%	8.6%
5	EDE	Empire District Elec	4.6%	4.8%	4.8%	5.0%	5.0%	9.8%	9.8%
6	GXP	Great Plains Energy	3.8%	3.9%	3.9%	6.0%	5.2%	9.9%	9.1%
7	OGE	OGE Energy Corp.	3.5%	3.6%	3.5%	4.6%	2.4%	8.2%	5.9%
8	OTTR	Otter Tail Corp.	4.6%	NA	4.8%	NA	6.0%	NA	10.8%
9	PNM	PNM Resources	3.0%	3.2%	3.2%	8.1%	9.4%	11.3%	12.6%
10	TE	TECO Energy	4.3%	4.5%	4.4%	7.1%	6.8%	11.6%	11.2%
11	WR	Westar Energy	3.9%	4.0%	4.0%	3.9%	3.9%	7.9%	7.9%
12	XEL	Xcel Energy, Inc.	3.7%	3.9%	3.9%	5.0%	4.7%	8.9%	8.5%
		Average						**9.6%**	**9.5%**

Sources: Value Line Investment Survey August 10, September 18, and October 30, 2015.
Zacks Investment Research, November 11, 2015 (http://www.zacks.com).
Yahoo Financial, November 11, 2015 (http://www.yahoo.com).
Companies from Exhibit No.___(JSG-2)

Exhibit JWW-1-B

D2015.6.51

Montana-Dakota Utilities

Direct Testimony of

John W. Wilson

on behalf of the

Montana Consumer Counsel

November 20, 2015

DCF Cost of Equity Indications

Earnings Growth Model

Electric Companies

			(1)	(2)	(3)	(4)	(5)	(6)	(7)
				Div Yield x (1 + 0.625g)		g		D/P + g	
		Company	Dividend Yield	Zacks	Yahoo	Zacks Growth	Yahoo Growth	Zacks	Yahoo
1	ALE	ALLETE, Inc	4.1%	4.3%	4.3%	5.0%	5.5%	9.3%	9.8%
2	LNT	Alliant Energy Corp.	3.7%	3.8%	3.8%	5.3%	5.4%	9.1%	9.2%
3	AEE	Ameren Corp.	4.0%	4.2%	4.2%	6.8%	6.4%	11.0%	10.5%
4	AEP	American Elec Pwr Co.	3.8%	3.9%	3.9%	4.7%	4.6%	8.6%	8.6%
5	AVA	Avista Corp.	4.1%	NA	4.2%	NA	5.0%	NA	9.2%
6	BKH	Black Hills Corp.	3.7%	NA	3.8%	MA	3.5%	NA	7.3%
7	CNP	CenterPoint Energy, Inc.	5.2%	5.3%	5.2%	3.4%	0.5%	8.7%	5.7%
8	CNL	Cleco Corp.	3.0%	3.0%	3.0%	3.0%	3.0%	6.0%	6.0%
9	CMS	CMS Energy Corp.	3.4%	3.6%	3.6%	6.2%	6.7%	9.8%	10.3%
10	ED	Consolidated Edison, Inc.	4.1%	4.2%	4.2%	2.9%	2.7%	7.1%	6.9%
11	D	Dominion Resources, Inc.	3.7%	3.8%	3.8%	6.2%	5.4%	10.0%	9.2%
12	DTE	DTE Energy Co.	3.6%	3.7%	3.7%	5.5%	4.9%	9.2%	8.6%
13	DUK	Duke Energy Corp.	4.4%	4.5%	4.5%	4.1%	3.3%	8.6%	7.8%
14	EIX	Edison International	2.8%	2.9%	2.7%	4.5%	-4.1%	7.4%	-1.4%
15	EE	El Paso Electric Co.	3.2%	3.4%	3.4%	6.7%	7.0%	10.1%	10.4%
16	EDE	Empire District Elec	4.6%	4.8%	4.8%	5.0%	5.0%	9.8%	9.8%
17	ETR	Entergy Corp.	4.8%	4.7%	4.7%	-1.7%	-2.6%	3.0%	2.1%
18	ES	Eversource Energy	3.4%	3.6%	3.6%	6.8%	6.6%	10.4%	10.2%
19	EXC	Exelon Corp.	3.9%	4.0%	4.0%	4.2%	5.0%	8.2%	9.1%
20	FE	FirstEnergy Corp.	4.3%	NA	4.3%	NA	-0.6%	NA	3.7%
21	GXP	Great Plains Energy	3.8%	3.9%	3.9%	6.0%	5.2%	9.9%	9.1%
22	HE	Hawaiian Elec.	4.2%	4.3%	4.3%	3.2%	3.2%	7.5%	7.5%
23	IDA	IDACORP, Inc.	3.1%	3.2%	3.2%	4.0%	4.0%	7.2%	7.2%
24	ITC	ITC Holdings Corp.	2.1%	2.2%	2.2%	9.0%	7.4%	11.2%	9.6%
25	MGEE	MGE Energy	2.9%	NA	3.0%	NA	4.0%	NA	7.0%
26	NEE	NextEra Energy, Inc.	3.1%	3.2%	3.2%	7.1%	6.9%	10.3%	10.1%
27	NWE	NorthWestern Corp.	3.7%	3.8%	3.8%	5.0%	6.8%	8.8%	10.6%
28	OGE	OGE Energy Corp.	3.5%	3.6%	3.5%	4.6%	2.4%	8.2%	5.9%
29	OTTR	Otter Tail Corp.	4.6%	NA	4.8%	NA	6.0%	NA	10.8%
30	POM	Pepco Holdings	4.2%	4.4%	4.4%	7.0%	4.3%	11.4%	8.7%
31	PCG	PG&E Corp.	3.5%	3.6%	3.7%	4.5%	5.9%	8.1%	9.6%
32	PNW	Pinnacle West Capital	3.9%	4.1%	4.1%	5.2%	5.2%	9.3%	9.2%
33	PNM	PNM Resources	3.0%	3.2%	3.2%	8.1%	9.4%	11.3%	12.6%
34	POR	Portland General Elec.	3.4%	3.4%	3.4%	4.1%	3.9%	7.5%	7.4%
35	PPL	PPL Corp.	4.7%	4.8%	4.8%	4.9%	4.9%	9.7%	9.7%
36	PEG	Pub Sv Enterprise Grp	3.8%	3.8%	3.8%	2.9%	1.5%	6.7%	5.3%
37	SCG	SCANA Corp.	4.1%	4.2%	4.2%	4.3%	4.5%	8.5%	8.6%
38	SRE	Sempra Energy	2.8%	2.9%	3.0%	8.2%	9.4%	11.1%	12.3%
39	SO	Southern Company	4.9%	5.1%	5.1%	3.9%	3.7%	9.0%	8.8%
40	TE	TECO Energy	4.3%	4.5%	4.4%	7.1%	6.8%	11.6%	11.2%
41	UIL	UIL Holdings	3.6%	3.8%	3.8%	7.8%	8.8%	11.6%	12.7%
42	VVC	Vectren Corp.	3.7%	3.8%	3.8%	5.7%	5.0%	9.5%	8.8%
43	WR	Westar Energy	3.9%	4.0%	4.0%	3.9%	3.9%	7.9%	7.9%

DCF Cost of Equity Indications

Earnings Growth Model

Electric Companies

			(1)	(2)	(3)	(4)	(5)	(6)	(7)
				Div Yield x (1 + 0.625g)		g		D/P + g	
		Company	Dividend Yield	Zacks	Yahoo	Zacks Growth	Yahoo Growth	Zacks	Yahoo
44	WEC	Wisconsin Energy	3.6%	3.7%	3.7%	6.2%	7.6%	9.9%	11.3%
45	XEL	Xcel Energy, Inc.	3.7%	3.9%	3.9%	5.0%	4.7%	8.9%	8.5%
		Average						**9.0%**	**8.5%**

Sources: Value Line Investment Survey August 10, September 18, and October 30, 2015.
Zacks Investment Research, November 11, 2015 (http://www.zacks.com).
Yahoo Financial, November 11, 2015 (http://www.yahoo.com).

Exhibit JWW-2-A

D2015.6.51

Montana-Dakota Utilities

Direct Testimony of

John W. Wilson

on behalf of the

Montana Consumer Counsel

November 20, 2015

DCF Cost of Equity Indications

Fundamental Growth Model

Selected Electric Companies from Exhibit No.___(JSG-2)

		Company	(1) Dividend Yield	(2) Div Yield x (1 + 0.625g)	(3) Value Line Forecast 2018-2020 EPS	(4) DPS	(5) ROE	(6) Retention Rate	(7) Fundamental Growth	(8) D/P + g
1	ALE	ALLETE, Inc	4.1%	4.2%	$4.00	$2.40	9.0%	40.0%	3.6%	7.8%
2	LNT	Alliant Energy Corp.	3.7%	3.8%	$4.50	$2.85	11.5%	36.7%	4.2%	8.0%
3	AEE	Ameren Corp.	4.0%	4.2%	$3.50	$1.95	10.5%	44.3%	4.7%	8.8%
4	AEP	American Elec Pwr Co.	3.8%	3.9%	$4.25	$2.65	10.0%	37.6%	3.8%	7.7%
5	EDE	Empire District Elec	4.6%	4.7%	$1.75	$1.20	9.0%	31.4%	2.8%	7.5%
6	GXP	Great Plains Energy	3.8%	3.9%	$2.00	$1.20	7.5%	40.0%	3.0%	6.9%
7	OGE	OGE Energy Corp.	3.5%	3.6%	$2.25	$1.55	11.5%	31.1%	3.6%	7.1%
8	OTTR	Otter Tail Corp.	4.6%	4.7%	$2.25	$1.32	12.5%	41.3%	5.2%	9.9%
9	PNM	PNM Resources	3.0%	3.1%	$2.35	$1.30	9.5%	44.7%	4.2%	7.3%
10	TE	TECO Energy	4.3%	4.4%	$1.40	$1.00	11.5%	28.6%	3.3%	7.6%
11	WR	Westar Energy	3.9%	4.0%	$3.00	$1.65	9.5%	45.0%	4.3%	8.3%
12	XEL	Xcel Energy, Inc.	3.7%	3.8%	$2.50	$1.60	10.0%	36.0%	3.6%	7.4%
		Average								**7.9%**

Sources: Value Line Investment Survey August 10, September 18, and October 30, 2015.
Companies from Exhibit No.___(JSG-2)

Exhibit JWW-2-B

D2015.6.51

Montana-Dakota Utilities

Direct Testimony of

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on behalf of the

Montana Consumer Counsel

November 20, 2015

DCF Cost of Equity Indications

Fundamental Growth Model

Electric Companies

		Company	(1) Dividend Yield	(2) Div Yield x (1 + 0.625g)	(3) Value Line Forecast 2018-2020 EPS	(4) DPS	(5) ROE	(6) Retention Rate	(7) Fundamental Growth	(8) D/P + g
1	ALE	ALLETE, Inc	4.1%	4.2%	$4.00	$2.40	9.0%	40.0%	3.6%	7.8%
2	LNT	Alliant Energy Corp.	3.7%	3.8%	$4.50	$2.85	11.5%	36.7%	4.2%	8.0%
3	AEE	Ameren Corp.	4.0%	4.2%	$3.50	$1.95	10.5%	44.3%	4.7%	8.8%
4	AEP	American Elec Pwr Co.	3.8%	3.9%	$4.25	$2.65	10.0%	37.6%	3.8%	7.7%
5	AVA	Avista Corp.	4.1%	4.2%	$2.25	$1.55	9.0%	31.1%	2.8%	7.0%
6	BKH	Black Hills Corp.	3.7%	3.8%	$3.50	$1.90	9.5%	45.7%	4.3%	8.2%
7	CNP	CenterPoint Energy, Inc.	5.2%	5.3%	$1.35	$1.15	11.5%	14.8%	1.7%	7.0%
8	CNL	Cleco Corp.	3.0%	3.0%	$2.75	$1.90	9.0%	30.9%	2.8%	5.8%
9	CMS	CMS Energy Corp.	3.4%	3.5%	$2.25	$1.50	13.5%	33.3%	4.5%	8.0%
10	ED	Consolidated Edison, Inc.	4.1%	4.2%	$4.50	$2.90	9.0%	35.6%	3.2%	7.4%
11	D	Dominion Resources, Inc.	3.7%	3.8%	$4.75	$3.50	17.5%	26.3%	4.6%	8.4%
12	DTE	DTE Energy Co.	3.6%	3.7%	$5.75	$3.50	10.0%	39.1%	3.9%	7.6%
13	DUK	Duke Energy Corp.	4.4%	4.5%	$5.25	$3.80	8.5%	27.6%	2.3%	6.8%
14	EIX	Edison International	2.8%	2.9%	$5.25	$2.45	11.5%	53.3%	6.1%	9.0%
15	EE	El Paso Electric Co.	3.2%	3.3%	$2.75	$1.40	9.5%	49.1%	4.7%	8.0%
16	EDE	Empire District Elec	4.6%	4.7%	$1.75	$1.20	9.0%	31.4%	2.8%	7.5%
17	ETR	Entergy Corp.	4.8%	4.9%	$5.50	$3.80	8.5%	30.9%	2.6%	7.5%
18	ES	Eversource Energy	3.4%	3.5%	$3.75	$2.10	10.0%	44.0%	4.4%	7.9%
19	EXC	Exelon Corp.	3.9%	4.0%	$2.75	$1.40	8.5%	49.1%	4.2%	8.2%
20	FE	FirstEnergy Corp.	4.3%	4.4%	$3.00	$1.60	8.5%	46.7%	4.0%	8.4%
21	GXP	Great Plains Energy	3.8%	3.9%	$2.00	$1.20	7.5%	40.0%	3.0%	6.9%
22	HE	Hawaiian Elec.	4.2%	4.3%	$2.00	$1.30	9.5%	35.0%	3.3%	7.6%
23	IDA	IDACORP, Inc.	3.1%	3.2%	$4.25	$2.45	8.5%	42.4%	3.6%	6.8%
24	ITC	ITC Holdings Corp.	2.1%	2.2%	$2.75	$1.10	15.5%	60.0%	9.3%	11.5%
25	MGEE	MGE Energy	2.9%	3.1%	$3.15	$1.35	13.0%	57.1%	7.4%	10.5%

DCF Cost of Equity Indications

Fundamental Growth Model

Electric Companies

			(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
			Dividend	Div Yield x	Value Line Forecast 2018-2020			Retention	Fundamental	
		Company	Yield	(1 + 0.625g)	EPS	DPS	ROE	Rate	Growth	D/P + g
26	NEE	NextEra Energy, Inc.	3.1%	3.1%	$7.50	$5.00	12.5%	33.3%	4.2%	7.3%
27	NWE	NorthWestern Corp.	3.7%	3.8%	$3.75	$2.25	10.0%	40.0%	4.0%	7.8%
28	OGE	OGE Energy Corp.	3.5%	3.6%	$2.25	$1.55	11.5%	31.1%	3.6%	7.1%
29	OTTR	Otter Tail Corp.	4.6%	4.7%	$2.25	$1.32	12.5%	41.3%	5.2%	9.9%
30	POM	Pepco Holdings	4.2%	4.4%	$2.00	$1.08	10.0%	46.0%	4.6%	9.0%
31	PCG	PG&E Corp.	3.5%	3.6%	$4.25	$2.20	10.5%	48.2%	5.1%	8.7%
32	PNW	Pinnacle West Capital	3.9%	4.0%	$4.50	$2.95	10.0%	34.4%	3.4%	7.5%
33	PNM	PNM Resources	3.0%	3.1%	$2.35	$1.30	9.5%	44.7%	4.2%	7.3%
34	POR	Portland General Elec.	3.4%	3.4%	$2.75	$1.50	9.5%	45.5%	4.3%	7.8%
35	PPL	PPL Corp.	4.7%	4.8%	$2.50	$1.60	10.5%	36.0%	3.8%	8.5%
36	PEG	Pub Sv Enterprise Grp	3.8%	3.9%	$3.25	$1.90	10.5%	41.5%	4.4%	8.2%
37	SCG	SCANA Corp.	4.1%	4.2%	$4.50	$2.50	9.5%	44.4%	4.2%	8.4%
38	SRE	Sempra Energy	2.8%	2.9%	$7.25	$3.60	12.5%	50.3%	6.3%	9.2%
39	SO	Southern Company	4.9%	5.1%	$3.50	$2.43	13.5%	30.6%	4.1%	9.2%
40	TE	TECO Energy	4.3%	4.4%	$1.40	$1.00	11.5%	28.6%	3.3%	7.6%
41	UIL	UIL Holdings	3.6%	3.7%	$2.75	$1.73	10.0%	37.1%	3.7%	7.4%
42	VVC	Vectren Corp.	3.7%	3.8%	$3.25	$1.80	15.0%	44.6%	6.7%	10.5%
43	WR	Westar Energy	3.9%	4.0%	$3.00	$1.65	9.5%	45.0%	4.3%	8.3%
44	WEC	Wisconsin Energy	3.6%	3.6%	$3.50	$2.30	11.0%	34.3%	3.8%	7.4%
45	XEL	Xcel Energy, Inc.	3.7%	3.8%	$2.50	$1.60	10.0%	36.0%	3.6%	7.4%
		Average								**8.1%**

Sources: Value Line Investment Survey August 10, September 18, and October 30, 2015.

Exhibit JWW-3-A

D2015.6.51

Montana-Dakota Utilities

Direct Testimony of

John W. Wilson

on behalf of the

Montana Consumer Counsel

November 20, 2015

Capital Asset Pricing Model

Cost of Equity Capital: $k = R_f + \beta (R_m - R_f)$

Risk-free Yield (R_f)	1% to 5%
Beta Coefficient (β)*	0.78
Equity Risk Premium ($R_m - R_f$)	3% to 7%
Estimated Cost of Equity Capital (k)	3.35% - 10.48%
Mid Point of Range	6.92%

**Beta Coefficient for the 12 Companies from Exhibit No___(JSG-2)*

Exhibit JWW-3-B

D2015.6.51

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Capital Asset Pricing Model

Cost of Equity Capital: $k = R_f + \beta (R_m - R_f)$

Risk-free Yield (R_f)	1% to 5%
Beta Coefficient (β)*	0.74
Equity Risk Premium ($R_m - R_f$)	3% to 7%
Estimated Cost of Equity Capital (k)	3.22% - 10.18%
Mid Point of Range	6.70%

**Beta Coefficient for all 45 Electric Companies.*

Exhibit JWW-4-A

D2015.6.51

Montana-Dakota Utilities

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Comparable Expected Market Earnings Rates

Selected Electric Companies from Exhibit No.___(JSG-2)

		Company	(1) Projected Book Return	(2) Projected Market/Book	(3) Expected Market Earnings Rate
1	ALE	ALLETE, Inc	9.41%	1.27	7.41%
2	LNT	Alliant Energy Corp.	12.99%	1.88	6.90%
3	AEE	Ameren Corp.	10.29%	1.29	8.00%
4	AEP	American Elec Pwr Co.	10.12%	1.42	7.14%
5	EDE	Empire District Elec	8.64%	1.17	7.41%
6	GXP	Great Plains Energy	7.48%	1.01	7.41%
7	OGE	OGE Energy Corp.	11.11%	1.78	6.25%
8	OTTR	Otter Tail Corp.	12.43%	2.24	5.56%
9	PNM	PNM Resources	9.22%	1.47	6.25%
10	TE	TECO Energy	11.67%	1.75	6.67%
11	WR	Westar Energy	10.26%	1.54	6.67%
12	XEL	XCEL Energy	10.31%	1.44	7.14%
		Average	**10.33%**	**1.52**	**6.90%**

Sources: Value Line Investment Survey August 10, September 18, and October 30, 2015.
Companies from Exhibit No.___(JSG-2)

Exhibit JWW-4-B

D2015.6.51

Montana-Dakota Utilities

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November 20, 2015

Comparable Expected Market Earnings Rates

Electric Companies

		Company	(1) Projected Book Return	(2) Projected Market/Book	(3) Expected Market Earnings Rate
1	ALE	ALLETE, Inc	9.41%	1.27	7.41%
2	LNT	Alliant Energy Corp.	12.99%	1.88	6.90%
3	AEE	Ameren Corp.	10.29%	1.29	8.00%
4	AEP	American Elec Pwr Co.	10.12%	1.42	7.14%
5	AVA	Avista Corp.	8.33%	1.29	6.45%
6	BKH	Black Hills Corp.	9.79%	1.42	6.90%
7	CNP	CenterPoint Energy, Inc.	11.49%	1.95	5.88%
8	CNL	Cleco Corp.	8.87%	1.42	6.25%
9	CMS	CMS Energy Corp.	12.68%	1.90	6.67%
10	ED	Consolidated Edison, Inc.	8.87%	1.24	7.14%
11	D	Dominion Resources, Inc.	16.96%	2.97	5.71%
12	DTE	DTE Energy Co.	9.83%	1.33	7.41%
13	DUK	Duke Energy Corp.	8.17%	1.31	6.25%
14	EIX	Edison International	11.41%	1.54	7.41%
15	EE	El Paso Electric Co.	9.32%	1.35	6.90%
16	EDE	Empire District Elec	8.64%	1.17	7.41%
17	ETR	Entergy Corp.	8.63%	1.34	6.45%
18	ES	Eversource Energy	9.80%	1.37	7.14%
19	EXC	Exelon Corp.	8.21%	0.99	8.33%
20	FE	FirstEnergy Corp.	8.39%	1.05	8.00%
21	GXP	Great Plains Energy	7.48%	1.01	7.41%
22	HE	Hawaiian Elec.	10.00%	1.25	8.00%
23	IDA	IDACORP, Inc.	9.03%	1.45	6.25%
24	ITC	ITC Holdings Corp.	15.49%	2.79	5.56%
25	MGEE	MGE Energy	12.60%	1.89	6.67%
26	NEE	NextEra Energy, Inc.	12.55%	2.07	6.06%
27	NWE	NorthWestern Corp.	9.80%	1.37	7.14%
28	OGE	OGE Energy Corp.	11.11%	1.78	6.25%
29	OTTR	Otter Tail Corp.	12.43%	2.24	5.56%
30	POM	Pepco Holdings	9.85%	1.38	7.14%
31	PCG	PG&E Corp.	10.06%	1.21	8.33%
32	PNW	Pinnacle West Capital	9.52%	1.29	7.41%
33	PNM	PNM Resources	9.22%	1.47	6.25%
34	POR	Portland General Elec.	9.09%	1.14	8.00%
35	PPL	PPL Corp.	10.53%	1.42	7.41%
36	PEG	Pub Sv Enterprise Grp	10.40%	1.46	7.14%
37	SCG	SCANA Corp.	9.89%	1.29	7.69%
38	SRE	Sempra Energy	12.18%	2.01	6.06%
39	SO	Southern Company	13.46%	1.82	7.41%
40	TE	TECO Energy	11.67%	1.75	6.67%

Comparable Expected Market Earnings Rates

Electric Companies

		Company	(1) Projected Book Return	(2) Projected Market/Book	(3) Expected Market Earnings Rate
41	UIL	UIL Holdings	9.03%	1.44	6.25%
42	VVC	Vectren Corp.	14.87%	2.23	6.67%
43	WR	Westar Energy	10.26%	1.54	6.67%
44	WEC	Wisconsin Energy	10.94%	1.59	6.90%
45	XEL	XCEL Energy	10.31%	1.44	7.14%
		Average	**10.53%**	**1.55**	**6.93%**

Sources: Value Line Investment Survey August 10, September 18, and October 30, 2015.

Exhibit JWW-5-A

D2015.6.51

Montana-Dakota Utilities

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Montana Consumer Counsel

November 20, 2015

Comparative Risk Indicators

Selected Electric Companies from Exhibit No.___(JSG-2)

		Company	(1) Beta	(2) Safety	(3) Price Stability	(4) Earnings Predictability	(5) Financial Strenght
1	ALE	ALLETE, Inc	0.80	2	95	80	A
2	LNT	Alliant Energy Corp.	0.80	2	100	75	A
3	AEE	Ameren Corp.	0.75	2	95	85	A
4	AEP	American Elec Pwr Co.	0.70	2	100	90	A
5	EDE	Empire District Elec	0.70	2	90	85	B++
6	GXP	Great Plains Energy	0.85	3	95	70	B+
7	OGE	OGE Energy Corp.	0.90	1	90	95	A+
8	OTTR	Otter Tail Corp.	0.85	3	85	50	B+
9	PNM	PNM Resources	0.85	3	85	30	B
10	TE	TECO Energy	0.80	2	90	80	B++
11	WR	Westar Energy	0.75	2	100	90	B++
12	XEL	XCEL Energy	0.65	1	100	100	A
		Average	**0.78**	**2.08**	**93.75**	**77.50**	**B++**

Sources: Value Line Investment Survey August 10, September 18, and October 30, 2015.
Companies from Exhibit No.___(JSG-2)

Exhibit JWW-5-B

D2015.6.51

Montana-Dakota Utilities

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November 20, 2015

Comparative Risk Indicators

Comparable Electric Companies

		Company	(1) Beta	(2) Safety	(3) Price Stability	(4) Earnings Predictability	(5) Financial Strenght
1	ALE	ALLETE, Inc	0.80	2	95	80	A
2	LNT	Alliant Energy Corp.	0.80	2	100	75	A
3	AEE	Ameren Corp.	0.75	2	95	85	A
4	AEP	American Elec Pwr Co.	0.70	2	100	90	A
5	AVA	Avista Corp.	0.80	2	95	80	A
6	BKH	Black Hills Corp.	0.95	2	80	40	A
7	CNP	CenterPoint Energy, Inc.	0.80	2	95	90	B++
8	CNL	Cleco Corp.	0.75	1	100	80	A
9	CMS	CMS Energy Corp.	0.70	2	100	75	B++
10	ED	Consolidated Edison, Inc.	0.60	1	100	85	A+
11	D	Dominion Resources, Inc.	0.70	2	100	80	B++
12	DTE	DTE Energy Co.	0.75	2	100	95	B++
13	DUK	Duke Energy Corp.	0.60	2	100	80	A
14	EIX	Edison International	0.70	2	95	65	A
15	EE	El Paso Electric Co.	0.75	2	90	85	B++
16	EDE	Empire District Elec	0.70	2	90	85	B++
17	ETR	Entergy Corp.	0.65	3	95	80	B++
18	ES	Eversource Energy	0.75	1	100	85	A
19	EXC	Exelon Corp.	0.65	3	90	65	B++
20	FE	FirstEnergy Corp.	0.65	3	90	50	B+
21	GXP	Great Plains Energy	0.85	3	95	70	B+
22	HE	Hawaiian Elec.	0.80	2	90	80	A
23	IDA	IDACORP, Inc.	0.80	2	95	95	B++
24	ITC	ITC Holdings Corp.	0.65	2	95	95	B++
25	MGEE	MGE Energy	0.75	1	95	95	A
26	NEE	NextEra Energy, Inc.	0.70	2	100	75	A
27	NWE	NorthWestern Corp.	0.70	3	100	95	B+
28	OGE	OGE Energy Corp.	0.90	1	90	95	A+
29	OTTR	Otter Tail Corp.	0.85	3	85	50	B+
30	POM	Pepco Holdings	0.65	3	100	70	B+
31	PCG	PG&E Corp.	0.65	3	95	60	B+
32	PNW	Pinnacle West Capital	0.75	1	100	70	A+
33	PNM	PNM Resources	0.85	3	85	30	B
34	POR	Portland General Elec.	0.80	2	100	70	B++
35	PPL	PPL Corp.	0.65	2	100	60	B++
36	PEG	Pub Sv Enterprise Grp	0.75	1	95	75	A++
37	SCG	SCANA Corp.	0.75	2	100	100	B++
38	SRE	Sempra Energy	0.80	2	100	90	A
39	SO	Southern Company	0.55	2	100	100	A
40	TE	TECO Energy	0.80	2	90	80	B++

Comparative Risk Indicators

Comparable Electric Companies

		Company	(1) Beta	(2) Safety	(3) Price Stability	(4) Earnings Predictability	(5) Financial Strenght
41	UIL	UIL Holdings	0.75	2	90	85	B++
42	VVC	Vectren Corp.	0.80	2	95	80	A
43	WR	Westar Energy	0.75	2	100	90	B++
44	WEC	Wisconsin Energy	0.70	1	100	95	A+
45	XEL	XCEL Energy	0.65	1	100	100	A
		Average	**0.74**	**2.00**	**95.67**	**79.00**	**B++**

Sources: Value Line Investment Survey August 10, September 18, and October 30, 2015.

Exhibit JWW-6-A

D2015.6.51

Montana-Dakota Utilities

Direct Testimony of

John W. Wilson

on behalf of the

Montana Consumer Counsel

November 20, 2015

Summary

Cost of Common Equity Return Indicators

Selected Electric Companies from Exhibit No.___(JSG-2)

DCF Evidence (Average)	
Zacks - Earnings Growth	9.6%
Yahoo - Earnings Growth	8.5%
Fundamental DCF	7.9%
CAPM Evidence	3.35% - 10.48%
Comparable Expected Market Earnings	6.9%
Average of Above Measures	7.9%
Indicated Range of Reasonableness	7.5% - 9%

Exhibit JWW-6-B

D2015.6.51

Montana-Dakota Utilities

Direct Testimony of

John W. Wilson

on behalf of the

Montana Consumer Counsel

November 20, 2015

Summary

Cost of Common Equity Return Indicators

Electric Companies

DCF Evidence (Average)	
Zacks - Earnings Growth	9.0%
Yahoo - Earnings Growth	8.5%
Fundamental DCF	8.1%
CAPM Evidence	3.22% - 10.18%
Comparable Expected Market Earnings	6.9%
Average of Above Measures	7.8%
Indicated Range of Reasonableness	7.4% - 9%

Exhibit JWW-7

D2015.6.51

Montana-Dakota Utilities

Direct Testimony of

John W. Wilson

on behalf of the

Montana Consumer Counsel

November 20, 2015

MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY - MONTANA
Embedded Class Cost of Service Study
Summary Sheet
Pro Forma 2014

Exhibit No.__JWW-7

Operating Income and Rate of Return	Total Montana	Total Residential	Total Small General	Total Large General	Total Municipal Pumping	Total Lighting
Sales Revenues	55,454,439	16,960,743	10,235,790	26,888,012	465,178	904,717
Adjustments to Sales Revenues	150,374	(55,569)	249,219	(38,106)	(1,869)	(3,302)
Total Sales Revenues	55,604,813	16,905,174	10,485,009	26,849,906	463,309	901,415
Other Revenues	2,739,121	735,106	413,049	1,031,088	24,890	534,988
Adjustments to Other Revenues	(516,836)	(167,131)	(93,083)	(240,231)	(5,124)	(11,267)
Total Other Revenues	2,222,285	567,975	319,966	790,857	19,766	523,721
Total Operating Revenues	57,827,098	17,473,149	10,804,975	27,640,763	483,075	1,425,136
Operating Expense						
Cost of Fuel and Purchased Power	22,311,650	5,472,615	3,667,315	12,682,135	207,077	282,508
Adj. to Cost of Fuel and Purchased Pwr	(1,809,943)	(471,172)	(304,614)	(992,233)	(18,823)	(23,101)
Total Cost of Fuel and Purchased Pwr	20,501,707	5,001,443	3,362,701	11,689,902	188,254	259,407
Other O&M Expense	15,814,581	6,141,742	3,056,525	5,987,077	166,478	462,759
Adjustments to Other O&M	3,453,811	1,006,355	603,834	1,749,547	36,571	57,504
Total Other O&M Expense	19,268,392	7,148,097	3,660,359	7,736,624	203,049	520,263
Total Operation & Maintenance Expense	39,770,099	12,149,540	7,023,060	19,426,526	391,303	779,670
Depreciation Expense	6,901,084	2,269,011	1,272,996	3,055,489	74,991	228,597
Adjustment to Depreciation Expense	4,608,077	1,339,292	817,620	2,308,827	48,002	94,336
Total Depreciation Expense	11,509,161	3,608,303	2,090,616	5,364,316	122,993	322,933
Taxes Other Than Income Taxes	4,080,303	1,745,543	878,826	1,207,280	45,116	203,538
Adjustment to Taxes Other Than Income	617,219	212,142	118,239	261,599	6,936	18,303
Total Taxes Other Than Income	4,697,522	1,957,685	997,065	1,468,879	52,052	221,841
Current Income Taxes - Fed. & State	(4,064,984)	(1,642,930)	(727,952)	(1,514,244)	(85,114)	(94,744)
Adjustment to Current Income Taxes	(13,304,337)	(3,717,610)	(2,213,048)	(7,020,590)	(141,991)	(211,098)
Total Current Income Taxes	(17,369,321)	(5,360,540)	(2,941,000)	(8,534,834)	(227,105)	(305,842)
Deferred Income Taxes	5,966,982	2,039,488	1,143,826	2,537,376	67,620	178,672
Adjustment to Deferred Income Tax	7,080,844	1,887,718	1,203,430	3,821,459	76,664	91,573
Total Deferred Income Taxes	13,047,826	3,927,206	2,347,256	6,358,835	144,284	270,245
Total Operating Expenses	51,655,287	16,282,194	9,516,997	24,083,722	483,527	1,288,847
Pro Forma Operating Income	6,171,811	1,190,955	1,287,978	3,557,041	(452)	136,289
Rate Base	87,013,106	30,374,924	17,228,497	36,018,428	937,933	2,453,324
Adjustment to Rate Base	87,944,242	23,725,617	15,107,537	46,878,007	953,108	1,279,973
Total Pro Forma Rate Base	174,957,348	54,100,541	32,336,034	82,896,435	1,891,041	3,733,297
Pro Forma Rate of Return	3.528%	2.201%	3.983%	4.291%	-0.024%	3.651%

MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY - MONTANA
Embedded Class Cost of Service Study
Summary Sheet
Twelve Months Ended December 31, 2014

		Residential Rate 10				Total
Operating Income and Rate of Return	Total Montana	Demand Prod. & Trans.	Demand Distribution	Energy	Customer	Residential Rate 10
Operating Sales Revenues	55,454,439	267,588	0	15,379,354	1,313,801	16,960,743
Adjustments to Sales Revenues	150,374	(227,383)	0	167,410	4,404	(55,569)
Total Sales Revenues	55,604,813	40,205	0	15,546,764	1,318,205	16,905,174
Other Revenues	2,739,121	458,894	27,071	56,580	192,561	735,106
Adjustments to Other Revenues	(516,836)	(53,847)	(4,916)	(56,579)	(51,789)	(167,131)
Total Other Revenues	2,222,285	405,047	22,155	1	140,772	567,975
Total Operating Revenues	57,827,098	445,252	22,155	15,546,765	1,458,977	17,473,149
Operating Expense						
Cost of Fuel and Purchased Power	22,311,650	268,149	0	5,204,466	0	5,472,615
Adj. to Cost of Fuel and Purchased Pwr	(1,809,943)	(227,944)	0	(243,228)	0	(471,172)
Total Cost of Fuel and Purchased Pwr	20,501,707	40,205	0	4,961,238	0	5,001,443
Other O&M Expense	15,814,581	2,991,501	273,120	0	2,877,121	6,141,742
Adjustments to Other O&M	3,453,811	531,173	16,420	315,033	143,729	1,006,355
Total Other O&M Expense	19,268,392	3,522,674	289,540	315,033	3,020,850	7,148,097
Total Operation & Maintenance Expense	39,770,099	3,562,879	289,540	5,276,271	3,020,850	12,149,540
Depreciation Expense	6,901,084	1,475,668	120,422	0	672,921	2,269,011
Adjustment to Depreciation Expense	4,608,077	1,056,680	53,556	0	229,056	1,339,292
Total Depreciation Expense	11,509,161	2,532,348	173,978	0	901,977	3,608,303
Taxes Other Than Income Taxes	4,080,303	479,589	221,057	0	1,044,897	1,745,543
Adjustment to Taxes Other Than Income	617,219	125,163	15,159	0	71,820	212,142
Total Taxes Other Than Income	4,697,522	604,752	236,216	0	1,116,717	1,957,685
Current Income Taxes - Fed. & State	(4,064,984)	(3,386,204)	(386,159)	4,020,134	(1,890,701)	(1,642,930)
Adjustment to Current Income Taxes	(13,304,337)	(3,370,931)	(62,231)	15,371	(299,819)	(3,717,610)
Total Current Income Taxes	(17,369,321)	(6,757,135)	(448,390)	4,035,505	(2,190,520)	(5,360,540)
Deferred Income Taxes	5,966,982	1,216,399	150,585	0	672,504	2,039,488
Adjustment to Deferred Income Tax	7,080,844	1,880,283	1,360	0	6,075	1,887,718
Total Deferred Income Taxes	13,047,826	3,096,682	151,945	0	678,579	3,927,206
Total Operating Expenses	51,655,287	3,039,526	403,289	9,311,776	3,527,603	16,282,194
Pro Forma Operating Income	6,171,811	(2,594,274)	(381,134)	6,234,989	(2,068,626)	1,190,955
Rate Base	87,013,106	16,226,671	2,832,315	306,662	11,009,276	30,374,924
Adjustment to Rate Base	87,944,242	22,382,149	249,866	(12,483)	1,106,085	23,725,617
Total Pro Forma Rate Base	174,957,348	38,608,820	3,082,181	294,179	12,115,361	54,100,541
Pro Forma Rate of Return	3.528%	-6.719%	-12.366%	2119.454%	-17.074%	2.201%

MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY - MONTANA
Embedded Class Cost of Service Study
Summary Sheet
Twelve Months Ended December 31, 2014

		Small General Rate 20				Total
Operating Income and	Total	Demand	Demand			Small General
Rate of Return	Montana	Prod. & Trans.	Distribution	Energy	Customer	Rate 20
Operating Sales Revenues	55,454,439	158,486	1,487,528	7,262,246	1,128,739	10,037,000
Adjustments to Sales Revenues	150,374	(134,673)	311,894	63,735	4,784	245,740
Total Sales Revenues	55,604,813	23,813	1,799,422	7,325,982	1,133,523	10,282,740
Other Revenues	2,739,121	272,904	14,329	37,228	72,690	397,151
Adjustments to Other Revenues	(516,836)	(31,893)	(2,602)	(37,229)	(18,423)	(90,147)
Total Other Revenues	2,222,285	241,011	11,727	(1)	54,267	307,004
Total Operating Revenues	57,827,098	264,824	1,811,149	7,325,981	1,187,790	10,589,744
Operating Expense						
Cost of Fuel and Purchased Power	22,311,650	158,818	0	3,424,559	0	3,583,377
Adj. to Cost of Fuel and Purchased Pwr	(1,809,943)	(135,005)	0	(160,045)	0	(295,050)
Total Cost of Fuel and Purchased Pwr	20,501,707	23,813	0	3,264,514	0	3,288,327
Other O&M Expense	15,814,581	1,771,790	144,566	0	1,023,506	2,939,862
Adjustments to Other O&M	3,453,811	314,600	8,692	207,291	52,627	583,210
Total Other O&M Expense	19,268,392	2,086,390	153,258	207,291	1,076,133	3,523,072
Total Operation & Maintenance Expense	39,770,099	2,110,203	153,258	3,471,805	1,076,133	6,811,399
Depreciation Expense	6,901,084	894,835	63,733	0	266,135	1,224,703
Adjustment to Depreciation Expense	4,608,077	663,136	28,344	0	99,225	790,705
Total Depreciation Expense	11,509,161	1,557,971	92,077	0	365,360	2,015,408
Taxes Other Than Income Taxes	4,080,303	285,782	116,994	0	439,672	842,448
Adjustment to Taxes Other Than Income	617,219	75,282	8,023	0	30,201	113,506
Total Taxes Other Than Income	4,697,522	361,064	125,017	0	469,873	955,954
Current Income Taxes - Fed. & State	(4,064,984)	(2,047,891)	380,098	1,522,526	(501,558)	(646,825)
Adjustment to Current Income Taxes	(13,304,337)	(2,092,824)	89,910	(8,169)	(126,461)	(2,137,544)
Total Current Income Taxes	(17,369,321)	(4,140,715)	470,008	1,514,357	(628,019)	(2,784,369)
Deferred Income Taxes	5,966,982	730,673	79,696	0	287,151	1,097,520
Adjustment to Deferred Income Tax	7,080,844	1,158,516	720	0	2,594	1,161,830
Total Deferred Income Taxes	13,047,826	1,889,189	80,416	0	289,745	2,259,350
Total Operating Expenses	51,655,287	1,777,712	920,776	4,986,162	1,573,092	9,257,742
Pro Forma Operating Income	6,171,811	(1,512,888)	890,373	2,339,819	(385,302)	1,332,002
Rate Base	87,013,106	9,866,218	1,485,363	201,785	5,215,229	16,768,595
Adjustment to Rate Base	87,944,242	13,904,624	136,971	(8,214)	490,990	14,524,371
Total Pro Forma Rate Base	174,957,348	23,770,842	1,622,334	193,571	5,706,219	31,292,966
Pro Forma Rate of Return	3.528%	-6.364%	54.882%	1208.765%	-6.752%	4.257%

MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY - MONTANA
Embedded Class Cost of Service Study
Summary Sheet
Twelve Months Ended December 31, 2014

		Irrigation Power Rate 25				Total
Operating Income and Rate of Return	Total Montana	Demand Prod. & Trans.	Demand Distribution	Energy	Customer	Irrigation Rate 25
Operating Sales Revenues	55,454,439	7,007	49,752	120,486	21,545	198,790
Adjustments to Sales Revenues	150,374	(5,954)	957	8,161	315	3,479
Total Sales Revenues	55,604,813	1,053	50,709	128,647	21,860	202,269
Other Revenues	2,739,121	11,824	1,006	836	2,232	15,898
Adjustments to Other Revenues	(516,836)	(1,410)	(183)	(836)	(507)	(2,936)
Total Other Revenues	2,222,285	10,414	823	0	1,725	12,962
Total Operating Revenues	57,827,098	11,467	51,532	128,647	23,585	215,231
Operating Expense						
Cost of Fuel and Purchased Power	22,311,650	7,022	0	76,916	0	83,938
Adj. to Cost of Fuel and Purchased Pwr	(1,809,943)	(5,969)	0	(3,595)	0	(9,564)
Total Cost of Fuel and Purchased Pwr	20,501,707	1,053	0	73,321	0	74,374
Other O&M Expense	15,814,581	78,343	10,156	0	28,164	116,663
Adjustments to Other O&M	3,453,811	13,911	610	4,656	1,447	20,624
Total Other O&M Expense	19,268,392	92,254	10,766	4,656	29,611	137,287
Total Operation & Maintenance Expense	39,770,099	93,307	10,766	77,977	29,611	211,661
Depreciation Expense	6,901,084	35,029	4,479	0	8,785	48,293
Adjustment to Depreciation Expense	4,608,077	21,200	1,992	0	3,723	26,915
Total Depreciation Expense	11,509,161	56,229	6,471	0	12,508	75,208
Taxes Other Than Income Taxes	4,080,303	12,259	8,220	0	15,899	36,378
Adjustment to Taxes Other Than Income	617,219	3,078	564	0	1,091	4,733
Total Taxes Other Than Income	4,697,522	15,337	8,784	0	16,990	41,111
Current Income Taxes - Fed. & State	(4,064,984)	(81,331)	5,188	17,448	(22,432)	(81,127)
Adjustment to Current Income Taxes	(13,304,337)	(71,564)	(1,937)	2,467	(4,470)	(75,504)
Total Current Income Taxes	(17,369,321)	(152,895)	3,251	19,915	(26,902)	(156,631)
Deferred Income Taxes	5,966,982	30,080	5,599	0	10,627	46,306
Adjustment to Deferred Income Tax	7,080,844	41,453	51	0	96	41,600
Total Deferred Income Taxes	13,047,826	71,533	5,650	0	10,723	87,906
Total Operating Expenses	51,655,287	83,511	34,922	97,892	42,930	259,255
Pro Forma Operating Income	6,171,811	(72,044)	16,610	30,755	(19,345)	(44,024)
Rate Base	87,013,106	380,589	22,313	4,532	52,468	459,902
Adjustment to Rate Base	87,944,242	473,631	38,169	(184)	71,550	583,166
Total Pro Forma Rate Base	174,957,348	854,220	60,482	4,348	124,018	1,043,068
Pro Forma Rate of Return	3.528%	-8.434%	27.463%	707.336%	-15.599%	-4.221%

MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY - MONTANA
Embedded Class Cost of Service Study
Summary Sheet
Twelve Months Ended December 31, 2014

		Large General Primary Rate 30				Total
Operating Income and Rate of Return	Total Montana	Demand Prod. & Trans.	Demand Distribution	Energy	Customer	LG Primary Rate 30
Operating Sales Revenues	55,454,439	69,785	878,039	1,855,756	30,738	2,834,318
Adjustments to Sales Revenues	150,374	(59,300)	8,185	77,406	342	26,633
Total Sales Revenues	55,604,813	10,485	886,224	1,933,162	31,080	2,860,951
Other Revenues	2,739,121	119,252	6,859	13,344	953	140,408
Adjustments to Other Revenues	(516,836)	(14,043)	(1,397)	(13,344)	(289)	(29,073)
Total Other Revenues	2,222,285	105,209	5,462	0	664	111,335
Total Operating Revenues	57,827,098	115,694	891,686	1,933,162	31,744	2,972,286
Operating Expense						
Cost of Fuel and Purchased Power	22,311,650	69,931	0	1,227,474	0	1,297,405
Adj. to Cost of Fuel and Purchased Pwr	(1,809,943)	(59,446)	0	(57,365)	0	(116,811)
Total Cost of Fuel and Purchased Pwr	20,501,707	10,485	0	1,170,109	0	1,180,594
Other O&M Expense	15,814,581	780,157	77,588	0	16,039	873,784
Adjustments to Other O&M	3,453,811	138,524	4,671	74,300	1,114	218,609
Total Other O&M Expense	19,268,392	918,681	82,259	74,300	17,153	1,092,393
Total Operation & Maintenance Expense	39,770,099	929,166	82,259	1,244,409	17,153	2,272,987
Depreciation Expense	6,901,084	376,934	28,342	0	3,024	408,300
Adjustment to Depreciation Expense	4,608,077	261,421	12,206	0	796	274,423
Total Depreciation Expense	11,509,161	638,355	40,548	0	3,820	682,723
Taxes Other Than Income Taxes	4,080,303	124,414	51,273	0	3,981	179,668
Adjustment to Taxes Other Than Income	617,219	32,202	3,518	0	274	35,994
Total Taxes Other Than Income	4,697,522	156,616	54,791	0	4,255	215,662
Current Income Taxes - Fed. & State	(4,064,984)	(867,030)	250,686	252,107	838	(363,399)
Adjustment to Current Income Taxes	(13,304,337)	(842,569)	(11,331)	18,562	(1,431)	(836,769)
Total Current Income Taxes	(17,369,321)	(1,709,599)	239,355	270,669	(593)	(1,200,168)
Deferred Income Taxes	5,966,982	313,345	34,319	0	2,257	349,921
Adjustment to Deferred Income Tax	7,080,844	473,335	310	0	20	473,665
Total Deferred Income Taxes	13,047,826	786,680	34,629	0	2,277	823,586
Total Operating Expenses	51,655,287	801,218	451,582	1,515,078	26,912	2,794,790
Pro Forma Operating Income	6,171,811	(685,524)	440,104	418,084	4,832	177,496
Rate Base	87,013,106	4,134,792	(11,192)	72,326	31,209	4,227,135
Adjustment to Rate Base	87,944,242	5,591,096	280,410	(2,944)	18,577	5,887,139
Total Pro Forma Rate Base	174,957,348	9,725,888	269,218	69,382	49,786	10,114,274
Pro Forma Rate of Return	3.528%	-7.048%	163.475%	602.583%	9.706%	1.755%

MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY - MONTANA
Embedded Class Cost of Service Study
Summary Sheet
Twelve Months Ended December 31, 2014

		Large General Secondary Rate 30				Total
Operating Income and	Total	Demand	Demand			LG Secondary
Rate of Return	Montana	Prod. & Trans.	Distribution	Energy	Customer	Rate 30
Operating Sales Revenues	55,454,439	187,278	3,701,741	7,002,488	217,590	11,109,097
Adjustments to Sales Revenues	150,374	(159,138)	59,659	95,333	2,490	(1,656)
Total Sales Revenues	55,604,813	28,140	3,761,400	7,097,821	220,080	11,107,441
Other Revenues	2,739,121	324,004	14,590	49,074	7,672	395,340
Adjustments to Other Revenues	(516,836)	(37,687)	(2,649)	(49,073)	(1,807)	(91,216)
Total Other Revenues	2,222,285	286,317	11,941	1	5,865	304,124
Total Operating Revenues	57,827,098	314,457	3,773,341	7,097,822	225,945	11,411,565
Operating Expense						
Cost of Fuel and Purchased Power	22,311,650	187,670	0	4,514,126	0	4,701,796
Adj. to Cost of Fuel and Purchased Pwr	(1,809,943)	(159,530)	0	(210,964)	0	(370,494)
Total Cost of Fuel and Purchased Pwr	20,501,707	28,140	0	4,303,162	0	4,331,302
Other O&M Expense	15,814,581	2,093,665	147,192	0	100,393	2,341,250
Adjustments to Other O&M	3,453,811	371,751	8,850	273,244	5,648	659,493
Total Other O&M Expense	19,268,392	2,465,416	156,042	273,244	106,041	3,000,743
Total Operation & Maintenance Expense	39,770,099	2,493,556	156,042	4,576,406	106,041	7,332,045
Depreciation Expense	6,901,084	1,085,866	64,898	0	29,380	1,180,144
Adjustment to Depreciation Expense	4,608,077	834,564	28,863	0	12,375	875,802
Total Depreciation Expense	11,509,161	1,920,430	93,761	0	41,755	2,055,946
Taxes Other Than Income Taxes	4,080,303	340,068	119,136	0	53,250	512,454
Adjustment to Taxes Other Than Income	617,219	90,537	8,169	0	3,655	102,361
Total Taxes Other Than Income	4,697,522	430,605	127,305	0	56,905	614,815
Current Income Taxes - Fed. & State	(4,064,984)	(2,477,764)	1,246,370	997,006	(20,176)	(254,564)
Adjustment to Current Income Taxes	(13,304,337)	(2,604,612)	(10,040)	(6,310)	(14,932)	(2,635,894)
Total Current Income Taxes	(17,369,321)	(5,082,376)	1,236,330	990,696	(35,108)	(2,890,458)
Deferred Income Taxes	5,966,982	877,391	81,155	0	35,168	993,714
Adjustment to Deferred Income Tax	7,080,844	1,430,295	733	0	318	1,431,346
Total Deferred Income Taxes	13,047,826	2,307,686	81,888	0	35,486	2,425,060
Total Operating Expenses	51,655,287	2,069,901	1,695,326	5,567,102	205,079	9,537,408
Pro Forma Operating Income	6,171,811	(1,755,444)	2,078,015	1,530,720	20,866	1,874,157
Rate Base	87,013,106	12,007,813	1,487,853	265,985	713,273	14,474,924
Adjustment to Rate Base	87,944,242	17,316,408	148,077	(10,827)	64,394	17,518,052
Total Pro Forma Rate Base	174,957,348	29,324,221	1,635,930	255,158	777,667	31,992,976
Pro Forma Rate of Return	3.528%	-5.986%	127.023%	599.911%	2.683%	5.858%

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		Optional TOD Large General Rate 31				Total
Operating Income and	Total	Demand	Demand			TOD
Rate of Return	Montana	Prod. & Trans.	Distribution	Energy	Customer	Rate 31
Operating Sales Revenues	55,454,439	21,462	377,634	709,305	9,086	1,117,487
Adjustments to Sales Revenues	150,374	(18,237)	2,228	22,670	(230)	6,431
Total Sales Revenues	55,604,813	3,225	379,862	731,975	8,856	1,123,918
Other Revenues	2,739,121	36,811	1,960	4,550	349	43,670
Adjustments to Other Revenues	(516,836)	(4,319)	(393)	(4,550)	(103)	(9,365)
Total Other Revenues	2,222,285	32,492	1,567	0	246	34,305
Total Operating Revenues	57,827,098	35,717	381,429	731,975	9,102	1,158,223
Operating Expense						
Cost of Fuel and Purchased Power	22,311,650	21,507	0	418,583	0	440,090
Adj. to Cost of Fuel and Purchased Pwr	(1,809,943)	(18,282)	0	(19,562)	0	(37,844)
Total Cost of Fuel and Purchased Pwr	20,501,707	3,225	0	399,021	0	402,246
Other O&M Expense	15,814,581	239,934	21,823	0	5,712	267,469
Adjustments to Other O&M	3,453,811	42,602	1,314	25,338	344	69,598
Total Other O&M Expense	19,268,392	282,536	23,137	25,338	6,056	337,067
Total Operation & Maintenance Expense	39,770,099	285,761	23,137	424,359	6,056	739,313
Depreciation Expense	6,901,084	118,426	8,180	0	1,070	127,676
Adjustment to Depreciation Expense	4,608,077	84,877	3,541	0	366	88,784
Total Depreciation Expense	11,509,161	203,303	11,721	0	1,436	216,460
Taxes Other Than Income Taxes	4,080,303	38,471	14,832	0	1,735	55,038
Adjustment to Taxes Other Than Income	617,219	10,042	1,018	0	120	11,180
Total Taxes Other Than Income	4,697,522	48,513	15,850	0	1,855	66,218
Current Income Taxes - Fed. & State	(4,064,984)	(271,735)	121,306	116,018	(758)	(35,169)
Adjustment to Current Income Taxes	(13,304,337)	(270,693)	(3,328)	4,862	(679)	(269,838)
Total Current Income Taxes	(17,369,321)	(542,428)	117,978	120,880	(1,437)	(305,007)
Deferred Income Taxes	5,966,982	97,596	9,954	0	1,043	108,593
Adjustment to Deferred Income Tax	7,080,844	150,961	90	0	9	151,060
Total Deferred Income Taxes	13,047,826	248,557	10,044	0	1,052	259,653
Total Operating Expenses	51,655,287	243,706	178,730	545,239	8,962	976,637
Pro Forma Operating Income	6,171,811	(207,989)	202,699	186,736	140	181,586
Rate Base	87,013,106	1,302,332	184,984	24,664	25,832	1,537,812
Adjustment to Rate Base	87,944,242	1,797,366	16,072	(1,004)	1,753	1,814,187
Total Pro Forma Rate Base	174,957,348	3,099,698	201,056	23,660	27,585	3,351,999
Pro Forma Rate of Return	3.528%	-6.710%	100.817%	789.248%	0.508%	5.417%

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		Contract Services Rate 35				Total
Operating Income and Rate of Return	Total Montana	Demand Prod. & Trans.	Demand Distribution	Energy	Customer	Contract Srvcs. Rate 35
Operating Sales Revenues	55,454,439	216,501	2,034,538	9,501,655	11,802	11,764,496
Adjustments to Sales Revenues	150,374	(183,971)	6,064	108,525	(282)	(69,664)
Total Sales Revenues	55,604,813	32,530	2,040,602	9,610,180	11,520	11,694,832
Other Revenues	2,739,121	377,096	5,734	65,190	860	448,880
Adjustments to Other Revenues	(516,836)	(43,567)	(930)	(65,190)	(264)	(109,951)
Total Other Revenues	2,222,285	333,529	4,804	0	596	338,929
Total Operating Revenues	57,827,098	366,059	2,045,406	9,610,180	12,116	12,033,761
Operating Expense						
Cost of Fuel and Purchased Power	22,311,650	216,955	0	5,996,636	0	6,213,591
Adj. to Cost of Fuel and Purchased Pwr	(1,809,943)	(184,425)	0	(280,249)	0	(464,674)
Total Cost of Fuel and Purchased Pwr	20,501,707	32,530	0	5,716,387	0	5,748,917
Other O&M Expense	15,814,581	2,420,366	51,643	0	14,666	2,486,675
Adjustments to Other O&M	3,453,811	429,760	3,594	362,982	1,041	797,377
Total Other O&M Expense	19,268,392	2,850,126	55,237	362,982	15,707	3,284,052
Total Operation & Maintenance Expense	39,770,099	2,882,656	55,237	6,079,369	15,707	9,032,969
Depreciation Expense	6,901,084	1,302,700	25,685	0	2,697	1,331,082
Adjustment to Depreciation Expense	4,608,077	1,049,616	13,738	0	698	1,064,052
Total Depreciation Expense	11,509,161	2,352,316	39,423	0	3,395	2,395,134
Taxes Other Than Income Taxes	4,080,303	397,077	55,636	0	3,526	456,239
Adjustment to Taxes Other Than Income	617,219	107,288	3,813	0	243	111,344
Total Taxes Other Than Income	4,697,522	504,365	59,449	0	3,769	567,583
Current Income Taxes - Fed. & State	(4,064,984)	(2,960,684)	709,068	1,402,802	(5,515)	(854,329)
Adjustment to Current Income Taxes	(13,304,337)	(3,230,091)	(13,588)	(15,518)	(1,546)	(3,260,743)
Total Current Income Taxes	(17,369,321)	(6,190,775)	695,480	1,387,284	(7,061)	(4,115,072)
Deferred Income Taxes	5,966,982	1,037,569	38,630	0	1,979	1,078,178
Adjustment to Deferred Income Tax	7,080,844	1,755,550	349	0	18	1,755,917
Total Deferred Income Taxes	13,047,826	2,793,119	38,979	0	1,997	2,834,095
Total Operating Expenses	51,655,287	2,341,681	888,568	7,466,653	17,807	10,714,709
Pro Forma Operating Income	6,171,811	(1,975,622)	1,156,838	2,143,527	(5,691)	1,319,052
Rate Base	87,013,106	14,462,873	789,997	353,339	69,026	15,675,235
Adjustment to Rate Base	87,944,242	21,492,998	61,452	(14,382)	3,449	21,543,517
Total Pro Forma Rate Base	174,957,348	35,955,871	851,449	338,957	72,475	37,218,752
Pro Forma Rate of Return	3.528%	-5.495%	135.867%	632.389%	-7.852%	3.544%

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		Municipal Pumping Rate 48				Total
Operating Income and Rate of Return	Total Montana	Demand Prod. & Trans.	Demand Distribution	Energy	Customer	Municipal Pumping Rate 48
Operating Sales Revenues	55,454,439	11,360	102,564	322,915	28,339	465,178
Adjustments to Sales Revenues	150,374	(9,653)	1,092	6,393	299	(1,869)
Total Sales Revenues	55,604,813	1,707	103,656	329,308	28,638	463,309
Other Revenues	2,739,121	19,401	1,277	2,127	2,085	24,890
Adjustments to Other Revenues	(516,836)	(2,286)	(232)	(2,127)	(479)	(5,124)
Total Other Revenues	2,222,285	17,115	1,045	0	1,606	19,766
Total Operating Revenues	57,827,098	18,822	104,701	329,308	30,244	483,075
Operating Expense						
Cost of Fuel and Purchased Power	22,311,650	11,384	0	195,693	0	207,077
Adj. to Cost of Fuel and Purchased Pwr	(1,809,943)	(9,677)	0	(9,146)	0	(18,823)
Total Cost of Fuel and Purchased Pwr	20,501,707	1,707	0	186,547	0	188,254
Other O&M Expense	15,814,581	127,000	12,867	0	26,611	166,478
Adjustments to Other O&M	3,453,811	22,550	773	11,845	1,403	36,571
Total Other O&M Expense	19,268,392	149,550	13,640	11,845	28,014	203,049
Total Operation & Maintenance Expense	39,770,099	151,257	13,640	198,392	28,014	391,303
Depreciation Expense	6,901,084	61,108	5,674	0	8,209	74,991
Adjustment to Depreciation Expense	4,608,077	42,106	2,523	0	3,373	48,002
Total Depreciation Expense	11,509,161	103,214	8,197	0	11,582	122,993
Taxes Other Than Income Taxes	4,080,303	20,232	10,413	0	14,471	45,116
Adjustment to Taxes Other Than Income	617,219	5,228	715	0	993	6,936
Total Taxes Other Than Income	4,697,522	25,460	11,128	0	15,464	52,052
Current Income Taxes - Fed. & State	(4,064,984)	(140,629)	22,109	50,824	(17,418)	(85,114)
Adjustment to Current Income Taxes	(13,304,337)	(135,999)	(2,502)	617	(4,107)	(141,991)
Total Current Income Taxes	(17,369,321)	(276,628)	19,607	51,441	(21,525)	(227,105)
Deferred Income Taxes	5,966,982	50,885	7,093	0	9,642	67,620
Adjustment to Deferred Income Tax	7,080,844	76,513	64	0	87	76,664
Total Deferred Income Taxes	13,047,826	127,398	7,157	0	9,729	144,284
Total Operating Expenses	51,655,287	130,701	59,729	249,833	43,264	483,527
Pro Forma Operating Income	6,171,811	(111,879)	44,972	79,475	(13,020)	(452)
Rate Base	87,013,106	670,014	104,481	11,531	151,907	937,933
Adjustment to Rate Base	87,944,242	902,346	21,833	(469)	29,398	953,108
Total Pro Forma Rate Base	174,957,348	1,572,360	126,314	11,062	181,305	1,891,041
Pro Forma Rate of Return	3.528%	-7.115%	35.603%	718.450%	-7.181%	-0.024%

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		Outdoor Lighting Rate 52				Total
Operating Income and Rate of Return	Total Montana	Demand Prod. & Trans.	Demand Distribution	Energy	Customer	Outdoor Lighting Rate 52
Operating Sales Revenues	55,454,439	3,936	0	360,423	0	364,359
Adjustments to Sales Revenues	150,374	(3,344)	0	2,329	0	(1,015)
Total Sales Revenues	55,604,813	592	0	362,752	0	363,344
Other Revenues	2,739,121	6,779	348	938	177,389	185,454
Adjustments to Other Revenues	(516,836)	(792)	(63)	(938)	(2,744)	(4,537)
Total Other Revenues	2,222,285	5,987	285	0	174,645	180,917
Total Operating Revenues	57,827,098	6,579	285	362,752	174,645	544,261
Operating Expense						
Cost of Fuel and Purchased Power	22,311,650	3,944	0	86,301	0	90,245
Adj. to Cost of Fuel and Purchased Pwr	(1,809,943)	(3,352)	0	(4,033)	0	(7,385)
Total Cost of Fuel and Purchased Pwr	20,501,707	592	0	82,268	0	82,860
Other O&M Expense	15,814,581	43,996	3,510	0	152,467	199,973
Adjustments to Other O&M	3,453,811	7,811	211	5,224	8,486	21,732
Total Other O&M Expense	19,268,392	51,807	3,721	5,224	160,953	221,705
Total Operation & Maintenance Expense	39,770,099	52,399	3,721	87,492	160,953	304,565
Depreciation Expense	6,901,084	22,298	1,547	0	77,091	100,936
Adjustment to Depreciation Expense	4,608,077	16,604	688	0	21,144	38,436
Total Depreciation Expense	11,509,161	38,902	2,235	0	98,235	139,372
Taxes Other Than Income Taxes	4,080,303	7,103	2,839	0	89,871	99,813
Adjustment to Taxes Other Than Income	617,219	1,874	194	0	6,168	8,236
Total Taxes Other Than Income	4,697,522	8,977	3,033	0	96,039	108,049
Current Income Taxes - Fed. & State	(4,064,984)	(51,009)	(4,962)	108,076	(119,432)	(67,327)
Adjustment to Current Income Taxes	(13,304,337)	(52,324)	(799)	79	(25,968)	(79,012)
Total Current Income Taxes	(17,369,321)	(103,333)	(5,761)	108,155	(145,400)	(146,339)
Deferred Income Taxes	5,966,982	18,182	1,935	0	61,952	82,069
Adjustment to Deferred Income Tax	7,080,844	28,933	17	0	560	29,510
Total Deferred Income Taxes	13,047,826	47,115	1,952	0	62,512	111,579
Total Operating Expenses	51,655,287	44,060	5,180	195,647	272,339	517,226
Pro Forma Operating Income	6,171,811	(37,481)	(4,895)	167,105	(97,694)	27,035
Rate Base	87,013,106	245,936	36,694	5,085	1,149,485	1,437,200
Adjustment to Rate Base	87,944,242	347,668	3,101	(207)	95,720	446,282
Total Pro Forma Rate Base	174,957,348	593,604	39,795	4,878	1,245,205	1,883,482
Pro Forma Rate of Return	3.528%	-6.314%	-12.301%	3425.687%	-7.846%	1.435%

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		Street Lighting Rate 41				Total
Operating Income and	Total	Demand	Demand			SL
Rate of Return	Montana	Prod. & Trans.	Distribution	Energy	Customer	Rate 41
Operating Sales Revenues	55,454,439	8,361	0	531,997	0	540,358
Adjustments to Sales Revenues	150,374	(7,104)	0	4,817	0	(2,287)
Total Sales Revenues	55,604,813	1,257	0	536,814	0	538,071
Other Revenues	2,739,121	14,407	741	1,999	332,387	349,534
Adjustments to Other Revenues	(516,836)	(1,683)	(135)	(1,999)	(2,913)	(6,730)
Total Other Revenues	2,222,285	12,724	606	0	329,474	342,804
Total Operating Revenues	57,827,098	13,981	606	536,814	329,474	880,875
Operating Expense						
Cost of Fuel and Purchased Power	22,311,650	8,379	0	183,884	0	192,263
Adj. to Cost of Fuel and Purchased Pwr	(1,809,943)	(7,122)	0	(8,594)	0	(15,716)
Total Cost of Fuel and Purchased Pwr	20,501,707	1,257	0	175,290	0	176,547
Other O&M Expense	15,814,581	93,472	7,480	0	161,834	262,786
Adjustments to Other O&M	3,453,811	16,597	450	11,131	7,594	35,772
Total Other O&M Expense	19,268,392	110,069	7,930	11,131	169,428	298,558
Total Operation & Maintenance Expense	39,770,099	111,326	7,930	186,421	169,428	475,105
Depreciation Expense	6,901,084	47,404	3,299	0	76,958	127,661
Adjustment to Depreciation Expense	4,608,077	35,336	1,467	0	19,097	55,900
Total Depreciation Expense	11,509,161	82,740	4,766	0	96,055	183,561
Taxes Other Than Income Taxes	4,080,303	15,094	6,055	0	82,576	103,725
Adjustment to Taxes Other Than Income	617,219	3,982	416	0	5,669	10,067
Total Taxes Other Than Income	4,697,522	19,076	6,471	0	88,245	113,792
Current Income Taxes - Fed. & State	(4,064,984)	(108,437)	(10,577)	137,565	(45,968)	(27,417)
Adjustment to Current Income Taxes	(13,304,337)	(111,314)	(1,705)	111	(19,178)	(132,086)
Total Current Income Taxes	(17,369,321)	(219,751)	(12,282)	137,676	(65,146)	(159,503)
Deferred Income Taxes	5,966,982	38,643	4,125	0	53,835	96,603
Adjustment to Deferred Income Tax	7,080,844	61,540	37	0	486	62,063
Total Deferred Income Taxes	13,047,826	100,183	4,162	0	54,321	158,666
Total Operating Expenses	51,655,287	93,574	11,047	324,097	342,903	771,621
Pro Forma Operating Income	6,171,811	(79,593)	(10,441)	212,717	(13,429)	109,254
Rate Base	87,013,106	522,902	78,240	10,835	404,147	1,016,124
Adjustment to Rate Base	87,944,242	739,643	6,616	(441)	87,873	833,691
Total Pro Forma Rate Base	174,957,348	1,262,545	84,856	10,394	492,020	1,849,815
Pro Forma Rate of Return	3.528%	-6.304%	-12.304%	2046.536%	-2.729%	5.906%

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		Rate 32 Secondary				Total
Operating Income and Rate of Return	Total Montana	Demand Prod. & Trans.	Demand Distribution	Energy	Customer	Secondary Rate 32
Operating Sales Revenues	55,454,439	1,294	16,095	43,582	1,644	62,615
Adjustments to Sales Revenues	150,374	(1,100)	917	356	(24)	149
Total Sales Revenues	55,604,813	194	17,012	43,938	1,620	62,764
Other Revenues	2,739,121	2,230	118	304	138	2,790
Adjustments to Other Revenues	(516,836)	(261)	(21)	(304)	(40)	(626)
Total Other Revenues	2,222,285	1,969	97	0	98	2,164
Total Operating Revenues	57,827,098	2,163	17,109	43,938	1,718	64,928
Operating Expense						
Cost of Fuel and Purchased Power	22,311,650	1,297	0	27,956	0	29,253
Adj. to Cost of Fuel and Purchased Pwr	(1,809,943)	(1,103)	0	(1,307)	0	(2,410)
Total Cost of Fuel and Purchased Pwr	20,501,707	194	0	26,649	0	26,843
Other O&M Expense	15,814,581	14,474	1,180	0	2,245	17,899
Adjustments to Other O&M	3,453,811	2,570	71	1,692	137	4,470
Total Other O&M Expense	19,268,392	17,044	1,251	1,692	2,382	22,369
Total Operation & Maintenance Expense	39,770,099	17,238	1,251	28,341	2,382	49,212
Depreciation Expense	6,901,084	7,310	521	0	456	8,287
Adjustment to Depreciation Expense	4,608,077	5,415	231	0	120	5,766
Total Depreciation Expense	11,509,161	12,725	752	0	576	14,053
Taxes Other Than Income Taxes	4,080,303	2,335	956	0	590	3,881
Adjustment to Taxes Other Than Income	617,219	615	64	0	41	720
Total Taxes Other Than Income	4,697,522	2,950	1,020	0	631	4,601
Current Income Taxes - Fed. & State	(4,064,984)	(16,729)	4,655	6,259	(968)	(6,783)
Adjustment to Current Income Taxes	(13,304,337)	(17,091)	93	(131)	(217)	(17,346)
Total Current Income Taxes	(17,369,321)	(33,820)	4,748	6,128	(1,185)	(24,129)
Deferred Income Taxes	5,966,982	5,969	651	0	350	6,970
Adjustment to Deferred Income Tax	7,080,844	9,462	6	0	3	9,471
Total Deferred Income Taxes	13,047,826	15,431	657	0	353	16,441
Total Operating Expenses	51,655,287	14,524	8,428	34,469	2,757	60,178
Pro Forma Operating Income	6,171,811	(12,361)	8,681	9,469	(1,039)	4,750
Rate Base	87,013,106	80,586	12,347	1,647	8,742	103,322
Adjustment to Rate Base	87,944,242	113,556	1,043	(67)	580	115,112
Total Pro Forma Rate Base	174,957,348	194,142	13,390	1,580	9,322	218,434
Pro Forma Rate of Return	3.528%	-6.367%	64.829%	599.327%	-11.146%	2.175%

Exhibit JWW-8

D2015.6.51

Montana-Dakota Utilities

Direct Testimony of

John W. Wilson

on behalf of the

Montana Consumer Counsel

November 20, 2015

MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY - MONTANA
Embedded Class Cost of Service Study
Summary Sheet
Pro Forma 2014

Exhibit No.__JWW-8

Operating Income and Rate of Return	Total Montana	Total Residential	Total Small General	Total Large General	Total Municipal Pumping	Total Lighting
Sales Revenues	55,454,439	16,960,743	10,235,790	26,888,012	465,178	904,717
Adjustments to Sales Revenues	150,374	(55,569)	249,219	(38,106)	(1,869)	(3,302)
Total Sales Revenues	55,604,813	16,905,174	10,485,009	26,849,906	463,309	901,415
Other Revenues	2,739,121	664,202	419,009	1,096,707	36,745	522,458
Adjustments to Other Revenues	(516,836)	(161,745)	(97,760)	(238,459)	(9,354)	(9,518)
Total Other Revenues	2,222,285	502,457	321,249	858,248	27,391	512,940
Total Operating Revenues	57,827,098	17,407,631	10,806,258	27,708,154	490,700	1,414,355
Operating Expense						
Cost of Fuel and Purchased Power	22,311,650	5,472,615	3,667,315	12,682,135	207,077	282,508
Adj. to Cost of Fuel and Purchased Pwr	(1,809,943)	(471,172)	(304,614)	(992,233)	(18,823)	(23,101)
Total Cost of Fuel and Purchased Pwr	20,501,707	5,001,443	3,362,701	11,689,902	188,254	259,407
Other O&M Expense	15,814,581	5,040,800	3,050,234	6,993,736	411,434	318,377
Adjustments to Other O&M	3,453,811	928,718	610,980	1,827,689	39,053	47,371
Total Other O&M Expense	19,268,392	5,969,518	3,661,214	8,821,425	450,487	365,748
Total Operation & Maintenance Expense	39,770,099	10,970,961	7,023,915	20,511,327	638,741	625,155
Depreciation Expense	6,901,084	1,960,159	1,265,085	3,314,006	165,979	195,855
Adjustment to Depreciation Expense	4,608,077	1,232,620	819,221	2,396,852	74,504	84,880
Total Depreciation Expense	11,509,161	3,192,779	2,084,306	5,710,858	240,483	280,735
Taxes Other Than Income Taxes	4,080,303	1,286,263	805,475	1,643,291	181,343	163,931
Adjustment to Taxes Other Than Income	617,219	178,075	115,729	292,692	15,354	15,369
Total Taxes Other Than Income	4,697,522	1,464,338	921,204	1,935,983	196,697	179,300
Current Income Taxes - Fed. & State	(4,064,985)	(623,256)	(661,921)	(2,445,804)	(344,403)	10,399
Adjustment to Current Income Taxes	(13,304,338)	(3,562,895)	(2,267,317)	(7,126,654)	(153,417)	(194,055)
Total Current Income Taxes	(17,369,323)	(4,186,151)	(2,929,238)	(9,572,458)	(497,820)	(183,656)
Deferred Income Taxes	5,966,982	1,720,324	1,117,821	2,828,655	146,709	153,473
Adjustment to Deferred Income Tax	7,080,844	1,855,067	1,248,672	3,826,502	62,633	87,970
Total Deferred Income Taxes	13,047,826	3,575,391	2,366,493	6,655,157	209,342	241,443
Total Operating Expenses	51,655,285	15,017,318	9,466,680	25,240,867	787,443	1,142,977
Pro Forma Operating Income	6,171,813	2,390,313	1,339,578	2,467,287	(296,743)	271,378
Rate Base	87,013,108	26,153,734	16,445,738	40,248,500	2,079,781	2,085,355
Adjustment to Rate Base	87,944,242	23,002,668	15,530,275	47,259,411	947,096	1,204,792
Total Pro Forma Rate Base	174,957,350	49,156,402	31,976,013	87,507,911	3,026,877	3,290,147
Pro Forma Rate of Return	3.528%	4.863%	4.189%	2.820%	-9.804%	8.248%

MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY - MONTANA
Embedded Class Cost of Service Study
Summary Sheet
Twelve Months Ended December 31, 2014

Exhibit No.__JWW-8

Operating Income and Rate of Return	Total Montana	Residential Rate 10 Demand Prod. & Trans.	Demand Distribution	Energy	Customer	Total Residential Rate 10
Operating Sales Revenues	55,454,439	267,588	0	15,379,354	1,313,801	16,960,743
Adjustments to Sales Revenues	150,374	(227,383)	0	167,410	4,404	(55,569)
Total Sales Revenues	55,604,813	40,205	0	15,546,764	1,318,205	16,905,174
Other Revenues	2,739,121	188,820	26,525	392,117	56,740	664,202
Adjustments to Other Revenues	(516,836)	(22,492)	(7,585)	(107,176)	(24,492)	(161,745)
Total Other Revenues	2,222,285	166,328	18,940	284,941	32,248	502,457
Total Operating Revenues	57,827,098	206,533	18,940	15,831,705	1,350,453	17,407,631
Operating Expense						
Cost of Fuel and Purchased Power	22,311,650	268,149	0	5,204,466	0	5,472,615
Adj. to Cost of Fuel and Purchased Pwr	(1,809,943)	(227,944)	0	(243,228)	0	(471,172)
Total Cost of Fuel and Purchased Pwr	20,501,707	40,205	0	4,961,238	0	5,001,443
Other O&M Expense	15,814,581	1,187,353	421,407	2,376,922	1,055,118	5,040,800
Adjustments to Other O&M	3,453,811	241,350	13,785	643,971	29,612	928,718
Total Other O&M Expense	19,268,392	1,428,703	435,192	3,020,893	1,084,730	5,969,518
Total Operation & Maintenance Expense	39,770,099	1,468,908	435,192	7,982,131	1,084,730	10,970,961
Depreciation Expense	6,901,084	650,640	225,453	944,968	139,098	1,960,159
Adjustment to Depreciation Expense	4,608,077	326,937	96,007	793,473	16,203	1,232,620
Total Depreciation Expense	11,509,161	977,577	321,460	1,738,441	155,301	3,192,779
Taxes Other Than Income Taxes	4,080,303	219,829	392,317	550,666	123,451	1,286,263
Adjustment to Taxes Other Than Income	617,219	57,385	26,895	85,234	8,561	178,075
Total Taxes Other Than Income	4,697,522	277,214	419,212	635,900	132,012	1,464,338
Current Income Taxes - Fed. & State	(4,064,985)	(1,724,159)	(669,421)	1,834,463	(64,139)	(623,256)
Adjustment to Current Income Taxes	(13,304,338)	(1,165,132)	(99,158)	(2,249,084)	(49,521)	(3,562,895)
Total Current Income Taxes	(17,369,323)	(2,889,291)	(768,579)	(414,621)	(113,660)	(4,186,151)
Deferred Income Taxes	5,966,982	579,464	269,950	796,909	74,001	1,720,324
Adjustment to Deferred Income Tax	7,080,844	715,221	2,439	1,136,738	669	1,855,067
Total Deferred Income Taxes	13,047,826	1,294,685	272,389	1,933,647	74,670	3,575,391
Total Operating Expenses	51,655,285	1,129,093	679,674	11,875,498	1,333,053	15,017,318
Pro Forma Operating Income	6,171,813	(922,560)	(660,734)	3,956,207	17,400	2,390,313
Rate Base	87,013,108	6,903,834	4,165,562	12,464,998	2,619,340	26,153,734
Adjustment to Rate Base	87,944,242	7,794,187	468,711	14,643,680	96,090	23,002,668
Total Pro Forma Rate Base	174,957,350	14,698,021	4,634,273	27,108,678	2,715,430	49,156,402
Pro Forma Rate of Return	3.528%	-6.277%	-14.258%	14.594%	0.641%	4.863%

MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY - MONTANA
Embedded Class Cost of Service Study
Summary Sheet
Twelve Months Ended December 31, 2014

Operating Income and Rate of Return	Total Montana	Small General Rate 20 Demand Prod. & Trans.	Demand Distribution	Energy	Customer	Total Small General Rate 20
Operating Sales Revenues	55,454,439	158,486	1,487,528	7,262,246	1,128,739	10,037,000
Adjustments to Sales Revenues	150,374	(134,673)	311,894	63,735	4,784	245,740
Total Sales Revenues	55,604,813	23,813	1,799,422	7,325,982	1,133,523	10,282,740
Other Revenues	2,739,121	124,463	35,633	216,533	32,942	409,571
Adjustments to Other Revenues	(516,836)	(14,758)	(12,242)	(54,718)	(13,795)	(95,513)
Total Other Revenues	2,222,285	109,705	23,391	161,815	19,147	314,058
Total Operating Revenues	57,827,098	133,518	1,822,813	7,487,797	1,152,670	10,596,798
Operating Expense						
Cost of Fuel and Purchased Power	22,311,650	158,818	0	3,424,559	0	3,583,377
Adj. to Cost of Fuel and Purchased Pwr	(1,809,943)	(135,005)	0	(160,045)	0	(295,050)
Total Cost of Fuel and Purchased Pwr	20,501,707	23,813	0	3,264,514	0	3,288,327
Other O&M Expense	15,814,581	782,967	334,107	1,350,699	503,835	2,971,608
Adjustments to Other O&M	3,453,811	158,163	20,557	398,263	20,407	597,390
Total Other O&M Expense	19,268,392	941,130	354,664	1,748,962	524,242	3,568,998
Total Operation & Maintenance Expense	39,770,099	964,943	354,664	5,013,476	524,242	6,857,325
Depreciation Expense	6,901,084	429,796	119,312	621,769	61,224	1,232,101
Adjustment to Depreciation Expense	4,608,077	215,967	50,804	522,092	10,263	799,126
Total Depreciation Expense	11,509,161	645,763	170,116	1,143,861	71,487	2,031,227
Taxes Other Than Income Taxes	4,080,303	145,132	214,068	349,874	68,631	777,705
Adjustment to Taxes Other Than Income	617,219	37,900	14,687	55,208	4,752	112,547
Total Taxes Other Than Income	4,697,522	183,032	228,755	405,082	73,383	890,252
Current Income Taxes - Fed. & State	(4,064,985)	(1,132,168)	192,524	156,817	164,893	(617,934)
Adjustment to Current Income Taxes	(13,304,338)	(769,129)	61,731	(1,481,575)	(27,678)	(2,216,651)
Total Current Income Taxes	(17,369,323)	(1,901,297)	254,255	(1,324,758)	137,215	(2,834,585)
Deferred Income Taxes	5,966,982	382,778	142,850	524,326	37,012	1,086,966
Adjustment to Deferred Income Tax	7,080,844	472,455	1,291	747,978	334	1,222,058
Total Deferred Income Taxes	13,047,826	855,233	144,141	1,272,304	37,346	2,309,024
Total Operating Expenses	51,655,285	747,674	1,151,931	6,509,965	843,673	9,253,243
Pro Forma Operating Income	6,171,813	(614,156)	670,882	977,832	308,997	1,343,555
Rate Base	87,013,108	4,560,180	2,186,956	8,155,583	1,305,686	16,208,405
Adjustment to Rate Base	87,944,242	5,148,573	265,435	9,629,617	62,778	15,106,403
Total Pro Forma Rate Base	174,957,350	9,708,753	2,452,391	17,785,200	1,368,464	31,314,808
Pro Forma Rate of Return	3.528%	-6.326%	27.356%	5.498%	22.580%	4.290%

MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY - MONTANA
Embedded Class Cost of Service Study
Summary Sheet
Twelve Months Ended December 31, 2014

		Irrigation Power Rate 25				Total
Operating Income and Rate of Return	Total Montana	Demand Prod. & Trans.	Demand Distribution	Energy	Customer	Irrigation Rate 25
Operating Sales Revenues	55,454,439	7,007	49,752	120,486	21,545	198,790
Adjustments to Sales Revenues	150,374	(5,954)	957	8,161	315	3,479
Total Sales Revenues	55,604,813	1,053	50,709	128,647	21,860	202,269
Other Revenues	2,739,121	2,614	1,708	4,245	871	9,438
Adjustments to Other Revenues	(516,836)	(324)	(557)	(993)	(373)	(2,247)
Total Other Revenues	2,222,285	2,290	1,151	3,252	498	7,191
Total Operating Revenues	57,827,098	3,343	51,860	131,899	22,358	209,460
Operating Expense						
Cost of Fuel and Purchased Power	22,311,650	7,022	0	76,916	0	83,938
Adj. to Cost of Fuel and Purchased Pwr	(1,809,943)	(5,969)	0	(3,595)	0	(9,564)
Total Cost of Fuel and Purchased Pwr	20,501,707	1,053	0	73,321	0	74,374
Other O&M Expense	15,814,581	16,375	19,385	27,157	15,709	78,626
Adjustments to Other O&M	3,453,811	3,511	957	8,565	557	13,590
Total Other O&M Expense	19,268,392	19,886	20,342	35,722	16,266	92,216
Total Operation & Maintenance Expense	39,770,099	20,939	20,342	109,043	16,266	166,590
Depreciation Expense	6,901,084	8,834	8,383	13,965	1,802	32,984
Adjustment to Depreciation Expense	4,608,077	4,438	3,570	11,727	360	20,095
Total Depreciation Expense	11,509,161	13,272	11,953	25,692	2,162	53,079
Taxes Other Than Income Taxes	4,080,303	2,999	14,806	7,674	2,291	27,770
Adjustment to Taxes Other Than Income	617,219	780	1,016	1,228	158	3,182
Total Taxes Other Than Income	4,697,522	3,779	15,822	8,902	2,449	30,952
Current Income Taxes - Fed. & State	(4,064,985)	(24,911)	(6,607)	(12,147)	(322)	(43,987)
Adjustment to Current Income Taxes	(13,304,338)	(15,917)	(3,600)	(30,379)	(770)	(50,666)
Total Current Income Taxes	(17,369,323)	(40,828)	(10,207)	(42,526)	(1,092)	(94,653)
Deferred Income Taxes	5,966,982	7,869	10,038	11,778	1,170	30,855
Adjustment to Deferred Income Tax	7,080,844	9,712	91	16,800	11	26,614
Total Deferred Income Taxes	13,047,826	17,581	10,129	28,578	1,181	57,469
Total Operating Expenses	51,655,285	14,743	48,039	129,689	20,966	213,437
Pro Forma Operating Income	6,171,813	(11,400)	3,821	2,210	1,392	(3,977)
Rate Base	87,013,108	93,798	(59,029)	182,508	20,056	237,333
Adjustment to Rate Base	87,944,242	105,843	92,229	216,195	9,605	423,872
Total Pro Forma Rate Base	174,957,350	199,641	33,200	398,703	29,661	661,205
Pro Forma Rate of Return	3.528%	-5.710%	11.509%	0.554%	4.693%	-0.601%

MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY - MONTANA
Embedded Class Cost of Service Study
Summary Sheet
Twelve Months Ended December 31, 2014

Operating Income and Rate of Return	Total Montana	Large General Primary Rate 30 Demand Prod. & Trans.	Demand Distribution	Energy	Customer	Total LG Primary Rate 30
Operating Sales Revenues	55,454,439	69,785	878,039	1,855,756	30,738	2,834,318
Adjustments to Sales Revenues	150,374	(59,300)	8,185	77,406	342	26,633
Total Sales Revenues	55,604,813	10,485	886,224	1,933,162	31,080	2,860,951
Other Revenues	2,739,121	31,691	20,130	66,644	888	119,353
Adjustments to Other Revenues	(516,836)	(3,872)	(7,007)	(15,472)	(369)	(26,720)
Total Other Revenues	2,222,285	27,819	13,123	51,172	519	92,633
Total Operating Revenues	57,827,098	38,304	899,347	1,984,334	31,599	2,953,584
Operating Expense						
Cost of Fuel and Purchased Power	22,311,650	69,931	0	1,227,474	0	1,297,405
Adj. to Cost of Fuel and Purchased Pwr	(1,809,943)	(59,446)	0	(57,365)	0	(116,811)
Total Cost of Fuel and Purchased Pwr	20,501,707	10,485	0	1,170,109	0	1,180,594
Other O&M Expense	15,814,581	198,861	185,025	427,940	13,324	825,150
Adjustments to Other O&M	3,453,811	41,796	11,754	136,089	862	190,501
Total Other O&M Expense	19,268,392	240,657	196,779	564,029	14,186	1,015,651
Total Operation & Maintenance Expense	39,770,099	251,142	196,779	1,734,138	14,186	2,196,245
Depreciation Expense	6,901,084	107,933	48,476	211,959	2,717	371,085
Adjustment to Depreciation Expense	4,608,077	54,235	16,696	179,760	701	251,392
Total Depreciation Expense	11,509,161	162,168	65,172	391,719	3,418	622,477
Taxes Other Than Income Taxes	4,080,303	36,577	74,727	93,880	3,460	208,644
Adjustment to Taxes Other Than Income	617,219	9,527	5,135	17,624	238	32,524
Total Taxes Other Than Income	4,697,522	46,104	79,862	111,504	3,698	241,168
Current Income Taxes - Fed. & State	(4,064,985)	(318,445)	184,660	(182,049)	2,468	(313,366)
Adjustment to Current Income Taxes	(13,304,338)	(194,010)	(20,058)	(498,244)	(1,273)	(713,585)
Total Current Income Taxes	(17,369,323)	(512,455)	164,602	(680,293)	1,195	(1,026,951)
Deferred Income Taxes	5,966,982	96,125	46,946	167,197	1,991	312,259
Adjustment to Deferred Income Tax	7,080,844	118,644	424	267,912	18	386,998
Total Deferred Income Taxes	13,047,826	214,769	47,370	435,109	2,009	699,257
Total Operating Expenses	51,655,285	161,728	553,785	1,992,177	24,506	2,732,196
Pro Forma Operating Income	6,171,813	(123,424)	345,562	(7,843)	7,093	221,388
Rate Base	87,013,108	1,145,651	96,181	2,582,866	41,375	3,866,073
Adjustment to Rate Base	87,944,242	1,292,993	308,022	3,417,785	13,081	5,031,881
Total Pro Forma Rate Base	174,957,350	2,438,644	404,203	6,000,651	54,456	8,897,954
Pro Forma Rate of Return	3.528%	-5.061%	85.492%	-0.131%	13.025%	2.488%

MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY - MONTANA
Embedded Class Cost of Service Study
Summary Sheet
Twelve Months Ended December 31, 2014

		Large General Secondary Rate 30				Total
Operating Income and Rate of Return	Total Montana	Demand Prod. & Trans.	Demand Distribution	Energy	Customer	LG Secondary Rate 30
Operating Sales Revenues	55,454,439	187,278	3,701,741	7,002,488	217,590	11,109,097
Adjustments to Sales Revenues	150,374	(159,138)	59,659	95,333	2,490	(1,656)
Total Sales Revenues	55,604,813	28,140	3,761,400	7,097,821	220,080	11,107,441
Other Revenues	2,739,121	152,791	68,030	248,115	5,476	474,412
Adjustments to Other Revenues	(516,836)	(18,087)	(24,560)	(57,911)	(2,256)	(102,814)
Total Other Revenues	2,222,285	134,704	43,470	190,204	3,220	371,598
Total Operating Revenues	57,827,098	162,844	3,804,870	7,288,025	223,300	11,479,039
Operating Expense						
Cost of Fuel and Purchased Power	22,311,650	187,670	0	4,514,126	0	4,701,796
Adj. to Cost of Fuel and Purchased Pwr	(1,809,943)	(159,530)	0	(210,964)	0	(370,494)
Total Cost of Fuel and Purchased Pwr	20,501,707	28,140	0	4,303,162	0	4,331,302
Other O&M Expense	15,814,581	961,290	503,462	1,588,555	74,712	3,128,019
Adjustments to Other O&M	3,453,811	193,783	40,428	502,062	3,981	740,254
Total Other O&M Expense	19,268,392	1,155,073	543,890	2,090,617	78,693	3,868,273
Total Operation & Maintenance Expense	39,770,099	1,183,213	543,890	6,393,779	78,693	8,199,575
Depreciation Expense	6,901,084	527,988	121,501	819,622	9,405	1,478,516
Adjustment to Depreciation Expense	4,608,077	265,307	51,742	688,225	2,209	1,007,483
Total Depreciation Expense	11,509,161	793,295	173,243	1,507,847	11,614	2,485,999
Taxes Other Than Income Taxes	4,080,303	178,257	227,510	450,104	12,807	868,678
Adjustment to Taxes Other Than Income	617,219	46,557	15,624	71,994	884	135,059
Total Taxes Other Than Income	4,697,522	224,814	243,134	522,098	13,691	1,003,737
Current Income Taxes - Fed. & State	(4,064,985)	(1,408,917)	999,923	(738,197)	41,978	(1,105,213)
Adjustment to Current Income Taxes	(13,304,338)	(944,631)	(51,448)	(1,933,586)	(4,518)	(2,934,183)
Total Current Income Taxes	(17,369,323)	(2,353,548)	948,475	(2,671,783)	37,460	(4,039,396)
Deferred Income Taxes	5,966,982	470,228	145,486	691,203	6,582	1,313,499
Adjustment to Deferred Income Tax	7,080,844	580,393	1,314	985,956	59	1,567,722
Total Deferred Income Taxes	13,047,826	1,050,621	146,800	1,677,159	6,641	2,881,221
Total Operating Expenses	51,655,285	898,395	2,055,542	7,429,100	148,099	10,531,136
Pro Forma Operating Income	6,171,813	(735,551)	1,749,328	(141,075)	75,201	947,903
Rate Base	87,013,108	5,601,885	2,291,925	10,710,091	231,549	18,835,450
Adjustment to Rate Base	87,944,242	6,324,803	264,556	12,688,158	12,633	19,290,150
Total Pro Forma Rate Base	174,957,350	11,926,688	2,556,481	23,398,249	244,182	38,125,600
Pro Forma Rate of Return	3.528%	-6.167%	68.427%	-0.603%	30.797%	2.486%

MONTANA-DAKOTA UTILITIES CO.
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		Optional TOD Large General Rate 31				Total
Operating Income and Rate of Return	Total Montana	Demand Prod. & Trans.	Demand Distribution	Energy	Customer	TOD Rate 31
Operating Sales Revenues	55,454,439	21,462	377,634	709,305	9,086	1,117,487
Adjustments to Sales Revenues	150,374	(18,237)	2,228	22,670	(230)	6,431
Total Sales Revenues	55,604,813	3,225	379,862	731,975	8,856	1,123,918
Other Revenues	2,739,121	14,362	7,564	23,839	280	46,045
Adjustments to Other Revenues	(516,836)	(1,715)	(2,694)	(5,700)	(117)	(10,226)
Total Other Revenues	2,222,285	12,647	4,870	18,139	163	35,819
Total Operating Revenues	57,827,098	15,872	384,732	750,114	9,019	1,159,737
Operating Expense						
Cost of Fuel and Purchased Power	22,311,650	21,507	0	418,583	0	440,090
Adj. to Cost of Fuel and Purchased Pwr	(1,809,943)	(18,282)	0	(19,562)	0	(37,844)
Total Cost of Fuel and Purchased Pwr	20,501,707	3,225	0	399,021	0	402,246
Other O&M Expense	15,814,581	90,294	61,806	151,647	4,366	308,113
Adjustments to Other O&M	3,453,811	18,415	4,470	47,090	230	70,205
Total Other O&M Expense	19,268,392	108,709	66,276	198,737	4,596	378,318
Total Operation & Maintenance Expense	39,770,099	111,934	66,276	597,758	4,596	780,564
Depreciation Expense	6,901,084	49,433	14,190	72,424	655	136,702
Adjustment to Depreciation Expense	4,608,077	24,840	5,073	61,398	163	91,474
Total Depreciation Expense	11,509,161	74,273	19,263	133,822	818	228,176
Taxes Other Than Income Taxes	4,080,303	16,706	23,031	32,722	879	73,338
Adjustment to Taxes Other Than Income	617,219	4,360	1,583	6,059	61	12,063
Total Taxes Other Than Income	4,697,522	21,066	24,614	38,781	940	85,401
Current Income Taxes - Fed. & State	(4,064,985)	(132,903)	98,114	(34,454)	819	(68,424)
Adjustment to Current Income Taxes	(13,304,338)	(88,555)	(6,786)	(171,912)	(447)	(267,700)
Total Current Income Taxes	(17,369,323)	(221,458)	91,328	(206,366)	372	(336,124)
Deferred Income Taxes	5,966,982	44,025	14,264	57,291	472	116,052
Adjustment to Deferred Income Tax	7,080,844	54,340	129	91,364	4	145,837
Total Deferred Income Taxes	13,047,826	98,365	14,393	148,655	476	261,889
Total Operating Expenses	51,655,285	84,180	215,874	712,650	7,202	1,019,906
Pro Forma Operating Income	6,171,813	(68,308)	168,858	37,464	1,817	139,831
Rate Base	87,013,108	524,540	231,842	886,367	16,616	1,659,365
Adjustment to Rate Base	87,944,242	592,172	23,879	1,166,090	829	1,782,970
Total Pro Forma Rate Base	174,957,350	1,116,712	255,721	2,052,457	17,445	3,442,335
Pro Forma Rate of Return	3.528%	-6.117%	66.032%	1.825%	10.416%	4.062%

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Operating Income and Rate of Return	Total Montana	Contract Services Rate 35 Demand Prod. & Trans.	Demand Distribution	Energy	Customer	Total Contract Srvcs. Rate 35
Operating Sales Revenues	55,454,439	216,501	2,034,538	9,501,655	11,802	11,764,496
Adjustments to Sales Revenues	150,374	(183,971)	6,064	108,525	(282)	(69,664)
Total Sales Revenues	55,604,813	32,530	2,040,602	9,610,180	11,520	11,694,832
Other Revenues	2,739,121	108,675	30,378	314,369	605	454,027
Adjustments to Other Revenues	(516,836)	(13,188)	(11,595)	(73,037)	(260)	(98,080)
Total Other Revenues	2,222,285	95,487	18,783	241,332	345	355,947
Total Operating Revenues	57,827,098	128,017	2,059,385	9,851,512	11,865	12,050,779
Operating Expense						
Cost of Fuel and Purchased Power	22,311,650	216,955	0	5,996,636	0	6,213,591
Adj. to Cost of Fuel and Purchased Pwr	(1,809,943)	(184,425)	0	(280,249)	0	(464,674)
Total Cost of Fuel and Purchased Pwr	20,501,707	32,530	0	5,716,387	0	5,748,917
Other O&M Expense	15,814,581	682,316	170,951	1,847,587	11,708	2,712,562
Adjustments to Other O&M	3,453,811	142,145	19,127	660,218	688	822,178
Total Other O&M Expense	19,268,392	824,461	190,078	2,507,805	12,396	3,534,740
Total Operation & Maintenance Expense	39,770,099	856,991	190,078	8,224,192	12,396	9,283,657
Depreciation Expense	6,901,084	371,284	12,843	931,414	2,697	1,318,238
Adjustment to Depreciation Expense	4,608,077	186,566	6,870	846,048	698	1,040,182
Total Depreciation Expense	11,509,161	557,850	19,713	1,777,462	3,395	2,358,420
Taxes Other Than Income Taxes	4,080,303	125,719	36,261	321,378	3,354	486,712
Adjustment to Taxes Other Than Income	617,219	32,764	2,500	76,684	231	112,179
Total Taxes Other Than Income	4,697,522	158,483	38,761	398,062	3,585	598,891
Current Income Taxes - Fed. & State	(4,064,985)	(1,206,135)	704,705	(442,726)	(4,385)	(948,541)
Adjustment to Current Income Taxes	(13,304,338)	(666,709)	(17,043)	(2,508,028)	(1,400)	(3,193,180)
Total Current Income Taxes	(17,369,323)	(1,872,844)	687,662	(2,950,754)	(5,785)	(4,141,721)
Deferred Income Taxes	5,966,982	330,668	19,315	726,447	1,979	1,078,409
Adjustment to Deferred Income Tax	7,080,844	408,136	174	1,308,029	18	1,716,357
Total Deferred Income Taxes	13,047,826	738,804	19,489	2,034,476	1,997	2,794,766
Total Operating Expenses	51,655,285	439,284	955,703	9,483,438	15,588	10,894,013
Pro Forma Operating Income	6,171,813	(311,267)	1,103,682	368,074	(3,723)	1,156,766
Rate Base	87,013,108	3,940,637	426,058	11,327,787	68,391	15,762,873
Adjustment to Rate Base	87,944,242	4,447,817	34,755	16,549,908	3,366	21,035,846
Total Pro Forma Rate Base	174,957,350	8,388,454	460,813	27,877,695	71,757	36,798,719
Pro Forma Rate of Return	3.528%	-3.711%	239.508%	1.320%	-5.188%	3.143%

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Operating Income and Rate of Return	Total Montana	Municipal Pumping Rate 48 Demand Prod. & Trans.	Demand Distribution	Energy	Customer	Total Municipal Pumping Rate 48
Operating Sales Revenues	55,454,439	11,360	102,564	322,915	28,339	465,178
Adjustments to Sales Revenues	150,374	(9,653)	1,092	6,393	299	(1,869)
Total Sales Revenues	55,604,813	1,707	103,656	329,308	28,638	463,309
Other Revenues	2,739,121	5,071	2,739	28,007	928	36,745
Adjustments to Other Revenues	(516,836)	(621)	(924)	(7,416)	(393)	(9,354)
Total Other Revenues	2,222,285	4,450	1,815	20,591	535	27,391
Total Operating Revenues	57,827,098	6,157	105,471	349,899	29,173	490,700
Operating Expense						
Cost of Fuel and Purchased Power	22,311,650	11,384	0	195,693	0	207,077
Adj. to Cost of Fuel and Purchased Pwr	(1,809,943)	(9,677)	0	(9,146)	0	(18,823)
Total Cost of Fuel and Purchased Pwr	20,501,707	1,707	0	186,547	0	188,254
Other O&M Expense	15,814,581	31,819	27,505	336,904	15,206	411,434
Adjustments to Other O&M	3,453,811	6,698	1,563	30,167	625	39,053
Total Other O&M Expense	19,268,392	38,517	29,068	367,071	15,831	450,487
Total Operation & Maintenance Expense	39,770,099	40,224	29,068	553,618	15,831	638,741
Depreciation Expense	6,901,084	17,262	10,619	136,208	1,890	165,979
Adjustment to Depreciation Expense	4,608,077	8,674	4,522	60,924	384	74,504
Total Depreciation Expense	11,509,161	25,936	15,141	197,132	2,274	240,483
Taxes Other Than Income Taxes	4,080,303	5,850	18,926	154,210	2,357	181,343
Adjustment to Taxes Other Than Income	617,219	1,524	1,298	12,369	163	15,354
Total Taxes Other Than Income	4,697,522	7,374	20,224	166,579	2,520	196,697
Current Income Taxes - Fed. & State	(4,064,985)	(50,951)	6,169	(302,051)	2,430	(344,403)
Adjustment to Current Income Taxes	(13,304,338)	(31,034)	(4,836)	(116,706)	(841)	(153,417)
Total Current Income Taxes	(17,369,323)	(81,985)	1,333	(418,757)	1,589	(497,820)
Deferred Income Taxes	5,966,982	15,373	12,716	117,382	1,238	146,709
Adjustment to Deferred Income Tax	7,080,844	18,975	115	43,532	11	62,633
Total Deferred Income Taxes	13,047,826	34,348	12,831	160,914	1,249	209,342
Total Operating Expenses	51,655,285	25,897	78,597	659,486	23,463	787,443
Pro Forma Operating Income	6,171,813	(19,740)	26,874	(309,587)	5,710	(296,743)
Rate Base	87,013,108	183,227	138,193	1,719,656	38,705	2,079,781
Adjustment to Rate Base	87,944,242	206,790	43,040	693,308	3,958	947,096
Total Pro Forma Rate Base	174,957,350	390,017	181,233	2,412,964	42,663	3,026,877
Pro Forma Rate of Return	3.528%	-5.061%	14.828%	-12.830%	13.384%	-9.804%

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		Outdoor Lighting Rate 52				Total
Operating Income and Rate of Return	Total Montana	Demand Prod. & Trans.	Demand Distribution	Energy	Customer	Outdoor Lighting Rate 52
Operating Sales Revenues	55,454,439	3,936	0	360,423	0	364,359
Adjustments to Sales Revenues	150,374	(3,344)	0	2,329	0	(1,015)
Total Sales Revenues	55,604,813	592	0	362,752	0	363,344
Other Revenues	2,739,121	2,383	341	8,032	164,152	174,908
Adjustments to Other Revenues	(516,836)	(286)	(97)	(2,360)	(186)	(2,929)
Total Other Revenues	2,222,285	2,097	244	5,672	163,966	171,979
Total Operating Revenues	57,827,098	2,689	244	368,424	163,966	535,323
Operating Expense						
Cost of Fuel and Purchased Power	22,311,650	3,944	0	86,301	0	90,245
Adj. to Cost of Fuel and Purchased Pwr	(1,809,943)	(3,352)	0	(4,033)	0	(7,385)
Total Cost of Fuel and Purchased Pwr	20,501,707	592	0	82,268	0	82,860
Other O&M Expense	15,814,581	14,982	5,414	47,284	10,333	78,013
Adjustments to Other O&M	3,453,811	3,075	177	11,618	564	15,434
Total Other O&M Expense	19,268,392	18,057	5,591	58,902	10,897	93,447
Total Operation & Maintenance Expense	39,770,099	18,649	5,591	141,170	10,897	176,307
Depreciation Expense	6,901,084	8,185	2,896	15,669	38,488	65,238
Adjustment to Depreciation Expense	4,608,077	4,114	1,233	13,158	9,223	27,728
Total Depreciation Expense	11,509,161	12,299	4,129	28,827	47,711	92,966
Taxes Other Than Income Taxes	4,080,303	2,768	5,040	9,589	35,935	53,332
Adjustment to Taxes Other Than Income	617,219	722	345	1,445	2,460	4,972
Total Taxes Other Than Income	4,697,522	3,490	5,385	11,034	38,395	58,304
Current Income Taxes - Fed. & State	(4,064,985)	(23,263)	(8,600)	69,162	790	38,089
Adjustment to Current Income Taxes	(13,304,338)	(14,676)	(1,274)	(38,082)	(10,835)	(64,867)
Total Current Income Taxes	(17,369,323)	(37,939)	(9,874)	31,080	(10,045)	(26,778)
Deferred Income Taxes	5,966,982	7,290	3,468	13,215	28,434	52,407
Adjustment to Deferred Income Tax	7,080,844	8,999	31	18,849	257	28,136
Total Deferred Income Taxes	13,047,826	16,289	3,499	32,064	28,691	80,543
Total Operating Expenses	51,655,285	12,788	8,730	244,175	115,649	381,342
Pro Forma Operating Income	6,171,813	(10,099)	(8,486)	124,249	48,317	153,981
Rate Base	87,013,108	86,867	54,903	208,386	660,687	1,010,843
Adjustment to Rate Base	87,944,242	98,065	5,538	243,041	39,674	386,318
Total Pro Forma Rate Base	174,957,350	184,932	60,441	451,427	700,361	1,397,161
Pro Forma Rate of Return	3.528%	-5.461%	-14.040%	27.524%	6.899%	11.021%

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Operating Income and Rate of Return	Total Montana	Street Lighting Rate 41 Demand Prod. & Trans.	Demand Distribution	Energy	Customer	Total SL Rate 41
Operating Sales Revenues	55,454,439	8,361	0	531,997	0	540,358
Adjustments to Sales Revenues	150,374	(7,104)	0	4,817	0	(2,287)
Total Sales Revenues	55,604,813	1,257	0	536,814	0	538,071
Other Revenues	2,739,121	5,074	727	13,688	328,061	347,550
Adjustments to Other Revenues	(516,836)	(609)	(208)	(3,723)	(2,049)	(6,589)
Total Other Revenues	2,222,285	4,465	519	9,965	326,012	340,961
Total Operating Revenues	57,827,098	5,722	519	546,779	326,012	879,032
Operating Expense						
Cost of Fuel and Purchased Power	22,311,650	8,379	0	183,884	0	192,263
Adj. to Cost of Fuel and Purchased Pwr	(1,809,943)	(7,122)	0	(8,594)	0	(15,716)
Total Cost of Fuel and Purchased Pwr	20,501,707	1,257	0	175,290	0	176,547
Other O&M Expense	15,814,581	31,884	11,541	83,130	113,809	240,364
Adjustments to Other O&M	3,453,811	6,547	378	22,651	2,361	31,937
Total Other O&M Expense	19,268,392	38,431	11,919	105,781	116,170	272,301
Total Operation & Maintenance Expense	39,770,099	39,688	11,919	281,071	116,170	448,848
Depreciation Expense	6,901,084	17,423	6,176	33,386	73,632	130,617
Adjustment to Depreciation Expense	4,608,077	8,755	2,630	28,035	17,732	57,152
Total Depreciation Expense	11,509,161	26,178	8,806	61,421	91,364	187,769
Taxes Other Than Income Taxes	4,080,303	5,891	10,747	19,406	74,555	110,599
Adjustment to Taxes Other Than Income	617,219	1,537	737	3,007	5,116	10,397
Total Taxes Other Than Income	4,697,522	7,428	11,484	22,413	79,671	120,996
Current Income Taxes - Fed. & State	(4,064,985)	(49,521)	(18,336)	60,631	(20,464)	(27,690)
Adjustment to Current Income Taxes	(13,304,338)	(31,234)	(2,717)	(79,830)	(15,407)	(129,188)
Total Current Income Taxes	(17,369,323)	(80,755)	(21,053)	(19,199)	(35,871)	(156,878)
Deferred Income Taxes	5,966,982	15,517	7,395	28,157	49,997	101,066
Adjustment to Deferred Income Tax	7,080,844	19,152	67	40,163	452	59,834
Total Deferred Income Taxes	13,047,826	34,669	7,462	68,320	50,449	160,900
Total Operating Expenses	51,655,285	27,208	18,618	414,026	301,783	761,635
Pro Forma Operating Income	6,171,813	(21,486)	(18,099)	132,753	24,229	117,397
Rate Base	87,013,108	184,887	117,064	440,228	332,333	1,074,512
Adjustment to Rate Base	87,944,242	208,715	11,811	517,366	80,582	818,474
Total Pro Forma Rate Base	174,957,350	393,602	128,875	957,594	412,915	1,892,986
Pro Forma Rate of Return	3.528%	-5.459%	-14.044%	13.863%	5.868%	6.202%

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		Rate 32 Secondary				Total
Operating Income and Rate of Return	Total Montana	Demand Prod. & Trans.	Demand Distribution	Energy	Customer	Secondary Rate 32
Operating Sales Revenues	55,454,439	1,294	16,095	43,582	1,644	62,615
Adjustments to Sales Revenues	150,374	(1,100)	917	356	(24)	149
Total Sales Revenues	55,604,813	194	17,012	43,938	1,620	62,764
Other Revenues	2,739,121	915	347	1,539	69	2,870
Adjustments to Other Revenues	(516,836)	(109)	(121)	(359)	(30)	(619)
Total Other Revenues	2,222,285	806	226	1,180	39	2,251
Total Operating Revenues	57,827,098	1,000	17,238	45,118	1,659	65,015
Operating Expense						
Cost of Fuel and Purchased Power	22,311,650	1,297	0	27,956	0	29,253
Adj. to Cost of Fuel and Purchased Pwr	(1,809,943)	(1,103)	0	(1,307)	0	(2,410)
Total Cost of Fuel and Purchased Pwr	20,501,707	194	0	26,649	0	26,843
Other O&M Expense	15,814,581	5,758	3,024	9,853	1,257	19,892
Adjustments to Other O&M	3,453,811	1,171	203	3,112	65	4,551
Total Other O&M Expense	19,268,392	6,929	3,227	12,965	1,322	24,443
Total Operation & Maintenance Expense	39,770,099	7,123	3,227	39,614	1,322	51,286
Depreciation Expense	6,901,084	3,156	974	5,076	259	9,465
Adjustment to Depreciation Expense	4,608,077	1,585	415	4,262	59	6,321
Total Depreciation Expense	11,509,161	4,741	1,389	9,338	318	15,786
Taxes Other Than Income Taxes	4,080,303	1,066	1,766	2,788	299	5,919
Adjustment to Taxes Other Than Income	617,219	279	121	446	21	867
Total Taxes Other Than Income	4,697,522	1,345	1,887	3,234	320	6,786
Current Income Taxes - Fed. & State	(4,064,985)	(8,543)	3,021	(4,492)	(246)	(10,260)
Adjustment to Current Income Taxes	(13,304,338)	(5,650)	(161)	(12,068)	(127)	(18,006)
Total Current Income Taxes	(17,369,323)	(14,193)	2,860	(16,560)	(373)	(28,266)
Deferred Income Taxes	5,966,982	2,811	1,167	4,280	178	8,436
Adjustment to Deferred Income Tax	7,080,844	3,468	11	6,107	2	9,588
Total Deferred Income Taxes	13,047,826	6,279	1,178	10,387	180	18,024
Total Operating Expenses	51,655,285	5,295	10,541	46,013	1,767	63,616
Pro Forma Operating Income	6,171,813	(4,295)	6,697	(895)	(108)	1,399
Rate Base	87,013,108	33,481	18,734	66,332	6,192	124,739
Adjustment to Rate Base	87,944,242	37,801	1,897	78,579	287	118,564
Total Pro Forma Rate Base	174,957,350	71,282	20,631	144,911	6,479	243,303
Pro Forma Rate of Return	3.528%	-6.025%	32.459%	-0.617%	-1.667%	0.575%