Montana-Dakota UTILITIES CO.
A Division of MDU Resources Group, Inc.

BEFORE THE MONTANA PUBLIC SERVICE COMMISSION

DOCKET NO. D2015.6.51

PREPARED REBUTTAL TESTIMONY OF

J. STEPHEN GASKE

Q1. Please state your name, position and business address.

A1. My name is J. Stephen Gaske and I am a Senior Vice President of Concentric Energy Advisors Inc., 1300 19th Street NW, Suite 620, Washington, DC 20036.

Q2. Are you the same J. Stephen Gaske who filed Prepared Direct Testimony earlier in this proceeding?

A2. Yes.

Q3. What is the purpose of your rebuttal testimony in this proceeding?

A3. I am responding to the Direct Testimonies concerning return on common equity filed by Consumer Counsel witness John W. Wilson and Montana Large Customer Group ("LCG") witness Michael P. Gorman and the testimony on capital structure filed by Mr. Gorman. These witnesses recommend an 8.50 percent and 9.35 percent allowed return on common equity, respectively, for Montana-Dakota's Montana electric operations. However, as shown in my Prepared Direct Testimony, and as discussed herein, a return on common equity of 10.0 percent is required in order for Montana-Dakota to be in a position to raise capital on reasonable terms. I disagree with several areas presented in the testimonies of Dr. Wilson and Mr. Gorman that lead them to recommend an inadequate return, including:

1. Failure to recognize that Montana-Dakota's Montana electric operations face greater overall risks than the typical company in the proxy group.
2. Use of DCF estimates of the required rate of return that are less than or close to bond yields;
3. Reliance on unreliable and unsupportable capital asset pricing model ("CAPM") estimates of the required rate of return;
4. Failure to recognize that a flotation cost adjustment is required in order to meet a capital attraction standard that must be met regardless of whether the regulated company has incurred flotation costs in the past, or can demonstrate that it will definitely incur such costs in the near future;
5. Use of an unsupportable Risk Premium approach; and
6. Mr. Gorman's recommendation to reduce the common equity ratio in the capital structure.

I. REASONABLENESS OF ROE RECOMMENDATIONS

Q4. Please provide an overview of Mr. Gorman's and Dr. Wilson's ROE recommendations in this proceeding.

A4. Mr. Gorman argues for a range of return on equity of 9.0 percent to 9.65 percent, and recommends a cost of equity of 9.35 percent based on the results of his constant growth DCF model, sustainable growth DCF model, multi-stage DCF model, CAPM analysis, and Risk Premium analyses. In performing his DCF and CAPM analyses, Mr. Gorman used the same proxy group that I used in my Prepared Direct Testimony with the exception of TECO Energy, Inc. because it recently announced that it will be acquired by Emera, Inc. Mr. Gorman discards his Constant Growth

DCF result of 9.53 percent because in his opinion, investment analysts' growth estimates were too high to be considered reasonable.[1] In lieu of the Constant Growth DCF approach, Mr. Gorman produces what he calls a Sustainable Growth model and a Multi-Stage DCF model wherein the long-term growth rate is simply a forecast of U.S. Gross Domestic Product ("GDP") growth.

Dr. Wilson argues for a range of return on equity of 7.5 percent to 9.0 percent based on the results of his earnings growth DCF model, fundamental growth DCF model, CAPM analysis and Comparable Earnings analysis.

In performing his DCF and CAPM analyses, Dr. Wilson uses my proxy group as well as a proxy group comprised of the universe of companies classified as electric utilities by Value Line. In applying his DCF analysis, Dr. Wilson uses a combination of analysts' growth rates, projected dividend growth rates, book value growth rates and retained earnings.

Q5. Please assess the reasonableness of both Mr. Gorman's 9.35 percent and Dr. Wilson's 8.50 percent recommended returns on common equity.

A5. Figure 1**Error! Reference source not found.** below is a histogram of all returns on common equity authorized in electric utility rate proceedings covered by Regulatory Research Associates between 2011 and 2015.

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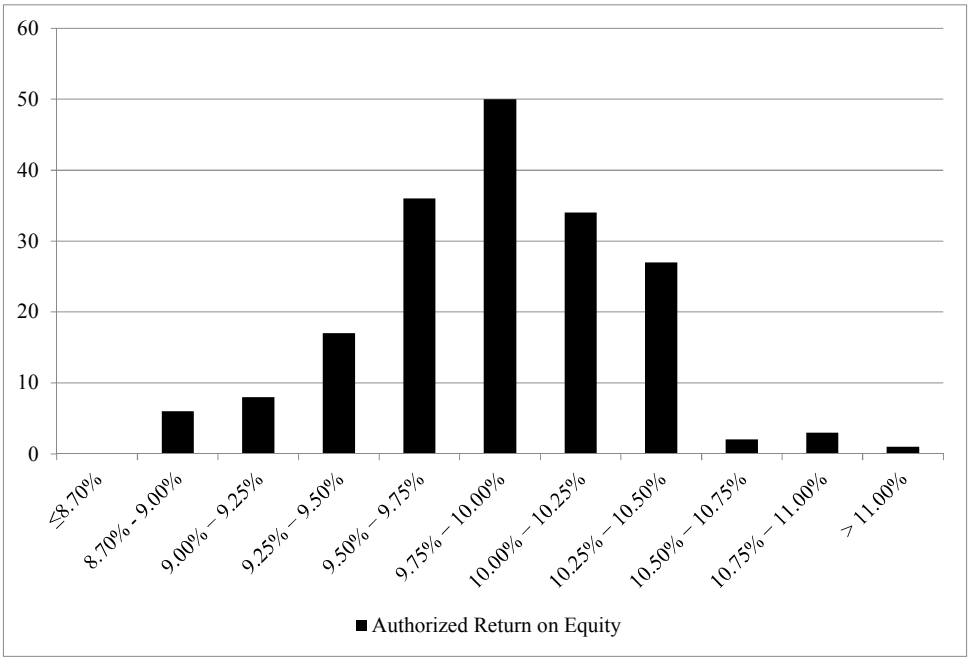
1 Direct Testimony and Exhibits of Michael Gorman, at 20.

Figure 1: Authorized Returns on Equity for Electric Utilities (2011-2015)[2]



Considering Dr. Wilson's recommended ROE of 8.50 percent, of the 184 rate proceedings with explicit ROE awards, zero have been less than 8.70 percent. This indicates that Dr. Wilson's recommendation is lower than any return allowed by Commissions during the past 5 years. Regarding Mr. Gorman's recommendation of 9.35 percent, only 18 of the 184 ROEs authorized between 2011 and 2015 have been lower than 9.35 percent. This is approximately only 10 percent of all awards for the time period. The median and mode of the 184 ROE's authorized between 2011 and 2015 are both approximately 10.0 percent, which corroborates the reasonableness of

[2] Source: Regulatory Research Associates.

my recommended 10 percent cost of common equity. It is evident that setting the authorized return on common equity for Montana-Dakota's Montana electric utility operations at 8.50 or 9.35 percent would violate the comparable investment standard set forth by the United States Supreme Court in Federal Power Commission v. Hope Natural Gas Company (1944). The return recommendations of Mr. Gorman and Dr. Wilson would not provide investors with an ROE that is "commensurate with returns on investments in other enterprises having corresponding risks."[3]

Q6. Please summarize your concern with Mr. Gorman's and Dr. Wilson's analyses and recommendations.

A6. My primary issue with their analyses is that both witnesses underestimate the risk of Montana Dakota's Montana electric operations in comparison to the risks of the proxy companies. As described below, Montana-Dakota is far smaller, and has a greater exposure to coal-fired generation, than any of the proxy companies. It therefore has a cost of capital that is significantly above the average or median for the proxy companies.

The most significant other flaw in Mr. Gorman's analysis is that he gives no consideration to his Constant Growth DCF results which indicate a median return requirement of 9.53 percent and a third quartile return requirement of 10.26

[3] Federal Power Commission v. Hope Natural Gas Company, 320 U.S. 591, 603 (1944).

1 percent.[4] Mr. Gorman's Constant Growth DCF analysis confirms the
2 reasonableness of my recommendation and the Company's requested rate of return.

3 The most significant other flaw in Dr. Wilson's analysis is the obvious implausibility
4 of many of its results. For example, a number of his cost of common equity results
5 are less than 100 basis points above the Baa utility bond yield. Another flaw in his
6 analysis is the use of the entire group of 45 companies that Value Line classifies as
7 electric utilities as his proxy group. Many of these companies are in no way
8 comparable to Montana-Dakota's Montana electric utility operations, which have a
9 far greater concentration of coal-fired generation, than any of his proxy companies.
10 Therefore, most of these companies are inappropriate proxies for estimating a return
11 on equity for Montana-Dakota's Montana operations.

12 In addition, I disagree with Mr. Gorman and Dr. Wilson in other areas of our analyses,
13 including: (1) certain growth rates used in our respective DCF analyses; (2) the use
14 of a CAPM analysis, and (3) the appropriateness and application of a flotation cost
15 adjustment. Furthermore, Mr. Gorman and I disagree on the approaches used in our
16 respective Risk Premium analyses. Finally, the low-end of Dr. Wilson's CAPM
17 estimates are in no way plausible and should not be used to calculate a range of results
18 for the return on equity.

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[4] If Otter Tail Corporation's Yahoo growth rate of 6.0 percent is included in Mr. Gorham's Constant Growth DCF analysis the third quartile return requirement is 10.48 percent.

II. COMPARABLE COMPANIES IN THE PROXY GROUP

Q7. What is the purpose of a proxy group?

A7. The purpose of a proxy group is to select companies with comparable characteristics and risk profiles to the subject company. Comparability is more important than the number of companies contained in the proxy group. The importance of selecting a proxy group that is similar in overall financial and business risk to the subject company was endorsed by the United States Court of Appeals for the District of Columbia (the "Court of Appeals") in the Petal Gas Storage decision. In that decision, the Court of Appeals acknowledged that in developing a proxy group, the goal is to rely on companies that are of similar risk to the subject company for the determination of cost of equity:

> *That proxy group arrangements must be risk-appropriate is the common theme in each argument. The principle is well-established. See Hope Natural Gas Co., 320 U.S. at 603 ("[T]he return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks."); CAPP I, 254 F.3d at 293 ("[A] utility must offer a risk-adjusted expected rate of return sufficient to attract investors."). The principle captures what proxy groups do, namely, provide market-determined stock and dividend figures from public companies comparable to a target company for which those figures are unavailable. CAPP I, 254 F.3d at 293–94. Market determined stock figures reflect a company's risk level and, when combined with dividend values, permit calculation of the "risk-adjusted expected rate of return sufficient to attract investors."* [5]
>
> *********
>
> *What matters is that the overall proxy group arrangement makes sense in terms of relative risk and, even more importantly, in terms of the statutory command to set "just and reasonable" rates, 15 U.S.C. § 717c, that are "commensurate with returns on investments in other enterprises having corresponding risks" and "sufficient to assure confidence in the financial*

[5] *Petal Gas Storage v. FERC*, 496 F.3d 695, 699 (D.C. Cir. 2007).

> *integrity of the enterprise . . . [and] maintain its credit and . . . attract capital," Hope Natural Gas Co., 320 U.S. at 603.*[6]

Thus, the Courts recognize the importance of developing a proxy group that adequately represents the ongoing risks and prospects of the subject company.

Q8. Have any other state Commissions recognized that comparability is more important than the number of companies in the proxy group?

A8. Yes. In 2004, the New Hampshire Public Utilities Commission recognized that comparability is more important than the size of the proxy group:

> *[T]he DCF is an economic theory for which a more comparable sample, rather than a larger sample, produces results that are more likely to be representative of the subject utility. The size of the sample is irrelevant when, as here, the sample is not random.*[7]

Q9. Do you agree with Dr. Wilson's inclusion of all 45 companies classified as electric utilities by Value Line in his proxy group?

A9. No, I do not. Many of the companies in Dr. Wilson's group are highly-diversified companies that have minor electric operations. The purpose of my analysis is to estimate a rate of return that is required for a company with risks comparable to those of Montana-Dakota's Montana electric utility operations. Not every company that Value Line lists in its electric utility industry group is solely, or even primarily, an electric utility. Instead, several diversified companies are included in that category by virtue of historical precedent without regard to whether they have risks comparable to those of Montana-Dakota's Montana electric utility operations.

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[6] *Ibid.*, at 700.

[7] Re: Verizon New Hampshire, 232 P.U.R. 4th 24 (N.H.P.U.C., 2004).

Consequently, I eliminated any company that did not derive at least 80 percent of its operating income from regulated electric utility operations in 2014, or that did not have at least 80 percent of its total assets devoted to the provision of electric utility service in 2014. Table 1 below presents four examples of companies that are classified as electric utilities by Value Line but actually devote a small portion of their business to regulated electric operations.

Table 1: Percent Regulated Electric Operations

		Revenue	Net Income	Assets
PPL Corporation[8]	PPL	38.72%	35.85%	38.33%
Public Service Enterprise Group Inc.[9]	PEG	45.48%	37.89%	45.66%
Sempra Energy[10]	SRE	33.75%	45.75%	N/A
Vectren Corporation[11]	VVC	25.14%	47.78%	32.85%

Based on this data, it is unreasonable to consider any of these four companies as comparable to Montana-Dakota's regulated electric utility operations in Montana when many companies that are far more comparable are available.

Q10. Does the ownership of coal-fired facilities present additional risk that must be considered in the selection of a proxy group?

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8 PPL Corporation, Form 10K, 12/31/2014, at 174-176.
9 Public Service Enterprise Group Inc. Form 10-K 12/31/2014, at 165-166.
10 Sempra Energy Form 10-K 12/31/2014, at 203,260,266,271,377-379.
11 Vectren Corporation Form 10-K 12/31/2014, at 105-107.

A10. Yes, it does. Dr. Wilson does not apply a screen for ownership of regulated coal-fired generation assets, while I have utilized companies that derive at least 50 percent of their generation from coal-fired plants.

There are significant operating and regulatory risks associated with the ownership of generation assets, especially coal-fired generation. Various forms of pending regulation before the U.S. Environmental Protection Agency could have a significant effect on the economic viability of MDU's portfolio of coal generation in the future. While MDU might be able to recover a carbon tax through its Fuel and Purchased Power Cost Tracking Adjustment, it is unclear at this time how the implantation of the clean power plan ("CPP") will affect the future compliance of MDU's existing generating facilities. The capital expenditures required to ensure future compliance may not make economic sense, and there is no guarantee that these facilities could even be modified to comply under CPP regulations.

By not screening the universe of electric utilities based on their ownership of regulated coal-fired generation assets, Dr. Wilson has failed to account for these very important risks. Companies that do not own coal-fired generation have different operating and regulatory risks, and their inclusion in the proxy group undermines the comparability of the group to Montana-Dakota's electric utility operations in Montana.

Inevitably there is a tradeoff between having enough companies to make a reasonable sample size, and including companies that are too dissimilar to be reasonable proxies. However, with twelve companies, my study contains a sufficiently large sample that

there is no reason to include more diversified companies that are likely to be less comparable to Montana-Dakota's electric utility operations.

III. Relative Risk of Montana-Dakota's Montana Operations

Q11. Please summarize your areas of disagreement with Mr. Gorman and Dr. Wilson concerning the relative risks associated with Montana-Dakota's electric utility operations in the State of Montana.

A11. As noted in my Direct Testimony, the Company's electric utility operations in Montana face significant business risks, which is why my recommended ROE is above the median, but below the third quartile of the range of my Basic DCF analysis. Mr. Gorman and Dr. Wilson's recommendations do not recognize that the risks of Montana-Dakota's electric operations in Montana are greater than those of the proxy company. In addition, neither recognize that the perceived regulatory risk faced by Montana-Dakota is above average relative to that of the proxy companies. For these reasons, it is appropriate to select an authorized return toward the upper end of the range of reasonableness.

Q12. Please explain your disagreement with Mr. Gorman's assessment of the Company's business risk?

A12. In discussing the business risks of Montana-Dakota's electric utility operations, Mr. Gorman addresses the risks faced by MDU Resources, but fails to recognize the significant risk associated with the small size of the Company's Montana electric operations compared to the proxy group. As explained in my Direct Testimony, the typical proxy company is between 40 and 75 times larger than Montana-

Dakota's jurisdictional electric utility operations, which serves approximately 25,800 customers across 30 communities in the state of Montana. The higher rate of return required by smaller utility operations has been demonstrated empirically.[12]

Moody's Investors Service has described how it considers the diversity of utility operations as a risk. Specifically, in "Rating Methodology for Regulated Electric and Gas Utilities" Moody's stated:

> *We also consider the diversity of utility operations (e.g., regulated electric, gas, water, steam) when there are material operations in more than one area. Economic diversity is a typically a function of the population, size and breadth of the territory and the businesses that drive its GDP and employment. For the size of the territory, we typically consider the number of customers and the volumes of generation and/or throughput. For breadth, we consider the number of sizeable metropolitan areas served, the economic diversity and vitality in those metropolitan areas, and any concentration in a particular area or industry.*[13]

Montana Dakota's Montana electric operations have the small size and small town service territory lack of diversity described by Moody's. Moody's rating methodology confirms that companies with those attributes have elevated risk and also confirms that an allowed return above the return required for the typical proxy company is appropriate in this proceeding.

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[12] Michael Annin, *Equity and the Small-Stock Effect*, Public Utilities Fortnightly, October 15, 1995.

[13] Moody's, "Rating Methodology: Regulated Electric and Gas Utilities," December 23, 2013, p. 19.

1 **IV. DCF Growth Rate Estimates**

2 **Q13. What growth rate estimates does Mr. Gorman use in his three DCF models?**

3 A13. For his Constant Growth DCF model, Mr. Gorman uses a simple average of three
4 different consensus estimates of earnings growth (Zacks, Reuters, and SNL
5 estimated growth rates, whereas I use those provided by Zacks and Yahoo! Finance
6 (which are both based on consensus forecasts) and the Value Line retention growth
7 rate forecast. His Sustainable Growth model uses a growth rate based on Value
8 Line's three-to-five year projections of earnings, dividends, earned return on book
9 equity, and projected book value growth from stock issuances. The results of these
10 inputs to his analysis are similar to mine. His analysts' growth estimates are
11 somewhat lower than mine and his sustainable growth estimate is somewhat higher
12 than mine.

13 However, Mr. Gorman's Multi-Stage Growth model uses growth rates for each
14 company that are a form of weighted average of the analysts' forecasts for each
15 company and the economy-wide GDP forecast. Mr. Gorman gave the U.S. GDP
16 growth rate a heavy weight for each company because he assumed that each proxy
17 company's growth would converge to the projected growth for the U.S. GDP of 4.4
18 percent within 10 years. As discussed below, this is inappropriate.

19 **Q14. Please discuss the effect of including Otter Tail Corporation analysts' growth**
20 **rate in Mr. Gorman's DCF models.**

21 A14. A consensus estimate of long-term growth for Otter Tail Corporation ("Otter Tail")
22 is available from Yahoo! Finance, but is not available from the three analysts that

Mr. Gorman utilizes in his analysis. Currently the Yahoo! Finance growth rate for Otter Tail is 6.00 percent. Schedule 1, Exhibit No.__(JSG-04) presents a revised version of Mr. Gorman's Exhibits MPG-4 which includes Otter Tail in the overall return calculation with the Yahoo! Finance growth rate included. For the constant growth DCF model, including Otter Tail in the average return increases Mr. Gorman's result from 9.36 percent to 9.50 percent and increases the third quartile required return from 10.26 percent to 10.48 percent. A 6.00 percent growth rate for Otter Tail is reasonable and is lower than the growth rate calculated for Otter Tail by Mr. Gorman in his sustainable growth rate DCF model shown in Exhibit MPG-8.

Q15. Did Mr. Gorman provide any assessment of the growth rates used in his Constant Growth DCF model to growth estimates by reference to other benchmarks?

A15. Yes. Mr. Gorman notes that the average growth estimate for his proxy group in his Constant Growth DCF model "produces overstated return estimates". He states that "a long-term sustainable growth rate for a utility stock cannot exceed the growth rate of the economy in which it sells its goods and services"[14] and therefore the long-term GDP growth rate of 4.40 percent is the maximum logical growth rate. Regarding his calculated sustainable long-term growth rates, he believes that since they are based on projections of earnings, dividends and book value for three to five years that "these parameters may change over time, and may result in long-term

[14] Direct Testimony of Michael Gorman, at 20.

growth rates being lower than that implied through the sustainable growth rate model."[15]

Q16. Do you agree with Mr. Gorman's use of projected nominal GDP growth rates as a benchmark for assessing his earnings growth rates?

A16. It is important to note that the GDP growth rate is an average for all activities in the economy. At any given point in time, some companies or industries grow faster than the economy while other companies or industries are declining. Thus, it is not unusual for some companies or industries to be below or exceed the average GDP growth rate for significant periods of time.

That is why it is important to place primary reliance upon company-specific growth rate information in order to distinguish between sectors and companies with declining, or below average growth, and those that are expected to comprise the above-average growth sectors.

In addition, the use of GDP (or, for that matter pre-tax profit) growth rates in Mr. Gorman's DCF analyses is flawed in that it assumes that over the long-term, all companies in the proxy group converge to the same growth rate.

Q17. Do you believe that analysts' growth rates are a superior measure of long-term investor expectations?

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[15] Direct Testimony of Michael Gorman, at 23.

A17. Although analysts' longest-term growth forecasts are typically expressed as five-year forecasts, these forecasts generally represent growth rate expectations for a longer period of time than the five-years expressed in the forecast. There is a large amount of literature that suggests analysts' growth rate forecasts are a superior measure of the long-term growth rate expectations that are reflected in stock prices. For example, Vander Weide and Carleton found that analysts' growth rate forecasts have a very highly significant relationship with stock prices.[16] This indicates that the analysts' estimates are an accurate estimator of long-term growth rate expectations implicit in stock prices, even though the analysts' estimates are putatively five-year estimates. Similarly, Marston, Harris and Crawford examine publicly available data from 1982-1985 and find that plausible measures of risk are more closely related to expected returns derived from a constant growth model than to those derived from multistage growth models.[17] In addition, Roger Morin cites several published studies which demonstrate that growth forecasts made by security analysts represent an appropriate source of DCF growth rates and are reasonable indicators of investor expectations.[18]

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[16] Vanderweide, J.H. and Carleton, W.T., "Investor Growth Expectations: Analysts vs. History," *The Journal of Portfolio Management*, Spring 1988, pp. 78-82.

[17] F. Marston, R. Harris, and P. Crawford, "Risk and Return in Equity Markets: Evidence Using Financial Analysts' Forecasts," in *Handbook of Security Analysts' Forecasting and Asset Allocation*, J. Guerard and M. Gultekin (eds.), Greenwich, CT, JAI Press; as described in R. Harris and F. Marston, "Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts," *Financial Management*, Summer 1992, p. 64.

[18] Morin, Roget T, New Regulatory Finance, p. 298.

1 **V. DCF Analyses of Mr. Gorman and Dr. Wilson**

2 **Q18. Please summarize Mr. Gorman's position with respect to the Constant Growth**
3 **DCF.**

4 A18. Mr. Gorman constructed a Constant Growth DCF model using analyst growth rates,
5 a Constant Growth DCF model using sustainable growth, and a Multi-Stage Growth
6 Model with a range of average ROE estimates from 8.55 percent to 9.36 percent.
7 He states that "certain constant growth DCF estimates using three-to-five year
8 growth rate projections are far too high to be rational of long-term sustainable
9 growth produce overstated DCF results", but then also states that "I am also
10 concerned about my low-end DCF estimate as being reflective of capital cost when
11 the rates determined in this case will be in effect". Finally, he recommends a range
12 of DCF return of 8.6 percent to 9.4 percent, with a midpoint estimate of 9.0
13 percent.[19] Mr. Gorman does not include the required flotation cost adjustment, nor
14 does he make an appropriate adjustment for the greater risk of Montana-Dakota's
15 Montana electric utility operations relative to his proxy group companies.

16 **Q19. Do you agree with Mr. Gorman's conclusion regarding his DCF returns?**

17 A19. No, I do not. As discussed above, it is not reasonable to assume that long-term
18 growth for all companies in the comparable group will converge to the U.S. GDP
19 growth rate. It is unreasonable to assume that the growth rate of the earnings and
20 capital investment of all companies in the economy, much less all companies in the

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[19] Direct Testimony and Exhibits of Michael Gorman, at 31.

same industry, will be equal to the average growth rate in the economy. Instead, some companies can be expected to grow more rapidly than the rest of the economy because they retain and reinvest more of their earnings while other companies can be expected to grow more slowly.

In addition, the results of the Carleton and Vander Weide study referenced above validated the importance of analysts' earnings forecasts, including the application of those forecasts to utility companies. This confirms that analysts' earnings forecasts are the best available indicator of projected growth, and, therefore, are appropriate inputs to stock valuation and ROE estimation models.

Q20. Please comment on Dr. Wilson's DCF analysis presented in Exhibit No.__JWW-1.

A20. Exhibit No.__JWW-1-A and JWW-1-B presents Dr. Wilson's DCF analysis based on analyst estimates of earnings growth. Dr. Wilson calculates two separate ROEs, one using my proxy group of companies and one for each of his 45 proxy group companies that Value Line classifies as electric utilities, both based on earnings growth rates from Value Line and Zacks. Dr. Wilson also does not include the required flotation cost adjustment, nor does he make an appropriate adjustment for the greater risk of Montana-Dakota's Montana electric utility operations relative to the proxy group companies.

Most importantly, Dr. Wilson fails to assess the reasonableness of the ROEs produced by his analysis when in some cases the resulting ROE is lower than the cost of debt. For the month of November 2015, the average cost of debt based on the Moody's Baa-

1 rated Utility Bond Index is 5.57 percent. Column 4 of Exhibit No.__JWW-1 presents
2 Dr. Wilson's calculated ROEs based on Yahoo! earnings growth rates, and four of the
3 45 companies have ROEs that are less than the cost of debt. Three more companies
4 have ROEs that are less than the cost of debt plus 100 basis points. In my opinion,
5 any return on common equity estimates that are less than the yield on Baa-rated utility
6 bonds plus 100 basis points are not plausible, but results that are approximately the
7 same as, or less than the cost of debt are *prima facie* incorrect and inadequate. No
8 investors would invest in these common stocks unless they could expect to earn a
9 return substantially higher than the return available on bonds that are considerably less
10 risky. In all, seven of his 45 companies have DCF results based on Yahoo! growth
11 rates that are obviously implausible and not meaningful. Because DCF results that
12 are obviously incorrect are included in Dr. Wilson's analysis, no weight should be
13 given to the 8.50 percent average rate of return that Dr. Wilson calculated.

14 **Q21. What is the average required rate of return on common equity when the seven**
15 **obviously inadequate results are excluded?**

16 A21. In this case, the third quartile (column 9) would be 10.26 percent. Those results are
17 shown in Schedule 2, Exhibit No.__(JSG-04). When the flotation cost adjustment
18 is applied to convert these secondary market requirements into an estimate of the
19 primary market cost of capital, the average and third quartile cost of capital for the
20 group would be 9.70 and 10.63 percent, respectively which verifies my
21 recommended ROE of 10.0 percent.

VI. Capital Asset Pricing Model Analysis

Q22. Please describe your disagreement with Mr. Gorman's and Dr. Wilson's use of the Capital Asset Pricing Model to estimate the cost of common equity capital for Montana-Dakota.

A22. I have several areas of disagreement concerning the Capital Asset Pricing Model ("CAPM"). On a conceptual level, the CAPM is an unreliable method for estimating the cost of common equity capital because the input assumptions are extremely subjective, unreliable and are based on historical rather than forecasted information. The CAPM has many weaknesses that make it an unreliable method for estimating the cost of common equity capital. In that regard, Fama and French observed:

> *Unfortunately, the empirical record of the model is poor – poor enough to invalidate the way it is used in applications. The CAPM's empirical problems may reflect theoretical failings, the result of many simplifying assumptions. But they may also be caused by difficulties in implementing valid tests of the model.*[20]

In particular, Beta cannot be measured accurately and is not a reliable predictor of stock returns. For example, when the underlying calculations of Beta are examined, it is very common to find that the "R-squared" statistic is so low that there is no statistical significance to the Beta estimate. Moreover, in the most comprehensive test of the CAPM hypothesis that has ever been conducted, Fama and French found that the level of Beta does not correlate well with the returns on common stocks. Instead,

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[20] Eugene F. Fama and Kenneth R. French, "The Capital Asset Pricing Model: Theory and Evidence," *Journal of Economic Perspectives*, Volume 18, Number 3, Summer 2004, at 25.

1 Fama and French found that firm size (with smaller companies requiring higher
2 returns) and market-to-book ratio are the two variables that best explain the returns
3 for common stocks.[21] With regard to these findings Value Line commented as
4 follows:

> 5 *Indeed, Professor Fama concluded, 'The fact is that Beta, as the sole*
> 6 *variable explaining returns on stocks, is dead.' These findings support*
> 7 *previous studies that have called into question the real-world*
> 8 *applicability of the CAPM Beta, including papers by Keim (Financial*
> 9 *Analysts Journal, 1986), and Roll (Journal of Financial Economics,*
> 10 *1977). Never before, however, has the lack of a statistically significant*
> 11 *relationship between beta and return been so rigorously and*
> 12 *dramatically established.*[22]

13 Fama and French also comment on the reliability of Beta in predicting equity returns,
14 especially for stocks with lower betas, such as many regulated public utilities:

> 15 *But empirical work, old and new, tells us that the relation between*
> 16 *Beta and average return is flatter than predicted by the Sharpe-*
> 17 *Lintner version of the CAPM. As a result, CAPM estimates for the*
> 18 *cost of equity for high beta stocks are too high (relative to historical*
> 19 *average returns) and estimates of low Beta stocks are too low (French*
> 20 *and Blume, 1970).*[23]

21 **Q23. Are there other problems that are specific to the CAPM analyses conducted by**
22 **Messrs. Gorman and Wilson?**

23 A23. In addition to the proven inaccuracy and unreliability of Beta, the market risk
24 premium, another important component of the CAPM equation, changes over time.

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[21] Fama and French, "The Cross-Section of Expected Stock Returns," Journal of Finance, Vol. XLVII, No. 2, June 1992, 427-465.

[22] Value Line Industry Review, March 13, 1992, pp 1-8.

[23] "The Capital Asset Pricing Model: Theory and Evidence," Journal of Economic Perspectives, Volume 8, Number 3, Summer 2004, Eugene F. Fama and Kenneth R. French, at 43-44.

Research studies provide empirical support for the proposition that equity risk premia generally increase as interest rates decrease, and vice versa. In fact, the data provided in Mr. Gorman's Schedules MPG-11 and MPG-12 produce statistical results that are consistent with existing research in this area. Using Mr. Gorman's data, I performed a linear regression to estimate the relationship between 30-year U.S. Treasury bonds and the risk premium required for regulated electric utilities. The resulting equation is presented in Schedule 3, Exhibit No.__(JSG-04 p.2) and re-created below:

$$\text{Intercept} + \text{Coefficient} \times \text{Bond Yield} = \text{Risk Premium}$$

$$0.072 - 0.441 \times \text{Bond Yield} = \text{Risk Premium}$$

The regression statistics indicate that this equation is statistically significant and the R-square reveals that 83 percent of the variation in the risk premium is explained by the bond yield. The negative coefficient in the above equation demonstrates the inverse relationship between bond yields and the risk premium. For every change of 100 basis points in the bond yield, the risk premium changes by approximately 44 basis points in the opposite direction.

Q24. What do you conclude from this analysis?

A24. It is not appropriate to rely on historical market risk premia for a current cost of equity estimate because the relationships between equity returns and bond yields may not reflect the current circumstances. Despite this fact, Mr. Gorman used historical market risk premiums and both Mr. Gorman and Dr. Wilson used badly outdated risk premiums.

For example, Mr. Gorman calculated two alternative estimates for the risk premium. He calls one of his estimates a "forward-looking" estimate, but that number is really derived from the average historical real return on common stocks from 1926-2014, adjusted for projected inflation. From those historical returns, he subtracts the current expected bond yield to get a risk premium estimate. Although two of the three elements in his "forward-looking" risk premium are forward-looking, the essential core element of the calculation is an historical average. Mr. Gorman's other risk premium, which he calls an historical risk premium, is calculated somewhat differently, but it is obviously based on historical averages rather than current forward-looking data.

In contrast, Dr. Wilson's CAPM would have been based on forward-looking data if we were living in an earlier time period. Remarkably, the four sources that he cites for his risk premium are Dinson, March and Staunton (2000), Fama and French (1988 and 1989), and Welch (2001). Whatever risk premiums those authors expected during the conditions that existed 15 to 28 years ago, their expectations in those eras are irrelevant for calculating the current risk premiums.

` There generally is a strong inverse relationship between required risk premiums and bond yields, and we are currently in a period with exceptionally low bond yields and above-average risk premiums. Thus, Mr. Gorman's historical average data and Dr. Wilson's outdated estimates assume inappropriately low market risk premiums for current market conditions.

Q25. Do the CAPM analyses of Dr. Wilson and Mr. Gorman produce plausible results?

A25. No. Mr. Gorman's CAPM estimate based on the long-term historical average produces a return of 8.49 percent, and as noted above, a return this low has never been awarded in the last five years or in the last 30 years.

Dr. Wilson also calculated a range of CAPM results based on my proxy group and his proxy group. His CAPM calculations show the following ranges:

Exhibit No.	Low	High
JWW-3-A	*3.35%*	10.48%
JWW-3-B	*3.22%*	10.18%

The high end of Dr. Wilson's CAPM ranges are slightly above, but consistent with, my recommendation of 10.00 percent. However, at the low end of his range he calculates CAPM return on equity estimates of between 3.35 percent (using my proxy group) and 3.22 percent (using the 45 Value Line Electrics). At a time when Baa utility bond yields for the month of November 2015 are approximately 5.57 percent, an estimate that the required rate of return on common equity is 3.35 percent, or less, is not even remotely plausible and should not be included to calculate an indicated range of reasonableness as Dr. Wilson has done. In fact, he uses these low-end estimates to calculate a mid-point of his ranges, but those mid-point estimates are meaningless because they are based on implausible low-end estimates.

Q26. Have you developed a CAPM result for this rebuttal?

A26. Yes. Some analysts use the CAPM to adjust for differences in risk between the market average and a particular group of proxy companies. As discussed above, I do not consider the CAPM to be a reliable measure of the cost of capital, but one could use it to adjust the S&P 500 DCF results to achieve a risk-adjusted benchmark for the natural gas distribution company proxy group.

For example, Schedule 5, page 1 of Exhibit No. ___(JSG-2) of my filed Direct Testimony indicates that the forward-looking required market rate of return is approximately 12.40 percent. This forward-looking return is remarkably similar to the 1926-2014 historical average return on common stocks published by Ibbotson Associates and is therefore a plausible and reasonable forward-looking estimate.

Beta is frequently used as the measure of relative risk in the CAPM. As shown on Schedule 4, Exhibit No.__(JSG-04), the average beta estimated by Value Line for the proxy companies is 0.78. Using this beta estimate with the current required return on the S&P 500 would produce the following CAPM results:

S&P Current Required Return	12.40
Less: Nov '15 T-Bond	3.03
Market Risk Premium	9.37
x Proxy Company VL Beta	0.78
Proxy Risk Premium	7.33
Plus: Nov '15 T-Bond	3.03
Proxy CAPM Cost of Eq.	**10.36**

1 Thus, if one were to use the CAPM as a benchmark of a reasonable return, this
2 benchmark fully supports the recommended ROE of 10.0 percent in this proceeding.[24]

3 **VII. Flotation Cost Adjustment**

4 **Q27. What are Mr. Gorman's concerns with your estimate of flotation costs?**

5 A27. Mr. Gorman asserts that the flotation cost adjustment for MDU "is not based on
6 known and measurable costs at MDU".[25] In addition, Mr. Gorman believes I should
7 have identified MDU Resources' actual flotation costs that are properly allocated
8 to regulated operations, show the time period these costs were incurred, and show
9 how they have been treated for ratemaking purposes in the past.[26]

10 **Q28. How do you respond to his concerns?**

11 A28. As a preliminary matter, Mr. Gorman's discussion of my flotation cost estimate
12 appears to pertain to the methodology for calculating flotation costs and the
13 application of those costs to the cost of equity, as opposed to the overall
14 appropriateness of a flotation cost adjustment. That is, while Mr. Gorman states
15 that my flotation cost adjustment should be denied, he does not reject the
16 appropriateness of a flotation cost adjustment, *per se*.[27] However, while Mr.

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[24] This CAPM calculation method is identical to the one adopted by the U.S. Federal Energy Regulatory Commission earlier this year. *Martha Coakley, et al. v. Bangor Hydro-Electric Company, et al.*, Opinion No. 531, 147 FERC ¶ 61,234 (2014); aff'd in Opinion No. 531-B, 150 FERC ¶ 61,165 (March 3, 2015). Note that FERC used the CAPM only as a benchmark, but set the allowed rate of return above the median indicated by a DCF analysis of proxy companies because of the current abnormal financial market conditions.

[25] Direct Testimony of Michael Gorman, at 49-50.

[26] *Ibid*.

[27] *Ibid*.

1 Gorman suggests that I should have approached my analysis of flotation costs in a
2 different way, he does not provide an estimate of his own or a framework by which
3 to perform such a calculation.

4 **Q29. Please summarize your position regarding a flotation cost adjustment as it**
5 **relates to Mr. Gorman's testimony and your revised results.**

6 A29. For the reasons noted above, I continue to believe that a flotation cost adjustment
7 is reasonable in this case. To address Mr. Gorman's concern, I calculated the actual
8 flotation costs incurred by MDU Resources Group as a result of its three most
9 recent public offerings in 1998, 2002, and 2004. The average flotation cost for
10 these three issuances (shown in Schedule 5, Exhibit No.__(JSG-04)) was 3.6
11 percent which corroborates my flotation cost adjustment of 3.5 percent.

12 **Q30. What arguments does Dr. Wilson provide in opposition to your use of a flotation**
13 **cost adjustment?**

14 A30. Dr. Wilson claims that electric utilities (including MDU) realize equity growth
15 through retained earnings and not through new public stock issuances. Dr. Wilson
16 continues that retained earnings and other forms of equity like dividend
17 reinvestment plans and parent company infusions do not incur issuance costs.[28]
18 This argument is off point because it misstates the purpose of the flotation cost
19 adjustment explained in my Prepared Direct Testimony. Under the capital

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[28] Direct Testimony of John W. Wilson, at 12.

1 attraction standard, an allowed rate of return must be sufficient to *enable* the
2 regulated company to attract capital in primary capital markets on reasonable terms.

3 This standard applies equally to both companies that have no need to attract capital,
4 and to companies that have enormous needs for new capital. In the absence of a
5 flotation cost adjustment, the allowed rate of return would reflect the rate of return
6 required in the secondary market where ownership of stock certificates is bought and
7 sold with no effect on the investment capital available to the utility. That secondary
8 market rate of return is fundamentally different from the rate of return that the utility
9 requires in order to attract capital in the primary market.

10 **Q31. Is there support in academic literature for your approach, which multiplies the**
11 **entire return by a specified factor to adjust for flotation costs?**

12 A31. Yes. Myron Gordon, who is credited with developing the DCF model for
13 estimating rate of return, has stated that a regulatory agency should set the allowed
14 rate of return greater than the investor return requirement so as to allow the firm to
15 issue stock at a price that will yield net proceeds equal to book value. Professor
16 Gordon advocates the following adjustment:

17 *The agency need only estimate the proportion that the proceeds per share on*
18 *an issue bear to the price of the stock and adjust the allowed rate of return so*
19 *that the price per share is the indicated ratio of the book value per share. If*
20 *the proceeds on an issue are 91 percent of market price, the agency should*
21 *maintain market price at about 110 percent of book value.*[29]

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[29] Myron J. Gordon, *The Cost of Capital to a Public Utility*, Michigan State University, 1974, pp 165-166.

1 In order to meet this requirement, the flotation cost adjustment must be applied to the
2 entire rate of return. The flotation cost adjustment that I have proposed attempts to
3 meet the same standard.

4 **VIII. Risk Premium Analysis**

5 **Q32. Please summarize Mr. Gorman's bond yield plus equity risk premium analysis.**
6 A32. In addition to his CAPM analysis, Mr. Gorman included two additional Risk
7 Premium approaches to estimate Montana-Dakota's cost of equity.

8 Mr. Gorman's first approach calculates the annual risk premium for each year from
9 1986 through September 2015 by taking the difference between regulatory
10 commission-authorized equity returns and a long-term Treasury bond yields.[30]
11 From that data, Mr. Gorman selected the 1987-1991 5-year average risk premium
12 of 4.25 percent as the low end of his range, and the 2011-2015 5-year average risk
13 premium of 6.55 percent as the high end. He then used a weighted average of these
14 two numbers to derive his risk premium of estimate of 5.63 percent.[31] However, if
15 one wanted to know the most recently required risk premium it would be more
16 accurate to simply use the 2011-2015 average. That approach indicates a utility
17 return requirement of 10.35 percent.[32]

18 Mr. Gorman's second approach calculates the average risk premium for the period
19 1986 through September 2015 as the difference between the average authorized equity

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30 Exhibit MPG-12.
31 .4 x 4.25% + .6 x 6.55% = 5.63%
32 Direct Testimony of Michael Gorman, at 36, line 5.

returns for electric utility companies and the concurrent A-rated utility bond yield. From that data, Mr. Gorman again used the 1987-1991 5-year average of 2.88 percent, and the 2011-2015 5-year average of 5.44 percent, to produce a weighted average of 4.42 percent.[33] Again, if one wants to know the most recently required risk premium it would make more sense to simply use the 2011-2015 average in Mr. Gorman's calculation. That approach indicates a current utility return requirement of 10.81 percent.[34]

Q33. Mr. Gorman suggests that your Risk Premium analysis is flawed because it is based on the broad market for common stocks and does not reflect the below market risk of MDU and utility operations in general. How do you respond?

A33. As discussed in my Direct Testimony, the purpose of my Risk Premium and Market DCF analyses are to serve as benchmarks to assess the reasonableness of my DCF analysis and places in context the Company's requested ROE of 10.00 percent.[35] The small company risk adder serves as a useful indicator of the cost of capital for Montana-Dakota because an electric utility must offer potential returns that allow it to compete for equity capital with other investments. I have acknowledged that electric utility companies generally have lower risks than the average small company. However, the average risk premiums earned by small companies are informative, and provide some relevant context for the authorized return for Montana-Dakota's electric operations in Montana. Therefore, I believe this

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[33] 0.4 x 2.88% + 0.6 x 5.44% = 4.42%.

[34] Direct Testimony of Michael Gorman, at 36, line 11.

[35] Direct Testimony of J. Stephen Gaske, at 37.

information is relevant for purposes of demonstrating the reasonableness of my recommended rate of return. I have not used my Risk Premium analysis to establish the recommended cost of common equity capital for the Company, but only to corroborate the reasonableness of my DCF results.

During the course of this year, the spread between Baa and Treasury's has increased dramatically. As shown in Schedule 6, Exhibit No.___(JSG-04), interest rates on longer-term A-rated and Baa-rated public utility bonds have increased substantially since the beginning of the year. Between January 2015 and November 2015, the average yield on A-rated public utility bonds increased from 3.58 percent to 4.40 percent, and the average yield on Baa-rated public utility bonds increased from 4.39 percent to 5.57 percent. Credit spreads, which measure the incremental cost of corporate debt relative to U.S. Treasury bonds, have increased dramatically in the past year, with the average spread of Baa-rated utility bonds over 30-year U.S. Treasury bonds increasing from 1.94 percent in January 2015 to 2.54 percent in November 2015. Thus, both risk premiums and interest rates have increased during the course of the year.

IX. Market DCF Analysis

Q34. How do you respond to Mr. Gorman's concerns regarding your Market DCF Analysis?

A34. Mr. Gorman has concerns with the growth rate I use in my Market DCF analysis because it is above what he believes is a long-term sustainable growth rate of 4.4.[36]

However, my current Market DCF rate of return estimate is 12.4 percent, which is very close to the 12.1 percent long-term average return earned by common stocks during the period 1926-2014. Thus, the overall return estimate is clearly in a long-term sustainable range. The purpose of my Risk Premium and Market DCF analyses are to serve as benchmarks to assess the reasonableness of my DCF analysis and provide context for my recommended ROE of 10.00 percent.[37]

As noted earlier, analysts' earnings growth rate forecasts are a superior measure of the long-term growth rate expectations that are reflected in stock prices. My approach to conducting a market DCF is virtually identical to one adopted by the Federal Regulatory Energy Commission ("FERC") in a recent order. In response to arguments similar to those proffered by Mr. Gorman in this proceeding, the FERC concluded:

> We are also unpersuaded that the growth rate projection in the NETOs' CAPM study was skewed by the NETOs' reliance on analysts' projections of non-utility companies' medium-term earnings growth, or that the study failed to consider that those analysts' estimates reflect unsustainable short-term stock repurchase programs

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[36] Direct Testimony of Michael Gorman, at 55.

[37] Direct Testimony of J. Stephen Gaske, at 37.

> and are not long-term projections. As explained above, the NETOs based their growth rate input on data from IBES, which the Commission has found to be a reliable source of such data. Thus, the time periods used for the growth rate projections in the NETOs' CAPM study are the time periods over which IBES forecasts earnings growth. Petitioners' arguments against the time period on which the NETOs' CAPM analysis is based are, in effect, arguments that IBES data are insufficient in a CAPM study. [38]
>
> ****
>
> While an individual company cannot be expected to sustain high short term growth rates in perpetuity, the same cannot be said for a stock index like the S&P 500 that is regularly updated to contain only companies with high market capitalization, and the record in this proceeding does not indicate that the growth rate of the S&P 500 stock index is unsustainable.[39]

For good reason, the FERC did not agree with the argument that analysts' projections for the S&P 500 are unsustainable.

Q35. On page 55 of his testimony, Mr. Gorman argues that the companies I use in my Market DCF analysis have risk characteristics that are significantly different than the risks encountered by MDU and its parent company. What is your response?

A35. I agree that those companies have different risks, which is why my recommended rate of return for Montana-Dakota's Montana electric operations, 10 percent, is significantly less than the 12.40 percent DCF rate of return estimated for the market as a whole.[40] Moreover, as shown earlier, if one were to use a CAPM beta to adjust

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[38] 150 FERC ¶ 61,165, Docket Nos. EL11-66-002, Opinion No. 531-B, para. 112.

[39] *Ibid.,* at para. 113.

[40] Schedule 5, Direct Testimony Exhibit No_(JSG-02).

for the differences in risk, the result is an indicated rate of return of 10.36 percent for the proxy companies.

X. Earnings Yield Estimates

Q36. At pages 22-27 of his Direct Testimony, Dr. Wilson presents an analysis that he calls a "Comparable Earnings" analysis. Is it correct to describe this as a Comparable Earnings analysis?

A36. No, it is not. Dr. Wilson's "Comparable Earnings" analysis is something that is widely-referred to as an "Earnings Yield." In his analysis, Dr. Wilson takes the projected rate of return on the book value of equity for his 45 proxy group companies and also for my proxy group and divides it by the projected market-to-book ratio for his companies. Algebraically, his calculation consists of:

$$\frac{\textit{Return on Equity}}{\textit{Market-to-Book Ratio}} = \frac{\dfrac{\textit{Earnings per Share}}{\textit{Book Value per Share}}}{\dfrac{\textit{Price per Share}}{\textit{Book Value per Share}}}$$

Because book value per share appears in both the numerator and the denominator, it cancels itself out, and Dr. Wilson's "Comparable Earnings" formula is really:

$$\frac{\textit{Earnings per Share}}{\cancel{\textit{Book Value per Share}}} \; x \; \frac{\cancel{\textit{Book Value per Share}}}{\textit{Price per Share}} = \frac{\textit{Earnings per Share}}{\textit{Price per Share}}$$

Earnings per share divided by price per share equals the earnings yield. This calculation is neither a comparable earnings analysis, nor a rate of return, nor a cost of capital estimate. In short, it has no perceptible relevance for the task of estimating an allowed rate of return.

Q37. What do Mr. Wilson's Exhibit Nos. JWW-4-A and JWW-4-B show with regard to the real comparable earnings that investors currently expect electric utilities to earn?

A37. The Comparable Earnings standard requires that the allowed rate of return should be commensurate with returns on investments in other enterprises having corresponding risks. Column 1 of Mr. Wilson's Exhibit No. JWW-4-A indicates that investors expect the average proxy company to earn 10.33 percent on the book value of its common equity. Similarly, Exhibit No. JWW-4-B shows an expected average return on book value of 10.53 percent. In comparison, the returns recommended by Dr. Wilson (8.5 percent) and Mr. Gorman (9.35 percent) would be too low to meet the Comparable earnings standard, and an allowed rate of return of 10.0 percent is required in order to be reasonably comparable with the returns investors could earn by investing in utility assets located elsewhere.

XI. CAPITAL STRUCTURE

Q38. At pages 10-13 of his testimony Mr. Gorman recommends reducing Montana-Dakota's ratemaking capital structure from 49.52 percent to 46.14 percent. Is this change appropriate?

A38. No. Montana-Dakota's filed equity ratio is comfortably within the range of equity ratios of the proxy companies. As shown in my Direct Testimony Exhibit No. ___(JSG-2), Schedule 6, the proxy company common equity ratios are in a range between 38 percent and 56 percent. Three of the 12 proxy companies have higher common equity ratios than Montana-Dakota, which indicates that its common equity ratio is neither unusual nor extreme.

1 **Q39. What effect does the capital structure have on the costs of doing business?**

2 A39. Most large companies are financed using a mix of debt and equity capital.
3 Including a reasonably small amount of debt in the capital structure can provide a
4 low-cost source of funds because the common equity holders shield lenders from a
5 portion of the risks of the company. However, the requirement to pay a fixed level
6 of interest and repay principal as scheduled, causes the possibility of bankruptcy or
7 other financial distress to increase as the firm takes on more debt. Financial
8 "leverage" provided by fixed debt payments also tends to translate relatively small
9 fluctuations in a company's operating income into much larger variations in the net
10 income available to common stockholders. When the proportion of debt is
11 increased beyond some level, both the lenders and the stockholders require greater
12 rates of return on their investments to compensate for the greater risks involved. In
13 financial theory, there is an optimal range of equity ratios that minimizes the overall
14 cost of capital of a company.

15 **Q40. Is it common for commissions to adjust the ratemaking capital structure when**
16 **the capital structure is normal in comparison with companies that have similar**
17 **risks?**

18 A40. No. Because there are numerous factors that go into establishing a company's
19 capital structure, the common approach is for regulators to recognize that, unless
20 the capital structure is extreme, the appropriate capital structure is a matter for
21 management discretion and judgement.

Q41. What factors are important for determining the appropriate capital structure for a company?

A41. The amount of debt that is economical for a firm depends on its business risks and the perceived probability that it could experience unexpected difficulties that would render it unable to meet its debt obligations. Although firms in the same industry generally tend to have similar business risks, there is often a general, very broad, range of equity ratios associated with companies in particular industries. Firms in the same industry have different capital structures for many reasons. For example, within a given industry, there may be wide differences in the vintages of capital and operating strategies of individual companies. Another important factor is the quality of a firm's earnings in terms of cash flow and continuing operations. When all factors are considered the managers of a company are usually in the best position to evaluate the prospective risks and operating needs of their company and determine the most appropriate capital structure.

Q42. In addition to individual differences in business risks, are there other important factors that can determine the appropriate capital structure for a company?

A42. Yes. Another important factor is the transaction cost of raising new capital. In order to borrow funds from outside sources a company typically pays issuance costs that are close to one percent of the amount borrowed. In contrast, raising new common equity funds from outside sources generally involves flotation costs that are 3-5 percent of the amount of capital raised. In addition, on a percentage basis, flotation and issuance costs generally are proportionately lower for larger issues. Consequently, there often is a "pecking order," whereby firms attempt to raise as

much new capital as possible from internally-generated retained earnings and issue debt only when internal funds are not sufficient to finance attractive projects and maintain the desired dividend levels. The higher flotation costs associated with raising equity capital from external sources means that, up to a point, it is less expensive to issue debt for as much external financing as possible before turning to the external equity markets.

Different companies also have different patterns of needs for financing. A company might take on large amounts of debt to finance new projects, but then pay down its debt and increase its equity ratio over time after the project is in service. When a company's debt ratio is high, its financial flexibility is restricted. This means that its ability to undertake additional projects is limited and it may not be able to refinance its debt or raise new capital if adverse circumstances arise.

Thus, when one considers financing costs and the often uneven pattern of capital investments, there may be times when achieving the target capital structure may not be as desirable as minimizing the issuance costs that the firm incurs as it operates on a dynamic basis. A well-managed company might reasonably maintain a relatively high equity ratio for extended periods of time and then undertake a large amount of additional debt to finance a new project. The important point is that wide differences in capital structures exist within any given industry from time to time and a determination of the "appropriate" capital structure for a particular company should not be made in a vacuum which ignores that company's unique history, business needs and circumstances.

1 **Q43. Do ratings agencies consider Montana-Dakota's capital structure to be**
2 **reasonable?**
3 A43. Yes. Standard & Poor's indicates that it believes that MDU has intermediate
4 financial risks because of "its commitment to maintaining a solid balance sheet …"

5 **XII. SUMMARY**

6 **Q44. Please summarize the conclusions of your Rebuttal Testimony.**
7 A44. The returns on common equity recommended by Mr. Gorman and Dr. Wilson are
8 inadequate to meet the tests of a reasonable rate of return because they are based
9 on flawed analyses.

10 **Q45. Does this conclude your Prepared Rebuttal Testimony?**
11 A45. Yes.

Montana-Dakota Utilities Co.

CONSTANT GROWTH DCF MODEL (Exhibit MPG-4)
MODIFIED TO INCLUDE OTTER TAIL

Line	Company	13-Week Avg. Stock Price (1)	Analysts' Growth (2)	Annualized Dividend (3)	Adjusted Yield (4)	Constant Growth DCF (5)
1	ALLETE, Inc.	$49.70	5.50%	$2.02	4.29%	9.79%
2	Alliant Energy Corporation	$58.72	5.58%	$2.20	3.96%	9.54%
3	Ameren Corporation	$41.77	6.42%	$1.64	4.18%	10.59%
4	American Electric Power Company, Inc	$56.17	4.94%	$2.12	3.96%	8.90%
5	Empire District Electric Company	$22.44	4.67%	$1.04	4.85%	9.52%
6	Great Plains Energy Inc.	$26.31	6.46%	$0.98	3.97%	10.42%
7	OGE Energy Corp.	$28.38	4.44%	$1.00	3.68%	8.12%
8	Otter Tail Corporation	$26.66	**6.00%**	$1.23	**4.89%**	**10.89%**
9	PNM Resources, Inc.	$26.98	7.35%	$0.80	3.18%	10.54%
10	Westar Energy, Inc.	$38.11	3.50%	$1.44	3.91%	7.41%
11	Xcel Energy Inc.	$34.83	4.96%	$1.28	3.86%	8.82%
14	**Average (excl. OTTR)**	**$38.34**	**5.38%**	**$1.45**	**3.98%**	**9.36%**
15	**Median (excl. OTTR)**		**5.23%**			**9.53%**
16	**Average (incl. OTTR)**	**$37.28**	**5.44%**	**$1.43**	**4.07%**	**9.50%**
17	**Median (incl. OTTR)**		**5.50%**			**9.54%**
18	**Third Quartile (incl. OTTR)**		**6.21%**			**10.48%**

Source: Exhibit MPG-4, analyst growth rate for Otter Tail Corporation provided by Yahoo! Finance as of 12/18/2015

Montana-Dakota Utilities Co.

DCF Cost of Equity Indications
Earnings Growth Model
Electric Companies

			[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
				Div Yield x		g					Secondary Market:		Primary Market:
			Dividend	(1 + 0.625g)		Zacks	Yahoo	D/P + g			ROE With	Flotation Cos	Cost of
Line		Company	Yield	Zacks	Yahoo	Growth	Growth	Zacks	Yahoo	Exclude	Growth Rate	Adjustment	Capital
1	ALE	ALLETE, Inc	4.12%	4.25%	4.26%	5.00%	5.50%	9.25%	9.76%		9.76%	1.035	10.11%
2	LNT	Alliant Energy Corp.	3.72%	3.84%	3.84%	5.30%	5.40%	9.14%	9.24%		9.24%	1.035	9.57%
3	AEE	Ameren Corp.	4.03%	4.21%	4.19%	6.80%	6.35%	11.01%	10.54%		10.54%	1.035	10.91%
4	AEP	American Elec Pwr Co.	3.82%	3.93%	3.93%	4.70%	4.63%	8.63%	8.56%		8.56%	1.035	8.86%
5	AVA	Avista Corp.	4.10%	NA	4.23%	NA	5.00%	NA	9.23%		9.23%	1.035	9.55%
6	BKH	Black Hills Corp.	3.74%	NA	3.82%	MA	3.48%	NA	7.30%		7.30%	1.035	7.56%
7	CNP	CenterPoint Energy, Inc	5.21%	5.32%	5.23%	3.40%	0.45%	8.72%	5.68%	X			
8	CNL	Cleco Corp.	2.97%	3.03%	3.03%	3.00%	3.00%	6.03%	6.03%	X			
9	CMS	CMS Energy Corp.	3.43%	3.56%	3.57%	6.20%	6.72%	9.76%	10.29%		10.29%	1.035	10.65%
10	ED	Consolidated Edison, In	4.15%	4.22%	4.22%	2.90%	2.72%	7.12%	6.94%		6.94%	1.035	7.18%
11	D	Dominion Resources, In	3.68%	3.82%	3.81%	6.20%	5.41%	10.02%	9.22%		9.22%	1.035	9.54%
12	DTE	DTE Energy Co.	3.57%	3.69%	3.68%	5.50%	4.94%	9.19%	8.62%		8.62%	1.035	8.92%
13	DUK	Duke Energy Corp.	4.43%	4.55%	4.52%	4.10%	3.27%	8.65%	7.79%		7.79%	1.035	8.07%
14	EIX	Edison International	2.79%	2.86%	2.71%	4.50%	-4.08%	7.36%	-1.37%	X			
15	EE	El Paso Electric Co.	3.24%	3.38%	3.38%	6.70%	7.00%	10.08%	10.38%		10.38%	1.035	10.75%
16	EDE	Empire District Elec	4.61%	4.75%	4.75%	5.00%	5.00%	9.75%	9.75%		9.75%	1.035	10.09%
17	ETR	Entergy Corp.	4.77%	4.72%	4.70%	-1.70%	-2.61%	3.02%	2.09%	X			
18	ES	Eversource Energy	3.44%	3.59%	3.58%	6.80%	6.57%	10.39%	10.15%		10.15%	1.035	10.51%
19	EXC	Exelon Corp.	3.90%	4.00%	4.02%	4.20%	5.03%	8.20%	9.05%		9.05%	1.035	9.37%
20	FE	FirstEnergy Corp.	4.34%	NA	4.32%	NA	-0.64%	NA	3.68%	X			
21	GXP	Great Plains Energy	3.79%	3.94%	3.92%	6.00%	5.23%	9.94%	9.15%		9.15%	1.035	9.47%
22	HE	Hawaiian Elec.	4.19%	4.27%	4.27%	3.20%	3.20%	7.47%	7.47%		7.47%	1.035	7.73%
23	IDA	IDACORP, Inc.	3.09%	3.17%	3.17%	4.00%	4.00%	7.17%	7.17%		7.17%	1.035	7.42%
24	ITC	ITC Holdings Corp.	2.10%	2.21%	2.19%	9.00%	7.42%	11.21%	9.61%		9.61%	1.035	9.95%
25	MGEE	MGE Energy	2.92%	NA	2.99%	NA	4.00%	NA	6.99%		6.99%	1.035	7.23%
26	NEE	NextEra Energy, Inc.	3.05%	3.19%	3.18%	7.10%	6.90%	10.29%	10.08%		10.08%	1.035	10.44%
27	NWE	NorthWestern Corp.	3.68%	3.79%	3.83%	5.00%	6.81%	8.79%	10.64%		10.64%	1.035	11.01%
28	OGE	OGE Energy Corp.	3.49%	3.59%	3.54%	4.60%	2.40%	8.19%	5.94%	X			
29	OTTR	Otter Tail Corp.	4.59%	NA	4.76%	NA	6.00%	NA	10.76%		10.76%	1.035	11.14%
30	POM	Pepco Holdings	4.25%	4.44%	4.36%	7.00%	4.33%	11.44%	8.69%		8.69%	1.035	9.00%
31	PCG	PG&E Corp.	3.52%	3.62%	3.65%	4.50%	5.94%	8.12%	9.59%		9.59%	1.035	9.93%
32	PNW	Pinnacle West Capital	3.94%	4.06%	4.06%	5.20%	5.15%	9.26%	9.21%		9.21%	1.035	9.53%
33	PNM	PNM Resources	3.01%	3.16%	3.19%	8.10%	9.41%	11.26%	12.60%		12.60%	1.035	13.04%
34	POR	Portland General Elec.	3.35%	3.44%	3.44%	4.10%	3.92%	7.54%	7.36%		7.36%	1.035	7.61%
35	PPL	PPL Corp.	4.65%	4.79%	4.79%	4.90%	4.87%	9.69%	9.66%		9.66%	1.035	10.00%
36	PEG	Pub Sv Enterprise Grp	3.77%	3.84%	3.80%	2.90%	1.54%	6.74%	5.34%	X			
37	SCG	SCANA Corp.	4.06%	4.17%	4.17%	4.30%	4.45%	8.47%	8.62%		8.62%	1.035	8.92%
38	SRE	Sempra Energy	2.79%	2.93%	2.95%	8.20%	9.35%	11.13%	12.30%		12.30%	1.035	12.73%
39	SO	Southern Company	4.95%	5.07%	5.07%	3.90%	3.73%	8.97%	8.80%		8.80%	1.035	9.10%
40	TE	TECO Energy	4.27%	4.46%	4.45%	7.10%	6.78%	11.56%	11.23%		11.23%	1.035	11.62%
41	UIL	UIL Holdings	3.62%	3.80%	3.82%	7.80%	8.84%	11.60%	12.66%		12.66%	1.035	13.11%
42	VVC	Vectren Corp.	3.68%	3.81%	3.80%	5.70%	5.00%	9.51%	8.80%		8.80%	1.035	9.11%
43	WR	Westar Energy	3.89%	3.98%	3.98%	3.90%	3.90%	7.88%	7.88%		7.88%	1.035	8.16%
44	WEC	Wisconsin Energy	3.56%	3.70%	3.73%	6.20%	7.55%	9.90%	11.28%		11.28%	1.035	11.68%
45	XEL	Xcel Energy, Inc.	3.75%	3.87%	3.86%	5.00%	4.68%	8.87%	8.54%		8.54%	1.035	8.84%
		Third Quartile						**10.04%**	**10.08%**		**10.26%**		**10.62%**
		Average						**9.0%**	**8.5%**		**9.4%**		**9.69%**
		Median						**9.17%**	**9.05%**		**9.22%**		**9.54%**

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).

Montana-Dakota Utilities Co.
RISK PREMIUM ANALYSIS

Line	Year	[1] Indicated Risk Premium	[2] Average "A" Rated Utility Bond Yield
1	1986	4.35%	9.58%
2	1987	2.89%	10.10%
3	1988	2.30%	10.49%
4	1989	3.20%	9.77%
5	1990	2.84%	9.86%
6	1991	3.19%	9.36%
7	1992	3.40%	8.69%
8	1993	3.82%	7.59%
9	1994	3.03%	8.31%
10	1995	3.66%	7.89%
11	1996	3.64%	7.75%
12	1997	3.80%	7.60%
13	1998	4.62%	7.04%
14	1999	3.15%	7.62%
15	2000	3.19%	8.24%
16	2001	3.33%	7.76%
17	2002	3.79%	7.37%
18	2003	4.39%	6.58%
19	2004	4.59%	6.16%
20	2005	4.89%	5.65%
21	2006	4.29%	6.07%
22	2007	4.29%	6.07%
23	2008	3.93%	6.53%
24	2009	4.44%	6.04%
25	2010	4.78%	5.46%
26	2011	5.03%	5.04%
27	2012	5.88%	4.13%
28	2013	5.31%	4.48%
29	2014	5.48%	4.28%
30	2015 [3]	5.51%	4.04%
31	**Average**	**4.03%**	**7.19%**

[1] Gorman Exhibit MPG-13
[2] Gorman Exhibit MPG-13

SUMMARY OUTPUT
Y= Risk Premium
X = Treasury Bond Yield

Regression Statistics	
Multiple R	0.909287
R Square	**0.826803**
Adjusted R Square	0.820617
Standard Error	0.003835
Observations	30

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.001966	0.001966	133.665662	0.000000
Residual	28	0.000412	0.000015		
Total	29	0.002378			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	**0.072090**	0.002834	25.434568	0.000000	0.066284	0.077896	0.066284	0.077896
A Rated Utility Bond Yield	**-0.441936**	0.038225	-11.561387	0.000000	-0.520237	-0.363636	-0.520237	-0.363636

	[1]	[2]	[3]
	30-year U.S. Treasury	Risk Premium	Return on Equity
Long-term projection (2017-2021)	4.50%	5.22%	9.72%
Long-term projection (2022-2026)	4.80%	5.09%	9.89%
Average			9.80%

[1] Blue Chip Financial Forecasts, Vol. 34, No. 12, December 1, 2015, at 14
[2] 0.0721 + -0.4419 x [1]
[3] Equals [1] + [2]

Montana-Dakota Utilities Co.

Selected Electric Distribution Companies
Beta

Company	Ticker	Value Line
ALLETE, Inc.	ALE	0.80
Alliant Energy Corporation	LNT	0.80
Ameren Corporation	AEE	0.75
American Electric Power Company, Inc.	AEP	0.70
Empire District Electric Company	EDE	0.70
Great Plains Energy Inc.	GXP	0.85
OGE Energy Corporation	OGE	0.90
Otter Tail Corporation	OTTR	0.85
PNM Resources, Inc.	PNM	0.85
Westar Energy, Inc.	WR	0.75
Xcel Energy Inc.	XEL	0.65
Average		**0.78**
Median		**0.80**

Notes:
Source:Value Line, dated September 18, 2015 or October 30, 2015.

MDU RESOURCES GROUP, INC. COMMON STOCK OFFERINGS

Company	Ticker	Date	[1] Shares Issued	[2] Offering Price	[3] Underwriting Discount	[4] Offering Expense	[5] Gross Equity Issue	[6] Total Flotation Cost	[7] Net Proceeds	[8] Flotation Cost as % of Net Proceeds
MDU Resources Group, Inc.	MDU	2/4/2004	2,300,000	$23.32	$0.793	$350,000	$53,636,000	$2,173,900	$51,462,100	4.2%
MDU Resources Group, Inc.	MDU	11/19/2002	2,400,000	$24.00	$0.72	$192,500	$57,600,000	$1,920,500	$55,679,500	3.4%
MDU Resources Group, Inc.	MDU	4/21/1998	2,400,000	$35.625	$0.98	$210,000	$85,500,000	$2,562,000	$82,938,000	3.1%
										3.6%

[1] Source: Form 424B5 dated 4/22/1998, 11/20/2002, 2/5/2004; includes over-allotments
[2] Source: Form 424B5 dated 4/22/1998, 11/20/2002, 2/5/2004
[3] Source: Form 424B5 dated 4/22/1998, 11/20/2002, 2/5/2004
[4] Source: Form 424B5 dated 4/22/1998, 11/20/2002, 2/5/2004
[5] Equals [1] x [2]
[6] Equals ([1] x [3]) + [4]
[7] Equals [5] − [6]
[8] Equals [6] / [7]

Montana-Dakota Utilities Co.

Bond Yield Averages

January 2015 - November 2015

		[1]	[2]	[3]	[4]	[5]	[6]
		30-year U.S. Treasury Bond	Average Corporate	Public Utility Bonds		Credit Spreads	
				A-Rated	Baa-Rated	A-Rated	Baa-Rated
2015	JAN	2.46	3.84	3.58	4.39	1.13	1.94
	FEB	2.57	3.93	3.67	4.44	1.11	1.87
	MAR	2.63	3.98	3.74	4.51	1.12	1.88
	APR	2.59	3.93	3.75	4.51	1.16	1.92
	MAY	2.96	4.35	4.17	4.91	1.22	1.95
	JUN	3.11	4.56	4.39	5.13	1.28	2.01
	JUL	3.07	4.57	4.40	5.22	1.33	2.16
	AUG	2.86	4.48	4.25	5.23	1.39	2.37
	SEP	2.95	4.59	4.39	5.42	1.43	2.47
	OCT	2.89	4.52	4.29	5.47	1.40	2.58
	NOV	3.03	4.62	4.40	5.57	1.37	2.54
2015	AVG	2.83	4.31	4.09	4.98	1.27	2.15

Notes:
[1] Bloomberg Finance L.P., 30-Year U.S. Treasury Bond
[2] Bloomberg Finance L.P., Moody's Average Corporate Bond Index
[3] Bloomberg Finance L.P., Moody's A-Rated Utility Bond Index
[4] Bloomberg Finance L.P., Moody's Baa-Rated Utility Bond Index
[5] Equals Column [3] − Column [1]
[6] Equals Column [4] − Column [1]

MONTANA-DAKOTA UTILITIES CO.
A Division of MDU Resources Group, Inc.
Before the Public Service Commission of Montana

Docket No. D2015.6.51

Rebuttal Testimony
of
Garret Senger

Q. Would you please state your name and business address?

A. Yes. My name is Garret Senger and my business address is 400 North Fourth Street, Bismarck, North Dakota 58501.

Q. What is your position with Montana-Dakota Utilities Co.?

A. I am Executive Vice President of Regulatory Affairs and Chief Accounting Officer (CAO) for Montana-Dakota Utilities Co. (Montana-Dakota), and Great Plains Natural Gas Co. (Great Plains), divisions of MDU Resources Group, Inc.

Q. Are you same Garret Senger who filed direct testimony earlier in this proceeding?

A. Yes, I am.

Q. What is the purpose of your rebuttal testimony?

A. I am responding to the Direct Testimony concerning the capital structure and the cost of debt filed by Mr. Michael P. Gorman on behalf of the Montana Large Customer Group.

Q. Mr. Gorman makes an argument to remove the Company's Other Investments and Non-Utility Assets from the common equity component of the capital structure. Do you agree with his argument?

A. No, I do not agree with his argument. The Company's Balance Sheet is supported by a common capital structure with a like ratio of short and long term debt, preferred stock and common equity with the exception of account 123.1 Investment in Subsidiary Companies. As Mr. Gorman stated the largest component of the Other Investment Assets is related to the value of life insurance policies and the Company anticipates using these assets to satisfy a nonqualified benefit plan obligation. The liability for this benefit obligation is shown on the Form 1 in account 228.3 and is an offset to the asset. Mr. Gorman did not recognize this offset in his calculations but should have included the offset. The Company finances the utility and non-utility operations by using a common capital structure, so it would be incorrect to make adjustments to just the equity component of the capital structure. The equity ratio of 49.515% is appropriate as filed.

Q: Mr. Gorman in his testimony recalculates the Embedded Cost of Debt, do you agree with Mr. Gorman?

A. I agree with Mr. Gorman. The embedded cost of debt should be recalculated as the debt issuance agreements have been signed related to the $150 million of long term debt issuances. The Company issued three notes: $87 million 10-year note at 3.78 percent on October 29, 2015, $11million 15-year note at 4.87 percent on October 29, 2015 and $52 million 30-year note at 4.03 percent on December 10, 2015. The Company's revised cost of debt is 5.788 percent.

Q. Does this complete your rebuttal testimony?

A. Yes, it does.

MONTANA-DAKOTA UTILITIES CO.
A Division of MDU Resources Group, Inc.

Before the Public Service Commission of Montana

Docket No. D2015.6.51

Rebuttal Testimony
of
Alan L. Welte

Q. Please state your name and business address.

A. My name is Alan L. Welte and my business address is 400 North Fourth Street, Bismarck, North Dakota 58501.

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

A. I am the Director of Generation in the power production department of Montana-Dakota Utilities Co. (Montana-Dakota), a Division of MDU Resources Group, Inc.

Q. Are you the same Alan L. Welte who filed direct testimony earlier in this proceeding?

A. Yes, I am.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to discuss the status of the Lewis & Clark MATS project, the Big Stone AQCS project, the Thunder Spirit Wind (Thunder Spirit) project and the two Reciprocating Internal Combustion Engines (RICE) co-located with the Lewis & Clark Station which were addressed in the testimony of Mr. Albert E. Clark, testifying on behalf of the Montana Consumer Counsel, and Mr. Kevin C. Higgins testifying on behalf of the Montana Large Customer Group.

Q. Will you please provide a status update on the Lewis & Clark MATS project?

A. Yes. Montana-Dakota's Engineering, Procurement and Construction (EPC) contractor completed the construction and commissioning of the MATS project during a September 4 to November 15, 2015 outage at the Lewis & Clark Station. The Lewis & Clark Station returned to service producing energy and the initial operation, tuning, and testing of the MATS systems occurred in late November through mid-December following the outage. Preliminary Filterable Particulate Matter (FPM) testing was conducted on December 15 and 16, 2015. The test results indicated that the MATS project is achieving compliance with the MATS rule. The MATS project was designated to be in commercial operation on December 23, 2015.

Q. Will you please provide a status update on the Big Stone AQCS project?

A. Yes. Actual construction of the Big Stone AQCS project was completed at the end of the third quarter of 2015. Fourth quarter activities included start-up and check out of all the systems. Reliable operation was achieved and the systems were declared to be in commercial operation on December 29, 2015. Performance tests have been run on the systems and they are all meeting their guarantees for environmental performance.

Q. Will you please provide a status update on the Thunder Spirit Wind project?

A. Yes. As noted by Mr. Neigum, Montana-Dakota and ACE Wind LLC completed the required Asset Purchase Agreement transactions to transfer ownership of the project to Montana-Dakota on December 30, 2015. The project began producing energy in October of 2015 and was declared to be in commercial operation on December 31, 2015. The equipment supplier, Nordex, has completed the commissioning of all 43 wind turbines.

Q. Will you please provide a status update on the Lewis & Clark RICE project?

A. Yes. The individual unit first fire and bearing runs on the Lewis & Clark Reciprocating Internal Combustion Engine (RICE) project were completed on December 14, 2015. The units were first synchronized to the electric system on December 15, 2015. Burn-in periods were completed and both units were operated together at full load on December 17, 2015. The units were declared to be available for commercial operation on December 31, 2015.

Q. Projects of this magnitude often have trailing costs. Can you elaborate on whether these projects will have trailing costs and discuss the project costs closed to plant in service for Montana electric operations?

A. It is very common for large projects to have trailing costs for activities which do not affect commercial operation. For example, Montana-Dakota's equipment supplier, Nordex, has additional work that must be completed in order to satisfy the terms of the contract. That work will be completed during 2016 and the Company will be invoiced upon completion. This activity does not impact the commercial operation but is a cost that will ultimately be capitalized as a component of the project. Overall, the remaining costs are not material and the projected costs for all four projects are approximately the same as shown in the Company's rate case filing. I will refer you to the testimony of Mr. T. Jacobson for the December 31, 2015 plant in-service balance for each project.

Q. Does this complete your rebuttal testimony?

A. Yes, it does.

MONTANA-DAKOTA UTILITIES CO.
A Division of MDU Resources Group, Inc.

Before the Public Service Commission of Montana

Docket No. D2015.6.51

Rebuttal Testimony
of
Darcy J. Neigum

Q. Would you please state your name and business address?

A. Yes. My name is Darcy J. Neigum and my business address is 400 North Fourth Street, Bismarck, North Dakota 58501.

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

A. I am the Director of System Operations and Planning for Montana-Dakota Utilities Co. (Montana-Dakota), a Division of MDU Resources Group, Inc.

Q. Are you the same Darcy J. Neigum who filed direct testimony earlier in this proceeding?

A. Yes, I am.

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

A. The purpose of my rebuttal testimony is to address the testimony of Mr. Albert E. Clark, testifying on behalf of the Montana Consumer Counsel, and Mr. Kevin C. Higgins testifying on behalf of the Montana Large Customer Group in regard to the Thunder Spirit Wind (Thunder Spirit) project and the settlement proceeding with Southwest Power Pool (SPP).

Q. When was the last turbine at Thunder Spirit erected?

A. The last turbine at Thunder Spirit was erected on November 19, 2015.

Q. When did the first turbine at Thunder Spirit start producing power?

A. The first turbine at Thunder Spirit started producing power on October 21, 2015.

Q. When did Montana-Dakota complete the purchase of Thunder Spirit?

A. Montana-Dakota completed the purchase of Thunder Spirit on December 30, 2015.

Q. When did Montana-Dakota place Thunder Spirit in-service?

A. Montana-Dakota placed Thunder Spirit in-service on December 31, 2015.

Q. What is the status of the Federal Energy Regulatory Commission (FERC) Settlement Proceedings between the Southwest Power Pool (SPP) and Montana-Dakota regarding the Western Area Power Administration (Western) and Basin Electric Power Cooperative (Basin) Integration Filing to join SPP?

A. A Settlement Agreement between SPP and Montana-Dakota in the FERC Docket ER14-2850 and ER14-2851 was filed with FERC on December 10, 2015.

Q. When does Montana-Dakota expect an order from FERC on the SPP Settlement Agreement?

A. Montana-Dakota expects an order from FERC sometime before February 10, 2016 on the Settlement Agreement. On December 30, 2015

FERC Trial Staff issued its initial comments in support of certification of the Partial Settlement to the Commission for approval. No comments were filed by any party in opposition of the Settlement Agreement.

Q. What is the purpose of the Settlement Agreement between SPP and Montana-Dakota?

A. Among other things, the Settlement Agreement defines the transmission service that Montana-Dakota will take from SPP as a result of Western and Basin joining SPP as Transmission Owning Members on October 1, 2015; and the terms around which Montana-Dakota will receive Section 30.9 Facility Credits under the SPP Tariff to offset its SPP network transmission bill.

Q. When did Montana-Dakota start taking transmission Service from SPP?

A. Montana-Dakota began taking 36 MW of network transmission service from SPP on October 1, 2015 as a result of Western and Basin joining SPP as transmission owning members. The October 1, 2015 service from SPP was to replace an incremental network transmission service agreement that Montana-Dakota had with Western under the Western IS Tariff for delivery services above the legacy Western Transmission Service Agreement.

Montana-Dakota's legacy transmission service agreement with Western expired on December 31, 2015 at which point Montana-Dakota needs to take SPP transmission service for all its customer loads which depend on Western's transmission facilities.

Q. What is the net impact to customers of Western and Basin joining SPP and the Settlement Agreement?

A. Based upon the final terms of the Settlement Agreement, Montana-Dakota now estimates the net impact in additional transmission service charges to be less than $250,000 per year over 2015 costs to all customers in its integrated system.

Q. What did Montana-Dakota estimate the net customer impact to be if Western and Basin had not joined SPP?

A. If Western and Basin had not joined SPP, Montana-Dakota had previously estimated the impact to customers associated with the expiration of the Western Transmission Service Agreement to be around $6 million per year to all customers in its integrated system.

Q. What would have happened if Montana-Dakota had decided to exit MISO and join SPP instead of taking transmission service from two regional transmission organizations?

A. If Montana-Dakota had decided to withdraw from MISO and join SPP it would have needed to procure an additional 120-130 MW of generation capacity to meet the resource adequacy, or peak demand, requirements under the SPP Tariff that it did not otherwise need to purchase under the MISO Tariff. The net impact would be additional costs to Montana-Dakota's customers to meet resource adequacy requirements under the SPP Tariff.

Also, the Western and Basin zonal transmission rate under the SPP Tariff is expected to be higher than Montana-Dakota's zonal transmission

rate under the MISO Tariff. The net impact again would be higher transmission costs to all of Montana-Dakota customers because only half of Montana-Dakota's customer load will be required to take transmission service under the Settlement Agreement with SPP versus all of Montana-Dakota's customers taking transmission service from SPP if Montana-Dakota exited MISO and joined SPP.

Q. Why is the net customer impact still an estimate if Montana-Dakota has entered into a settlement agreement with SPP?

Even though Montana-Dakota knows what type of transmission service and applicable charges it will take from SPP, it does not know the final bill determinates that will be used to calculate its SPP transmission bill.

In particular, Basin and its members are still party to another FERC settlement over the facilities and annual transmission revenue that Basin and its members will receive under the SPP Tariff. However, the new SPP charges will be effective January 1, 2016.

Q. What information is used to the calculation of the net customer impact associated with the expiration of the Western Transmission Service Agreement and the SPP Settlement?

A. The following components make up the net transmission impact calculation:

1. Amount of Montana-Dakota customer load (MWs) taking transmission service. This number is dependent on the 12 month

average peak demand for the previous year of Montana-Dakota's customer load and will not be known until the end of January 2016.

2. Final SPP Transmission Rates. This rate will not be known until at least February 2016 and may even be adjusted further pending the outcome of Basin's on-going settlement proceeding and ultimate agreement for qualifying facilities and annual transmission revenues.

3. Amount of Facility Credits that Montana-Dakota receives under the SPP Tariff. Dependent on the FERC order with the Montana-Dakota / SPP Settlement Agreement which is expected by February 10, 2016.

4. Amount of transmission service that Basin takes from MISO for Montana-Dakota for transmission services as a result of the termination of the Common Use Agreement between Montana-Dakota and Basin. Montana-Dakota is still waiting for a final list of Basin's loads which will be taking MISO transmission service and the associated 2015 twelve month average peak load amount.

Q. What did Montana-Dakota base the net transmission expenses calculation on associated with the expiration of the Western Transmission Service Agreement?

A. The following is a list of assumptions that Montana-Dakota used to calculate the net transmission impact associated with the expiration of the Western Transmission Agreement:

MDU load taking SPP Trans. Service	325 MW
MDU load service factor	65%

SPP transmission rate (Sch. 9 and 11)	$4.00 per kWmonth
SPP Schedule 1 and 1a rate	$0.39 per MWh
SPP Schedule 2 rate	$0.02 per kWmonth
SPP Schedule 12	$0.0374 per MWh
MDU Facility Credits from SPP	$10,000,000 per year
Basin loads taking MISO service	50 MW

Q. Which of these assumptions have changed since the filing in this rate case?

The following is a list of updated assumptions for the net transmission impact calculation:

MDU load taking SPP Trans. Service	280 MW
MDU load service factor	65%
SPP transmission rate (Sch. 9 and 11)	$4.41 per kWmonth
SPP Schedule 1 rate	$0.20 per kWmonth
SPP Schedule 1a rate	$0.39 per MWh
SPP Schedule 2 rate	$0.02 per kWmonth
SPP Schedule 12	$0.0374 per MWh
MDU Facility Credits from SPP	$11,470,000 per year
Basin loads taking MISO service	125 MW

Q. Are there any other proceedings which will impact the net amount of money that Montana-Dakota will pay to SPP for transmission service?

A. Yes. The MISO Transmission Owners, which Montana-Dakota is a member, are in a contested hearing at FERC under docket EL15-45 which

will ultimately reduce the return on equity (ROE) that the MISO Transmission Owners are using to calculate their annual transmission revenue requirement under the MISO Tariff.

A lower MISO ROE will reduce the amount of facility credits that Montana-Dakota receives under the SPP Tariff and it will reduce the MISO transmission rate that Basin Electric will pay for MISO transmission service for use of Montana-Dakota's transmission facilities under the MISO Tariff.

The net impact of a lower MISO ROE is unknown at this time.

Q. If the Settlement Agreement is not approved by FERC until February 10, 2016; what transmission service will Montana-Dakota have to take from SPP on January 1, 2016?

On January 1, 2016, Montana-Dakota began taking network transmission service from SPP for approximately 280 MW of network load. If the settlement agreement is not approved until February 2016, Montana-Dakota may not be eligible to receive facility credits, for a period of time, under the SPP Tariff dependent upon the effective date of the Settlement Agreement established by FERC. The parties to the Settlement Agreement requested an effective date of October 1, 2015, which will establish a refund period.

Q. Does the pending Settlement Agreement preclude SPP from charging Montana-Dakota for transmission services?

A. No. SPP will be charging Montana-Dakota for transmission services with or without the Settlement Agreement.

Q. Would the Transmission Cost Recovery Rider (TCRR) proposed by the Company provide a means of addressing the variability associated with transmission service requirements and RTO charges?

A. In my opinion, the TCRR would provide the mechanism necessary to address the transmission charges applicable under the new construct without the Western Agreement and with the requirement to take transmission service under SPP in order to serve portions of Montana-Dakota's loads. SPP's rate is subject to change on a monthly basis and the requirements are based on the energy requirements. This variable expense which will be subject to change both upward and downward over time is appropriately recovered through the TCRR. As noted by Mr. Jacobson, Montana-Dakota is also responsible for costs shared for transmission projects in each RTO. These costs would be appropriately recovered through the TCRR.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

PUBLIC SERVICE COMMISSION

OF THE STATE OF MONTANA

REBUTTAL TESTIMONY OF

EARL M. ROBINSON

DOCKET NO. D2015.6.51

MONTANA DAKOTA UTILITIES CO.

ELECTRIC PLANT

&

COMMON PLANT

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I. WITNESS INTRODUCTION

Q1. WHAT IS YOUR NAME, OCCUPATION AND BUSINESS ADDRESS?

A. My name is Earl M. Robinson. I am a Principal of AUS Consultants. My office is located at 792 Old Highway 66, Suite 200, Tijeras, NM 87059.

Q2. ARE YOU THE SAME EARL M. ROBINSON WHO FILED DIRECT TESTIMONY EARLIER IN THIS PROCEEDING?

A. Yes, I am.

II. PURPOSE OF TESTIMONY

Q3. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my testimony is to rebut the depreciation testimony and exhibits set forth by the Montana Consumer Counsel (MCC) witness Jacob Pous. I also address assertions by him regarding the provision of data, and data interpretation, along with sponsoring Exhibit Nos.___(EMR-3), (EMR-4), (EMR-5), and (EMR-6).

III. BACKGROUND

Q4. HOW IS DEPRECIATION DEFINED?

A. Depreciation is defined in the 1996 NARUC "Public Utility Depreciation Practices" publication as follows: "Depreciation**,** as applied to depreciable utility plant, means the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of utility plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy,

obsolescence, changes in the art, changes in demand, and requirements of public authorities."

Q5. WHY IS DEPRECIATION IMPORTANT TO THE REVENUE REQUIREMENTS OF A UTILITY COMPANY?

A. Depreciation expense enables a company to recover in a timely manner the capital costs related to its plant in service. Appropriate depreciation rates will allow recovery of a company's investments in depreciable assets over a life that provides for full recovery of the investments, less net salvage. Furthermore, the inclusion of the appropriate level of depreciation recovery in revenue requirements serves to reduce overall costs (total of depreciation and return) to customers as opposed to a situation where an inadequate level of annual depreciation expense is currently being provided in rates. The higher level of costs to customers (depreciation and return) resulting from the use of inadequate (lower) depreciation expense is the product of a higher level of rate base being retained for longer periods of time.

Q6. WHAT IS THE GUIDING PRINCIPLE IN DEVELOPING THE ESTIMATED DEPRECIATION RATES AND EXPENSE FOR A COMPANY'S OPERATING PROPERTY?

A. The goal is to estimate depreciation parameters that will develop annual depreciation rates that when applied to the Company's plant in service investment will recover the Company's first (original cost) and end of life cost over the useful average service life of the property. That is, the total cost of the property should be ratably recovered from the customers that have benefitted from the use (that have consumed the property) of the property in the receipt of their service. The process should incorporate the current best estimates of life and salvage so that there is no

intended deferral or acceleration in the depreciation process. The end goal should be full recovery at the end of life-no more and no less. The end result should be reasonable and rational as it relates to the Company's specific operating property and general experience that the Company has been and is anticipated to achieve in the foreseeable future. While comparisons can be made to other operating companies, the depreciation rates and expense are to be used to recovery the operating property of the company being studied and therefore, should be based upon the requirements of the studied company.

IV. SUMMARY

Q7. ARE THE RESULTS OF THE DEPRECIATION STUDIES THAT YOU PERFORMED FOR MDU'S ELECTRIC AND COMMON PLANT REASONABLE AND RATIONAL AND DO THEY REFLECT THE CURRENT BEST ESTIMATES OF THE DEPRECIATION LEVEL (AS OF DECEMBER 31, 2014) REQUIRED TO APPROPRIATELY RECOVER THE COMPANY PROPERTY INVESTMENTS AND END OF LIFE COST OVER THE REMAINING LIFE OF THE PROPERTY?

A. Yes, the results of the MDU-Electric's 12-31-14 depreciation study is a modest increase of $1,993,230 (relative to the Company's 12-31-14 depreciable plant in service) of annual depreciation expense or approximately 5.7%. The application of the proposed account level depreciation rates to the December 31, 2014 Electric depreciable plant in service is an annual depreciation expense amount of $36,880,451 or a composite depreciation rate of 3.04%.

The results of the MDU-Common's 12-31-14 depreciation study is an increase of $275,554 or 10.4% relative to the Company's 12-31-14 depreciable plant in service. The application of the proposed account level depreciation rates to

the December 31, 2014 Common Plant depreciable plant in service is an annual depreciation expense amount of $2,924,572 or a composite depreciation rate of 4.30%.

Q8. ARE MR. POUS' ALTERNATIVE DEPRECIATION RATES AND EXPENSE REASONABLE AND RATIONAL?

A. No. Mr. Pous is proposing that the Company's Electric Plant book depreciation rates and expense be lowered from the present composite depreciation rate of 2.88% to 2.63% or $2,976,925 (8.5%) below the Company's current depreciation expense and from the proposed composite depreciation rate of 3.04% to Mr. Pous' composite depreciation rate of 2.63% which is $4,970,155 (13.5%) below the Company's proposed depreciation expense.

For MDU-Common Plant Mr. Pous is proposing that the Company's book depreciation rates and expense be lowered from the present composite depreciation rate of 3.89% to 3.24% or $446,223 (16.9%) below the Company's current depreciation expense and from the proposed composite depreciation rate of 4.30% to Mr. Pous' composite depreciation rate of 3.24% which is $721,787 (24.7%) below the Company's proposed depreciation expense. Mr. Pous' position is clearly unreasonable and irrational.

V. <u>SPECIFIC AVERAGE SERVICE LIFE RESPONSES</u>

Q9. MR. POUS HAS PROPOSED ALTERNATIVE AVERAGE SERVICE LIVES FOR A VARIETY PROPERTY ACCOUNTS, AS COMPARED TO THOSE SET FORTH IN THE MDU DEPRECIATION STUDY REPORTS. PLEASE PROVIDE YOUR COMMENTS WITH REGARD TO MR. POUS' PROPOSALS.

A. With regard to the average service life issues, I will address the items in order by property account.

<u>Other Production Plant—Wind Farm Investment Life Span</u>

Q10. PLEASE PROVIDE YOUR COMMENTS REGARDING MR. POUS' UNSUPPORTED PROPOSAL TO CHANGE THE LIFE SPAN FOR THE COMPANY WIND TURBINE FACILITIES FROM 20 TO 25 YEAR.

A. First and foremost, nothing significant has a changed, from an operating basis or future expectations for the facilities--comprising the company's wind farm operating properties. Thus there is no justification for any change to the average service underlying the current depreciation rates. Mr. Pous' position is clearly unsupported, based strictly on judgment and unrelated information.

Furthermore, in response to Mr. Pous' Data Request MCC-200, Mr. Pous was provided the follow responses, which he simply ignored and made an unjustified alternative service life proposal.

"There are a few large entities that operate an extensive quantity (most of) the Wind Farms throughout the US. In general, one of the largest operators (NextEra), has a practice, that if the WTGs (Wind Turbine Generator) is older and smaller, less than 1 MW, the life is routinely in the high teens. For the newer, more mid-sized ones, 1-1.5 MW, (MDU's wind turbines are of 1.5 MW capacity) a life of around 20 years is used. Also supporting the use of the 20 year life is WTG purchase contracts where the manufacturers have indicated a design life of 20 years. The newest and largest ones, <u>above 1.5 MW</u> can have lives in the low 20's even though manufacturers routinely have a 20 year design life. Once wind farms approach the 20 year age it is not uncommon that cannibalization occurs to keep

various units running. Furthermore, it is not uncommon for units, as they continue to age, to experience a variety of maintenance issues, and/or outright failures.

Q11. PLEASE PROVIDE YOUR COMMENTS REGARDING MR. POUS' AVERAGE SERVICE LIFE PROPOSAL FOR ACCOUNT 355.

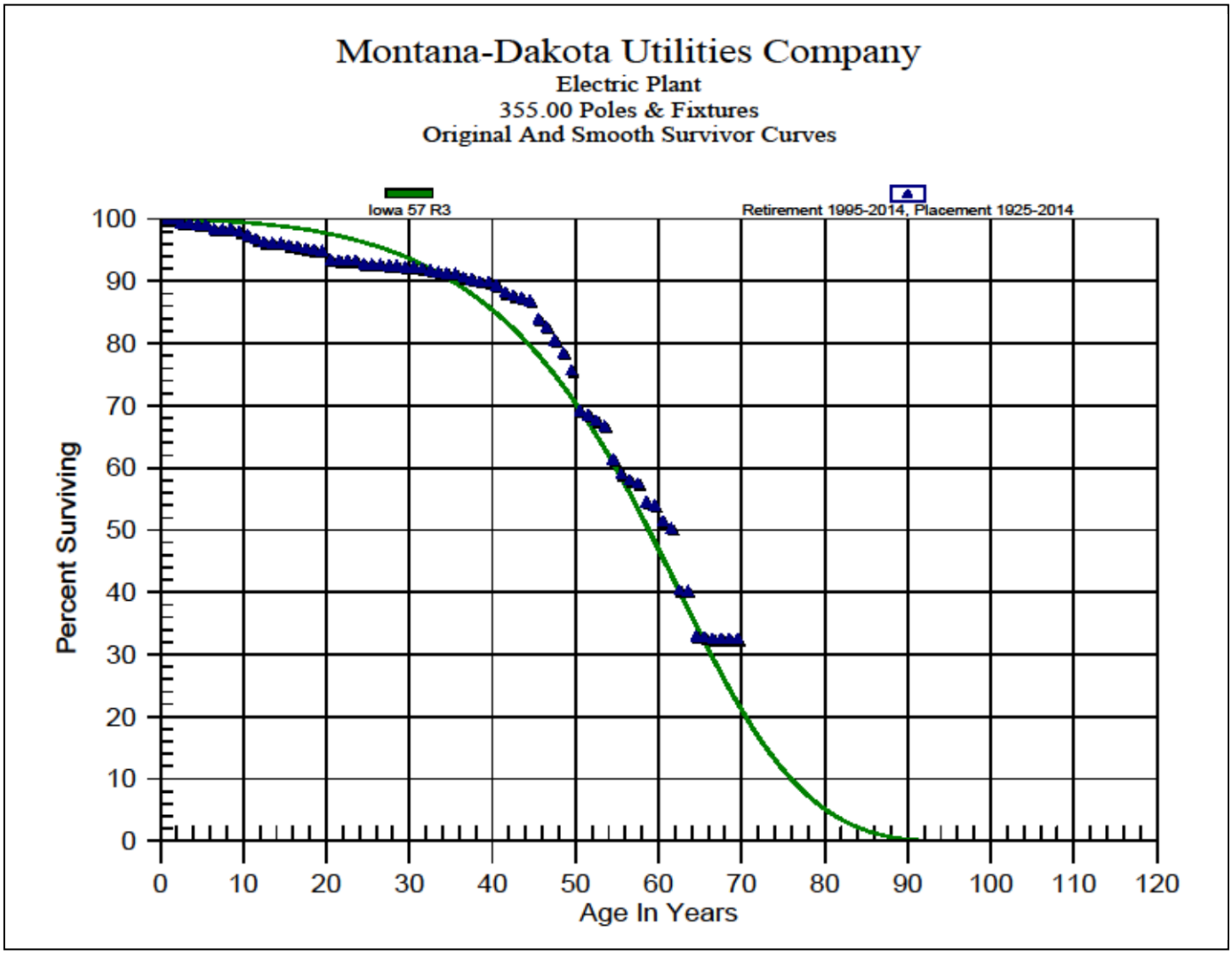
A. My discussion is as follows.

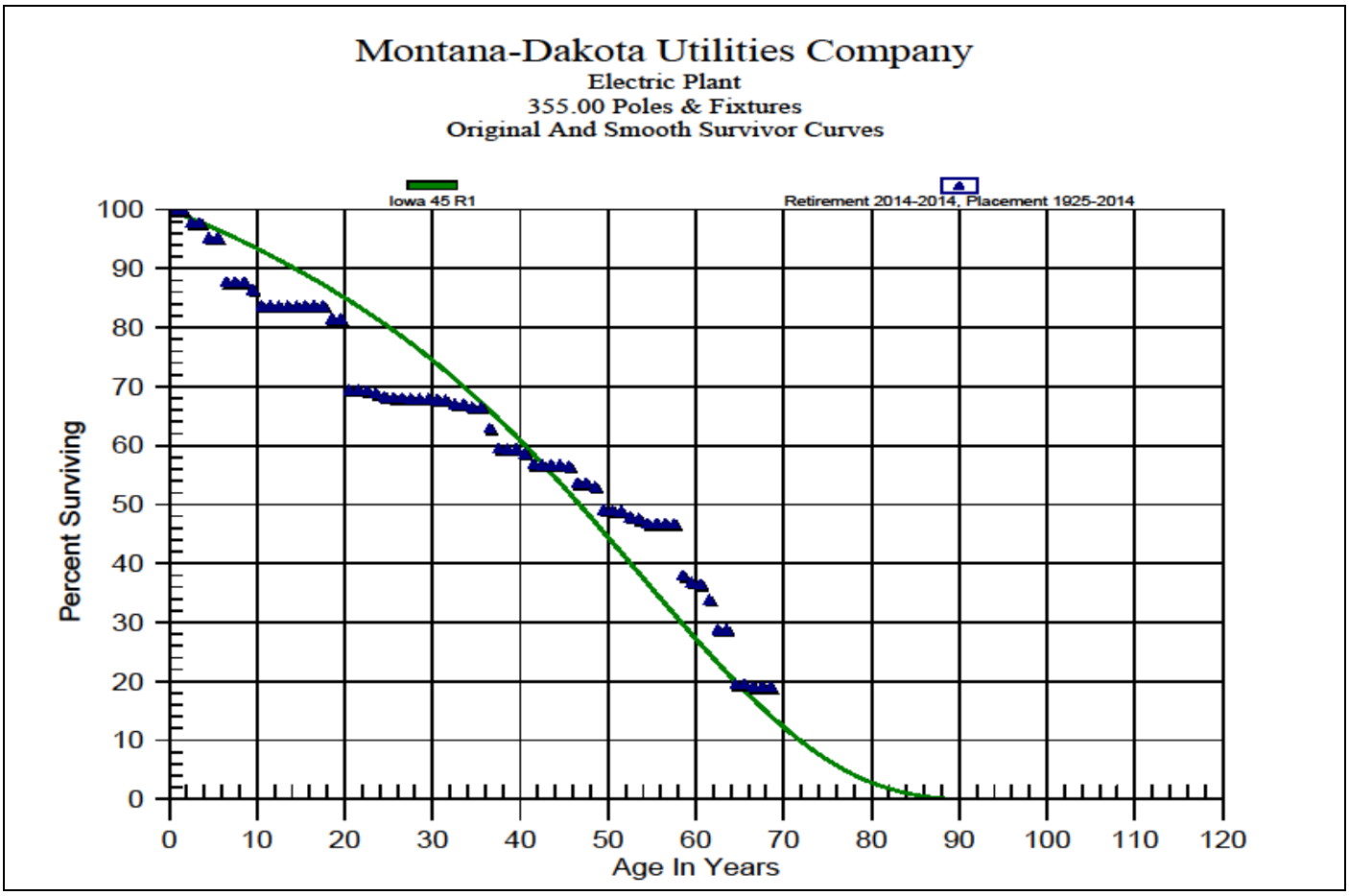
<u>Account 355-Poles & Fixtures</u>

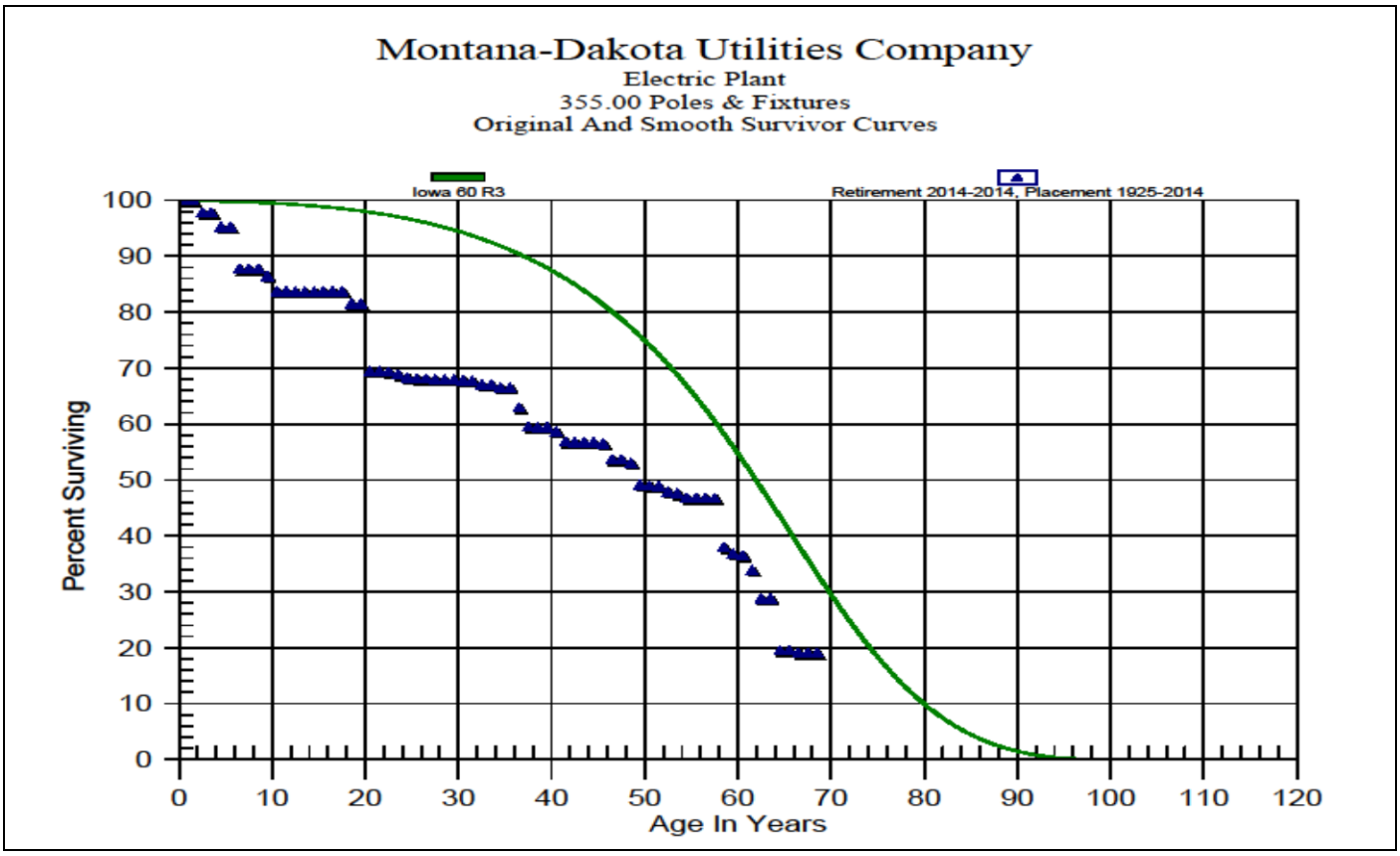
Current Average Service Life: 45-R2

MDU Proposed Avg. Service Life: 50-R3

Mr. Pous Proposed Avg. Serv. Life: 60-R3




Montana-Dakota Utilities Company
Electric Plant
355.00 Poles & Fixtures
Original And Smooth Survivor Curves
Iowa 45 R1
Retirement 2014-2014, Placement 1925-2014
Percent Surviving
Age In Years


Montana-Dakota Utilities Company
Electric Plant
355.00 Poles & Fixtures
Original And Smooth Survivor Curves
Iowa 60 R3
Retirement 2014-2014, Placement 1925-2014
Percent Surviving
Age In Years

1

Mr. Pous has been continuously critical of the supposed lack of provided data, and any items that support the Company's proposals, yet when information such as the following is provided in the depreciation study, he seeks to discredit it or simply ignores the information.

During the last several years the Company has been in an increasing growth mode having increased its plant investment by approximately a third. Historically, the activity has been more on the growth side as opposed to replacement of existing facilities, however, during the most recent study year replacements/retirements have accelerated rather dramatically. In fact while the overall and more 5 year experience band analysis produced life indication of an estimated 57 years' average service life, the current 2014 band produced an average service life indication of 45 years.

In future years it is anticipated that replacement of existing facilities will likely occur at higher levels. Over the immediate coming 5 years management anticipates building approximately 100 miles of pole transmission line of which one half is expected to be continued growth/expansion while the remaining one half is expected to be replacement of existing property with further activity in more distant years. This significant increase in plant activity can be anticipated to continue the shorter life presently being experience.

Even at the estimated average service life of a 50-R3 life and curve, recommended per this study, the recovery period is at the higher end of the industry range of service lives.

Conversely, Mr. Pous relies on his statement of supposed benefits, and the resulting longer life, from "advance poles inspections and chemical treatment" for

the Company's pole investments. More often, such efforts referenced by Mr. Pous are focused on enabling the facilities to reach the original intended life as opposed to any material extension of life. MDU has a process for maintaining it poles and, as such, the activity is inclusive within its operating history. More importantly, the physical attribute (force of retirement) is just one of many factors that impact the overall average service life of poles or any operating property. The many other retirement forces will continue to drive the future life of poles.

Finally, in response to Mr. Pous' MCC-211 data request, the Company provided its 5 year capital budget indicating its intent to replace more than 178 miles of transmission lines as substantiated in the electronic file provided as Attachment A to that request. Mr. Pous simply chose to ignore the data, and chose to propose an unreasonable longer service life for the property group.

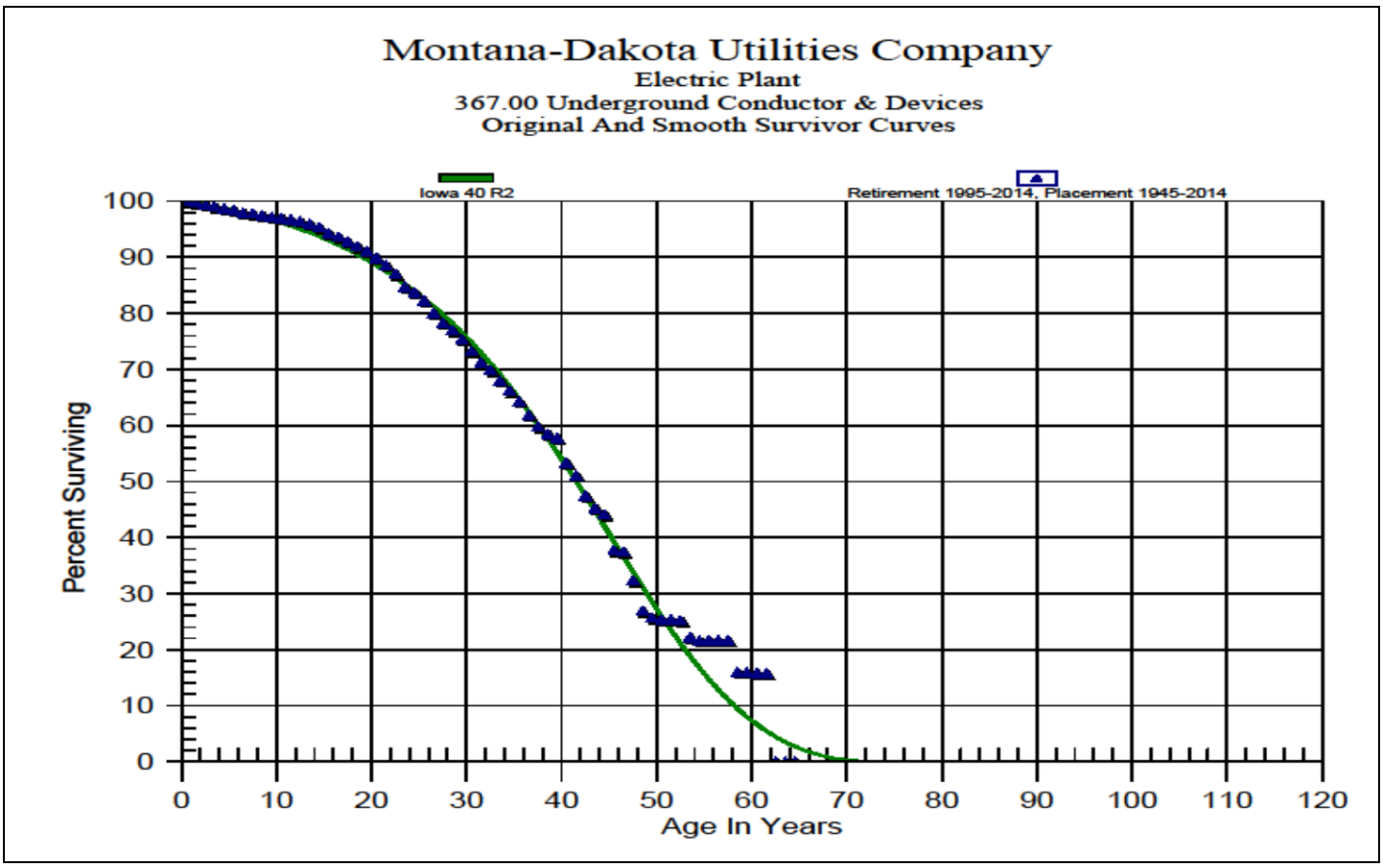
The 50 year average service life, which is a 5 year extension beyond the current underlying service life, estimated in the MDU deprecation study for the property group, is a reasonable and rational proposal.

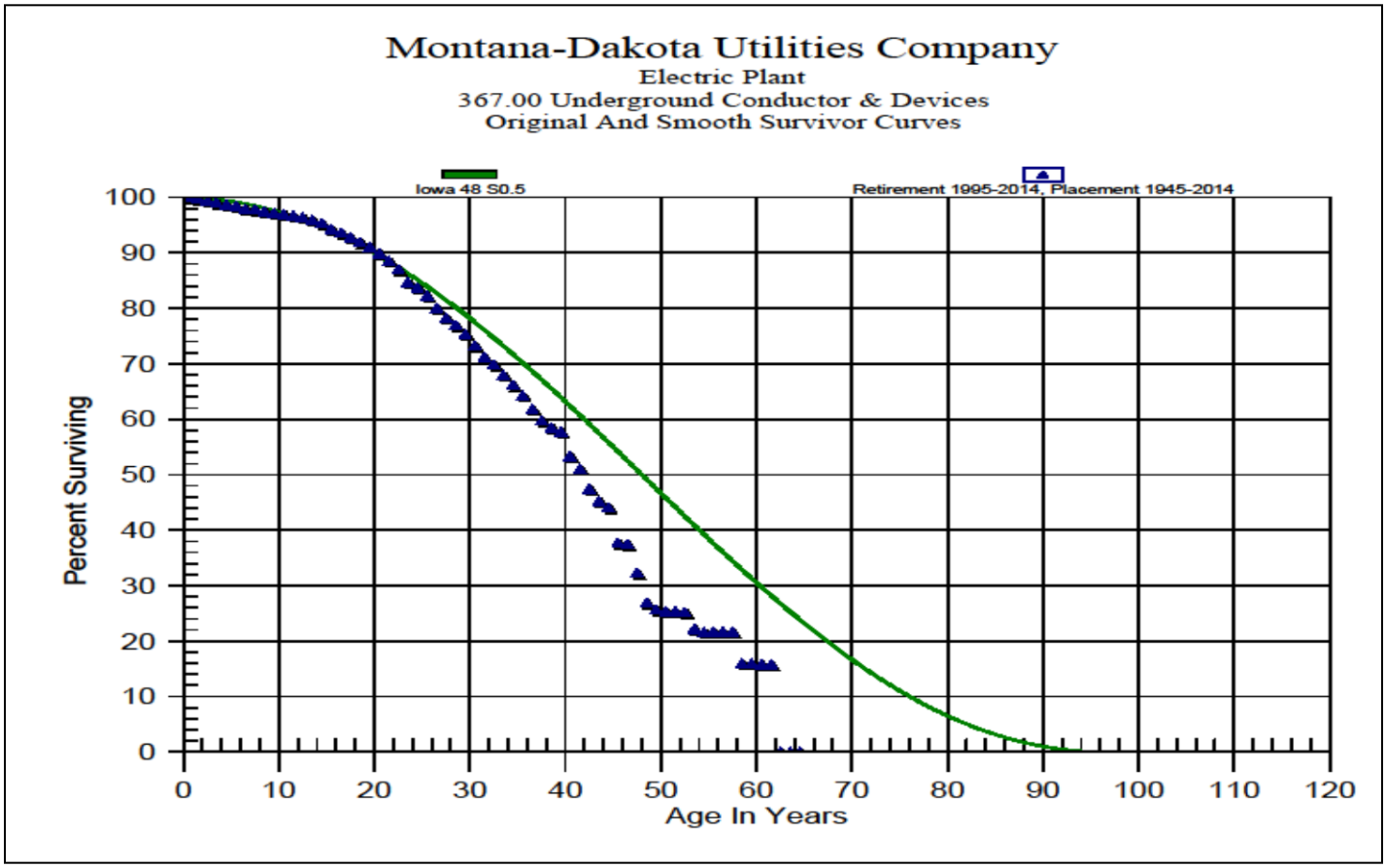
Q12. PLEASE PROVIDE YOUR COMMENTS REGARDING MR. POUS' PROPOSAL FOR ACCOUNT 367.

A. My discussion is as follows.

<u>Account 367-Underground Conductor & Devices</u>

Current Average Service Life:	30-R3
MDU Proposed Avg. Service Life:	40-R2
Mr. Pous Proposed Avg. Serv. Life:	48-S0.5


Montana-Dakota Utilities Company
Electric Plant
367.00 Underground Conductor & Devices
Original And Smooth Survivor Curves
Iowa 40 R2
Retirement 1995-2014, Placement 1945-2014
Percent Surviving
Age In Years


Montana-Dakota Utilities Company
Electric Plant
367.00 Underground Conductor & Devices
Original And Smooth Survivor Curves
Iowa 48 S0.5
Retirement 1995-2014, Placement 1945-2014
Percent Surviving
Age In Years

1

The property investment within this account is related to underground distribution cables. Activity related to upgrades and ongoing changes of the property group are deemed to be normal and therefore future replacements are not anticipated to be materially different than occurred during recent years, notwithstanding that there are residual amounts of higher failure rate cables that remaining to be changed out. Subsequent vintage cables (placed after earlier high failure rate cables) have continued to experience changes even with the decline in higher failure rates cables. In analyzing the historical data, the level of retirements as a percent of original cost and average age of retirements, while varying somewhat from year to year, have been continuous and generally consistent over more recent periods suggesting that there has been no decline in activity, as suggested by Mr. Pous for the basis of his further extension of the longer average service life proposed in the Company depreciation study for this property group. The proposed average service life generated from the historical data is an excellent fit to Company's level of experience that can be anticipated to continue in future years.

Mr. Pous has opined that earlier generation driven cable replacements and upgrade are a thing of the past and that future lives will be much longer than in prior years. The Company's estimated average service life already includes a measurable average service life increase—to which Mr. Pous, based simply upon generalizations, with no empirical evidence, proposes an even longer service life. That being 8 years or 20 percent beyond the already 33% increase in life incorporated in the proposed depreciation study rates.

In the course of completing the depreciation study analysis and estimation for MDU's Account 367 property group, an Iowa 40-R2 life and curve was estimated by Mr. Robinson. The proposed/estimated Iowa 40-R2 average service life and curve is an increase in the Average Service Life by 10 years or 33% over the current average service life of 30 years. Furthermore, the current book depreciation reserve for the property group is only at 23% of the required level of recovery amount--- clearly not an indication of the current average service life being excessively short. In fact, if one were to look at a whole life average service life rate for a 40 life property, the raw life rates would be 2.50% as opposed to the Company's proposed average remaining life (ARL) depreciation for the property group of 3.00%. This result indicates that the book depreciation reserve is lower than it should be. ARL depreciation rates give consideration to all factors, including the current book depreciation reserve in developing the proposed depreciation rates. When a book depreciation reserve is lower than it should be the ARL depreciation rate is driven to a higher level to make up for the current under recovery level.

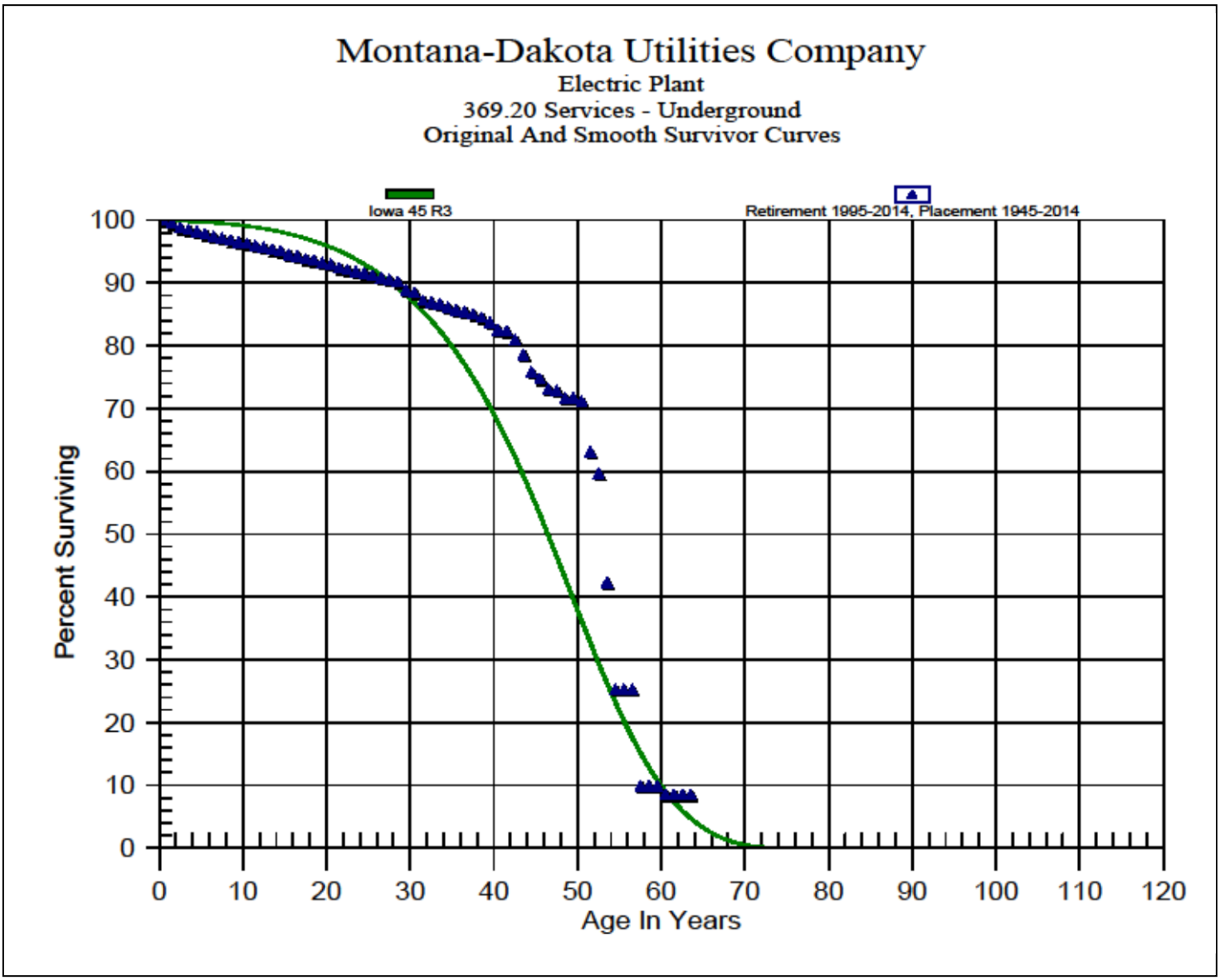
Conversely, if one were to adopt Mr. Pous' flawed average service life of 48 years the whole life depreciation rate would be a mere 2.08% percent rate. In fact Mr. Pous calculates and proposes an ARL depreciation rate of 2.14% for Underground Services, a totally unacceptable level, especially in light of the current level of book depreciation reserve. Furthermore, in looking at the above plot of Mr. Pous' estimated 48 year average service life it can easily be see that that he is proposing a maximum life that extends far beyond that which the Company has experienced to date.

Q13. PLEASE PROVIDE YOUR COMMENTS REGARDING MR. POUS' PROPOSAL FOR ACCOUNT 369.2.

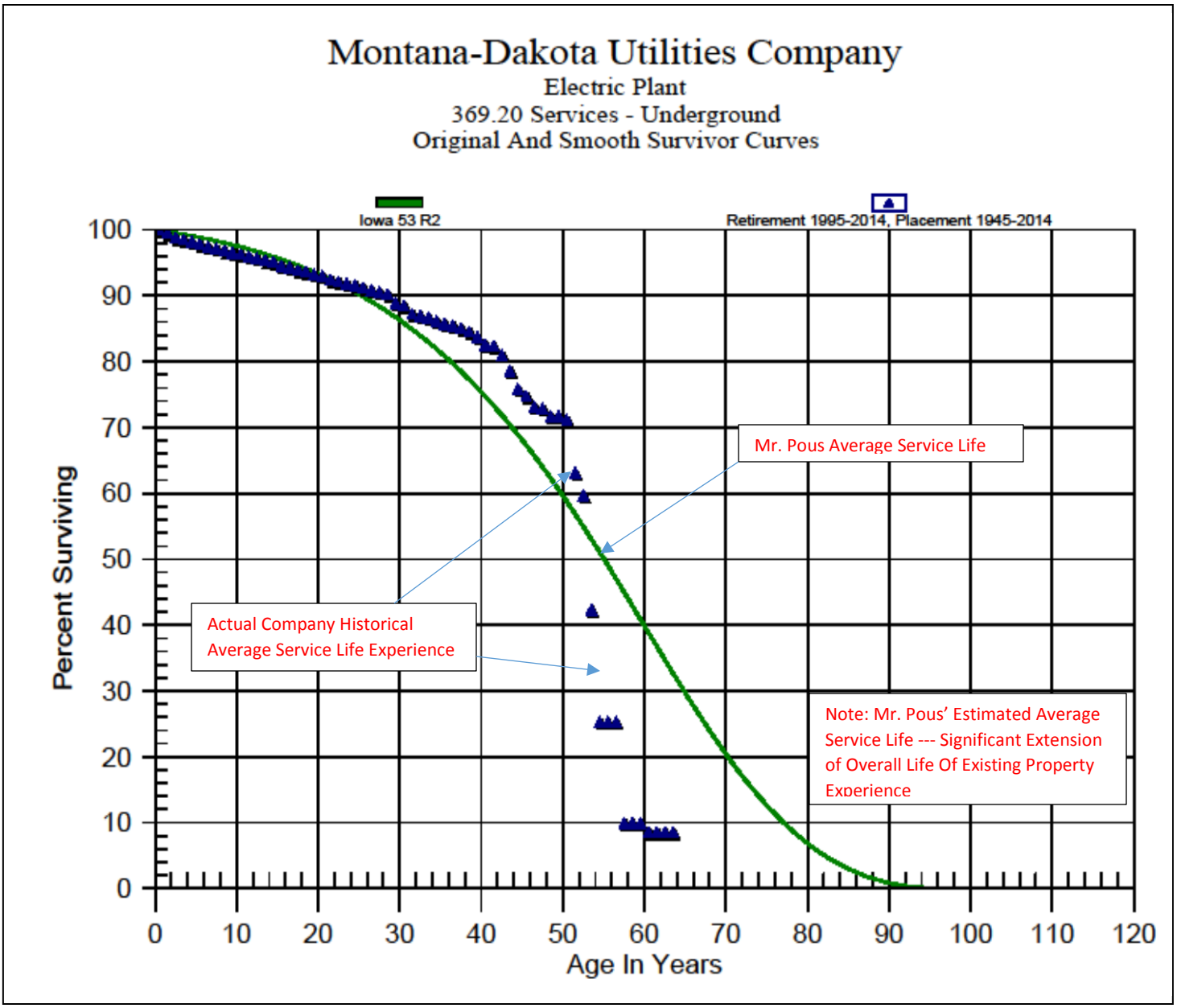
A. My discussion is as follows.

<u>Account 369.2-Underground Services</u>

Current Average Service Life:	30-R4
MDU Proposed Avg. Service Life:	45-R3
Mr. Pous Proposed Avg. Serv. Life:	53-R2


Montana-Dakota Utilities Company
Electric Plant
369.20 Services - Underground
Original And Smooth Survivor Curves
Iowa 45 R3
Retirement 1995-2014, Placement 1945-2014
Percent Surviving
100
90
80
70
60
50
40
30
20
10
0
0
10
20
30
40
50
60
70
80
90
100
110
120
Age In Years

1



The property investment within this account is related to underground customer services with the property being somewhat similar to Underground Distribution Cables but sized to carry lower voltage levels. Activity related to upgrades and ongoing changes of the property group are deemed to be normal and therefore future replacements are not anticipated to be materially different than occurred during recent years.

In analyzing the historical data the level of retirements as a percent of original cost and average age of retirements have remained, while varying somewhat from year to year, continuous and generally consistent over more recent periods suggesting that there has been no decline in activity suggested by Mr. Pous for the basis of his further extension of the longer average service life proposed in the Company depreciation study for this property group.

Mr. Pous has opined that future lives will be much longer than in prior years. The Company's estimated average service life already includes a measurable average service life increase—to which Mr. Pous, based simply upon generalizations, with no empirical evidence proposes and even longer service life. That being 8 years or 18 percent beyond the already 50% increase in life incorporated in the proposed depreciation study rates.

In the course of completing the depreciation study analysis and estimation for MDU's property group an Iowa 45-R3 life and curve as estimated by Mr. Robinson, which is an increase in the Average Service Life by 15 years or 50% over the current average service life. Furthermore, the current book depreciation reserve for the property group is at 42% of the required level of recovery amount---clearly not an indication of the current average service life being excessively short. In fact, if one were to look at a whole life average service life rate for a 45 life property the raw life rates would be 2.22% as opposed to the Company's proposed average remaining life (ARL) depreciation for the property group of 2.64% which indicates that the book depreciation reserve is lower than it should be. ARL depreciation rates give consideration to all factors, including the current book depreciation reserve in developing the proposed depreciation rates. When a book

depreciation reserve is lower than it should be the ARL depreciation rate is driven to a higher level to make up for the current under recovery level.

Conversely, if one were to adopt Mr. Pous' flawed average service life of 53 years the whole life depreciation rate would be a mere 1.53% percent rate. In fact Mr. Pous calculates and proposes an ARL depreciation rate of 1.35% for Underground Services, a total unacceptable level, especially in light of the current level of book depreciation reserve. Furthermore, in looking at the above plot of Mr. Pous' estimated 53 year average service life it can easily be see that that he is proposing a life that extends far beyond that which the Company has experienced to date.

Q14. PLEASE PROVIDE YOUR COMMENTS REGARDING MR. POUS' PROPOSAL FOR ACCOUNT 390-ELECTRIC.

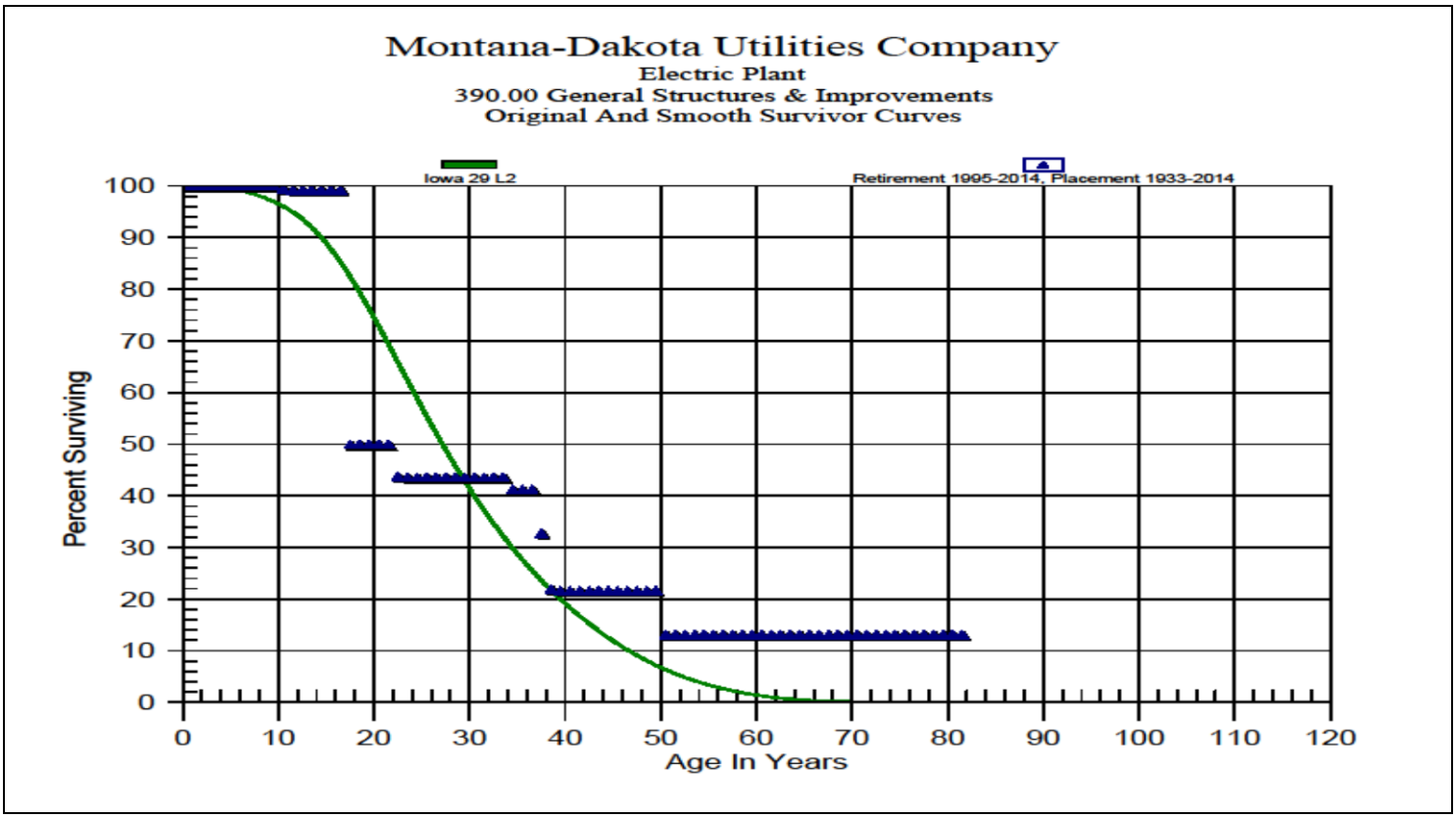
A. My discussion is as follows.

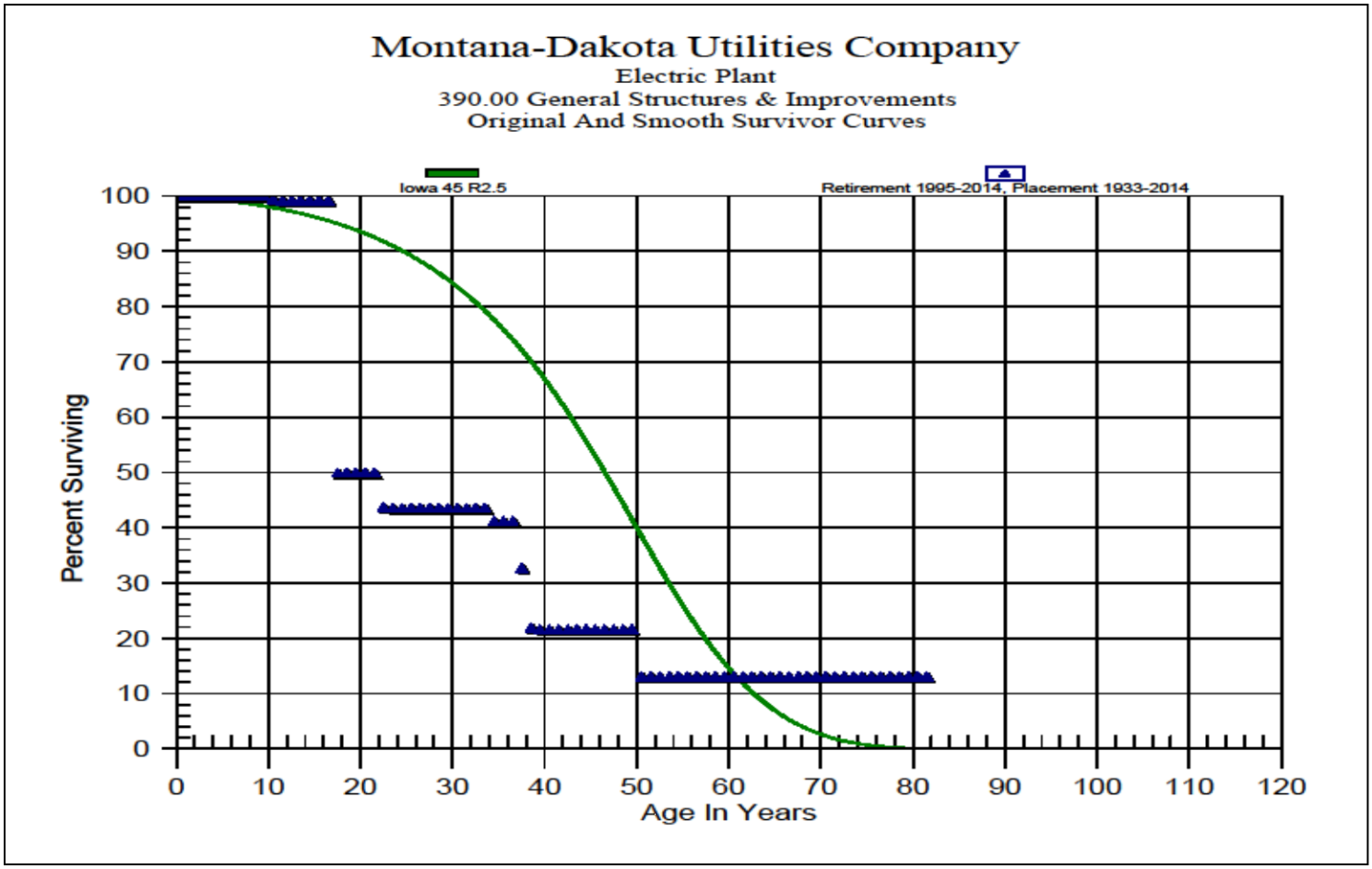
<u>Account 390-Strucutres & Imp-Electric Plant</u>

Current Average Service Life: 35-R2.5

MDU Proposed Avg. Service Life: 29-L2

Mr. Pous Proposed Avg. Serv. Life: 45-R2.5


Montana-Dakota Utilities Company
Electric Plant
390.00 General Structures & Improvements
Original And Smooth Survivor Curves
Iowa 29 L2
Retirement 1995-2014, Placement 1933-2014
Percent Surviving
Age In Years


Montana-Dakota Utilities Company
Electric Plant
390.00 General Structures & Improvements
Original And Smooth Survivor Curves
Iowa 45 R2.5
Retirement 1995-2014, Placement 1933-2014
Percent Surviving
Age In Years

1

The investment in this property group is quite limited, at $835,304, in comparison to the Company's overall $1.2 billion of depreciable investment. The only reason that it even warrants the following discussion is the fact that Mr. Pous referenced the account and highlighted it as a specific representation of the "supposed dramatic error in the life selected when analyzing the data" in the Mr. Robinson's average service life estimation process. Mr. Pous opines that a fifty year average service life would be more appropriate after he selectively adjusts the company actual data. He is states that a 39 year life is better fit of historical data—a statement that is simply false.

Notwithstanding that all the Company's historical data was included in the depreciation study and/or in in the depreciation databases and, a complete listing of the Company's CPR was provided in response to Mr. Pous' data request, he simply ignored the obvious facts surrounding this asset property group.

As initially indicated the investment in this property group is quite limited, at $835,304, in comparison to the Company's overall $1.2 billion of depreciable investment.

The largest investment currently within the property account totals approximately $165,000 with most others being significantly smaller with little overall value. Given the characteristics of each of the operating property locations, and the minor investments attributed to any one of the facilities, the Company can and likely will make changes in future years with little or minor thought of any impact. That is, the Company can make changes quickly as desired or required to accommodate each of the facilities use. To say that these minor/minimal properties have an average service life of 50 years with a maximum life of approximately 75

years or even an average service life of 45 years with a maximum of approximately 60 years (as proposed by Mr. Pous) is totally unreasonable and bordering on absurdity.

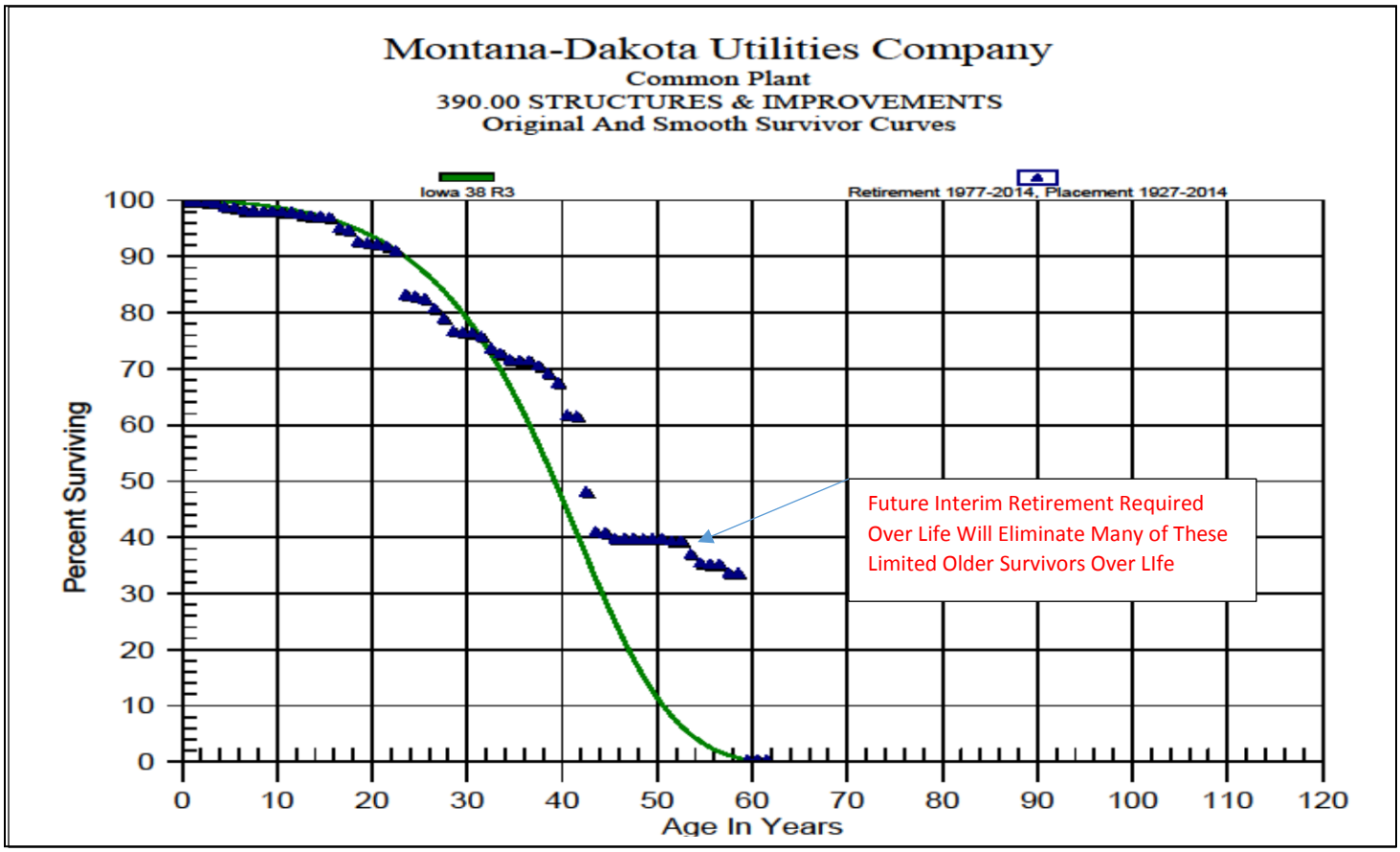
Conversely, the MDU proposed average service life of 29 years for this very minor asset property category more reasonably represents the life that can be anticipated.

Q15. PLEASE PROVIDE YOUR COMMENTS REGARDING MR. POUS' PROPOSAL FOR ACCOUNT 390-COMMON PLANT.

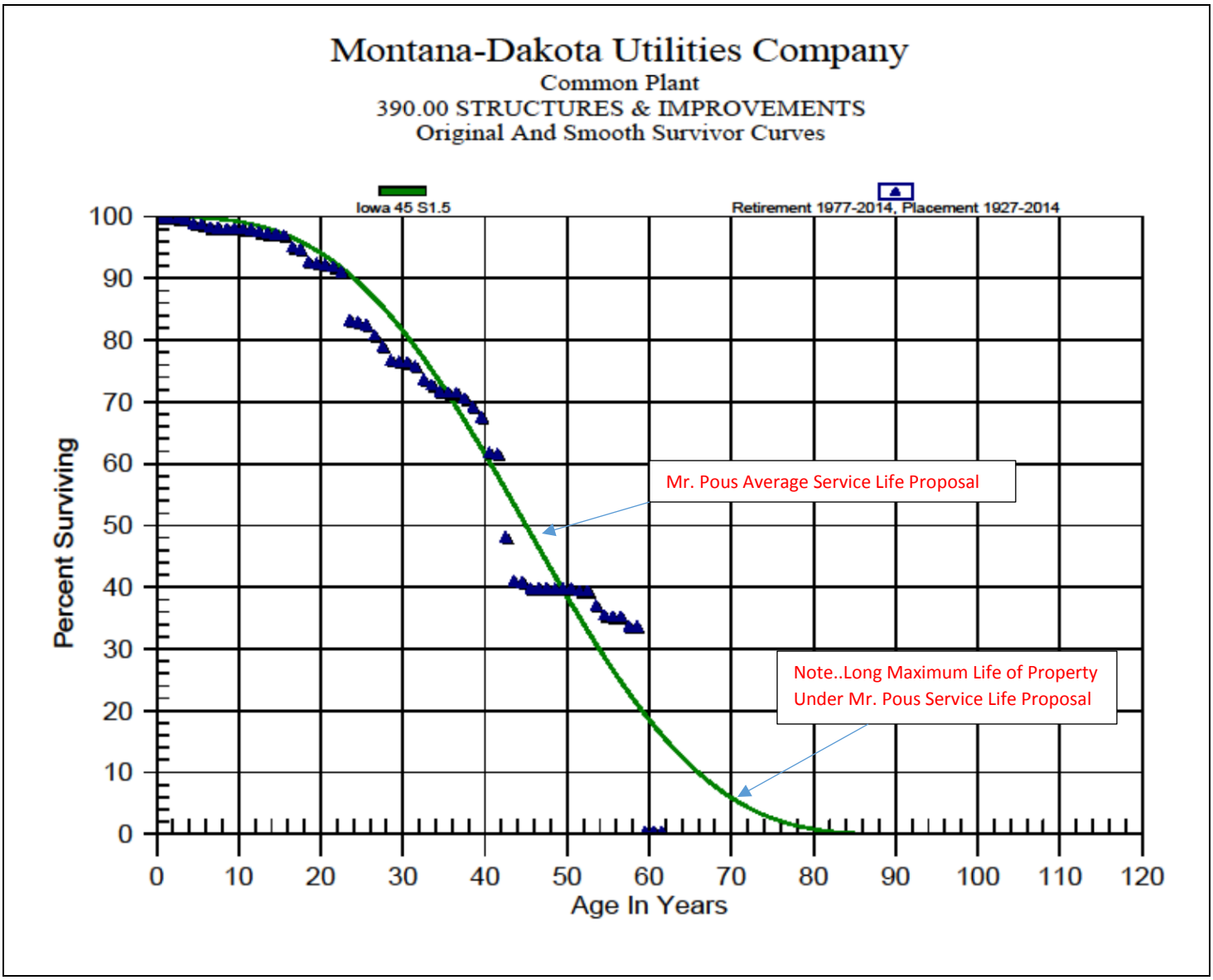
A. My discussion is as follows.

<u>Account 390-Structures & Imp-Common Plant</u>

Current Average Service Life:	35-R3
MDU Proposed Avg. Service Life:	38-R3
Mr. Pous Proposed Avg. Serv. Life:	45-S1.5


Montana-Dakota Utilities Company
Common Plant
390.00 STRUCTURES & IMPROVEMENTS
Original And Smooth Survivor Curves
Iowa 38 R3
Retirement 1977-2014, Placement 1927-2014
Percent Surviving
Age In Years
Future Interim Retirement Required Over Life Will Eliminate Many of These Limited Older Survivors Over LIfe

1



In his testimony Mr. Pous highlights that data was missing from the historical presentation within the depreciation report. In data request MCC-151, Mr. Pous did ask if there were any items of net salvage that were excluded as abnormal. Unfortunately, at the time, and in the process of responding to more than 125 depreciation data requests, there was an oversight in that in response to the request it was stated that no data was excluded as being atypical or abnormal, when in fact both the average service life retirement and net salvage data related to

abnormal transactions were excluded from the presented service life analysis and net salvage results.

Mr. Pous also requested and was provided with a complete copy of all service life and net salvage database details. The applicable retirements and corresponding net salvage activity was/is contained within the provided detailed data. Within the depreciation databases, the information in question is coded as category “7” information, which serves to exclude the information when processed through the AUS Consultants’ depreciation modules for service life and salvage analysis. In formatting the information for his software model, Mr. Pous would had to consider the coded data to operate within his system.

To repeat, the abnormal items in both the average service life analysis were excluded from the information presented in the depreciation study, with the result that the MDU proposed average service life was longer that would otherwise have been estimated and the net salvage was less positive (more negative) than would otherwise have been presented. With the included exclusions, from both life and salvage data, both analysis processes were in harmony.

In fitting and estimating average service life characteristic for the property group consideration was given to the fact that increased levels of interim retirement will occur from older vintages as the Company continues to utilize and maintain/upgrade the properties over their remaining lives. Hence, the estimated Iowa R3 survivor curve and 38 year life, as opposed the Mr. Pous recommend 45-S1.5 Iowa survivor curve which suggests far higher levels of retirements earlier in life and much longer end of live (in the range of 25 years longer than that with the

Company's estimated R3 curve), was selected as the appropriate life characteristic for the property group.

In addition to actuarial analysis of the Company's property group there is another general process that can be used to assess the life that can be anticipated to be achieved by various larger structures. Essentially a building is comprised of an overall superstructure that will provide service throughout the life of the facility plus numerous additional components related to build out, fit and finish/interiors, HVAC and other such items that would experience change outs over the life of the facility. Routinely fit and finish and appurtenant items are more specialized and relatively higher cost components (on a square foot basis) as opposed to more commodity type items such as foundations, steel framing, masonry, etc. It is estimated that the superstructure portion of a structure could be in the range of 50 to 60 percent of the cost of a building. At the most it is estimated the cost of the superstructure to be 2/3 of the building cost with the remaining 1/3 being relative to the components subject to interim replacement over the life of the building. Finishing a building with all the mechanical, electrical, interiors, HVAC, etc. is a labor intensive and costly process. Furthermore, these are all items that are subject to far short lives. The interiors of office type structures get changed out even more frequently. A reasonable range for the superstructure portion of an office building would be 60 years for 67 percent of the cost, and 20 years for the finish components at 33 percent of the cost. The cost of the replacement components at 20 and 40 year periods would be at higher cost due to the passage of time and overall increased cost. Furthermore, increased care is routinely required of construction crews when reworking an occupied facility resulting in

higher cost. An accompanying Exhibit No.___(EMR-5) summarizes the resulting composite life giving consideration to the discussed applicable inputs. The result is an implicit average service life of about 38 years. The 38 year average service life result is comparable to both the life indication for Account 390-Common Plant plus the general range of lives from industry survey results.

VI. GENERAL NET SALVAGE DISCUSSION

Q16. DO YOU HAVE A GENERAL STATEMENT ABOUT MR. POUS' POSITION ON NET SALVAGE?

A. Yes, Mr. Pous seeks to discredit the MDU salvage proposals by saying that the Company provides little support for it proposed depreciation values. (Page 71). Throughout his over 125 pages of testimony, Mr. Pous repeats over and over that there is a lack of data and support has not been provided for Mr. Robinson's depreciation proposals. I will not even attempt to address all of Mr. Pous' continuous attacks. I will seek to address several representative misleading and incorrect attacks.

Mr. Pous has continuously, throughout his entire testimony on net salvage, been critical of the level of detail data provided. In most of the references, he has referred to the study only providing the three most recent rolling band averages, an overall average, and the forecast net salvage. At best, these statements are apparently meant to mislead the reader of his testimony to think that the referenced items were the only information that was provided in the study report. This misleading "reference" is totally wrong and improper. The information that Mr. Pous referenced is contained as a quick reference summary in the Section 4 narrative of the depreciation study report. Counter to Mr. Pous' implication/inference, Section 8

of the electric depreciation study report and Section 7 of the Common Plant depreciation study report includes a full listing of all individual years' net salvage analysis along with 3 year rolling band analysis using the yearly listed net salvage data. Section 8 also contains the development the corresponding forecast net salvage for each of the Company's property groups. All available net salvage information from the company's books and records are displayed in tabulator form in Section 8 of the Electric and Section 7 of the Common Plant MDU depreciation study reports.

Furthermore, in addition to all the information contained in the depreciation study report, Mr. Pous requested and received all underlying depreciation databases, and related information as well as a complete CPR listing of all the plant in service activity that was available to Mr. Robinson in the performance of his depreciation study. To say that information was not provided is simply wrong.

On another topic, Mr. Pous states "Mr. Robinson claims that all depreciation witnesses and texts support his process is not only unsubstantiated, but it is incorrect." Mr. Pous states (page 73) "I have been in contested cases with every major and probably minor outside consultant… over the past 40 years, and I have not found anyone who performs net salvage analysis as does Mr. Robinson."

Mr. Pous is simply playing both semantics and loose and fast with the facts. The standard methodology to historically analyze yearly gross salvage and cost of removal is to relate the amounts to the corresponding original cost retirements occurring in the same year. It is also routine practice to complete three or five year rolling analysis band to levelize the year to year retirement and net salvage activity amounts. Also, shrinking bands may be performed on the net salvage data base.

This is exactly what is contained within the net salvage analysis sections of the depreciation study reports. (Section 8-Electric and Section 7-Common Plant). In addition to this presentation the net salvage sections also include the presentation of the net salvage forecast.

Mr. Pous is constantly berating any and all consultants and/or other depreciation study preparers for not providing sufficient details and/or supporting data for their net salvage estimates. Mr. Pous' criticism/semantics "I have not found anyone who perform net salvage as does Mr. Robinson" is likely related to the additional forecast net salvage data provided at the end of each property groups' standard net salvage presentation (Yearly and 3-year Rolling Band Analysis of Gross Salvage, Cost of Removal, and Net Salvage as a percentage of Original Cost Retirements). (See NARUC page 18 and Fitch and Wolf pgs. 261-271 for discussion about the net salvage analysis array) Mr. Pous, notwithstanding his continually demands for additional information simply objects to the inclusion of the forecast analysis as it provides additional insight into the level of future net salvage (percentage) that can be anticipated to occur when property reaches the end of its life.

Apparently, Mr. Pous fails to recall, in saying that "I have not found anyone who performs net salvage analysis as does Mr. Robinson" that he (Mr. Pous) was involved in one or more studies with the type of data that he apparently is criticizing. The genesis of Mr. Robinson's forecast net salvage presentation was in working with a Canadian client (ATCO Gas) likely some 25 years or more ago. Mr. Pous was a participant in that rate proceeding. Mr. Robinson has simply perpetuated the net salvage forecast presentation in all the subsequent depreciation studies that he

performs inasmuch as it demonstrates several factors that impact long term net salvage.

First, Company retirements that generate the historically experienced net salvage results as of a study date have occurred at ages far less than the average service life of the property group being studied. As such, due to the younger aged retirements a lower level of cost of removal and higher level of gross salvage would have occurred within the historical experience. This is an age sensitivity factor of net salvage (gross salvage and cost of removal) that Mr. Pous vehemently rejects notwithstanding the treatise/discussion related to aged sensitivity of net salvage is contained in the Wolf and Fitch "Depreciation System" textbook that Mr. Pous quotes on more than one occasion as an authoritative depreciation reference. For example, first on page 261, the text book discusses the relationship of net salvage to the original cost of retirements and the development of a salvage ratio (SR-Gross Salvage and Cost of Removal). In additional it discusses the use of 3-year rolling bands or moving averages to better understand the data. Next, related to age sensitivity of net salvage, the text discusses the increasing level of negative net salvage overtime as the age of property retirements increase. The Table (14.3) on page 271 of the text summarizes the increasing levels of SR's as the property retirements continue to become older in age.

Another example of Mr. Pous' misleading testimony statements is on page 88 of his testimony. Mr. Pous includes three quotes (for which he did not provide a page reference) from the NARUC Depreciation Practices Manual seeking to support his statement and decision to essentially ignore Company historical net salvage data.

On page 87 of his testimony Mr. Pous ask himself the question: **"Do your review and analyses of net salvage rely on the company's historical data to the same extent as your life analysis did? <u>No, and they should not</u>. Life analysis relies on actuarial analyses, a powerful analytical tool and a much longer, robust, and meaningful database than is relied upon for net salvage purposes.").**

First, with regard to Mr. Pous' statement in which to a large degree, he discounts or ignores the historical net salvage data, it is simply another circumstance of demanding detailed data, and then when it is provided, ignoring the information, and making his own generalizations about what the future net salvage will be, contrary to actual Company facts. Mr. Pous makes the statement that the net salvage database in less inclusive than the service life database--his statement is false. MDU's historical service life database generally includes actuarial activity from 1995 through 2014 (other property accounts have actuarial data starting during later years). By comparison, the Company's historical net salvage database for most property groups, spans the years 1968 to 2014—a period some 27 years longer than the range of years for which actuarial life analysis data is available. Accordingly, the Company's net salvage database is far more robust than its service life database.

With regard to the NARUC depreciation manual, Mr. Pous' first (page 18) quote is:

> "One of the practical difficulties of estimating net salvage is that report salvage is a mixture of salvage of items retired and reused internally,

> salvage on items sold externally as functional equipment, and salvage on items junked and sold and scrap…"

To view the statement in the context of which it was written, the additional sentence from the NARUC manual text needs to be considered:

> "Because of the likelihood of reuse is greater for items that are retired at early ages, the historical salvage is usually higher than the future salvage to be realized when the account begins to decline and there is little opportunity for reuse. <u>Therefore, under these circumstances, book salvage may overstate the average salvage realized over the entire life of the account."</u>

Even more important is the fact that gross salvage a far more minor factor than cost of retirement/removal for the overwhelming majority of a Company's operating property group. Gross Salvage is for a large part a somewhat limited item. By comparison, Cost of Retirement/Removal essentially is the entire issue in this rate case and typically is the issue in the majority of all rate cases.

Mr. Pous' second (misleading) NARUC (page 19) quote is:

> "The sensitivity of salvage and cost of retirement to the age of the property retired is also troublesome…"

Again, the entire quote that should have been included:

> "The sensitivity of salvage and cost of retirement to the age of the property retired is also troublesome. Due to inflation and other factors, there is a tendency for cost of retirement, typically labor, to increase more rapidly than material prices. (Only <u>limited amounts</u> of material are sold for scrape or returned to stores for reuse). In an

> increase number of instances, the average net salvage is estimated to be a large negative number when expressed as a percentage of original cost, sometimes in excess of negative 100%." <u>This may look unrealistic but is appropriate and necessary so that the required cost allocation occurs."</u>

(Expressing negative net salvage as a percentage of the original cost retirement that generated the negative net salvage is the standard depreciation study process).

Clearly, these are the facts as they exist in the real world, with regard to the end of life cost for property being used in the provision of service to customers, and which should be recovered over the life of the property.

The third (page 19-) NAURC quote that Mr. Pous misrepresented as applicable to the MDU depreciation study is:

> "Nevertheless, a careful analysis of retirements should be made to determine of such large negative salvage value are due to unusual circumstances. An example is the retirement of old cast iron gas mains in congested metropolitan areas. Due to urban renewal, a utility may have significant amount of such activity for a few years. Since most of the investment in this account may now be plastic main in rural or suburban areas when access is easier, the removal of old cast iron mains at today's cost may not be representative of the cost that can be expected for plastic mains."

This third quote has little or nothing to do with MDU's Electric property give that the property groups being studied are electric and not gas, and MDU operates

in smaller communities and rural areas as opposed to congested large metropolitan areas. Furthermore, MDU has not and is not doing large urban renewal projects.

Conversely, on at least one, if not more occasions, Mr. Pous has raised the issue of economies of scale in the retirement/replacement of property. This discussion is a significantly misguided/misleading attempt at seeking to reduce an estimate of future negative net salvage that has been occurring at increasing higher net negative amounts over a long period of years. MDU has not, over the long period of years, and will not to any significant degree experience any high levels of economies of scale. Replacing operating property is not an assembly line process. It is a unique effort that is handled on a unit by unit of property. While there may be some circumstances where multiple items of property are adjacent to one another are removed, many of the retirements/removals are completed on a limited quantity basis at different parts of the operating system.

Looking to another issue, Pous states that Mr. Robinson used an inflation factor and forecast negative net salvage in estimating the future net salvage for the proposed annual depreciation rates. This is a totally false and misleading statement that was made by Mr. Pous on many locations throughout his testimony. Given the number of times that Mr. Pous repeated the statement, it obviously was intentional with the goal of influencing the Commission to a false understanding of the true facts.

As specifically stated in the MDU Response to MCC Data Request MCC-167, the future net salvage estimates were not based upon the forecast net salvage analysis, but were based upon a review of the Company's historical experience

over it historical period of operation. The range of years' data was reviewed and considered.

That is, within the MDU-Electric depreciation study there was no net salvage included within the development of the proposed depreciation rates for the Steam and Other Production functions. Notwithstanding the occurrence of actual (experienced) interim negative net salvage and the further expectation of future end of life terminal negative net salvage (decommissioning cost), Company management requested that no such cost be included in the development of the proposed depreciation rates related to its generating facilities. Company management will address the recovery of those components of cost through a separate regulatory request.

Likewise, while shown in the net salvage analysis, Sec 8 of the Electric study and Section 7 of the Common Plant study, **the analysis of net future inflation has not been specifically included or requested within the net salvage estimates.** The information is included within the studies to identify the levels of ultimate future net salvage percents that are anticipated to be experienced throughout the remaining life of the property groups. This circumstance will occur inasmuch as the historical retirements that produced the level of net salvage experienced to date occurred in conjunction with retirements of property that was of far younger ages than the estimated average service life of each of the applicable studied property groups. Accordingly, future retirements will need to occur at far older ages to achieve the estimated average service life, therefore, far higher levels of negative net salvage, much of which is related to labor cost, will result with the occurrence of the older aged retirement amounts. Accordingly, the experienced historical net

salvage likely significantly understates the overall net salvage that will be experienced as the property groups continue to age.

The net salvage forecast analysis is simply an additional tool used to provide information about the level of net salvage anticipated to occur relative to the current plant in service through the end of its life. Lastly, the historical component of net salvage is what has transpired for the smaller portion of the Company's property that has been retired to date. As noted, such retirements have routinely occurred at ages far younger than the average service of the various property groups.

The estimated future net salvage percent for each property group, while it gives consideration to the overall average, recent experience, and forecast analysis, most weight is given to the more recent years three-year rolling averages. The process is one of gradualism towards more future looking calculations which is more representative of the future net salvage, as opposed to overall historical averages, that can be anticipated during future periods and at the end of life of the property group. The estimation of future net salvage is not a mathematical or averaging process but one of interpretation of the range of recent gross salvage, cost of removal/retirement, and net salvage and how such levels can more reasonable be anticipated to occurring during coming years.

Net salvage experienced from year to year has never been and never will be linear. As with any raw data there will always be variations, sometimes rather significant variations. The goal and task of estimating future net salvage is to estimate a level of net salvage that is in a reasonable range of which is expected to occur within the foreseeable future, knowing full well that in the longer time period it is highly likely that the level of future negative net salvage (the overwhelming

majority of utility property accounts experience negative net salvage as opposed to any material positive net salvage) will occur at levels far more significant than presently occurring.

VII. POWER PLAN IMPLEMENTATION

Q17. WHAT ARE YOUR COMMENTS REGARDING THE COMPANY'S IMPLEMENTATION OF ITS POWERPLAN DATA RECORD SYSTEM AND ANY IMPACT ON THE NET SALVAGE ESTIMATES INCLUDED IN THE MDU DEPRECIATION STUDY REPORT?

A. MDU did implement the use of the PowerPlan data record system during 2013. While using the J D Edwards (JDE) record system, prior to PowerPlan implementation, cost of removal had to be charged to a separate retirement account from the addition on replacement projects. It is believed that in conjunction with the use of JDE, in various cases the cost of removal incorrectly ended up as an addition, as opposed to cost of removal where it belonged, because the Field staff did not want to enter two accounts. PowerPlan automatically charges the retirement account through the use of work order percentage allocations assigned by the Field Project managers through the derivation process. Accordingly, the Field are then no longer required to code every charge to addition or retirement. Such simplification of field reporting was a selling point of PowerPlan, and it is a standard function used by most utility companies using the PowerPlan system.

The higher cost of removal percentage in 2013/2014 is due to the fact that as a result of the PowerPlan implementation tasks, the Company was somewhat behind on processing original cost of retirements. During the 2013/2014 system

process implementation phase, the Company could not use the automated PowerPlan work order system to process original cost of retirements at the same time as the recording of cost of removal. During the initial time period, the cost of removal got recorded to the book depreciation reserve when the addition side of a replacement project was unitized. The CPR retirements were subsequently recorded and mostly caught up to date during 2014. Accordingly, when viewing the cost of removal information during 2013 or 2014, a combined/aggregate net salvage for 2013/2014, as a cost of removal percentage of original cost retirements, is more representative of what is anticipated on a going forward basis. Due to the continual effort to totally eliminate the processing lag experienced with the roll out of the PowerPlan record system, there may be some residual 2014 cost of removal that may related to 2015 retirements.

In the completion of the net salvage analysis, in the preparation of the MDU depreciation study, any “spikes” contained within the net salvage data were substantial discounted in estimating the future negative net salvage percent for the various property accounts. This can be easily seen in viewing the various net salvage trend line exhibits included with this testimony. Even though the stated criteria for estimating future net salvage based upon the range of net salvage data with greater weight in more recent experience, it can be seen that the estimates of net salvage are not merely a quantitative trend line number or average—it is an interpretation of the range of the net salvage data. It can be readily seen that the estimates of negative net salvage generally trail even more recent experience, as opposed to using any forecast data as continuously and incorrectly referenced by Mr. Pous in his flawed testimony and net salvage estimates.

VIII. NET SALVAGE ISSUES OPINED BY MR. POUS

Q18. WHAT ARE SOME OF THE NET SALVAGE ISSUES FOCUSED ON BY MR. POUS IN HIS TESTIMONY?

A. I will now address the specific property group's for which Mr. Pous suggested alternative negative net salvage percents. For the most part, Mr. Pous has advanced unsupported generalization or unreasonable or irrational hypothesis to lower the negative net salvage and resulting annual depreciation rates. Throughout his testimony, Mr. Pous has stated and/or implied that the Company's net salvage data was either not properly recorded and/or that in near term periods that the Company will experience net salvage that is materially different from the Company's recent experience or trend of net salvage. Mr. Pous premise that there are material changes that will occur to the recent level of current net salvage is seriously flawed. He has not provide any empirical facts to support his unsupported generalized statements. Accordingly, the Company's provided information along with the accompanying additional rebuttal exhibits are the most compelling data available and demonstrates that the proposed net salvage factors set forth in the MDU Depreciation studies are conservative, reasonable, and rational net salvage levels to be included in the proposed depreciation rates.

While in the process of completing the salvage estimation process specific trend-line analysis/charts were not contained in the report presentation, however, as clearing stated in testimony and data responses, a visual review of the tabular data was a considered in the estimation of negative net salvage percent for each property group. Mr. Pous, had he desired and truly wanted the specific charts, and felt that he needed those graphical inputs/presentations, he could have prepared

such analysis/charts, but he chose not to and simply used subjective irrational statements to supposedly support his flawed estimates.

Net Salvage Trends

To highlight the trends that have been occurring within Company's historical experience, I am presenting graphical charts in this testimony and as **(EMR Exhibit 3)** of MDU's yearly historical net salvage percentages that were provided in the depreciation study in tabular form. Along with the charts of historical experience included are linear trend lines of net salvage trends for each of the property groups, for which Mr. Pous proposed a reduction in the level of proposed net salvage from that included in the ultimately developed annual depreciation rates for MDU's property groups.

To counter any criticism that the net salvage trend-lines for the property groups being discussed are influenced by some higher than normal levels of negative net salvage percents for years 2013/2014 and other selected years, a second set of charts **(EMR Exhibit 4)** is being presented, as well. That is, for any of the years that experienced negative net salvage percent spikes, for one or more years in the linear analysis process, the negative net salvage percent for that year was subjectively capped at a lower percentage range compared to that which was experienced during an earlier period. Even with this reduction of actual Company negative net salvage experience, the resulting linear trends of the percentage level of negative net salvage percents are still above and, on various occasions, significantly greater that the negative net salvage percent estimated for the proposed MDU depreciation rates.

On several occasions Mr. Pous seeks to substitute or insert the results of other levels of negative net salvage into the currently study results. Each company is unique in that it has its own operating characteristics and depreciation rates are developed on that specific data of the operating company. That is, there are specific reasons why depreciation factors vary and are not the same from company to company. First, the study referenced on page 107 of Mr. Pous' testimony and related footnote is related to a study prepared in the range of 5-10 years ago.

For example, in electric depreciation studies prepared for other operating companies such as Consolidated Edison of NY, Delmarva, Progress-NC, and PSEG during the period 2003 to 2008 have included Account 365 negative net salvage percent of -60%, -100%, -60%, and -60%, respectively. Again these studies are related to the periods similar to the current as proposed MDU depreciation study rates. The point being that depreciation parameters range from company to company and different service territories as well as time periods.

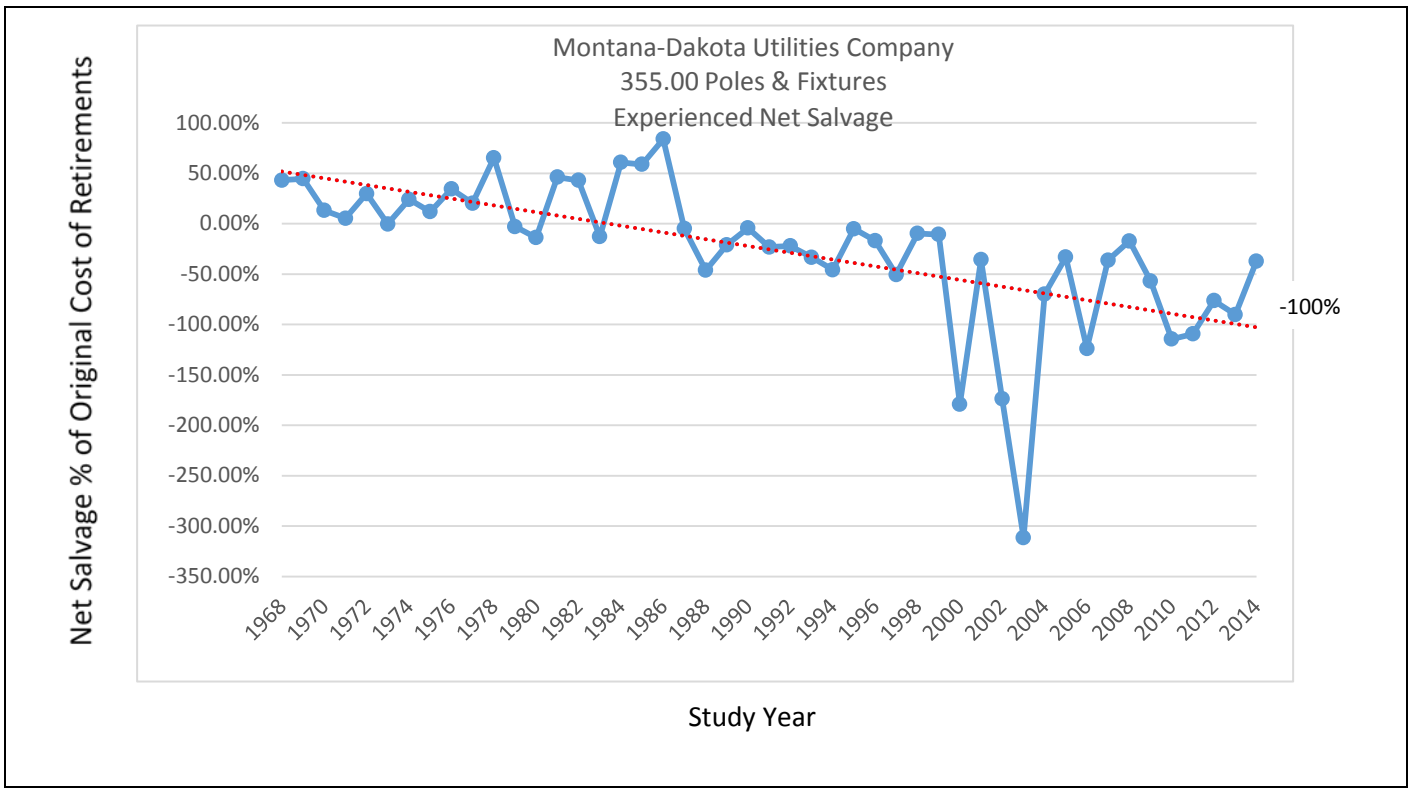
IX. SPECIFIC NET SALVAGE RESPONSES

Q19. PLEASE PROVIDE YOUR COMMENTS REGARDING MR. POUS' NET SALVAGE PROPOSAL FOR ACCOUNT 355.

A. My discussion is as follows.

Account 355-Poles & Fixtures

Current Negative Net Salvage:	-35%
Proposed Negative Net Salvage	-50%
Mr. Pous Proposed Neg. Net Salv.	-35%
Linear Trended Neg. Net Salv.	-100%
Adjd Linear Trended Neg. Net Salv.	-90%



(See EMR Exhibit 3 and 4-For Complete Plot Displays)

With regard to cost of retirement/removal Mr. Pous has made subjective adjustments, based upon his statements that the Company reported an unusual disproportionate level of emergency related expense, a disproportionate level of overtime expense and high level of contractor activity with regard to this property group. While the Company may have utilized contractors to remove facilities such activity would have been in lieu of the use of Company labor to perform the same task and would not have any material impact on the ultimate level of cost removal charges. In fact, companies often use contractors to perform construction work for several reasons that may include but not be limited to the desire not to use higher cost overtime for Company employees. Also, often times the use of contractor labor may be less expensive that the cost of Company labor with benefits.

As for Mr. Pous' statement of the disproportionate level of emergency related expense and overtime expense is questionable. Normally, the Company would be performing emergency and overtime expenses related to providing service to customers and not the removal of property being retired or no longer in service. While there may be some circumstance where such events occur, it would be more of an exception as opposed to normal operating procedure. The Company routinely would return, after the fact, to remove out of service plant once new plant was in place or service restored.

Mr. Pous, counter to his continual criticism of lack of specific information, made nothing but broad generalization, having provided no empirical calculations of the specific calculations of charges that should not have been charged to cost of removal.

Last, but far from least, even if Mr. Pous would have or could have developed a specific exhibit of excluded cost of removal/retirement, there is such a significant variance between the Linear Trended negative net salvage level of -90 to -100% and the conservative -50% negative net salvage estimated in the MDU depreciation report that the Company proposed level is clearly justified and supported.

Q20. PLEASE PROVIDE YOUR COMMENTS REGARDING MR. POUS' NET SALVAGE PROPOSAL FOR ACCOUNT 364.

A. My discussion is as follows.

<u>Account 364-Poles, Towers & Fixtures</u>

Current Negative Net Salvage: -70%

Proposed Negative Net Salvage -75%

Mr. Pous Proposed Neg. Net Salv. -70%

Linear Trended Neg. Net Salv. -125%

Adjd Linear Trended Neg. Net Salv. -115%

Mr. Pous again starts off with this continual incorrect statement that the Mr. Robinson's estimate of net salvage includes a 2.75% inflation rate when he has been told several times in the current case as well as during various other cases (within this jurisdiction as well as other jurisdictions) that I have prepared depreciation studies, that future inflation is not included in the net salvage estimate. Mr. Pous' continual statements are incorrect and misleading. Mr. Pous apparently does not like the provision of any information that is counter to his flawed representation/estimate of future net salvage.

Mr. Pous again repeats his statements from Account 355 about disproportionate level of emergency related expense, a disproportionate level of overtime expense and high level of contractor activity relative to this property group as a basis for his subjective theoretical adjustment and flawed estimate of net salvage.

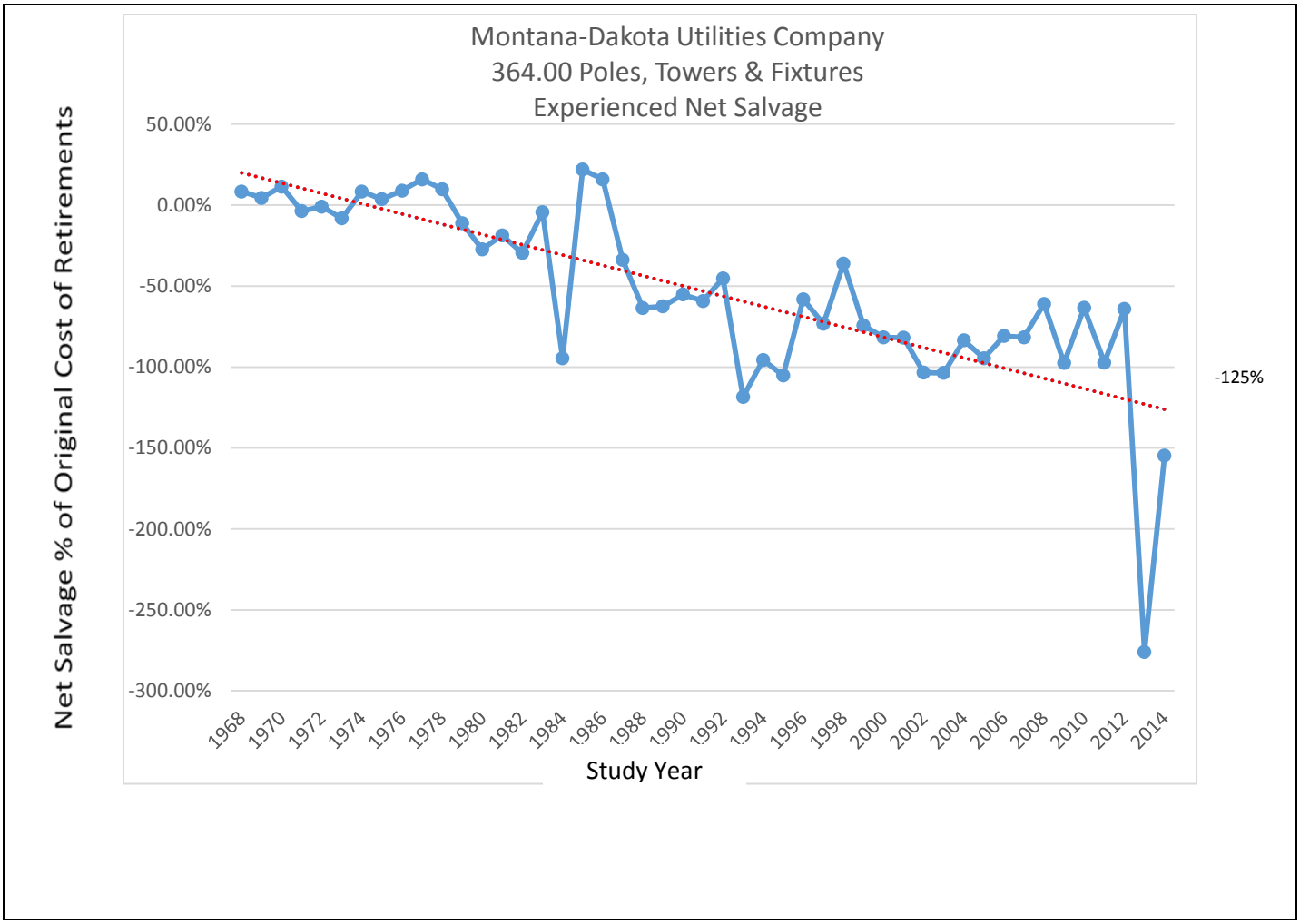
Mr. Pous, counter to his continual criticism of lack of specific information in the MDU depreciation study, made nothing but broad generalization, having provided no empirical calculations of the specific calculations of charges that he (Mr. Pous) indicates should not have been charged to cost of removal.

Mr. Pous also raises the argument about time synchronization of net salvage—that any out of sync retirements versus salvage data will significantly skew or improperly impact the resulting net salvage estimate. Notwithstanding Mr. Pous' inference to the contrary, that is one of several benefits of salvage rolling

band analysis (three year or otherwise) are completed. Historically, it has not been uncommon for companies to potentially record retirements near the end of one accounting period with work order closings, and then to physically complete the actual retirement or removal work in next accounting period and correspondingly record the cost of removal or gross salvage during the following time period. By completing rolling band analysis the activities both get levelized over the period of years plus both activities get collected into the same time period. **(Note-The depreciation text book Depreciation Systems by Fitch and Wolf represented on various occasions by Mr. Pous as an authoritative depreciation source discusses the use of salvage rolling band analysis on page 161).**

Mr. Pous also raises the issue that the Company implemented the use of Power Plan, a new property record system for the company, and speculates that the implementation and resulting data was the specific information used to estimate the proposed changes to the future net salvage percents. Mr. Pous simply speculates that was the cause without investigating the data—from which can easily be seen that significant weight <u>was not</u> given to the higher levels of 2013/2014 negative net salvage percents. He simply criticized the Company and Mr. Robinson for failing to volunteer the implementation the Power Plan system—Mr. Pous simply did not check but made a flawed assumption and then blamed his error on the "supposed lack of data" that was in clear sight. The Company has and continues over time to change/update record systems routinely, as required, to operate its business. (See earlier discussion about the Company's implementation of the PowerPlan record system and its impact on underlying data during the 2013/2014 time period).

It is to be noted and should be obvious in reviewing the MDU proposed negative net salvage percent for Account 364 that in the process of estimating the future net salvage percent for Account 364, the occurrence of the high level of negative net salvage during 2013 and 2014 while it was viewed, and considered, it was significantly discounted in estimating the -75 percent net salvage for the property group.



(See EMR Exhibit 3 and 4 -For Complete Plot Displays)

Q21. PLEASE PROVIDE YOUR COMMENTS REGARDING MR. POUS' NET SALVAGE PROPOSAL FOR ACCOUNT 365.

A. My discussion is as follows.

Account 365-Overhead Conductor & Devices

Current Negative Net Salvage:	-70%
Proposed Negative Net Salvage	-85%
Mr. Pous Proposed Neg. Net Salv.	-70%
Linear Trended Neg. Net Salv.	-125%
Adjd Linear Trended Neg. Net Salv.	-110%

Mr. Pous uses much of the same repetitive arguments, from the prior property groups, as to why he is proposing a retention of the current level of negative net salvage.

That is, Mr. Pous also raises the argument about time synchronization of net salvage—that any out of sync retirements versus salvage data will significantly skew or improperly impact the resulting net salvage estimate. Notwithstanding Mr. Pous' inference to the contrary, that is one of several benefits of salvage rolling band analysis (three year or otherwise) are completed. Historically, it was not uncommon for companies to potentially record retirements near the end of one accounting period with work order closings, and then to physically complete the actual retirement or removal work in next accounting period and correspondingly record the cost of removal or gross salvage. By completing rolling band analysis the activity both gets levelized over the period of years plus both activities get collected into the same time period. **(Note-The depreciation text book Depreciation Systems by Fitch and Wolf represented on various occasions by Mr. Pous as an authoritative depreciation source discusses the use of salvage rolling band analysis on page 161).**

Within this property group, Mr. Pous again raises the issue that the Company implemented the use of PowerPlan, a new property record system for the company, and speculates that the implementation and resulting data was the specific information used to estimate the proposed changes to the future net salvage percents. Mr. Pous simply speculates that was the cause without investigating the data—from which can easily be seen that significant weight <u>was not</u> given to the higher levels of 2013/2014 negative net salvage percents. He simply criticized the Company and Mr. Robinson for failing to volunteer the implementation the Power Plan system—Mr. Pous simply did not check but made a flawed assumption and then blamed his error on the "supposed lack of data" that was in clear sight. The Company has and continues over time to change/update record systems routinely, as required, to operate its business. (See earlier discussion about the Company's implementation of the PowerPlan record system and its impact on underlying data during the 2013/2014 time period).

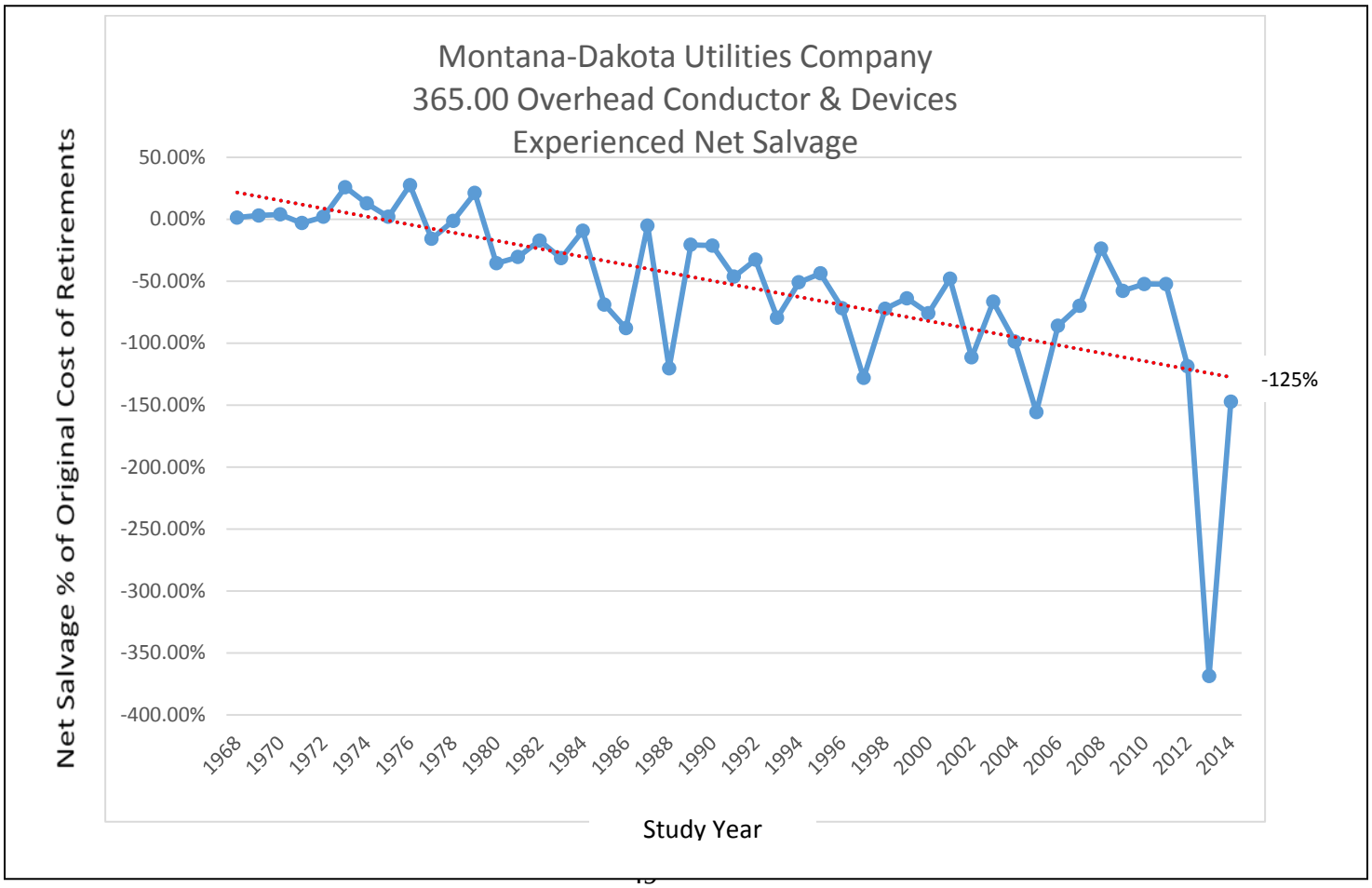
It is to be noted and should be obvious in reviewing the MDU proposed negative net salvage percent for Account 365 that in the process of estimating the future net salvage percent for Account 365, the occurrence of the high level of negative net salvage during 2013 and 2014 while it was viewed, and considered, it was significantly discounted in estimating the -85 percent net salvage for the property group.

On several occasions Mr. Pous seeks to substitute or insert the results of other levels of negative net salvage into the currently study results. Each company is unique in that it has its own operating characteristics and depreciation rates are developed on that specific data of the operating company. That is there are specific

reason why depreciation factors vary and are not the same from company to company. First, the study referenced on page 107 of Mr. Pous' testimony and related footnote is related to a study prepared in the range of 5-10 years ago.

For example, in electric depreciation studies prepared for other operating companies such as Consolidated Edison of NY, Delmarva, Progress-NC, and PSEG during the period 2003 to 2008 have included Account 365 negative net salvage percent of -60%, -100%, -60%, and -60%, respectively. Again these studies are related to the periods similar to the current as proposed MDU depreciation study rates.

The point being that depreciation parameters range over from company to company and different service territories as well as time periods.



(See EMR Exhibit 3 and 4 -For Complete Plot Displays)

Q22. PLEASE PROVIDE YOUR COMMENTS REGARDING MR. POUS' NET SALVAGE PROPOSAL FOR ACCOUNT 367.

A. My discussion is as follows.

<u>Account 367-Underground Conductor & Devices</u>

Current Negative Net Salvage:	-15%
Proposed Negative Net Salvage	-25%
Mr. Pous Proposed Neg. Net Salv.	-15%
Linear Trended Neg. Net Salv.	-35%
Adjd Linear Trended Neg. Net Salv.	-35%

Mr. Pous uses much of the same repetitive arguments, from the prior property groups, as to why he is proposing a retention of the current level of negative net salvage.

Mr. Pous continues to play the "inflation is included in the net salvage card" even though he is, or should be well aware that any specific inflation adjustment is not included in the negative net salvage estimate(s).

Mr. Pous raises the argument about time synchronization of net salvage—that any out of sync retirements versus salvage data will significantly skew or improperly impact the resulting net salvage estimate. Notwithstanding Mr. Pous' inference to the contrary, that is one of several benefits of salvage rolling band analysis (three year or otherwise) are completed. Historically, it was not uncommon for companies to potentially record retirements near the end of one accounting period with work order closings, and then to physically complete the actual

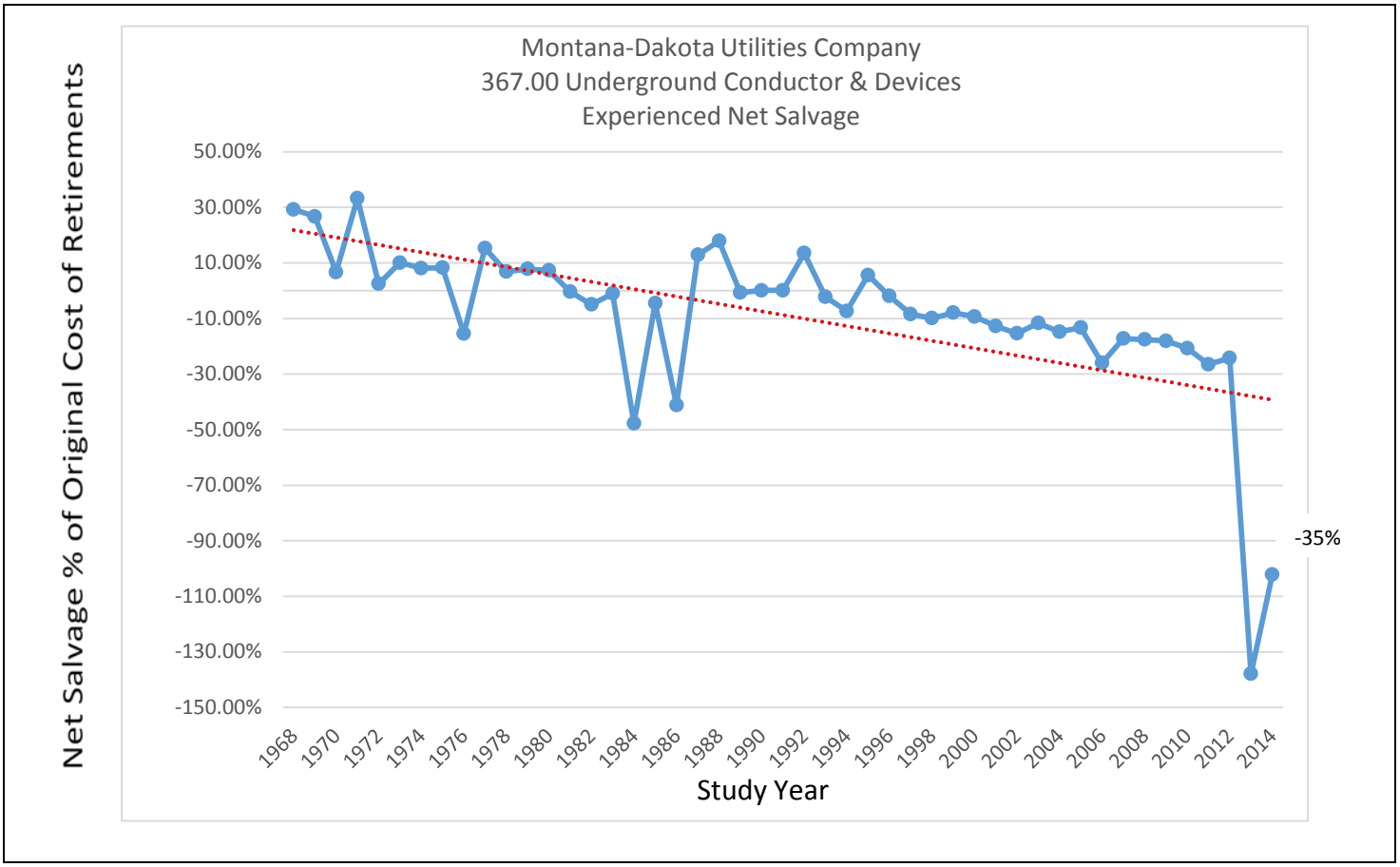
retirement or removal work in next accounting period and correspondingly record the cost of removal or gross salvage. By completing rolling band analysis the activity both gets levelized over the period of years plus both activities get collected into the same time period. **(Note-The depreciation text book Depreciation Systems by Fitch and Wolf represented on various occasions by Mr. Pous as an authoritative depreciation source discusses the use of salvage rolling band analysis on page 161).**

Within this property group, Mr. Pous again raises the issue that the Company implemented the use of PowerPlan, a new property record system for the company, and speculates that the implementation and resulting data was the specific information used to estimate the proposed changes to the future net salvage percents. Mr. Pous simply speculates that was the cause without investigating the data—from which can easily be seen that significant weight <u>was not</u> given to the higher levels of 2013/2014 negative net salvage percents. He simply criticized the Company and Mr. Robinson for failing to volunteer the implementation the Power Plan system—Mr. Pous simply did not check but made a flawed assumption and then blamed his error on the "supposed lack of data" that was in clear sight. The Company has and continues over time to change/update record systems routinely, as required, to operate its business. (See earlier discussion about the Company's implementation of the PowerPlan record system and its impact on underlying data during the 2013/2014 time period).

Another area that Mr. Pous discusses in support of his incorrect/flawed proposed negative net salvage is the common misconception and argument that the property group is abandoned in place and thus will not experience any

measurable levels of cost of retirement. This circumstance simply is not true. There always are end of life disconnection costs that are related to property placed in service years earlier. Mr. Pous highlights the fact that 2014 did not experience a level of gross salvage while other earlier years did. The fact that Gross Salvage, while not significant, have occurred indicates that not all properties are being abandoned in place, and will contribute to the increasing levels of cost of removal over time.

It is to be noted and should be obvious in reviewing the MDU proposed negative net salvage percent for Account 367 that in the process of estimating the future net salvage percent for Account 365, the occurrence of the high level of negative net salvage during 2013 and 2014 while it was viewed, and considered, it was significantly discounted in estimating the -25 percent net salvage for the



property group.

Mr. Pous' net salvage review and recommendation is clearly flawed in that he simply did not review the specific data that was provided as compared to the negative -25% net salvage percent proposed in the MDU depreciation study for this account. The MDU proposal is a modest increase from negative -15% to negative -25% and

(See EMR Exhibit 3 and 4 -For Complete Plot Displays)

is in no way reflective of the negative -138 and -102 net salvage that Mr. Pous focuses on in his testimony. Mr. Pous should focus on what level of negative net salvage that is being proposed in the study recommendations as opposed to what actual data was recorded per books.

Q23. PLEASE PROVIDE YOUR COMMENTS REGARDING MR. POUS' NET SALVAGE PROPOSAL FOR ACCOUNT 368.

A. My discussion is as follows.

<u>Account 368-Line Transformers</u>

Current Negative Net Salvage:	0%
Proposed Negative Net Salvage	-20%
Mr. Pous Proposed Neg. Net Salv.	-10%
Linear Trended Neg. Net Salv.	-22%
Add Linear Trended Neg. Net Salv.	-20%

As with prior accounts Mr. Pous raises the same argument about time synchronization of net salvage—that any out of sync retirements versus salvage data will significantly skew or improperly impact the resulting net salvage estimate. Notwithstanding Mr. Pous' inference to the contrary, that is one of several benefits

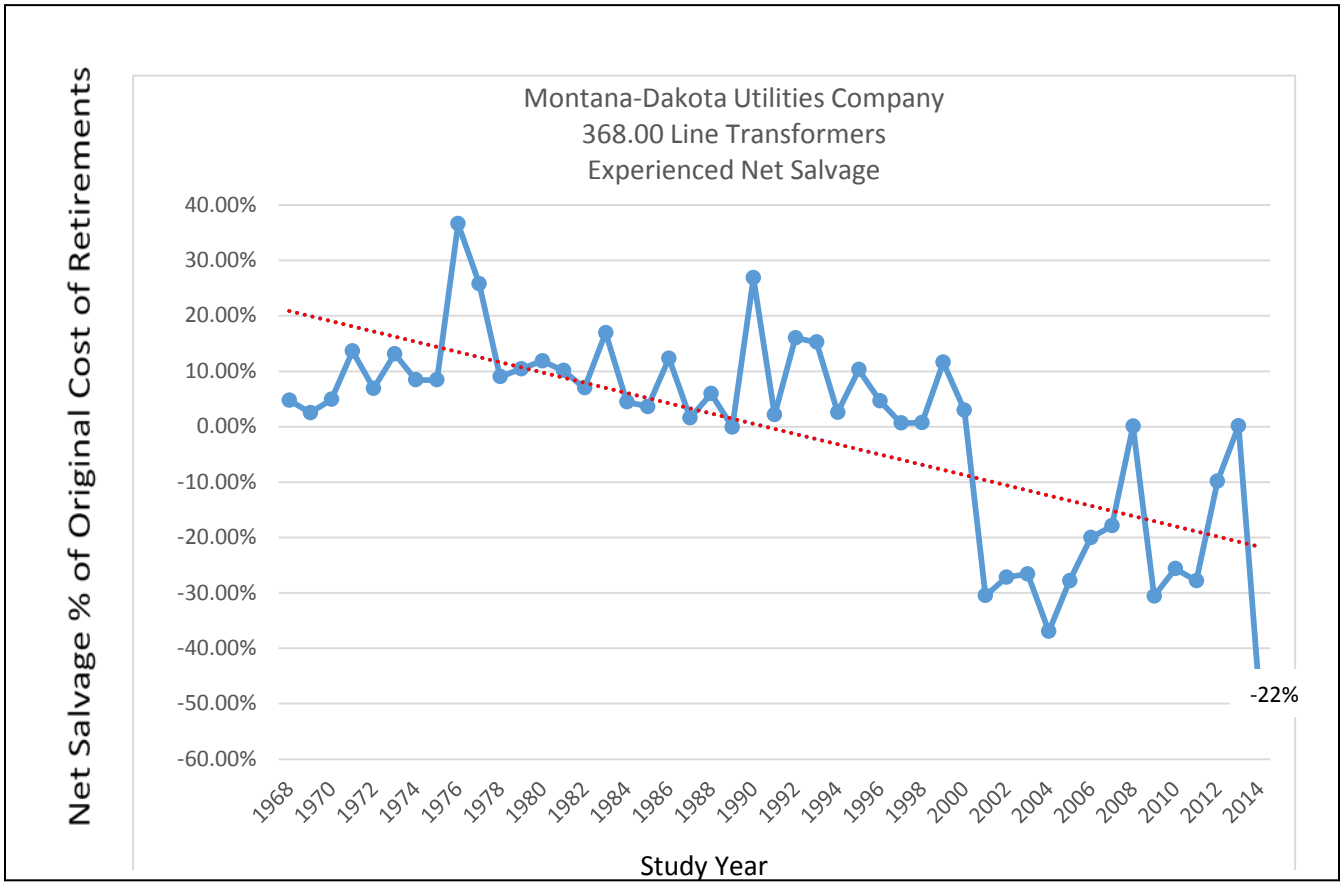
of salvage rolling band analysis (three year or otherwise) are completed. Historically, it was not uncommon for companies to potentially record retirements near the end of one accounting period with work order closings, and then to physically complete the actual retirement or removal work in next accounting period and correspondingly record the cost of removal or gross salvage. By completing rolling band analysis the activity both gets levelized over the period of years plus both activities get collected into the same time period. **(Note-The depreciation text book Depreciation Systems by Fitch and Wolf represented on various occasions by Mr. Pous as an authoritative depreciation source discusses the use of salvage rolling band analysis on page 161).**

Mr. Pous argues that there was no gross salvage during 2014 and that that circumstance makes the proposed net salvage estimate invalid. Counter to Mr. Pous' assertion, the level of negative net salvage within the earlier depreciation study was actually understated from the level that has been occurring during the period from 2001 through 2011. For most years during that period the actual experienced negative net salvage has been well in excess of negative -20% -- the negative net salvage level requested in the current study.

Notwithstanding that some of MDU customers are located in community areas nearer to the central operations, many customers and their corresponding transformers are spread across the Company's large service territory. As such, there will always be considerable costs associated with returning retired property units to stores for ultimate disposal, etc.

Within this property group, Mr. Pous again raises the issue that the Company implemented the use of PowerPlan, a new property record system for the company,

and speculates that the implementation and resulting data was the specific information used to estimate the proposed changes to the future net salvage percents. Mr. Pous simply speculates that was the cause without investigating the data—from which can easily be seen that significant weight <u>was not</u> given to the higher levels of 2013/2014 negative net salvage percents. He simply criticized the Company and Mr. Robinson for failing to volunteer the implementation the Power Plan system—Mr. Pous simply did not check but made a flawed assumption and then blamed his error on the "supposed lack of data" that was in clear sight. The Company has and continues over time to change/update record systems routinely, as required, to operate its business. (See earlier discussion about the Company's implementation of the PowerPlan record system and its impact on underlying data during the 2013/2014 time period).



Based on the range of net salvage data, and significantly discounting information from the individual 2013 and 2014 years, that were considered unusual and not within the experience trend, a the proposed -20% net salvage is clearly appropriate and supportable. As a general aside, looking at the results of the 2013 and 2014 together the average net salvage is approximately -25% which is clearly representative of the experience for the recent decade plus.

(See EMR Exhibit 3 and 4 -For Complete Plot Displays)

Q24. PLEASE PROVIDE YOUR COMMENTS REGARDING MR. POUS' NET SALVAGE PROPOSAL FOR ACCOUNT 369.1.

A. My discussion is as follows.

<u>Account 369.1-Overhead Services</u>

Current Negative Net Salvage:	-70%
Proposed Negative Net Salvage	-50%
Mr. Pous Proposed Neg. Net Salv.	-70%
Linear Trended Neg. Net Salv.	-60%
Adjd Linear Trended Neg. Net Salv.	-58%

Mr. Pous states that through discovery, notwithstanding, that the Company does not maintain records identifying a separation of cost between overhead and underground, for cost of removal and salvage that segregation of costs were obtained. Mr. Pous then quotes some supposed statistic/percentage that was generated from the cost data for the past five year period. Mr. Pous has provided no such analysis schedules in support of his claims. Mr. Pous claims that the data is the basis of his estimate of a -70% net salvage for Overhead Services and -20% net salvage for Underground Services. Given the effort expended to obtain detailed

depreciation database records in the process of completing the depreciation study, there are questions as to the manner in which the costs attributable were allocated or identified.

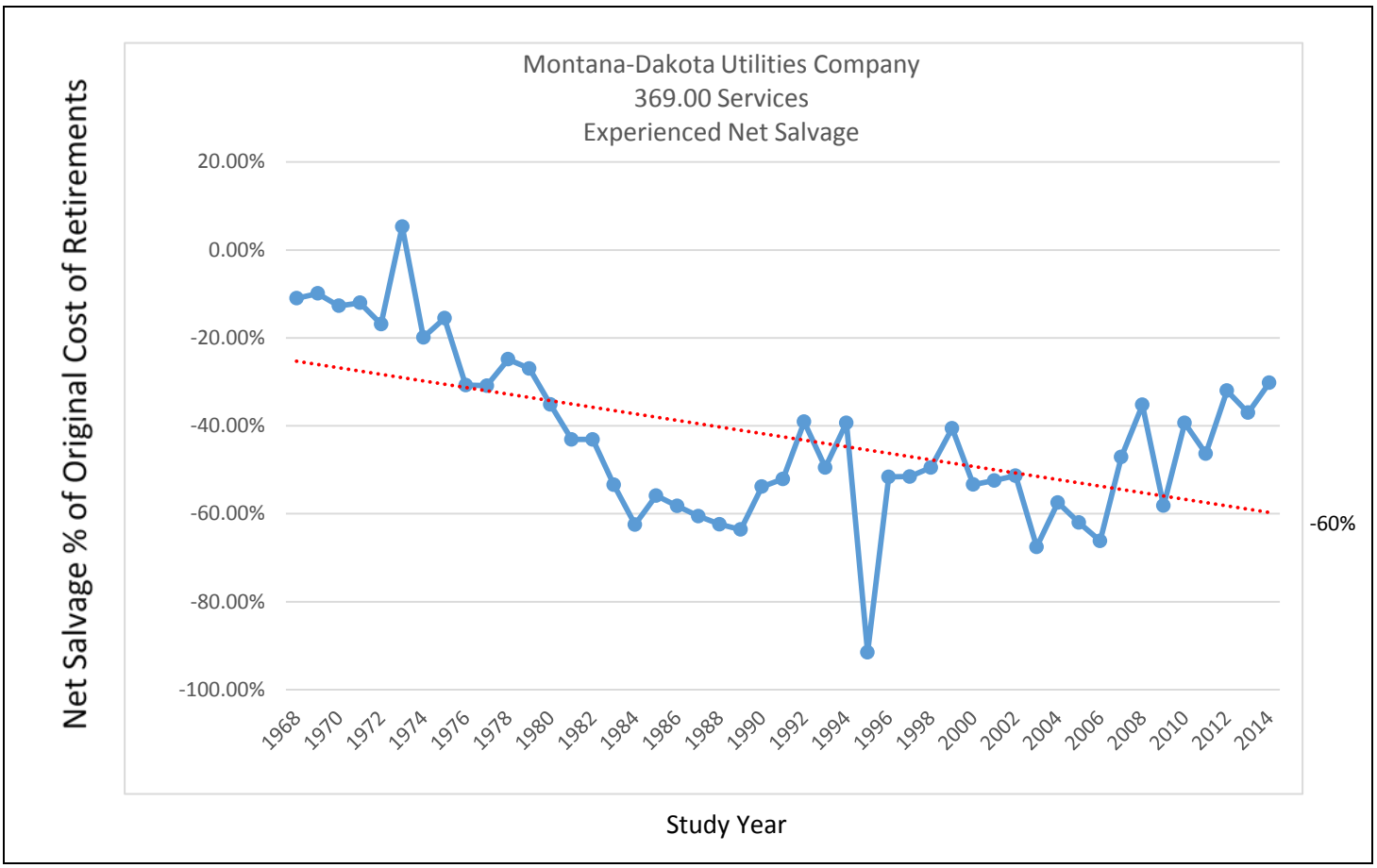
MDU experienced negative net salvage, based upon historical Company net salvage data, has become less negative of the last couple of years. Accordingly, Mr. Robinson in estimating future net salvage currently reduced the future negative net salvage by more than 30% (as a percent from the base of the current 70%) from negative -70% to negative -50%. It appears that Mr. Pous used a simple arithmetic average in his supposed analysis to arrive at a much lower percentage of negative net salvage stating that Mr. Robinson used the most recent three year average for other property accounts—an assertion that is totally false and counter to any and all statement Mr. Robinson has made with regard to estimating future net salvage. Mr. Pous' proposed reduction in annual depreciation expense related to his negative net salvage adjustment is an additional $328,664 below the already 30 percent reduction of estimated negative net salvage from current MDU negative net salvage percent. This is far from anything that could be considered gradualism and especially in light of the probability that the last couple of years' experience are an aberration and that in future years it is more than likely that negative net salvage percents will return to levels previously experienced and even higher.

With regard to developing negative net salvage for each of the sub categories of Overhead and Underground Service, I am not at all opposed, and am actually in favor of such identification, if it is completed in the correct manner and estimates are made that represents the level of negative net salvage that is expected for each of the property groups. However, such a process should not

simply be an effort to reduce depreciation rates, which is rather obvious with Mr. Pous' apparent flawed calculations, assertions, and recommendations.

The investments the company's services property groups are approximately $4.5 million for Overhead Services, and $28.5 million for Underground Services for a total of approximately $33 million. Thus Overhead Services are about 14% of the total Services investment and Underground Services are about 86% of total Service investments. In general without any specific facts, -20% negative net salvage for Underground Services, in general, seems to be a much lower negative level that it should be. Absent additional information, and presuming that the negative -20% were to be correct, that would mean that the corresponding negative net salvage for Overhead Services would need to be in excess of negative -325%, {[(100%x-50%)-(86%x-20%)]/14%}, for the overall Services account average to be negative -50%, (which is known to be a reasonable and appropriate level given the overall property group historic experience and likely future occurrences of negative net salvage. This demonstration calculation shows that Mr. Pous' estimate of -20% negative net salvage for Underground Services is significantly flawed.

Absent any additional specific empirical information, the -50% negative net salvage for the total Services property group is the most appropriate net salvage factor to be used for both Overhead and Underground Services.



(See EMR Exhibit 3 and 4-For Complete Plot Displays)

Q25. PLEASE PROVIDE YOUR COMMENTS REGARDING MR. POUS' NET SALVAGE PROPOSAL FOR ACCOUNT 369.2.

A. My discussion is as follows.

<u>Account 369.2-Underground Services</u>

Current Negative Net Salvage:	-70%
Proposed Negative Net Salvage	-50%
Mr. Pous Proposed Neg. Net Salv.	-20%
Linear Trended Neg. Net Salv.	-60%
Adjd Linear Trended Neg. Net Salv.	-58%

Mr. Pous states that through discovery, notwithstanding, that the Company does not maintain records identifying a separation of cost between overhead and

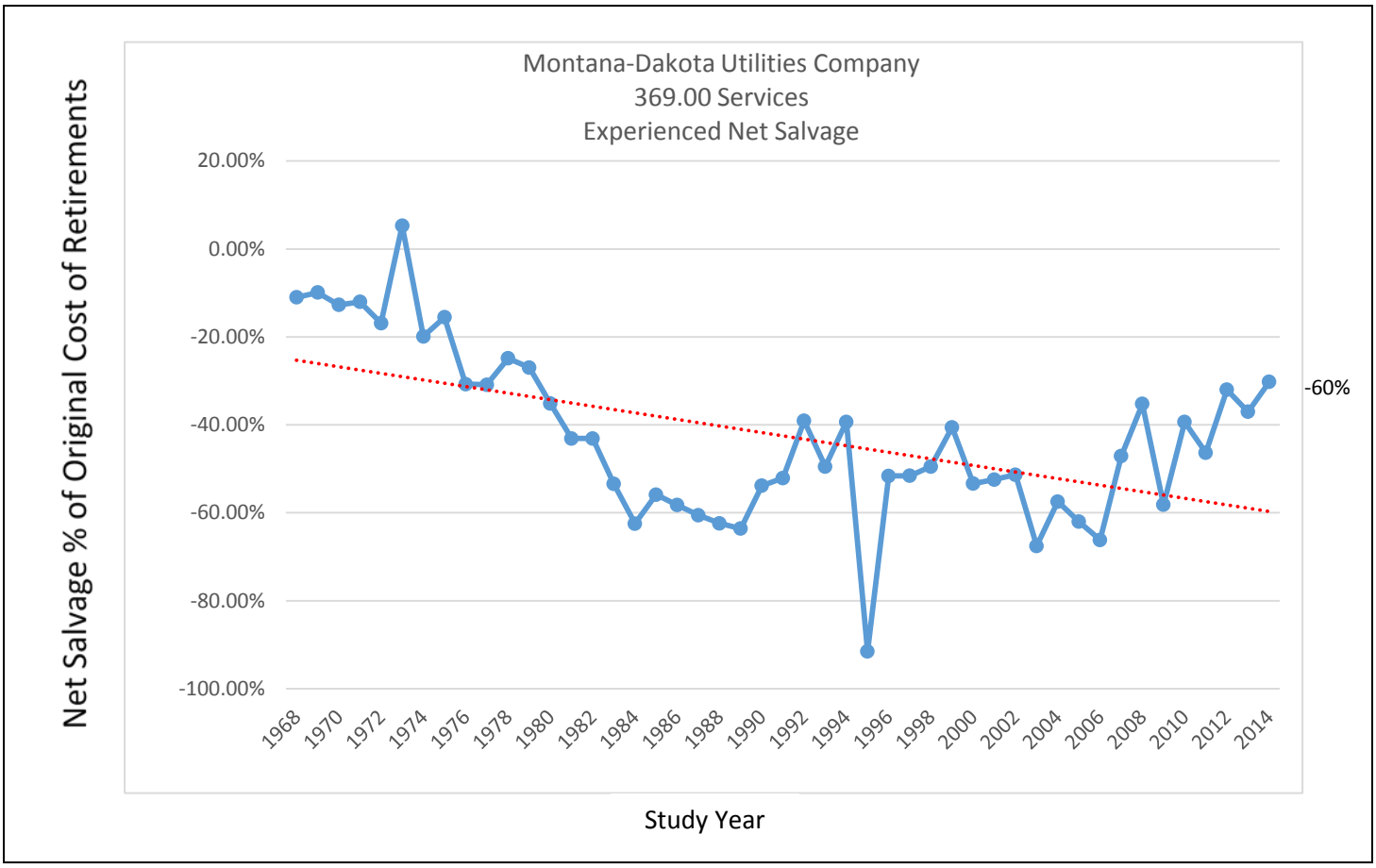
underground, for cost of removal and salvage that segregation of costs were obtained. Mr. Pous then quotes some supposed statistic, percentage that were generated from the cost data for the past five year period. Mr. Pous has provided no such analysis schedules in support of his claims. Mr. Pous claims that the data is the basis of his estimate of a -70% net salvage for Overhead Services and -20% net salvage for Underground Services. Given the effort expended to obtain detailed depreciation database records in the process of completing the depreciation study, there are questions as to the manner in which the costs attributable were allocated or identified.

MDU experienced negative net salvage, based upon historical Company net salvage data, has become less negative of the last couple of years. Accordingly, Mr. Robinson in estimating future net salvage currently reduced the future negative net salvage by more than 30% from negative -70% to negative -50%. It appears that Mr. Pous used a simple arithmetic average to a much lower percentage of negative net salvage stating that Mr. Robinson used the most recent three year average for other property accounts—an assertion that is totally false and counter to any and all statement Mr. Robinson has made with regard to estimating future net salvage. Mr. Pous' proposed reduction in annual depreciation expense related to his negative net salvage adjustment is an additional $328,664 below the already 30 percent reduction of estimated negative net salvage from current MDU negative net salvage percent. This is far from anything that could be considered gradualism and especially in light of the probability that the last couple of years' experience are an aberration and that in future years it is more than likely that negative net salvage percents will return to levels previously experienced and even higher.

With regard to developing negative net salvage for each of the sub categories of Overhead and Underground Service, I am not at all opposed, and am actually in favor of such identification, if it is completed in the correct manner and estimates are made that represents the level of negative net salvage that is expected for each of the property groups. However, such a process should not simply be an effort to reduce depreciation rates, which is rather obvious with Mr. Pous' apparent flawed calculations, assertions, and recommendations.

The investments the company's services property groups are approximately $4.5 million for Overhead Services and $28.5 million for Underground Services for a total of approximately $33 million. Thus Overhead Services are about 14% of the total Services investment and Underground Services are about 86% of the total Service investments. In general, without any specific facts, Mr. Pous' stated -20% negative net salvage for Underground Services, seems to be a much lower negative level than it should be. Absent additional information, and presuming that the negative -20% were to be correct, that would mean that the corresponding negative net salvage for Overhead Services would need to be in excess of negative -325%, {[(100%x-50%)-(86%x-20%)]/14%}, for the overall Services account average to be negative -50%, (which is known to be a reasonable and appropriate level given the overall property group historic experience and likely future occurrences of negative net salvage. This demonstration calculation shows that Mr. Pous' estimate of -20% negative net salvage for Underground Services is significant flawed.

Absent any additional specific empirical information, the -50% negative net salvage for the total Services property group is the most appropriate net salvage factor to be used for both Overhead and Underground Services.



(See EMR Exhibit 3 and 4-For Complete Plot Displays)

Q26. PLEASE PROVIDE YOUR COMMENTS REGARDING MR. POUS' NET SALVAGE PROPOSAL FOR ACCOUNT 390-ELECTRIC.

A. My discussion is as follows.

<u>Account 390-Structures & Imp-Electric Plant</u>

Current Negative Net Salvage: -10%

Proposed Negative Net Salvage -10%

Mr. Pous Proposed Neg. Net Salv. 25%

Linear Trended Neg. Net Salv. -10%

Adjd Linear Trended Neg. Net Salv. -7%

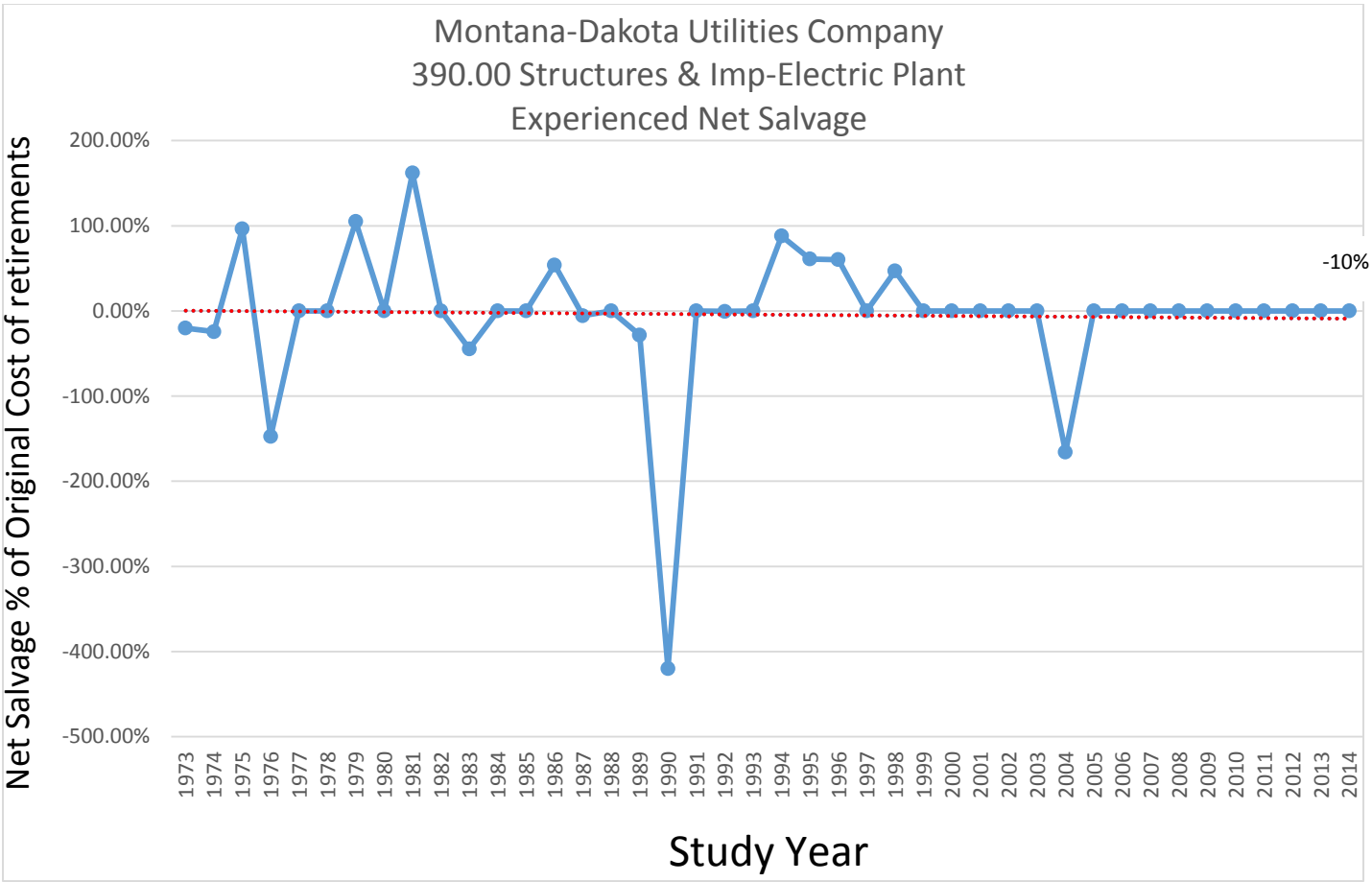
The investment in this property group is quite limited, at $835,304, in comparison to the Company's overall $1.2 billion of depreciable investment. The company has disposed of most of it unused or unwanted structures during earlier years.

The only reason that it even warrants the following discussion is the fact that Mr. Pous referenced the account and highlighted it as a specific representation of the "supposed dramatic error" in the Mr. Robinson's net salvage estimate process. Mr. Pous highlights that the overall net salvage for the property group was a positive 28% and thus extrapolated that the current properties comprising the investment in the property groups are equally or highly marketable and could generate 50% or more positive net salvage. Over the history of the property group, yearly net salvage has ranged from positive 162% for a $26 thousand dollar property retirement to negative -420% for a $9 thousand dollar retirement and numerous points in between. The total retirements that generated the overall net salvage of 28% was approximately $460,000. The largest investment current investment with in the property account totals approximately $165,000 with most others being significant smaller with little overall value. Given that the property are specific to the electric operations and scattered around the operating territory, it is more likely than not that future use will generally be limited to utility operations. Thus when they reach end of life and/or the company desires to expand or change

the use of the facilities it will likely incur significant cost of removal in refurbishing the facilities.

Accordingly, Mr. Pous' recommended 25% positive net salvage for the property group is significantly flawed and unwarranted.

Conversely, the MDU proposed -10% negative net salvage would likely be only a small fraction of cost that would be incurred in such circumstances and is the



most reasonable estimate at the current time.

(See EMR Exhibit 3 and 4-For Complete Plot Displays)

Q27. PLEASE PROVIDE YOUR COMMENTS REGARDING MR. POUS' NET SALVAGE PROPOSAL FOR ACCOUNT 390-COMMON PLANT.

A. My discussion is as follows.

<u>Account 390-Structures & Imp-Common Plant</u>

Current Negative Net Salvage:	-10%
Proposed Negative Net Salvage	5%
Mr. Pous Proposed Net Salv.	40%
Linear Trended Neg. Net Salv.	-20%
Adjd Linear Trended Neg. Net Salv.	-10%

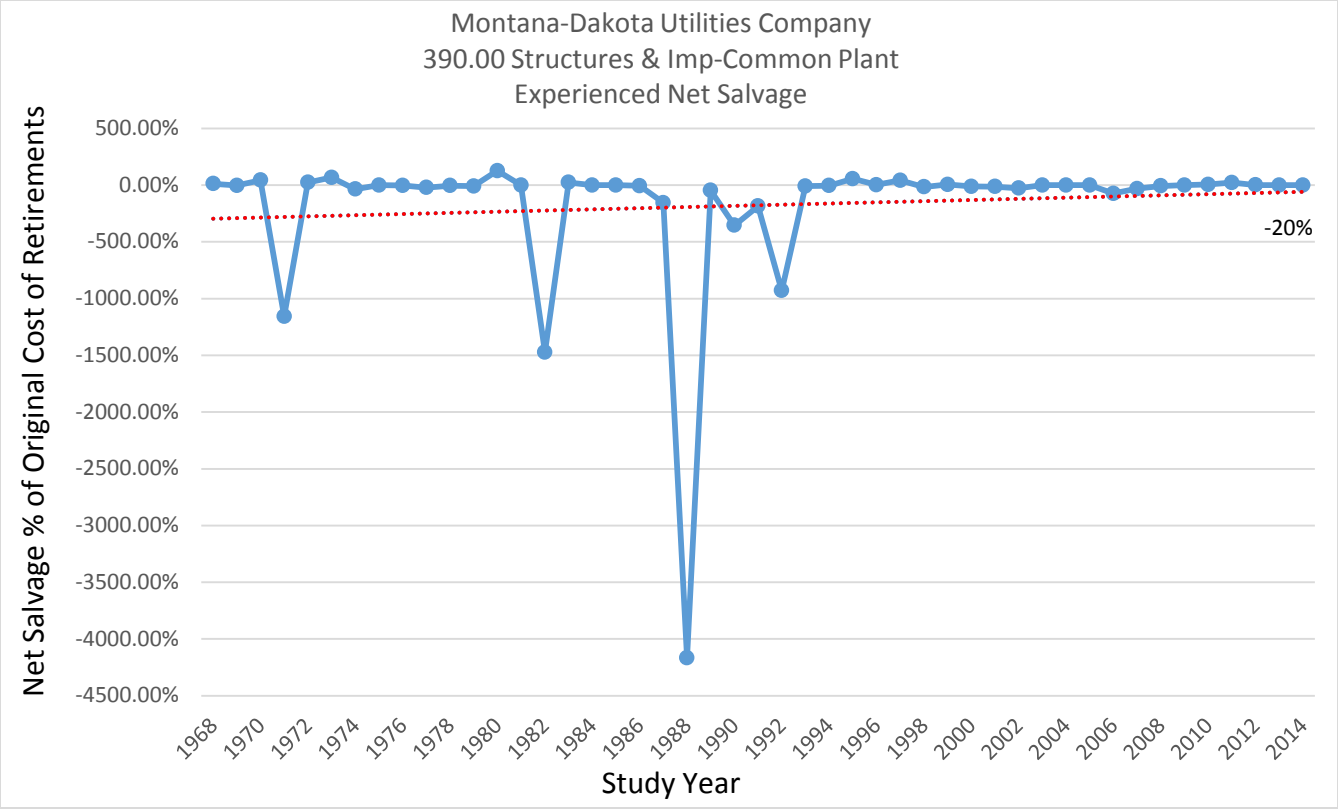
In his testimony Mr. Pous highlights that gross net salvage data was missing from the historical presentation within the depreciation report. In data request MCC-151, Mr. Pous did ask if there were any items of net salvage that were excluded as abnormal. Unfortunately, at the time, and in the process of responding to more than 125 depreciation data requests, there was an oversight in that in response to the request it was stated that no data was excluded as being atypical or abnormal, when in fact both the retirement and net salvage related to the above transactions were excluded from the presented service life analysis and net salvage results. Mr. Pous also requested and was provided with a complete copy of all service life and net salvage database details. The applicable retirements and corresponding net salvage activity was/is contained within the provided detailed data. Within the depreciation databases, the information in question is coded as category "7" information, which serves to exclude the information when processed through the AUS Consultants depreciation module for service life and salvage analysis. In formatting the information for his software model, Mr. Pous would had

to consider the coded data to operate within his system.

Mr. Pous is recommending positive 40% net salvage for the investment in the Common Plant Structures based upon the historical net salvage data. In his testimony, Mr. Pous continual criticizes Mr. Robinson in preparing the MDU study and net salvage estimates for failing to consider any unique factors behind the historical experience. Notwithstanding that the Company, in prior depreciation MDU studies, and rate cases in this jurisdiction has provided a fully and complete explanation of the reasons for the experienced Account 390-Common Plant positive net salvage, Mr. Pous simply chooses to ignore the facts.

The positive net salvage activity that has occurred within this property group is not related to actual salvage, but is simply internal (inter-company) accounting entries. That is, the overwhelming majority (99 plus percent) of the $1,803,313 is related to the investment in the Corporate Headquarters building that was bought and sold within a relatively short period of time (6 years – bought in 1994, sold to MDUR in 2001 and then sold to third party in 2004). At the time it was decided to create a separate Company under the corporate umbrella to hold the assets of the building and contents. Later, a new building was constructed on the new Corporate Campus and the old building was sold to a third party. MDU utility originally had 100% of the corporate office building and contents on their books, and then when the new Company under MDU Resources was formed, it was sold at net book value to MDUR FutureSource. After several years of not having any investment on the utility books for the new corporate office it was decided that MDU utility should once again have the investment on their books (end of 2005) except the utility share is only 35%.

The net salvage analysis completed on the data, exclusive of the inter-company transactions, produces experienced historical net salvage of negative -5.6% net salvage as opposed to the 69% that Mr. Pous references. It is likely that given the location size of the various properties comprising the property group investment, such properties will continue to operate as MDU facilities. During the subsequent years, to maintain the facilities in a desirable state of condition, various upgrades/changes obviously will occur. In conjunction with any such changes there will be a variety of interim retirements of components of the structure along with numerous expenditures for the cost to removal those components. Retrofit of existing facilities results in significant levels of Cost of Removal due to the added care required in making changes to existing buildings, opposed to simply demolishing the structures. Given that the Company may eventually experience some overall positive net salvage, the MDU depreciation study currently incorporates positive 5% net salvage for the property group.



(See EMR Exhibit 3 and 4-For Complete Plot Displays)

Q28. WILL YOU SUMMARIZE THE DIFFERENCES BETWEEN YOUR PROPOSED DEPREICATION RATES AND THOSE OF MR. POUS?

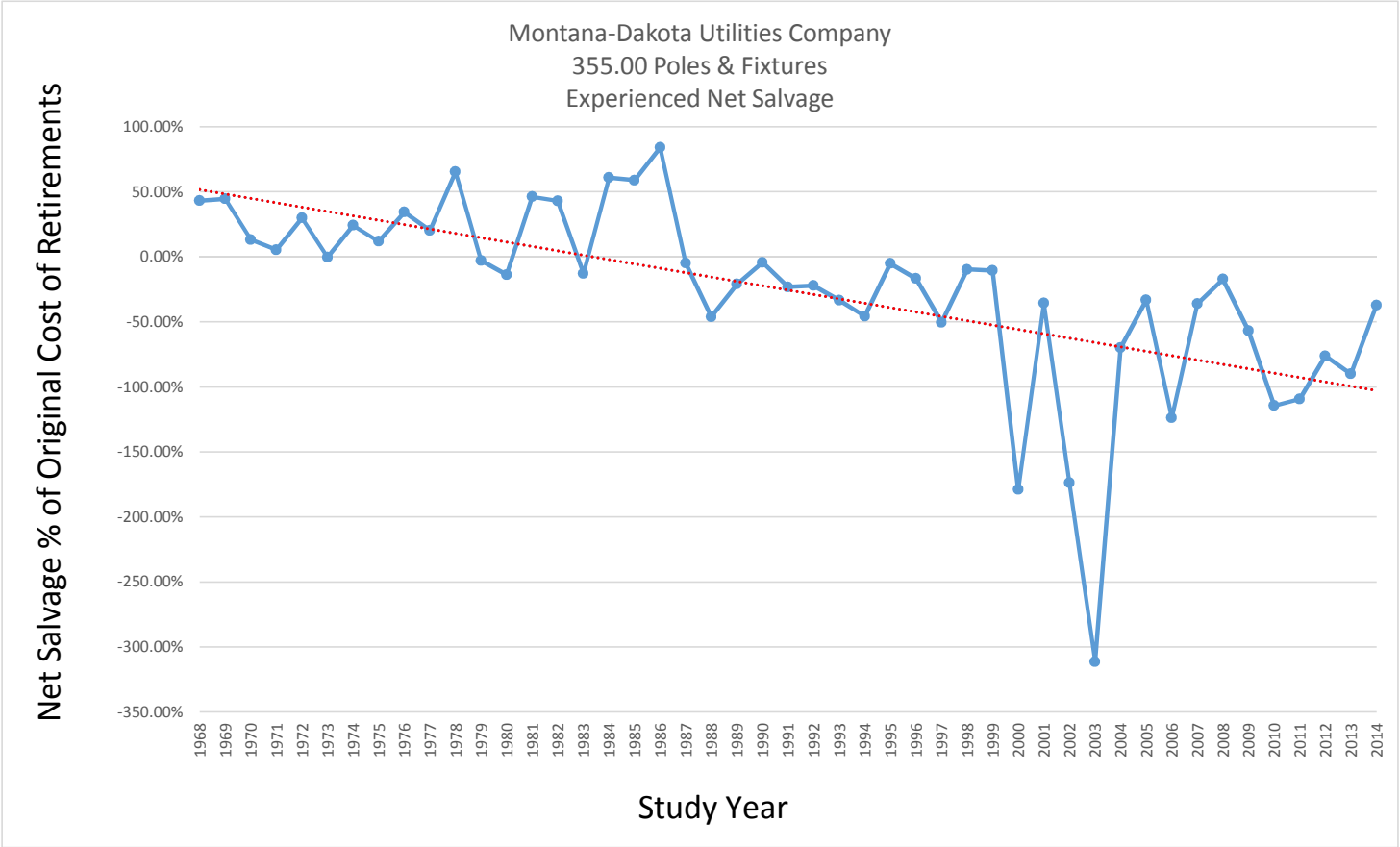
A. Yes, I will. Please refer to Exhibit No. ___(EMR-6). I have clearly provided the depreciation parameters used in the electric and common depreciation studies as well as those proposed by Mr. Pous. In addition, the depreciation parameters currently used by Montana-Dakota are displayed as well.

Q29. DOES THAT CONCLUDE YOUR REBUTTAL TESTIMONY

A. Yes.

Montana-Dakota Utilities---Electric Plant
Trend Analysis of Experience Net Salvage

Study Year	Neg. Net Salv. Amount	Net Salvage % of Original Cost of Ret.
1968	44,899	43.06%
1969	49,186	44.50%
1970	17,048	13.10%
1971	3,735	5.36%
1972	24,904	29.83%
1973	-492	-0.38%
1974	20,860	24.16%
1975	20,713	11.88%
1976	8,334	34.36%
1977	10,375	20.25%
1978	21,646	65.36%
1979	-1,153	-2.95%
1980	-3,541	-13.86%
1981	28,045	46.18%
1982	23,678	42.96%
1983	-11,795	-12.91%
1984	74,414	60.76%
1985	42,017	58.83%
1986	109,086	83.99%
1987	-10,687	-5.00%
1988	-33,077	-46.25%
1989	-19,083	-21.07%
1990	-4,344	-4.41%
1991	-30,084	-23.26%
1992	-33,963	-22.17%
1993	-23,928	-33.41%
1994	-83,357	-45.81%
1995	-6,018	-5.20%
1996	-53,813	-16.81%
1997	-72,909	-50.45%
1998	-9,137	-9.76%
1999	-1,717	-10.67%
2000	-25,886	-179.06%
2001	-22,728	-35.69%
2002	-34,481	-173.78%
2003	-162,021	-311.41%
2004	-101,463	-69.87%
2005	-10,421	-33.20%
2006	-55,602	-123.83%
2007	-12,164	-36.22%
2008	-14,703	-17.23%
2009	-8,072	-56.92%
2010	-65,194	-114.47%
2011	-282,519	-109.44%
2012	-92,112	-76.33%
2013	-58,573	-90.17%
2014	-291,412	-37.22%

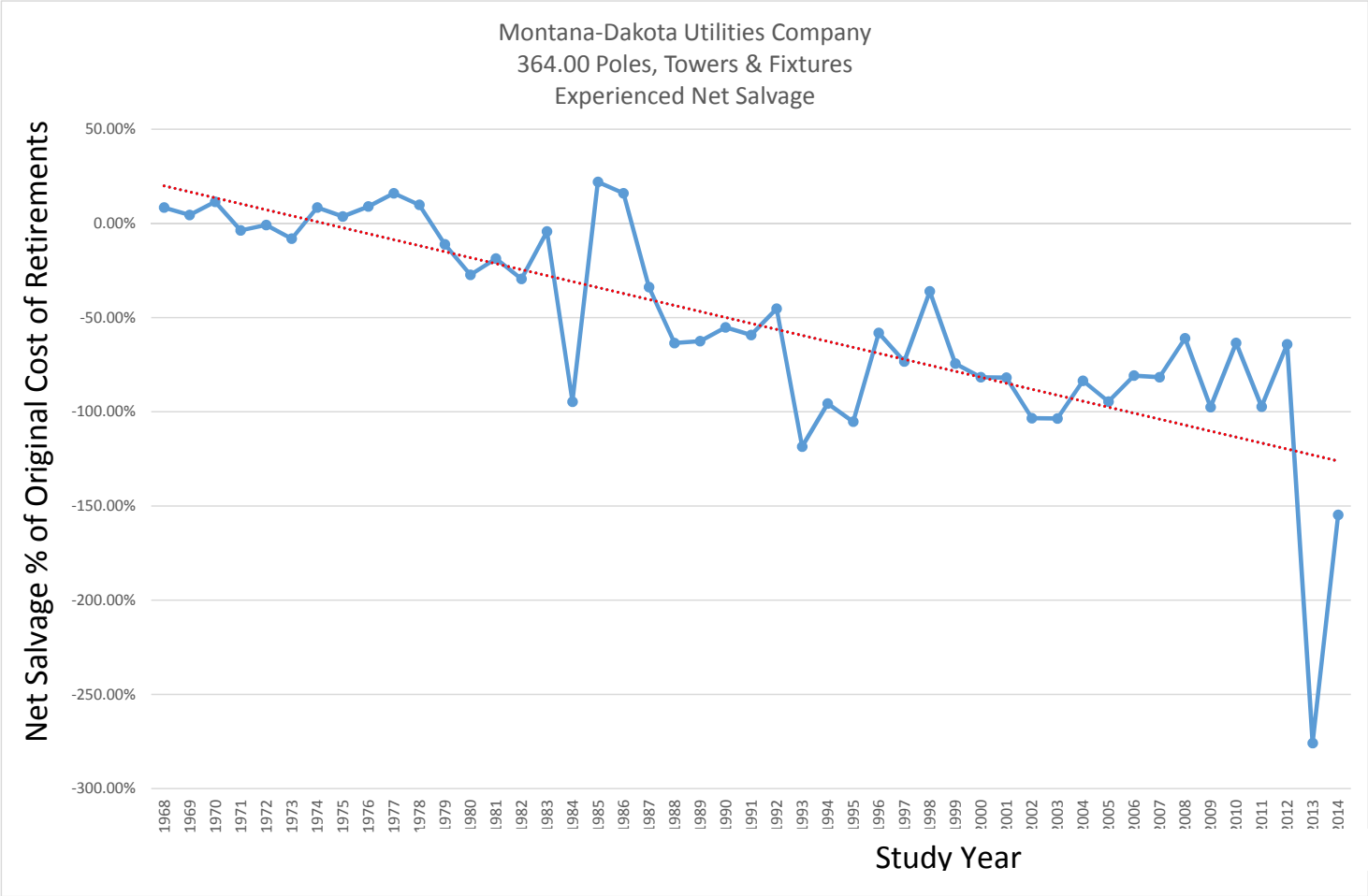


-101%

MDU Current Net Salvage Percent	**-35%**
MDU Depr Study Proposed Netative Net Salvage	**-50%**
Pous Proposed Negative Net Salvage	**-35%**

Montana-Dakota Utilities---Electric Plant
Trend Analysis of Experience Net Salvage

Study Year	Neg. Net Salv. Amount	Net Salvage % of Original Cost of Ret.
1968	13,933	8.41%
1969	8,763	4.48%
1970	20,576	11.45%
1971	-4,492	-3.73%
1972	-1,299	-0.88%
1973	-12,561	-8.14%
1974	12,136	8.43%
1975	4,651	3.68%
1976	11,440	8.96%
1977	23,851	15.96%
1978	14,006	9.82%
1979	-28,587	-11.15%
1980	-29,101	-27.32%
1981	22,508	-18.68%
1982	-46,035	-29.50%
1983	-6,920	-4.30%
1984	-61,123	-94.67%
1985	43,300	21.99%
1986	25,157	15.97%
1987	-42,218	-33.88%
1988	-57,097	-63.55%
1989	-60,419	-62.54%
1990	-71,030	-55.20%
1991	-71,272	-59.26%
1992	-68,650	-45.26%
1993	-153,154	-118.51%
1994	-136,372	-95.61%
1995	-92,982	-105.27%
1996	-165,004	-58.16%
1997	-94,269	-73.29%
1998	-84,429	-36.07%
1999	-87,921	-74.40%
2000	-86,871	-81.67%
2001	-87,005	-81.88%
2002	-118,951	-103.41%
2003	-110,438	-103.58%
2004	-120,221	-83.56%
2005	-130,594	-94.60%
2006	-134,859	-80.82%
2007	-76,927	-81.65%
2008	-166,250	-61.01%
2009	-142,318	-97.55%
2010	-61,802	-63.45%
2011	-183,566	-97.29%
2012	-139,737	-64.19%
2013	-522,499	-275.90%
2014	-762,640	-154.74%

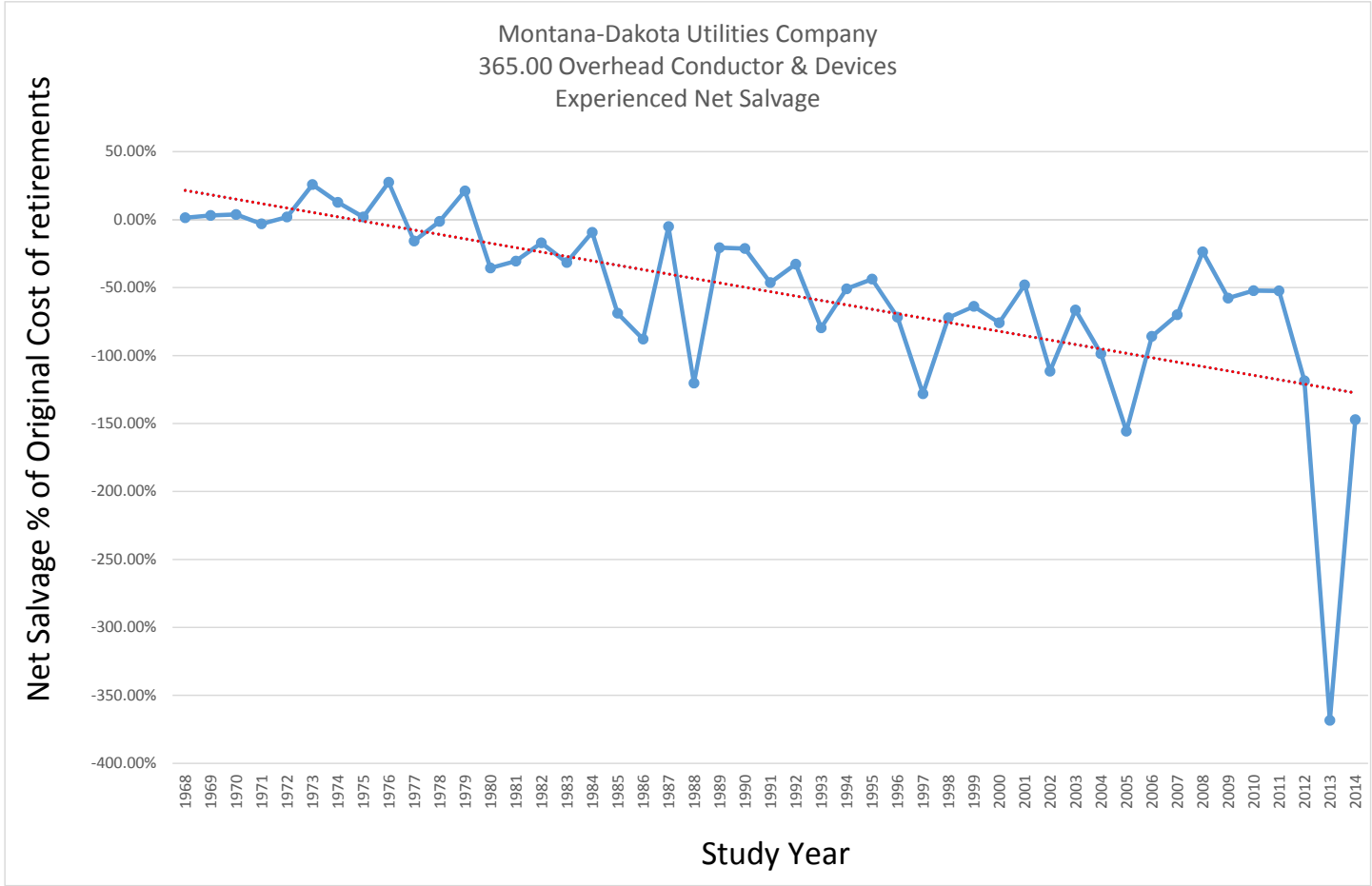


-125%

MDU Current Net Salvage Percent	**-70%**
MDU Depr Study Proposed Netative Net Salvage	**-95%**
Pous Proposed Negative Net Salvage	**-70%**

Montana-Dakota Utilities---Electric Plant
Trend Analysis of Experience Net Salvage

Study Year	Neg. Net Salv. Amount	Net Salvage % of Original Cost of Ret.
1968	1,891	1.36%
1969	5,327	3.05%
1970	6,025	3.78%
1971	-3,300	-3.14%
1972	2,408	1.89%
1973	34,078	25.78%
1974	16,689	12.75%
1975	2,330	1.93%
1976	31,776	27.45%
1977	-17,932	-15.81%
1978	-1,479	-1.33%
1979	40,092	21.14%
1980	-33,692	-35.62%
1981	-21,637	-30.52%
1982	-26,992	-17.15%
1983	-35,615	-31.54%
1984	-9,811	-9.37%
1985	-138,717	-68.86%
1986	-85,679	-87.91%
1987	-3,606	-5.15%
1988	-59,879	-120.32%
1989	-9,788	-20.63%
1990	-15,805	-21.25%
1991	-27,797	-46.36%
1992	-38,959	-32.74%
1993	-53,030	-79.56%
1994	-45,591	-50.89%
1995	-21,013	-43.78%
1996	-73,113	-71.76%
1997	67,810	-128.10%
1998	-51,731	-72.18%
1999	-35,970	-63.82%
2000	-37,646	-75.86%
2001	-40,365	-48.05%
2002	-67,999	-111.52%
2003	-54,774	-66.55%
2004	-76,289	-98.68%
2005	-80,751	-155.64%
2006	-63,483	-85.89%
2007	-45,870	-69.98%
2008	-64,099	-23.68%
2009	-46,071	-57.75%
2010	-25,857	-52.23%
2011	-48,049	-52.42%
2012	-179,622	-118.59%
2013	-301,451	-368.42%
2014	-496,872	-147.20%

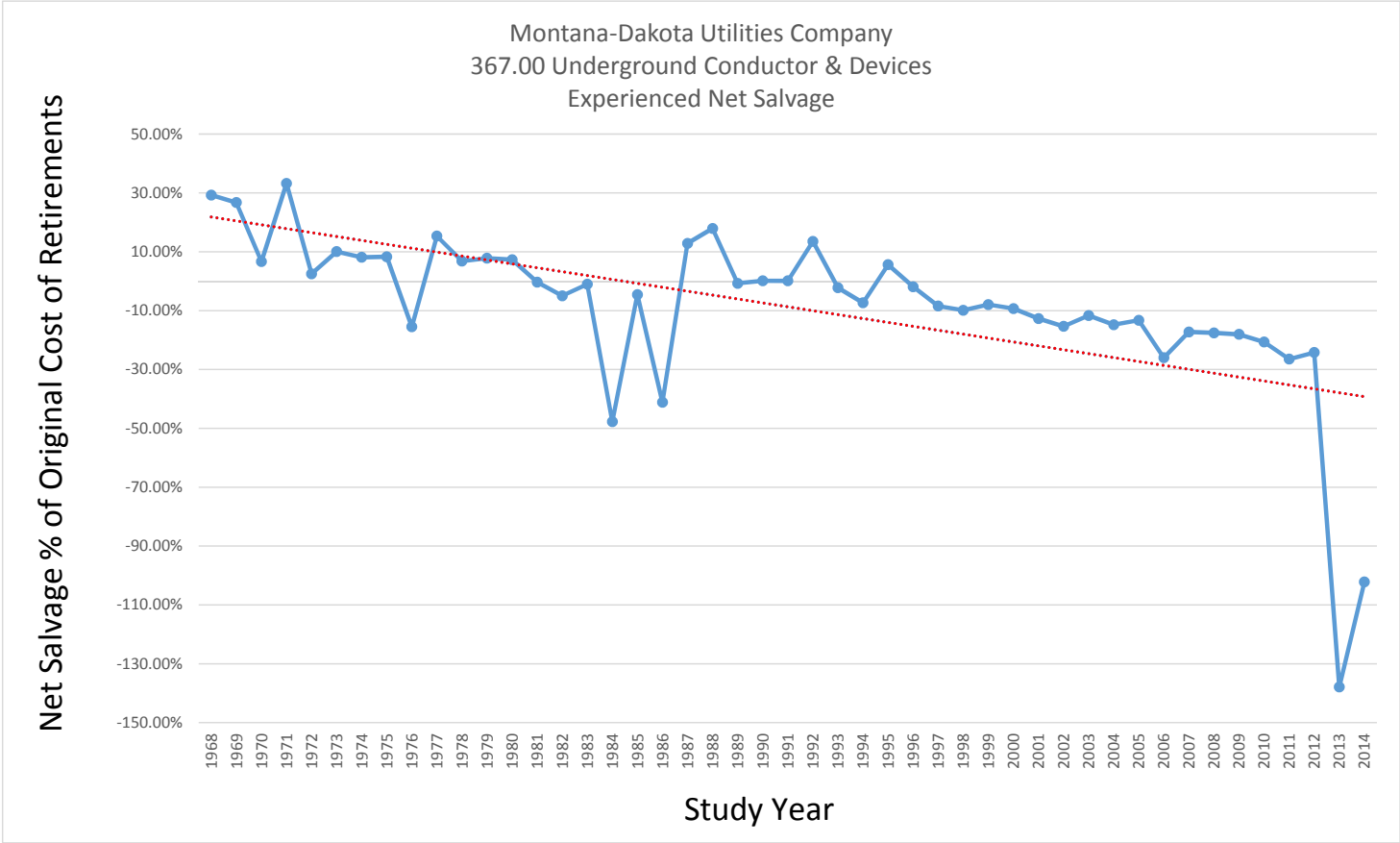


-125%

MDU Current Net Salvage Percent	**-70%**
MDU Depr Study Proposed Netative Net Salvage	**-85%**
Pous Proposed Negative Net Salvage	**-70%**

Montana-Dakota Utilities---Electric Plant
Trend Analysis of Experience Net Salvage

Study Year	Neg. Net Salv. Amount	Net Salvage % of Original Cost of Ret.
1968	375	29.26%
1969	20	26.74%
1970	68	6.67%
1971	336	33.25%
1972	109	2.50%
1973	136	10.07%
1974	143	8.14%
1975	160	8.30%
1976	-555	-15.49%
1977	1,449	15.33%
1978	578	6.83%
1979	1,565	7.82%
1980	1,262	7.32%
1981	-88	-0.32%
1982	-1,278	-4.96%
1983	-280	-1.02%
1984	-10,095	-47.75%
1985	-2,958	-4.54%
1986	-4,314	-41.16%
1987	4,581	12.86%
1988	6,721	17.93%
1989	-225	-0.72%
1990	54	0.13%
1991	534	0.14%
1992	11,024	13.54%
1993	-3,179	-2.23%
1994	-13,415	-7.35%
1995	7,326	5.62%
1996	-7,403	-1.88%
1997	-14,975	-8.43%
1998	-18,056	-9.88%
1999	-21,871	-7.93%
2000	-23,356	-9.30%
2001	-30,781	-12.70%
2002	-48,208	-15.35%
2003	-36,416	-11.65%
2004	-38,328	-14.79%
2005	-32,413	-13.28%
2006	-42,152	-26.01%
2007	-33,953	-17.24%
2008	-112,076	-17.56%
2009	-70,789	-18.06%
2010	-39,217	-20.68%
2011	-138,734	-26.48%
2012	-53,633	-24.22%
2013	-611,827	-137.90%
2014	-465,097	-102.21%

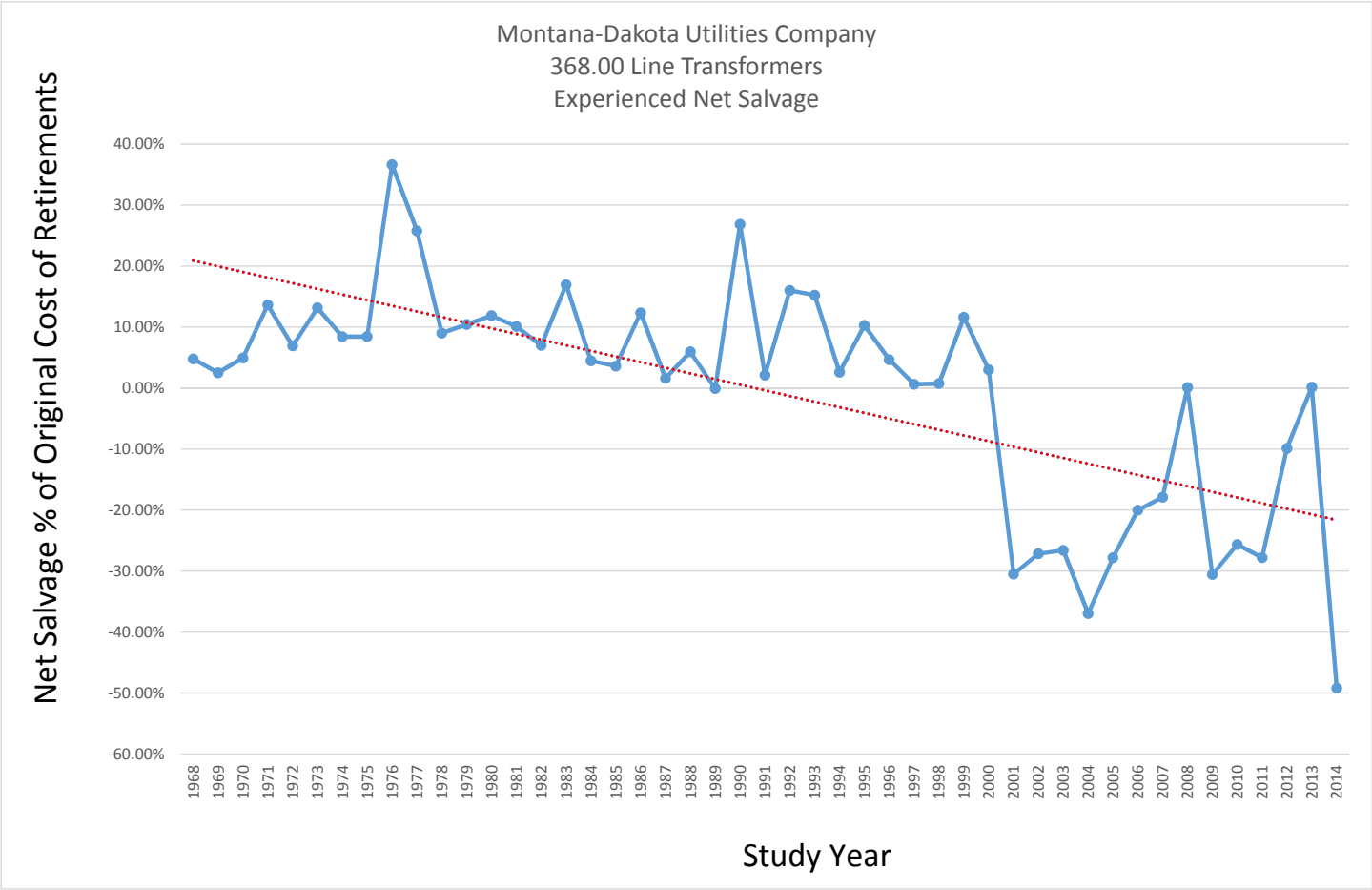


-38%

MDU Current Net Salvage Percent	**-15%**
MDU Depr Study Proposed Netative Net Salvage	**-25%**
Pous Proposed Negative Net Salvage	**-15%**

Montana-Dakota Utilities---Electric Plant
Trend Analysis of Experience Net Salvage

Study Year	Neg. Net Salv. Amount	Net Salvage % of Original Cost of Ret.
1968	2,401	4.77%
1969	1,392	2.50%
1970	2,299	4.92%
1971	6,906	13.63%
1972	3,450	6.91%
1973	3,629	13.14%
1974	2,678	8.43%
1975	1,561	8.44%
1976	28,542	36.62%
1977	10,613	25.77%
1978	5,267	9.00%
1979	4,573	10.43%
1980	8,255	11.87%
1981	4,573	10.09%
1982	5,337	6.99%
1983	19,087	16.94%
1984	5,379	4.47%
1985	6,531	3.60%
1986	14,601	12.33%
1987	2,964	1.60%
1988	6,519	5.94%
1989	-132	-0.09%
1990	16,855	26.85%
1991	2,633	2.12%
1992	10,337	16.01%
1993	13,413	15.23%
1994	1,535	2.58%
1995	2,307	10.28%
1996	4,201	4.65%
1997	422	0.62%
1998	1,120	0.73%
1999	10,903	11.61%
2000	2,565	2.98%
2001	-25,854	-30.51%
2002	-32,683	-27.17%
2003	-27,260	-26.61%
2004	-42,271	-36.97%
2005	-28,431	-27.81%
2006	-28,335	-20.04%
2007	-21,358	-17.90%
2008	161	0.08%
2009	-54,994	-30.57%
2010	-35,581	-25.65%
2011	-52,877	-27.80%
2012	-17,743	-9.89%
2013	890	0.15%
2014	-266,825	-49.21%

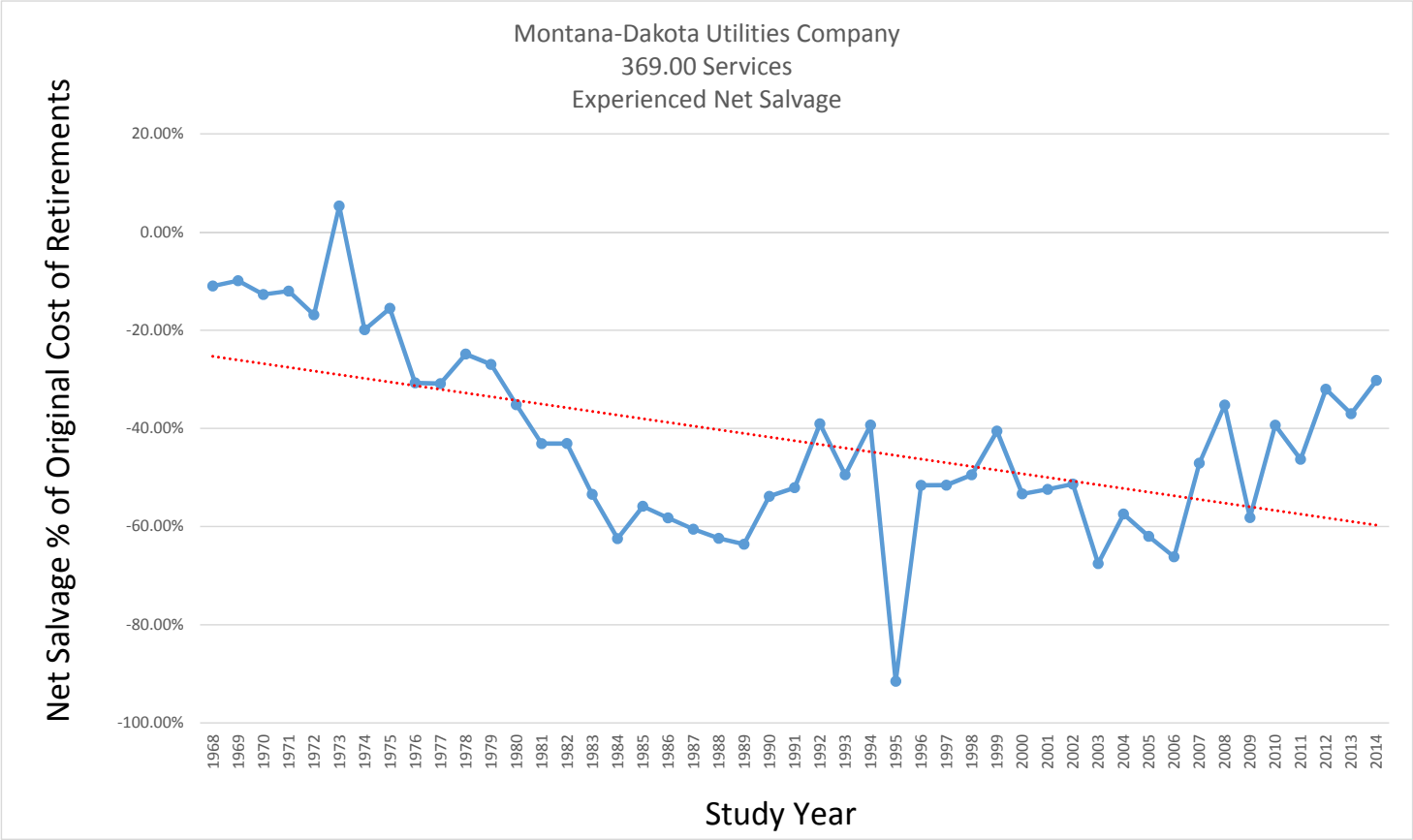


-22%

MDU Current Net Salvage Percent	**0%**
MDU Depr Study Proposed Netative Net Salvage	**-20%**
Pous Proposed Negative Net Salvage	**-10%**

Montana-Dakota Utilities---Electric Plant
Trend Analysis of Experience Net Salvage

Study Year	Neg. Net Salv. Amount	Net Salvage % of Original Cost of Ret.
1968	-6,565	-11.00%
1969	-5,856	-9.91%
1970	-8,254	-12.72%
1971	-6,193	-12.03%
1972	-7,829	-16.88%
1973	3,145	5.30%
1974	-10,487	-19.90%
1975	-8,944	-15.54%
1976	-15,596	-30.73%
1977	-22,144	-30.88%
1978	-12,479	-24.86%
1979	-17,819	-26.96%
1980	-20,458	-35.17%
1981	-25,471	-43.10%
1982	-24,860	-43.09%
1983	-32,303	-53.44%
1984	-33,445	-62.47%
1985	-41,742	-55.87%
1986	-26,374	-58.24%
1987	-67	-60.53%
1988	-33,254	-62.40%
1989	-38,710	-63.60%
1990	-29,252	-53.84%
1991	-33,935	-52.09%
1992	-30,710	-39.07%
1993	-32,391	-49.47%
1994	-44,263	-39.33%
1995	-9,916	-91.54%
1996	-61,677	-51.60%
1997	-39,010	-51.56%
1998	-42,675	-49.47%
1999	-40,763	-40.56%
2000	-45,038	-53.35%
2001	-38,448	-52.42%
2002	-45,088	-51.35%
2003	-47,529	-67.55%
2004	-61,378	-57.45%
2005	-67,627	-62.00%
2006	-84,551	-66.18%
2007	-32,516	-47.10%
2008	-84,283	-35.25%
2009	-69,834	-58.16%
2010	-40,838	-39.36%
2011	-92,499	-46.31%
2012	-55,789	-32.02%
2013	-54,942	-37.03%
2014	-51,155	-30.24%

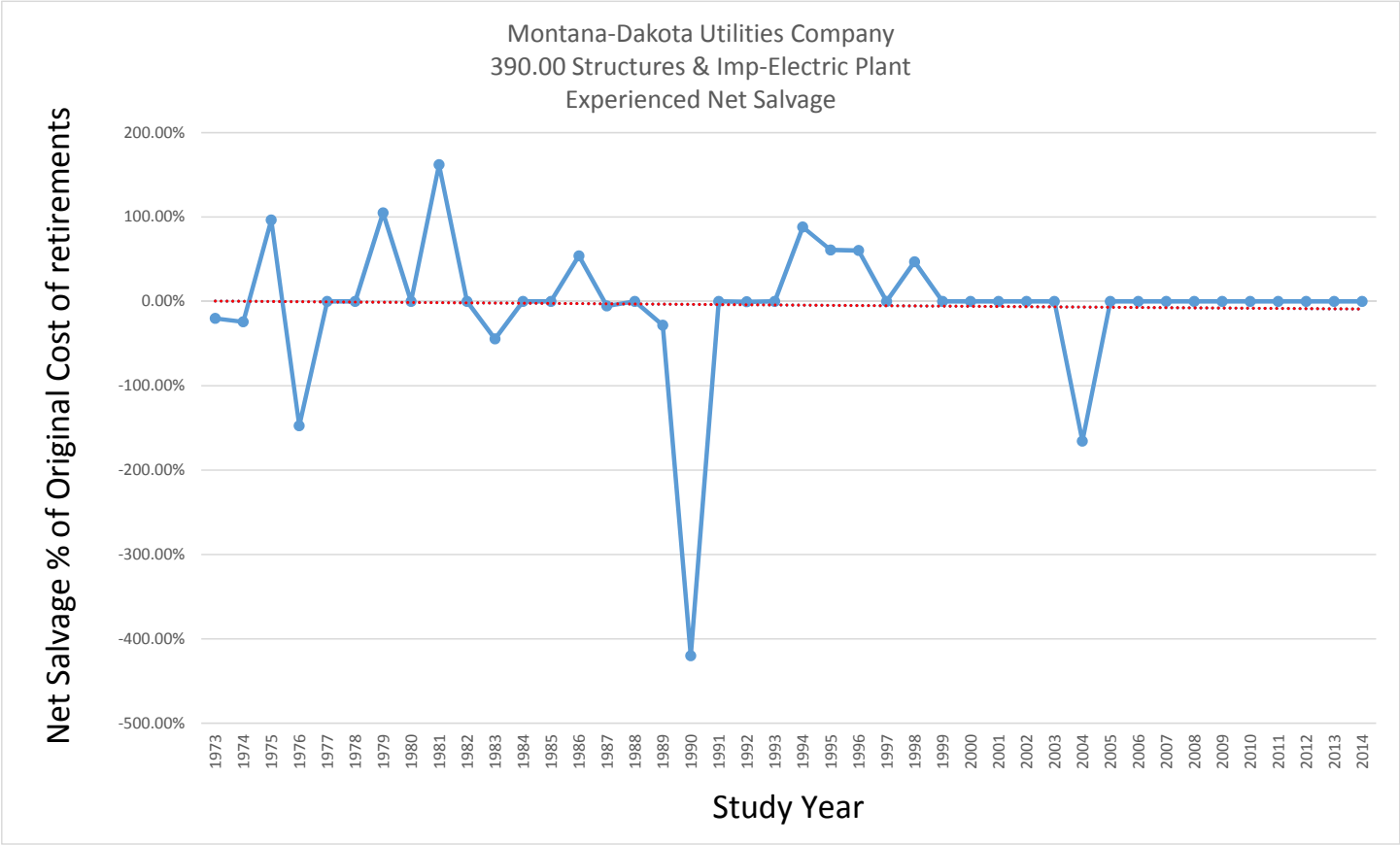


-60%

MDU Current Net Salvage Percent	**-70%**
MDU Depr Study Proposed Netative Net Salvage	**-50%**
Pous Proposed 369 OH Service Net Salvage Percent	**-70%**
Pous Proposed 369 UG Service Net Salvage Percent	**-20%**

Montana-Dakota Utilities---Electric Plant
Trend Analysis of Experience Net Salvage

Study Year	Neg. Net Salv. Amount	Net Salvage % of Original Cost of Ret.
1973	-1,376	-20.19%
1974	-3,056	-24.28%
1975	2,506	96.48%
1976	-1,638	-147.46%
1977	0	0.00%
1978	0	0.00%
1979	11,049	104.98%
1980	0	0.00%
1981	43,085	161.95%
1982	0	0.00%
1983	-4,698	-44.47%
1984	0	0.00%
1985	0	0.00%
1986	2,084	53.95%
1987	-2,341	-5.47%
1988	0	0.00%
1989	-7,267	-28.33%
1990	-36,678	-419.99%
1991	0	0.00%
1992	-7	-0.47%
1993	0	0.00%
1994	11,756	88.10%
1995	13,073	60.95%
1996	38,025	60.31%
1997	0	0.00%
1998	84,379	46.96%
1999	0	0.00%
2000	0	0.00%
2001	0	0.00%
2002	0	0.00%
2003	0	0.00%
2004	-18,500	-165.71%
2005	0	0.00%
2006	0	0.00%
2007	0	0.00%
2008	0	0.00%
2009	0	0.00%
2010	0	0.00%
2011	0	0.00%
2012	0	0.00%
2013	0	0.00%
2014	0	0.00%

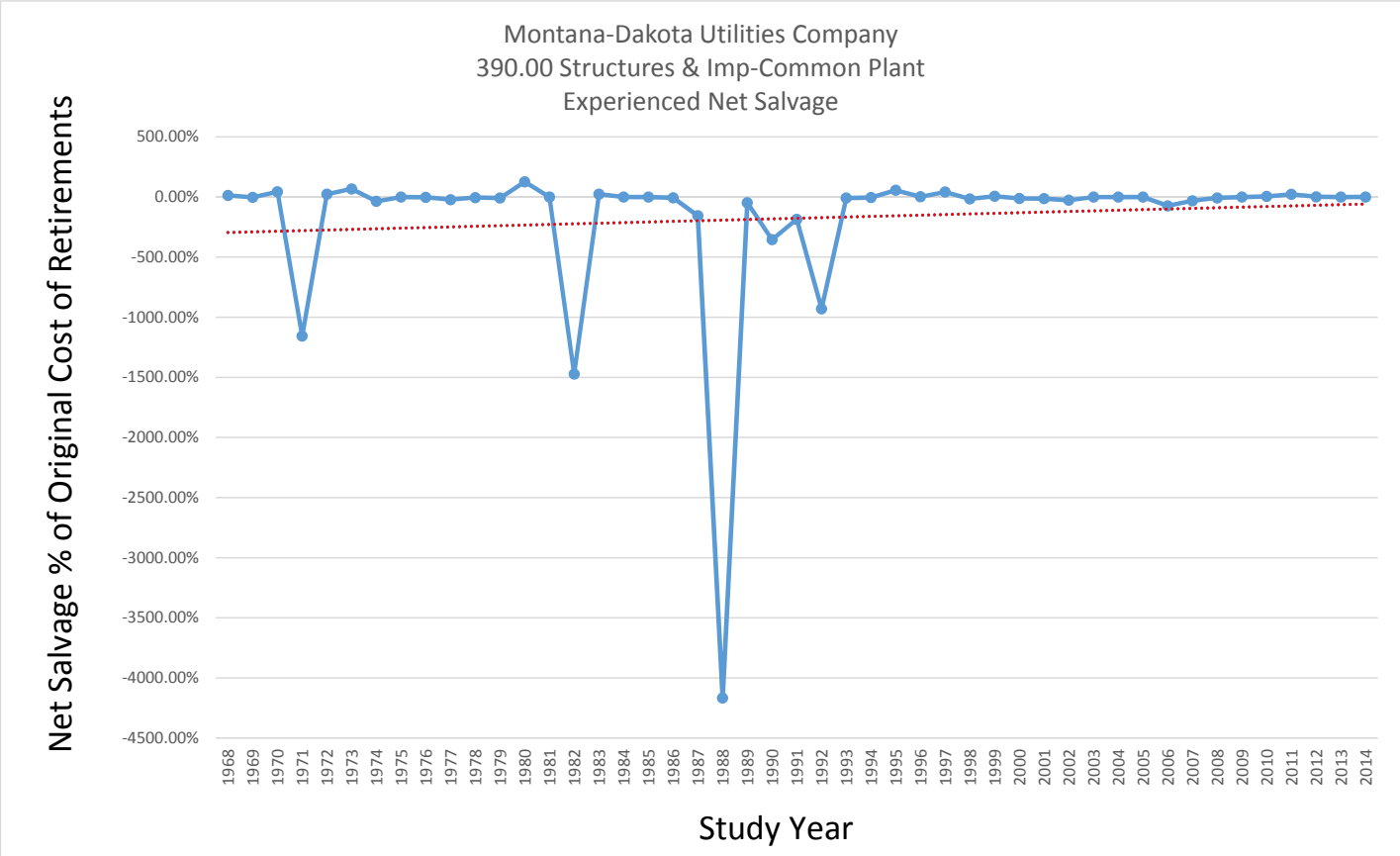


-10%

MDU Current Net Salvage Percent	**-10%**
MDU Depr Study Proposed Netative Net Salvage	**-10%**
Pous Proposed Net Salvage	**25%**

Montana-Dakota Utilities-Common Plant
Trend Analysis of Experience Net Salvage

Study Year	Neg. Net Salv. Amount	Net Salvage % of Original Cost of Ret.
1968	622	13.08%
1969	-629	-2.72%
1970	4,149	43.51%
1971	-641	-1156.20%
1972	20,750	23.31%
1973	556	67.55%
1974	-2,381	-35.80%
1975	0	0.00%
1976	-18	-2.55%
1977	-7,358	-21.92%
1978	-304	-5.11%
1979	-31	-8.53%
1980	46,043	126.39%
1981	0	0.00%
1982	-35,198	-1472.52%
1983	34,949	23.10%
1984	239	0.00%
1985	0	0.00%
1986	-22,554	-6.39%
1987	-178,544	-155.70%
1988	-44,408	-4166.57%
1989	-1,362	-46.83%
1990	-4,383	-354.75%
1991	-21,000	-185.55%
1992	-59,486	-929.46%
1993	-5,515	-8.24%
1994	-3,296	-4.32%
1995	139,579	56.00%
1996	4,207	2.41%
1997	41,099	42.03%
1998	-40,399	-15.79%
1999	18,459	6.08%
2000	-20,651	-12.00%
2001	-14,719	-13.41%
2002	-29,202	-26.54%
2003	0	0.00%
2004	-26,474	0.00%
2005	-225	0.00%
2006	-9,973	-73.71%
2007	-14,205	-31.55%
2008	-2,070	-7.68%
2009	0	0.00%
2010	2,894	4.90%
2011	19,408	21.94%
2012	3,622	1.88%
2013	0	0.00%
2014	1,212	0.16%



-40%

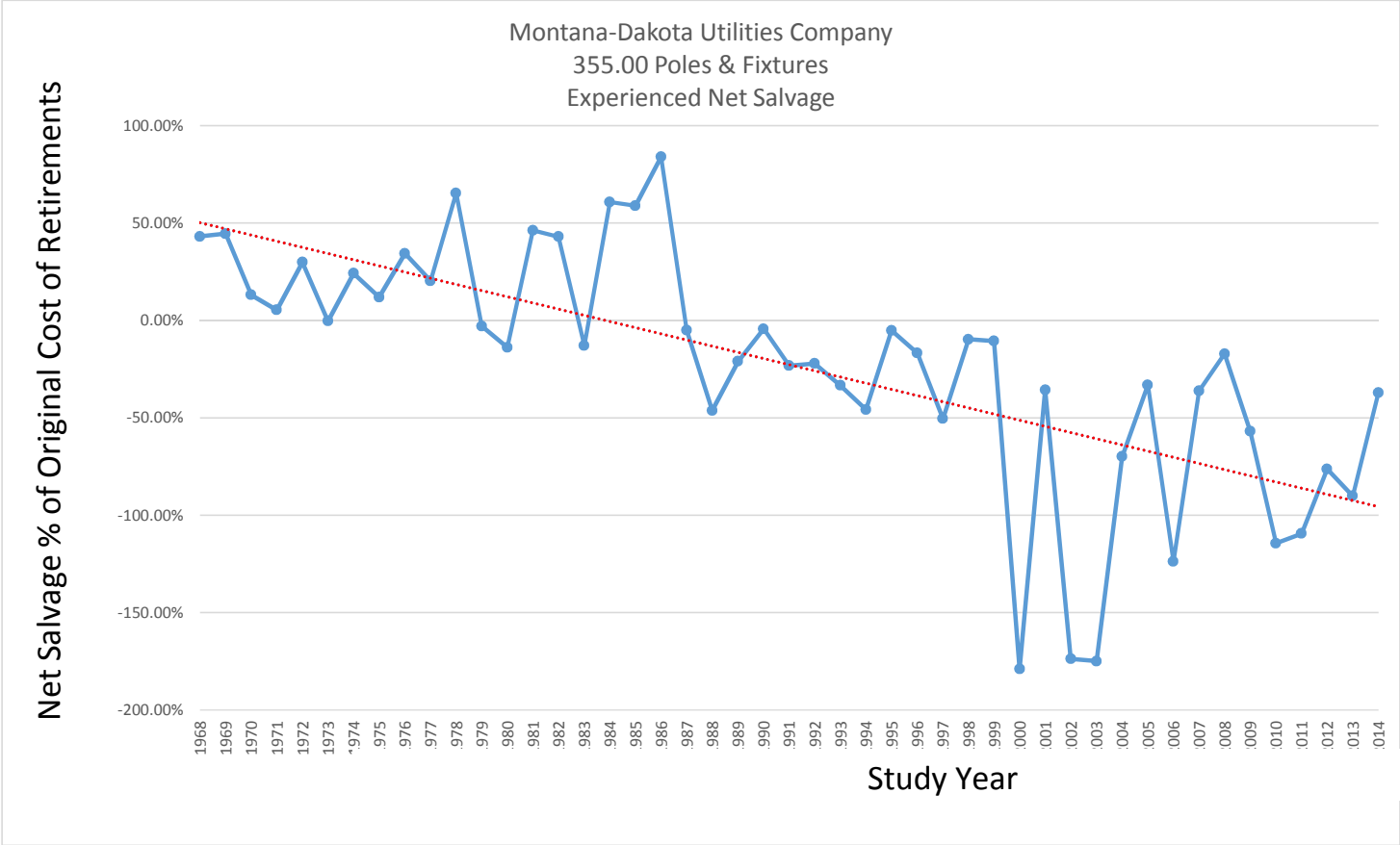
MDU Current Net Salvage Percent	**-10%**
MDU Depr Study Proposed Netative Net Salvage	**5%**
Pous Proposed Net Salvage	**40%**

Montana-Dakota Utilities---Electric Plant

Trend Analysis of Experience Net Salvage -With Estimated Capped Negative Net Salvage for Analysis Purposes (And Display)

EMR Exhibit 4

Study Year	Neg. Net Salv. Amount	Net Salvage % of Original Cost of Ret.	
1968	44,899	43.06%	
1969	49,186	44.50%	
1970	17,048	13.10%	
1971	3,735	5.36%	
1972	24,904	29.83%	
1973	-492	-0.38%	
1974	20,860	24.16%	
1975	20,713	11.88%	
1976	8,334	34.36%	
1977	10,375	20.25%	
1978	21,646	65.36%	
1979	-1,153	-2.95%	
1980	-3,541	-13.86%	
1981	28,045	46.18%	
1982	23,678	42.96%	
1983	-11,795	-12.91%	
1984	74,414	60.76%	
1985	42,017	58.83%	
1986	109,086	83.99%	
1987	-10,687	-5.00%	
1988	-33,077	-46.25%	
1989	-19,083	-21.07%	
1990	-4,344	-4.41%	
1991	-30,084	-23.26%	
1992	-33,963	-22.17%	
1993	-23,928	-33.41%	
1994	-83,357	-45.81%	
1995	-6,018	-5.20%	
1996	-53,813	-16.81%	
1997	-72,909	-50.45%	
1998	-9,137	-9.76%	
1999	-1,717	-10.67%	
2000	-25,886	-179.06%	
2001	-22,728	-35.69%	
2002	-34,481	-173.78%	Actual
2003	-162,021	**-175.00%**	-311.41%
2004	-101,463	-69.87%	
2005	-10,421	-33.20%	**Estimated**
2006	-55,602	-123.83%	**Capped**
2007	-12,164	-36.22%	**Neg. Net**
2008	-14,703	-17.23%	**Salv. For**
2009	-8,072	-56.92%	**Analysis**
2010	-65,194	-114.47%	**Purposes**
2011	-282,519	-109.44%	
2012	-92,112	-76.33%	
2013	-58,573	-90.17%	
2014	-291,412	-37.22%	



-95%

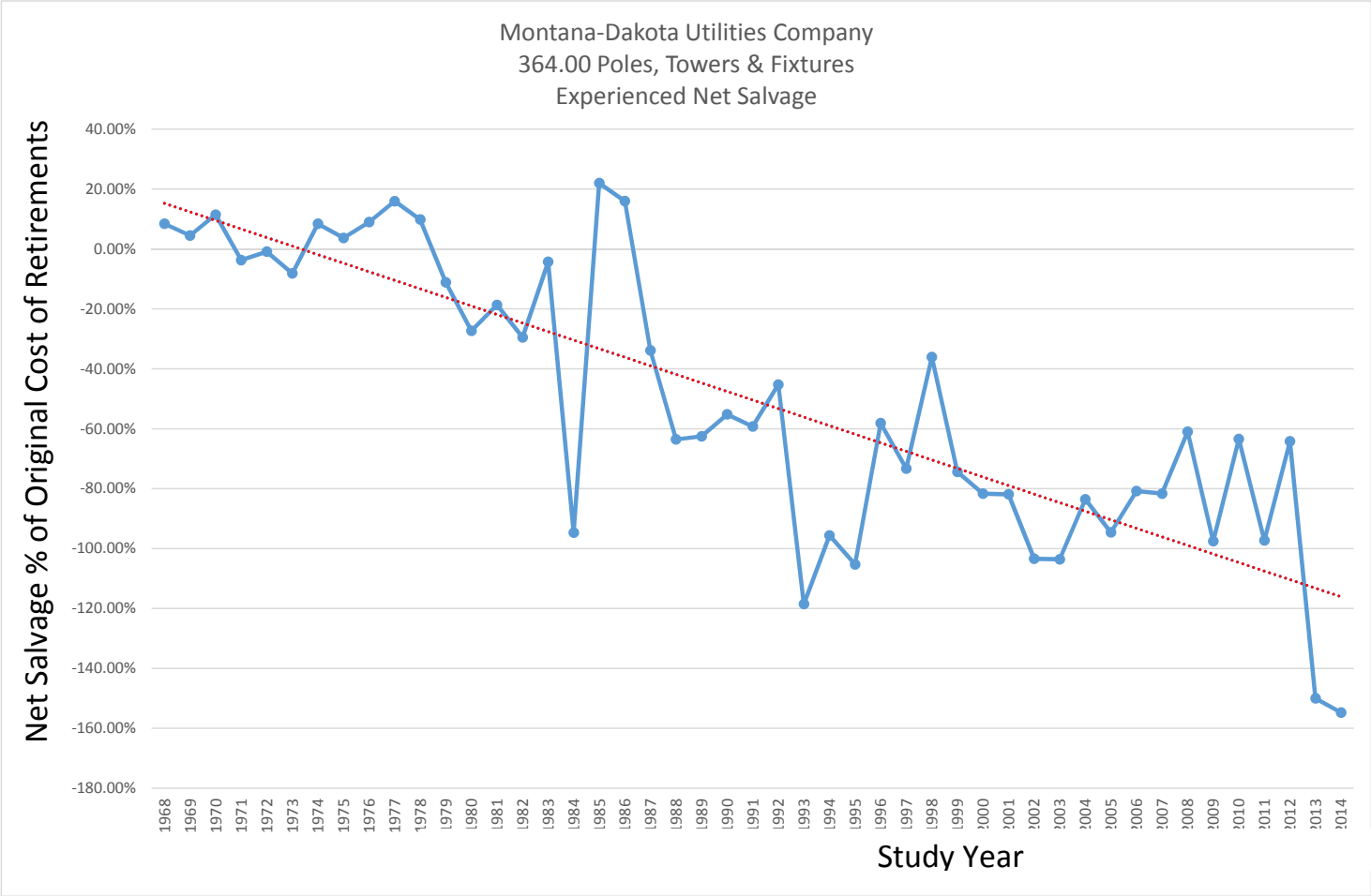
MDU Current Net Salvage Percent	**-35%**
MDU Depr Study Proposed Netative Net Salvage	**-50%**
Pous Proposed Negative Net Salvage	**-35%**

Montana-Dakota Utilities---Electric Plant

Trend Analysis of Experience Net Salvage -With Estimated Capped Negative Net Salvage for Analysis Purposes (And Display)

EMR Exhibit 4

Study Year	Neg. Net Salv. Amount	Net Salvage % of Original Cost of Ret.	
1968	13,933	8.41%	
1969	8,763	4.48%	
1970	20,576	11.45%	
1971	-4,492	-3.73%	
1972	-1,299	-0.88%	
1973	-12,561	-8.14%	
1974	12,136	8.43%	
1975	4,651	3.68%	
1976	11,440	8.96%	
1977	23,851	15.96%	
1978	14,006	9.82%	
1979	-28,587	-11.15%	
1980	-29,101	-27.32%	
1981	22,508	-18.68%	
1982	-46,035	-29.50%	
1983	-6,920	-4.30%	
1984	-61,123	-94.67%	
1985	43,300	21.99%	
1986	25,157	15.97%	
1987	-42,218	-33.88%	
1988	-57,097	-63.55%	
1989	-60,419	-62.54%	
1990	-71,030	-55.20%	
1991	-71,272	-59.26%	
1992	-68,650	-45.26%	
1993	-153,154	-118.51%	
1994	-136,372	-95.61%	
1995	-92,982	-105.27%	
1996	-165,004	-58.16%	
1997	-94,269	-73.29%	
1998	-84,429	-36.07%	
1999	-87,921	-74.40%	
2000	-86,871	-81.67%	
2001	-87,005	-81.88%	
2002	-118,951	-103.41%	
2003	-110,438	-103.58%	
2004	-120,221	-83.56%	
2005	-130,594	-94.60%	**Estimated**
2006	-134,859	-80.82%	**Capped**
2007	-76,927	-81.65%	**Neg. Net**
2008	-166,250	-61.01%	**Salv. For**
2009	-142,318	-97.55%	**Analysis**
2010	-61,802	-63.45%	**Purposes**
2011	-183,566	-97.29%	
2012	-139,737	-64.19%	Actual
2013	-522,499	**-150.00%**	-275.90%
2014	-762,640	-154.74%	



-115%

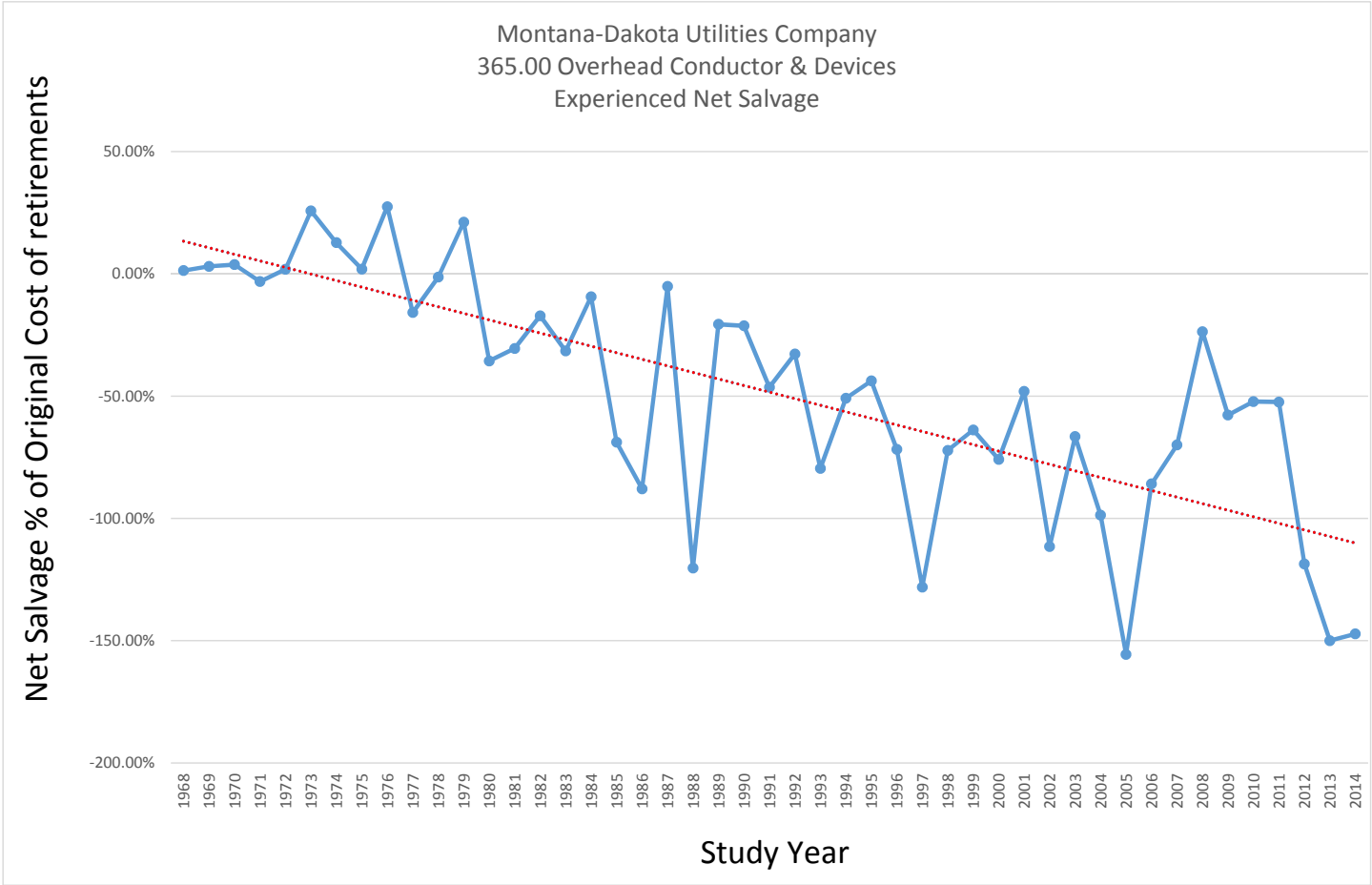
MDU Current Net Salvage Percent	**-70%**
MDU Depr Study Proposed Netative Net Salvage	**-95%**
Pous Proposed Negative Net Salvage	**-70%**

Montana-Dakota Utilities---Electric Plant

Trend Analysis of Experience Net Salvage -With Estimated Capped Negative Net Salvage for Analysis Purposes (And Display)

EMR Exhibit 4

Study Year	Neg. Net Salv. Amount	Net Salvage % of Original Cost of Ret.	
1968	1,891	1.36%	
1969	5,327	3.05%	
1970	6,025	3.78%	
1971	-3,300	-3.14%	
1972	2,408	1.89%	
1973	34,078	25.78%	
1974	16,689	12.75%	
1975	2,330	1.93%	
1976	31,776	27.45%	
1977	-17,932	-15.81%	
1978	-1,479	-1.33%	
1979	40,092	21.14%	
1980	-33,692	-35.62%	
1981	-21,637	-30.52%	
1982	-26,992	-17.15%	
1983	-35,615	-31.54%	
1984	-9,811	-9.37%	
1985	-138,717	-68.86%	
1986	-85,679	-87.91%	
1987	-3,606	-5.15%	
1988	-59,879	-120.32%	
1989	-9,788	-20.63%	
1990	-15,805	-21.25%	
1991	-27,797	-46.36%	
1992	-38,959	-32.74%	
1993	-53,030	-79.56%	
1994	-45,591	-50.89%	
1995	-21,013	-43.78%	
1996	-73,113	-71.76%	
1997	67,810	-128.10%	
1998	-51,731	-72.18%	
1999	-35,970	-63.82%	
2000	-37,646	-75.86%	
2001	-40,365	-48.05%	
2002	-67,999	-111.52%	
2003	-54,774	-66.55%	
2004	-76,289	-98.68%	
2005	-80,751	-155.64%	**Estimated**
2006	-63,483	-85.89%	**Capped**
2007	-45,870	-69.98%	**Neg. Net**
2008	-64,099	-23.68%	**Salv. For**
2009	-46,071	-57.75%	**Analysis**
2010	-25,857	-52.23%	**Purposes**
2011	-48,049	-52.42%	
2012	-179,622	-118.59%	Actual
2013	-301,451	**-150.00%**	-368.42%
2014	-496,872	-147.20%	



-110%

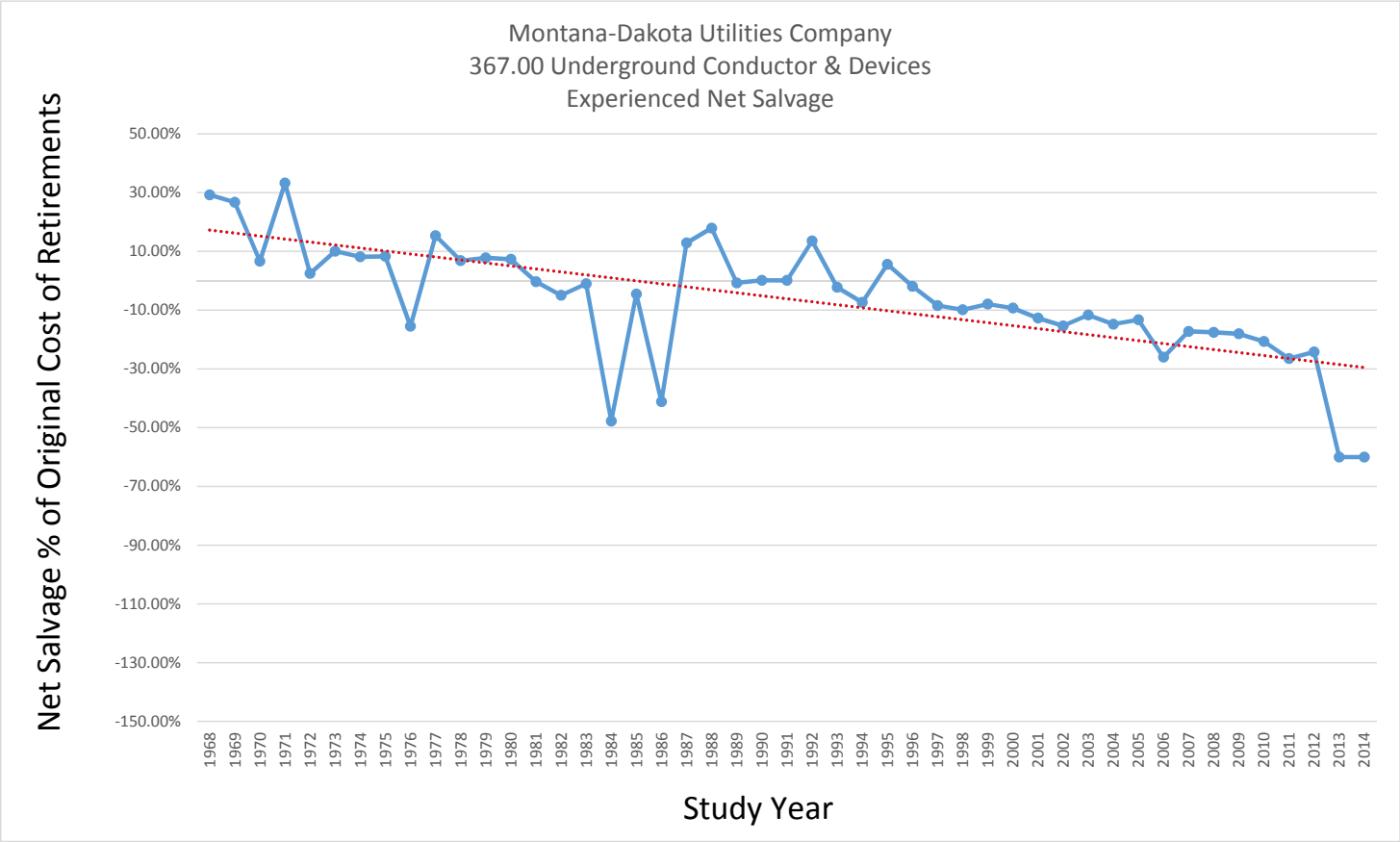
MDU Current Net Salvage Percent	**-70%**
MDU Depr Study Proposed Netative Net Salvage	**-85%**
Pous Proposed Negative Net Salvage	**-70%**

Montana-Dakota Utilities---Electric Plant

Trend Analysis of Experience Net Salvage -With Estimated Capped Negative Net Salvage for Analysis Purposes (And Display)

EMR Exhibit 4

Study Year	Neg. Net Salv. Amount	Net Salvage % of Original Cost of Ret.	
1968	375	29.26%	
1969	20	26.74%	
1970	68	6.67%	
1971	336	33.25%	
1972	109	2.50%	
1973	136	10.07%	
1974	143	8.14%	
1975	160	8.30%	
1976	-555	-15.49%	
1977	1,449	15.33%	
1978	578	6.83%	
1979	1,565	7.82%	
1980	1,262	7.32%	
1981	-88	-0.32%	
1982	-1,278	-4.96%	
1983	-280	-1.02%	
1984	-10,095	-47.75%	
1985	-2,958	-4.54%	
1986	-4,314	-41.16%	
1987	4,581	12.86%	
1988	6,721	17.93%	
1989	-225	-0.72%	
1990	54	0.13%	
1991	534	0.14%	
1992	11,024	13.54%	
1993	-3,179	-2.23%	
1994	-13,415	-7.35%	
1995	7,326	5.62%	
1996	-7,403	-1.88%	
1997	-14,975	-8.43%	
1998	-18,056	-9.88%	
1999	-21,871	-7.93%	
2000	-23,356	-9.30%	
2001	-30,781	-12.70%	
2002	-48,208	-15.35%	
2003	-36,416	-11.65%	
2004	-38,328	-14.79%	
2005	-32,413	-13.28%	**Estimated**
2006	-42,152	-26.01%	**Capped**
2007	-33,953	-17.24%	**Neg. Net**
2008	-112,076	-17.56%	**Salv. For**
2009	-70,789	-18.06%	**Analysis**
2010	-39,217	-20.68%	**Purposes**
2011	-138,734	-26.48%	
2012	-53,633	-24.22%	Actual
2013	-611,827	**-60.00%**	-137.90%
2014	-465,097	**-60.00%**	-102.21%



-30%

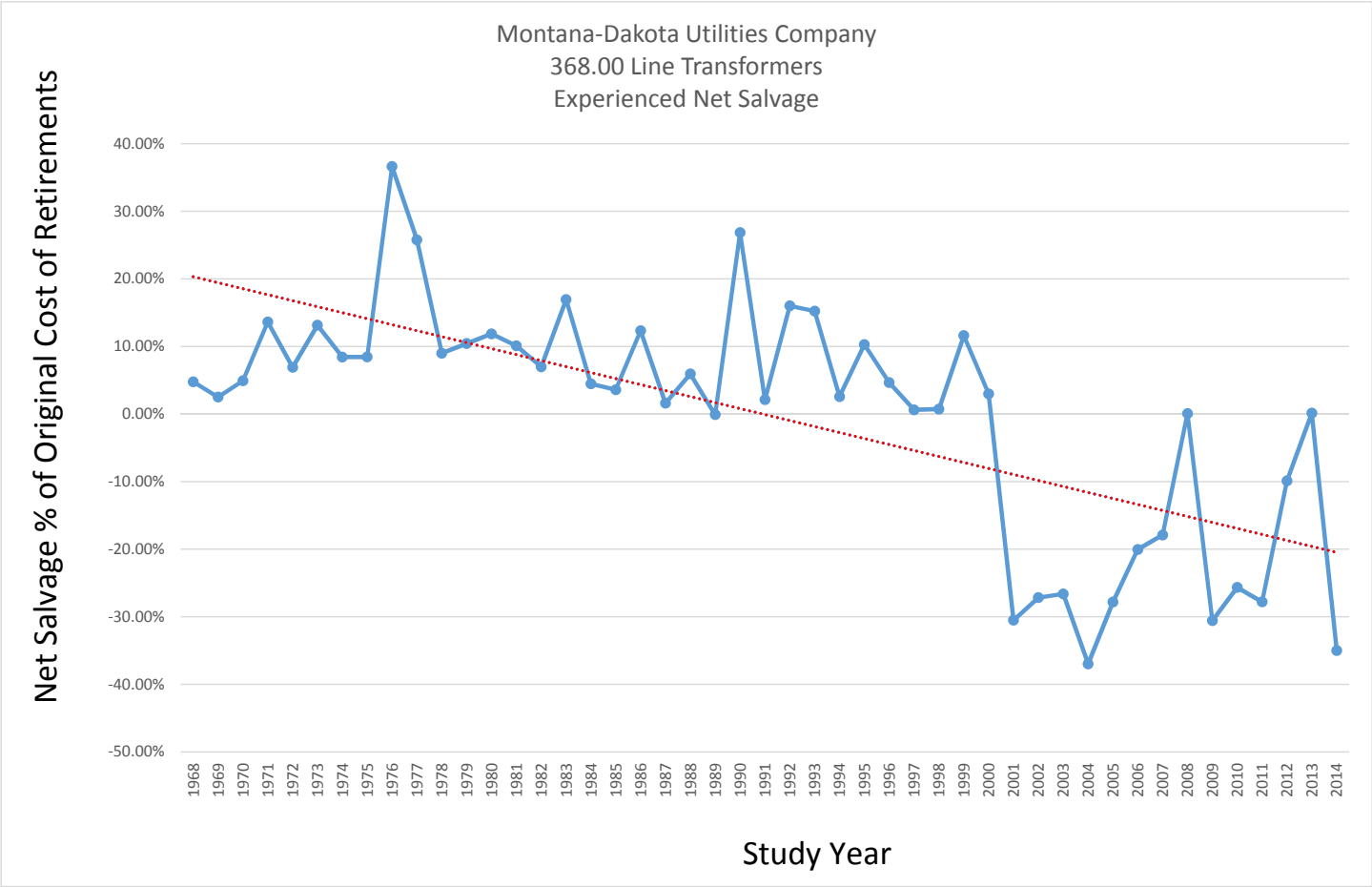
MDU Current Net Salvage Percent	**-15%**
MDU Depr Study Proposed Netative Net Salvage	**-25%**
Pous Proposed Negative Net Salvage	**-15%**

Montana-Dakota Utilities---Electric Plant

Trend Analysis of Experience Net Salvage -With Estimated Capped Negative Net Salvage for Analysis Purposes (And Display)

EMR Exhibit 4

Study Year	Neg. Net Salv. Amount	Net Salvage % of Original Cost of Ret.	
1968	2,401	4.77%	
1969	1,392	2.50%	
1970	2,299	4.92%	
1971	6,906	13.63%	
1972	3,450	6.91%	
1973	3,629	13.14%	
1974	2,678	8.43%	
1975	1,561	8.44%	
1976	28,542	36.62%	
1977	10,613	25.77%	
1978	5,267	9.00%	
1979	4,573	10.43%	
1980	8,255	11.87%	
1981	4,573	10.09%	
1982	5,337	6.99%	
1983	19,087	16.94%	
1984	5,379	4.47%	
1985	6,531	3.60%	
1986	14,601	12.33%	
1987	2,964	1.60%	
1988	6,519	5.94%	
1989	-132	-0.09%	
1990	16,855	26.85%	
1991	2,633	2.12%	
1992	10,337	16.01%	
1993	13,413	15.23%	
1994	1,535	2.58%	
1995	2,307	10.28%	
1996	4,201	4.65%	
1997	422	0.62%	
1998	1,120	0.73%	
1999	10,903	11.61%	
2000	2,565	2.98%	
2001	-25,854	-30.51%	
2002	-32,683	-27.17%	
2003	-27,260	-26.61%	
2004	-42,271	-36.97%	
2005	-28,431	-27.81%	
2006	-28,335	-20.04%	**Estimated**
2007	-21,358	-17.90%	**Capped**
2008	161	0.08%	**Neg. Net**
2009	-54,994	-30.57%	**Salv. For**
2010	-35,581	-25.65%	**Analysis**
2011	-52,877	-27.80%	**Purposes**
2012	-17,743	-9.89%	
2013	890	0.15%	Actual
2014	-266,825	**-35.00%**	-49.21%



-21%

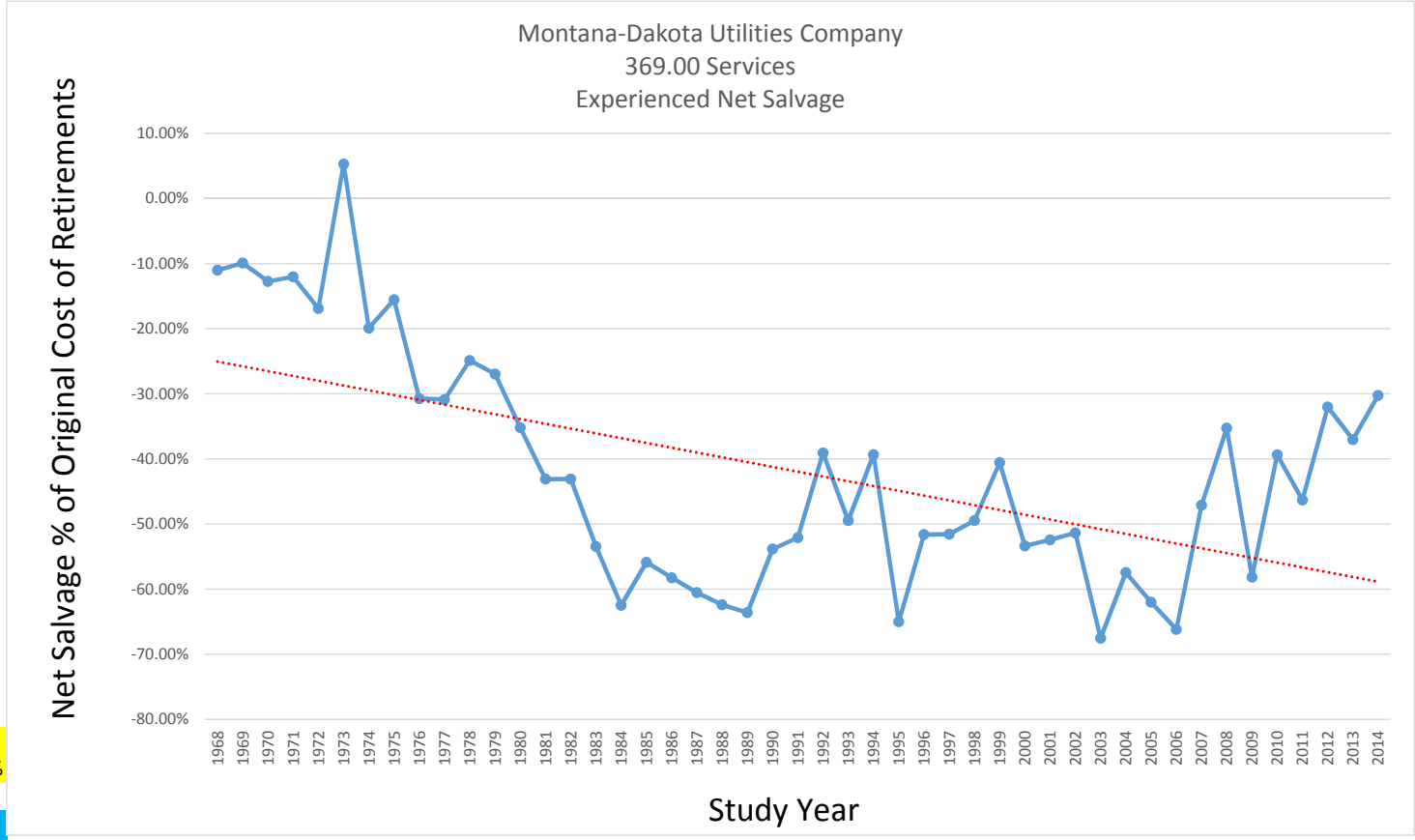
MDU Current Net Salvage Percent	**0%**
MDU Depr Study Proposed Netative Net Salvage	**-20%**
Pous Proposed Negative Net Salvage	**-10%**

Montana-Dakota Utilities---Electric Plant

Trend Analysis of Experience Net Salvage -With Estimated Capped Negative Net Salvage for Analysis Purposes (And Display)

EMR Exhibit 4

Study Year	Neg. Net Salv. Amount	Net Salvage % of Original Cost of Ret.	
1968	-6,565	-11.00%	
1969	-5,856	-9.91%	
1970	-8,254	-12.72%	
1971	-6,193	-12.03%	
1972	-7,829	-16.88%	
1973	3,145	5.30%	
1974	-10,487	-19.90%	
1975	-8,944	-15.54%	
1976	-15,596	-30.73%	
1977	-22,144	-30.88%	
1978	-12,479	-24.86%	
1979	-17,819	-26.96%	
1980	-20,458	-35.17%	
1981	-25,471	-43.10%	
1982	-24,860	-43.09%	
1983	-32,303	-53.44%	
1984	-33,445	-62.47%	
1985	-41,742	-55.87%	
1986	-26,374	-58.24%	
1987	-67	-60.53%	
1988	-33,254	-62.40%	
1989	-38,710	-63.60%	
1990	-29,252	-53.84%	
1991	-33,935	-52.09%	
1992	-30,710	-39.07%	
1993	-32,391	-49.47%	
1994	-44,263	-39.33%	Actual
1995	-9,916	**-65.00%**	-91.54%
1996	-61,677	-51.60%	
1997	-39,010	-51.56%	**Estimated**
1998	-42,675	-49.47%	**Capped**
1999	-40,763	-40.56%	**Neg. Net**
2000	-45,038	-53.35%	**Salv. For**
2001	-38,448	-52.42%	**Analysis**
2002	-45,088	-51.35%	**Purposes**
2003	-47,529	-67.55%	
2004	-61,378	-57.45%	
2005	-67,627	-62.00%	
2006	-84,551	-66.18%	
2007	-32,516	-47.10%	
2008	-84,283	-35.25%	
2009	-69,834	-58.16%	
2010	-40,838	-39.36%	
2011	-92,499	-46.31%	
2012	-55,789	-32.02%	
2013	-54,942	-37.03%	
2014	-51,155	-30.24%	



-58%

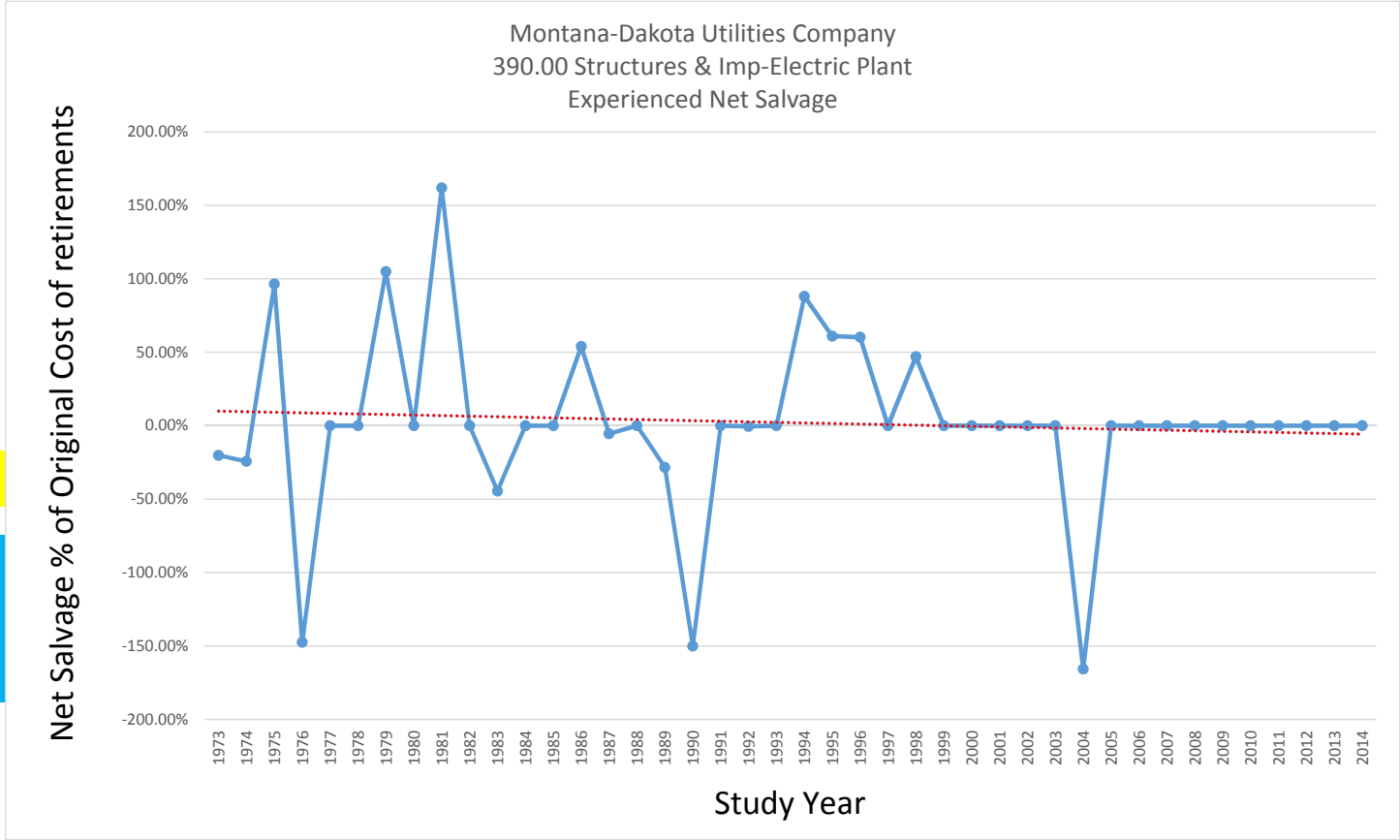
MDU Current Net Salvage Percent	**-70%**
MDU Depr Study Proposed Netative Net Salvage	**-50%**
Pous Proposed 369 OH Service Net Salvage Percent	**-70%**
Pous Proposed 369 UG Service Net Salvage Percent	**-20%**

Montana-Dakota Utilities---Electric Plant

Trend Analysis of Experience Net Salvage -With Estimated Capped Negative Net Salvage for Analysis Purposes (And Display)

EMR Exhibit 4

Study Year	Neg. Net Salv. Amount	Net Salvage % of Original Cost of Ret.	
1973	-1,376	-20.19%	
1974	-3,056	-24.28%	
1975	2,506	96.48%	
1976	-1,638	-147.46%	
1977	0	0.00%	
1978	0	0.00%	
1979	11,049	104.98%	
1980	0	0.00%	
1981	43,085	161.95%	
1982	0	0.00%	
1983	-4,698	-44.47%	
1984	0	0.00%	
1985	0	0.00%	
1986	2,084	53.95%	
1987	-2,341	-5.47%	
1988	0	0.00%	
1989	-7,267	-28.33%	Actual
1990	-36,678	**-150.00%**	-419.99%
1991	0	0.00%	
1992	-7	-0.47%	**Estimated**
1993	0	0.00%	**Capped**
1994	11,756	88.10%	**Neg. Net**
1995	13,073	60.95%	**Salv. For**
1996	38,025	60.31%	**Analysis**
1997	0	0.00%	**Purposes**
1998	84,379	46.96%	
1999	0	0.00%	
2000	0	0.00%	
2001	0	0.00%	
2002	0	0.00%	
2003	0	0.00%	
2004	-18,500	-165.71%	
2005	0	0.00%	
2006	0	0.00%	
2007	0	0.00%	
2008	0	0.00%	
2009	0	0.00%	
2010	0	0.00%	
2011	0	0.00%	
2012	0	0.00%	
2013	0	0.00%	
2014	0	0.00%	



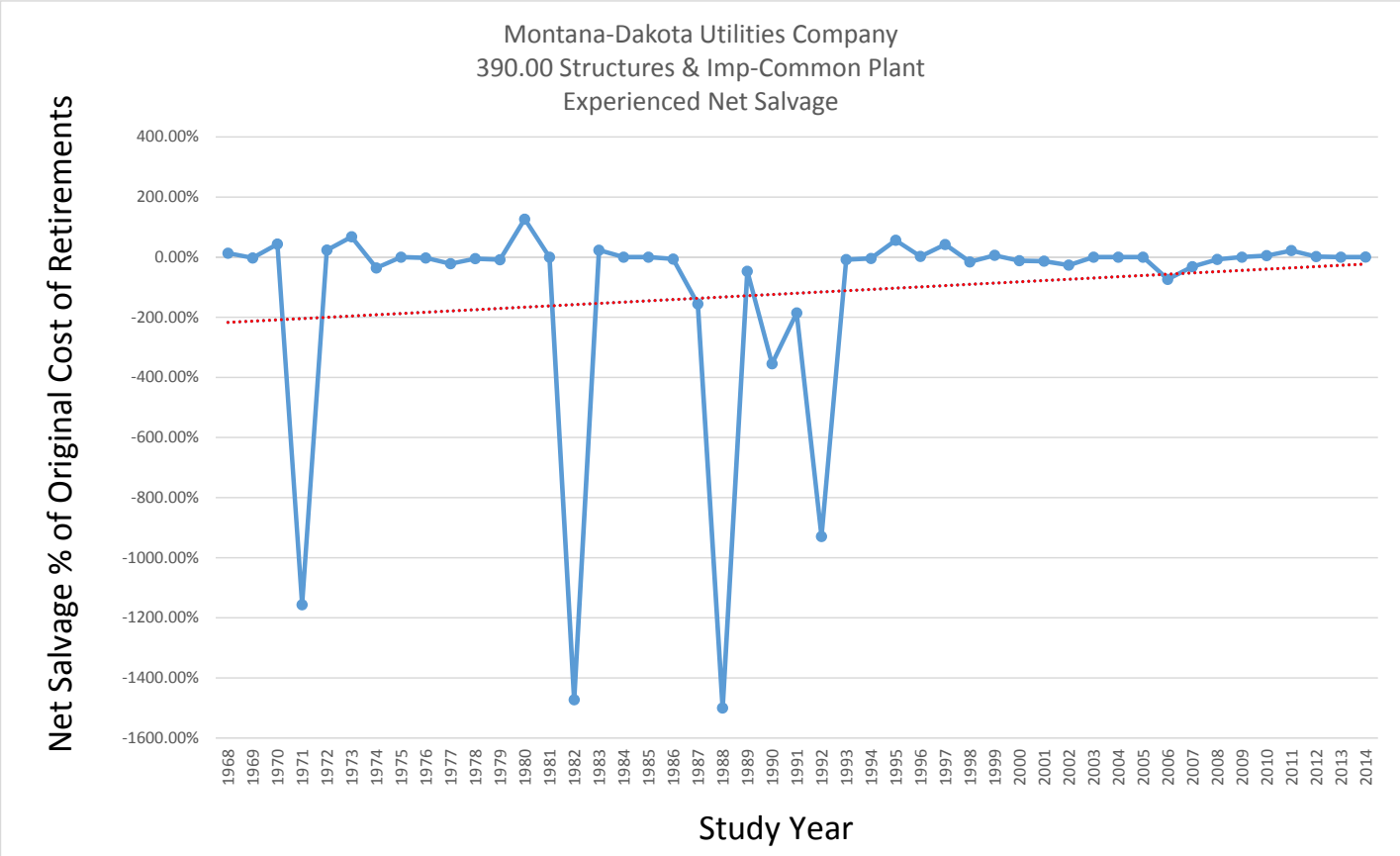
-5%

MDU Current Net Salvage Percent	**-10%**
MDU Depr Study Proposed Netative Net Salvage	**-10%**
Pous Proposed Net Salvage	**25%**

Montana-Dakota Utilities-Common Plant

Trend Analysis of Experience Net Salvage -With Estimated Capped Negative Net Salvage for Analysis Purposes (And Display)

Study Year	Neg. Net Salv. Amount	Net Salvage % of Original Cost of Ret.	
1968	622	13.08%	
1969	-629	-2.72%	
1970	4,149	43.51%	
1971	-641	-1156.20%	
1972	20,750	23.31%	
1973	556	67.55%	
1974	-2,381	-35.80%	
1975	0	0.00%	
1976	-18	-2.55%	
1977	-7,358	-21.92%	
1978	-304	-5.11%	
1979	-31	-8.53%	
1980	46,043	126.39%	
1981	0	0.00%	
1982	-35,198	-1472.52%	
1983	34,949	23.10%	
1984	239	0.00%	
1985	0	0.00%	
1986	-22,554	-6.39%	
1987	-178,544	-155.70%	Actual
1988	-44,408	**-1500.00%**	-4166.57%
1989	-1,362	-46.83%	
1990	-4,383	-354.75%	**Estimated**
1991	-21,000	-185.55%	**Capped**
1992	-59,486	-929.46%	**Neg. Net**
1993	-5,515	-8.24%	**Salv. For**
1994	-3,296	-4.32%	**Analysis**
1995	139,579	56.00%	**Purposes**
1996	4,207	2.41%	
1997	41,099	42.03%	
1998	-40,399	-15.79%	
1999	18,459	6.08%	
2000	-20,651	-12.00%	
2001	-14,719	-13.41%	
2002	-29,202	-26.54%	
2003	0	0.00%	
2004	-26,474	0.00%	
2005	-225	0.00%	
2006	-9,973	-73.71%	
2007	-14,205	-31.55%	
2008	-2,070	-7.68%	
2009	0	0.00%	
2010	2,894	4.90%	
2011	19,408	21.94%	
2012	3,622	1.88%	
2013	0	0.00%	
2014	1,212	0.16%	



-10%

MDU Current Net Salvage Percent	**-10%**
MDU Depr Study Proposed Netative Net Salvage	**5%**
Pous Proposed Net Salvage	**40%**

MDU-Common Plant

EMR Exhibit 5

Account 390-Structures & Improvements

Calculation of Implicit Average Service Life

Investment	**$1,000,000**	**Cost**	**Life (Yrs)**	**Component Inflation**
Superstructure	**67%**	**$670,000**	60	
Components -- (HVAC,Roof, Interior-Upgrades/Repl, Carpet, Windows, Etc).	**33%**	**$330,000**	20	2%

Year	Superstructure Cost	Recovery Period	Total Weight	Component Cost	Recovery Period	Total Weight	Component Inflation Factor	Weighted ASL (Yrs)	Sum Weights
1	670,000	60	40,200,000	330,000	20	6,600,000	1.00		46,800,000
2	670,000	60	40,200,000	330,000	20	6,600,000	1.02		
3	670,000	60	40,200,000	330,000	20	6,600,000	1.04		
4	670,000	60	40,200,000	330,000	20	6,600,000	1.06		
5	670,000	60	40,200,000	330,000	20	6,600,000	1.08		
6	670,000	60	40,200,000	330,000	20	6,600,000	1.10		
7	670,000	60	40,200,000	330,000	20	6,600,000	1.13		
8	670,000	60	40,200,000	330,000	20	6,600,000	1.15		
9	670,000	60	40,200,000	330,000	20	6,600,000	1.17		
10	670,000	60	40,200,000	330,000	20	6,600,000	1.20		
11	670,000	60	40,200,000	330,000	20	6,600,000	1.22		
12	670,000	60	40,200,000	330,000	20	6,600,000	1.24		
13	670,000	60	40,200,000	330,000	20	6,600,000	1.27		
14	670,000	60	40,200,000	330,000	20	6,600,000	1.29		
15	670,000	60	40,200,000	330,000	20	6,600,000	1.32		
16	670,000	60	40,200,000	330,000	20	6,600,000	1.35		
17	670,000	60	40,200,000	330,000	20	6,600,000	1.37		
18	670,000	60	40,200,000	330,000	20	6,600,000	1.40		
19	670,000	60	40,200,000	330,000	20	6,600,000	1.43		
20	670,000	60	40,200,000	330,000	20	6,600,000	1.46		
21	670,000	60	40,200,000	480,748	20	9,614,954			9,614,954
22	670,000	60	40,200,000	480,748	20	9,614,954			
23	670,000	60	40,200,000	480,748	20	9,614,954			
24	670,000	60	40,200,000	480,748	20	9,614,954			
25	670,000	60	40,200,000	480,748	20	9,614,954			
26	670,000	60	40,200,000	480,748	20	9,614,954			
27	670,000	60	40,200,000	480,748	20	9,614,954			
28	670,000	60	40,200,000	480,748	20	9,614,954			
29	670,000	60	40,200,000	480,748	20	9,614,954			
30	670,000	60	40,200,000	480,748	20	9,614,954			
31	670,000	60	40,200,000	480,748	20	9,614,954			
32	670,000	60	40,200,000	480,748	20	9,614,954			
33	670,000	60	40,200,000	480,748	20	9,614,954			
34	670,000	60	40,200,000	480,748	20	9,614,954			
35	670,000	60	40,200,000	480,748	20	9,614,954			
36	670,000	60	40,200,000	480,748	20	9,614,954			
37	670,000	60	40,200,000	480,748	20	9,614,954			
38	670,000	60	40,200,000	480,748	20	9,614,954			
39	670,000	60	40,200,000	480,748	20	9,614,954			
40	670,000	60	40,200,000	700,359	20	14,007,172			14,007,172
41	670,000	60	40,200,000	700,359	20	14,007,172			
42	670,000	60	40,200,000	700,359	20	14,007,172			
43	670,000	60	40,200,000	700,359	20	14,007,172			
44	670,000	60	40,200,000	700,359	20	14,007,172			
45	670,000	60	40,200,000	700,359	20	14,007,172			
46	670,000	60	40,200,000	700,359	20	14,007,172			
47	670,000	60	40,200,000	700,359	20	14,007,172			
48	670,000	60	40,200,000	700,359	20	14,007,172			
49	670,000	60	40,200,000	700,359	20	14,007,172			
50	670,000	60	40,200,000	700,359	20	14,007,172			
51	670,000	60	40,200,000	700,359	20	14,007,172			
52	670,000	60	40,200,000	700,359	20	14,007,172			
53	670,000	60	40,200,000	700,359	20	14,007,172			
54	670,000	60	40,200,000	700,359	20	14,007,172			
55	670,000	60	40,200,000	700,359	20	14,007,172			
56	670,000	60	40,200,000	700,359	20	14,007,172			
57	670,000	60	40,200,000	700,359	20	14,007,172			
58	670,000	60	40,200,000	700,359	20	14,007,172			
59	670,000	60	40,200,000	700,359	20	14,007,172			
60	670,000	60	40,200,000	700,359	20	14,007,172			
	Superstructure		**Componet-1st Replacements**	**Componet-2nd Replacement**		**Sum of Investments**			
Investments	**670,000**		**480,748**	**700,359**		1,851,106		**38.04**	**70,422,126**

Montana-Dakota Utilities **EMR Exhibit 6**

Electric & Common

Summary of Depreciation Parameters for Selected Property Groups Contested by MCC Wittness Mr. Pous And Responded to by MDU

Acct No	Account Description	Current Life Parameter	MDU Proposed Life Parameter	MCC-Mr. Pous Proposed Life Parameter	Current Net Salv Parameters	MDU Proposed Net Salv Par.	MCC-Mr. Pous Proposed Net Salv Parameter	Total Proposed Depreciation Expense: Total 12-31-14 MDU	Total 12-31-14 MCC-Mr. Pous	(MCC Prop. Net Red) 12/31/2014
	Wind Turbines									
341	Other Prod-Struc & Imp	20 Yr Life Span	20 Yr Life Span	25 Yr Life Span				401,867	308,679	(93,188)
344	Other Prod-Generators	20 Yr Life Span	20 Yr Life Span	25 Yr Life Span				4,647,873	3,380,444	(1,267,429)
345	Other Prod-Acces Elec Equip	20 Yr Life Span	20 Yr Life Span	25 Yr Life Span				919,396	680,878	(238,518)
346	Other Prod-Misc Power Plt Eq	20 Yr Life Span	20 Yr Life Span	25 Yr Life Span				58,255	56,280	(1,975)
355	Trans-Poles & Fixtures	45-R2	50-R3	60-R3	-35%	-50%	-35%	1,702,895	1,153,881	(549,014)
364	Distr-Poles, Towers && Fix				-70%	-75%	-70%	1,412,246	1,162,338	(249,908)
365	Distr-OH Cond & Devices				-70%	-85%	-70%	841,771	738,601	(103,170)
367	Distr-UG Cond & Devices	30-R3	40-R2	48-S0.5	-15%	-25%	-15%	2,756,383	1,963,209	(793,174)
368	Distr-Line Transformers				0%	-20%	-10%	1,362,427	1,203,342	(159,085)
369.1	Distr-Services-OH				-70%	-50%	-70%	122,366	161,807	39,441
369.2	Distr-Services-UG	30-R4	45-R3	53-R2	-70%	-50%	-20%	752,857	384,772	(368,085)
	Total Acct 369							**875,223**	**546,579**	**(328,644)**
390	Elec-Struct & Improv	35-R2.5	29-L2	45-R2.5	-10%	-10%	25%	27,565	6,779	(20,786)
	Total Electric							**15,005,901**	**11,201,010**	**(3,804,891)**
390	Common-Str & Improv	35-R3	38-R3	45-S1.5	-10%	5%	40%	1,138,811	417,024	(721,787)
	Total Common							**1,138,811**	**417,024**	**(721,787)**
	Grand Total Elec & Common							**16,144,712**	**11,618,034**	**(4,526,678)**

MONTANA-DAKOTA UTILITIES CO.
A Division of MDU Resources Group, Inc.

Before the Public Service Commission of Montana

Docket No. D2015.6.51

Rebuttal Testimony
of
Travis R. Jacobson

Q. Would you please state your name and business address?

A. Yes. My name is Travis R. Jacobson and my business address is 400 North Fourth Street, Bismarck, North Dakota 58501.

Q. What is your position with Montana-Dakota Utilities Co.?

A. I am the Regulatory Analysis Manager of Montana-Dakota Utilities Co. (Montana-Dakota), a Division of MDU Resources Group, Inc.

Q. Are you the same Travis R. Jacobson who filed direct testimony earlier in this proceeding?

A. Yes, I am.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to address certain adjustments proposed by Mr. Albert E. Clark, testifying on behalf of the Montana Consumer Counsel, and Mr. Kevin C. Higgins on behalf of the Montana Large Customer Group. I am sponsoring Exhibit No.___ (TRJ-5), Plant Additions and Exhibit No.___(TRJ-6), Summary of Montana-Dakota's position regarding MCC Adjustments.

<u>Testimony of Albert E. Clark</u>

Q. On pages 5 and 6 of his testimony, Mr. Clark criticizes the Company's methodology in developing the test period. Would you

address his concerns?

A. Mr. Clark characterized Montana-Dakota's development of the pro forma adjustments as making "substantial post-test year adjustments that are based solely on the 2015 operating and construction budgets". Mr. Clark is incorrect. Montana-Dakota used the 2015 operating budget only as a guide, incorporating the budget amounts when, after reviewing the budget amount and supporting documentation, it was deemed to be an appropriate known and measurable adjustment.

Q. Beginning on page 6, Mr. Clark made an adjustment to the Company's proposed KVAR penalty revenue. Do you agree with his adjustment?

A. No, I do not. With respect to the KVAR penalty revenue, Montana-Dakota has historically used a three year average of KVAR penalty revenues in order to smooth out the year to year fluctuations in KVAR revenue. Mr. Clark suggests there is no justification for a three year average and, instead, recommends the 2014 per books amount to be consistent with other components of other revenues. Montana-Dakota believes that a three year average is appropriate in order to smooth out year to year fluctuations whereas other components of other revenue are much more stable year to year. Montana-Dakota has used the three year average in the computation of KVAR penalty revenue in the revenue requirement in both the D2007.7.79 and D2010.8.82 rate filings.

Q. Mr. Clark adjusts Montana-Dakota's uncollectible accounts expense on page 9 of his testimony and company use on page 13. Do you agree with these adjustments?

A. No. While Mr. Clark correctly points out these adjustments should match the final revenue increase, his adjustment for each item is overstated, at a minimum, if you take into account the errors Mr. Clark has acknowledged and has corrected in his responses to Data Requests Nos. MDU-004 and MDU-005.

Q. Beginning on page 11 of his testimony, Mr. Clark adjusts Montana-Dakota's self-insurance expense. Do you agree with his rationale?

A. No. Mr. Clark proposed to use a four year average rather than the Company's five year average reducing self-insurance expense by $14,137. His rationale was that 2012 was too high and, therefore, should be thrown out. Interestingly, 2012 was in the middle of the averaging period. The Company used a five year average in order to achieve a representative expense over a period of time and removing only the highest year clearly distorts the results and should be rejected for lack of reasonable basis.

Q. On page 13 of his testimony, Mr. Clark makes a contingent adjustment to the Company's pro forma production taxes. Will you comment on his adjustment?

A. Yes. Mr. Clark removed $112,051 related to a pro forma adjustment to production taxes related to Thunder Spirit. Mr. Clark states it is based

on the proposition that Thunder Spirit does not come into service by December 31, 2015. As discussed in the rebuttal testimony of Mr. A. Welte, the Thunder Spirit facility began producing energy in October of 2015 and was declared to be in commercial operation as of December 31, 2015. Mr. Clark does agree that this adjustment should be reversed to match the inclusion of Thunder Spirit.

Q. Mr. Clark proposes to increase the amortization period over which Montana-Dakota would recover regulatory commission expense. Do you agree with his rationale?

A. No. Mr. Clark acknowledged that Montana-Dakota has filed cases in 2007, 2010 and 2015 but contends five years is most appropriate. Considering the current national environmental culture and the magnitude of costs to comply with current and proposed environmental rules, it is unreasonable to amortize the cost of this rate case over a five year period and extending the amortization period will result in higher costs upon the Company's next filing. The $37,640 adjustment should be rejected and rate case expense should be amortized over a three year period.

Q. On page 14, Mr. Clark describes his adjustment to the RICE project located at the Lewis & Clark station site. What changes does he make and do you agree with him?

A. Mr. Clark referenced two data responses which the Company provided at his request. Each of those responses provided detail as to pro forma costs specific to the RICE and MATS projects. I do agree with Mr.

Clark in his determination of the RICE unit costs. However, he has effectively removed all of the incremental costs associated with the MATS project. Mr. Clark does not discuss or support any reason for removing these costs. Therefore, I find no rational basis for removing the incremental MATS operating costs and the reduction to Montana-Dakota's O&M in the amount of $36,405 should be rejected.

Q. Mr. Clark proposes to remove all transmission charges the Company has included in this rate filing. Does the Company agree with Mr. Clark?

A. Absolutely not. Transmission charges are certainly a significant component of the cost of delivering energy to the customer. Montana-Dakota has incurred transmission expense in the test year and has reflected a reclassification of $186,584 (Montana-Dakota Adjustment No. 11, Rule 38.5.157, Statement G, page 12 of 35) related to a transmission arrangement that is being replaced with transmission service provided by SPP. Additionally, actual 2014 WAPA NITS transmission services in the amount of $269,476 (Statement Workpapers G-62) will also be provided by SPP in a like tariff arrangement effective October 1, 2015. These two components alone account for $456,060 of the $1,620,619 that Mr. Clark claimed that the Company "utterly failed to substantiate." All remaining costs are further discussed in the direct testimony of Mr. D. Neigum. Mr. Neigum's testimony does include reasonable estimates of charges as of the date of filing the rate case and contemplates the Company's expected

volumes affected by SPP. Mr. Neigum further discusses updates to the SPP transmission charges in his rebuttal testimony.

During 2015, the Company did incur net transmission expenses of approximately $1,268,300, including the facilities charge (referenced in Adjustment No. 11) of $199,800 and joint use revenue (similar to Adjustment No. 3) of $282,000. The total SPP charges incurred during the last quarter of 2015 are $115,500 and MISO Schedule 26/26a expenses were approximately $846,000.

In summary, I disagree that the Company "utterly failed to substantiate" its pro forma transmission adjustment and Mr. Clark's recommendation to reduce test year expense by $1,631,698 should be rejected. While the incremental SPP costs are expected to be offset by revenue credits for Montana-Dakota owned facilities used in SPP's system, the annual 2015 expense is representative of ongoing transmission expenses.

Q. Relative to transmission expenses, has the Company considered alternative mechanisms to ensure only actual costs incurred are recovered from its customers?

A. Yes, it has. As discussed in the direct testimony of Ms. T. Aberle, Montana-Dakota has proposed a Transmission Cost Recovery Rider (TCRR). Implementation of such a rider would completely satisfy Mr. Clark's concerns and remove any discrepancy between the Company's computation of the revenue requirement and the actual costs incurred.

While the transmission system must be designed and built to deliver energy during the system peak (i.e. capital investment), the transmission charges incurred to deliver energy to the customer are largely predicated on energy usage. The use of a tracker more closely aligns energy usage and the associated charges.

A transmission tracker will also allow a timely tracking of expenses associated with both MISO and SPP. The Company does not control the costs associated with projects cost shared across all members of each RTO but is responsible for costs incurred through these entities. Montana electric operations portion of Montana-Dakota's assigned MISO Schedule 26 and 26a costs have increased from about $497,000 in 2014 to $846,000 during 2015. SPP has similar costs that will be borne by all loads in SPP.

Q. Mr. Clark's last adjustment to Other O&M reduces regional market expense by $15,577. Does the Company agree with this reduction?

A. No, it does not. Once again, Mr. Clark chose to take a volatile expense and use the low point. Montana-Dakota has demonstrated that this expense changes year over year and using an average is much more appropriate.

Q. Mr. Clark proposes an adjustment to deprecation rates to reflect the depreciation rates proposed by Mr. Jacob Pous. Does the Company agree with those propose depreciation rates?

A. Mr. Pous proposed the Company adopt the probable end of life of

the other operating partners for the Big Stone Station located in South Dakota. Montana-Dakota does accept that recommendation. Mr. Pous also proposed to lengthen the service life the Thunder Spirit wind facility located in North Dakota from 20 year to 25 years. Montana-Dakota does accept that recommendation as well.

All remaining depreciation adjustments recommended by Mr. Pous should be rejected. Mr. Earl M. Robinson of AUS Consultants addresses the remaining proposed deprecation rates in his rebuttal testimony.

Q. Has Mr. Clark supported the adjustment to deferred taxes shown on Exhibit No. ___(AEC-2), Column (AA)?

A. No. Mr. Clark indicated in his response to Data Request No. MDU-004, part c. that the adjustment was related to taxes other than income taxes because of a reduction in property tax associated with post-test year plant additions. Montana-Dakota does not record deferred taxes associated with property taxes. Further, Mr. Clark indicated in his testimony that adjustments to depreciation expense along with the associated change in deferred tax, including the rate base impact, are shown in Exhibit No. ___(AEC-2), Column (R). Finally, any change to deferred taxes must have an associated income statement change on which it is calculated. In this case, Mr. Clark has reflected no income statement impact. Therefore, the entire $141,113 adjustment should be rejected. The associated impact to the deferred taxes of $70,557 shown on the rate base statement must also be rejected for the same reason.

Q. On pages 18-20, Mr. Clark discusses his adjustment to post-test period plant additions and the related adjustments. Do you agree with his adjustments?

A. No, I do not. Mr. Clark prepared his testimony prior to December 31, 2015 and was provided the latest information available, which was through September 30, 2015. Mr. Clark also excluded two projects with a combined value of $2,292,863 from the capital additions provided by the Company as of September 30, 2015. The projects are both transmission lines located in Montana – one near Glendive and the other between Baker and Plevna – and were placed in service in order to serve Montana-Dakota's customers in the state of Montana. The Glendive project is a rebuild of an existing transmission line that is about 70 years old and is being rebuilt because of its condition. The Baker/Plevna project is a new transmission line being built for reliability by providing a secondary feed to existing customers and, at the same time, will allow for increased capacity to allow for load growth. Both projects should have been included in the Company's original request but were missed because of an incorrect in-service date used in the fixed asset accounting system.

The test period, as acknowledged by Mr. Clark in his testimony, continues until December 31, 2015. The removal of all capital additions placed into service subsequent to September 30, 2015 as well as the transmission projects is unreasonable and Montana-Dakota should be allowed to include all additions completed in 2015. Total plant additions

through December 31, 2015, as shown in Exhibit No.___(TRJ-5), are $100,610,326. This projection includes the four large generation projects which total $88,371,305. The remaining total of $12,239,021 actually exceeds the amount requested in the rate case filing of $10,342,630.

My second issue with this proposed adjustment is the approach in which Mr. Clark has made the adjustments. Each of the projects closed to plant in-service in this filing result in a rate base increase equal to one-half of the value of that addition. Deprecation and property tax are also calculated on the 50 percent value. Mr. Clark appropriately used the one-half method for his adjustment to rate base. However, the adjustment for both depreciation and property tax incorrectly used the total value of the capital addition. The effect is a doubling of Mr. Clark's adjustment to depreciation and property tax associated with plant additions.

Q. Were there other issues raised by Mr. Clark that you would like to address?

A. Yes. There are two additional issues. First, Mr. Clark proposed to shorten the amortization of the over-recovery of decommissioning cost from ten years to five years. Montana-Dakota does not take issue with that adjustment. However, Mr. Clark's supporting schedules to his testimony did not reflect the appropriate adjustment to deferred taxes nor did it reflect the rate base impact. Mr. Clark did acknowledge, in the response to Data Request No. MDU-004, part a, that the income tax expense was incorrectly computed and did provide a correction.

However, he failed to adjust the rate base accordingly.

The second issue relates to the recently enacted bonus tax deprecation election available to the Company. Mr. Clark referenced the extension of bonus tax depreciation in his testimony. In late December, a tax extenders bill was signed into law by President Obama. The bill included an extension of the 50 percent bonus tax depreciation on eligible assets placed in service during 2015. Given the magnitude of the capital additions, specifically regarding the four large generation projects, electing bonus depreciation may appear to have a dramatic downward impact on the Company's revenue requirement as noted by Mr. Clark.

However, Mr. Clark has not considered all aspects of the election of bonus depreciation and its impact on rate base as it relates to Montana-Dakota's electric utility operations. For calendar year 2014, Montana-Dakota's Montana electric operations produced a taxable loss as presented in Rule 38.5.169, Statement J, page 6, which was due in part to the large tax deduction related to 2014 bonus tax depreciation. While not readily apparent, Montana-Dakota did not fully utilize the Production Tax Credits (PTCs) earned in 2014 due to the taxable loss. Un-utilized PTCs are appropriately shown on the rate base statement as an offset to accumulated deferred taxes thereby increasing the overall rate base. On a pro forma basis, as shown in Rule 38.5.169, Statement J, page 9, the Montana electric operations also produce a taxable loss. Even after inclusion of the proposed rate increase of $11.8 million, Montana electric

operations would continue to show a taxable loss in the pro forma period, before any application of 2015 bonus tax depreciation, which limits the amount of bonus tax depreciation the Company would be able to utilize and receive an offset to cash taxes paid.

The reason for the pro forma taxable loss is that the large generation assets already provide significant tax depreciation before any consideration of bonus tax depreciation. The pro forma tax depreciation amounts to $21.3 million with only $4 million of book depreciation, which has a significant effect on taxable income. Thunder Spirit qualifies as a five year tax life asset and receives 20 percent tax depreciation in the year it is placed in service and 32 percent tax depreciation in the second year of its life. The Big Stone AQCS project will receive 50 percent tax depreciation on eligible capital dollars expended prior to 2015 regardless of the Company's election in 2015 and is also eligible for accelerated tax depreciation granted by the IRS for pollution control assets. The MATS project also qualifies for accelerated tax depreciation for pollution control assets.

Montana-Dakota has reflected adjustments for the purpose of setting rates on an on-going basis. Electing to take bonus tax depreciation results in a lower taxable income, which results in a higher deferred tax liability and at the same time reduces rate base. However, in the case where the tax payer is unable to utilize the additional tax depreciation, un-utilized deferred tax liabilities are offset by net operating

loss carryforward (or deferred tax assets) on the rate base. The net effect on the rate base would be the same as if no election for bonus depreciation was taken. Additionally, un-utilized PTCs are also included in rate base as an offset to accumulated deferred tax, ultimately a rate base addition. Taken as a whole, the election of bonus tax depreciation increases the revenue requirement when the additional tax deprecation cannot be utilized. As mentioned, the pro forma Montana electric operations produce a taxable loss before any consideration of 2015 bonus tax depreciation. In addition, while PTCs were shown as being fully utilized, the Company does not expect full utilization during 2015. However, on an on-going basis (which was the premise the rate case was prepared) Montana-Dakota does expect to utilize PTCs if bonus depreciation is not elected in 2015. If bonus tax depreciation is elected in 2015, Montana-Dakota does not expect the PTCs to be fully utilized for an extended period of time and the resulting effect would be harmful to customers. Therefore, while Mr. Clark's proposal to reflect bonus tax depreciation for 2015 is reasonable in theory, in reality Montana-Dakota will not be able to use the 2015 bonus tax depreciation and no adjustment should be contemplated.

Q. You have included Exhibit No.___(TRJ-6). Will you please describe its purpose?

A. Yes. I have provided a summary of all adjustments to the income statement followed by all adjustments to the rate base statement that have

been recommended by Mr. Clark. I have also provided a summary of the Company's position regarding the MCC's adjustments as I have describe above. There are additional adjustments that Mr. Clark failed to make but Company acceptance of the five year amortization period for decommissioning costs necessitates further adjustments.

Testimony of Kevin C. Higgins

Q. Mr. Higgins has restated the rate base addition for its four major plant additions in 2015. Do you agree with Mr. Higgin's recommendation?

A. No. Mr. Higgins indicated that the test period approach advanced by the Company is highly problematic. Mr. Higgins primary issue is related to the four large generation projects which were placed in-service during December 2015. Montana-Dakota has used the same approach in front of this same Commission in both Docket Nos. D2007.7.79 and 86.5.28 for the other wind farms owned by the Company, Cedar Hills and Diamond Willow, as well as the incremental purchases of the Company's share of the Big Stone and Coyote generating stations. In each case, the Commission approved the approach recognizing that, at the time the final rates were implemented, the facilities would be used and providing service to the customers in the state of Montana.

Montana-Dakota has included the full effect of the wind in its computation of pro forma fuel and purchased power expense as well as the full effect of the PTCs in its revenue requirement. Again, at the time

the rates become effective, the associated savings will be reflected in fuel and purchased power and through lower tax expense because of the PTCs related to Thunder Spirit Generation. Mr. Higgins has used what amounts to a daily averaging for his computation of rate base additions for the four large generation projects based on the final in-service date. The in-service dates are important but it is also important to understand that the Big Stone Station has been producing energy since October 2015 while finishing work on AQCS has been taking place. Thunder Spirit has had turbines providing energy since October 2015 and the Lewis & Clark Station was producing energy in November following the MATS installation outage while remaining work was finished as well.

As discussed in his testimony, Mr. A. Welte provides support that each of the four large generation projects were placed in-service during 2015. Mr. Higgins averaging method would unduly penalize the Company for complying with environmental regulations and building capacity and energy resources to meet its customers' needs which are currently used and useful and should be rejected in its entirety.

One last point, it is also important to understand that Montana-Dakota's has updated its annual fuel and purchased power cost tracking adjustment pursuant to the terms of its Rate 35 to reflect the inclusion of Thunder Spirit generation. So, from a practical standpoint, savings resulting from Thunder Spirit wind generation have already begun to impact customers as a reduction to fuel and purchased power. Exclusion

of any portion of the asset would result in a significant mismatch to the benefits received by Rate 35 customers.

Q. Mr. Higgins proposed an adjustment to transmission expense. Do you agree with his adjustment?

A. Mr. Higgins does recognize the changes that have taken place during the pro forma period. He has recommended an alternative computation which results in a reduction in the pro forma expense in the amount of $984,337. As noted earlier in my testimony, Montana-Dakota has proposed a Transmission Cost Recovery Rider (TCRR). Implementation of such a rider should resolve Mr. Higgins' concern and remove any discrepancy between the Company's computation of the revenue requirement and the actual costs incurred.

2015 transmission expenses, as provided above, are less than the Company's pro forma amount included in the revenue requirement. At the same time, the actual expense is higher than projected by Mr. Higgins and his adjustment of $984,337 should be rejected.

Q. Are there other adjustments brought forward by Mr. Higgins? If so, do you agree?

A. Another adjustment proposed by Mr. Higgins is a reduction in the generation overhaul expenses included in the Big Stone pro forma adjustment proposed by the Company on page 30 of his testimony. I do not agree with his adjustment in large part because, as noted in my direct testimony, Montana-Dakota did not have a major overhaul in the base

year 2014. Mr. Higgins does correctly point out that certain costs were incurred in 2014 in advance of a major overhaul but it hardly constitutes a major overhaul. I do not take issue with using an average major overhaul cost over a period of time but the inclusion of 2014 is certainly not appropriate. For this reason, Mr. Higgins adjustment for $311,858 should be rejected.

Q. Are there other recommendations you would like to address?

A. Yes, I would also like to address the recommendation to change the fuel and purchased power adjustment mechanism from the current 90/10 sharing band to 85/15. The Company proposed to share wholesale sales margin 85/15 as an incentive to maintain its generation assets in order to offer them into the MISO market as low cost resources. Doing so also benefits the customer in that only least cost generation, which is dispatched by MISO rather than the Company, serves the customer with generation in excess of the customer load being considered wholesale sales. The MISO market provides the customer the benefit of all member company's least cost generation. Therefore, I disagree that the sharing of pool sales margin and fuel and purchased power must move in tandem and Mr. Higgins adjustment should be rejected.

Q. Did either Mr. Clark or Mr. Higgins recommend adjustments to the cost of capital used in the computation of the revenue requirement in this filing?

A. Yes, both recommended changes to the cost of capital used in the

revenue requirement. Mr. Senger and Dr. Gaske will address the issue of capital structure and rate of return in their testimonies.

Q. Does this complete your rebuttal testimony?

A. Yes, it does.

MONTANA-DAKOTA UTILITIES CO.
2015 PLANT ADDITIONS - SUMMARY
ELECTRIC UTILITY - MONTANA

	As Filed	2015 Actual
Steam Production	$27,704,846	$27,944,013
Other Production	66,948,194	64,410,738
Total Production	$94,653,040	$92,354,751
Transmission	1,576,156	3,188,880
Distribution 1/	3,897,364	3,158,816
General		
Other	588,119	864,287
Transportation	269,517	306,073
Intangible	124,718	14,479
Total General	$982,354	$1,184,839
Common		
Other	314,566	105,495
Computer Equipment	154,715	102,708
Structures and Improvements	172,983	150,092
Transportation	132,018	118,704
Total Common	$774,282	$476,999
Common Intangible	445,252	246,041
Total Plant Additions	$102,328,448	$100,610,326
Large Generation Projects:		
AQCS Project - Big Stone	$21,841,157	$20,764,960
MATS compliance - L&C	3,663,366	3,390,411
RICE Units - L&C	9,812,164	9,619,378
Thunder Spirit Wind Farm	56,669,131	54,596,556

1/ Excludes growth additions of $1,219,967.

MONTANA CONSUMER COUNSEL
Mr. Clark Testimony Summary

Page	MCC Proposed Adjustment	Adjustment Amount	Accepted Adjustment	Explanation
6	KVAR	$ 10,760		
8	Incremental Labor	(56,985)	$ (56,985)	Based on updated labor estimate
9	401K and Other Benefits	(1,864)	(1,864)	Correction of error
9	Bad Debts	(9,526)		
10	Postage	(1,314)	(1,314)	Updated actuals
11	Advertising	(2,840)	(2,840)	Correction of error
11	Self-insurance	(14,137)		
12	Hesket III O&M	(39,918)		
13	Company Use	(7,472)		
14	Rate Case Expense	(37,640)		
14	MATS and L&C RICE Unit	(36,405)		
15	Transmission costs	(1,631,698)		
15	Regional Market expense	(15,777)		
10	Decommissioning	(671,219)	(671,219)	Reduce amortization to 5 years
21	Big Stone - Depreciation	(227,875)	(227,875)	Life extension from 2017 to 2046
21	Big Stone - Depreciation	(414,982)	(414,982)	Life extension from 2017 to 2046
21	Thunder Spirit Wind	(566,692)	(566,692)	Life extention from 20 to 25 years
21	Cedar Hills & Diamond Willow	(416,541)		
21	Acct 355, 364, 365, 367-9, 390	(413,447)		
21	Lower Plant Adds	(146,008)		
7	MPSC & MCC Taxes	(5,565)	(5,565)	Update rates - effective 10/1/2015
13	Production taxes	(112,051)		
21	Lower Property Tax	(128,106)		
	Income Tax-changes above	1,957,095	767,795	Income tax at 39.3875%
17	Income tax - interest deduction	18,321		
20	Income Tax Post Test Year	(141,114)		
	Income Statement Changes	**$ (3,134,520)**	**$ (1,181,541)**	
18	Lower cap ex additions	$ (3,335,703)		
21	Lower depreciation exp	601,936	$ 113,938	Life extension from 2017 to 2046
	Decommissioning		335,610	Reduce amortization to 5 years
21	Lower depreciation exp-large projects	981,673	981,673	Big Stone AQCS and Thunder Spirit
17	Materials & Supplies	424,558	424,558	Updated actuals
17	Fuel Stores	61,661	61,661	Updated actuals
17	Prepaid Insurance	13,524	13,524	Updated actuals
17	Injuries & Damages	(22,710)	(22,710)	Updated actuals
21	Deferred tax on deprecation	(237,087)	(56,969)	Life extension from 2017 to 2046
21	Deferred tax on large project depr	(386,656)	(386,656)	Big Stone AQCS and Thunder Spirit
20	Deferred tax on tax adjustment	70,557		
	Deferred tax on decommissioning		(132,188)	Reduce amortization to 5 years
	Rate Base Changes	**$ (1,828,247)**	**$ 1,332,441**	

MONTANA-DAKOTA UTILITIES CO.
A Division of MDU Resources Group, Inc.

Before the Public Service Commission of Montana

Docket No. D2015.6.51

Rebuttal Testimony
of
Tamie A. Aberle

Q. Would you please state your name and business address?

A. Yes. My name is Tamie A. Aberle, and my business address is 400 North Fourth Street, Bismarck, North Dakota 58501.

Q. What is your position with Montana-Dakota Utilities Co.?

A. I am the Director of Regulatory Affairs for Montana-Dakota Utilities Co. (Montana-Dakota), a Division of MDU Resources Group, Inc.

Q. Are you the same Tamie A. Aberle who filed direct testimony in this proceeding?

A. Yes, I am.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of this rebuttal testimony is to address recommendations made by Stephen Baron, testifying on behalf of the Montana Large Customer Group (LCG) and Dr. John W. Wilson, testifying on behalf of the Montana Consumer Counsel (MCC) regarding their embedded cost of service study and rate design proposals in this case.

Q. Do you anticipate any changes to your pre-filed direct testimony at the time of the hearing on this matter?

A. Yes. I will be adopting Ms. Sara Cardwell's testimony submitted in this case and addressed by Mr. Baron and Dr. Wilson.

Q. Would you please address the embedded cost of service studies submitted by Mr. Baron and Dr. Wilson starting with the allocation of production related costs?

A. As is evident by the testimonies of both Dr. Wilson on behalf of the MCC and Mr. Baron on behalf of LCG, there are various options available to allocate electric production and transmission related costs. Mr. Baron provides several options with a preference for classifying production related investment and costs as demand costs and allocating those costs to each class using a 12-cp allocator. The Company agrees with Mr. Baron that production related costs should be classified as a demand related. However, I suggest the AED factor is the most reasonable means of allocating demand related costs. While a portion of Montana-Dakota's generating facilities are associated primarily with meeting peak demands the majority of the generating capacity on Montana-Dakota's system (baseload facilities) is associated with meeting average demands throughout the year. I do not agree with Mr. Baron's assertion that the AED allocation methodology will unduly penalize those classes that are controlling their peaks and unduly reward those classes that are using the system in a less efficient manner. To the extent customer classes are controlling peak demand, the excess demand to be allocated above the average will account for that peak demand control. I do agree with Mr.

Baron that the excess demand should have been calculated based on the 2014 peak and not the average of the single peaks over a 3 year period.

Dr. Wilson suggests that the appropriate methodology for allocating production related costs is to first classify production related costs as 50% attributable to energy and 50% attributable to demand with the amount assigned to energy allocated on an energy factor and the amounts classified as demand allocated on each class' 12-CP demand requirements. I do not agree that it is appropriate to classify 50% of the fixed costs associated with generating facilities as energy related and allocating those costs on a variable energy factor. While the AED factor recognizes the average demand of each class based on energy, those costs should not be classified as energy related and left to be recovered through an energy component.

Q. Would you please address Mr. Baron's allocation factor utilized to allocate wind production facilities?

A. Mr. Baron attributes the average cost of MISO energy purchases during the test year of $29.70 as compared to a single year cost of installed wind capacity as the percentage of the wind production investments to be allocated based on energy. Based on the results of this calculation Mr. Baron proposes to allocate 48.7% of the Company's wind facilities based on energy as compared to the Company's proposal to allocate 83.5% on energy after assigning 16.5% to be allocated on the demand factor based on the MISO accreditation process for the wind facilities. Montana-

Dakota's allocation recognizes that wind projects are primarily an energy supply resource with some amount of capacity allocation assigned for resource adequacy purposes. Wind generation displaces the marginal cost energy resource that a utility would otherwise self-supply or purchase from another party. This reduces the dependency on higher marginal energy cost units of generation. The allocation methodology proposed by Mr. Baron looks at a forecasted fuel savings calculated at a point in time versus an annual revenue requirement that decreases over time. I also do not agree with the revenue requirement calculated for the wind facilities as shown on Exhibit No. SJB-9. The deferred taxes associated with the wind facilities are significantly understated and the production tax credits were incorrectly applied causing the revenue requirement to be overstated. Depending on the forecast for future energy and fuel prices and the amount of accumulated depreciation for the investment, Mr. Baron's methodology could vary significantly over time and is not an accurate means to determine the demand allocation for wind investments.

Q. Do you agree with the methodologies applied by Dr. Wilson for allocating transmission related costs?

A. I do not. Dr. Wilson determines that transmission should be allocated in the same manner as production related plant with 50% classified as energy and allocated on an energy factor and 50% classified as demand related and allocated on 12-CP demand. The Company does not dispute that a 12-CP demand allocator is an acceptable alternative to

the AED allocator proposed by the Company. However, Dr. Wilson's classification of 50% of the fixed transmission costs as energy related with an allocation on an energy factor is not appropriate. This proposal inadequately recognizes that transmission investment represents fixed costs that are not appropriately recovered though a variable component. While transmission is certainly necessary for the delivery of energy, the recovery of transmission investment should not be dependent on energy delivered. Dr. Wilson's approach results in shifting costs to the higher load factor rate classes.

Q. Turning to distribution related costs, do you agree with the allocation methodology proposed by Dr. Wilson?

A. I do not. Dr. Wilson classifies 50% of distribution costs as energy related and 50% as demand related with the exception of meters that are classified as 100% customer related. There is no basis for classifying distribution costs on an energy basis and further allocating distribution costs on an energy factor. The Electric Utility Cost Allocation Manual prepared by the National Association of Regulatory Utility Commissioners' Staff Subcommittee on Electricity and Economics 1992 edition (NARUC manual) recognizes that distribution related costs are not energy related as noted on page 90 of the NARUC manual:

> "When the utility installs distribution plant to provide service to a customer and to meet the individual customer's peak

demand requirements, the utility must classify distribution plant separately into demand- and customer-related costs".

The NARUC manual also provides tables at pages 87 and 88 showing the preferred classification of Distribution Plant and Distribution Expenses. The classification of distribution investment and expenses shown in the tables is the same as that proposed by Montana-Dakota. Station equipment is classified as demand related, meters and services are classified as customer related and all other distribution sub accounts are classified as demand related and customer related. An allocation of fixed distribution costs on a variable cost allocator (energy use) is not appropriate. Station equipment, distribution lines and line transformer costs are not affected by the amount of energy used by a customer but rather the demand each customer places on the system and the fact the customer is connected to the system. Furthermore, these costs are fixed costs and do not vary with the amount of electricity.

Q. Would you please provide a summary of the cost study results?

A. Yes. The results of the application of the proposed allocation methodologies results in a shift of cost responsibility between the classes from that proposed by Montana-Dakota. As noted below, Mr. Baron's class study results in a shift in costs away from the large general service and contract service schedules and moves those costs to the smaller use residential and small general service classes.

Dr. Wilson's cost study provides a shift away from the smaller use

residential and small general service classed and moves that cost responsibility to the large energy use and predominately high load factor customers in the large general service and contract service schedules as shown below:

	Cost of Service @ Overall ROR		
	Montana-Dakota 1/	**MCC 2/**	**LCG 3/**
Residential Service - Rate 10	$21,727,557	$19,122,060	$22,112,399
Small General Service			
Rate 20	12,007,871	11,991,496	12,069,707
Rate 25	406,091	291,875	445,147
Total Small General	12,413,962	12,283,371	12,514,854
Large General Service			
Rate 30	15,860,552	17,937,993	15,869,498
Rate 31	1,244,326	1,324,765	1,274,706
Rate 32	82,330	91,000	82,784
Rate 35	14,185,465	14,401,272	13,628,907
Total Large General	31,372,673	33,755,030	30,855,895
Municipal Lighting - Rate 41	589,552	581,497	591,075
Municipal Pumping - Rate 48	701,506	1,334,426	730,211
Outdoor Lighting - Rate 52	555,108	283,971	555,919
Total Montana Electric	**$67,360,358**	**$67,360,355**	**$67,360,353**

1/ Company's filing - Rule 38.5.176, Statement L.
2/ Wilson JWW-8 Cost of Service Workpapers.
3/ Support provided for Baron SJB-9 in Response No. PSC-73.

In addition to the class responsibility shift, Dr. Wilson's classification of costs results in a reallocation of approximately $27 million in cost responsibility from the demand and customer components to the energy component as compared to Montana-Dakota's cost study. This results in approximately 72% of the total revenue requirement under Dr. Wilson's

class study classified as energy. Given the capital intense nature of the fixed electric system infrastructure necessary to provide safe and reliable service it is not logical that 72% of total costs would be considered energy related. The Company's proposed class study should be considered as a reasonable means of appropriately assigning embedded costs to each customer class for purposes of providing a basis for allocating revenue responsibility and establishing pricing components.

Q. Do you agree with Mr. Baron's proposed mitigation proposal for allocating the revenue increase to each of the classes?

A. I do not. Given the magnitude of the increase, allocating an increase to any particular class with a cap of 1.5 times the average increase is too significant a step to take with this rate case in the face of impacts to customers.

Q. Would you please provide your opinion regarding Dr. Wilson's proposed allocation of the revenue increase?

A. Dr. Wilson's allocation of the revenue increase is driven by the embedded class study results discussed above. Given the Company's disagreement with those class study results the allocation of the revenue increase is disputed given the overstated allocation of costs on an energy basis and the disregard for customer related costs. I specifically do not agree that the Residential class is providing an adequate return on investment under even Dr. Wilson's class study where the residential class return at 4.863% is well below the requested return of 7.588%.

Q. Do you agree with Dr. Wilson that customer charges should not be raised for any customer because such charges do not contribute to efficient resource use or energy consumption decisions as stated on page 67 of his direct testimony?

A. No, I do not agree with the notion that customer charges (base rates) should be held below cost for the sake of encouraging conservation. As noted above I also do not agree that the cost studies supporting unrealistic customer components should be used to support this concept. It is imperative that appropriate fixed costs be collected through the customer charge or base rate in order to minimize intra class subsidies and provide customers with the appropriate price signal. Customer conservation leading to reduced energy use should not result in unrecovered fixed costs that will ultimately result in future price increases.

Q. Dr. Wilson also addresses the two new Rider Tariffs the Company is proposing at page 68 of his testimony. Would you please comment on his recommendation that the proposed new Riders be rejected?

A. Yes. The proposed new Riders - the Environmental Cost Recovery Rider and the Transmission Recovery Rider should be considered by the Commission in order to efficiently and effectively adjust customer rates for these cost changes outside of a rate case. I do not agree that implementation of the riders would bias investment and expenditure decisions or undermine management efficiency incentives. The value of the Transmission Tracker is evidenced by the uncertainties surrounding the

net transmission expense associated with the need for Montana-Dakota to now take service under SPP's transmission tariffs as described by Mr. Neigum and cost allocations coming from MISO and SPP. A specific application of the Environmental Cost Recovery Rider is not apparent at this time. However, as with the Transmission Rider, any proposed costs proposed to be recovered through the Environmental Rider would be submitted to the Commission for approval.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.