BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

IN THE MATTER OF THE APPLICATION OF EL PASO ELECTRIC COMPANY FOR REVISION OF ITS RETAIL ELECTRIC RATES PURSUANT TO ADVICE NOTICE NO. 267 EL PASO ELECTRIC COMPANY, Applicant.	Case No. 20-00104-UT

DIRECT TESTIMONY OF

DAVID J. GARRETT

ON BEHALF OF

CITY OF LAS CRUCES AND DOÑA ANA COUNTY

OCTOBER 9, 2020

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I. INTRODUCTION

Q. State your name and occupation.

A. My name is David J. Garrett. I am a consultant specializing in public utility regulation. I am the managing member of Resolve Utility Consulting PLLC.

Q. Summarize your educational background and professional experience.

A. I received a B.B.A. with a major in Finance, an M.B.A., and a Juris Doctor from the University of Oklahoma. I worked in private legal practice for several years before accepting a position as assistant general counsel at the Oklahoma Corporation Commission in 2011. At the commission, I worked in the Office of General Counsel in regulatory proceedings. In 2012, I began working for the Public Utility Division as a regulatory analyst providing testimony in regulatory proceedings. After leaving the commission, I formed Resolve Utility Consulting PLLC, where I have represented various consumer groups and state agencies in utility regulatory proceedings, primarily in the areas of cost of capital and depreciation. I am a Certified Depreciation Professional with the Society of Depreciation Professionals. I am also a Certified Rate of Return Analyst with the Society of Utility and Regulatory Financial Analysts. A more complete description of my qualifications and regulatory experience is included in my curriculum vitae.[1]

[1] Exhibit DJG-1.

Q. Describe the purpose and scope of your testimony in this proceeding.

A. I am testifying on behalf of the City of Las Cruces and Doña Ana County (collectively "CLC-DAC") in response to the present application filed by El Paso Electric Company ("EPE" or the "Company"). Specifically, I address the cost of capital, capital structure, and fair rate of return for EPE in response to the direct testimonies of Company witnesses Jennifer E. Nelson and Lisa D. Budtke. I also address the Company's proposed depreciation rates in response to the direct testimony of Company witness John J. Spanos, who sponsors the Company's depreciation study. Because these two issues are voluminous, I have separated the executive summary, the body of my testimony, and my exhibits by each issue: Cost of Capital and Depreciation.

II. EXECUTIVE SUMMARY

A. Part One: Cost of Capital

Q. Explain the concept of the "weighted average cost of capital."

A. The term "cost of capital" refers to the weighted average cost of all types of components within a company's capital structure, including debt and equity. Determining the cost of debt is relatively straight-forward. Interest cost rates on bonds are contractual, derived, "embedded costs" that are generally calculated by dividing total interest payments by the book value of outstanding debt. In contrast, determining the cost of equity is more complex. Unlike the known contractual cost of debt, there is no explicit "cost" of equity; thus, the cost of equity must be estimated through various financial models. The overall weighted average cost of capital ("WACC") includes the cost of debt and the estimated cost of equity. It is a "weighted average," because it is based upon the Company's relative levels of debt and equity, or "capital structure." Companies in the competitive market often use their WACC as the discount rate to determine the value of capital projects, so it is important that this figure be closely estimated. The basic WACC equation used in regulatory proceedings is presented as follows:

Equation 1:
Weighted Average Cost of Capital

$$WACC = \left(\frac{D}{D+E}\right) C_D + \left(\frac{E}{D+E}\right) C_E$$

where: $WACC$ = *weighted average cost of capital*
D = *book value of debt*
C_D = *embedded cost of debt capital*
E = *book value of equity*
C_E = *market-based cost of equity capital*

Thus, the three components of the weighted average cost of capital include the following:

1. Cost of Equity
2. Cost of Debt
3. Capital Structure

The term "cost of capital" is necessarily synonymous with the "weighted average cost of capital," and the terms are used interchangeably throughout this testimony.

Q. Describe the relationship between the cost of equity, required return on equity ("ROE"), earned ROE, and awarded ROE.

A. While "cost of equity," "required ROE," "earned ROE," and "awarded ROE" are interrelated factors and concepts, they are all technically different from each other. The financial models presented in this case were created as tools for estimating the "cost of equity," which is synonymous to the "required ROE" that investors expect based on the amount of risk inherent in the equity investment. In other words, the cost of equity from the company's perspective equals the required ROE from the investor's perspective.

The "earned ROE" is a historical return that is measured from a company's accounting statements, and it is used to measure how much shareholders earned for investing in a company. A company's earned ROE is not the same as the company's cost of equity. For example, an investor who invests in a risky company may *require* a return on investment of 10%. If the company used the same estimates as the investor, then the company will estimate that its *cost* of equity is also 10%. If the company performs poorly and the investor *earns* a return of only 7%, this does not mean that the investor required only 7%, or that the investor will not still require a 10% return the following period. Thus, the cost of equity is not the same as the earned ROE.

Finally, the "awarded" return on equity is unique to the regulatory environment; it is the return authorized by a regulatory commission pursuant to legal guidelines. As discussed later in this testimony, the awarded ROE should be based on the utility's *cost* of equity. The relationship between the terms and concepts discussed thus far could be summarized in the following sentence: If the awarded ROE reflects a utility's cost of equity, then it should allow the utility to achieve an earned ROE that is sufficient to satisfy the required return of its equity investors. Thus, the "required" or "expected" return from an investor's standpoint is not simply what the investor wishes he could get. Likewise, the expected return of a utility investor has nothing to do with what the investor "expects" the ROE awarded by a regulatory commission to be. Rather, the expected return/cost of equity is estimated through objective, mathematical financial modeling based on risk.

Q. Describe the Company's position regarding its cost of capital in this case.

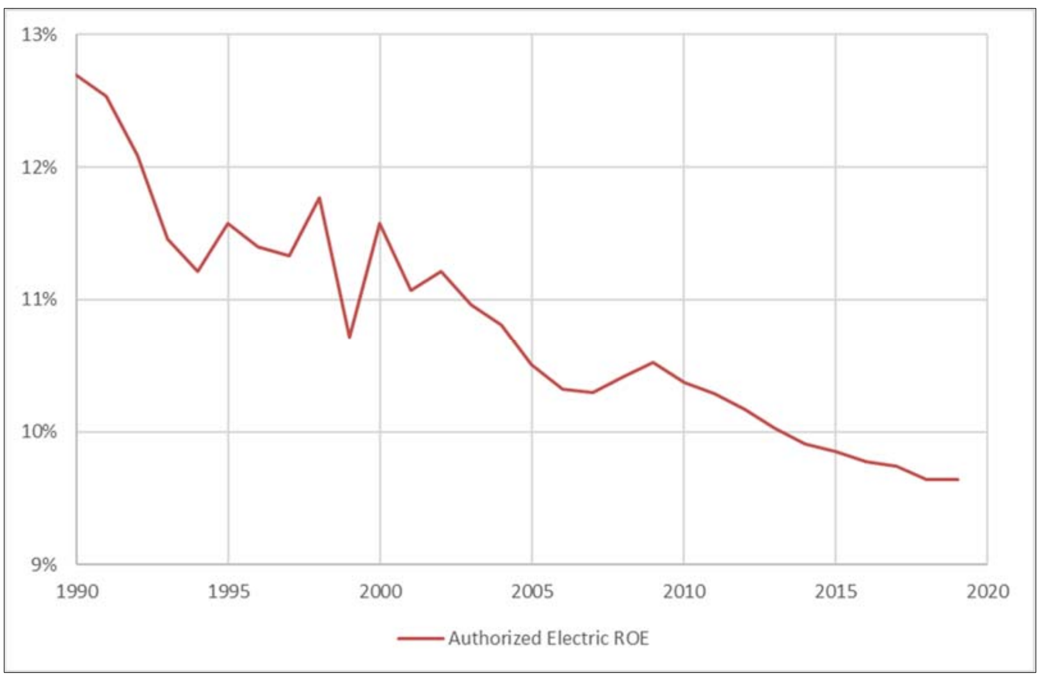
A. In this case, Ms. Nelson proposes an awarded return on equity of 10.3% for the Company.[2] Ms. Nelson relies on the Discounted Cash Flow ("DCF") Model, the Capital Asset Pricing Model ("CAPM"), and other models in making her recommendation.

[2] Direct Testimony of Jennifer E. Nelson, p. 5, line 11.

Q. Please discuss the Company's ROE proposal in the context of historic trends in awarded ROEs for electric utilities.

A. Over the past thirty years, capital costs for all companies have generally declined. This is due in large part to generally declining interest rates over the same period. Likewise, awarded ROEs for electric utilities have also decreased since 1990. The graph below shows a trend in the annual awarded returns for electric utilities from 1990 to 2019.[3]

Figure 1:
Historic Awarded ROEs for Electric Utilities



[3] *See also* Exhibit DJG-14.

As shown in the graph above, awarded ROEs for electric utilities have generally declined over the past 30 years.[4] To the extent the Commission is inclined to consider the awarded ROEs of other utilities in making its decision in this case, the Commission should also consider this downward trend in awarded ROEs.

Q. Are you suggesting that regulators should simply set ROEs according to a national average of awarded ROEs?

A. No. As illustrated further in my testimony, there is strong evidence suggesting that regulators consistently award ROEs that are notably higher than utilities' actual cost of equity. This is likely due to the fact that over the past 30 years, interest rates and cost of capital have declined at a faster rate than regulators' willingness to decrease awarded ROEs. In other words, awarded ROEs have appropriately been decreasing in accordance with declining capital costs; however, they have not decreased quickly enough to keep pace. To the extent regulators have been persuaded to conform to a national average of awarded ROEs when making their decisions in a particular case, it has contributed to this "lag" in awarded returns, which have effectively failed to track with declining interest rates over the same time period. In other words, whether objective market indicators influencing cost of equity are rising or falling, simply reverting to a national mean of awarded ROEs will effectively prevent those ROEs from properly rising and falling with the

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[4] *See* Exhibit DJG-14.

market indicators, such as interest rates. In today's economic environment, if a regulator awards an ROE that is equivalent to the national average, that awarded ROE will be above the market-based cost of equity for a regulated utility. Therefore, to suggest that the Commission simply set the Company's awarded ROE based on a national average would not result in a fair return, and it would promote the perpetuation of a national phenomenon of artificially inflated ROEs for regulated utilities.

Q. Please summarize your recommendation to the Commission.

A. Pursuant to the legal and technical standards guiding this issue, the awarded ROE should be based on, or reflective of, the utility's cost of equity. As I explain in more detail below, the Company's estimated cost of equity is approximately 7.0%. However, these legal standards do not mandate the awarded ROE be set exactly equal to the cost of equity. Rather, in *Federal Power Commission v. Hope Natural Gas Co.*,[5] the U.S. Supreme Court ("Court" or "Supreme Court") found that, although the awarded return should be based on a utility's cost of capital, it also indicated that the "end result" should be just and reasonable. If the Commission were to award a return equal to the Company's estimated cost of equity of 7.0%, it would be accurate from a technical standpoint, and it would also significantly

[5] *See Federal Power Commission v. Hope Natural Gas Co*., 320 U.S. 591, 603 (1944). Here, the Court states that it is not mandating the various permissible ways in which the rate of return may be determined, but instead indicates that the end result should be just and reasonable. This is sometimes called the "end result" doctrine.

reduce the excess wealth transfer from ratepayers to shareholders that would otherwise occur if the Company's proposal were adopted. I recommend, however, the Commission award an ROE to the Company's shareholders that is remarkably higher than the EPE's actual cost of equity in this case. Specifically, I recommend an awarded ROE of 9.0%.

The ratemaking concept of "gradualism," though usually applied from the customer's standpoint to minimize rate shock, could also be applied to shareholders. An awarded return as low as 7.0% in any current rate proceeding would represent a substantial change from the "status quo," which as I prove later in this testimony, involves awarded ROEs that clearly exceed market-based cost of equity for utilities. However, while generally reducing awarded ROEs for utilities would move awarded returns closer to market-based costs and reduce part of the excess transfer of wealth from ratepayers to shareholders, I believe it is advisable to do so gradually. One of the primary reasons the Company's cost of equity is so low is because the Company is a very low-risk asset. In general, utility stocks are low-risk investments because movements in their stock prices are relatively involatile. If the Commission were to make a significant, sudden change in the awarded ROE anticipated by regulatory stakeholders, it could have the undesirable effect of notably increasing the Company's risk profile and would arguably be at odds with the *Hope* Court's "end result" doctrine. An awarded ROE of 9.0% represents a good balance between the Supreme Court's indications that awarded

ROEs should be based on cost, while also recognizing that the end result must be reasonable under the circumstances. An awarded ROE of 9.0% also represents a gradual move toward the Company's market-based cost of equity, and it would be fair to the Company's shareholders because 9.0% is about 250 basis points above the Company's market-based cost of equity. Nonetheless, it is clear that the Company's proposed ROE of 10.3% is excessive and unreasonable, as further discussed below.

Q. Please provide an overview of the problems you have identified with Ms. Nelson's testimony regarding cost of equity and the awarded ROE.

A. Ms. Nelson proposes a return on equity of 10.3%.[6] Ms. Nelson's recommendations are based on the CAPM, DCF Model, and other models. However, several of her key assumptions and inputs to these models violate fundamental, widely-accepted tenets in finance and valuation, while other assumptions and inputs are simply unrealistic. The key areas of concern are summarized as follows:

1. Terminal Growth Rate

In her DCF Model, Ms. Nelson's average long-term growth rate applied to the Company exceeds the long-term growth rate for the entire U.S. economy. In fact, Ms. Nelson's projected growth rates for her proxy companies are as high as 10%,[7] which is more than two times the projected U.S. GDP growth. It is a

[6] Direct Testimony of Jennifer E. Nelson, p. 2, line 19.

[7] Exhibit RBH-2.

fundamental concept in finance that, in the long run, a company cannot fundamentally grow at a faster rate than the aggregate economy in which it operates; this is especially true for a regulated utility with a defined service territory. Thus, the results of Ms. Nelson's DCF Model are upwardly biased and are not reflective of current market conditions.

2. Equity Risk Premium

Ms. Nelson's estimate for the Equity Risk Premium ("ERP"), the single most important factor in estimating the cost of equity and a key input to the CAPM, is significantly higher than the estimates reported by thousands of experts across the country. Specifically, Ms. Nelson's ERP estimate is as high as 13.5%, which is more than twice as high as the average ERP estimated by thousands of other experts around the county.[8] In direct contradiction to Ms. Nelson's assertion that her analysis is "forward-looking,"[9] Ms. Nelson incorporates ERP data dating back to 1980 into some of her risk premium analyses.[10] Moreover, in estimating the ERP, Ms. Nelson did not follow conventional approaches, but rather conducted a DCF analysis on a sample of the entire market. This decision is especially problematic because Ms. Nelson used long-term growth rates as high as 64% in her

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[8] *See* Exhibit RBH-6; *see also* Exhibit DJG-10.

[9] *See e.g.*, Direct Testimony of Jennifer E. Nelson, p. 66, line 10.

[10] Exhibit RBH-7.

analysis.[11] Specifically, Ms. Nelson estimated a long-term growth rate of 64% for Incyte Corp ("Incyte"), a biopharmaceutical company.[12] In 2019, Incyte reported earnings of $447 million.[13] If we apply Ms. Nelson's 64% annual growth rate to Incyte's 2019 earnings, in only 25 years Incyte's earnings would be more than $100 trillion, which would dwarf the GDP of the entire planet. Many of Ms. Nelson's other long-term growth estimates are similarly too high to be considered realistic. This example highlights why it is important not to overestimate long-term growth rates in either the DCF Model or the CAPM. As a result, Ms. Nelson's estimate of the most important factor in the CAPM is more than twice as high as the results estimated and reported by thousands of survey respondents and other experts.[14] Thus, Ms. Nelson's CAPM cost of equity estimate is overstated, unsupported, and unreasonable.

3. Bond Yield Plus Risk Premium Model

Ms. Nelson's own risk premium model is not market-based in that it considers awarded ROEs dating back to 1980[15] — a contradiction to Ms. Nelson's claim that her cost of equity models are "forward-looking."[16] As discussed in this

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[11] Exhibit No. (RBH-1), Document No. 4.

[12] *Id*.

[13] https://finance.yahoo.com/quote/INCY/financials?p=INCY

[14] *See* Exhibit DJG-10.

[15] Exhibit No. (RBH-1), Document No. 7.

[16] *See e.g.*, Direct Testimony of Jennifer E. Nelson, p. 66, line 10.

testimony, awarded ROEs are consistently higher than market-based costs of equity for utility companies. Unlike the CAPM, which is a Nobel-prize-winning risk premium model found in nearly every fundamental textbook on finance and investments, the type of risk premium analysis offered by Ms. Nelson and other utility ROE witnesses are almost exclusively seen in the testimonies of utility ROE witnesses, and it results in cost of equity estimates unreflective of current market conditions. Given the reality that awarded ROEs have consistently exceeded utility market-based costs of equity for decades, any model that attempts to leverage the unbalanced relationship between awarded ROEs and any market-based factor (such as U.S. Treasury bonds in this case) will only serve to perpetuate the unfortunate discrepancy between awarded ROEs and utilities' actual costs of equity. Our purpose here should be to use objective, market-based models (the DCF and CAPM) to estimate the cost of equity so we can then use that estimate to help determine a fair awarded ROE. In contrast, Ms. Nelson's risk premium analysis relies on nothing more than an echo chamber of outdated awarded ROEs that have no bearing on the Company's current, market-based cost of equity.

Q. Would the results of any of Ms. Nelson's cost of equity models actually equate to reasonable results for the EPE's warded ROE in this case?

A. Yes. Ms. Nelson conducted several versions of the DCF Model using various growth rates and lengths of time for average stock prices. Ms. Nelson's lowest

DCF result was 7.85%.[17] This result is the closest to EPE's market-based cost of equity. If the Commission were to set EPE's cost of equity at Ms. Nelson's 7.85% DCF result, it would not only conform with the legal standards governing this issue, but it would also minimize the excess wealth transfer from ratepayers to shareholders relative to Ms. Nelson's other cost of equity estimates. Ms. Nelson's DCF Models also produced results of 7.90%, 7.96%, 8.33%, 8.61%, 8.72%, and 9.09%.[18] Each of these results are much closer to the Company's actual cost of equity than Ms. Nelson's other estimates and her ultimate recommendation. Moreover, each of these DCF would represent fair outcomes for EPE's awarded ROE in this case under the circumstances.

Q. Describe the harmful impact to customers and the state's economy if the Commission were to adopt the Company's inflated ROE recommendation.

A. When the awarded return is set significantly above the true cost of equity, it results in an inappropriate and excess transfer of wealth from ratepayers to shareholders beyond that which is required by law. This excess outflow of funds from New Mexico's economy would not benefit its businesses or citizens, nor would it result in better utility service. Instead, New Mexico businesses in the Company's service territory would be less competitive with businesses in surrounding states, and

[17] Exhibit No. (RBH-1), Document No. 2.

[18] *Id*.

individual ratepayers would receive inflated costs for basic goods and services, along with higher utility bills.

B. <u>Part Two: Depreciation</u>

Q. Summarize the key points of your testimony regarding depreciation.

A. In the context of utility ratemaking, "depreciation" refers to a cost allocation system designed to measure the rate by which a utility may recover its capital investments in a systematic and rational manner. I employed a well-established depreciation system and used actuarial analysis and comparative analysis to analyze the Company's depreciable assets in order to develop reasonable depreciation rates in this case. In this case, I propose adjustments to the service lives and net salvage rates for several of EPE's transmission and distribution accounts. For each of these accounts, I propose a longer average remaining life and/or higher net salvage rate, which results in lower depreciation rates and expense. In addition, my proposed depreciation rates do not incorporate EPE's proposed retirement date changes for several of its production units.[19] The table below summarizes my proposed adjustments to EPE's proposed depreciation accrual.

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[19] Please see the Direct Testimony of Mark E. Garrett for a substantive discussion on CLC-DAC's adjustments to EPE's proposed accelerated depreciation rates due to updated probable retirement dates of several of its generating facilities.

Figure 2:
Depreciation Accrual Comparison

Plant Function	Plant Balance 12/31/2019	Company Proposed Accrual	Garrett Proposed Accrual	**Garrett Accrual Adjustment**
Steam Production	$ 565,455,715	$ 21,326,362	$ 17,552,280	$ (3,774,082)
Gas Turbine	518,021,063	19,226,357	14,136,554	(5,089,803)
Transmission	532,343,334	9,023,893	8,275,788	(748,105)
Distribution	1,347,787,849	29,846,554	28,149,622	(1,696,932)
General	171,715,519	6,601,194	6,616,766	15,572
Total Depreciable Plant	$ 3,135,323,480	$ 86,024,360	$ 74,731,009	**$ (11,293,351)**

As shown in this table, my proposed adjustments would reduce EPE's proposed annual depreciation accrual by $11.3 million.[20]

Q. Please summarize your proposed adjustments to the company's depreciation parameters for its mass property accounts.

A. The table below summarizes my proposed adjustments to service life (i.e., Iowa curve) and net salvage rates for EPE's transmission and distribution accounts.

Figure 3:
Mass Property Depreciation Parameter Comparison

		Company Proposal				Garrett Proposal			
Account No.	Description	Iowa Curve Type AL	NS Rate	Depr Rate	Annual Accrual	Iowa Curve Type AL	NS Rate	Depr Rate	Annual Accrual
	TRANSMISSION PLANT								
353.00	STATION EQUIPMENT	R4 - 50	-5%	1.56%	2,948,962	R3 - 58	-5%	1.40%	2,647,195
355.00	WOOD AND STEEL POLES	S3 - 55	-20%	1.91%	3,115,165	S3 - 55	-15%	1.79%	2,918,845
356.00	OVERHEAD CONDUCTORS AND DEVICES	R5 - 60	-15%	1.61%	1,579,563	R4 - 65	-10%	1.35%	1,329,527
	DISTRIBUTION PLANT								
362.00	STATION EQUIPMENT	R2 - 65	-5%	1.43%	4,102,971	R1.5 - 71	0%	1.24%	3,568,711
364.00	POLES, TOWERS AND FIXTURES	R3 - 45	-30%	3.11%	5,697,660	R3 - 45	-25%	2.94%	5,396,941
366.00	UNDERGROUND CONDUIT	R4 - 65	-5%	1.50%	2,124,461	R4 - 71	0%	1.27%	1,804,272
368.00	LINE TRANSFORMERS	R3 - 52	-15%	2.34%	6,629,377	R3 - 52	-10%	2.21%	6,260,694
369.00	SERVICES	S3 - 65	-15%	1.38%	779,571	S3 - 65	0%	1.08%	607,181

[20] *See* Exhibit DJG-17. The annual accrual applies to plant balances as of the depreciation study date.

The details behind these adjustments are further discussed in the depreciation section of my testimony.

Q. Please describe why it is important not to overestimate depreciation rates.

A. Under the rate base rate of return model, the utility is allowed to recover the original cost of its prudent investments required to provide service. Depreciation systems are designed to allocate those costs in a systematic and rational manner — specifically, over the service life of the utility's assets. If depreciation rates are overestimated (i.e., service lives are underestimated), it encourages economic inefficiency. Unlike competitive firms, regulated utility companies are not always incentivized by natural market forces to make the most economically efficient decisions. If a utility is allowed to recover the cost of an asset before the end of its useful life, this could incentivize the utility to unnecessarily replace the asset in order to increase its rate base, which results in economic waste. Thus, from a public policy perspective, it is preferable for regulators to ensure that assets are not depreciated before the end of their true useful lives. While underestimating the useful lives of depreciable assets could financially harm current ratepayers and encourage economic waste, unintentionally overestimating depreciable lives (i.e., underestimating depreciation rates) does not necessarily harm the Company financially. This is because if an asset's life is overestimated, there are a variety of measures that regulators can use to ensure the utility is not financially harmed. Thus, the process of depreciation strives for a perfect match between actual and estimated useful life. When these estimates are not exact, however, it is better that useful lives are not underestimated for these reasons.

PART ONE: COST OF CAPITAL

III. LEGAL STANDARDS AND THE AWARDED RETURN

Q. Discuss the legal standards governing the awarded rate of return on capital investments for regulated utilities.

A. In *Wilcox v. Consolidated Gas Co. of New York*,[21] the Supreme Court first addressed the meaning of a fair rate of return for public utilities. The Court found that "the amount of risk in the business is a most important factor" in determining the appropriate allowed rate of return.[22] Later in two landmark cases, the Court set forth the standards by which public utilities are allowed to earn a return on capital investments. In *Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia*,[23] the Court held:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public . . . but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical

[21] *Wilcox v. Consolidated Gas Co. of New York*, 212 U.S. 19 (1909).

[22] *Id*. at 48.

[23] *Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia*, 262 U.S. 679, 692-93 (1923).

> management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties.

In *Federal Power Commission v. Hope Natural Gas Company*,[24] the Court expanded on the guidelines set forth in *Bluefield* and stated:

> From the investor or company point of view it is important that there be enough revenue not only for operating expenses *but also for the capital costs of the business*. These include service on the debt and dividends on the stock. By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.

The cost of capital models I have employed in this case are in accordance with the foregoing legal standards.

Q. Is it important that the awarded rate of return be based on the Company's actual cost of capital?

A. Yes. The *Hope* Court makes it clear that the allowed return should be based on the actual cost of capital. Under the rate base rate of return model, a utility should be allowed to recover all its reasonable expenses, its capital investments through depreciation, and a return on its capital investments sufficient to satisfy the required return of its investors. The "required return" from the investors' perspective is synonymous with the "cost of capital" from the utility's perspective. Scholars agree that the allowed rate of return should be based on the actual cost of capital:

> Since by definition the cost of capital of a regulated firm represents

[24] *Federal Power Commission v. Hope Natural Gas Co*., 320 U.S. 591, 603 (1944) (emphasis added).

> precisely the expected return that investors could anticipate from other investments while bearing no more or less risk, and since investors will not provide capital unless the investment is expected to yield its opportunity cost of capital, the correspondence of the definition of the cost of capital with the court's definition of legally required earnings appears clear.[25]

The models I have employed in this case closely estimate the Company's true cost of equity. If the Commission sets the awarded return based on my lower, and more reasonable rate of return, it will comply with the U.S. Supreme Court's standards, allow the Company to maintain its financial integrity, and satisfy the claims of its investors. On the other hand, if the Commission sets the allowed rate of return much *higher* than the true cost of capital, it arguably results in an inappropriate transfer of wealth from ratepayers to shareholders. As Ms. Nelson notes:

> [I]f the allowed rate of return is greater than the cost of capital, capital investments are undertaken and investors' opportunity costs are more than achieved. Any excess earnings over and above those required to service debt capital accrue to the equity holders, and the stock price increases. In this case, the wealth transfer occurs from ratepayers to shareholders.[26]

Thus, it is important to understand that the *awarded* return and the *cost* of capital are different but related concepts. The two concepts are related in that the legal and technical standards encompassing this issue require that the awarded return reflect the true cost of capital. On the other hand, the two concepts are different in that the

[25] A. Lawrence Kolbe, James A. Read, Jr. & George R. Hall, *The Cost of Capital: Estimating the Rate of Return for Public Utilities* 21 (The MIT Press 1984).

[26] Roger A. Morin, *New Regulatory Finance* 23-24 (Public Utilities Reports, Inc. 2006) (1994).

legal standards do not mandate that awarded returns exactly match the cost of capital. Awarded returns are set through the regulatory process and may be influenced by a number of factors other than objective market drivers. The cost of capital, on the other hand, should be evaluated objectively and be closely tied to economic realities. In other words, the cost of capital is driven by stock prices, dividends, growth rates, and — most importantly — it is driven by risk. The cost of capital can be estimated by financial models used by firms, investors, and academics around the world for decades. The problem is, with respect to regulated utilities, there has been a trend in which awarded returns fail to closely track with actual market-based cost of capital as further discussed below. To the extent this occurs, the results are detrimental to ratepayers and the state's economy.

Q. Describe the economic impact that occurs when the awarded return strays too far from the U.S. Supreme Court's cost of equity standard.

A. As discussed further in the sections below, Ms. Nelson's recommended awarded ROE is much higher than the Company's actual cost of capital based on objective market data. When the awarded ROE is set far above the *cost* of equity, it runs the risk of violating the U.S. Supreme Court's standards that the awarded return should be *based on the cost of capital*. If the Commission were to adopt the Company's position in this case, it would be permitting an excess transfer of wealth from New Mexico customers to Company shareholders. Moreover, establishing an awarded return that far exceeds the true cost of capital effectively prevents the awarded returns from changing along with economic conditions. This is especially true given the fact that regulators tend to be influenced by the awarded returns in other jurisdictions, regardless of the various unknown factors influencing those awarded returns. This is yet another reason why it is crucial for regulators to focus on the target utility's actual *cost* of equity, rather than awarded returns from other jurisdictions. Awarded returns may be influenced by settlements and other political factors not based on true market conditions. In contrast, the true cost of equity as estimated through objective models is not influenced by these factors but is instead driven by market-based factors. If regulators rely too heavily on the awarded returns from other jurisdictions, it can create a cycle over time that bears little relation to the market-based cost of equity. In fact, this is exactly what we have observed since 1990.

Q. Illustrate and compare the relationship between awarded utility returns and market cost of equity since 1990.

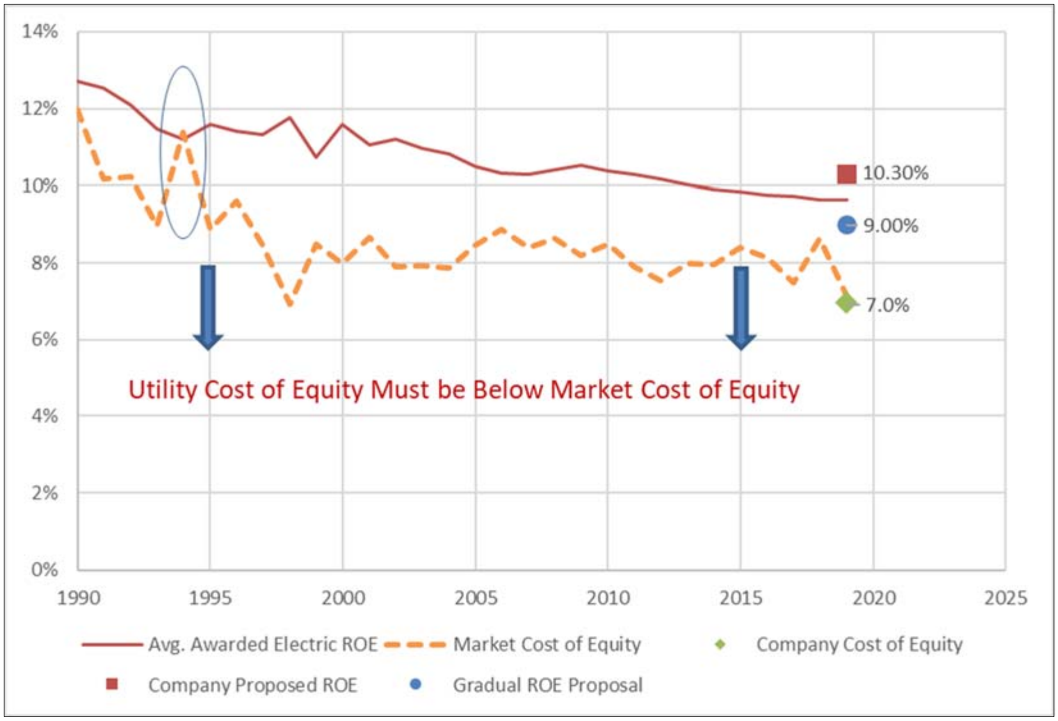
A. As shown in the figure below, awarded returns for public utilities have been above the average required market return since 1990.[27] Because utility stocks are consistently far less risky than the average stock in the marketplace, the cost of equity for utility companies is *less* than the market cost of equity. This is a fact, not an opinion. The graph below shows two trend lines. The top line is the average

[27] *See* Exhibit DJG-14.

annual awarded returns since 1990 for U.S. regulated utilities. The bottom line is the required market return over the same period. As discussed in more detail later in my testimony, the required market return is essentially the return that investors would require if they invested in the entire market. In other words, the required market return is essentially the cost of equity of the entire market. Since it is undisputed (even by utility witnesses) that utility stocks are less risky than the average stock in the market, then the utilities' cost of equity must be less than the market cost of equity.[28] Thus, awarded returns (the solid line) should generally be *below* the market cost of equity (the dotted line), since awarded returns are supposed to be based on true cost of equity.

[28] This fact can be objectively measured through a term called "beta," as discussed later in the testimony. Utility betas are less than one, which means utility stocks are less risky than the "average" stock in the market.

Figure 4:
Awarded ROEs vs. Market Cost of Equity



Because utility stocks are less risky than the average stock in the market, utility cost of equity is *below* market cost of equity (the dotted line in this graph). However, as shown in this graph, awarded ROEs have been consistently *above* the market cost of equity for many years. As shown in the graph, since 1990 there was only one year in which the average awarded ROE was below the market cost of equity — 1994. In other words, 1994 was the year that regulators awarded ROEs that were the closest to utilities' market-based cost of equity. In my opinion, when awarded ROEs for utilities are below the market cost of equity, they more closely conform to the standards set forth by *Hope* and *Bluefield* and minimize the excess wealth transfer from ratepayers to shareholders. The graph also shows the current discrepancy between awarded ROEs and market cost of equity along with the various positions in this case. In this case, Ms. Nelson's proposal of a 10.3% ROE is about 400 basis points above the Company's cost of equity of about 7.0%. As discussed previously, my recommended ROE of 9.0% represents a gradual move towards actual cost, is reasonable under the circumstances, and is in accord with the decisions of the U.S. Supreme Court.

Q. Have other analysts commented on this national phenomenon of awarded ROEs exceeding the market-based cost equity for utilities?

A. Yes. In his article published in Public Utilities Fortnightly in 2016, Steve Huntoon observed that even though utility stocks are less risky than the stocks of competitive industries, utility stocks have nonetheless outperformed the broader market.[29] Specifically, Huntoon notes the following three points which lead to a problematic conclusion:

> 1. Jack Bogle, the founder of Vanguard Group and a Wall Street legend, provides rigorous analysis that the long-term total return for the broader market will be around 7 percent going forward. Another Wall Street legend, Professor Burton Malkiel, corroborates that 7 percent in the latest edition of his seminal work, *A Random Walk Down Wall Street*.

[29] Steve Huntoon, "Nice Work If you can Get It," Public Utilities Fortnightly (Aug. 2016).

> 2. Institutions like pension funds are validating [the first point] by piling on risky investments to try and get to a 7.5 percent total return, as reported by the Wall Street Journal.
>
> 3. Utilities are being granted returns on equity around 10 percent.[30]

In a follow-up article analyzing and agreeing with Mr. Huntoon's findings, Leonard Hyman and William Tilles found that utility equity investors expect about a 7.5% annual return.[31]

Other scholars have also observed that awarded ROEs have not appropriately tracked with declining interest rates over the years, and that excessive awarded ROEs have negative economic impacts. In a 2017 white paper, Charles S. Griffey stated:

[30] *Id*.

[31] Leonard Hyman & William Tilles, "Don't Cry for Utility Shareholders, America," Public Utilities Fortnightly (October 2016).

> The "risk premium" being granted to utility shareholders is now higher than it has ever been over the last 35 years. Excessive utility ROEs are detrimental to utility customers and the economy as a whole. From a societal standpoint, granting ROEs that are higher than necessary to attract investment creates an inefficient allocation of capital, diverting available funds away from more efficient investments. From the utility customer perspective, if a utility's awarded and/or achieved ROE is higher than necessary to attract capital, customers pay higher rates without receiving any corresponding benefit.[32]

It is interesting that both Mr. Huntoon and Mr. Griffey use the word "sticky" in their articles to describe the fact that awarded ROEs have declined at a much slower rate than interest rates and other economic factors resulting in a decline in capital costs and expected returns on the market. It is not hard to see why this phenomenon of sticky ROEs has occurred. Because awarded ROEs are often based primarily on a comparison with other awarded ROEs around the country, the average awarded returns effectively fail to adapt to true market conditions, and regulators seem reluctant to deviate from the average. Once utilities and regulatory commissions become accustomed to awarding rates of return higher than market conditions actually require, this trend becomes difficult to reverse. Nevertheless, the fact is that utility stocks are *less risky* than the average stock in the market, and thus, awarded ROEs should be less than the expected return on the market. However,

[32] Charles S. Griffey, "When 'What Goes Up' Does Not Come Down: Recent Trends in Utility Returns," White Paper (February 2017).

that is rarely the case. "Sooner or later, *regulators may see the gap between allowed returns and cost of capital*."[33]

Q. Summarize the legal standards governing the awarded ROE issue.

A. The Commission should strive to move the awarded return to a level more closely aligned with the Company's actual, market-derived cost of capital while keeping in mind the following legal principles:

1. Risk is the most important factor when determining the awarded return. The awarded return should be commensurate with those on investments of corresponding risk.

The legal standards articulated in *Hope* and *Bluefield* demonstrate that the Court understands one of the most basic, fundamental concepts in financial theory: the more (less) risk an investor assumes, the more (less) return the investor requires. Since utility stocks are very low risk, the return required by equity investors should be relatively low. I have used financial models in this case to closely estimate EPE's cost of equity, and these financial models account for risk. The public utility industry is one of the least risky industries in the entire country. The cost of equity models confirm this fact in that they produce relatively low cost of equity results. In turn, the awarded ROE in this case should reflect the fact that EPE is a low-risk company.

[33] Leonard Hyman & William Tilles, "Don't Cry for Utility Shareholders, America," Public Utilities Fortnightly (October 2016) (emphasis added).

2. The awarded return should be sufficient to assure financial soundness under efficient management.

Because awarded returns in the regulatory environment have not closely tracked market-based trends and commensurate risk, utility companies have been able to remain more than financially sound, perhaps despite management inefficiencies. In fact, the transfer of wealth from ratepayers to shareholders has been so far removed from actual cost-based drivers that even under relatively inefficient management a utility could remain financially sound. Therefore, regulatory commissions should strive to set the awarded return to a regulated utility at a level based on accurate market conditions to promote prudent and efficient management and minimize economic waste.

IV. GENERAL CONCEPTS AND METHODOLOGY

Q. Discuss your approach to estimating the cost of equity in this case.

A. While a competitive firm must estimate its own cost of capital to assess the profitability of competing capital projects, regulators determine a utility's cost of capital to establish a fair rate of return. The legal standards set forth above do not include specific guidelines regarding the models that must be used to estimate the cost of equity. Over the years, however, regulatory commissions have consistently relied on several models. The models I have employed in this case have been the two most widely used and accepted in regulatory proceedings for many years. These models are the Discounted Cash Flow Model ("DCF Model") and the Capital

Asset Pricing Model ("CAPM"). The specific inputs and calculations for these models are described in more detail below.

Q. Please explain why multiple models are used to estimate the cost of equity.

A. The models used to estimate the cost of equity attempt to measure the return on equity required by investors by estimating several different inputs. It is preferable to use multiple models because the results of any one model may contain a degree of imprecision, especially depending on the reliability of the inputs used at the time of conducting the model. By using multiple models, the analyst can compare the results of the models and look for outlying results and inconsistencies. Likewise, if multiple models produce a similar result, it may indicate a narrower range for the cost of equity estimate.

Q. Please discuss the benefits of choosing a proxy group of companies in conducting cost of capital analyses.

A. The cost of equity models in this case can be used to estimate the cost of capital of any individual, publicly-traded company. There are advantages, however, to conducting cost of capital analysis on a "proxy group" of companies that are comparable to the target company. First, it is better to assess the financial soundness of a utility by comparing it to a group of other financially sound utilities. Second, using a proxy group provides more reliability and confidence in the overall results because there is a larger sample size. Finally, the use of a proxy group is often a pure necessity when the target company is a subsidiary that is not publicly traded. This is because the financial models used to estimate the cost of equity require information from publicly-traded firms, such as stock prices and dividends.

Q. Describe the proxy group you selected in this case.

A. In this case, I chose to use the same proxy group used by Ms. Nelson. There could be reasonable arguments made for the inclusion or exclusion of a particular company in a proxy group; however, the cost of equity results are influenced far more by the underlying assumptions and inputs to the various financial models than the composition of the proxy groups.[34] By using the same proxy group, we can remove a relatively insignificant variable from the equation and focus on the primary factors driving the Company's cost of equity estimate in this case.

V. RISK AND RETURN CONCEPTS

Q. Discuss the general relationship between risk and return.

A. Risk is among the most important factors for the Commission to consider when determining the allowed return. Thus, it is necessary to understand the relationship between risk and return. There is a direct relationship between risk and return: the more (or less) risk an investor assumes, the larger (or smaller) return the investor will demand. There are two primary types of risk: firm-specific risk and market

[34] *See* Exhibit DJG-2.

risk. Firm-specific risk affects individual companies, while market risk affects all companies in the market to varying degrees.

Q. Discuss the differences between firm-specific risk and market risk.

A. Firm-specific risk affects individual companies, rather than the entire market. For example, a competitive firm might overestimate customer demand for a new product, resulting in reduced sales revenue. This is an example of a firm-specific risk called "project risk."[35] There are several other types of firm-specific risks, including: (1) "financial risk" — the risk that equity investors of leveraged firms face as residual claimants on earnings; (2) "default risk" — the risk that a firm will default on its debt securities; and (3) "business risk" — which encompasses all other operating and managerial factors that may result in investors realizing less than their expected return in that particular company. While firm-specific risk affects individual companies, market risk affects all companies in the market to varying degrees. Examples of market risk include interest rate risk, inflation risk, and the risk of major socio-economic events. When there are changes in these risk factors, they affect all firms in the market to some extent.[36]

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[35] Aswath Damodaran, *Investment Valuation: Tools and Techniques for Determining the Value of Any Asset* 62-63 (3rd ed., John Wiley & Sons, Inc. 2012).

[36] *See* Zvi Bodie, Alex Kane & Alan J. Marcus, *Essentials of Investments* 149 (9th ed., McGraw-Hill/Irwin 2013).

Analysis of the U.S. market in 2001 provides a good example for contrasting firm-specific risk and market risk. During that year, Enron Corp.'s stock fell from $80 per share and the company filed bankruptcy at the end of the year. If an investor's portfolio had held only Enron stock at the beginning of 2001, this irrational investor would have lost the entire investment by the end of the year due to assuming the full exposure of Enron's firm-specific risk (in that case, imprudent management). On the other hand, a rational, diversified investor who invested the same amount of capital in a portfolio holding every stock in the S&P 500 would have had a much different result that year. The rational investor would have been relatively unaffected by the fall of Enron because her portfolio included about 499 other stocks. Each of those stocks, however, would have been affected by various *market* risk factors that occurred that year, including the terrorist attacks on September 11th, which affected all stocks in the market. Thus, the rational investor would have incurred a relatively minor loss due to market risk factors, while the irrational investor would have lost everything due to firm-specific risk factors.

Q. Can investors easily minimize firm-specific risk?

A. Yes. A fundamental concept in finance is that firm-specific risk can be eliminated through diversification.[37] If someone irrationally invested all their funds in one firm, they would be exposed to all the firm-specific risk *and* the market risk inherent in that single firm. Rational investors, however, are risk-averse and seek to eliminate risk they can control. Investors can essentially eliminate firm-specific risk by adding more stocks to their portfolio through a process called "diversification." There are two reasons why diversification eliminates firm-specific risk. First, each stock in a diversified portfolio represents a much smaller percentage of the overall portfolio than it would in a portfolio of just one or a few stocks. Thus, any firm-specific action that changes the stock price of one stock in the diversified portfolio will have only a small impact on the entire portfolio.[38]

The second reason why diversification eliminates firm-specific risk is that the effects of firm-specific actions on stock prices can be either positive or negative for each stock. Thus, in large diversified portfolios, the net effect of these positive and negative firm-specific risk factors will be essentially zero and will not affect

[37] *See* John R. Graham, Scott B. Smart & William L. Megginson, *Corporate Finance: Linking Theory to What Companies Do* 179-80 (3rd ed., South Western Cengage Learning 2010).

[38] *See* Aswath Damodaran, *Investment Valuation: Tools and Techniques for Determining the Value of Any Asset* 64 (3rd ed., John Wiley & Sons, Inc. 2012).

the value of the overall portfolio.[39] Firm-specific risk is also called "diversifiable risk" because it can be easily eliminated through diversification.

Q. Is it well-known and accepted that, because firm-specific risk can be easily eliminated through diversification, the market does not reward such risk through higher returns?

A. Yes. Because investors eliminate firm-specific risk through diversification, they know they cannot expect a higher return for assuming the firm-specific risk in any one company. Thus, the risks associated with an individual firm's operations are not rewarded by the market. In fact, firm-specific risk is also called "unrewarded" risk for this reason. Market risk, on the other hand, cannot be eliminated through diversification. Because market risk cannot be eliminated through diversification, investors expect a return for assuming this type of risk. Market risk is also called "systematic risk." Scholars recognize the fact that market risk, or "systematic risk," is the only type of risk for which investors expect a return for bearing:

> If investors can cheaply eliminate some risks through diversification, then we should not expect a security to earn higher returns for risks that can be eliminated through diversification. Investors can expect compensation *only* for bearing systematic risk (i.e., risk that cannot be diversified away).[40]

These important concepts are illustrated in the figure below. Some form of this figure is found in many financial textbooks.

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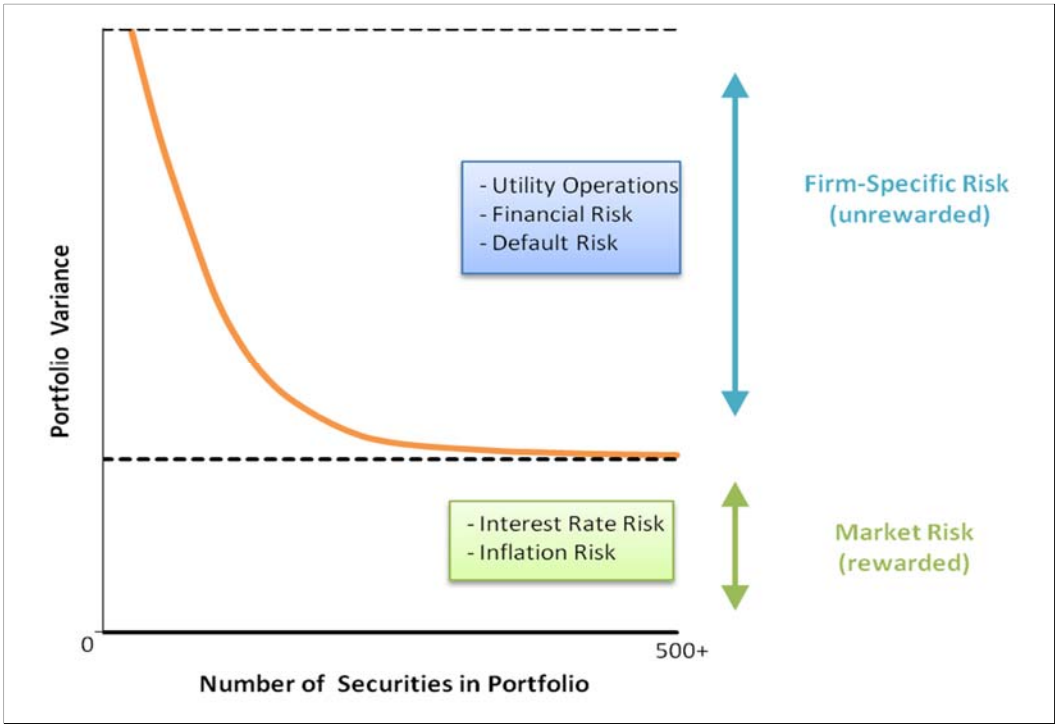
[39] *Id*.

[40] *See* John R. Graham, Scott B. Smart & William L. Megginson, *Corporate Finance: Linking Theory to What Companies Do* 180 (3rd ed., South Western Cengage Learning 2010).

Figure 5:
Effects of Portfolio Diversification



This figure shows that as stocks are added to a portfolio, the amount of firm-specific risk is reduced until it is essentially eliminated. No matter how many stocks are added, however, there remains a certain level of fixed market risk. The level of market risk will vary from firm to firm. Market risk is the only type of risk that is rewarded by the market and is thus the primary type of risk the Commission should consider when determining the allowed return.

Q. Describe how market risk is measured.

A. Investors who want to eliminate firm-specific risk must hold a fully diversified portfolio. To determine the amount of risk that a single stock adds to the overall market portfolio, investors measure the covariance between a single stock and the market portfolio. The result of this calculation is called "beta."[41] Beta represents the sensitivity of a given security to the market as a whole. The market portfolio of all stocks has a beta equal to one. Stocks with betas greater than one are relatively more sensitive to market risk than the average stock. For example, if the market increases (decreases) by 1.0%, a stock with a beta of 1.5 will, on average, increase (decrease) by 1.5%. In contrast, stocks with betas of less than one are less sensitive to market risk, such that if the market increases (decreases) by 1.0%, a stock with a beta of 0.5 will, on average, only increase (decrease) by 0.5%. Thus, stocks with low betas are relatively insulated from market conditions. The beta term is used in the CAPM to estimate the cost of equity, which is discussed in more detail later.[42]

Q. Are public utilities characterized as defensive firms that have low betas, low market risk, and are relatively insulated from overall market conditions?

A. Yes. Although market risk affects all firms in the market, it affects different firms to varying degrees. Firms with high betas are affected more than firms with low betas, which is why firms with high betas are riskier. Stocks with betas greater than one are generally known as "cyclical stocks." Firms in cyclical industries are

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[41] *Id*. at 180-81.

[42] Though it will be discussed in more detail later, Exhibit DJG-8 shows that the average beta of the proxy group was less than 1.0. This confirms the well-known concept that utilities are relatively low-risk firms.

sensitive to recurring patterns of recession and recovery known as the "business cycle."[43] Thus, cyclical firms are exposed to a greater level of market risk. Securities with betas less than one, on the other hand, are known as "defensive stocks." Companies in defensive industries, such as public utility companies, "will have low betas and performance that is comparatively unaffected by overall market conditions."[44] In fact, financial textbooks often use utility companies as prime examples of low-risk, defensive firms. The figure below compares the betas of several industries and illustrates that the utility industry is one of the least risky industries in the U.S. market.[45]

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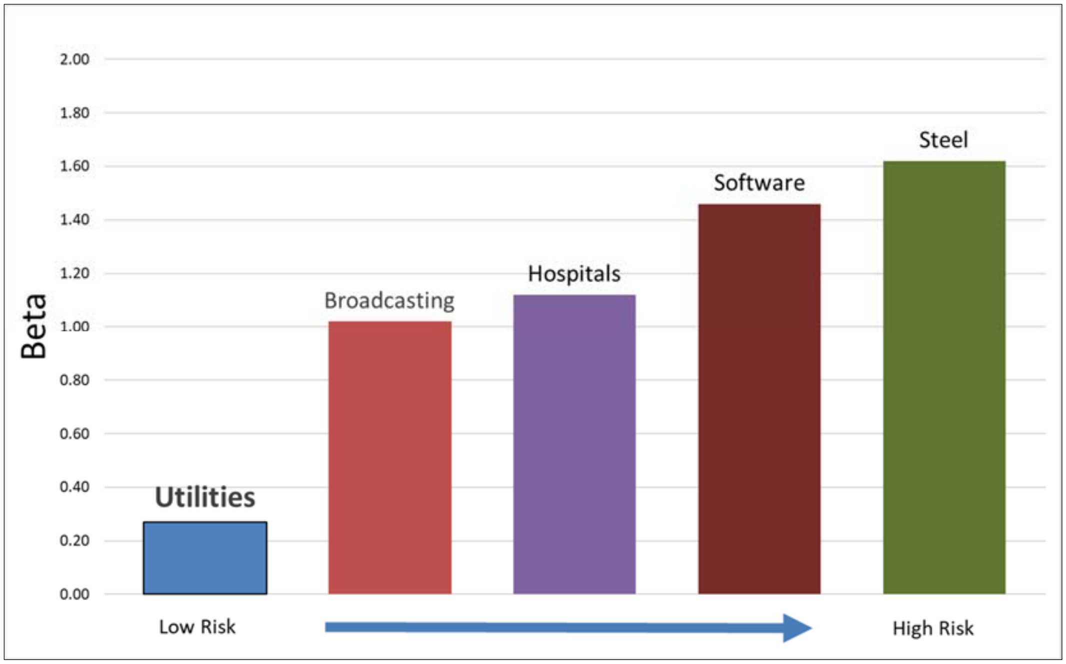
[43] *See* Zvi Bodie, Alex Kane & Alan J. Marcus, *Essentials of Investments* 382 (9th ed., McGraw-Hill/Irwin 2013).

[44] *Id*. at 383.

[45] *See* Betas by Sector (US) available at http://pages.stern.nyu.edu/~adamodar/ (2018). (After clicking the link, click "Data" then "Current Data" then "Risk / Discount Rate" from the drop down menu, then "Total Beta by Industry Sector"). The exact beta calculations are not as important as illustrating the well-known fact that utilities are very low-risk companies. The fact that the utility industry is one of the lowest risk industries in the country should not change from year to year.

Figure 6:
Beta by Industry



The fact that utilities are defensive firms that are exposed to little market risk is beneficial to society. When the business cycle enters a recession, consumers can be assured that their utility companies will be able to maintain normal business operations and provide safe and reliable service under prudent management. Likewise, utility investors can be confident that utility stock prices will not widely fluctuate. So, while it is recognized and accepted that utilities are defensive firms that experience little market risk and are relatively insulated from market conditions, this fact should also be appropriately reflected in the Company's awarded return.

VI. DISCOUNTED CASH FLOW ANALYSIS

Q. Describe the Discounted Cash Flow ("DCF") model.

A. The Discounted Cash Flow ("DCF") Model is based on a fundamental financial model called the "dividend discount model," which maintains that the value of a security is equal to the present value of the future cash flows it generates. Cash flows from common stock are paid to investors in the form of dividends. There are several variations of the DCF Model. These versions, along with other formulas and theories related to the DCF Model are discussed in more detail in Appendix A. For this case, I chose to use the Quarterly Approximation DCF Model.

Q. Describe the inputs to the DCF Model.

A. There are three primary inputs in the DCF Model: (1) stock price; (2) dividend; and (3) the long-term growth rate. The stock prices and dividends are known inputs based on recorded data, while the growth rate projection must be estimated. I discuss each of these inputs separately below.

A. Stock Price

Q. How did you determine the stock price input of the DCF Model?

A. For the stock price (P_0), I used a 30-day average of stock prices for each company in the proxy group.[46] Analysts sometimes rely on average stock prices for longer

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[46] Exhibit DJG-3.

periods (e.g., 60, 90, or 180 days). According to the efficient market hypothesis, however, markets reflect all relevant information available at a particular time, and prices adjust instantaneously to the arrival of new information.[47] Past stock prices, in essence, reflect outdated information. The DCF Model used in utility rate cases is a derivation of the dividend discount model, which is used to determine the current value of an asset. Thus, according to the dividend discount model and the efficient market hypothesis, the value for the "P_0" term in the DCF Model should technically be the current stock price, rather than an average.

Q. Why did you use a 30-day average for the current stock price input?

A. Using a short-term average of stock prices for the current stock price input adheres to market efficiency principles while avoiding any irregularities that may arise from using a single current stock price. In the context of a utility rate proceeding, there is a significant length of time from when an application is filed, and testimony is due. Choosing a current stock price for one particular day could raise a separate issue concerning which day was chosen to be used in the analysis. In addition, a single stock price on a particular day may be unusually high or low. It is arguably ill-advised to use a single stock price in a model that is ultimately used to set rates

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[47] *See* Eugene F. Fama, *Efficient Capital Markets: A Review of Theory and Empirical Work*, Vol. 25, No. 2 The Journal of Finance 383 (1970); *see also* John R. Graham, Scott B. Smart & William L. Megginson, *Corporate Finance: Linking Theory to What Companies Do* 357 (3rd ed., South Western Cengage Learning 2010). The efficient market hypothesis was formally presented by Eugene Fama in 1970 and is a cornerstone of modern financial theory and practice.

for several years, especially if a stock is experiencing some volatility. Thus, it is preferable to use a short-term average of stock prices, which represents a good balance between adhering to well-established principles of market efficiency while avoiding any unnecessary contentions that may arise from using a single stock price on a given day. The stock prices I used in my DCF analysis are based on 30-day averages of adjusted closing stock prices for each company in the proxy group.[48]

B. <u>Dividend</u>

Q. Describe how you determined the dividend input of the DCF Model.

A. The dividend term in the Quarterly Approximation DCF Model is the current quarterly dividend per share. I obtained the most recent quarterly dividend paid for each proxy company.[49] The Quarterly Approximation DCF Model assumes that the company increases its dividend payments each quarter. Thus, the model assumes that each quarterly dividend is greater than the previous one by $(1 + g)^{0.25}$. This expression could be described as the dividend quarterly growth rate, where the term "g" is the growth rate and the exponential term "0.25" signifies one quarter of the year.

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[48] Exhibit DJG-3. Adjusted closing prices, rather than actual closing prices, are ideal for analyzing historical stock prices. The adjusted price provides an accurate representation of the firm's equity value beyond the mere market price because it accounts for stock splits and dividends.

[49] Exhibit DJG-4. Nasdaq Dividend History, available at http://www.nasdaq.com/quotes/dividend-history.aspx.

Q. Does the Quarterly Approximation DCF Model result in the highest cost of equity in this case relative to other DCF Models, all else held constant?

A. Yes. The DCF Model I employed in this case results in a higher DCF cost of equity estimate than the annual or semi-annual DCF Models due to the quarterly compounding of dividends inherent in the model. In essence, the Quarterly Compounding DCF Model I used results in the *highest* cost of equity estimate, all else held constant.

Q. Are the stock price and dividend inputs for each proxy company a significant issue in this case?

A. No. Although my stock price and dividend inputs are more recent than those used by Ms. Nelson, there is not a statistically significant difference between them because utility stock prices and dividends are generally quite stable. This is another reason that cost of capital models such as the CAPM and the DCF Model are well-suited to be conducted on utilities. The differences between my DCF Model and Ms. Nelson's DCF Model are primarily driven by differences in our growth rate estimates, which are further discussed below.

C. <u>Growth Rate</u>

Q. Summarize the growth rate input in the DCF Model.

A. The most critical input in the DCF Model is the growth rate. Unlike the stock price and dividend inputs, the growth rate input must be estimated. As a result, the growth rate is often the most contentious DCF input in utility rate cases. The DCF model used in this case is based on the constant growth valuation model. Under this model, a stock is valued by the present value of its future cash flows in the form of dividends. Before future cash flows are discounted by the cost of equity, however, they must be "grown" into the future by a long-term growth rate. As stated above, one of the inherent assumptions of this model is that these cash flows in the form of dividends grow at a constant rate forever. Thus, the growth rate term in the constant growth DCF model is often called the "constant," "stable," or "terminal" growth rate. For young, high-growth firms, estimating the growth rate to be used in the model can be especially difficult, and may require the use of multi-stage growth models. For mature, low-growth firms such as utilities, however, estimating the terminal growth rate is more transparent. The growth term of the DCF Model is one of the most important, yet apparently most misunderstood aspects of cost of equity estimations in utility regulatory proceedings. Therefore, I have devoted a more detailed explanation of this issue in the following sections, which are organized as follows:

(1) The Various Determinants of Growth

(2) Reasonable Estimates for Long-Term Growth

(3) Quantitative vs. Qualitative Determinants of Utility Growth: Circular References, "Flatworm" Growth, and the Problem with Analysts' Growth Rates

(4) Growth Rate Recommendation

1. <u>The Various Determinants of Growth</u>

Q. Describe the various determinants of growth.

A. Although the DCF Model directly considers the growth of dividends, there are a variety of growth determinants that should be considered when estimating growth rates. It should be noted that these various growth determinants are used primarily to determine the short-term growth rates in multi-stage DCF models. For utility companies, it is necessary to focus primarily on long-term growth rates, which are discussed in the following section. That is not to say that these growth determinants cannot be considered when estimating long-term growth; however, as discussed below, long-term growth must be constrained much more than short-term growth, especially for young firms with high growth opportunities. Additionally, I briefly discuss these growth determinants here because it may reveal some of the source of confusion in this area.

1. <u>Historical Growth</u>

Looking at a firm's actual historical experience may theoretically provide a good starting point for estimating short-term growth. However, past growth is not always a good indicator of future growth. Some metrics that might be considered here are historical growth in revenues, operating income, and net income. Since dividends are paid from earnings, estimating historical earnings growth may provide an indication of future earnings and dividend growth. In general, however, revenue growth tends to be more consistent and predictable than earnings growth because it is less likely to be influenced by accounting adjustments.[50]

2. Analyst Growth Rates

Analyst growth rates refer to short-term projections of earnings growth published by institutional research analysts such as Value Line and Bloomberg. A more detailed discussion of analyst growth rates, including the problems with using them in the DCF Model to estimate utility cost of equity, is provided in a later section.

3. Fundamental Determinants of Growth

Fundamental growth determinants refer to firm-specific financial metrics that arguably provide better indications of near-term sustainable growth. One such metric for fundamental growth considers the return on equity and the retention ratio.

[50] *See* Aswath Damodaran, *Investment Valuation: Tools and Techniques for Determining the Value of Any Asset* 279 (3rd ed., John Wiley & Sons, Inc. 2012).

The idea behind this metric is that firms with high ROEs and retention ratios should have higher opportunities for growth.[51]

Q. Did you use any of these growth determinants in your DCF Model?

A. No. Primarily, these growth determinants discussed above would provide better indications of short to mid-term growth for firms with average to high growth opportunities. However, utilities are mature, low-growth firms. While it may not be unreasonable on its face to use any of these growth determinants for the growth input in the DCF Model, we must keep in mind that the stable growth DCF Model considers only *long-term* growth rates, which are constrained by certain economic factors, as discussed further below.

2. <u>Reasonable Estimates for Long-Term Growth</u>

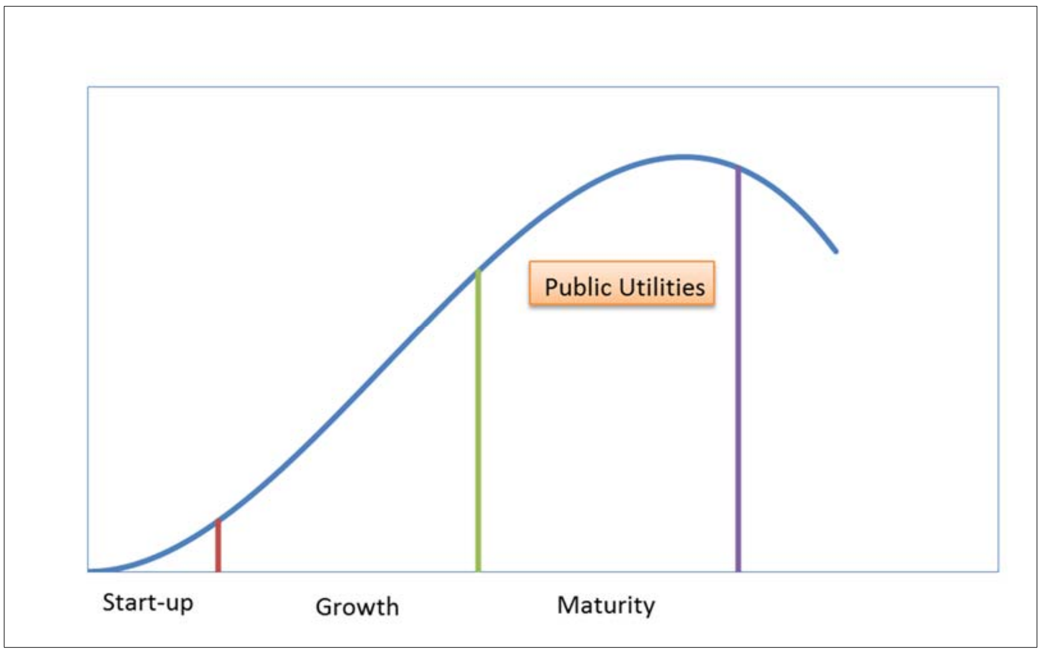
Q. Describe what is meant by long-term growth.

A. In order to make the DCF a viable, practical model, an infinite stream of future cash flows must be estimated and then discounted back to the present. Otherwise, each annual cash flow would have to be estimated separately. Some analysts use "multi-stage" DCF Models to estimate the value of high-growth firms through two or more stages of growth, with the final stage of growth being constant. However, it is not necessary to use multi-stage DCF Models to analyze the cost of equity of regulated

[51] *Id*. at 291-292.

utility companies. This is because regulated utilities are already in their "terminal," low growth stage. Unlike most competitive firms, the growth of regulated utilities is constrained by physical service territories and limited primarily by the customer and load growth within those territories. The figure below illustrates the well-known business/industry life-cycle pattern.

Figure 7:
Industry Life Cycle



In an industry's early stages, there are ample opportunities for growth and profitable reinvestment. In the maturity stage however, growth opportunities diminish, and firms choose to pay out a larger portion of their earnings in the form of dividends instead of reinvesting them in operations to pursue further growth opportunities. Once a firm is in the maturity stage, it is not necessary to consider higher short-term growth metrics in multi-stage DCF Models; rather, it is sufficient to analyze the cost of equity using a stable growth DCF Model with one terminal, long-term growth rate. Because utilities are in their maturity stage, their real growth opportunities are primarily limited to the population growth within their defined service territories, which is usually less than 2%.

Q. Is it true that the terminal growth rate cannot exceed the growth rate of the economy, especially for a regulated utility company?

A. Yes. A fundamental concept in finance is that no firm can grow forever at a rate higher than the growth rate of the economy in which it operates.[52] Thus, the terminal growth rate used in the DCF Model should not exceed the aggregate economic growth rate. This is especially true when the DCF Model is conducted on public utilities because these firms have defined service territories. As stated by Dr. Damodaran:

> "If a firm is a purely domestic company, either because of internal constraints . . . or external constraints (such as those imposed by a government), the growth rate in the domestic economy will be the limiting value."[53]

In fact, it is reasonable to assume that a regulated utility would grow at a rate that is *less* than the U.S. economic growth rate. Unlike competitive firms, which might increase their growth by launching a new product line, franchising, or expanding

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[52] *See generally* Aswath Damodaran, *Investment Valuation: Tools and Techniques for Determining the Value of Any Asset* 306 (3rd ed., John Wiley & Sons, Inc. 2012).

[53] *Id*.

into new and developing markets, utility operating companies with defined service territories cannot do any of these things to grow. Gross domestic product ("GDP") is one of the most widely used measures of economic production and is used to measure aggregate economic growth. According to the Congressional Budget Office's Budget Outlook, the long-term forecast for nominal U.S. GDP growth is 3.9%, which includes an inflation rate of 2%.[54] For mature companies in mature industries, such as utility companies, the terminal growth rate will likely fall between the expected rate of inflation and the expected rate of nominal GDP growth. Thus, EPE's terminal growth rate is realistically between 2% and 4%.

Q. Is it reasonable to assume that the terminal growth rate will not exceed the risk-free rate?

A. Yes. In the long term, the risk-free rate will converge on the growth rate of the economy. For this reason, financial analysts sometimes use the risk-free rate for the terminal growth rate value in the DCF model.[55] I discuss the risk-free rate in further detail later in this testimony.

Q. Please summarize the various long-term growth rate estimates that can be used as the terminal growth rate in the DCF Model.

A. The reasonable long-term growth rate determinants are summarized as follows:

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[54] Congressional Budget Office – The 2019 Long-Term Budget Outlook p. 54, https://www.cbo.gov/publication/55331.

[55] Aswath Damodaran, *Investment Valuation: Tools and Techniques for Determining the Value of Any Asset* 307 (3rd ed., John Wiley & Sons, Inc. 2012).

1. Nominal GDP Growth
2. Inflation
3. Current Risk-Free Rate

Any of the foregoing growth determinants could provide a reasonable input for the terminal growth rate in the DCF Model for a utility company, including EPE. In general, we should expect that utilities will, at the very least, grow at the rate of projected inflation. However, the long-term growth rate of any U.S. company, especially utilities, will be constrained by nominal U.S. GDP growth.

3. <u>Qualitative Growth: The Problem with Analysts' Growth Rates</u>

Q. Describe the differences between "quantitative" and "qualitative" growth determinants.

A. Assessing "quantitative" growth simply involves mathematically calculating a historic metric for growth (such as revenues or earnings) or calculating various fundamental growth determinants using various figures from a firm's financial statements (such as ROE and the retention ratio). However, any thorough assessment of company growth should be based upon a "qualitative" analysis. Such an analysis would consider specific strategies that company management will implement to achieve a sustainable growth in earnings. Therefore, it is important to begin the analysis of EPE' growth rate with this simple, qualitative question: How is this regulated utility going to achieve a sustained growth in earnings? If this question were asked of a competitive firm, there could be several answers depending on the type of business model, such as launching a new product line, franchising, rebranding to target a new demographic, or expanding into a developing market. Regulated utilities, however, cannot engage in these potential growth opportunities.

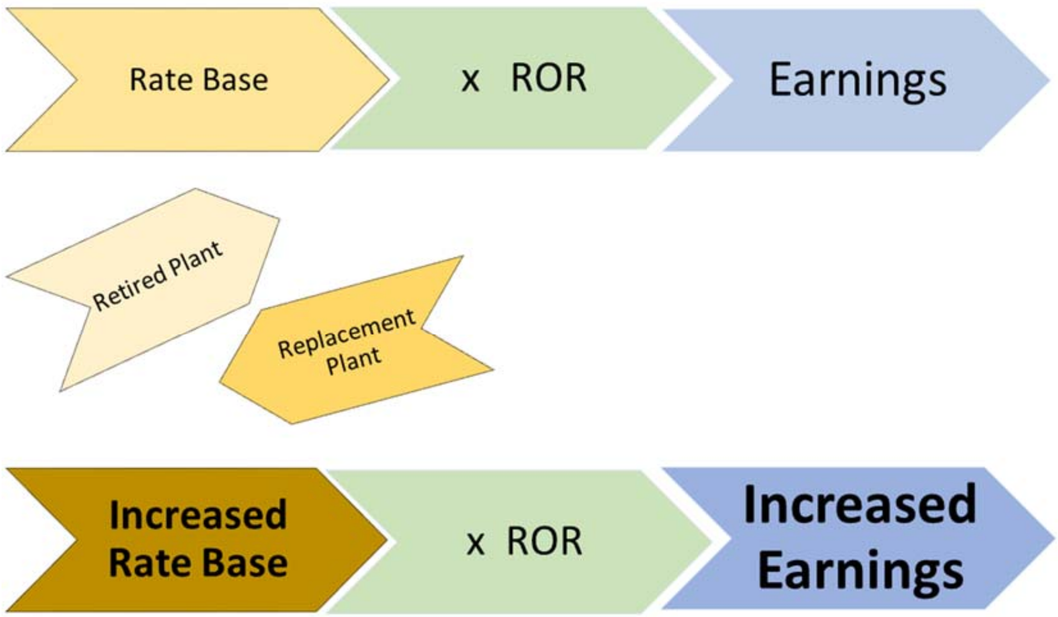
Q. Why is it especially important to emphasize real, qualitative growth determinants when analyzing the growth rates of regulated utilities?

A. While qualitative growth analysis is important regardless of the entity being analyzed, it is especially important in the context of utility ratemaking. This is because the rate base rate of return model inherently possesses two factors that can contribute to distorted views of utility growth when considered exclusively from a quantitative perspective. These two factors are (1) rate base and (2) the awarded ROE. I will discuss each factor further below. It is important to keep in mind that the ultimate objective of this analysis is to provide a foundation upon which to base the fair rate of return for the utility. Thus, we should strive to ensure that each individual component of the financial models used to estimate the cost of equity are also "fair." If we consider only quantitative growth determinants, it may lead to projected growth rates that are overstated and ultimately unfair, because they result in inflated cost of equity estimates.

Q. How does rate base relate to growth determinants for utilities?

A. Under the rate base rate of return model, a utility's rate base is multiplied by its awarded rate of return to produce the required level of operating income. Therefore, increases to rate base generally result in increased earnings. Thus, utilities have a natural financial incentive to increase rate base. In short, utilities have a financial incentive to increase rate base regardless of whether such increases are driven by a corresponding increase in demand. Under these circumstances, utilities have been able to increase their rate bases by a far greater extent than what any concurrent increase in demand would have required. In other words, utilities "grew" their earnings by simply retiring old assets and replacing them with new assets. If the tail of a flatworm is removed and regenerated, it does not mean the flatworm actually grew. Likewise, if a competitive, unregulated firm announced plans to close production plants and replace them with new plants, it would not be considered a real determinant of growth unless analysts believed this decision would directly result in increased market share for the company and a real opportunity for sustained increases in revenues and earnings. In the case of utilities, the mere replacement of old plant with new plant does not increase market share, attract new customers, create franchising opportunities, or allow utilities to penetrate developing markets, but may result in short-term, quantitative earnings growth. This "flatworm growth" in earnings was merely the quantitative byproduct of the rate base rate of return model, and not an indication of real, fair, or qualitative growth. The following diagram illustrates this concept.

Figure 8:
Analysts' Earnings Growth Projections: The "Flatworm Growth" Problem

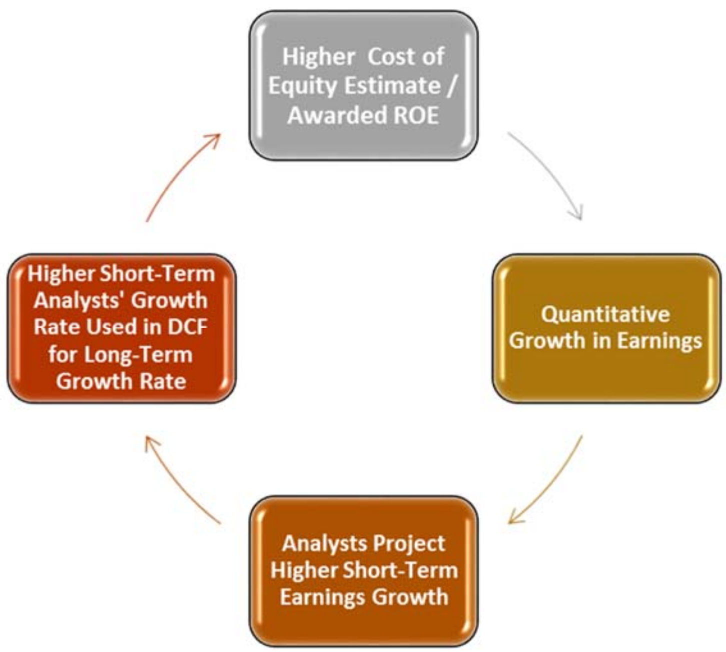


Of course, utilities might sometimes add new plant to meet a modest growth in customer demand. However, as the foregoing discussion demonstrates, it would be more appropriate to consider load growth projections and other qualitative indicators, rather than mere increases to rate base or earnings, to attain a fair assessment of growth.

Q. Please discuss the other way in which analysts' earnings growth projections do not provide indications of fair, qualitative growth for regulated utilities.

A. If we give undue weight to analysts' projections for utilities' earnings growth, it will not provide an accurate reflection of real, qualitative growth because a utility's earnings are heavily influenced by the ultimate figure that all this analysis is supposed to help us estimate: the awarded return on equity. This creates a circular reference problem or feedback loop. In other words, if a regulator awards an ROE that is above market-based cost of capital (which is often the case, as discussed above), this could lead to higher short-term growth rate projections from analysts. If these same inflated, short-term growth rate estimates are used in the DCF Model (and they often are by utility witnesses), it could lead to higher awarded ROEs; and the cycle continues, as illustrated in the following figure:

Figure 9:
Analysts' Earnings Growth Projections: The "Circular Reference" Problem



Therefore, it is not advisable to simply consider the quantitative growth projections published by analysts, as this practice will not necessarily provide fair indications of real utility growth.

Q. Are there any other problems with relying on analysts' growth projections?

A. Yes. While the foregoing discussion shows two reasons why we cannot rely on analysts' growth rate projections to provide fair, qualitative indicators of utility growth in a stable growth DCF Model, the third reason is perhaps the most obvious and indisputable. Various institutional analysts, such as Zacks, Value Line, and Bloomberg, publish estimated projections of earnings growth for utilities. These estimates, however, are *short-term* growth rate projections, ranging from 3 – 10 years. Many utility ROE analysts, however, inappropriately insert these short-term growth projections into the DCF Model as *long-term* growth rate projections. For example, assume that an analyst at Bloomberg estimates that a utility's earnings will grow by 7% per year over the next 3 years. This analyst may have based this short-term forecast on a utility's plans to replace depreciated rate base (i.e., "flatworm" growth) or on an anticipated awarded return that is above market-based cost of equity (i.e., "circular reference" problem). When a utility witness uses this figure in a DCF Model, however, it is the *witness*, not the Bloomberg analyst that is testifying to the regulator that the utility's earnings will qualitatively grow by 7% per year over the *long-term*, which is an unrealistic assumption.

4. Long-Term Growth Rate Recommendation

Q. Describe the growth rate input used in your DCF Model.

A. I considered various qualitative determinants of growth for the Company, along with the maximum allowed growth rate under basic principles of finance and economics. The following chart shows the various long-term growth determinants discussed in this section.[56]

Figure 10:
Terminal Growth Rate Determinants

Terminal Growth Determinants	Rate
Nominal GDP	3.9%
Inflation	2.0%
Risk Free Rate	1.4%
Highest	**3.9%**

For the long-term growth rate in my DCF model, I selected the maximum, reasonable long-term growth rate of 3.9%, which means my model assumes that the Company's qualitative growth in earnings will match the nominal growth rate of the entire U.S. economy over the long run.

Q. Please describe the final results of your DCF Model.

A. I used the Quarterly Approximation DCF Model discussed above to estimate the Company's cost of equity capital. I obtained an average of reported dividends and stock prices from the proxy group, and I used a reasonable terminal growth rate estimate for the Company. Applying this model, my DCF cost of equity estimate

[56] Exhibit DJG-5.

for the Company is 7.4%.[57] As noted above, this estimate is likely at the higher end of the reasonable range due to my relatively high estimate for the long-term growth rate. That is, my long-term growth rate input assumes EPE' earnings will qualitatively grow at the same rate as the U.S. economy over the long-run — a very generous assumption.

D. Response to Ms. Nelson's DCF Model

Q. Ms. Nelson's DCF Model yielded much higher results. Did you find any errors in her analysis?

A. Yes, I found several errors. Ms. Nelson's DCF Model produced cost of equity results as high as 9.86%.[58] The results of Ms. Nelson's DCF Model are overstated primarily because of a fundamental error regarding her growth rate inputs.

Q. Describe the problems with Ms. Nelson's long-term growth input.

A. Ms. Nelson used long-term growth rates in her proxy group as high as 10%,[59] which is more than two times greater than the projected, long-term nominal U.S. GDP growth (approximately 4.0%). This means Ms. Nelson's growth rate assumption violates the basic principle that no company can grow at a greater rate than the economy in which it operates over the long-term, especially a regulated utility company with a defined service territory. Furthermore, Ms. Nelson used short-

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[57] Exhibit DJG-6.

[58] Exhibit RBH-2.

[59] *Id*.

term, quantitative growth estimates published by analysts. As discussed above, these analysts' estimates are inappropriate to use in the DCF Model as long-term growth rates because they are estimates for short-term growth. For example, Ms. Nelson incorporated a 10% long-term growth rate for NextEra Energy, Inc. ("NEE"), which was reported by Value Line.[60] This means that an analyst from Value Line apparently thinks that NEE's earnings will quantitatively increase by 10% each year over the next *several* years. However, it is Ms. Nelson, not the Value Line analyst, who is suggesting to the Commission that NEE's earnings will grow by 10% each year, every year, for many decades into the future.[61] This assumption is simply not realistic, and it contradicts fundamental concepts of long-term growth. The growth rate assumptions used by Ms. Nelson for many of the proxy companies suffer from the same unrealistic assumptions.[62] As a result, her DCF cost of equity estimates are overstated.

[60] *Id*.

[61] *Id*. Technically, the constant growth rate in the DCF Model grows dividends each year to "infinity." Yet, even if we assumed that the growth rate applied to only a few decades, the annual growth rate would still be too high to be considered realistic.

[62] *Id*.

VII. CAPITAL ASSET PRICING MODEL ANALYSIS

Q. Describe the Capital Asset Pricing Model.

A. The Capital Asset Pricing Model is a market-based model founded on the principle that investors expect higher returns for incurring additional risk.[63] The CAPM estimates this expected return. The various assumptions, theories, and equations involved in the CAPM are discussed further in Appendix B. Using the CAPM to estimate the cost of equity of a regulated utility is consistent with the legal standards governing the fair rate of return. The U.S. Supreme Court has recognized that "the amount of *risk* in the business is a most important factor" in determining the allowed rate of return,[64] and that "the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding *risks*."[65] The CAPM is a useful model because it directly considers the amount of risk inherent in a business and directly measures the most important component of a fair rate of return analysis: Risk.

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[63] William F. Sharpe, *A Simplified Model for Portfolio Analysis* 277-93 (Management Science IX 1963); *see also* John R. Graham, Scott B. Smart & William L. Megginson, *Corporate Finance: Linking Theory to What Companies Do* 208 (3rd ed., South Western Cengage Learning 2010).

[64] *Wilcox*, 212 U.S. at 48 (emphasis added).

[65] *Hope Natural Gas Co.*, 320 U.S. at 603 (emphasis added).

Q. Describe the inputs for the CAPM.

A. The basic CAPM equation requires only three inputs to estimate the cost of equity: (1) the risk-free rate; (2) the beta coefficient; and (3) the equity risk premium. Each input is discussed separately below.

A. <u>The Risk-Free Rate</u>

Q. Explain the risk-free rate.

A. The first term in the CAPM is the risk-free rate (R_F). The risk-free rate is simply the level of return investors can achieve without assuming any risk. The risk-free rate represents the bare minimum return that any investor would require on a risky asset. Even though no investment is technically void of risk, investors often use U.S. Treasury securities to represent the risk-free rate because they accept that those securities essentially contain no default risk. The Treasury issues securities with different maturities, including short-term Treasury Bills, intermediate-term Treasury Notes, and long-term Treasury Bonds.

Q. Is it preferable to use the yield on long-term Treasury bonds for the risk-free rate in the CAPM?

A. Yes. In valuing an asset, investors estimate cash flows over long periods of time. Common stock is viewed as a long-term investment, and the cash flows from dividends are assumed to last indefinitely. As a result, short-term Treasury bill yields are rarely used in the CAPM to represent the risk-free rate. Short-term rates are subject to greater volatility and thus can lead to unreliable estimates. Instead, long-term Treasury bonds are usually used to represent the risk-free rate in the CAPM. I considered a 30-day average of daily Treasury yield curve rates on 30-year Treasury bonds in my risk-free rate estimate, which resulted in a risk-free rate of 1.41%.[66]

B. <u>The Beta Coefficient</u>

Q. How is the beta coefficient used in this model?

A. As discussed above, beta represents the sensitivity of a given security to movements in the overall market. The CAPM states that in efficient capital markets, the expected risk premium on each investment is proportional to its beta. Recall that a security with a beta greater (less) than one is more (less) risky than the market portfolio. An index such as the S&P 500 Index is used as a proxy for the market portfolio. The historical betas for publicly traded firms are published by various institutional analysts. Beta may also be calculated through a linear regression analysis, which provides additional statistical information about the relationship between a single stock and the market portfolio. As discussed above, beta also represents the sensitivity of a given security to the market as a whole. The market portfolio of all stocks has a beta equal to one. Stocks with betas greater than one are relatively more sensitive to market risk than the average stock. For example, if

[66] Exhibit DJG-7.

the market increases (decreases) by 1.0%, a stock with a beta of 1.5 will, on average, increase (decrease) by 1.5%. In contrast, stocks with betas of less than one are less sensitive to market risk. For example, if the market increases (decreases) by 1.0%, a stock with a beta of 0.5 will, on average, only increase (decrease) by 0.5%.

Q. Describe the source for the betas you used in your CAPM analysis.

A. I used betas recently published by Value Line Investment Survey. The beta for each proxy company is less than 1.0, and the average beta for the proxy group is only 0.85.[67] Thus, we have an objective measure to prove the well-known concept that utility stocks are less risky than the average stock in the market. While there is evidence suggesting that betas published by sources such as Value Line may actually overestimate the risk of utilities (and thus overestimate the CAPM), I used the betas published by Value Line in the interest of reasonableness.[68]

C. <u>The Equity Risk Premium</u>

Q. Describe the equity risk premium.

A. The final term of the CAPM is the equity risk premium ("ERP"), which is the required return on the market portfolio less the risk-free rate ($R_M – R_F$). In other words, the ERP is the level of return investors expect above the risk-free rate in exchange for investing in risky securities. Many experts agree that "the single most

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[67] Exhibit DJG-8.

[68] *See* Appendix B for a more detailed discussion of raw beta calculations and adjustments.

important variable for making investment decisions is the equity risk premium."[69] Likewise, the ERP is arguably the single most important factor in estimating the cost of capital in this matter. There are three basic methods that can be used to estimate the ERP: (1) calculating a historical average; (2) taking a survey of experts; and (3) calculating the implied ERP. I will discuss each method in turn, noting advantages and disadvantages of these methods.

1. <u>Historical Average</u>

Q. Describe the historical equity risk premium.

A. The historical ERP may be calculated by simply taking the difference between returns on stocks and returns on government bonds over a certain period of time. Many practitioners rely on the historical ERP as an estimate for the forward-looking ERP because it is easy to obtain. However, there are disadvantages to relying on the historical ERP.

Q. What are the limitations of relying solely on a historical average to estimate the current or forward-looking ERP?

A. As I mentioned, many investors use the historic ERP because it is convenient and easy to calculate. What matters in the CAPM model, however, is not the actual risk

[69] Elroy Dimson, Paul Marsh & Mike Staunton, *Triumph of the Optimists: 101 Years of Global Investment Returns* 4 (Princeton University Press 2002).

premium from the past, but rather the current and forward-looking risk premium.[70] Some investors may think that a historic ERP provides some indication of what the prospective risk premium is; however, there is empirical evidence to suggest the prospective, forward-looking ERP is actually *lower* than the historical ERP. In a landmark publication on risk premiums around the world, *Triumph of the Optimists*, the authors suggest through extensive empirical research that the prospective ERP is lower than the historical ERP.[71] This is due in large part to what is known as "survivorship bias" or "success bias" — a tendency for failed companies to be excluded from historical indices.[72] From their extensive analysis, the authors make the following conclusion regarding the prospective ERP:

> The result is a forward-looking, geometric mean risk premium for the United States . . . of around 2½ to 4 percent and an arithmetic mean risk premium . . . that falls within a range from a little below 4 to a little above 5 percent.[73]

Indeed, these results are lower than many reported historical risk premiums. Other noted experts agree:

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[70] John R. Graham, Scott B. Smart & William L. Megginson, *Corporate Finance: Linking Theory to What Companies Do* 330 (3rd ed., South Western Cengage Learning 2010).

[71] Elroy Dimson, Paul Marsh & Mike Staunton, Triumph of the Optimists: 101 Years of Global Investment Returns 194 (Princeton University Press 2002).

[72] *Id*. at 34.

[73] *Id*. at 194.

> The historical risk premium obtained by looking at U.S. data is biased upwards because of survivor bias. . . . The true premium, it is argued, is much lower. This view is backed up by a study of large equity markets over the twentieth century (*Triumph of the Optimists*), which concluded that the historical risk premium is closer to 4%.[74]

Regardless of the variations in historic ERP estimates, many leading scholars and practitioners agree that simply relying on a historic ERP to estimate the risk premium going forward is not ideal. Fortunately, "a naïve reliance on long-run historical averages is not the only approach for estimating the expected risk premium."[75]

Q. Did you rely on the historical ERP as part of your CAPM analysis in this case?

A. No. Due to the limitations of this approach, I primarily relied on the ERP reported in expert surveys and the implied ERP method discussed below.

2. EXPERT SURVEYS

Q. Describe the expert survey approach to estimating the ERP.

A. As its name implies, the expert survey approach to estimating the ERP involves conducting a survey of experts including professors, analysts, chief financial officers and other executives around the country and asking them what they think the ERP is. Graham and Harvey have performed such a survey since 1996. In their

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[74] Aswath Damodaran, *Equity Risk Premiums: Determinants, Estimation and Implications – The 2015 Edition* 17 (New York University 2015).

[75] John R. Graham, Scott B. Smart & William L. Megginson, *Corporate Finance: Linking Theory to What Companies Do* 330 (3rd ed., South Western Cengage Learning 2010).

2018 survey, they found that experts around the country believe the current ERP is only 4.4%.[76] The IESE Business School conducts a similar expert survey. Their 2020 expert survey reported an average ERP of 5.6%.[77]

3. IMPLIED EQUITY RISK PREMIUM

Q. Describe the implied equity risk premium approach.

A. The third method of estimating the ERP is arguably the best. The implied ERP relies on the stable growth model proposed by Gordon, often called the "Gordon Growth Model," which is a basic stock valuation model widely used in finance for many years.[78] This model is a mathematical derivation of the DCF Model. In fact, the underlying concept in both models is the same: The current value of an asset is equal to the present value of its future cash flows. Instead of using this model to determine the discount rate of one company, we can use it to determine the discount rate for the entire market by substituting the inputs of the model. Specifically, instead of using the current stock price (P_0), we will use the current value of the

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[76] John R. Graham and Campbell R. Harvey, *The Equity Risk Premium in 2018*, at 3 (Fuqua School of Business, Duke University 2014), copy available at https://papers.ssrn.com/sol3/papers.cfm?abstract_id=3151162.

[77] Pablo Fernandez, Pablo Linares & Isabel F. Acin, *Market Risk Premium used in 59 Countries in 2018: A Survey*, at 3 (IESE Business School 2018), copy available at http://www.valumonics.com/wp-content/uploads/2017/06/Discount-rate-Pablo-Fern%C3%A1ndez.pdf. IESE Business School is the graduate business school of the University of Navarra. IESE offers Master of Business Administration (MBA), Executive MBA and Executive Education programs. IESE is consistently ranked among the leading business schools in the world.

[78] Myron J. Gordon and Eli Shapiro, *Capital Equipment Analysis: The Required Rate of Profit* 102-10 (Management Science Vol. 3, No. 1 Oct. 1956).

S&P 500 (V_{500}). Instead of using the dividends of a single firm, we will consider the dividends paid by the entire market. Additionally, we should consider potential dividends. In other words, stock buybacks should be considered in addition to paid dividends, as stock buybacks represent another way for the firm to transfer free cash flow to shareholders. Focusing on dividends alone without considering stock buybacks could understate the cash flow component of the model, and ultimately understate the implied ERP. The market dividend yield plus the market buyback yield gives us the gross cash yield to use as our cash flow in the numerator of the discount model. This gross cash yield is increased each year over the next five years by the growth rate. These cash flows must be discounted to determine their present value. The discount rate in each denominator is the risk-free rate (R_F) plus the discount rate (K). The following formula shows how the implied return is calculated. Since the current value of the S&P is known, we can solve for K: The implied market return.[79]

Equation 2:
Implied Market Return

$$V_{500} = \frac{CY_1(1+g)^1}{(1+R_F+K)^1} + \frac{CY_2(1+g)^2}{(1+R_F+K)^2} + \cdots + \frac{CY_5(1+g)^5 + TV}{(1+R_F+K)^5}$$

[79] *See* Exhibit DJG-9 for detailed calculation.

where:	V_{500}	=	*current value of index (S&P 500)*
	$CY_{1\text{-}5}$	=	*average cash yield over last five years (includes dividends and buybacks)*
	g	=	*compound growth rate in earnings over last five years*
	R_F	=	*risk-free rate*
	K	=	*implied market return (this is what we are solving for)*
	TV	=	*terminal value* $= CY_5\,(1+R_F)\,/\,K$

The discount rate is called the "implied" return here because it is based on the current value of the index as well as the value of free cash flow to investors projected over the next five years. Thus, based on these inputs, the market is "implying" the expected return; or in other words, based on the current value of all stocks (the index price) and the projected value of future cash flows, the market is telling us the return expected by investors for investing in the market portfolio. After solving for the implied market return (K), we simply subtract the risk-free rate from it to arrive at the implied ERP.

Equation 3:
Implied Equity Risk Premium

$$Implied\ Expected\ Market\ Return - R_F = Implied\ ERP$$

Q. Discuss the results of your implied ERP calculation.

A. After collecting data for the index value, operating earnings, dividends, and buybacks for the S&P 500 over the past six years, I calculated the dividend yield, buyback yield, and gross cash yield for each year. I also calculated the compound annual growth rate (g) from operating earnings. I used these inputs, along with the risk-free rate and current value of the index to calculate a current expected return on the entire market of 7.4%.[80] I subtracted the risk-free rate to arrive at the implied equity risk premium of 6.0%.[81] Dr. Damodaran, arguably one of the world's leading experts on the ERP, promotes the implied ERP method discussed above. Using variations of this method, he calculates and publishes his ERP results each month. Dr. Damodaran's *highest* ERP estimate for September 2020 using several implied ERP variations was only 5.0%.[82]

Q. What are the results of your final ERP estimate?

A. For the final ERP estimate I used in my CAPM analysis, I considered the results of the ERP surveys, the implied ERP calculations discussed above, and the estimated ERP reported by Duff & Phelps.[83] The results are presented in the following figure:

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[80] *Id*.

[81] *Id*.

[82] http://pages.stern.nyu.edu/~adamodar/

[83] *See also* Exhibit DJG-10.

Figure 11:
Equity Risk Premium Results

IESE Business School Survey	5.6%
Graham & Harvey Survey	4.4%
Duff & Phelps Report	6.0%
Damodaran (highest)	5.0%
Damodaran (COVID Adjusted)	4.6%
Garrett	6.0%
Average	**5.3%**
Highest	**6.0%**

While it would be reasonable to select any one of these ERP estimates to use in the CAPM, I conservatively selected the *highest* ERP estimate of 6.0% to use in my CAPM analysis. All else held constant, a higher ERP used in the CAPM will result in a higher cost of equity estimate.

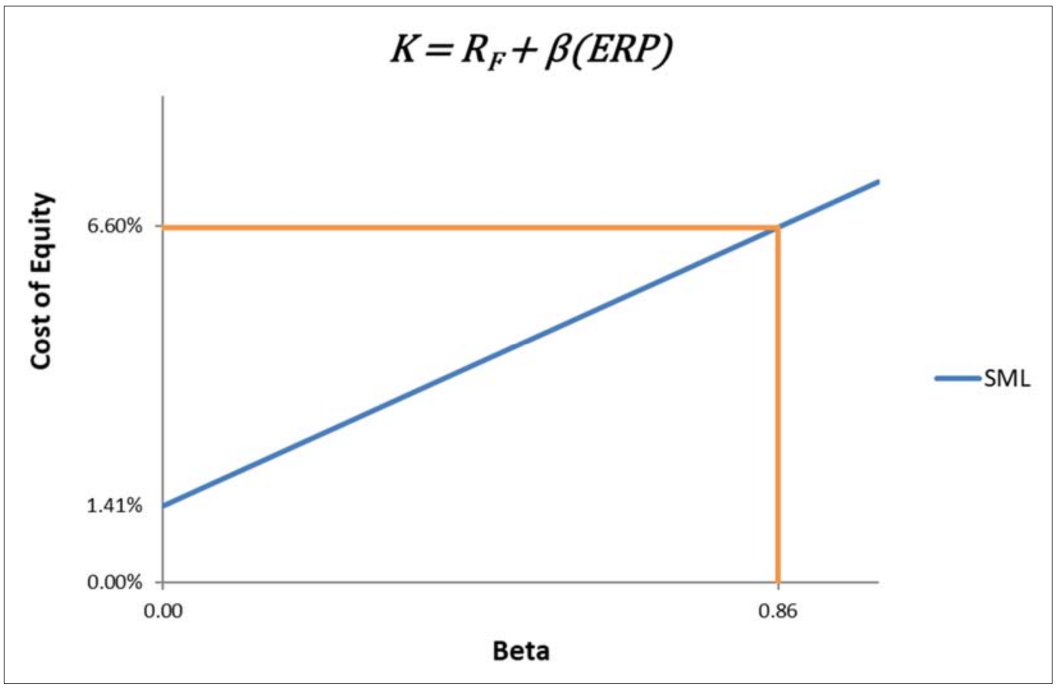
Q. Please explain the final results of your CAPM analysis.

A. Using the inputs for the risk-free rate, beta coefficient, and equity risk premium discussed above, I estimate that the Company's CAPM cost of equity is 6.6%.[84] The CAPM can be displayed graphically through what is known as the Security Market Line ("SML"). The following figure shows the expected return (cost of

[84] Exhibit DJG-11.

equity) on the y-axis, and the average beta for the proxy group on the x-axis. The SML intercepts the y-axis at the level of the risk-free rate. The slope of the SML is the equity risk premium.

Figure 12:
CAPM Graph



The SML provides the rate of return that will compensate investors for the beta risk of that investment. Thus, at an average beta of 0.86 for the proxy group, the estimated CAPM cost of equity for the Company is 6.6%.

D. Response to Ms. Nelson's CAPM Analysis and Other Issues

Q. Ms. Nelson's CAPM analysis yields considerably higher results. Did you find specific problems with Ms. Nelson's CAPM assumptions and inputs?

A. Yes. The results of Ms. Nelson's various CAPMs are as high as 16.75%,[85] which is considerably higher than my estimate. The main problem with Ms. Nelson's CAPM cost of equity result stems primarily from her estimate of the equity risk premium ("ERP").

1. Equity Risk Premium

Q. Did Ms. Nelson rely on a reasonable measure for the ERP?

A. No, she did not. Ms. Nelson estimates an ERP as high as 13.48%.[86] The ERP is one of three inputs in the CAPM equation, and it is one of the most single important factors for estimating the cost of equity in this case. As discussed above, I used three widely accepted methods for estimating the ERP, including consulting expert surveys, calculating the implied ERP based on aggregate market data, and considering the ERPs published by reputable analysts. The highest ERP found from my research and analysis is only 6.0%.[87] This means that Ms. Nelson's ERP estimate is more than twice as high as the highest reasonable ERP estimate I could either find or calculate.

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[85] Exhibit RBH-6.

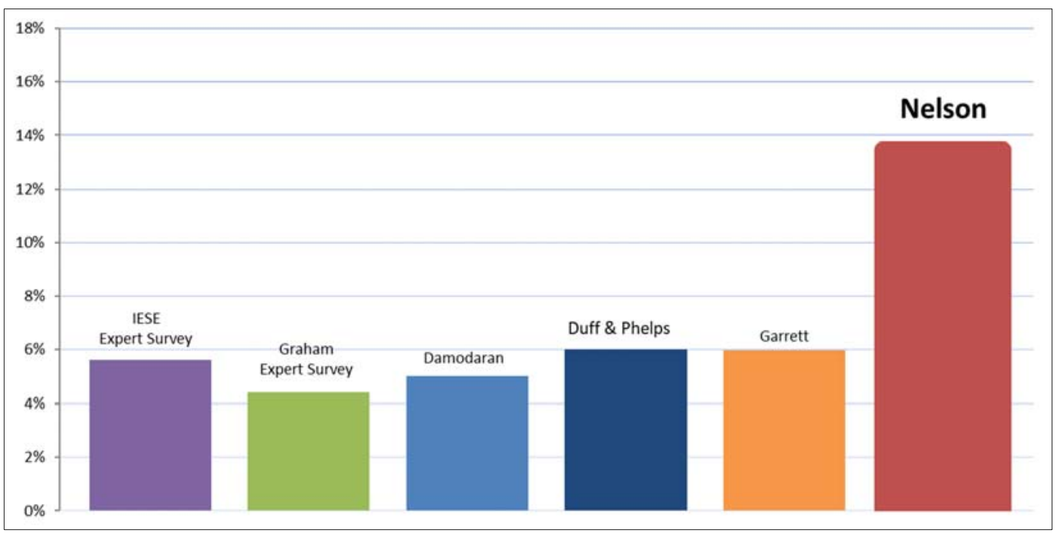
[86] *Id*.

[87] Exhibit DJG-10.

Q. Please discuss and illustrate how Ms. Nelson's ERP compares with other estimates for the ERP.

A. As discussed above, Graham and Harvey's 2018 expert survey reports an average ERP of 4.4%. The 2020 IESE Business School expert survey reports an average ERP of 5.6%. Similarly, Duff & Phelps recently estimated an ERP of 6.0%. The following chart illustrates that Ms. Nelson's ERP estimate is far out of line with industry norms.[88]

Figure 13:
Equity Risk Premium Comparison



When compared with other independent sources for the ERP (as well as my estimate), which do not have a wide variance, Ms. Nelson's ERP estimate is clearly

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[88] *See* Exhibit DJG-10. The ERP estimated by Dr. Damodaran is the highest of several ERP estimates under varying assumptions.

not within the range of reasonableness. As a result, her CAPM cost of equity estimate is overstated and unreliable.

2. <u>Other Risk Premium Analyses</u>

Q. Did you review Ms. Nelson's other risk premium analyses?

A. Yes. I am addressing Ms. Nelson's other risk premium analyses in this section because the CAPM itself is a risk premium model. In this case, Ms. Nelson conducted what she calls a "bond yield plus risk premium" analysis.[89] Many utility-company ROE witnesses conduct what they call a "historical risk premium analysis," "bond yield plus risk premium analysis" or "allowed return premium analysis." In short, these types of analyses simply compare the difference between awarded ROEs in the past with bond yields.

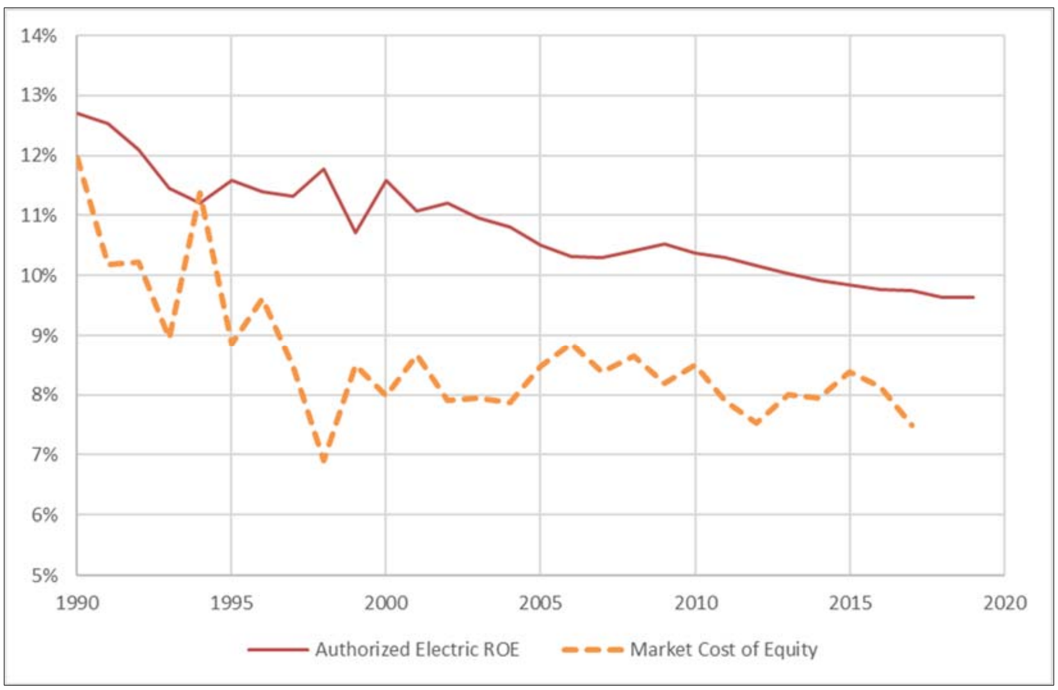
Q. Do you agree with the results of Ms. Nelson's risk premium analysis?

A. No. in fact, I disagree with the entire premise of the analysis. First, Ms. Nelson looked at awarded ROEs dating back to 1980 — a direct contradiction to Ms. Nelson's claim that the cost of equity is a "forward-looking" concept.[90] As discussed earlier in this testimony, it is clear that awarded ROEs are consistently higher than market-based cost of equity, and they have been for many years. Thus, these types of risk premium "models" are merely clever devices used to perpetuate

[89] Direct Testimony of Jennifer E. Nelson, p. 77.

[90] *See e.g.*, Direct Testimony of Jennifer E. Nelson, p. 66, line 10.

the discrepancy between awarded ROEs and market-based cost of equity. In other words, since awarded ROEs are consistently higher than market-based cost, a model that simply compares the discrepancy between awarded ROEs and any market-based factor (such as bond yields) will simply ensure that the discrepancy continues. The following graph shows the clear disconnect between awarded ROEs and utility cost of equity.[91]



Since it is indisputable that utility stocks are *less risky* than average stock in the market (with a beta equal to 1.0), utility cost of equity is *below* the market cost of equity (the dotted line in the graph above). The gap between the market cost of

[91] *See also* Exhibit DJG-14.

equity and inflated ROEs represents an excess transfer of wealth from customers to shareholders.

Furthermore, the risk premium analysis offered by Ms. Nelson is completely unnecessary when we already have a real risk premium model to use: the CAPM. The CAPM itself is a "risk premium" model; it takes the bare minimum return any investor would require for buying a stock (the risk-free rate), then adds a *premium* to compensate the investor for the extra risk he or she assumes by buying a stock rather than a riskless U.S. Treasury security. The CAPM has been utilized by companies around the world for decades for the same purpose we are using it in this case — to estimate cost of equity.

In stark contrast to the Nobel-prize-winning CAPM, the risk premium models relied upon by utility ROE witnesses are not market-based, and therefore have no value in helping us estimate the market-based cost of equity. Unlike the CAPM, which is found in almost every comprehensive financial textbook, the risk premium models used by utility witnesses are almost exclusively found in the texts and testimonies of such witnesses. Specifically, these risk premium models attempt to create an inappropriate link between market-based factors, such as interest rates, with awarded returns on equity. Inevitably, this type of model is used to justify a cost of equity that is much higher than one that would be dictated by market forces. Thus, the Commission should reject Ms. Nelson's risk premium model and focus on the risk premium model that has been used throughout the financial community for decades: the CAPM.

3. The Empirical CAPM

Q. Please summarize Ms. Nelson's ECAPM analysis.

A. Ms. Nelson offers another version of the CAPM that she calls the "empirical CAPM" ("ECAPM"). The premise of the ECAPM, which is found in the testimonies of many utility-ROE witnesses, is that the real CAPM underestimates the return required from low-beta securities, such as those of the proxy group.

Q. Do you agree with Ms. Nelson's ECAPM results?

A. No. The premise of Ms. Nelson's E-CAPM is that the real CAPM underestimates the return required from low-beta securities.[92] There are several problems with this concept, however. First, the betas both Ms. Nelson and I used in the real CAPM already account for the theory that low-beta stocks might have a tendency to be underestimated. In other words, the raw betas for each of the utility stocks in the proxy groups have already been adjusted by Value Line to be higher. Second, there is empirical evidence suggesting that the type of beta-adjustment method used by Value Line actually <u>overstates</u> betas from consistently low-beta industries like utilities. According to this research, it is better to employ an adjustment method

[92] Direct Testimony of Jennifer E. Nelson, p. 73 lines 10-11.

that adjusts raw betas toward an industry average, rather than the market average, which ultimately would result in betas that are lower than those published in Value Line.[93] Finally (and most pertinently), Ms. Nelson's ECAPM still suffers from the same overestimated ERP input discussed above.[94] Regardless of the differing theories regarding the mean reversion tendencies of low-beta securities, Ms. Nelson's ECAPM should be disregarded for its ERP inputs alone.

VIII. OTHER ISSUES

1. Firm-Specific Business Risks

Q. Describe Ms. Nelson's testimony regarding business risks.

A. In her direct testimony, Ms. Nelson suggests that various firm-specific risk factors should have an increasing effect on EPE's cost of equity, including the risks associated with capital expenditures, the regulatory environment, and other business risks.[95]

Q. Do you agree with Ms. Nelson that these firm-specific risk factors should influence EPE's cost of equity or awarded ROE?

A. No. The Commission should not consider these firm-specific business risk factors in making their decision on a fair awarded ROE for EPE. As discussed above, it is

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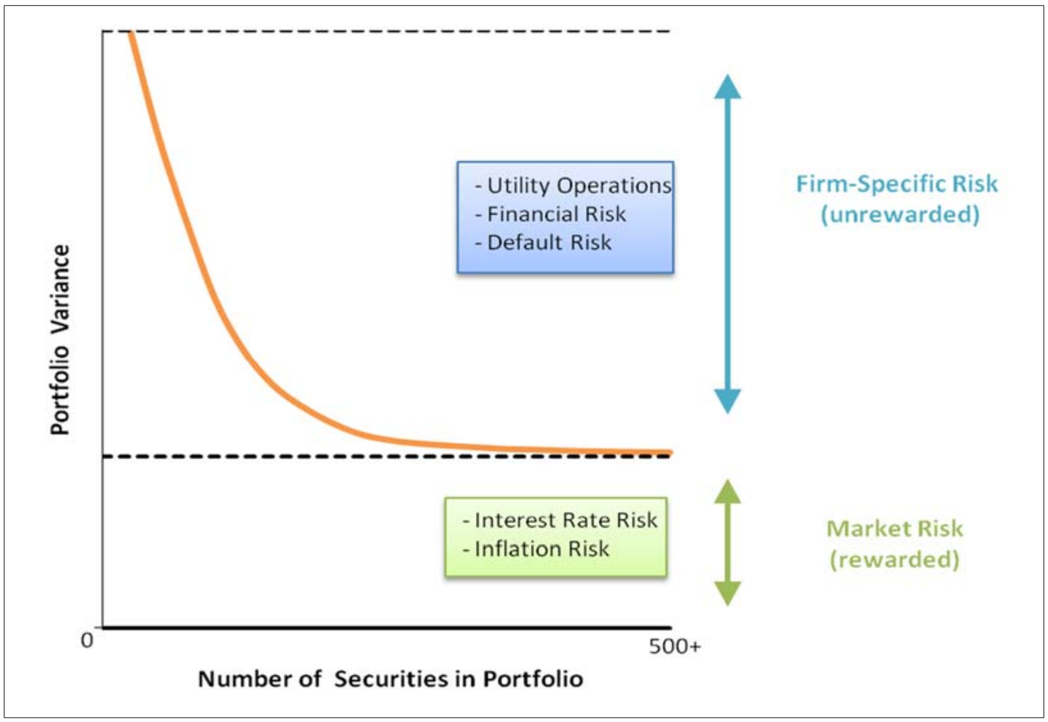
[93] *See* Appendix B for further discussion on these theories.

[94] *See* Exhibit RBH-6.

[95] See generally Direct Testimony of Jennifer E. Nelson, pp. 83-103.

a well-known concept in finance that firm-specific risks are unrewarded by the market. Scholars widely recognize the fact that market risk, or "systematic risk," is the only type of risk for which investors expect a return for bearing.[96] This important concept is illustrated again in the figure below.



Unlike interest rate risk, inflation risk, and other market risks that affect all companies in the stock market, the risk factors discussed by Ms. Nelson are merely business risks specific to EPE. Investors do not require additional compensation for assuming these firm-specific business risk. Another way to consider this issue

[96] *See* John R. Graham, Scott B. Smart & William L. Megginson, *Corporate Finance: Linking Theory to What Companies Do* 180 (3rd ed., South Western Cengage Learning 2010).

is to look at the CAPM and DCF Model. Did the creators of these highly regarded cost of equity models, which have been relied upon for decades by companies and investors to make crucial business decisions, simply neglect to add an input for business risks? Of course not. The DCF Model considers stock price, dividends, and a long-term growth rate. The CAPM considers the risk-free rate, beta, and the equity risk premium. Neither model includes an input or premium for business risks due to the well-known fact that investors do not expect a return for such risks. Therefore, the Company's firm-specific business risks, while perhaps relevant to other issues in the rate case, have no meaningful effect on the cost of equity estimate. Rather, it is market risk that is rewarded by the market, and this concept is thoroughly addressed in my CAPM analysis discussed above.

2. Small Size Effect

Q. Please describe Ms. Nelson's position regarding the size effect.

A. Ms. Nelson suggests that EPE's size should somehow have an increasing effect on its cost of equity estimate.[97] However, Ms. Nelson does not propose a specific premium to account for the size effect.[98]

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[97] *See generally* Direct Testimony of Jennifer E. Nelson, pp. 91-97.

[98] *Id*. at p. 97, lines 7-12.

Q. Do you agree with Ms. Nelson regarding the size effect?

A. No. The "size effect" phenomenon arose from a 1981 study conducted by Banz, which found that "in the 1936 – 1975 period, the common stock of small firms had, on average, higher risk-adjusted returns than the common stock of large firms."[99] According to Ibbotson, Banz's size effect study was "[o]ne of the most remarkable discoveries of modern finance."[100] Perhaps there was some merit to this idea at the time, but the size effect phenomenon was short lived. Banz's 1981 publication generated much interest in the size effect and spurred the launch of significant new small cap investment funds. However, this "honeymoon period lasted for approximately two years. . . ."[101] After 1983, U.S. small-cap stocks actually underperformed relative to large cap stocks. In other words, the size effect essentially reversed. In *Triumph of the Optimists*, the authors conducted an extensive empirical study of the size effect phenomenon around the world. They found that after the size effect phenomenon was discovered in 1981, it disappeared within a few years:

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[99] Rolf W. Banz, *The Relationship Between Return and Market Value of Common Stocks* 3-18 (Journal of Financial Economics 9 (1981)).

[100] 2015 Ibbotson Stocks, Bonds, Bills, and Inflation Classic Yearbook 99 (Morningstar 2015).

[101] Elroy Dimson, Paul Marsh & Mike Staunton, *Triumph of the Optimists: 101 Years of Global Investment Returns* 131 (Princeton University Press 2002).

> It is clear . . . that there was a global reversal of the size effect in virtually every country, with the size premium not just disappearing but going into reverse. Researchers around the world universally fell victim to Murphy's Law, with the very effect they were documenting – and inventing explanations for – promptly reversing itself shortly after their studies were published.[102]

In other words, the authors assert that the very discovery of the size effect phenomenon likely caused its own demise. The authors ultimately concluded that it is "inappropriate to use the term 'size effect' to imply that we should automatically expect there to be a small-cap premium," yet, this is exactly what utility witnesses often do in attempting to artificially inflate the cost of equity with a size premium. Other prominent sources have agreed that the size premium is a dead phenomenon. According to Ibbotson:

> The unpredictability of small-cap returns has given rise to another argument against the existence of a size premium: that markets have changed so that the size premium no longer exists. As evidence, one might observe the last 20 years of market data to see that the performance of large-cap stocks was basically equal to that of small cap stocks. In fact, large-cap stocks have outperformed small-cap stocks in five of the last 10 years.[103]

In addition to the studies discussed above, other scholars have concluded similar results. According to Kalesnik and Beck:

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[102] *Id*. at 133.

[103] 2015 Ibbotson Stocks, Bonds, Bills, and Inflation Classic Yearbook 112 (Morningstar 2015).

> Today, more than 30 years after the initial publication of Banz's paper, the empirical evidence is extremely weak even before adjusting for possible biases. . . . The U.S. long-term size premium is driven by the extreme outliers, which occurred three-quarters of a century ago. . . . Finally, adjusting for biases . . . makes the size premium vanish. If the size premium were discovered today, rather than in the 1980s, it would be challenging to even publish a paper documenting that small stocks outperform large ones.[104]

For all of these reasons, the Commission should reject the arbitrary size premium proposed by the Company.

IX. CAPITAL STRUCTURE

Q. Describe in general the concept of a company's capital structure.

A. "Capital structure" refers to the way a company finances its overall operations through external financing. The primary sources of long-term, external financing are debt capital and equity capital. Debt capital usually comes in the form of contractual bond issues that require the firm to make payments, while equity capital represents an ownership interest in the form of stock. Because a firm cannot pay dividends on common stock until it satisfies its debt obligations to bondholders, stockholders are referred to as "residual claimants." The fact that stockholders have a lower priority to claims on company assets increases their risk and the required return relative to bondholders. Thus, equity capital has a higher cost than debt

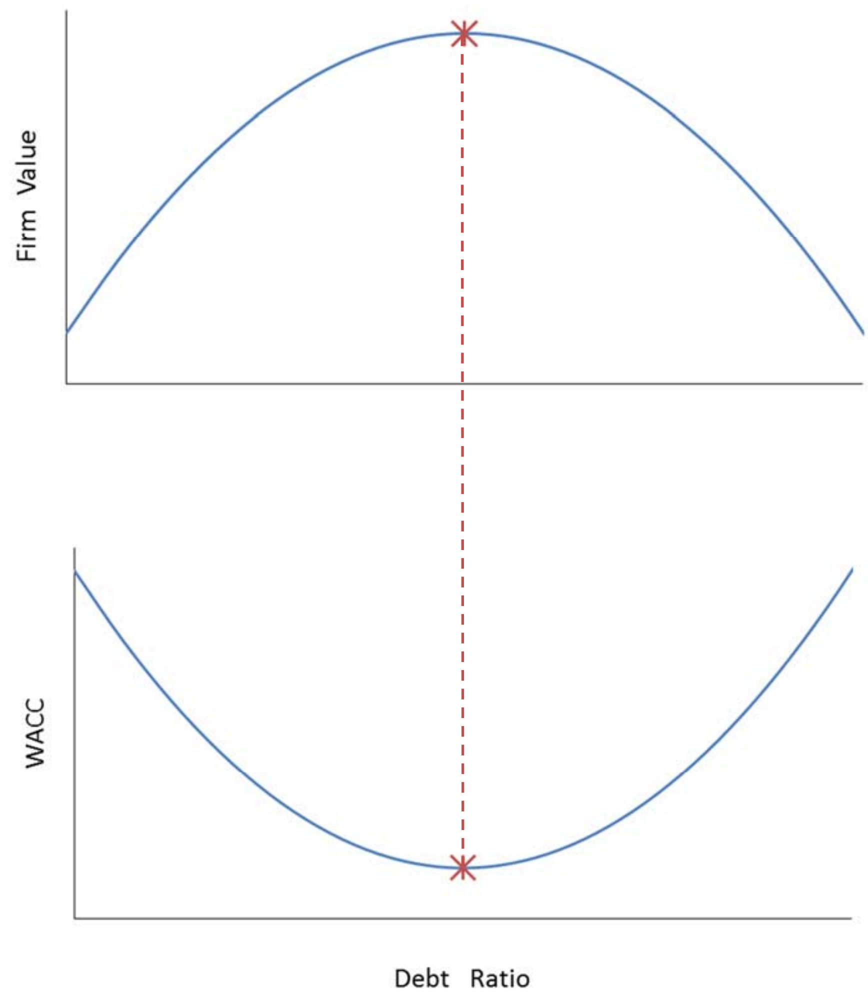
[104] Vitali Kalesnik and Noah Beck, *Busting the Myth About Size* (Research Affiliates 2014), available at https://www.researchaffiliates.com/Our%20Ideas/Insights/Fundamentals/Pages/284_Busting_the_Myth_About_Size.aspx (emphasis added).

capital. Firms can reduce their WACC by recapitalizing and increasing their debt financing. In addition, because interest expense is deductible, increasing debt also adds value to the firm by reducing the firm's tax obligation.

Q. Is it true that, by increasing debt, competitive firms can add value and reduce their WACC?

A. Yes, it is. A competitive firm can add value by increasing debt. After a certain point, however, the marginal cost of additional debt outweighs its marginal benefit. This is because the more debt the firm uses, the higher interest expense it must pay, and the likelihood of loss increases. This also increases the risk of non-recovery for both bondholders and shareholders, causing both groups of investors to demand a greater return on their investment. Thus, if debt financing is too high, the firm's WACC will increase instead of decrease. The following Figure 14 illustrates these concepts.

Figure 14:
Optimal Debt Ratio



As shown in Figure 14, a competitive firm's value is maximized when the WACC is minimized. In both graphs, the debt ratio is shown on the x-axis. By increasing its debt ratio, a competitive firm can minimize its WACC and maximize its value. At a certain point, however, the benefits of increasing debt do not outweigh the costs of the additional risks to both bondholders and shareholders, as each type of investor will demand higher returns for the additional risk they have assumed.[105]

Q. Does the rate base rate of return model effectively incentivize utilities to operate at the optimal capital structure?

A. No. While it is true that competitive firms maximize their value by minimizing their WACC, this is not the case for regulated utilities. Under the rate base rate of return model, a higher WACC results in higher rates, all else held constant. The basic revenue requirement equation is as follows:

Equation 4:
Revenue Requirement for Regulated Utilities

$$RR = O + d + T + \boldsymbol{r}(A - D)$$

where:

where:	RR	=	*revenue requirement*
	O	=	*operating expenses*
	d	=	*depreciation expense*
	T	=	*corporate tax*
	$\boldsymbol{r}$	=	***weighted average cost of capital (WACC)***
	A	=	*plant investments*
	D	=	*accumulated depreciation*

As shown in this equation, utilities can increase their revenue requirement by <u>increasing</u> their WACC, not by minimizing it. Thus, because there is no incentive for a regulated utility to minimize its WACC, a commission standing in the place

[105] *See* John R. Graham, Scott B. Smart & William L. Megginson, *Corporate Finance: Linking Theory to What Companies Do* 440-41 (3rd ed., South Western Cengage Learning 2010).

of competition must ensure that the regulated utility is operating at the lowest reasonable WACC.

Q. Can utilities generally afford to have higher debt levels than other industries?

A. Yes. Because regulated utilities have large amounts of fixed assets, stable earnings, and low risk relative to other industries, they can afford to have relatively higher debt ratios (or "leverage"). As aptly stated by Dr. Damodaran:

> Since financial leverage multiplies the underlying business risk, it stands to reason that firms that have high business risk should be reluctant to take on financial leverage. It also stands to reason that firms that operate in stable businesses should be much more willing to take on financial leverage. Utilities, for instance, have historically had high debt ratios but have not had high betas, mostly because their underlying businesses have been stable and fairly predictable.[106]

Note that the author explicitly contrasts utilities with firms that have high underlying business risk. Because utilities have low levels of risk and operate a stable business, they should generally operate with relatively high levels of debt to achieve their optimal capital structure.

Q. Are the capital structures of the proxy group a source that can be used to assess a prudent capital structure?

A. Yes. However, while the capital structures of the proxy group might provide some indication of an appropriate capital structure for the utility being studied, it is preferable to also consider additional types of analyses. The average debt ratios of

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[106] Aswath Damodaran, *Investment Valuation: Tools and Techniques for Determining the Value of Any Asset* 196 (3rd ed., John Wiley & Sons, Inc. 2012).

a utility proxy group will likely be lower than what would be observed in a pure competitive environment. As I explain above, this is because utilities do not have a financial incentive to operate at the optimal capital structure.

Q. How can utility regulatory commissions help overcome the fact that utilities do not have a natural financial incentive to minimize their cost of capital?

A. While under the rate base rate of return model utilities do not have a natural financial incentive to minimize their cost of capital, competitive firms, in contrast, can and do maximize their value by minimizing their cost of capital. Competitive firms minimize their cost of capital by including a sufficient amount of debt in their capital structures. They do not do this because it is required by a regulatory body, but rather because their shareholders demand it in order to maximize value. The Commission can provide this incentive to EPE by acting as a surrogate for competition and setting rates consistent with a capital structure that is similar to what would be appropriate in a competitive, as opposed to a regulated, environment.

Q. What was EPE's capital structure at the end of the 2019 Base Period?

A. EPE's actual capital structure as of December 31, 2019 consisted of 49.2% equity and 51% debt.[107]

[107] Direct Testimony of Lisa D. Budtke, p. 5, lines 15-18.

Q. What is the Company's proposed equity ratio?

A. According to EPE witness Ms. Budtke, the Company is proposing to use a Test Year capital structure consisting of 51% equity and 49% debt.[108]

Q. What is your recommended equity ratio?

A. I recommend that the Commission authorize a capital structure consisting of 49% equity and 51% debt. Not only is this capital structure consistent with EPE's actual capital structure at the end of the 2019 Base Period, but it is also reflective of the capital structure of the same proxy group used for the cost of equity analysis. Finally, as discussed further below, my recommended debt ratio is quite conservative in light of thousands of other firms operating in the U.S. market with notably higher debt ratios.

Q. Please describe your approach in assessing a fair capital structure for EPE.

A. To analyze EPE's appropriate capital structure, I examined the debt ratios of competitive industries as well as debt ratios of the proxy group. Based on either benchmark, the Company's proposed capital structure is unreasonably weighted to equity.

[108] *Id*. at p. 6, lines 7-13.

Q. What are the debt ratios observed in competitive industries?

A. I found that there are currently more than 3,500 firms in U.S. industries with higher debt ratios than that requested by EPE in this case.[109] Moreover, these firms have an average debt ratio of greater than 60%.[110] The following Figure 15 shows a sample of these industries with debt ratios higher than 55%.

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[109] Exhibit DJG-15.

[110] Exhibit DJG-15.

Figure 15:
Industries with Debt Ratios Greater than 55%[111]

Industry	# Firms	Debt Ratio
Tobacco	17	96%
Financial Svcs.	232	95%
Retail (Building Supply)	17	90%
Hospitals/Healthcare Facilities	36	88%
Advertising	47	80%
Retail (Automotive)	26	79%
Brokerage & Investment Banking	39	77%
Auto & Truck	13	75%
Food Wholesalers	17	70%
Bank (Money Center)	7	69%
Transportation	18	67%
Hotel/Gaming	65	67%
Packaging & Container	24	66%
Retail (Grocery and Food)	13	66%
Broadcasting	27	65%
R.E.I.T.	234	64%
Retail (Special Lines)	89	64%
Green & Renewable Energy	22	**64%**
Recreation	63	63%
Software (Internet)	30	63%
Air Transport	18	**63%**
Retail (Distributors)	80	62%
Computers/Peripherals	48	61%
Telecom (Wireless)	18	**61%**
Farming/Agriculture	31	61%
Cable TV	14	**60%**
Computer Services	106	60%
Beverage (Soft)	34	60%
Telecom. Services	67	**60%**
Trucking	33	59%
Power	52	**59%**
Office Equipment & Services	22	58%
Chemical (Diversified)	6	58%
Retail (Online)	70	58%
Aerospace/Defense	77	58%
Oil/Gas Distribution	24	58%
Business & Consumer Services	165	57%
Construction Supplies	44	57%
Real Estate (Operations & Services)	57	56%
Household Products	127	56%
Environmental & Waste Services	82	56%
Rubber& Tires	4	56%
Total / Average	**2,215**	**66%**

Many of the industries shown here, like public utilities, are generally well-established with large amounts of capital assets. The shareholders of these industries demand higher debt ratios to maximize their profits. There are several notable industries that are relatively comparable to public utilities (highlighted in Figure 15 above). For example, Green and Renewable Energy has an average debt ratio of 64% and Telecom Services has an average debt ratio of 60%. These debt ratios are significantly higher than EPE's proposed debt ratio of only 49%.

Q. Did you also look at the debt ratios of the proxy group?

A. Yes. According to the most recently reported year-end data from Value Line, the average debt ratio of the proxy group made up of similarly situated utilities is 51%.[112]

Q. What is your recommendation regarding EPE's capital structure?

A. In my opinion, EPE's proposed capital structure consists of an insufficient amount of debt, especially since EPE's awarded ROE in this case will certainly be above its market-based cost of equity, even if my recommendation is adopted. With an awarded ROE that is above market-based costs, EPE's overall cost of capital can be reduced by replacing higher-cost equity with lower-cost debt. I recommend the Commission apply a capital structure consisting of a 51% debt and 49% equity for

[111] Exhibit DJG-15.

[112] Exhibit DJG-16.

purposes of computing the Company's awarded rate of return. This recommendation is reasonable considering the fact that the average debt ratio of Ms. Nelson's own proxy group is also equal to 51%. Furthermore, there are thousands of firms across the country that operate with notably higher debt ratios, as discussed above. The figure below summarizes my findings.

Figure 16:
Debt Ratio Comparison

Source	Debt Ratio
Green & Renewable Energy	64%
Telecom (Wireless)	61%
Cable TV	60%
Telecom. Services	60%
Power	59%
Proxy Group of Utilities	**51%**
Garrett Proposal	**51%**
Company's Proposal	**49%**

Based on these findings, EPE's proposed debt ratio is an outlier as being far too low, and if adopted, would result in an unreasonably high WACC for shareholders.

Q. You previously noted that your recommended capital structure is similar to EPE's actual capital structure at the end of the 2019 Base Period. Was EPE's actual capital structure the primary factor influencing your proposed capital structure?

A. No. As discussed above, utilities do not have an incentive to operate with sufficient amounts of debt in their capital structures; thus, the actual capital structures of regulated utilities many not necessarily be indicative of capital structures that we would observe for these companies in a regulated environment. If, for example, EPE had a much higher equity ratio at the end of the 2019 Base Period, it would not change my proposed capital structure. It is also for this reason that my proposed capital structure is not influenced by EPE's agreement under which Sun Jupiter committed to purchase all of EPE's common stock or any other equity infusions from Sun Jupiter going forward.[113]

X. CONCLUSION AND RECOMMENDATION — COST OF CAPITAL

Q. Summarize the key points of your cost of capital testimony.

A. The awarded ROE in this case should be based on EPE's cost of equity. Closely estimating the cost of equity with the CAPM and other models is a relatively straightforward process that has been used in the competitive marketplace for many decades. While regulators determine the awarded return for utilities, they do not determine the cost of capital, which is primarily driven by the equity risk premium

[113] See Direct Testimony of Lisa D. Budtke, pp. 6-7.

and other market forces. Any objective estimation of EPE's cost of equity would result in one that is remarkably less than the awarded ROEs that are generally given to utility shareholders. While there may be policy reasons as to why the awarded return should be set higher than the cost of equity, we must be intellectually honest about where the cost of equity for a very low-risk company such as EPE actually is. Using reasonable and conservative inputs, the CAPM and DCF Model indicate that EPE's cost of equity is about 7.0%. This strongly indicates that the Company's proposed ROE of 10.3% is excessive and unreasonable.

Q. Please summarize your recommendation to the Commission regarding EPE's cost of capital.

A. I recommend the Commission award the Company with a 9.0% ROE. Although EPE's cost of equity is clearly much lower than 9.0% by any objective measure, the Commission should gradually reduce EPE's awarded return towards market-based levels, consistent with the *Hope* Court's end result doctrine. I also recommend that the Commission authorize EPE's actual capital structure at the end of the 2019 Base Period, which consists of 51% debt and 49% equity.

Q. Does this conclude the cost of capital portion of your testimony?

A. Yes. The following sections of my testimony are related to depreciation.

PART TWO: DEPRECIATION

XI. LEGAL STANDARDS

Q. Discuss the standard by which regulated utilities are allowed to recover depreciation expense.

A. In *Lindheimer v. Illinois Bell Telephone Co.*,[114] the U.S. Supreme Court stated that "depreciation is the loss, not restored by current maintenance, which is due to all the factors causing the ultimate retirement of the property. These factors embrace wear and tear, decay, inadequacy, and obsolescence." The *Lindheimer* Court also recognized that the original cost of plant assets, rather than present value or some other measure, is the proper basis for calculating depreciation expense.[115] Moreover, the *Lindheimer* Court found:

> [T]he company has the burden of making a convincing showing that the amounts it has charged to operating expenses for depreciation have not been excessive. That burden is not sustained by proof that its general accounting system has been correct. The calculations are mathematical, but the predictions underlying them are essentially matters of opinion.[116]

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[114] *Lindheimer v. Illinois Bell Tel. Co.*, 292 U.S. 151, 167 (1934).

[115] *Id*. (Referring to the straight-line method, the *Lindheimer* Court stated that "[a]ccording to the principle of this accounting practice, the loss is computed upon the actual cost of the property as entered upon the books, less the expected salvage, and the amount charged each year is one year's pro rata share of the total amount."). The original cost standard was reaffirmed by the Court in *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591, 606 (1944). The *Hope* Court stated: "Moreover, this Court recognized in [*Lindheimer*], supra, the propriety of basing annual depreciation on cost. By such a procedure the utility is made whole and the integrity of its investment maintained. No more is required."

[116] *Id*. at 169.

Thus, the Commission must ultimately determine if the Company has met its burden of proof by making a convincing showing that its proposed depreciation rates are not excessive.

Q. Should depreciation represent an allocated cost of capital to operation, rather than a mechanism to determine loss of value?

A. Yes. While the *Lindheimer* case and other early literature recognized depreciation as a necessary expense, the language indicated that depreciation was primarily a mechanism to determine loss of value.[117] Adoption of this "value concept" would require annual appraisals of extensive utility plant, and thus, is not practical in this context. Rather, the "cost allocation concept" recognizes that depreciation is a cost of providing service, and that in addition to receiving a "return on" invested capital through the allowed rate of return, a utility should also receive a "return of" its invested capital in the form of recovered depreciation expense. The cost allocation concept also satisfies several fundamental accounting principles, including verifiability, neutrality, and the matching principle.[118] The definition of "depreciation accounting" published by the American Institute of Certified Public Accountants ("AICPA") properly reflects the cost allocation concept:

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[117] *See* Frank K. Wolf & W. Chester Fitch, *Depreciation Systems* 71 (Iowa State University Press 1994).

[118] National Association of Regulatory Utility Commissioners, *Public Utility Depreciation Practices* 12 (NARUC 1996).

> Depreciation accounting is a system of accounting that aims to distribute cost or other basic value of tangible capital assets, less salvage (if any), over the estimated useful life of the unit (which may be a group of assets) in a systematic and rational manner. It is a process of allocation, not of valuation.[119]

Thus, the concept of depreciation as "the allocation of cost has proven to be the most useful and most widely used concept."[120]

XII. ANALYTIC METHODS

Q. Discuss your approach to analyzing the Company's depreciable property in this case.

A. I obtained and reviewed all of the data that was used to conduct the Company's depreciation study. I used the same plant data in my analysis to develop my proposed depreciation rates and applied those rates to the Company's updated plant balances to arrive at OPC's final adjustment to depreciation expense.[121]

Q. Discuss the definition and purpose of a depreciation system, as well as the depreciation system you employed for this project.

A. The legal standards set forth above do not mandate a specific procedure for conducting a depreciation analysis. These standards, however, direct that analysts use a system for estimating depreciation rates that will result in the "systematic and

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[119] American Institute of Accountants, *Accounting Terminology Bulletins Number 1: Review and Résumé* 25 (American Institute of Accountants 1953).

[120] Wolf *supra* n. 117, at 73.

[121] *See* Exhibit DJG-15.

rational" allocation of capital recovery for the utility. Over the years, analysts have developed "depreciation systems" designed to analyze grouped property in accordance with this standard. A depreciation system may be defined by several primary parameters: 1) a *method* of allocation; 2) a *procedure* for applying the method of allocation; 3) a *technique* of applying the depreciation rate; and 4) a *model* for analyzing the characteristics of vintage property groups.[122] In this case, I used the straight line method, the average life procedure, the remaining life technique, and the broad group model to analyze the Company's actuarial data; this system would be denoted as an "SL-AL-RL-BG" system. This depreciation system conforms to the legal standards set forth above and is commonly used by depreciation analysts in regulatory proceedings. I provide a more detailed discussion of depreciation system parameters, theories, and equations in Appendix C.

Q. Are there other reasonable depreciation systems that analysts may use?

A. Yes. There are multiple combinations of depreciation systems that analysts may use to develop deprecation rates. For example, many analysts use the broad group model instead of the equal life group model. In this case, however, I essentially used the same depreciation system that Mr. Spanos used. Although some of our

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[122] *See* Wolf *supra* n. 117, at 70, 140.

assumptions and inputs are different, the analytical system we applied is essentially the same.

XIII. ACTUARIAL ANALYSIS

Q. Describe the actuarial process you used to analyze the Company's depreciable property.

A. The study of retirement patterns of industrial property is derived from the actuarial process used to study human mortality. Just as actuarial analysts study historical human mortality data in order to predict how long a group of people will live, depreciation analysts study historical plant data in order to estimate the average lives of property groups. The most common actuarial method used by depreciation analysts is called the "retirement rate method." In the retirement rate method, original property data, including additions, retirements, transfers, and other transactions, are organized by vintage and transaction year.[123] The retirement rate method is ultimately used to develop an "observed life table," ("OLT") which shows the percentage of property surviving at each age interval. This pattern of property retirement is described as a "survivor curve." The survivor curve derived from the observed life table, however, must be fitted and smoothed with a complete

[123] The "vintage" year refers to the year that a group of property was placed in service (aka "placement" year). The "transaction" year refers to the accounting year in which a property transaction occurred, such as an addition, retirement, or transfer (aka "experience" year).

curve in order to determine the ultimate average life of the group.[124] The most widely used survivor curves for this curve fitting process were developed at Iowa State University in the early 1900s and are commonly known as the "Iowa curves."[125] A more detailed explanation of how the Iowa curves are used in the actuarial analysis of depreciable property is set forth in Appendix E. For a few of EPE's accounts, there were sufficient aged data to conduct actuarial analysis and traditional Iowa curve fitting techniques. Regardless of whether a particular account had sufficient aged data, I began my analysis of each account by organizing the data to develop observed life tables, which is discussed further below.

Q. Generally describe your approach in estimating the service lives of mass property.

A. I used all of the Company's aged property data to create an OLT for each account. The data points on the OLT can be plotted to form a curve (the "OLT curve"). The OLT curve is not a theoretical curve, rather, it is actual observed data from the Company's records that indicate the rate of retirement for each property group. An OLT curve by itself, however, is rarely a smooth curve, and is often not a "complete" curve (i.e., it does not end at zero percent surviving). In order to calculate average life (the area under a curve), a complete survivor curve is needed.

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[124] *See* Appendix E for a more detailed discussion of the actuarial analysis used to determine the average lives of grouped industrial property.

[125] *See* Appendix D for a more detailed discussion of the Iowa curves.

The Iowa curves are empirically-derived curves based on the extensive studies of the actual mortality patterns of many different types of industrial property. The curve-fitting process involves selecting the best Iowa curve to fit the OLT curve. This can be accomplished through a combination of visual and mathematical curve-fitting techniques, as well as professional judgment. The first step of my approach to curve-fitting involves visually inspecting the OLT curve for any irregularities. For example, if the "tail" end of the curve is erratic and shows a sharp decline over a short period of time, it may indicate that this portion of the data is less reliable, as further discussed below. After inspecting the OLT curve, I use a mathematical curve-fitting technique which essentially involves measuring the distance between the OLT curve and the selected Iowa curve in order to get an objective, mathematical assessment of how well the curve fits. After selecting an Iowa curve, I observe the OLT curve along with the Iowa curve on the same graph to determine how well the curve fits. I may repeat this process several times for any given account to ensure that the most reasonable Iowa curve is selected.

Q. Do you always select the mathematically best-fitting curve?

A. Not necessarily. Mathematical fitting is an important part of the curve-fitting process because it promotes objective, unbiased results. While mathematical curve fitting is important, however, it may not always yield the optimum result; therefore, it should not necessarily be adopted without further analysis.

Q. Should every portion of the OLT curve be given equal weight?

A. Not necessarily. Many analysts have observed that the points comprising the "tail end" of the OLT curve may often have less analytical value than other portions of the curve. In fact, "[p]oints at the end of the curve are often based on fewer exposures and may be given less weight than points based on larger samples. The weight placed on those points will depend on the size of the exposures."[126] In accordance with this standard, an analyst may decide to truncate the tail end of the OLT curve at a certain percent of initial exposures, such as one percent. Using this approach puts a greater emphasis on the most valuable portions of the curve. For my analysis in this case, I not only considered the entirety of the OLT curve, but I also conducted further analyses that involved fitting Iowa curves to the most significant part of the OLT curve for certain accounts. In other words, to verify the accuracy of my curve selection, I narrowed the focus of my additional calculation to consider the top 99% of the "exposures" (i.e., dollars exposed to retirement) and to eliminate the tail end of the curve representing the bottom 1% of exposures. I will illustrate an example of this approach in the discussion below.

[126] Wolf *supra* n. 117, at 46.

Q. Generally, describe the differences between the Company's service life proposals and your service life proposals.

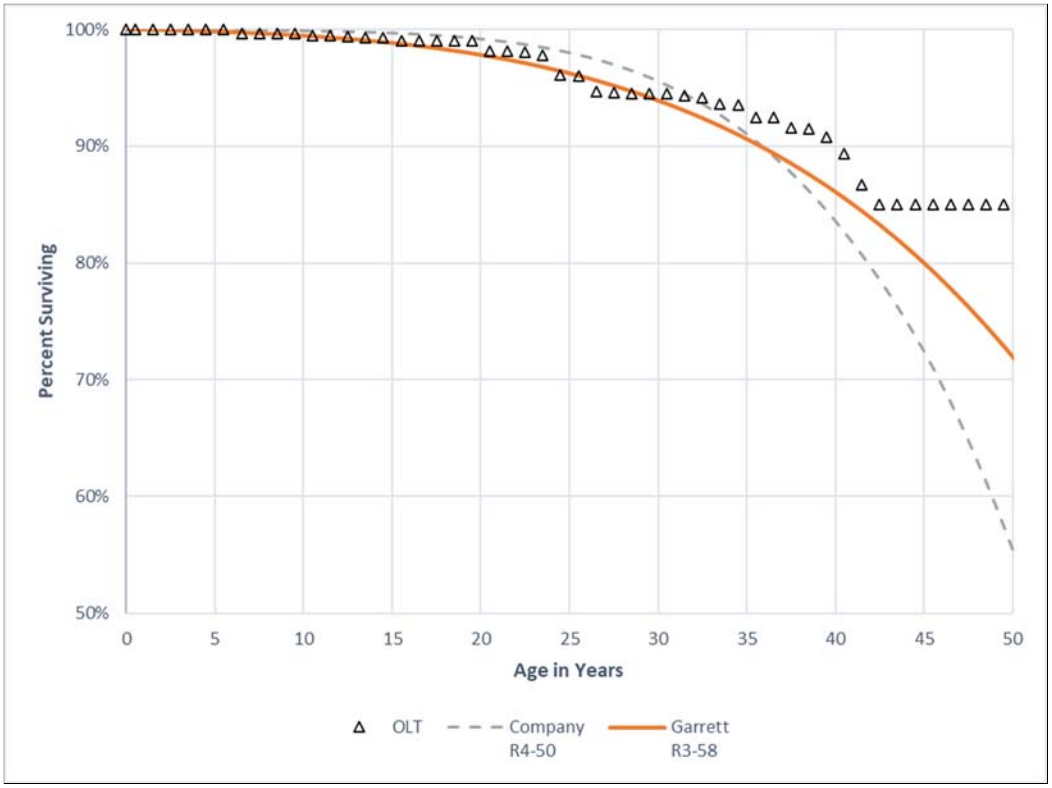
A. For each of these accounts discussed below, the Company's proposed service life, as estimated through Iowa curves, is too short to accurately describe the mortality characteristics of the account in my opinion. For the accounts in which I propose a longer service life, I took the objective approach and chose an Iowa curve that provides a better mathematical and/or visual fit to the observed historical retirement pattern derived from the Company's plant data.

A. <u>Account 353 – Station Equipment</u>

Q. Describe your service life estimate for this account and compare it with the Company's estimate.

A. The OLT curve for this account is shown in the graph below. The graph also shows the Iowa curves that Mr. Spanos and I selected to estimate the average life for this account. The average life is determined by calculating the area under the Iowa curves. Thus, a longer curve will produce a longer average life, and it will also result in a lower depreciation rate. For this account, Mr. Spanos selected the R4-50 Iowa curve, and I selected the R3-58 Iowa curve. The average lives resulting from each curve are indicated by the numbers after the dashes (50 and 58 in this case). Both Iowa curves are shown with the OLT curve in the graph below.

Figure 17:
Account 353 – Station Equipment



For this account, nearly all of the data points on the OLT curve are statistically relevant based on the 1% cutoff described above. Thus, it appears that the R4-50 curve selected by Mr. Spanos does not give enough statistical credit to data points occurring after the 35-year age interval.

Q. Does that Iowa curve you selected provide a better mathematical fit to the OLT curve for this account?

A. Yes. While visual curve-fitting techniques helped us to identify the most statistically relevant portions of the OLT curve for this account, mathematical curve-fitting techniques can help us determine which of the two Iowa curves provides the better fit. Mathematical curve fitting essentially involves measuring the distance between the OLT curve and the selected Iowa curve. The best mathematically-fitted curve is the one that minimizes the distance between the OLT curve and the Iowa curve, thus providing the closest fit. The "distance" between the curves is calculated using the "sum-of-squared differences" ("SSD") technique. For this account, the SSD, or "distance" between the OLT curve and the Company's curve is 0.2684, while the total SSD between the OLT curve and the R3-58 curve I selected is only 0.0537.[127] Thus, the R3-58 curve results in a closer mathematical fit.

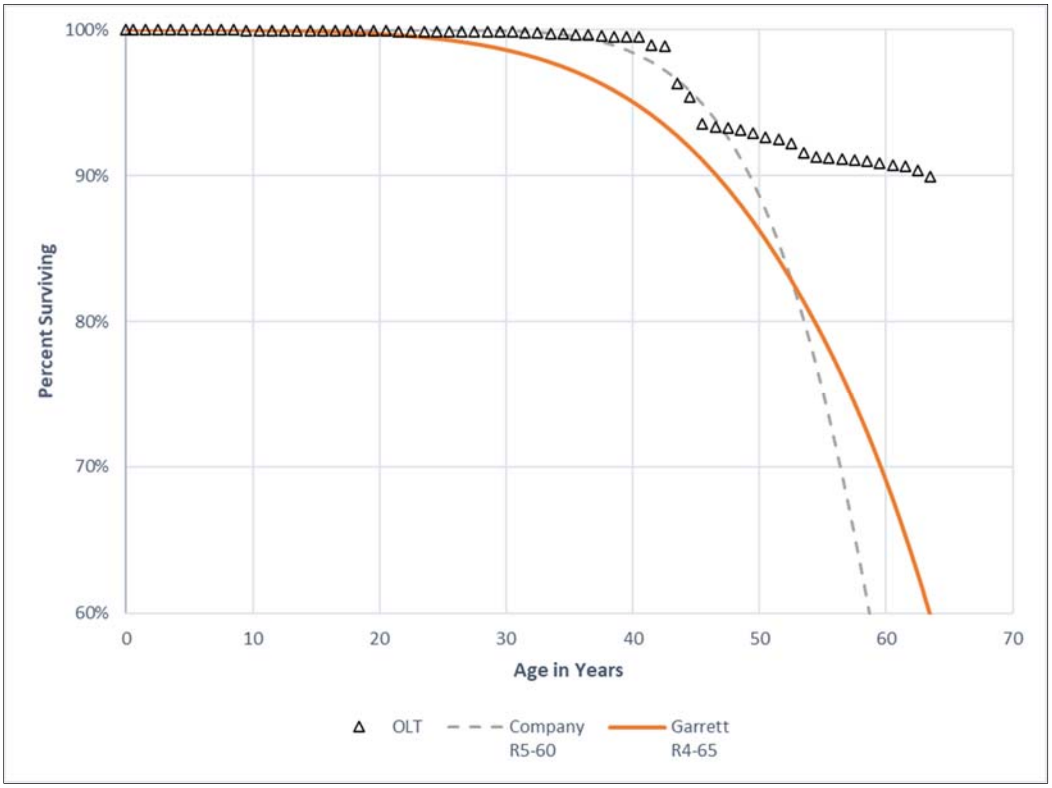
B. <u>Account 356 – Overhead Conductors and Devices</u>

Q. Describe your service life estimate for this account and compare it with the Company's estimate.

A. For this account, Mr. Spanos selected the R5-60 curve, and I selected the R4-65 curve. Both Iowa curves are shown with the OLT curve in the graph below.

[127] Exhibit DJG-21.

Figure 18:
Account 356 – Overhead Conductors and Devices



As with the account discussed above, nearly all of the data points on the OLT curve are statistically relevant. The R5-60 curve selected by Mr. Spanos has a relatively high mode, and therefore "drops" sharply as it approaches the average life (60 years for his curve). However, an average life of only 60 years combined with the R5 curve shape does not give much significance to the historical data occurring after the 50-year age interval. In my experience it is unusual to see the sharp decline described by an R% Iowa curve in Account 356. The R4-65 curve I selected is reasonable in that it does not attempt to match this OLT curve shape exactly (which could result in an unreasonably long Iowa curve), but also it does not assume as sharp of a decline as the R5 curve shape selected by Mr. Spanos.

Q. Does the Iowa curve you selected provide a better mathematical fit to the OLT curve for this account?

A. Yes. The total SSD for the Company's curve is 1.3043, while the SSD for the R4-65 curve I selected is 0.4972, which means it provides the closer fit.[128]

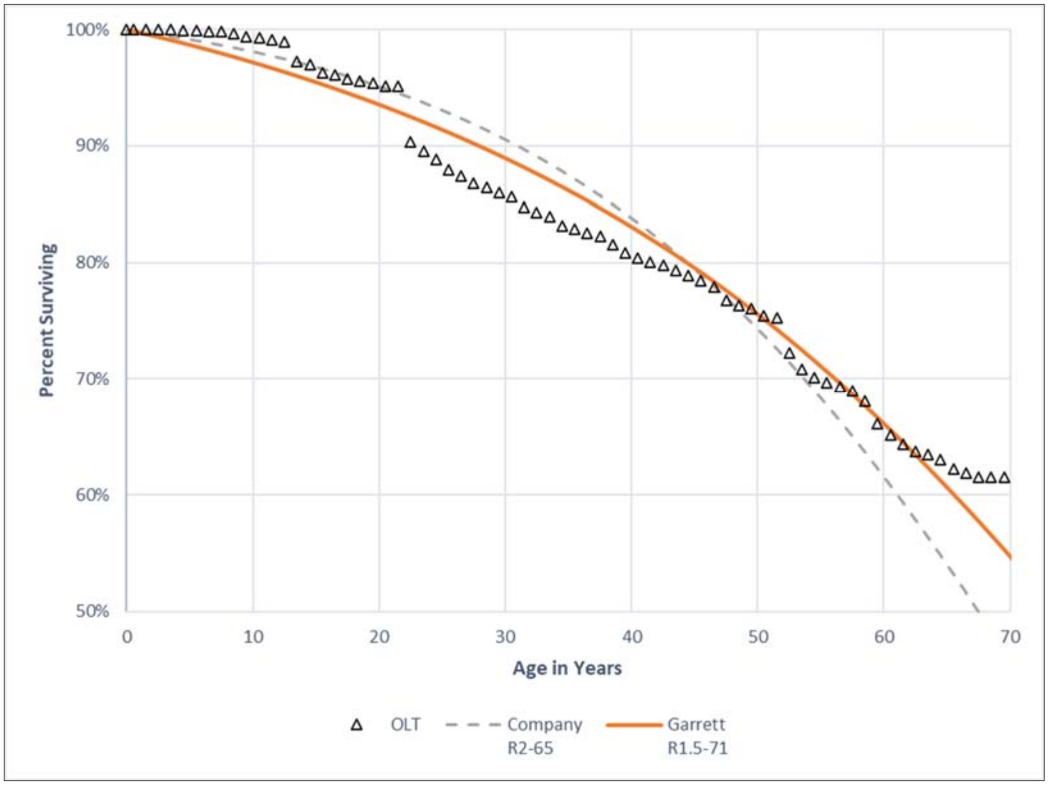
C. <u>Account 362 – Distribution Station Equipment</u>

Q. Describe your service life estimate for this account and compare it with the Company's estimate.

A. For this account, Mr. Spanos selected the R2-65 curve, and I selected the R1.5-71 curve. Both Iowa curves are shown with the OLT curve in the graph below.

[128] Exhibit DJG-22.

Figure 19:
Account 362 – Distribution Station Equipment



As with the accounts discussed above, the Iowa curve selected by Mr. Spanos has a higher mode, sharper decline, and shorter average life than what is otherwise indicated by EPE's own historical retirement data for this account.

Q. Does the Iowa curve you selected provide a better mathematical fit to the OLT curve for this account?

A. Yes. The total SSD for the Company's curve is 0.1372, while the SSD for the R1.5-71 curve I selected is only 0.0338, which means it provides the closer fit to the observed data.[129]

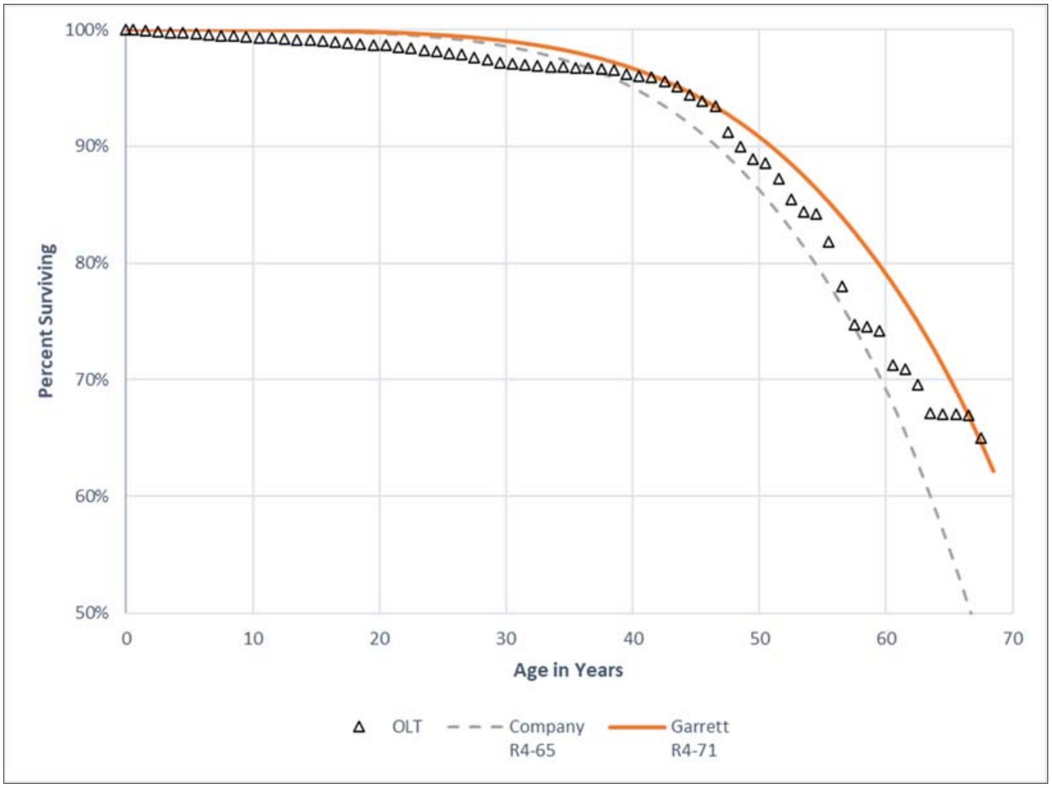
D. Account 366 – Underground Conduit

Q. Describe your service life estimate for this account and compare it with the Company's estimate.

A. For this account, Mr. Spanos selected the R4-65 curve, and I selected the R4-71 curve. Both Iowa curves are shown with the OLT curve in the graph below.

[129] Exhibit DJG-23.

Figure 20:
Account 366 – Underground Conduit



From a visual perspective, both Iowa curves appear to provide a relatively close fit to the observed data. We can use mathematical curve fitting techniques to determine which Iowa curve provides the closer fit.

Q. Does the Iowa curve you selected provide a better mathematical fit to the OLT curve for this account?

A. Yes. The total SSD for the Company's curve is 0.1168, while the SSD for the R4-71 curve I selected is only 0.0454, which means it provides the closer fit to the observed data.[130]

XIV. NET SALVAGE ANALYSIS

Q. Describe the concept of net salvage.

A. If an asset has any value left when it is retired from service, a utility might decide to sell the asset. The proceeds from this transaction are called "gross salvage." The corresponding expense associated with the removal of the asset from service is called the "cost of removal." The term "net salvage" equates to gross salvage less the cost of removal. Often, the net salvage for utility assets is a negative number (or percentage) because the cost of removing the assets from service exceeds any proceeds received from selling the assets. When a negative net salvage rate is applied to an account to calculate the depreciation rate, it results in increasing the total depreciable base to be recovered over a particular period of time and increases the depreciation rate. Therefore, a greater *negative* net salvage rate equates to a higher depreciation rate and expense, all else held constant.

[130] Exhibit DJG-24.

Q. Has there been a trend in increasing negative net salvage in the utility industry?

A. Yes. As discussed above, negative net salvage rates occur when the cost of removal exceeds the gross salvage of an asset when it is removed from service. Net salvage rates are calculated by considering gross salvage and removal costs as a percent of the original cost of the assets retired. In other words, salvage and removal costs are based on current dollars (when the assets are removed from service), while retirements are based on historical dollars, reflecting uninflated cost figures from years, and often decades earlier. Increasing labor costs associated with asset removal combined with the fact that original costs remain the same have contributed to increasing negative net salvage over time.

Q. Are you recommending any adjustments to the Company's proposed net salvage rates?

A. Yes. I am proposing adjustments to the net salvage rates of seven transmission and distribution accounts, as summarized in the figure below.

Figure 21:
Net Salvage Adjustments

Account No.	Description	EPE NS	Garrett NS
	TRANSMISSION PLANT		
355.00	WOOD AND STEEL POLES	-20%	-15%
356.00	OVERHEAD CONDUCTORS AND DEVICES	-15%	-10%
	DISTRIBUTION PLANT		
362.00	STATION EQUIPMENT	-5%	0%
364.00	POLES, TOWERS AND FIXTURES	-30%	-25%
366.00	UNDERGROUND CONDUIT	-5%	0%
368.00	LINE TRANSFORMERS	-15%	-10%
369.00	SERVICES	-15%	0%

As shown in the table, my proposed net salvage rates are slightly higher for each of these accounts than the net salvage rates proposed by Mr. Spanos. Thus, my proposed net salvage rates have a decreasing effect on depreciation rates and expense.

Q. Please describe the basis for your net salvage adjustments.

A. As part of my net salvage analysis, I analyzed the historical net salvage rates for each account that were provided in the depreciation study. Each of my proposed net salvage adjustments is based on a balancing of the overall historical net salvage experienced observed in each account with the more recent net salvage experience.

Q. Please provide an example of your approach.

A. I will use Account 355 as an example. The overall historical net salvage rate for Account 355 is -18%.[131] This is reflective of Mr. Spanos's proposed net salvage rate of -20%. However, according to the most recent five-year average, the historical net salvage rate experienced in this account is only -3%. This could indicate a trend toward a higher (i.e., less negative) net salvage rate. In my opinion, a more reasonable net salvage estimate for this account would be -15%. A net salvage rate of -15% balances the overall net salvage rate experience with the more recent experience in this account.

XV. PLANT RETIREMENT DATES

Q. In this case is EPE proposing to change the retirement dates for several of its generating facilities?

A. Yes. EPE is proposing to shorten the retirement date and accelerate the depreciation rates for several of its generating facilities, including Newman Unit 5, Rio Grande Unit 9, and Montana Power Station Units 1-4.[132] EPE proposes a 2045 retirement date for these facilities.[133]

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[131] *See* Sch. C-2 (Depreciation Study), p. VIII-25.

[132] *See generally* EPE's response to CLC-DAC 3-01.

[133] *Id*. at 3-01(e).

Q. Is CLC-DAC proposing to leave the retirement dates for these facilities unchanged?

A. Yes. Please see the Direct Testimony of Mark E. Garrett for a substantive discussion regarding CLC-DAC's position regarding the retirement dates and accelerated depreciation rates proposed by EPE for these facilities.

Q. In calculating your proposed depreciation rates, what are the retirement dates you used for the generating units at issue?

A. In calculating my proposed depreciation rates, I used the following retirement dates for the generating units at issue: Newman Unit 5 – 2061; Rio Grande Unit 9 – 2058; Montana Power Station Units 1-2 – 2060; and Montana Power Station Units 3-4 – 2061.[134]

Q. Did you incorporate interim retirements in the remaining life calculation for the generating units at issue?

A. Yes. Please see Exhibit DJG-26 for my detailed remaining life calculations.

XVI. CONCLUSION AND RECOMMENDATION — DEPRECIATION

Q. Please summarize the key points of your depreciation testimony.

A. I employed a well-established depreciation system and used actuarial and simulated analysis to statistically analyze the Company's depreciable assets in order to develop reasonable depreciation rates in this case. I made adjustments to the Company's proposed service life and net salvage for several accounts. Regarding

[134] *Id*. at 3-01(d).

service life, the Company's own historical data indicates that for several accounts, Mr. Spanos has recommended service lives that are too short, which has resulted in overestimated depreciation rate proposals. Regarding net salvage, I recommend the Commission limit the Company's proposed net salvage increases by 50% for several accounts in the interest of gradualism.

Q. Does this conclude your testimony?

A. Yes. I reserve the right to supplement this testimony as needed with any additional information that has been requested from the Company but not yet provided. To the extent I have not addressed an issue, method, calculation, account, or other matter relevant to the Company's proposals in this proceeding, it should not be construed that I am in agreement with the same.

BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

IN THE MATTER OF THE APPLICATION OF EL PASO ELECTRIC COMPANY FOR REVISION OF ITS RETAIL ELECTRIC RATES PURSUANT TO ADVICE NOTICE NO. 267	)	**Case No. 20-00104-UT**

AFFIDAVIT

STATE OF OKLAHOMA)
) SS.
COUNTY OF OKLAHOMA)

David J. Garrett, Managing Member of Resolve Utility Consulting PLLC, hereby deposes and states under oath that the information contained in the foregoing Direct Testimony of David J. Garrett, together with all exhibits attached thereto, are true and accurate based on my personal knowledge and belief.

SIGNED this 7th day of October, 2020.

DAVID J. GARRETT

Subscribed and sworn to before me this 7th day of October, 2020.

Notary Public

CHRISTINE D MUNOZ
NOTARY
No. 19007946
Exp. 8-7-23
PUBLIC
STATE OF OKLAHOMA

My Commission Expires:

8/7/23

APPENDIX A:

DISCOUNTED CASH FLOW MODEL THEORY

The Discounted Cash Flow ("DCF") Model is based on a fundamental financial model called the "dividend discount model," which maintains that the value of a security is equal to the present value of the future cash flows it generates. Cash flows from common stock are paid to investors in the form of dividends. There are several variations of the DCF Model. In its most general form, the DCF Model is expressed as follows:[135]

Equation 5:
General Discounted Cash Flow Model

$$P_0 = \frac{D_1}{(1+k)} + \frac{D_2}{(1+k)^2} + \cdots + \frac{D_n}{(1+k)^n}$$

where: P_0 = *current stock price*
$D_1 \ldots D_n$ = *expected future dividends*
k = *discount rate / required return*

The General DCF Model would require an estimation of an infinite stream of dividends. Since this would be impractical, analysts use more feasible variations of the General DCF Model, which are discussed further below.

The DCF Models rely on the following four assumptions:

1. Investors evaluate common stocks in the classical valuation framework; that is, they trade securities rationally at prices reflecting their perceptions of value;

2. Investors discount the expected cash flows at the same rate (K) in every future period;

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[135] *See* Zvi Bodie, Alex Kane & Alan J. Marcus, *Essentials of Investments* 410 (9th ed., McGraw-Hill/Irwin 2013).

3. The K obtained from the DCF equation corresponds to that specific stream of future cash flows alone; and

4. Dividends, rather than earnings, constitute the source of value.

The General DCF can be rearranged to make it more practical for estimating the cost of equity. Regulators typically rely on some variation of the Constant Growth DCF Model, which is expressed as follows:

Equation 6:
Constant Growth Discounted Cash Flow Model

$$K = \frac{D_1}{P_0} + g$$

where:	K	=	*discount rate / required return on equity*
	D_1	=	*expected dividend per share one year from now*
	P_0	=	*current stock price*
	g	=	*expected growth rate of future dividends*

Unlike the General DCF Model, the Constant Growth DCF Model solves directly for the required return (K). In addition, by assuming that dividends grow at a constant rate, the dividend stream from the General DCF Model may be essentially substituted with a term representing the expected constant growth rate of future dividends (g). The Constant Growth DCF Model may be considered in two parts. The first part is the dividend yield (D_1/P_0), and the second part is the growth rate (g). In other words, the required return in the DCF Model is equivalent to the dividend yield plus the growth rate.

In addition to the four assumptions listed above, the Constant Growth DCF Model relies on four additional assumptions as follows:[136]

[136] *Id.* at 254-56.

1. The discount rate (K) must exceed the growth rate (g);
2. The dividend growth rate (g) is constant in every year to infinity;
3. Investors require the same return (K) in every year; and
4. There is no external financing; that is, growth is provided only by the retention of earnings.

Since the growth rate in this model is assumed to be constant, it is important not to use growth rates that are unreasonably high. In fact, the constant growth rate estimate for a regulated utility with a defined service territory should not exceed the growth rate for the economy in which it operates.

The basic form of the Constant Growth DCF Model described above is sometimes referred to as the "Annual" DCF Model. This is because the model assumes an annual dividend payment to be paid at the end of every year, as well as an increase in dividends once each year. In reality however, most utilities pay dividends on a quarterly basis. The Constant Growth DCF equation may be modified to reflect the assumption that investors receive successive quarterly dividends and reinvest them throughout the year at the discount rate. This variation is called the Quarterly Approximation DCF Model.[137]

Equation 7:
Quarterly Approximation Discounted Cash Flow Model

$$K = \left[\frac{d_0(1+g)^{1/4}}{P_0} + (1+g)^{1/4}\right]^4 - 1$$

where:	K	=	*discount rate / required return*
	d_0	=	*current quarterly dividend per share*
	P_0	=	*stock price*
	g	=	*expected growth rate of future dividends*

[137] *Id.* at 348.

The Quarterly Approximation DCF Model assumes that dividends are paid quarterly, and that each dividend is constant for four consecutive quarters. All else held constant, this model results in the *highest* cost of equity estimate for the utility in comparison to other DCF Models because it accounts for the quarterly compounding of dividends. There are several other variations of the Constant Growth (or Annual) DCF Model, including a Semi-Annual DCF Model which is used by the Federal Energy Regulatory Commission ("FERC"). These models, along with the Quarterly Approximation DCF Model, have been accepted in regulatory proceedings as useful tools for estimating the cost of equity.

APPENDIX B:

CAPITAL ASSET PRICING MODEL THEORY

The Capital Asset Pricing Model ("CAPM") is a market-based model founded on the principle that investors demand higher returns for incurring additional risk.[138] The CAPM estimates this required return. The CAPM relies on the following assumptions:

1. Investors are rational, risk-adverse, and strive to maximize profit and terminal wealth;
2. Investors make choices based on risk and return. Return is measured by the mean returns expected from a portfolio of assets; risk is measured by the variance of these portfolio returns;
3. Investors have homogenous expectations of risk and return;
4. Investors have identical time horizons;
5. Information is freely and simultaneously available to investors.
6. There is a risk-free asset, and investors can borrow and lend unlimited amounts at the risk-free rate;
7. There are no taxes, transaction costs, restrictions on selling short, or other market imperfections; and,
8. Total asset quality is fixed, and all assets are marketable and divisible.[139]

While some of these assumptions may appear to be restrictive, they do not outweigh the inherent value of the model. The CAPM has been widely used by firms, analysts, and regulators for decades to estimate the cost of equity capital.

The basic CAPM equation is expressed as follows:

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[138] William F. Sharpe, *A Simplified Model for Portfolio Analysis* 277-93 (Management Science IX 1963); *see also* John R. Graham, Scott B. Smart & William L. Megginson, *Corporate Finance: Linking Theory to What Companies Do* 208 (3rd ed., South Western Cengage Learning 2010).

[139] *Id.*

Equation 8:
Capital Asset Pricing Model

$$K = R_F + \beta_i(R_M - R_F)$$

where:	K	=	*required return*
	R_F	=	*risk-free rate*
	β	=	*beta coefficient of asset i*
	R_M	=	*required return on the overall market*

There are essentially three terms within the CAPM equation that are required to calculate the required return (K): (1) the risk-free rate (R_F); (2) the beta coefficient (β); and (3) the equity risk premium ($R_M - R_F$), which is the required return on the overall market less the risk-free rate.

<u>Raw Beta Calculations and Adjustments</u>

A stock's beta equals the covariance of the asset's returns with the returns on a market portfolio, divided by the portfolio's variance, as expressed in the following formula:[140]

Equation 9:
Beta

$$\beta_i = \frac{\sigma_{im}}{\sigma_m^2}$$

where:	β_i	=	*beta of asset i*
	σ_{im}	=	*covariance of asset i returns with market portfolio returns*
	σ^2_m	=	*variance of market portfolio*

Betas that are published by various research firms are typically calculated through a regression analysis that considers the movements in price of an individual stock and movements in the price of the overall market portfolio. The betas produced by this regression analysis are considered "raw" betas. There is empirical evidence that raw betas should be adjusted to account

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[140] John R. Graham, Scott B. Smart & William L. Megginson, *Corporate Finance: Linking Theory to What Companies Do* 180-81 (3rd ed., South Western Cengage Learning 2010).

for beta's natural tendency to revert to an underlying mean.[141] Some analysts use an adjustment method proposed by Blume, which adjusts raw betas toward the market mean of one.[142] While the Blume adjustment method is popular due to its simplicity, it is arguably arbitrary, and some would say not useful at all. According to Dr. Damodaran: "While we agree with the notion that betas move toward 1.0 over time, the [Blume adjustment] strikes us as arbitrary and not particularly useful."[143] The Blume adjustment method is especially arbitrary when applied to industries with consistently low betas, such as the utility industry. For industries with consistently low betas, it is better to employ an adjustment method that adjusts raw betas toward an industry average, rather than the market average. Vasicek proposed such a method, which is preferable to the Blume adjustment method because it allows raw betas to be adjusted toward an industry average, and also accounts for the statistical accuracy of the raw beta calculation.[144] In other words, "[t]he Vasicek adjustment seeks to overcome one weakness of the Blume model by not applying the same adjustment to every security; rather, a security-specific adjustment is made depending on the statistical quality of the regression."[145] The Vasicek beta adjustment equation is expressed as follows:

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[141] *See* Michael J. Gombola and Douglas R. Kahl, *Time-Series Processes of Utility Betas: Implications for Forecasting Systematic Risk* 84-92 (Financial Management Autumn 1990).

[142] See Marshall Blume, *On the Assessment of Risk*, Vol. 26, No. 1 The Journal of Finance 1 (1971).

[143] *See* Aswath Damodaran, *Investment Valuation: Tools and Techniques for Determining the Value of Any Asset* 187 (3rd ed., John Wiley & Sons, Inc. 2012).

[144] Oldrich A. Vasicek, *A Note on Using Cross-Sectional Information in Bayesian Estimation of Security Betas* 1233-1239 (Journal of Finance, Vol. 28, No. 5, December 1973).

[145] 2012 Ibbotson Stocks, Bonds, Bills, and Inflation Valuation Yearbook 77-78 (Morningstar 2012).

Equation 10:
Vasicek Beta Adjustment

$$\beta_{i1} = \frac{\sigma^2_{\beta_{i0}}}{\sigma^2_{\beta 0} + \sigma^2_{\beta_{i0}}}\beta_0 + \frac{\sigma^2_{\beta 0}}{\sigma^2_{\beta 0} + \sigma^2_{\beta_{i0}}}\beta_{i0}$$

where:	β_{i1}	=	*Vasicek adjusted beta for security i*
	β_{i0}	=	*historical beta for security i*
	β_0	=	*beta of industry or proxy group*
	$\sigma^2_{\beta 0}$	=	*variance of betas in the industry or proxy group*
	$\sigma^2_{\beta i0}$	=	*square of standard error of the historical beta for security i*

The Vasicek beta adjustment is an improvement on the Blume model because the Vasicek model does not apply the same adjustment to every security. A higher standard error produced by the regression analysis indicates a lower statistical significance of the beta estimate. Thus, a beta with a high standard error should receive a greater adjustment than a beta with a low standard error. As stated in Ibbotson:

> While the Vasicek formula looks intimidating, it is really quite simple. The adjusted beta for a company is a weighted average of the company's historical beta and the beta of the market, industry, or peer group. How much weight is given to the company and historical beta depends on the statistical significance of the company beta statistic. If a company beta has a low standard error, then it will have a higher weighting in the Vasicek formula. If a company beta has a high standard error, then it will have lower weighting in the Vasicek formula. An advantage of this adjustment methodology is that it does not force an adjustment to the market as a whole. Instead, the adjustment can be toward an industry or some other peer group. *This is most useful in looking at companies in industries that on average have high or low betas*.[146]

Thus, the Vasicek adjustment method is statistically more accurate, and is the preferred method to use when analyzing companies in an industry that has inherently low betas, such as the utility industry. The Vasicek method was also confirmed by Gombola, who conducted a study

[146] *Id*. at 78 (emphasis added).

specifically related to utility companies. Gombola concluded that "[t]he strong evidence of auto-regressive tendencies in *utility* betas lends support to the application of adjustment procedures such as the . . . adjustment procedure presented by Vasicek."[147] Gombola also concluded that adjusting raw betas toward the market mean of 1.0 is *too high*, and that "[i]nstead, they should be adjusted toward a value that is less than one."[148] In conducting the Vasicek adjustment on betas in previous cases, it reveals that utility betas are even lower than those published by Value Line.[149] Gombola's findings are particular important here, because his study was conducted specifically on utility companies. This evidence indicates that using Value Line's betas in a CAPM cost of equity estimate for a utility company may lead to overestimated results. Regardless, adjusting betas to a level that is *higher* than Value Line's betas is not reasonable, and it would produce CAPM cost of equity results that are too high.

[147] Michael J. Gombola and Douglas R. Kahl, *Time-Series Processes of Utility Betas: Implications for Forecasting Systematic Risk* 92 (Financial Management Autumn 1990) (emphasis added).

[148] *Id*. at 91-92.

[149] *See e.g.* Responsive Testimony of David J. Garrett, filed March 21, 2016 in Cause No. PUD 201500273 before the Corporation Commission of Oklahoma (the Company's 2015 rate case), at pp. 56 – 59.

APPENDIX C:

THE DEPRECIATION SYSTEM

A depreciation accounting system may be thought of as a dynamic system in which estimates of life and salvage are inputs to the system, and the accumulated depreciation account is a measure of the state of the system at any given time.[150] The primary objective of the depreciation system is the timely recovery of capital. The process for calculating the annual accruals is determined by the factors required to define the system. A depreciation system should be defined by four primary factors: 1) a *method* of allocation; 2) a *procedure* for applying the method of allocation to a group of property; 3) a *technique* for applying the depreciation rate; and 4) a *model* for analyzing the characteristics of vintage groups comprising a continuous property group.[151] The figure below illustrates the basic concept of a depreciation system and includes some of the available parameters.[152]

There are hundreds of potential combinations of methods, procedures, techniques, and models, but in practice, analysts use only a few combinations. Ultimately, the system selected must result in the systematic and rational allocation of capital recovery for the utility. Each of the four primary factors defining the parameters of a depreciation system is discussed further below.

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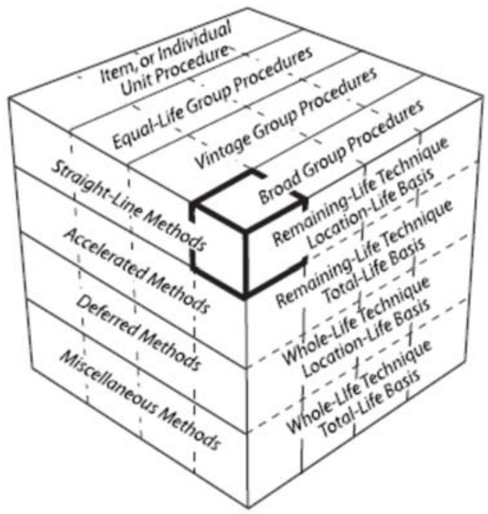
[150] Wolf *supra* n. 117, at 69-70.

[151] *Id.* at 70, 139-40.

[152] Edison Electric Institute, *Introduction to Depreciation* (inside cover) (EEI April 2013). Some definitions of the terms shown in this diagram are not consistent among depreciation practitioners and literature due to the fact that depreciation analysis is a relatively small and fragmented field. This diagram simply illustrates the some of the available parameters of a depreciation system.

Figure 22:
The Depreciation System Cube



1. Allocation Methods

The "method" refers to the pattern of depreciation in relation to the accounting periods. The method most commonly used in the regulatory context is the "straight-line method" — a type of age-life method in which the depreciable cost of plant is charged in equal amounts to each accounting period over the service life of plant.[153] Because group depreciation rates and plant balances often change, the amount of the annual accrual rarely remains the same, even when the straight-line method is employed.[154] The basic formula for the straight-line method is as follows:[155]

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[153] NARUC *supra* n. 118, at 56.

[154] *Id*.

[155] *Id*.

Equation 11:
Straight-Line Accrual

$$Annual\ Accrual = \frac{Gross\ Plant - Net\ Salavage}{Service\ Life}$$

Gross plant is a known amount from the utility's records, while both net salvage and service life must be estimated in order to calculate the annual accrual. The straight-line method differs from accelerated methods of recovery, such as the "sum-of-the-years-digits" method and the "declining balance" method. Accelerated methods are primarily used for tax purposes and are rarely used in the regulatory context for determining annual accruals.[156] In practice, the annual accrual is expressed as a rate which is applied to the original cost of plant in order to determine the annual accrual in dollars. The formula for determining the straight-line rate is as follows:[157]

Equation 12:
Straight-Line Rate

$$Depreciation\ Rate\ \% = \frac{100 - Net\ Salvage\ \%}{Service\ Life}$$

2. Grouping Procedures

The "procedure" refers to the way the allocation method is applied through subdividing the total property into groups.[158] While single units may be analyzed for depreciation, a group plan of depreciation is particularly adaptable to utility property. Employing a grouping procedure allows for a composite application of depreciation rates to groups of similar property, rather than

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[156] *Id*. at 57.

[157] *Id*. at 56.

[158] Wolf *supra* n. 117, at 74-75.

excessively conducting calculations for each unit. Whereas an individual unit of property has a single life, a group of property displays a dispersion of lives and the life characteristics of the group must be described statistically.[159] When analyzing mass property categories, it is important that each group contains homogenous units of plant that are used in the same general manner throughout the plant and operated under the same general conditions.[160]

The "average life" and "equal life" grouping procedures are the two most common. In the average life procedure, a constant annual accrual rate based on the average life of all property in the group is applied to the surviving property. While property having shorter lives than the group average will not be fully depreciated, and likewise, property having longer lives than the group average will be over-depreciated, the ultimate result is that the group will be fully depreciated by the time of the final retirement.[161] Thus, the average life procedure treats each unit as though its life is equal to the average life of the group. In contrast, the equal life procedure treats each unit in the group as though its life was known.[162] Under the equal life procedure the property is divided into subgroups that each has a common life.[163]

3. <u>Application Techniques</u>

The third factor of a depreciation system is the "technique" for applying the depreciation rate. There are two commonly used techniques: "whole life" and "remaining life." The whole life technique applies the depreciation rate on the estimated average service life of a group, while the

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[159] *Id*. at 74.

[160] NARUC *supra* n. 118, at 61-62.

[161] *See* Wolf *supra* n. 117, at 74-75.

[162] *Id*. at 75.

[163] *Id*.

remaining life technique seeks to recover undepreciated costs over the remaining life of the plant.[164]

In choosing the application technique, consideration should be given to the proper level of the accumulated depreciation account. Depreciation accrual rates are calculated using estimates of service life and salvage. Periodically these estimates must be revised due to changing conditions, which cause the accumulated depreciation account to be higher or lower than necessary. Unless some corrective action is taken, the annual accruals will not equal the original cost of the plant at the time of final retirement.[165] Analysts can calculate the level of imbalance in the accumulated depreciation account by determining the "calculated accumulated depreciation," (a.k.a. "theoretical reserve" and referred to in these appendices as "CAD"). The CAD is the calculated balance that would be in the accumulated depreciation account at a point in time using *current* depreciation parameters.[166] An imbalance exists when the actual accumulated depreciation account does not equal the CAD. The choice of application technique will affect how the imbalance is dealt with.

Use of the whole life technique requires that an adjustment be made to accumulated depreciation after calculation of the CAD. The adjustment can be made in a lump sum or over a period of time. With use of the remaining life technique, however, adjustments to accumulated depreciation are amortized over the remaining life of the property and are automatically included

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[164] NARUC *supra* n. 118, at 63-64.

[165] Wolf *supra* n. 117, at 83.

[166] NARUC *supra* n. 118, at 325.

in the annual accrual.[167] This is one reason that the remaining life technique is popular among practitioners and regulators. The basic formula for the remaining life technique is as follows:[168]

Equation 13:
Remaining Life Accrual

$$Annual\ Accrual = \frac{Gross\ Plant - Accumulated\ Depreciation - Net\ Salvage}{Average\ Remaining\ Life}$$

The remaining life accrual formula is similar to the basic straight-line accrual formula above with two notable exceptions. First, the numerator has an additional factor in the remaining life formula: the accumulated depreciation. Second, the denominator is "average remaining life" instead of "average life." Essentially, the future accrual of plant (gross plant less accumulated depreciation) is allocated over the remaining life of plant. Thus, the adjustment to accumulated depreciation is "automatic" in the sense that it is built into the remaining life calculation.[169]

4. <u>Analysis Model</u>

The fourth parameter of a depreciation system, the "model," relates to the way of viewing the life and salvage characteristics of the vintage groups that have been combined to form a continuous property group for depreciation purposes.[170] A continuous property group is created when vintage groups are combined to form a common group. Over time, the characteristics of the property may change, but the continuous property group will continue. The two analysis models

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[167] NARUC *supra* n. 118, at 65 ("The desirability of using the remaining life technique is that any necessary adjustments of [accumulated depreciation] . . . are accrued automatically over the remaining life of the property. Once commenced, adjustments to the depreciation reserve, outside of those inherent in the remaining life rate would require regulatory approval.").

[168] *Id*. at 64.

[169] Wolf *supra* n. 117, at 178.

[170] *See* Wolf *supra* n. 117, at 139 (I added the term "model" to distinguish this fourth depreciation system parameter from the other three parameters).

used among practitioners, the “broad group” and the “vintage group,” are two ways of viewing the life and salvage characteristics of the vintage groups that have been combined to from a continuous property group.

The broad group model views the continuous property group as a collection of vintage groups that each has the same life and salvage characteristics. Thus, a single survivor curve and a single salvage schedule are chosen to describe all the vintages in the continuous property group. In contrast, the vintage group model views the continuous property group as a collection of vintage groups that may have different life and salvage characteristics. Typically, there is not a significant difference between vintage group and broad group results unless vintages within the applicable property group experienced dramatically different retirement levels than anticipated in the overall estimated life for the group. For this reason, many analysts utilize the broad group procedure because it is more efficient.

APPENDIX D:

IOWA CURVES

Early work in the analysis of the service life of industrial property was based on models that described the life characteristics of human populations.[171] This explains why the word "mortality" is often used in the context of depreciation analysis. In fact, a group of property installed during the same accounting period is analogous to a group of humans born during the same calendar year. Each period the group will incur a certain fraction of deaths / retirements until there are no survivors. Describing this pattern of mortality is part of actuarial analysis and is regularly used by insurance companies to determine life insurance premiums. The pattern of mortality may be described by several mathematical functions, particularly the survivor curve and frequency curve. Each curve may be derived from the other so that if one curve is known, the other may be obtained. A survivor curve is a graph of the percent of units remaining in service expressed as a function of age.[172] A frequency curve is a graph of the frequency of retirements as a function of age. Several types of survivor and frequency curves are illustrated in the figures below.

1. <u>Development</u>

The survivor curves used by analysts today were developed over several decades from extensive analysis of utility and industrial property. In 1931 Edwin Kurtz and Robley Winfrey used extensive data from a range of 65 industrial property groups to create survivor curves

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[171] Wolf *supra* n. 117, at 276.

[172] *Id*. at 23.

representing the life characteristics of each group of property.[173] They generalized the 65 curves into 13 survivor curve types and published their results in *Bulletin 103: Life Characteristics of Physical Property*. The 13 type curves were designed to be used as valuable aids in forecasting probable future service lives of industrial property. Over the next few years, Winfrey continued gathering additional data, particularly from public utility property, and expanded the examined property groups from 65 to 176.[174] This resulted in 5 additional survivor curve types for a total of 18 curves. In 1935, Winfrey published *Bulletin 125: Statistical Analysis of Industrial Property Retirements*. According to Winfrey, "[t]he 18 type curves are expected to represent quite well all survivor curves commonly encountered in utility and industrial practices."[175] These curves are known as the "Iowa curves" and are used extensively in depreciation analysis in order to obtain the average service lives of property groups.

In 1942, Winfrey published *Bulletin 155: Depreciation of Group Properties*. In Bulletin 155, Winfrey made some slight revisions to a few of the 18 curve types, and published the equations, tables of the percent surviving, and probable life of each curve at five-percent intervals.[176] Rather than using the original formulas, analysts typically rely on the published tables containing the percentages surviving. This is because absent knowledge of the integration technique applied to each age interval, it is not possible to recreate the exact original published

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[173] *Id*. at 34.

[174] *Id*.

[175] Robley Winfrey, *Bulletin 125: Statistical Analyses of Industrial Property Retirements* 85, Vol. XXXIV, No. 23 (Iowa State College of Agriculture and Mechanic Arts 1935).

[176] Robley Winfrey, Bulletin 155: Depreciation of Group Properties 121-28, Vol XLI, No. 1 (The Iowa State College Bulletin 1942); see also Wolf supra n. 117, at 305-38 (publishing the percent surviving for each Iowa curve, including "O" type curve, at one percent intervals).

table values. In the 1970s, John Russo collected data from over 2,000 property accounts reflecting observations during the period 1965 – 1975 as part of his Ph.D. dissertation at Iowa State. Russo essentially repeated Winfrey's data collection, testing, and analysis methods used to develop the original Iowa curves, except that Russo studied industrial property in service several decades after Winfrey published the original Iowa curves. Russo drew three major conclusions from his research:[177]

1. No evidence was found to conclude that the Iowa curve set, as it stands, is not a valid system of standard curves;

2. No evidence was found to conclude that new curve shapes could be produced at this time that would add to the validity of the Iowa curve set; and

3. No evidence was found to suggest that the number of curves within the Iowa curve set should be reduced.

Prior to Russo's study, some had criticized the Iowa curves as being potentially obsolete because their development was rooted in the study of industrial property in existence during the early 1900s. Russo's research, however, negated this criticism by confirming that the Iowa curves represent a sufficiently wide range of life patterns, and that though technology will change over time, the underlying patterns of retirements remain constant and can be adequately described by the Iowa curves.[178]

Over the years, several more curve types have been added to Winfrey's 18 Iowa curves. In 1967, Harold Cowles added four origin-modal curves. In addition, a square curve is sometimes used to depict retirements which are all planned to occur at a given age. Finally, analysts

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[177] *See* Wolf *supra* n. 117, at 37.

[178] *Id.*

commonly rely on several "half curves" derived from the original Iowa curves. Thus, the term "Iowa curves" could be said to describe up to 31 standardized survivor curves.

2. <u>Classification</u>

The Iowa curves are classified by three variables: modal location, average life, and variation of life. First, the mode is the percent life that results in the highest point of the frequency curve and the "inflection point" on the survivor curve. The modal age is the age at which the greatest rate of retirement occurs. As illustrated in the figure below, the modes appear at the steepest point of each survivor curve in the top graph, as well as the highest point of each corresponding frequency curve in the bottom graph.

The classification of the survivor curves was made according to whether the mode of the retirement frequency curves was to the left, to the right, or coincident with average service life. There are three modal "families" of curves: six left modal curves (L0, L1, L2, L3, L4, L5); five right modal curves (R1, R2, R3, R4, R5); and seven symmetrical curves (S0, S1, S2, S3, S4, S5, S6).[179] In the figure below, one curve from each family is shown: L0, S3 and R1, with average life at 100 on the x-axis. It is clear from the graphs that the modes for the L0 and R1 curves appear to the left and right of average life respectively, while the S3 mode is coincident with average life.

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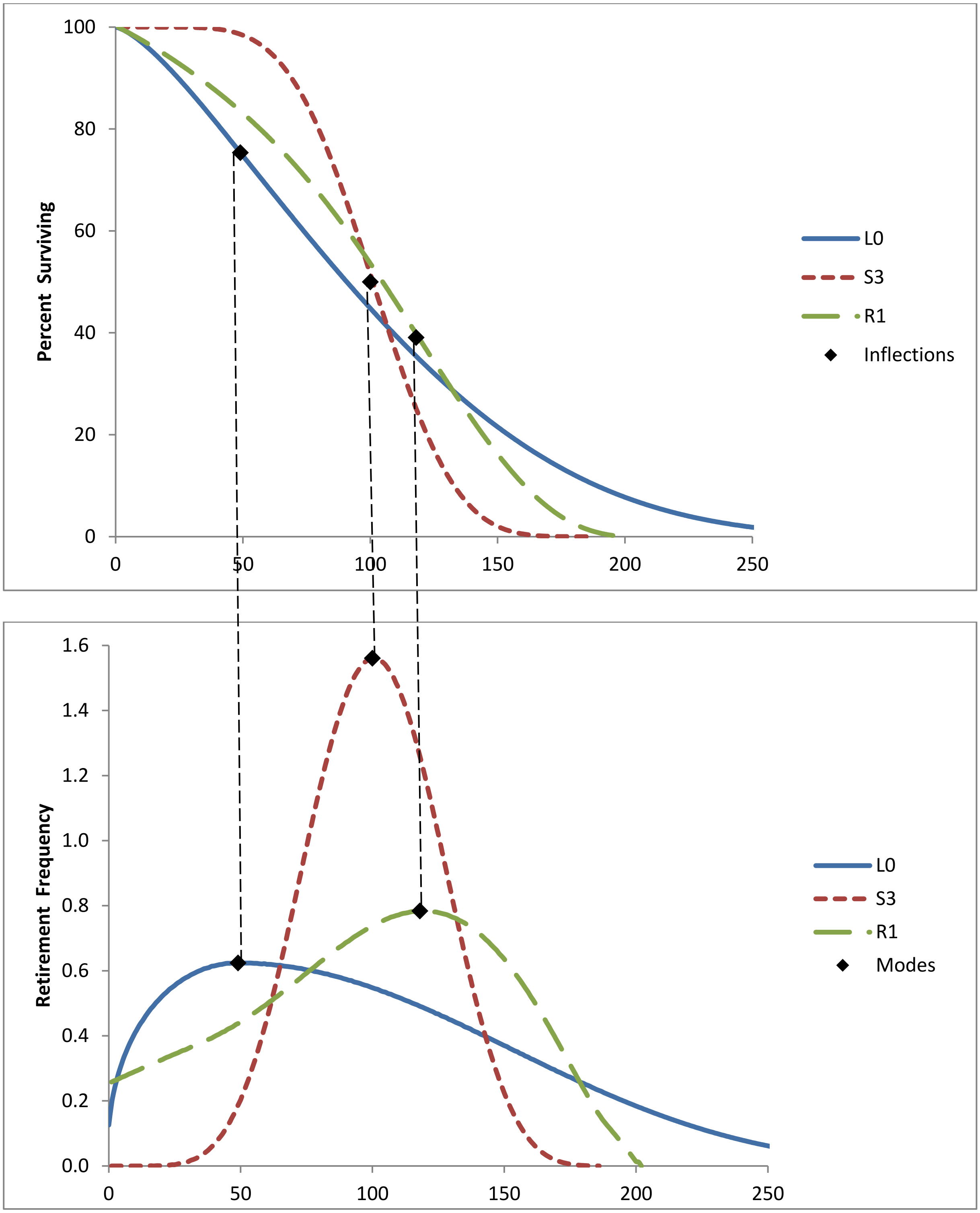
[179] In 1967, Harold A. Cowles added four origin-modal curves known as "O type" curves. There are also several "half" curves and a square curve, so the total amount of survivor curves commonly called "Iowa" curves is about 31 (see NARUC supra n. 118, at 68).

Figure 23:
Modal Age Illustration



The second Iowa curve classification variable is average life. The Iowa curves were designed using a single parameter of age expressed as a percent of average life instead of actual age. This was necessary in order for the curves to be of practical value. As Winfrey notes:

> Since the location of a particular survivor on a graph is affected by both its span in years and the shape of the curve, it is difficult to classify a group of curves unless one of these variables can be controlled. This is easily done by expressing the age in percent of average life."[180]

Because age is expressed in terms of percent of average life, any particular Iowa curve type can be modified to forecast property groups with various average lives.

The third variable, variation of life, is represented by the numbers next to each letter. A lower number (e.g., L1) indicates a relatively low mode, large variation, and large maximum life; a higher number (e.g., L5) indicates a relatively high mode, small variation, and small maximum life. All three classification variables – modal location, average life, and variation of life — are used to describe each Iowa curve. For example, a 13-L1 Iowa curve describes a group of property with a 13-year average life, with the greatest number of retirements occurring before (or to the left of) the average life, and a relatively low mode. The graphs below show these 18 survivor curves, organized by modal family.

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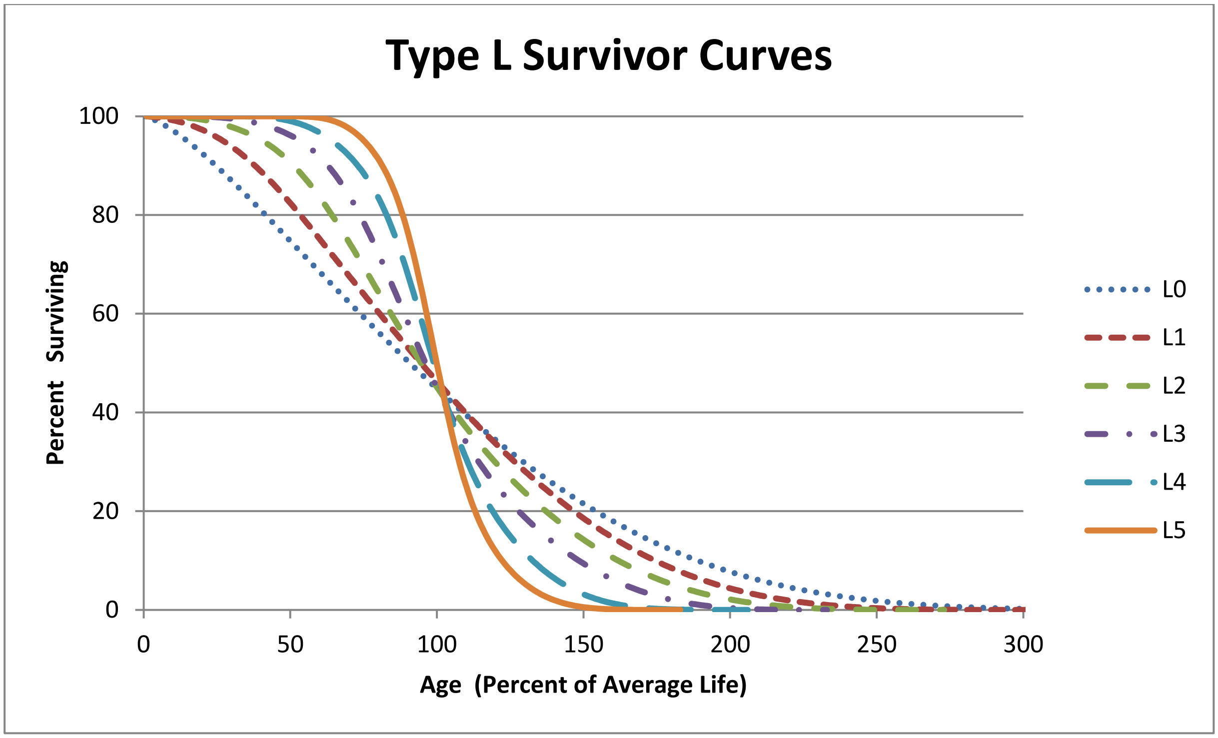
[180] Winfrey *supra* n. 166, at 60.

Figure 24:
Type L Survivor and Frequency Curves



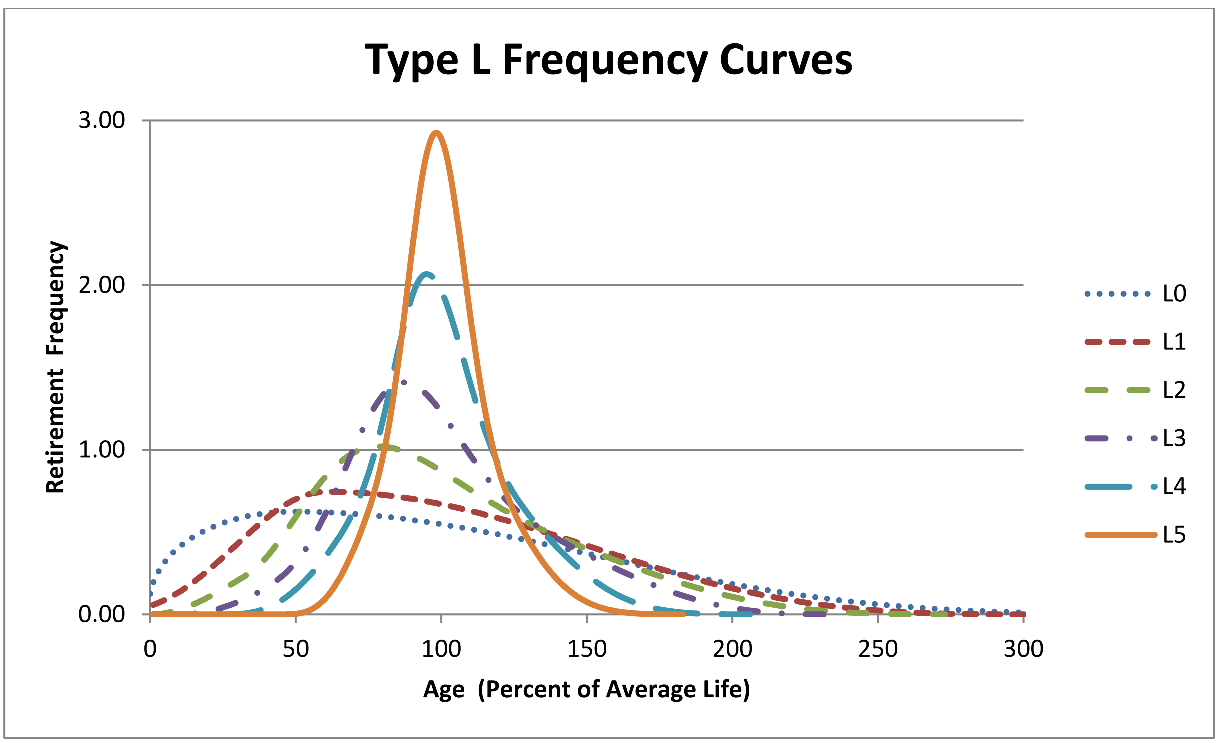
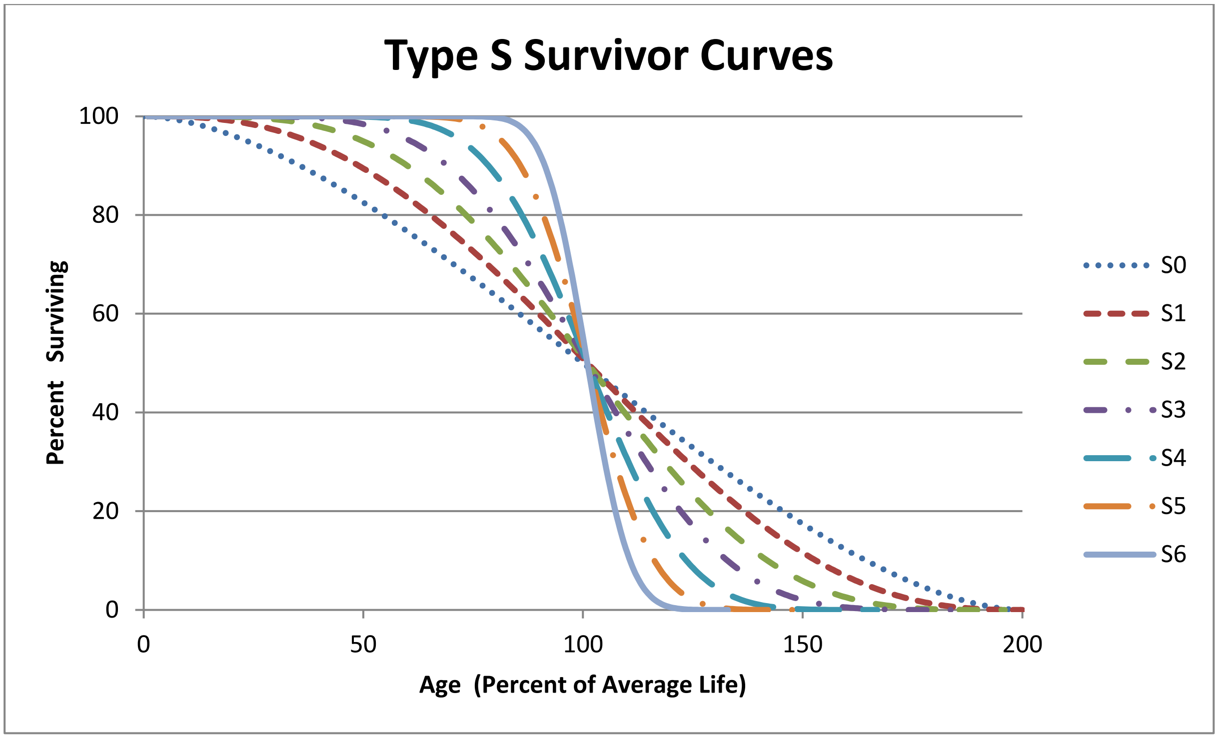


**Figure 25:
Type S Survivor and Frequency Curves**



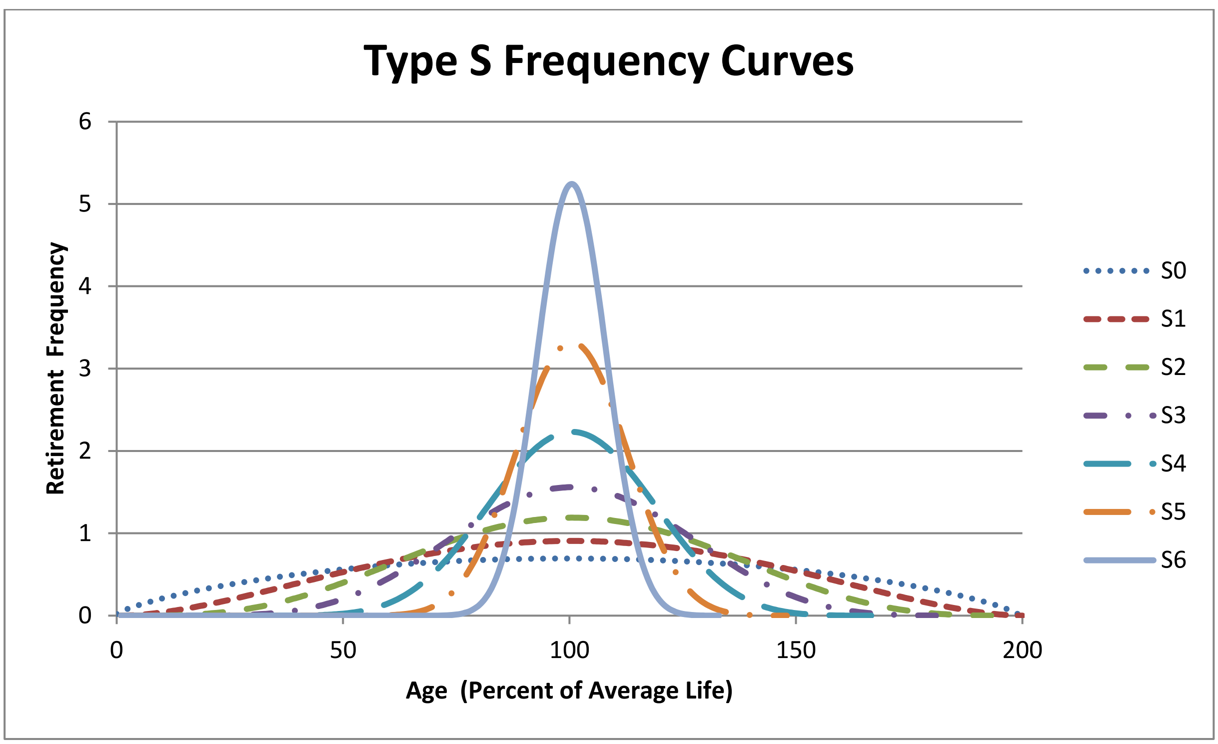
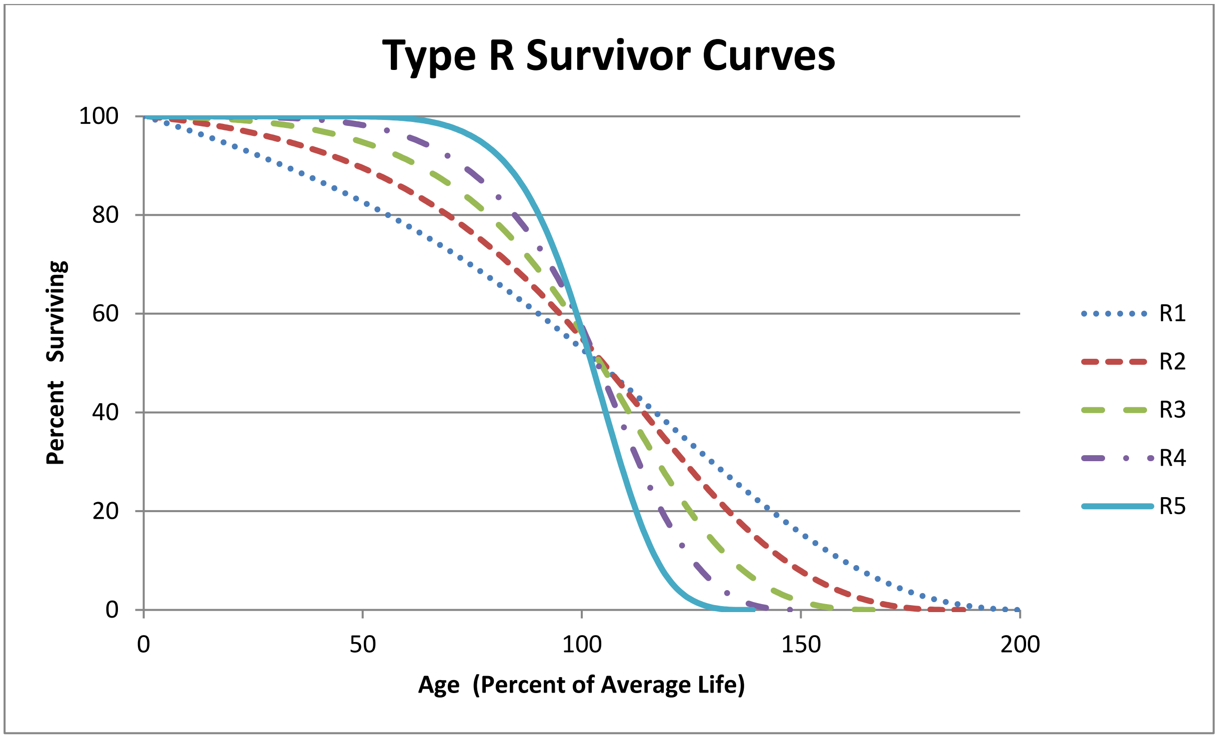
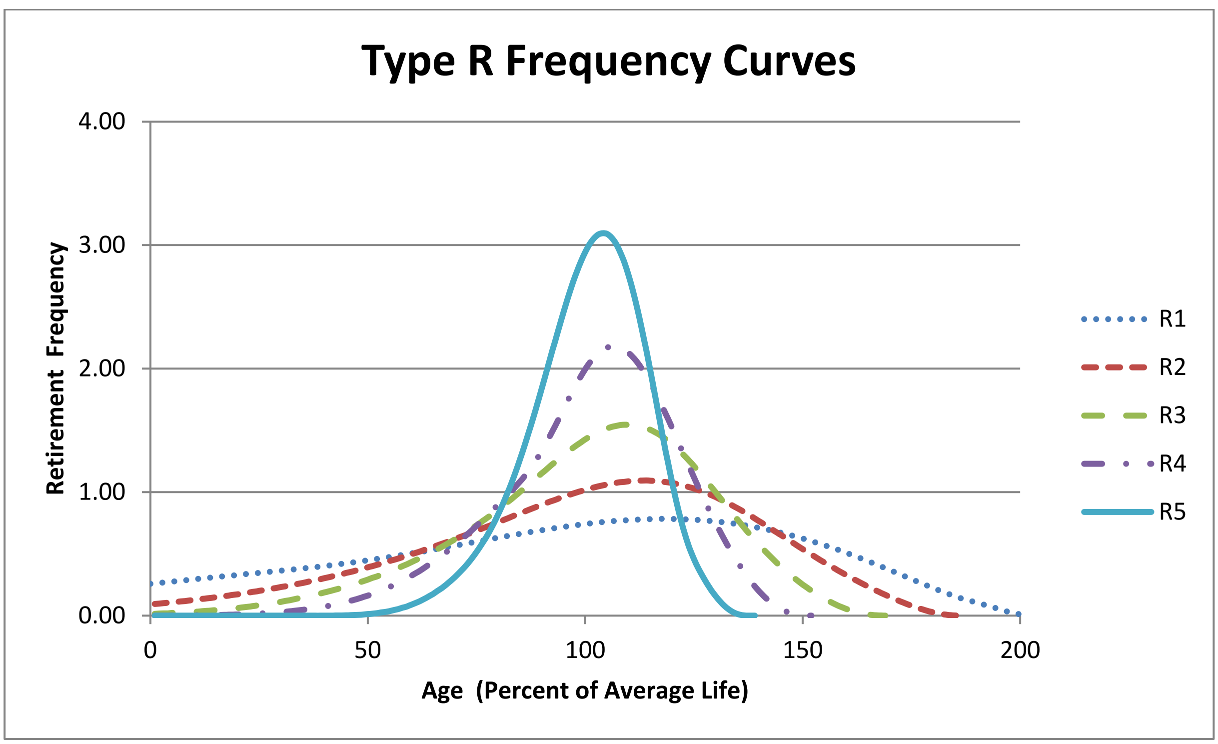


Figure 26:
Type R Survivor and Frequency Curves





As shown in the graphs above, the modes for the L family frequency curves occur to the left of average life (100% on the x-axis), while the S family modes occur at the average, and the R family modes occur after the average.

3. Types of Lives

Several other important statistical analyses and types of lives may be derived from an Iowa curve. These include: 1) average life; 2) realized life; 3) remaining life; and 4) probable life. The figure below illustrates these concepts. It shows the frequency curve, survivor curve, and probable life curve. Age M_x on the x-axis represents the modal age, while age AL_x represents the average age. Thus, this figure illustrates an "L type" Iowa curve since the mode occurs before the average.[181]

First, average life is the area under the survivor curve from age zero to maximum life. Because the survivor curve is measured in percent, the area under the curve must be divided by 100% to convert it from percent-years to years. The formula for average life is as follows:[182]

Equation 14:
Average Life

$$Average\ Life\ = \frac{Area\ Under\ Survivor\ Curve\ from\ Age\ 0\ to\ Max\ Life}{100\%}$$

Thus, average life may not be determined without a complete survivor curve. Many property groups being analyzed will not have experienced full retirement. This results in a "stub" survivor

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[181] From age zero to age M_x on the survivor curve, it could be said that the percent surviving from this property group is decreasing at an increasing rate. Conversely, from point M_x to maximum on the survivor curve, the percent surviving is decreasing at a decreasing rate.

[182] *See* NARUC *supra* n. 118, at 71.

curve. Iowa curves are used to extend stub curves to maximum life in order for the average life calculation to be made.

Realized life is similar to average life, except that realized life is the average years of service experienced to date from the vintage's original installations.[183] As shown in the figure below, realized life is the area under the survivor curve from zero to age RL_X. Likewise, unrealized life is the area under the survivor curve from age RL_X to maximum life. Thus, it could be said that average life equals realized life plus unrealized life.

Average remaining life represents the future years of service expected from the surviving property.[184] Remaining life is sometimes referred to as "average remaining life" and "life expectancy." To calculate average remaining life at age x, the area under the estimated future potion of the survivor curve is divided by the percent surviving at age x (denoted S_X). Thus, the average remaining life formula is:

Equation 15:
Average Remaining Life

$$Average\ Remaining\ Life\ = \frac{Area\ Under\ Survivor\ Curve\ from\ Age\ x\ to\ Max\ Life}{S_X}$$

It is necessary to determine average remaining life in order to calculate the annual accrual under the remaining life technique.

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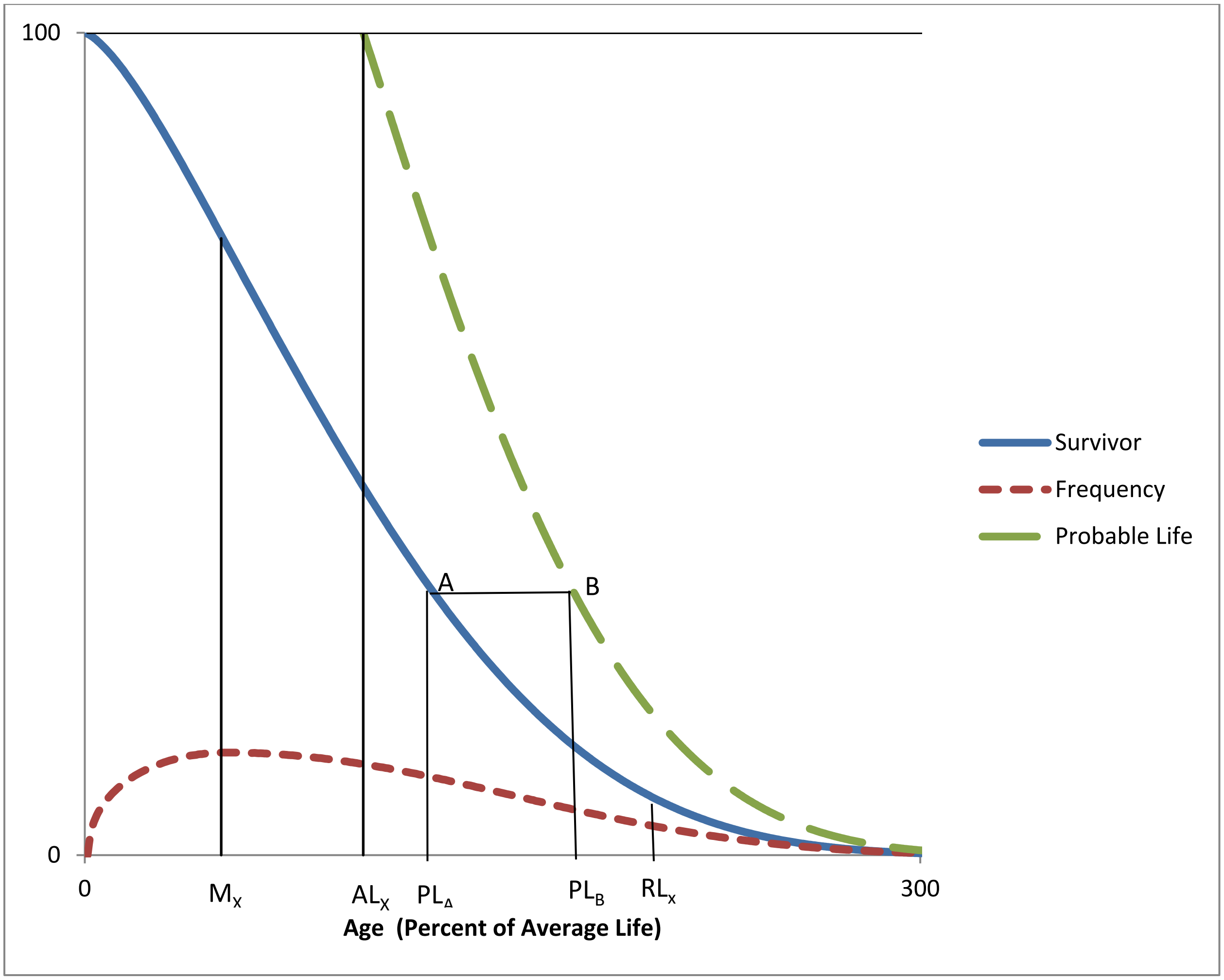
[183] *Id*. at 73.

[184] *Id*. at 74.

Figure 27:
Iowa Curve Derivations



Finally, the probable life may also be determined from the Iowa curve. The probable life of a property group is the total life expectancy of the property surviving at any age and is equal to the remaining life plus the current age.[185] The probable life is also illustrated in this figure. The probable life at age PL_A is the age at point PL_B. Thus, to read the probable life at age PL_A, see the corresponding point on the survivor curve above at point "A," then horizontally to point "B" on

[185] Wolf *supra* n. 117, at 28.

the probable life curve, and back down to the age corresponding to point "B." It is no coincidence that the vertical line from AL_X connects at the top of the probable life curve. This is because at age zero, probable life equals average life.

APPENDIX E:

ACTUARIAL ANALYSIS

Actuarial science is a discipline that applies various statistical methods to assess risk probabilities and other related functions. Actuaries often study human mortality. The results from historical mortality data are used to predict how long similar groups of people who are alive will live today. Insurance companies rely of actuarial analysis in determining premiums for life insurance policies.

The study of human mortality is analogous to estimating service lives of industrial property groups. While some humans die solely from chance, most deaths are related to age; that is, death rates generally increase as age increases. Similarly, physical plant is also subject to forces of retirement. These forces include physical, functional, and contingent factors, as shown in the table below.[186]

Figure 28:
Forces of Retirement

Physical Factors	Functional Factors	Contingent Factors
Wear and tear Decay or deterioration Action of the elements	Inadequacy Obsolescence Changes in technology Regulations Managerial discretion	Casualties or disasters Extraordinary obsolescence

While actuaries study historical mortality data in order to predict how long a group of people will live, depreciation analysts must look at a utility's historical data in order to estimate the average lives of property groups. A utility's historical data is often contained in the Continuing Property Records ("CPR"). Generally, a CPR should contain 1) an inventory of property record

[186] NARUC *supra* n. 118, at 14-15.

units; 2) the association of costs with such units; and 3) the dates of installation and removal of plant. Since actuarial analysis includes the examination of historical data to forecast future retirements, the historical data used in the analysis should not contain events that are anomalous or unlikely to recur.[187] Historical data is used in the retirement rate actuarial method, which is discussed further below.

The Retirement Rate Method

There are several systematic actuarial methods that use historical data in order to calculating observed survivor curves for property groups. Of these methods, the retirement rate method is superior, and is widely employed by depreciation analysts.[188] The retirement rate method is ultimately used to develop an observed survivor curve, which can be fitted with an Iowa curve to forecast average life. The observed survivor curve is calculated by using an observed life table ("OLT"). The figures below illustrate how the OLT is developed. First, historical property data are organized in a matrix format, with placement years on the left forming rows, and experience years on the top forming columns. The placement year (a.k.a. "vintage year" or "installation year") is the year of placement of a group of property. The experience year (a.k.a. "activity year") refers to the accounting data for a particular calendar year. The two matrices below use aged data — that is, data for which the dates of placements, retirements, transfers, and other transactions are known. Without aged data, the retirement rate actuarial method may not be employed. The first matrix is the exposure matrix, which shows the exposures at the beginning of

[187] *Id*. at 112-13.

[188] Anson Marston, Robley Winfrey & Jean C. Hempstead, *Engineering Valuation and Depreciation* 154 (2nd ed., McGraw-Hill Book Company, Inc. 1953).

each year.[189] An exposure is simply the depreciable property subject to retirement during a period. The second matrix is the retirement matrix, which shows the annual retirements during each year. Each matrix covers placement years 2003–2015, and experience years 2008-2015. In the exposure matrix, the number in the 2009 experience column and the 2003 placement row is $192,000. This means at the beginning of 2012, there was $192,000 still exposed to retirement from the vintage group placed in 2003. Likewise, in the retirement matrix, $19,000 of the dollars invested in 2003 was retired during 2012.

Figure 29:
Exposure Matrix

	Experience Years Exposures at January 1 of Each Year (Dollars in 000's)									
Placement Years	2008	2009	2010	2011	2012	2013	2014	2015	Total at Start of Age Interval	Age Interval
2003	261	245	228	211	**192**	173	152	131	131	11.5 - 12.5
2004	267	252	236	220	202	**184**	165	145	297	10.5 - 11.5
2005	304	291	277	263	248	232	**216**	198	536	9.5 - 10.5
2006	345	334	322	310	298	284	270	**255**	**847**	8.5 - 9.5
2007	367	357	347	335	324	312	299	286	1,201	7.5 - 8.5
2008	375	366	357	347	336	325	314	302	1,581	6.5 - 7.5
2009		377	366	356	346	336	327	319	1,986	5.5 - 6.5
2010			381	369	358	347	336	327	2,404	4.5 - 5.5
2011				386	372	359	346	334	2,559	3.5 - 4.5
2012					395	380	366	352	2,722	2.5 - 3.5
2013						401	385	370	2,866	1.5 - 2.5
2014							410	393	2,998	0.5 - 1.5
2015								416	3,141	0.0 - 0.5
Total	1919	2222	2514	2796	3070	3333	3586	3827	23,268	

[189] Technically, the last numbers in each column are "gross additions" rather than exposures. Gross additions do not include adjustments and transfers applicable to plant placed in a previous year. Once retirements, adjustments, and transfers are factored in, the balance at the beginning of the next account period is called an "exposure" rather than an addition.

Figure 30:
Retirement Matrix

Placement Years	Experience Years Retirments During the Year (Dollars in 000's) 2008	2009	2010	2011	2012	2013	2014	2015	Total During Age Interval	Age Interval
2003	16	17	18	19	**19**	20	21	23	23	11.5 - 12.5
2004	15	16	17	17	18	**19**	20	21	43	10.5 - 11.5
2005	13	14	14	15	16	17	**17**	18	59	9.5 - 10.5
2006	11	12	12	13	13	14	15	**15**	**71**	8.5 - 9.5
2007	10	11	11	12	12	13	13	14	82	7.5 - 8.5
2008	9	9	10	10	11	11	12	13	91	6.5 - 7.5
2009		11	10	10	9	9	9	8	95	5.5 - 6.5
2010			12	11	11	10	10	9	100	4.5 - 5.5
2011				14	13	13	12	11	93	3.5 - 4.5
2012					15	14	14	13	91	2.5 - 3.5
2013						16	15	14	93	1.5 - 2.5
2014							17	16	100	0.5 - 1.5
2015								18	112	0.0 - 0.5
Total	74	89	104	121	139	157	175	194	1,052	

These matrices help visualize how exposure and retirement data are calculated for each age interval. An age interval is typically one year. A common convention is to assume that any unit installed during the year is installed in the middle of the calendar year (i.e., July 1st). This convention is called the "half-year convention" and effectively assumes that all units are installed uniformly during the year.[190] Adoption of the half-year convention leads to age intervals of 0-0.5 years, 0.5-1.5 years, etc., as shown in the matrices.

The purpose of the matrices is to calculate the totals for each age interval, which are shown in the second column from the right in each matrix. This column is calculated by adding each number from the corresponding age interval in the matrix. For example, in the exposure matrix, the total amount of exposures at the beginning of the 8.5-9.5 age interval is \$847,000. This number was calculated by adding the numbers shown on the "stairs" to the left (192+184+216+255=847).

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[190] Wolf *supra* n. 117, at 22.

The same calculation is applied to each number in the column. The amounts retired during the year in the retirements matrix affect the exposures at the beginning of each year in the exposures matrix. For example, the amount exposed to retirement in 2008 from the 2003 vintage is $261,000. The amount retired during 2008 from the 2003 vintage is $16,000. Thus, the amount exposed to retirement in 2009 from the 2003 vintage is $245,000 ($261,000 - $16,000). The company's property records may contain other transactions which affect the property, including sales, transfers, and adjusting entries. Although these transactions are not shown in the matrices above, they would nonetheless affect the amount exposed to retirement at the beginning of each year.

The totaled amounts for each age interval in both matrices are used to form the exposure and retirement columns in the OLT, as shown in the chart below. This chart also shows the retirement ratio and the survivor ratio for each age interval. The retirement ratio for an age interval is the ratio of retirements during the interval to the property exposed to retirement at the beginning of the interval. The retirement ratio represents the probability that the property surviving at the beginning of an age interval will be retired during the interval. The survivor ratio is simply the complement to the retirement ratio (1 – retirement ratio). The survivor ratio represents the probability that the property surviving at the beginning of an age interval will survive to the next age interval.

Figure 31:
Observed Life Table

Age at Start of Interval	Exposures at Start of Age Interval	Retirements During Age Interval	Retirement Ratio	Survivor Ratio	Percent Surviving at Start of Age Interval
A	B	C	D = C / B	E = 1 - D	F
0.0	3,141	112	0.036	0.964	**100.00**
0.5	2,998	100	0.033	0.967	**96.43**
1.5	2,866	93	0.032	0.968	**93.21**
2.5	2,722	91	0.033	0.967	**90.19**
3.5	2,559	93	0.037	0.963	**87.19**
4.5	2,404	100	0.042	0.958	**84.01**
5.5	1,986	95	0.048	0.952	**80.50**
6.5	1,581	91	0.058	0.942	**76.67**
7.5	1,201	82	0.068	0.932	**72.26**
8.5	847	71	0.084	0.916	**67.31**
9.5	536	59	0.110	0.890	**61.63**
10.5	297	43	0.143	0.857	**54.87**
11.5	131	23	0.172	0.828	**47.01**
					38.91
Total	23,268	1,052			

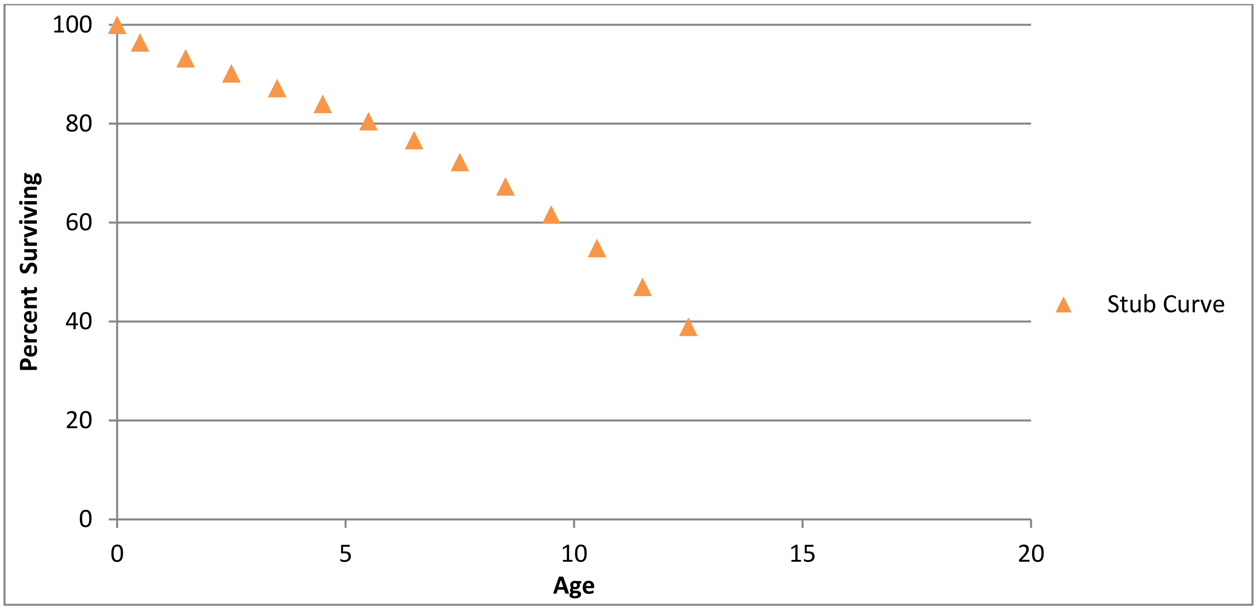
Column F on the right shows the percentages surviving at the beginning of each age interval. This column starts at 100% surviving. Each consecutive number below is calculated by multiplying the percent surviving from the previous age interval by the corresponding survivor ratio for that age interval. For example, the percent surviving at the start of age interval 1.5 is 93.21%, which was calculated by multiplying the percent surviving for age interval 0.5 (96.43%) by the survivor ratio for age interval 0.5 (0.967)[191].

The percentages surviving in Column F are the numbers that are used to form the original survivor curve. This particular curve starts at 100% surviving and ends at 38.91% surviving. An

[191] Multiplying 96.43 by 0.967 does not equal 93.21 exactly due to rounding.

observed survivor curve such as this that does not reach zero percent surviving is called a "stub" curve. The figure below illustrates the stub survivor curve derived from the OLT table above.

Figure 32:
Original "Stub" Survivor Curve



The matrices used to develop the basic OLT and stub survivor curve provide a basic illustration of the retirement rate method in that only a few placement and experience years were used. In reality, analysts may have several decades of aged property data to analyze. In that case, it may be useful to use a technique called "banding" in order to identify trends in the data.

<u>Banding</u>

The forces of retirement and characteristics of industrial property are constantly changing. A depreciation analyst may examine the magnitude of these changes. Analysts often use a technique called "banding" to assist with this process. Banding refers to the merging of several years of data into a single data set for further analysis, and it is a common technique associated with the retirement rate method.[192] There are three primary benefits of using bands in depreciation analysis:

1. Increasing the sample size. In statistical analyses, the larger the sample size in relation to the body of total data, the greater the reliability of the result;

2. Smooth the observed data. Generally, the data obtained from a single activity or vintage year will not produce an observed life table that can be easily fit; and

3. Identify trends. By looking at successive bands, the analyst may identify broad trends in the data that may be useful in projecting the future life characteristics of the property.[193]

Two common types of banding methods are the "placement band" method and the "experience band" method." A placement band, as the name implies, isolates selected placement years for analysis. The figure below illustrates the same exposure matrix shown above, except that only the placement years 2005-2008 are considered in calculating the total exposures at the beginning of each age interval.

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[192] NARUC *supra* n. 118, at 113.

[193] *Id.*

Figure 33:
Placement Bands

Placement Years	2008	2009	2010	2011	2012	2013	2014	2015	Total at Start of Age Interval	Age Interval
	Experience Years Exposures at January 1 of Each Year (Dollars in 000's)									
2003	261	245	228	211	192	173	152	131		11.5 - 12.5
2004	267	252	236	220	202	184	165	145		10.5 - 11.5
2005	304	291	277	263	248	232	216	198	198	9.5 - 10.5
2006	345	334	322	310	298	284	270	255	471	8.5 - 9.5
2007	367	357	347	335	324	312	299	286	788	7.5 - 8.5
2008	375	366	357	347	336	325	314	302	1,133	6.5 - 7.5
2009		377	366	356	346	336	327	319	1,186	5.5 - 6.5
2010			381	369	358	347	336	327	1,237	4.5 - 5.5
2011				386	372	359	346	334	1,285	3.5 - 4.5
2012					395	380	366	352	1,331	2.5 - 3.5
2013						401	385	370	1,059	1.5 - 2.5
2014							410	393	733	0.5 - 1.5
2015								416	375	0.0 - 0.5
Total	1919	2222	2514	2796	3070	3333	3586	3827	9,796	

The shaded cells within the placement band equal the total exposures at the beginning of age interval 4.5–5.5 ($1,237). The same placement band would be used for the retirement matrix covering the same placement years of 2005 – 2008. This of course would result in a different OLT and original stub survivor curve than those that were calculated above without the restriction of a placement band.

Analysts often use placement bands for comparing the survivor characteristics of properties with different physical characteristics.[194] Placement bands allow analysts to isolate the effects of changes in technology and materials that occur in successive generations of plant. For example, if in 2005 an electric utility began placing transmission poles with a special chemical treatment that extended the service lives of the poles, an analyst could use placement bands to isolate and analyze the effect of that change in the property group's physical characteristics. While placement

[194] Wolf *supra* n. 117, at 182.

bands are very useful in depreciation analysis, they also possess an intrinsic dilemma. A fundamental characteristic of placement bands is that they yield fairly complete survivor curves for older vintages. However, with newer vintages, which are arguably more valuable for forecasting, placement bands yield shorter survivor curves. Longer "stub" curves are considered more valuable for forecasting average life. Thus, an analyst must select a band width broad enough to provide confidence in the reliability of the resulting curve fit yet narrow enough so that an emerging trend may be observed.[195]

Analysts also use "experience bands." Experience bands show the composite retirement history for all vintages during a select set of activity years. The figure below shows the same data presented in the previous exposure matrices, except that the experience band from 2011 – 2013 is isolated, resulting in different interval totals.

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[195] NARUC *supra* n. 118, at 114.

Figure 34:
Experience Bands

Placement Years	2008	2009	2010	2011	2012	2013	2014	2015	Total at Start of Age Interval	Age Interval
	Experience Years Exposures at January 1 of Each Year (Dollars in 000's)									
2003	261	245	228	211	192	173	152	131		11.5 - 12.5
2004	267	252	236	220	202	184	165	145		10.5 - 11.5
2005	304	291	277	263	248	232	216	198	173	9.5 - 10.5
2006	345	334	322	310	298	284	270	255	376	8.5 - 9.5
2007	367	357	347	335	324	312	299	286	645	7.5 - 8.5
2008	375	366	357	347	336	325	314	302	752	6.5 - 7.5
2009		377	366	356	346	336	327	319	872	5.5 - 6.5
2010			381	369	358	347	336	327	959	4.5 - 5.5
2011				386	372	359	346	334	1,008	3.5 - 4.5
2012					395	380	366	352	1,039	2.5 - 3.5
2013						401	385	370	1,072	1.5 - 2.5
2014							410	393	1,121	0.5 - 1.5
2015								416	1,182	0.0 - 0.5
Total	1919	2222	2514	2796	3070	3333	3586	3827	9,199	

The shaded cells within the experience band equal the total exposures at the beginning of age interval 4.5–5.5 ($1,237). The same experience band would be used for the retirement matrix covering the same experience years of 2011 – 2013. This of course would result in a different OLT and original stub survivor than if the band had not been used. Analysts often use experience bands to isolate and analyze the effects of an operating environment over time.[196] Likewise, the use of experience bands allows analysis of the effects of an unusual environmental event. For example, if an unusually severe ice storm occurred in 2013, destruction from that storm would affect an electric utility's line transformers of all ages. That is, each of the line transformers from each placement year would be affected, including those recently installed in 2012, as well as those installed in 2003. Using experience bands, an analyst could isolate or even eliminate the 2013 experience year from the analysis. In contrast, a placement band would not effectively isolate the

[196] *Id.*

ice storm's effect on life characteristics. Rather, the placement band would show an unusually large rate of retirement during 2013, making it more difficult to accurately fit the data with a smooth Iowa curve. Experience bands tend to yield the most complete stub curves for recent bands because they have the greatest number of vintages included. Longer stub curves are better for forecasting. The experience bands, however, may also result in more erratic retirement dispersion making the curve fitting process more difficult.

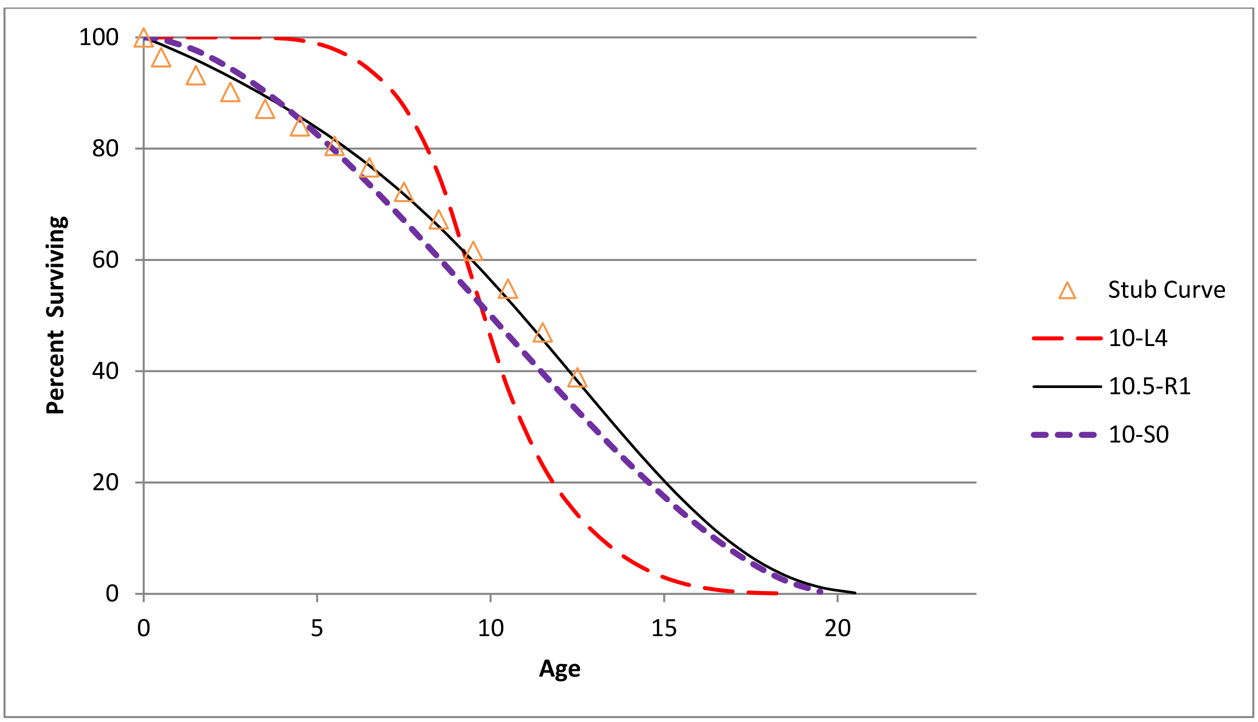
Depreciation analysts must use professional judgment in determining the types of bands to use and the band widths. In practice, analysts may use various combinations of placement and experience bands in order to increase the data sample size, identify trends and changes in life characteristics, and isolate unusual events. Regardless of which bands are used, observed survivor curves in depreciation analysis rarely reach zero percent. This is because, as seen in the OLT above, relatively newer vintage groups have not yet been fully retired at the time the property is studied. An analyst could confine the analysis to older, fully retired vintage groups in order to get complete survivor curves, but such analysis would ignore some the property currently in service and would arguably not provide an accurate description of life characteristics for current plant in service. Because a complete curve is necessary to calculate the average life of the property group, however, curve fitting techniques using Iowa curves or other standardized curves may be employed in order to complete the stub curve.

Curve Fitting

Depreciation analysts typically use the survivor curve rather than the frequency curve to fit the observed stub curves. The most commonly used generalized survivor curves used in the curve fitting process are the Iowa curves discussed above. As Wolf notes, if "the Iowa curves are adopted as a model, an underlying assumption is that the process describing the retirement pattern is one of the 22 [or more] processes described by the Iowa curves."[197]

Curve fitting may be done through visual matching or mathematical matching. In visual curve fitting, the analyst visually examines the plotted data to make an initial judgment about the Iowa curves that may be a good fit. The figure below illustrates the stub survivor curve shown above. It also shows three different Iowa curves: the 10-L4, the 10.5-R1, and the 10-S0. Visually, it is clear that the 10.5-R1 curve is a better fit than the other two curves.

Figure 35:
Visual Curve Fitting



In mathematical fitting, the least squares method is used to calculate the best fit. This mathematical method would be excessively time consuming if done by hand. With the use of

[197] Wolf *supra* n. 117, at 46 (22 curves includes Winfrey's 18 original curves plus Cowles's four "O" type curves).

modern computer software however, mathematical fitting is an efficient and useful process. The typical logic for a computer program, as well as the software employed for the analysis in this testimony is as follows:

> First (an Iowa curve) curve is arbitrarily selected. . . . If the observed curve is a stub curve, . . . calculate the area under the curve and up to the age at final data point. Call this area the realized life. Then systematically vary the average life of the theoretical survivor curve and calculate its realized life at the age corresponding to the study date. This trial and error procedure ends when you find an average life such that the realized life of the theoretical curve equals the realized life of the observed curve. Call this the average life.
>
> Once the average life is found, calculate the difference between each percent surviving point on the observed survivor curve and the corresponding point on the Iowa curve. Square each difference and sum them. The sum of squares is used as a measure of goodness of fit for that particular Iowa type curve. This procedure is repeated for the remaining 21 Iowa type curves. The "best fit" is declared to be the type of curve that minimizes the sum of differences squared.[198]

Mathematical fitting requires less judgment from the analyst and is thus less subjective. Blind reliance on mathematical fitting, however, may lead to poor estimates. Thus, analysts should employ both mathematical and visual curve fitting in reaching their final estimates. This way, analysts may utilize the objective nature of mathematical fitting while still employing professional judgment. As Wolf notes: "The results of mathematical curve fitting serve as a guide for the analyst and speed the visual fitting process. But the results of the mathematical fitting should be checked visually and the final determination of the best fit be made by the analyst."[199]

In the graph above, visual fitting was sufficient to determine that the 10.5-R1 Iowa curve was a better fit than the 10-L4 and the 10-S0 curves. Using the sum of least squares method, mathematical fitting confirms the same result. In the chart below, the percentages surviving from

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[198] Wolf *supra* n. 117, at 47.

[199] *Id*. at 48.

the OLT that formed the original stub curve are shown in the left column, while the corresponding percentages surviving for each age interval are shown for the three Iowa curves. The right portion of the chart shows the differences between the points on each Iowa curve and the stub curve. These differences are summed at the bottom. Curve 10.5-R1 is the best fit because the sum of the squared differences for this curve is less than the same sum of the other two curves. Curve 10-L4 is the worst fit, which was also confirmed visually.

Figure 36:
Mathematical Fitting

Age Interval	Stub Curve	Iowa Curves 10-L4	Iowa Curves 10-S0	Iowa Curves 10.5-R1	Squared Differences 10-L4	Squared Differences 10-S0	Squared Differences 10.5-R1
0.0	100.0	100.0	100.0	100.0	0.0	0.0	0.0
0.5	96.4	100.0	99.7	98.7	12.7	10.3	5.3
1.5	93.2	100.0	97.7	96.0	46.1	19.8	7.6
2.5	90.2	100.0	94.4	92.9	96.2	18.0	7.2
3.5	87.2	100.0	90.2	89.5	162.9	9.3	5.2
4.5	84.0	99.5	85.3	85.7	239.9	1.6	2.9
5.5	80.5	97.9	79.7	81.6	301.1	0.7	1.2
6.5	76.7	94.2	73.6	77.0	308.5	9.5	0.1
7.5	72.3	87.6	67.1	71.8	235.2	26.5	0.2
8.5	67.3	75.2	60.4	66.1	62.7	48.2	1.6
9.5	61.6	56.0	53.5	59.7	31.4	66.6	3.6
10.5	54.9	36.8	46.5	52.9	325.4	69.6	3.9
11.5	47.0	23.1	39.6	45.7	572.6	54.4	1.8
12.5	38.9	14.2	32.9	38.2	609.6	36.2	0.4
SUM					**3004.2**	**371.0**	**41.0**

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EDUCATION

University of Oklahoma — Norman, OK
Master of Business Administration — 2014
Areas of Concentration: Finance, Energy

University of Oklahoma College of Law — Norman, OK
Juris Doctor — 2007
Member, American Indian Law Review

University of Oklahoma — Norman, OK
Bachelor of Business Administration — 2003
Major: Finance

PROFESSIONAL DESIGNATIONS

Society of Depreciation Professionals
Certified Depreciation Professional (CDP)

Society of Utility and Regulatory Financial Analysts
Certified Rate of Return Analyst (CRRA)

The Mediation Institute
Certified Civil / Commercial & Employment Mediator

WORK EXPERIENCE

Resolve Utility Consulting PLLC — Oklahoma City, OK
Managing Member — 2016 – Present
Provide expert analysis and testimony specializing in depreciation and cost of capital issues for clients in utility regulatory proceedings.

Oklahoma Corporation Commission — Oklahoma City, OK
Public Utility Regulatory Analyst — 2012 – 2016
Assistant General Counsel — 2011 – 2012
Represented commission staff in utility regulatory proceedings and provided legal opinions to commissioners. Provided expert analysis and testimony in depreciation, cost of capital, incentive compensation, payroll and other issues.

Perebus Counsel, PLLC — Oklahoma City, OK
Managing Member — 2009 – 2011
Represented clients in the areas of family law, estate planning, debt negotiations, business organization, and utility regulation.

Moricoli & Schovanec, P.C. — Oklahoma City, OK
Associate Attorney — 2007 – 2009
Represented clients in the areas of contracts, oil and gas, business structures and estate administration.

TEACHING EXPERIENCE

University of Oklahoma — Norman, OK
Adjunct Instructor – "Conflict Resolution" — 2014 – Present
Adjunct Instructor – "Ethics in Leadership"

Rose State College — Midwest City, OK
Adjunct Instructor – "Legal Research" — 2013 – 2015
Adjunct Instructor – "Oil & Gas Law"

PUBLICATIONS

American Indian Law Review — Norman, OK
"Vine of the Dead: Reviving Equal Protection Rites for Religious Drug Use" — 2006
(31 Am. Indian L. Rev. 143)

VOLUNTEER EXPERIENCE

Calm Waters — Oklahoma City, OK
Board Member — 2015 – 2018
Participate in management of operations, attend meetings, review performance, compensation, and financial records. Assist in fundraising events.

Group Facilitator & Fundraiser — 2014 – 2018
Facilitate group meetings designed to help children and families cope with divorce and tragic events. Assist in fundraising events.

St. Jude Children's Research Hospital — Oklahoma City, OK
Oklahoma Fundraising Committee — 2008 – 2010
Raised money for charity by organizing local fundraising events.

PROFESSIONAL ASSOCIATIONS

Oklahoma Bar Association — 2007 – Present

Society of Depreciation Professionals — 2014 – Present
Board Member – President — 2017
Participate in management of operations, attend meetings, review performance, organize presentation agenda.

Society of Utility Regulatory Financial Analysts — 2014 – Present

SELECTED CONTINUING PROFESSIONAL EDUCATION

Society of Depreciation Professionals — Austin, TX
"Life and Net Salvage Analysis" — 2015
Extensive instruction on utility depreciation, including actuarial and simulation life analysis modes, gross salvage, cost of removal, life cycle analysis, and technology forecasting.

Society of Depreciation Professionals — New Orleans, LA
"Introduction to Depreciation" and "Extended Training" — 2014
Extensive instruction on utility depreciation, including average lives and net salvage.

Society of Utility and Regulatory Financial Analysts — Indianapolis, IN
46th Financial Forum. "The Regulatory Compact: Is it Still Relevant?" — 2014
Forum discussions on current issues.

New Mexico State University, Center for Public Utilities — Santa Fe, NM
Current Issues 2012, "The Santa Fe Conference" — 2012
Forum discussions on various current issues in utility regulation.

Michigan State University, Institute of Public Utilities — Clearwater, FL
"39th Eastern NARUC Utility Rate School" — 2011
One-week, hands-on training emphasizing the fundamentals of the utility ratemaking process.

New Mexico State University, Center for Public Utilities — Albuquerque, NM
"The Basics: Practical Regulatory Training for the Changing Electric Industries" — 2010
One-week, hands-on training designed to provide a solid foundation in core areas of utility ratemaking.

The Mediation Institute — Oklahoma City, OK
"Civil / Commercial & Employment Mediation Training" — 2009
Extensive instruction and mock mediations designed to build foundations in conducting mediations in civil matters.

Utility Regulatory Proceedings

Regulatory Agency	Utility Applicant	Docket Number	Issues Addressed	Parties Represented
Railroad Commission of Texas	Texas Gas Services Company	GUD 10928	Depreciation rates, service lives, net salvage	Gulf Coast Service Area Steering Committee
Public Utilities Commission of the State of California	Southern California Edison	A.19-08-013	Depreciation rates, service lives, net salvage	The Utility Reform Network
Massachusetts Department of Public Utilities	NSTAR Gas Company	D.P.U. 19-120	Depreciation rates, service lives, net salvage	Massachusetts Office of the Attorney General, Office of Ratepayer Advocacy
Georgia Public Service Commission	Liberty Utilities (Peach State Natural Gas)	42959	Depreciation rates, service lives, net salvage	Public Interest Advocacy Staff
Florida Public Service Commission	Florida Public Utilities Company	20190155-El 20190156-El 20190174-El	Depreciation rates, service lives, net salvage	Florida Office of Public Counsel
Illinois Commerce Commission	Commonwealth Edison Company	20-0393	Depreciation rates, service lives, net salvage	The Office of the Illinois Attorney General
Public Utility Commission of Texas	Southwestern Public Service Company	PUC 49831	Depreciation rates, service lives, net salvage	Alliance of Xcel Municipalities
South Carolina Public Service Commission	Blue Granite Water Company	2019-290-WS	Depreciation rates, service lives, net salvage	South Carolina Office of Regulatory Staff
Railroad Commission of Texas	CenterPoint Energy Resources	GUD 10920	Depreciation rates and grouping procedure	Alliance of CenterPoint Municipalities
Pennsylvania Public Utility Commission	Aqua Pennsylvania Wastewater	A-2019-3009052	Fair market value estimates for wastewater assets	Pennsylvania Office of Consumer Advocate
New Mexico Public Regulation Commission	Southwestern Public Service Company	19-00170-UT	Cost of capital and authorized rate of return	The New Mexico Large Customer Group; Occidental Permian
Indiana Utility Regulatory Commission	Duke Energy Indiana	45253	Cost of capital, depreciation rates, net salvage	Indiana Office of Utility Consumer Counselor
Maryland Public Service Commission	Columbia Gas of Maryland	9609	Depreciation rates, service lives, net salvage	Maryland Office of People's Counsel
Washington Utilities & Transportation Commission	Avista Corporation	UE-190334	Cost of capital, awarded rate of return, capital structure	Washington Office of Attorney General

Utility Regulatory Proceedings

Regulatory Agency	Utility Applicant	Docket Number	Issues Addressed	Parties Represented
Indiana Utility Regulatory Commission	Indiana Michigan Power Company	45235	Cost of capital, depreciation rates, net salvage	Indiana Office of Utility Consumer Counselor
Public Utilities Commission of the State of California	Pacific Gas & Electric Company	18-12-009	Depreciation rates, service lives, net salvage	The Utility Reform Network
Oklahoma Corporation Commission	The Empire District Electric Company	PUD 201800133	Cost of capital, authorized ROE, depreciation rates	Oklahoma Industrial Energy Consumers and Oklahoma Energy Results
Arkansas Public Service Commission	Southwestern Electric Power Company	19-008-U	Cost of capital, depreciation rates, net salvage	Western Arkansas Large Energy Consumers
Public Utility Commission of Texas	CenterPoint Energy Houston Electric	PUC 49421	Depreciation rates, service lives, net salvage	Texas Coast Utilities Coalition
Massachusetts Department of Public Utilities	Massachusetts Electric Company and Nantucket Electric Company	D.P.U. 18-150	Depreciation rates, service lives, net salvage	Massachusetts Office of the Attorney General, Office of Ratepayer Advocacy
Oklahoma Corporation Commission	Oklahoma Gas & Electric Company	PUD 201800140	Cost of capital, authorized ROE, depreciation rates	Oklahoma Industrial Energy Consumers and Oklahoma Energy Results
Public Service Commission of the State of Montana	Montana-Dakota Utilities Company	D2018.9.60	Depreciation rates, service lives, net salvage	Montana Consumer Counsel and Denbury Onshore
Indiana Utility Regulatory Commission	Northern Indiana Public Service Company	45159	Depreciation rates, grouping procedure, demolition costs	Indiana Office of Utility Consumer Counselor
Public Service Commission of the State of Montana	NorthWestern Energy	D2018.2.12	Depreciation rates, service lives, net salvage	Montana Consumer Counsel
Oklahoma Corporation Commission	Public Service Company of Oklahoma	PUD 201800097	Depreciation rates, service lives, net salvage	Oklahoma Industrial Energy Consumers and Wal-Mart
Nevada Public Utilities Commission	Southwest Gas Corporation	18-05031	Depreciation rates, service lives, net salvage	Nevada Bureau of Consumer Protection
Public Utility Commission of Texas	Texas-New Mexico Power Company	PUC 48401	Depreciation rates, service lives, net salvage	Alliance of Texas-New Mexico Power Municipalities
Oklahoma Corporation Commission	Oklahoma Gas & Electric Company	PUD 201700496	Depreciation rates, service lives, net salvage	Oklahoma Industrial Energy Consumers and Oklahoma Energy Results

Utility Regulatory Proceedings

Regulatory Agency	Utility Applicant	Docket Number	Issues Addressed	Parties Represented
Maryland Public Service Commission	Washington Gas Light Company	9481	Depreciation rates, service lives, net salvage	Maryland Office of People's Counsel
Indiana Utility Regulatory Commission	Citizens Energy Group	45039	Depreciation rates, service lives, net salvage	Indiana Office of Utility Consumer Counselor
Public Utility Commission of Texas	Entergy Texas, Inc.	PUC 48371	Depreciation rates, decommissioning costs	Texas Municipal Group
Washington Utilities & Transportation Commission	Avista Corporation	UE-180167	Depreciation rates, service lives, net salvage	Washington Office of Attorney General
New Mexico Public Regulation Commission	Southwestern Public Service Company	17-00255-UT	Cost of capital and authorized rate of return	HollyFrontier Navajo Refining; Occidental Permian
Public Utility Commission of Texas	Southwestern Public Service Company	PUC 47527	Depreciation rates, plant service lives	Alliance of Xcel Municipalities
Public Service Commission of the State of Montana	Montana-Dakota Utilities Company	D2017.9.79	Depreciation rates, service lives, net salvage	Montana Consumer Counsel
Florida Public Service Commission	Florida City Gas	20170179-GU	Cost of capital, depreciation rates	Florida Office of Public Counsel
Washington Utilities & Transportation Commission	Avista Corporation	UE-170485	Cost of capital and authorized rate of return	Washington Office of Attorney General
Wyoming Public Service Commission	Powder River Energy Corporation	10014-182-CA-17	Credit analysis, cost of capital	Private customer
Oklahoma Corporation Commission	Public Service Co. of Oklahoma	PUD 201700151	Depreciation, terminal salvage, risk analysis	Oklahoma Industrial Energy Consumers
Public Utility Commission of Texas	Oncor Electric Delivery Company	PUC 46957	Depreciation rates, simulated analysis	Alliance of Oncor Cities
Nevada Public Utilities Commission	Nevada Power Company	17-06004	Depreciation rates, service lives, net salvage	Nevada Bureau of Consumer Protection
Public Utility Commission of Texas	El Paso Electric Company	PUC 46831	Depreciation rates, interim retirements	City of El Paso

Utility Regulatory Proceedings

Regulatory Agency	Utility Applicant	Docket Number	Issues Addressed	Parties Represented
Idaho Public Utilities Commission	Idaho Power Company	IPC-E-16-24	Accelerated depreciation of North Valmy plant	Micron Technology, Inc.
Idaho Public Utilities Commission	Idaho Power Company	IPC-E-16-23	Depreciation rates, service lives, net salvage	Micron Technology, Inc.
Public Utility Commission of Texas	Southwestern Electric Power Company	PUC 46449	Depreciation rates, decommissioning costs	Cities Advocating Reasonable Deregulation
Massachusetts Department of Public Utilities	Eversource Energy	D.P.U. 17-05	Cost of capital, capital structure, and rate of return	Sunrun Inc.; Energy Freedom Coalition of America
Railroad Commission of Texas	Atmos Pipeline - Texas	GUD 10580	Depreciation rates, grouping procedure	City of Dallas
Public Utility Commission of Texas	Sharyland Utility Company	PUC 45414	Depreciation rates, simulated analysis	City of Mission
Oklahoma Corporation Commission	Empire District Electric Company	PUD 201600468	Cost of capital, depreciation rates	Oklahoma Industrial Energy Consumers
Railroad Commission of Texas	CenterPoint Energy Texas Gas	GUD 10567	Depreciation rates, simulated plant analysis	Texas Coast Utilities Coalition
Arkansas Public Service Commission	Oklahoma Gas & Electric Company	160-159-GU	Cost of capital, depreciation rates, terminal salvage	Arkansas River Valley Energy Consumers; Wal-Mart
Florida Public Service Commission	Peoples Gas	160-159-GU	Depreciation rates, service lives, net salvage	Florida Office of Public Counsel
Arizona Corporation Commission	Arizona Public Service Company	E-01345A-16-0036	Cost of capital, depreciation rates, terminal salvage	Energy Freedom Coalition of America
Nevada Public Utilities Commission	Sierra Pacific Power Company	16-06008	Depreciation rates, net salvage, theoretical reserve	Northern Nevada Utility Customers
Oklahoma Corporation Commission	Oklahoma Gas & Electric Co.	PUD 201500273	Cost of capital, depreciation rates, terminal salvage	Public Utility Division
Oklahoma Corporation Commission	Public Service Co. of Oklahoma	PUD 201500208	Cost of capital, depreciation rates, terminal salvage	Public Utility Division

Utility Regulatory Proceedings

Regulatory Agency	Utility Applicant	Docket Number	Issues Addressed	Parties Represented
Oklahoma Corporation Commission	Oklahoma Natural Gas Company	PUD 201500213	Cost of capital, depreciation rates, net salvage	Public Utility Division

Proxy Group Summary

Company	Ticker	[1] Market Cap. ($ millions)	[2] Market Category	[3] Moody's Ratings	[4] Value Line Safety Rank	[5] Financial Strength
ALLETE, Inc.	ALE	2,800	Mid Cap	Baa1	2	A
Alliant Energy Corporation	LNT	13,500	Large Cap	Baa2	2	A
Ameren Corporation	AEE	20,000	Large Cap	Baa1	2	A
American Electric Power Company, Inc.	AEP	39,000	Large Cap	Baa2	1	A+
Avangrid, Inc.	AGR	15,000	Large Cap	Baa1	2	B++
Avista Corporation	AVA	2,400	Mid Cap	Baa2	2	B++
CMS Energy Corporation	CMS	17,000	Large Cap	Baa1	2	B++
DTE Energy Company	DTE	23,000	Large Cap	Baa2	2	A
Duke Energy Corporation	DUK	62,000	Large Cap	Baa1	2	A
Evergy, Inc.	EVRG	12,000	Large Cap	Baa2	2	B++
Hawaiian Electric Industries, Inc.	HE	4,000	Mid Cap	Baa2	2	A
NextEra Energy, Inc.	NEE	136,000	Large Cap	Baa1	1	A+
NorthWestern Corporation	NWE	2,700	Mid Cap	Baa2	2	B++
OGE Energy Corp.	OGE	6,400	Mid Cap	Baa1	2	A
Otter Tail Corporation	OTTR	1,600	Small Cap	A3	2	A
Pinnacle West Capital Corporation	PNW	8,900	Mid Cap	A3	1	A+
PNM Resources, Inc.	PNM	3,100	Mid Cap	Baa3	3	B+
Portland General Electric Company	POR	3,800	Mid Cap	A3	2	B++
Southern Company	SO	57,000	Large Cap	Baa2	2	A
WEC Energy Group, Inc.	WEC	30,000	Large Cap	Baa1	1	A+
Xcel Energy Inc.	XEL	34,000	Large Cap	Baa1	1	A+

[1], [4], [5] Value Line Investment Survey

[2] Large Cap > $10 billion; Mid Cap > $2 billion; Small Cap > $200 million

[3] Bond ratings

DCF Stock and Index Prices

Ticker	^GSPC	ALE	LNT	AEE	AEP	AGR	AVA	CMS	DTE	DUK	EVRG	HE	NEE	NWE	OGE	OTTR	PNW	PNM	POR	SO	WEC	XEL
30-day Average	3404	54.21	53.40	78.97	80.31	48.76	36.14	60.92	116.61	81.97	52.11	34.24	280.51	52.00	31.46	38.65	74.30	42.92	38.58	52.86	94.11	69.33
Standard Deviation	67.9	2.20	1.15	1.69	1.95	0.59	1.03	0.75	1.86	1.56	0.94	0.91	3.84	2.04	1.33	1.42	3.10	1.65	3.15	0.76	2.53	1.26
08/10/20	3360	59.18	55.35	82.73	85.94	48.67	37.68	63.04	119.19	83.79	53.54	35.79	282.22	56.22	33.79	41.08	82.58	44.93	42.90	54.43	93.09	72.00
08/11/20	3334	58.04	53.66	80.65	83.29	48.87	37.33	61.01	116.37	82.71	52.88	35.19	276.40	54.95	32.82	40.80	80.77	43.89	42.57	53.56	90.28	70.08
08/12/20	3380	58.24	53.93	81.47	84.15	49.15	37.36	61.40	117.78	83.35	52.53	35.66	283.16	55.25	33.39	41.24	80.43	44.44	43.00	54.22	91.64	71.03
08/13/20	3373	57.39	53.98	80.86	83.66	49.57	36.93	60.96	117.14	82.74	52.15	35.29	282.97	54.82	33.04	40.31	78.49	44.78	42.11	54.37	91.44	70.83
08/14/20	3373	56.90	53.77	80.76	82.95	49.17	36.84	60.88	116.69	82.15	53.06	35.34	279.09	54.86	32.62	40.03	78.00	44.80	42.41	53.56	91.21	70.29
08/17/20	3382	56.22	53.90	80.92	81.23	48.77	36.30	61.00	116.03	82.60	52.71	35.03	281.57	54.39	32.44	40.04	76.40	44.98	42.17	53.59	92.12	69.76
08/18/20	3390	55.58	53.65	80.67	81.55	48.78	35.99	60.92	115.52	81.66	52.04	34.86	281.63	53.78	32.45	39.78	75.75	44.01	41.98	53.05	91.92	69.56
08/19/20	3375	55.26	53.82	80.64	80.92	48.80	35.98	60.68	116.01	81.66	51.51	35.10	280.92	53.40	32.08	39.43	76.02	43.81	41.94	53.19	91.72	69.15
08/20/20	3386	54.63	53.62	79.97	79.41	48.64	35.74	60.36	114.46	81.04	50.78	34.58	280.69	52.78	32.19	39.20	74.97	43.42	41.20	52.25	91.29	68.58
08/21/20	3397	54.28	54.08	80.21	79.08	49.02	35.65	60.39	114.83	81.00	50.41	34.38	280.99	52.80	31.98	39.32	74.26	43.85	41.41	52.37	91.99	69.18
08/24/20	3431	55.03	54.65	80.74	80.78	49.45	36.29	60.84	116.95	81.47	50.74	35.04	281.21	53.75	32.50	39.74	75.15	44.86	41.96	52.86	92.24	69.97
08/25/20	3444	54.71	54.25	79.10	79.77	49.03	37.06	60.21	115.99	80.85	51.21	34.87	279.90	52.98	32.17	39.35	74.47	44.14	38.45	52.41	92.28	68.54
08/26/20	3479	53.02	54.04	77.95	78.61	48.30	36.66	59.40	114.74	79.55	50.52	34.14	277.60	50.99	31.27	38.66	72.82	43.17	37.16	51.72	92.04	67.70
08/27/20	3485	53.79	54.00	78.44	78.37	48.37	36.75	59.72	116.01	79.55	52.92	34.40	278.88	51.57	31.54	39.08	73.23	43.47	38.21	52.20	92.35	68.20
08/28/20	3508	54.05	54.32	78.17	78.35	48.13	37.05	60.05	116.84	79.71	52.98	34.42	279.55	51.60	31.79	39.09	73.48	43.73	38.31	52.42	93.62	68.22
08/31/20	3500	53.96	54.15	78.61	78.83	48.04	36.86	60.49	117.64	80.34	53.22	34.61	279.17	51.02	31.86	38.85	73.35	43.68	38.15	52.18	94.08	69.04
09/01/20	3527	53.27	53.48	77.99	77.82	47.52	36.52	60.22	116.77	79.21	52.66	33.98	277.13	50.88	31.39	38.04	71.54	43.11	37.17	51.81	93.59	68.12
09/02/20	3581	54.45	54.66	79.73	80.31	48.44	37.01	61.76	119.42	81.47	53.27	34.35	288.26	51.65	32.33	38.79	73.92	43.98	37.69	53.21	97.41	71.10
09/03/20	3455	54.13	53.97	78.60	79.56	48.40	37.11	61.91	118.09	81.14	52.44	34.24	280.59	51.83	31.81	38.44	72.97	43.38	38.31	52.60	96.36	70.21
09/04/20	3427	53.78	53.29	78.47	79.05	48.67	37.10	61.66	117.78	80.97	51.87	34.31	277.32	51.21	31.54	38.19	72.40	43.01	38.41	52.29	96.49	69.58
09/08/20	3332	53.10	52.65	77.40	78.98	48.45	36.31	60.50	117.06	80.73	52.11	33.72	277.91	50.24	30.85	37.89	73.18	41.76	38.08	52.85	95.59	68.68
09/09/20	3399	52.10	53.78	78.38	79.91	49.05	36.17	61.69	118.67	82.59	52.70	33.75	282.37	50.90	31.08	37.89	72.63	42.16	38.14	52.85	97.77	70.15
09/10/20	3339	50.36	52.08	76.46	78.52	48.12	35.50	60.80	116.90	82.00	52.06	33.30	276.91	50.37	30.37	37.08	71.39	40.89	34.38	51.56	95.97	68.70
09/11/20	3341	50.75	51.86	76.60	79.15	47.94	34.44	60.91	117.41	83.03	51.94	32.96	278.15	49.63	30.16	36.77	70.90	40.84	34.05	51.76	95.96	68.43
09/14/20	3384	51.58	52.33	76.98	80.34	48.74	34.22	61.42	119.34	84.38	52.79	33.15	281.92	50.04	30.23	37.15	72.09	40.69	34.23	52.86	97.18	69.54
09/15/20	3401	51.58	52.76	77.50	80.00	49.91	34.58	61.11	117.53	84.45	52.37	33.10	295.70	50.05	29.48	36.74	72.02	41.00	33.69	53.01	99.15	70.41
09/16/20	3385	52.55	53.06	77.94	80.46	50.08	35.25	61.94	118.01	84.84	52.63	33.35	280.35	50.38	29.73	37.04	72.30	40.85	34.69	53.29	98.78	70.92
09/17/20	3357	53.22	52.18	77.62	80.04	49.43	34.57	61.34	115.85	84.60	52.20	33.25	279.52	49.97	29.38	36.91	72.16	40.09	35.35	53.52	96.11	68.44
09/18/20	3319	53.41	50.98	76.86	78.78	49.25	34.68	61.10	112.03	82.95	50.94	32.68	276.92	48.69	28.85	36.34	70.43	40.04	34.99	52.81	94.87	66.90
09/21/20	3281	51.75	49.83	76.62	79.36	48.14	34.33	59.99	111.30	82.57	50.01	32.44	276.20	48.92	28.69	36.28	70.81	39.91	34.24	53.03	94.86	66.64

All prices are adjusted closing prices reported by Yahoo! Finance, http://finance.yahoo.com

DCF Dividend Yields

Company	Ticker	[1] Dividend	[2] Stock Price	[3] Dividend Yield
ALLETE, Inc.	ALE	0.618	54.21	1.14%
Alliant Energy Corporation	LNT	0.380	53.40	0.71%
Ameren Corporation	AEE	0.495	78.97	0.63%
American Electric Power Company, Inc.	AEP	0.700	80.31	0.87%
Avangrid, Inc.	AGR	0.440	48.76	0.90%
Avista Corporation	AVA	0.405	36.14	1.12%
CMS Energy Corporation	CMS	0.407	60.92	0.67%
DTE Energy Company	DTE	1.013	116.61	0.87%
Duke Energy Corporation	DUK	0.965	81.97	1.18%
Evergy, Inc.	EVRG	0.505	52.11	0.97%
Hawaiian Electric Industries, Inc.	HE	0.330	34.24	0.96%
NextEra Energy, Inc.	NEE	1.400	280.51	0.50%
NorthWestern Corporation	NWE	0.600	52.00	1.15%
OGE Energy Corp.	OGE	0.387	31.46	1.23%
Otter Tail Corporation	OTTR	0.370	38.65	0.96%
Pinnacle West Capital Corporation	PNW	0.783	74.30	1.05%
PNM Resources, Inc.	PNM	0.308	42.92	0.72%
Portland General Electric Company	POR	0.407	38.58	1.05%
Southern Company	SO	0.640	52.86	1.21%
WEC Energy Group, Inc.	WEC	0.632	94.11	0.67%
Xcel Energy Inc.	XEL	0.430	69.33	0.62%
Average		**$0.58**	**$70.11**	**0.91%**

[1] 2020 Q3 reported quarterly dividends per share. Nasdaq.com
[2] Average stock price from Exhibit DJG-3
[3] = [1] / [2] (quarterly dividend yield)

DCF Terminal Growth Rate Determinants

Exhibit DJG-5

Terminal Growth Determinants	Rate	
Nominal GDP	3.9%	[1]
Inflation	2.0%	[2]
Risk Free Rate	1.4%	[5]
Highest	**3.9%**	

[1], [2] CBO, The 2019 Long-Term Budget Outlook, p. 54, June 2019

[3], [4] Historical growth rates from Joint 1-13 Attach.

[5] From Exhibit DJG-7

DCF Final Results

[1] Dividend (d_0)	[2] Stock Price (P_0)	[3] Growth Rate (g)	[4] **DCF Result**
$0.58	$70.11	3.90%	**7.4%**

[1] Average proxy dividend from Exhibit DJG-4

[2] Average proxy stock price from Exhibit DJG-3

[3] Highest growth determinant from Exhibit DJG-5

[4] Quarterly DCF Approximation = $[d_0(1 + g)^{0.25}/P_0 + (1 + g)^{0.25}]^4 - 1$

CAPM Risk-Free Rate

Date	Rate
08/10/20	1.25%
08/11/20	1.32%
08/12/20	1.37%
08/13/20	1.42%
08/14/20	1.45%
08/17/20	1.43%
08/18/20	1.40%
08/19/20	1.42%
08/20/20	1.38%
08/21/20	1.35%
08/24/20	1.35%
08/25/20	1.39%
08/26/20	1.41%
08/27/20	1.50%
08/28/20	1.52%
08/31/20	1.49%
09/01/20	1.43%
09/02/20	1.38%
09/03/20	1.34%
09/04/20	1.46%
09/08/20	1.43%
09/09/20	1.45%
09/10/20	1.43%
09/11/20	1.42%
09/14/20	1.42%
09/15/20	1.43%
09/16/20	1.45%
09/17/20	1.43%
09/18/20	1.45%
09/21/20	1.43%
Average	**1.41%**

*Daily Treasury Yield Curve Rates on 30-year T-bonds, http://www.treasury.gov/resources-center/data-chart-center/interest-rates/

CAPM Beta Coefficient

Company	Ticker	Beta
ALLETE, Inc.	ALE	0.85
Alliant Energy Corporation	LNT	0.85
Ameren Corporation	AEE	0.80
American Electric Power Company, Inc.	AEP	0.75
Avangrid, Inc.	AGR	0.80
Avista Corporation	AVA	0.95
CMS Energy Corporation	CMS	0.80
DTE Energy Company	DTE	0.90
Duke Energy Corporation	DUK	0.85
Evergy, Inc.	EVRG	1.00
Hawaiian Electric Industries, Inc.	HE	0.80
NextEra Energy, Inc.	NEE	0.85
NorthWestern Corporation	NWE	0.90
OGE Energy Corp.	OGE	1.05
Otter Tail Corporation	OTTR	0.85
Pinnacle West Capital Corporation	PNW	0.85
PNM Resources, Inc.	PNM	0.90
Portland General Electric Company	POR	0.85
Southern Company	SO	0.90
WEC Energy Group, Inc.	WEC	0.80
Xcel Energy Inc.	XEL	0.75
Average		0.86

Betas from Value Line Investment Survey

CAPM Implied Equity Risk Premium Estimate

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
Year	Market Value	Operating Earnings	Dividends	Buybacks	Earnings Yield	Dividend Yield	Buyback Yield	Gross Cash Yield
2014	18,245	1,004	350	553	5.50%	1.92%	3.03%	4.95%
2015	17,900	885	382	572	4.95%	2.14%	3.20%	5.33%
2016	19,268	920	397	536	4.77%	2.06%	2.78%	4.85%
2017	22,821	1,066	420	519	4.67%	1.84%	2.28%	4.12%
2018	21,027	1,282	456	806	6.10%	2.17%	3.84%	6.01%
2019	26,760	1,305	485	729	4.88%	1.81%	2.72%	4.54%

Cash Yield	4.96%	[9]
Growth Rate	5.37%	[10]
Risk-free Rate	1.41%	[11]
Current Index Value	3,404	[12]

	[13]	[14]	[15]	[16]	[17]
Year	1	2	3	4	5
Expected Dividends	178	188	198	208	220
Expected Terminal Value					3722
Present Value	166	163	160	157	2759
Intrinsic Index Value	3404	[18]			
Required Return on Market	7.40%	[19]			
Implied Equity Risk Premium	**6.0%**	[20]			

[1-4] S&P Quarterly Press Releases, data found at https://us.spindices.com/indices/equity/sp-500, Q4 2018

[1] Market value of S&P 500

[5] = [2] / [1]

[6] = [3] / [1]

[7] = [4] / [1]

[8] = [6] + [7]

[9] = Average of [8]

[10] = Compound annual growth rate of [2] = (end value / beginning value)^ $^{1/4}$-1

[11] Risk-free rate from DJG-1-7

[12] 30-day average of closing index prices from DJG-1-3 (^GSPC column)

[13-16] Expected dividends = [9]*[12]*(1+[10])^n ; Present value = expected dividend / (1+[11]+[19])^n

[17] Expected terminal value = expected dividend * (1+[11]) / [19] ; Present value = (expected dividend + expected terminal value) / (1+[11]+[19])^n

[18] = Sum([13-17]) present values.

[19] = [20] + [11]

[20] Internal rate of return calculation setting [18] equal to [12] and solving for the discount rate

CAPM Equity Risk Premium Results

IESE Business School Survey	5.6%	[1]
Graham & Harvey Survey	4.4%	[2]
Duff & Phelps Report	6.0%	[3]
Damodaran (highest)	5.0%	[4]
Damodaran (COVID Adjusted)	4.6%	[5]
Garrett	6.0%	[6]
Average	**5.3%**	
Highest	**6.0%**	

[1] IESE Business School Survey 2020
[2] Graham and Harvey Survey 2018
[3] Duff & Phelps, 3-5-2020
[4], [5] http://pages.stern.nyu.edu/~adamodar/ , 9-1-20
[6] From Exhibit DJG-9

CAPM Final Results

Exhibit DJG-11

		[1]	[2]	[3]	[4]
Company	Ticker	Risk-Free Rate	Value Line Beta	Risk Premium	CAPM Results
ALLETE, Inc.	ALE	1.41%	0.850	6.0%	6.5%
Alliant Energy Corporation	LNT	1.41%	0.850	6.0%	6.5%
Ameren Corporation	AEE	1.41%	0.800	6.0%	6.2%
American Electric Power Company, Inc.	AEP	1.41%	0.750	6.0%	5.9%
Avangrid, Inc.	AGR	1.41%	0.800	6.0%	6.2%
Avista Corporation	AVA	1.41%	0.950	6.0%	7.1%
CMS Energy Corporation	CMS	1.41%	0.800	6.0%	6.2%
DTE Energy Company	DTE	1.41%	0.900	6.0%	6.8%
Duke Energy Corporation	DUK	1.41%	0.850	6.0%	6.5%
Evergy, Inc.	EVRG	1.41%	1.000	6.0%	7.4%
Hawaiian Electric Industries, Inc.	HE	1.41%	0.800	6.0%	6.2%
NextEra Energy, Inc.	NEE	1.41%	0.850	6.0%	6.5%
NorthWestern Corporation	NWE	1.41%	0.900	6.0%	6.8%
OGE Energy Corp.	OGE	1.41%	1.050	6.0%	7.7%
Otter Tail Corporation	OTTR	1.41%	0.850	6.0%	6.5%
Pinnacle West Capital Corporation	PNW	1.41%	0.850	6.0%	6.5%
PNM Resources, Inc.	PNM	1.41%	0.900	6.0%	6.8%
Portland General Electric Company	POR	1.41%	0.850	6.0%	6.5%
Southern Company	SO	1.41%	0.900	6.0%	6.8%
WEC Energy Group, Inc.	WEC	1.41%	0.800	6.0%	6.2%
Xcel Energy Inc.	XEL	1.41%	0.750	6.0%	5.9%
Average			0.860		**6.6%**

[1] From DJG-1-7, risk-free rate exhibit
[2] From DJG-1-8, beta exhibit
[3] From DJG-1-10, equity risk premium exhibit
[6] = [1] + [2] * [3]

Cost of Equity Summary

Model	Cost of Equity
Discounted Cash Flow Model	7.4%
Capital Asset Pricing Model	6.6%
Average	**7.0%**

Market Cost of Equity

Source	Estimate	
IESE Survey	7.0%	[1]
Graham Harvey Survey	5.8%	[2]
Damodaran	6.4%	[3]
Garrett	7.4%	[4]
Average	6.7%	

[1] Average reported ERP + riskfree rate from DJG-1-7

[2] Average reported ERP + risk-free rate from DJG-1-7

[3] Recent highest reported ERP + risk-free rate from DJG-1-7

[4] From DJG-1-9, Implied ERP exhibit

Market Cost of Equity vs. Awarded Returns

Exhibit DJG-14

	[1]		[2]		[3]		[4]	[5]	[6]	[7]
	Electric Utilities		Gas Utilities		Total Utilities		S&P 500	T-Bond	Risk	Market
Year	ROE	#	ROE	#	ROE	#	Returns	Rate	Premium	COE
1990	12.70%	38	12.68%	33	12.69%	71	-3.06%	8.07%	3.89%	11.96%
1991	12.54%	42	12.45%	31	12.50%	73	30.23%	6.70%	3.48%	10.18%
1992	12.09%	45	12.02%	28	12.06%	73	7.49%	6.68%	3.55%	10.23%
1993	11.46%	28	11.37%	40	11.41%	68	9.97%	5.79%	3.17%	8.96%
1994	11.21%	28	11.24%	24	11.22%	52	1.33%	7.82%	3.55%	11.37%
1995	11.58%	28	11.44%	13	11.54%	41	37.20%	5.57%	3.29%	8.86%
1996	11.40%	18	11.12%	17	11.26%	35	22.68%	6.41%	3.20%	9.61%
1997	11.33%	10	11.30%	12	11.31%	22	33.10%	5.74%	2.73%	8.47%
1998	11.77%	10	11.51%	10	11.64%	20	28.34%	4.65%	2.26%	6.91%
1999	10.72%	6	10.74%	6	10.73%	12	20.89%	6.44%	2.05%	8.49%
2000	11.58%	9	11.34%	13	11.44%	22	-9.03%	5.11%	2.87%	7.98%
2001	11.07%	15	10.96%	5	11.04%	20	-11.85%	5.05%	3.62%	8.67%
2002	11.21%	14	11.17%	19	11.19%	33	-21.97%	3.81%	4.10%	7.91%
2003	10.96%	20	10.99%	25	10.98%	45	28.36%	4.25%	3.69%	7.94%
2004	10.81%	21	10.63%	22	10.72%	43	10.74%	4.22%	3.65%	7.87%
2005	10.51%	24	10.41%	26	10.46%	50	4.83%	4.39%	4.08%	8.47%
2006	10.32%	26	10.40%	15	10.35%	41	15.61%	4.70%	4.16%	8.86%
2007	10.30%	38	10.22%	35	10.26%	73	5.48%	4.02%	4.37%	8.39%
2008	10.41%	37	10.39%	32	10.40%	69	-36.55%	2.21%	6.43%	8.64%
2009	10.52%	40	10.22%	30	10.39%	70	25.94%	3.84%	4.36%	8.20%
2010	10.37%	61	10.15%	39	10.28%	100	14.82%	3.29%	5.20%	8.49%
2011	10.29%	42	9.92%	16	10.19%	58	2.10%	1.88%	6.01%	7.89%
2012	10.17%	58	9.94%	35	10.08%	93	15.89%	1.76%	5.78%	7.54%
2013	10.03%	49	9.68%	21	9.93%	70	32.15%	3.04%	4.96%	8.00%
2014	9.91%	38	9.78%	26	9.86%	64	13.52%	2.17%	5.78%	7.95%
2015	9.85%	30	9.60%	16	9.76%	46	1.38%	2.27%	6.12%	8.39%
2016	9.77%	42	9.54%	26	9.68%	68	11.77%	2.45%	5.69%	8.14%
2017	9.74%	53	9.72%	24	9.73%	77	21.61%	2.41%	5.08%	7.49%
2018	9.64%	37	9.62%	26	9.63%	63	-4.23%	2.68%	5.96%	8.64%
2019	9.64%	67			9.64%	67	31.22%	1.92%	5.20%	7.12%

[1], [2], [3] Average annual authorized ROE for electric and gas utilities, RRA Regulatory Focus: Major Rate Case Decisions

[3] = [1] + [2]

[4], [5], [6] Annual S&P 500 return, 10-year T-bond Rate, and equity risk premium published by NYU Stern School of Business

[7] = [5] + [6] ; Market cost of equity represents the required return for investing in all stocks in the market for a given year

Competitive Industry Debt Ratios

Industry	# Firms	Debt Ratio
Tobacco	17	96%
Financial Svcs. (Non-bank & Insurance)	232	95%
Retail (Building Supply)	17	90%
Hospitals/Healthcare Facilities	36	88%
Advertising	47	80%
Retail (Automotive)	26	79%
Brokerage & Investment Banking	39	77%
Auto & Truck	13	75%
Food Wholesalers	17	70%
Bank (Money Center)	7	69%
Transportation	18	67%
Hotel/Gaming	65	67%
Packaging & Container	24	66%
Retail (Grocery and Food)	13	66%
Broadcasting	27	65%
R.E.I.T.	234	64%
Retail (Special Lines)	89	64%
Green & Renewable Energy	22	64%
Recreation	63	63%
Software (Internet)	30	63%
Air Transport	18	63%
Retail (Distributors)	80	62%
Computers/Peripherals	48	61%
Telecom (Wireless)	18	61%
Farming/Agriculture	31	61%
Cable TV	14	60%
Computer Services	106	60%
Beverage (Soft)	34	60%
Telecom. Services	67	60%
Trucking	33	59%
Power	52	59%
Office Equipment & Services	22	58%
Chemical (Diversified)	6	58%
Retail (Online)	70	58%
Aerospace/Defense	77	58%
Oil/Gas Distribution	24	58%
Business & Consumer Services	165	57%
Construction Supplies	44	57%
Real Estate (Operations & Services)	57	56%
Household Products	127	56%
Environmental & Waste Services	82	56%
Rubber& Tires	4	56%
Transportation (Railroads)	8	55%
Retail (General)	18	54%
Chemical (Basic)	43	54%
Utility (Water)	17	54%
Building Materials	42	54%
Apparel	51	52%
Real Estate (Development)	20	51%
Healthcare Support Services	128	50%
Drugs (Biotechnology)	503	49%
Electrical Equipment	113	49%
Food Processing	88	48%
Machinery	120	48%
Furn/Home Furnishings	35	48%
Beverage (Alcoholic)	21	48%
Drugs (Pharmaceutical)	267	48%
Auto Parts	46	47%
Total / Average	**3,735**	**62%**

http://pages.stern.nyu.edu/~adamodar/New_Home_Page/datafile/dbtfund.htm

Proxy Group Debt Ratios

Company	Ticker	Debt Ratio
ALLETE, Inc.	ALE	39%
Alliant Energy Corporation	LNT	52%
Ameren Corporation	AEE	52%
American Electric Power Company, Inc.	AEP	56%
Avangrid, Inc.	AGR	31%
Avista Corporation	AVA	49%
CMS Energy Corporation	CMS	70%
DTE Energy Company	DTE	58%
Duke Energy Corporation	DUK	54%
Evergy, Inc.	EVRG	51%
Hawaiian Electric Industries, Inc.	HE	45%
NextEra Energy, Inc.	NEE	50%
NorthWestern Corporation	NWE	53%
OGE Energy Corp.	OGE	44%
Otter Tail Corporation	OTTR	47%
Pinnacle West Capital Corporation	PNW	47%
PNM Resources, Inc.	PNM	60%
Portland General Electric Company	POR	51%
Southern Company	SO	60%
WEC Energy Group, Inc.	WEC	53%
Xcel Energy Inc.	XEL	57%
Average		51%

Debt ratios from Value Line Investment Survey

Summary Accrual Adjustment

Plant Function	Plant Balance 12/31/2019	Company Proposed Accrual	Garrett Proposed Accrual	**Garrett Accrual Adjustment**
Steam Production	$ 565,455,715	$ 21,326,362	$ 17,552,280	$ (3,774,082)
Gas Turbine	518,021,063	19,226,357	14,136,554	(5,089,803)
Transmission	532,343,334	9,023,893	8,275,788	(748,105)
Distribution	1,347,787,849	29,846,554	28,149,622	(1,696,932)
General	171,715,519	6,601,194	6,616,766	15,572
Total Depreciable Plant	$ 3,135,323,480	$ 86,024,360	$ 74,731,009	**$ (11,293,351)**

Mass Property Parameter Comparison

Account No.	Description	Company Proposal Iowa Curve Type	AL	NS Rate	Depr Rate	Annual Accrual	Garrett Proposal Iowa Curve Type	AL	NS Rate	Depr Rate	Annual Accrual
	TRANSMISSION PLANT										
353.00	STATION EQUIPMENT	R4	50	-5%	1.56%	2,948,962	R3	58	-5%	1.40%	2,647,195
355.00	WOOD AND STEEL POLES	S3	55	-20%	1.91%	3,115,165	S3	55	-15%	1.79%	2,918,845
356.00	OVERHEAD CONDUCTORS AND DEVICES	R5	60	-15%	1.61%	1,579,563	R4	65	-10%	1.35%	1,329,527
	DISTRIBUTION PLANT										
362.00	STATION EQUIPMENT	R2	65	-5%	1.43%	4,102,971	R1.5	71	0%	1.24%	3,568,711
364.00	POLES, TOWERS AND FIXTURES	R3	45	-30%	3.11%	5,697,660	R3	45	-25%	2.94%	5,396,941
366.00	UNDERGROUND CONDUIT	R4	65	-5%	1.50%	2,124,461	R4	71	0%	1.27%	1,804,272
368.00	LINE TRANSFORMERS	R3	52	-15%	2.34%	6,629,377	R3	52	-10%	2.21%	6,260,694
369.00	SERVICES	S3	65	-15%	1.38%	779,571	S3	65	0%	1.08%	607,181

Detailed Rate Comparison

		[1]	[2]		[3]		[4]	
			Company Proposal		Garrett Proposal		Difference	
Account No.	Description	Plant 12/31/2019	Rate	Annual Accrual	Rate	Annual Accrual	Rate	Annual Accrual
	STEAM PRODUCTION PLANT							
311.00	STRUCTURES AND IMPROVEMENTS							
	RIO GRANDE UNIT 6	1,290,817	2.87%	37,023	2.87%	37,015	0.00%	-8
	RIO GRANDE UNIT 7	1,269,983	1.67%	21,167	1.67%	21,166	0.00%	-1
	RIO GRANDE UNIT 8	2,311,211	1.86%	42,993	1.86%	43,054	0.00%	61
	RIO GRANDE COMMON	4,433,409	6.07%	269,101	6.06%	268,598	-0.01%	-503
	NEWMAN UNIT 1	1,269,946	1.32%	16,728	1.31%	16,670	-0.01%	-58
	NEWMAN UNIT 2	1,035,405	10.93%	113,156	10.91%	112,979	-0.02%	-177
	NEWMAN UNIT 3	1,097,187	4.15%	45,506	4.14%	45,410	-0.01%	-96
	NEWMAN UNIT 4	15,848,533	6.10%	967,044	6.13%	972,161	0.03%	5,117
	NEWMAN UNIT 5	25,932,328	3.16%	819,233	2.00%	519,026	-1.16%	-300,207
	NEWMAN COMMON	18,900,582	3.85%	727,244	2.43%	458,914	-1.42%	-268,330
	Total Account 311.00	73,389,401	4.17%	3,059,195	3.40%	2,494,995	-0.77%	-564,200
312.00	BOILER PLANT EQUIPMENT							
	RIO GRANDE UNIT 6	2,973,008	0.00%	0	0.00%	0	0.00%	0
	RIO GRANDE UNIT 7	4,604,495	1.67%	76,741	1.67%	76,741	0.00%	0
	RIO GRANDE UNIT 8	15,577,498	2.62%	408,845	2.63%	409,411	0.01%	566
	RIO GRANDE COMMON	939,445	5.47%	51,374	5.46%	51,341	-0.01%	-33
	NEWMAN UNIT 1	8,696,638	4.70%	408,627	4.70%	408,627	0.00%	0
	NEWMAN UNIT 2	8,916,414	13.20%	1,176,873	13.14%	1,171,923	-0.06%	-4,950
	NEWMAN UNIT 3	6,743,234	4.54%	306,272	4.52%	304,565	-0.02%	-1,707
	NEWMAN UNIT 4	3,303,062	7.62%	251,778	7.62%	251,713	0.00%	-65
	NEWMAN UNIT 5	112,841,612	3.09%	3,484,552	1.97%	2,218,985	-1.12%	-1,265,567
	NEWMAN COMMON	6,752,670	3.64%	245,865	2.31%	155,819	-1.33%	-90,046
	Total Account 312.00	171,348,075	3.74%	6,410,927	2.95%	5,049,125	-0.79%	-1,361,802
313.00	ENGINES AND ENGINE-DRIVEN GENERATORS							
	NEWMAN UNIT 1	327,497	0.00%	0	0.00%	0	0.00%	0
	NEWMAN UNIT 4	24,780,032	7.19%	1,780,675	7.18%	1,779,707	-0.01%	-968
	NEWMAN UNIT 5	48,432,717	3.59%	1,738,596	2.41%	1,167,811	-1.18%	-570,785
	Total Account 313.00	73,540,247	4.79%	3,519,271	4.01%	2,947,518	-0.78%	-571,753
314.00	TURBOGENERATOR UNITS							
	RIO GRANDE UNIT 6	3,559,998	0.06%	1,966	0.06%	1,965	0.00%	-1
	RIO GRANDE UNIT 7	4,204,367	2.37%	99,611	2.36%	99,024	-0.01%	-587

Detailed Rate Comparison

		[1]	[2]		[3]		[4]	
			Company Proposal		Garrett Proposal		Difference	
Account No.	Description	Plant 12/31/2019	Rate	Annual Accrual	Rate	Annual Accrual	Rate	Annual Accrual
	RIO GRANDE UNIT 8	11,776,648	1.80%	212,382	1.81%	213,149	0.01%	767
	NEWMAN UNIT 1	13,716,383	7.03%	964,087	7.01%	961,888	-0.02%	-2,199
	NEWMAN UNIT 2	11,439,310	7.35%	840,772	7.34%	839,168	-0.01%	-1,604
	NEWMAN UNIT 3	12,089,865	6.95%	839,714	6.90%	834,107	-0.05%	-5,607
	NEWMAN UNIT 4	33,968,975	2.14%	725,854	2.13%	722,522	-0.01%	-3,332
	NEWMAN UNIT 5	61,650,972	3.53%	2,175,325	2.27%	1,400,130	-1.26%	-775,195
	NEWMAN COMMON	58,097	0.00%	0	0.00%	0	0.00%	0
	Total Account 314.00	152,464,615	3.84%	5,859,711	3.33%	5,071,952	-0.52%	-787,759
315.00	ACCESSORY ELECTRIC EQUIPMENT							
	RIO GRANDE UNIT 6	784,259	5.54%	43,483	5.67%	44,442	0.13%	959
	RIO GRANDE UNIT 7	856,688	9.99%	85,569	9.83%	84,203	-0.16%	-1,366
	RIO GRANDE UNIT 8	6,535,523	5.33%	348,355	5.31%	347,132	-0.02%	-1,223
	NEWMAN UNIT 1	1,148,175	1.76%	20,189	1.74%	20,013	-0.02%	-176
	NEWMAN UNIT 2	1,052,955	1.74%	18,315	1.72%	18,153	-0.02%	-162
	NEWMAN UNIT 3	1,150,892	5.37%	61,774	5.41%	62,216	0.04%	442
	NEWMAN UNIT 4	6,332,763	0.74%	46,879	0.74%	46,568	0.00%	-311
	NEWMAN UNIT 5	24,098,577	3.13%	753,558	1.98%	477,142	-1.15%	-276,416
	NEWMAN COMMON	157,237	4.04%	6,350	2.53%	3,985	-1.51%	-2,365
	Total Account 315.00	42,117,069	3.29%	1,384,472	2.62%	1,103,854	-0.67%	-280,618
316.00	MISCELLANEOUS POWER PLANT EQUIPMENT							
	RIO GRANDE UNIT 6	1,489,364	2.50%	37,245	2.50%	37,234	0.00%	-11
	RIO GRANDE UNIT 7	1,851,433	0.85%	15,680	0.85%	15,670	0.00%	-10
	RIO GRANDE UNIT 8	5,951,707	1.83%	108,647	1.83%	108,933	0.00%	286
	RIO GRANDE COMMON	1,938,696	4.56%	88,358	4.55%	88,281	-0.01%	-77
	NEWMAN UNIT 1	2,177,691	1.69%	36,748	1.69%	36,695	0.00%	-53
	NEWMAN UNIT 2	2,829,108	1.67%	47,268	1.67%	47,153	0.00%	-115
	NEWMAN UNIT 3	5,645,296	1.35%	76,351	1.35%	76,055	0.00%	-296
	NEWMAN UNIT 4	11,495,252	0.72%	82,268	0.71%	82,109	-0.01%	-159
	NEWMAN UNIT 5	1,771,257	2.38%	42,204	1.57%	27,746	-0.81%	-14,458
	NEWMAN ZERO LIQUID DISCHARGE	14,375,574	3.19%	458,420	2.09%	299,802	-1.10%	-158,618
	NEWMAN COMMON	3,070,930	3.24%	99,597	2.12%	65,158	-1.12%	-34,439
	Total Account 316.00	52,596,308	2.08%	1,092,786	1.68%	884,836	-0.40%	-207,950
	Total Steam Production Plant	565,455,715	3.77%	21,326,362	3.10%	17,552,280	-0.67%	-3,774,082

Detailed Rate Comparison

		[1]	[2]		[3]		[4]	
			Company Proposal		Garrett Proposal		Difference	
Account No.	Description	Plant 12/31/2019	Rate	Annual Accrual	Rate	Annual Accrual	Rate	Annual Accrual
	GAS TURBINE PLANT							
341.00	STRUCTURES AND IMPROVEMENTS							
	COPPER POWER STATION	791,864	1.33%	10,546	1.34%	10,585	0.01%	39
	RIO GRANDE UNIT 9	22,158,133	3.43%	760,586	2.36%	523,761	-1.07%	-236,825
	MONTANA POWER STATION UNIT 1	315,347	3.49%	11,015	2.27%	7,166	-1.22%	-3,849
	MONTANA POWER STATION UNIT 2	257,181	3.49%	8,981	2.27%	5,839	-1.22%	-3,142
	MONTANA POWER STATION UNIT 3	206,815	3.50%	7,246	2.23%	4,605	-1.27%	-2,641
	MONTANA POWER STATION UNIT 4	237,486	3.54%	8,406	2.25%	5,343	-1.29%	-3,063
	MONTANA POWER STATION COMMON	18,007,977	3.57%	642,237	2.28%	410,433	-1.29%	-231,804
	SOLAR FACILITIES	91,868	4.84%	4,449	4.83%	4,440	-0.01%	-9
	Total Account 341.00	42,066,673	3.46%	1,453,466	2.31%	972,173	-1.14%	-481,293
342.00	FUEL HOLDERS							
	COPPER POWER STATION	511,691	0.57%	2,910	0.57%	2,903	0.00%	-7
	RIO GRANDE UNIT 9	3,768,778	3.34%	125,815	2.35%	88,674	-0.99%	-37,141
	MONTANA POWER STATION COMMON	20,877,428	3.63%	757,417	2.38%	496,379	-1.25%	-261,038
	Total Account 342.00	25,157,897	3.52%	886,142	2.34%	587,956	-1.19%	-298,186
343.00	PRIME MOVERS							
	RIO GRANDE UNIT 9	59,555,058	3.70%	2,206,208	2.86%	1,705,346	-0.84%	-500,862
	MONTANA POWER STATION UNIT 1	78,609,841	3.76%	2,957,112	2.78%	2,182,752	-0.98%	-774,360
	MONTANA POWER STATION UNIT 2	73,503,725	3.77%	2,769,125	2.78%	2,045,506	-0.99%	-723,619
	MONTANA POWER STATION UNIT 3	63,009,557	3.85%	2,424,712	2.80%	1,764,060	-1.05%	-660,652
	MONTANA POWER STATION UNIT 4	62,425,439	3.89%	2,425,286	2.83%	1,763,879	-1.06%	-661,407
	MONTANA POWER STATION COMMON	34,687,535	3.78%	1,312,508	2.78%	963,538	-1.00%	-348,970
	Total Account 343.00	371,791,155	3.79%	14,094,951	2.80%	10,425,081	-0.99%	-3,669,870
344.00	GENERATORS							
	COPPER POWER STATION	10,369,392	3.51%	364,223	3.51%	364,036	0.00%	-187
	RIO GRANDE UNIT 9	8,420,577	3.47%	292,562	2.56%	215,545	-0.91%	-77,017
	MONTANA POWER STATION UNIT 1	6,122,691	3.65%	223,421	2.56%	156,651	-1.09%	-66,770
	MONTANA POWER STATION UNIT 2	6,122,691	3.65%	223,200	2.56%	156,562	-1.09%	-66,638
	MONTANA POWER STATION UNIT 3	6,241,096	3.61%	225,112	2.48%	154,473	-1.13%	-70,639
	MONTANA POWER STATION UNIT 4	6,126,228	3.63%	222,331	2.49%	152,598	-1.14%	-69,733
	MONTANA POWER STATION COMMON	63	3.17%	2	2.31%	1	-0.86%	-1

Detailed Rate Comparison

		[1]	[2]		[3]		[4]	
			Company Proposal		Garrett Proposal		Difference	
Account No.	Description	Plant 12/31/2019	Rate	Annual Accrual	Rate	Annual Accrual	Rate	Annual Accrual
	SOLAR FACILITIES	1,187,262	5.23%	62,103	5.23%	62,086	0.00%	-17
	Total Account 344.00	44,590,001	3.62%	1,612,954	2.83%	1,261,951	-0.79%	-351,003
345.00	ACCESSORY ELECTRIC EQUIPMENT							
	COPPER POWER STATION	2,306,861	6.66%	153,586	6.65%	153,467	-0.01%	-119
	RIO GRANDE UNIT 9	5,186,611	3.48%	180,297	2.60%	135,045	-0.88%	-45,252
	MONTANA POWER STATION UNIT 1	3,115,518	3.70%	115,423	2.64%	82,352	-1.06%	-33,071
	MONTANA POWER STATION UNIT 2	3,029,962	3.70%	112,104	2.64%	80,015	-1.06%	-32,089
	MONTANA POWER STATION UNIT 3	2,686,650	3.76%	100,898	2.63%	70,748	-1.13%	-30,150
	MONTANA POWER STATION UNIT 4	2,250,774	3.79%	85,397	2.66%	59,823	-1.13%	-25,574
	MONTANA POWER STATION COMMON	9,316,081	3.61%	336,482	2.55%	237,603	-1.06%	-98,879
	SOLAR FACILITIES	167,360	5.30%	8,862	5.28%	8,842	-0.02%	-20
	Total Account 345.00	28,059,816	3.90%	1,093,049	2.95%	827,896	-0.94%	-265,153
346.00	MISCELLANEOUS POWER PLANT EQUIPMENT							
	COPPER POWER STATION	4,170,624	0.30%	12,405	0.30%	12,387	0.00%	-18
	RIO GRANDE UNIT 9	410,060	3.31%	13,569	2.34%	9,581	-0.97%	-3,988
	MONTANA POWER STATION UNIT 1	297,569	3.45%	10,257	2.30%	6,852	-1.15%	-3,405
	MONTANA POWER STATION UNIT 2	275,751	3.43%	9,456	2.29%	6,318	-1.14%	-3,138
	MONTANA POWER STATION UNIT 3	229,358	3.51%	8,043	2.29%	5,262	-1.22%	-2,781
	MONTANA POWER STATION UNIT 4	231,228	3.55%	8,204	2.32%	5,366	-1.23%	-2,838
	MONTANA POWER STATION COMMON	740,931	3.22%	23,861	2.12%	15,730	-1.10%	-8,131
	Total Account 346.00	6,355,521	1.35%	85,795	0.97%	61,496	-0.38%	-24,299
	Total Gas Turbine Plant	518,021,063	3.71%	19,226,357	2.73%	14,136,554	-0.98%	-5,089,803
	TRANSMISSION PLANT							
350.10	LAND RIGHTS	18,917,746	1.02%	192,753	1.02%	192,848	0.00%	95
350.10	LAND RIGHTS - ISLETA	16,824,156	3.79%	636,818	3.79%	636,818	0.00%	0
352.00	STRUCTURES AND IMPROVEMENTS	12,463,443	1.16%	144,867	1.16%	144,810	0.00%	-57
353.00	STATION EQUIPMENT	188,643,566	1.56%	2,948,962	1.40%	2,647,195	-0.16%	-301,767
354.00	STEEL TOWERS AND FIXTURES	30,170,782	1.19%	359,891	1.19%	359,839	0.00%	-52
355.00	WOOD AND STEEL POLES	163,484,540	1.91%	3,115,165	1.79%	2,918,845	-0.12%	-196,320
356.00	OVERHEAD CONDUCTORS AND DEVICES	98,265,749	1.61%	1,579,563	1.35%	1,329,527	-0.26%	-250,036
359.00	ROADS AND TRAILS	3,573,353	1.28%	45,874	1.28%	45,905	0.00%	31

Detailed Rate Comparison

		[1]	[2]		[3]		[4]	
			Company Proposal		Garrett Proposal		Difference	
Account No.	Description	Plant 12/31/2019	Rate	Annual Accrual	Rate	Annual Accrual	Rate	Annual Accrual
	Total Transmission Plant	532,343,334	1.70%	9,023,893	1.55%	8,275,788	-0.14%	-748,105
	DISTRIBUTION PLANT							
360.10	LAND RIGHTS	2,578,795	1.32%	33,963	1.32%	33,955	0.00%	-8
361.00	STRUCTURES AND IMPROVEMENTS	21,788,555	1.46%	317,742	1.46%	317,870	0.00%	128
362.00	STATION EQUIPMENT	287,622,780	1.43%	4,102,971	1.24%	3,568,711	-0.19%	-534,260
364.00	POLES, TOWERS AND FIXTURES	183,367,772	3.11%	5,697,660	2.94%	5,396,941	-0.17%	-300,719
365.00	OVERHEAD CONDUCTORS AND DEVICES	117,036,296	2.35%	2,747,955	2.35%	2,749,335	0.00%	1,380
366.00	UNDERGROUND CONDUIT	141,830,292	1.50%	2,124,461	1.27%	1,804,272	-0.23%	-320,189
367.00	UNDERGROUND CONDUCTORS AND DEVICES	166,797,046	3.07%	5,117,534	3.07%	5,117,987	0.00%	453
368.00	LINE TRANSFORMERS	283,609,012	2.34%	6,629,377	2.21%	6,260,694	-0.13%	-368,683
369.00	SERVICES	56,297,452	1.38%	779,571	1.08%	607,181	-0.30%	-172,390
370.00	METERS	61,010,255	2.62%	1,598,992	2.62%	1,596,396	0.00%	-2,596
371.00	INSTALLATIONS ON CUSTOMERS' PREMISES	14,098,584	3.22%	454,004	3.22%	453,868	0.00%	-136
373.00	STREET LIGHTING AND SIGNAL SYSTEMS	11,751,010	2.06%	242,324	2.06%	242,411	0.00%	87
	Total Distribution Plant	1,347,787,849	2.21%	29,846,554	2.09%	28,149,622	-0.13%	-1,696,932
	GENERAL PLANT							
390.00	STRUCTURES AND IMPROVEMENTS							
	SYSTEMS OPERATIONS BUILDING	15,318,735	3.66%	560,769	3.66%	561,272	0.00%	503
	STANTON TOWER	38,933,123	2.30%	896,927	2.30%	896,115	0.00%	-812
	EASTSIDE OPERATIONS CENTER	42,631,420	2.11%	898,410	2.11%	897,875	0.00%	-535
	OTHER STRUCTURES	17,628,831	2.97%	524,165	2.97%	524,014	0.00%	-151
	Total Account 390.00	114,512,108	2.52%	2,880,271	2.51%	2,879,276	0.00%	-995
391.00	OFFICE FURNITURE AND EQUIPMENT	6,751,956	0.49%	32,752	0.49%	32,779	0.00%	27
393.00	STORES EQUIPMENT	53,348	0.37%	195	0.37%	196	0.00%	1
394.00	TOOLS, SHOP AND GARAGE EQUIPMENT	5,680,076	3.44%	195,583	3.44%	195,258	0.00%	-325
395.00	LABORATORY EQUIPMENT	5,226,132	6.65%	347,704	6.68%	349,056	0.03%	1,352
396.00	POWER OPERATED EQUIPMENT	4,300,329	3.86%	165,782	3.85%	165,754	-0.01%	-28
397.00	COMMUNICATION EQUIPMENT	30,616,208	8.43%	2,580,060	8.48%	2,595,737	0.05%	15,677
398.00	MISCELLANEOUS EQUIPMENT	4,575,362	8.72%	398,847	8.71%	398,711	-0.01%	-136

Detailed Rate Comparison

		[1]	[2]		[3]		[4]	
			Company Proposal		Garrett Proposal		Difference	
Account No.	Description	Plant 12/31/2019	Rate	Annual Accrual	Rate	Annual Accrual	Rate	Annual Accrual
	Total General Plant	171,715,519	3.84%	6,601,194	3.85%	6,616,766	0.01%	15,572
	TOTAL DEPRECIABLE PLANT	**$ 3,135,323,480**	**2.74%**	**$ 86,024,360**	**2.38%**	**$ 74,731,009**	**-0.36%**	**$ (11,293,351)**

[1], [2] From depreciation study
[3] From Depreciation Rate Development exhibit
[4] = [3] - [2]

Depreciation Rate Development

Account No.	Description	[1] Plant 12/31/2019	[2] Iowa Curve Type	AL	[3] Net Salvage	[4] Depreciable Base	[5] Book Reserve	[6] Future Accruals	[7] Remaining Life	[8] Service Life Accrual	[9] Service Life Rate	[10] Net Salvage Accrual	[11] Net Salvage Rate	[12] Total Accrual	[13] Total Rate
	STEAM PRODUCTION PLANT														
311.00	STRUCTURES AND IMPROVEMENTS														
	RIO GRANDE UNIT 6	1,290,817	R3	100	-5.0%	1,355,358	1,281,328	74,030	2.00	4,744	0.37%	32,270	2.50%	37,015	**2.87%**
	RIO GRANDE UNIT 7	1,269,983	R3	100	-5.0%	1,333,482	1,269,984	63,498	3.00	0	0.00%	21,166	1.67%	21,166	**1.67%**
	RIO GRANDE UNIT 8	2,311,211	R3	100	-5.0%	2,426,772	1,828,321	598,451	13.90	34,740	1.50%	8,314	0.36%	43,054	**1.86%**
	RIO GRANDE COMMON	4,433,409	R3	100	-5.0%	4,655,079	894,702	3,760,378	14.00	252,765	5.70%	15,834	0.36%	268,598	**6.06%**
	NEWMAN UNIT 1	1,269,946	R3	100	-5.0%	1,333,444	1,283,433	50,011	3.00	-4,495	-0.35%	21,166	1.67%	16,670	**1.31%**
	NEWMAN UNIT 2	1,035,405	R3	100	-5.0%	1,087,175	748,238	338,937	3.00	95,722	9.24%	17,257	1.67%	112,979	**10.91%**
	NEWMAN UNIT 3	1,097,187	R3	100	-5.0%	1,152,046	834,174	317,872	7.00	37,573	3.42%	7,837	0.71%	45,410	**4.14%**
	NEWMAN UNIT 4	15,848,533	R3	100	-5.0%	16,640,960	9,933,049	6,707,911	6.90	857,317	5.41%	114,844	0.72%	972,161	**6.13%**
	NEWMAN UNIT 5	25,932,328	R3	100	-5.0%	27,228,945	6,104,581	21,124,364	40.70	487,168	1.88%	31,858	0.12%	519,026	**2.00%**
	NEWMAN COMMON	18,900,582	R3	100	-5.0%	19,845,611	1,025,528	18,820,083	41.01	435,871	2.31%	23,044	0.12%	458,914	**2.43%**
	Total Account 311.00	73,389,401			-5.0%	77,058,871	25,203,337	51,855,534	20.78	2,201,405	3.00%	293,590	0.40%	2,494,995	**3.40%**
312.00	BOILER PLANT EQUIPMENT														
	RIO GRANDE UNIT 6	2,973,008	R4	70	-5.0%	3,121,658	3,121,658	0	0.00						
	RIO GRANDE UNIT 7	4,604,495	R4	70	-5.0%	4,834,720	4,604,496	230,224	3.00	0	0.00%	76,742	1.67%	76,741	**1.67%**
	RIO GRANDE UNIT 8	15,577,498	R4	70	-5.0%	16,356,372	10,665,565	5,690,807	13.90	353,376	2.27%	56,034	0.36%	409,411	**2.63%**
	RIO GRANDE COMMON	939,445	R4	70	-5.0%	986,417	267,650	718,767	14.00	47,985	5.11%	3,355	0.36%	51,341	**5.46%**
	NEWMAN UNIT 1	8,696,638	R4	70	-5.0%	9,131,469	7,905,587	1,225,882	3.00	263,683	3.03%	144,944	1.67%	408,627	**4.70%**
	NEWMAN UNIT 2	8,916,414	R4	70	-5.0%	9,362,235	5,846,465	3,515,769	3.00	1,023,316	11.48%	148,607	1.67%	1,171,923	**13.14%**
	NEWMAN UNIT 3	6,743,234	R4	70	-5.0%	7,080,396	4,948,440	2,131,957	7.00	256,399	3.80%	48,166	0.71%	304,565	**4.52%**
	NEWMAN UNIT 4	3,303,062	R4	70	-5.0%	3,468,215	1,706,224	1,761,991	7.00	228,120	6.91%	23,593	0.71%	251,713	**7.62%**
	NEWMAN UNIT 5	112,841,612	R4	70	-5.0%	118,483,692	28,281,943	90,201,749	40.65	2,080,189	1.84%	138,797	0.12%	2,218,985	**1.97%**
	NEWMAN COMMON	6,752,670	R4	70	-5.0%	7,090,304	715,753	6,374,551	40.91	147,566	2.19%	8,253	0.12%	155,819	**2.31%**
	Total Account 312.00	171,348,075			-5.0%	179,915,479	68,063,781	111,851,698	22.15	4,400,635	2.57%	648,491	0.38%	5,049,125	**2.95%**
313.00	ENGINES AND ENGINE-DRIVEN GENERATORS														
	NEWMAN UNIT 1	327,497	R2.5	55	0.0%	327,497	327,497	0	0.00						
	NEWMAN UNIT 4	24,780,032	R2.5	55	0.0%	24,780,032	12,500,053	12,279,980	6.90	1,779,707	7.18%	0	0.00%	1,779,707	**7.18%**
	NEWMAN UNIT 5	48,432,717	R2.5	55	0.0%	48,432,717	5,328,814	43,103,903	36.91	1,167,811	2.41%	0	0.00%	1,167,811	**2.41%**
	Total Account 313.00	73,540,247			0.0%	73,540,247	18,156,364	55,383,883	18.79	2,947,518	4.01%	0	0.00%	2,947,518	**4.01%**
314.00	TURBOGENERATOR UNITS														
	RIO GRANDE UNIT 6	3,559,998	R2.5	75	-5.0%	3,737,998	3,734,067	3,931	2.00	-87,035	-2.44%	89,000	2.50%	1,965	**0.06%**
	RIO GRANDE UNIT 7	4,204,367	R2.5	75	-5.0%	4,414,586	4,117,514	297,071	3.00	28,951	0.69%	70,073	1.67%	99,024	**2.36%**
	RIO GRANDE UNIT 8	11,776,648	R2.5	75	-5.0%	12,365,480	9,445,338	2,920,142	13.70	170,169	1.44%	42,980	0.36%	213,149	**1.81%**
	NEWMAN UNIT 1	13,716,383	R2.5	75	-5.0%	14,402,203	11,516,540	2,885,663	3.00	733,281	5.35%	228,606	1.67%	961,888	**7.01%**
	NEWMAN UNIT 2	11,439,310	R2.5	75	-5.0%	12,011,275	9,493,772	2,517,503	3.00	648,513	5.67%	190,655	1.67%	839,168	**7.34%**
	NEWMAN UNIT 3	12,089,865	R2.5	75	-5.0%	12,694,358	6,855,613	5,838,746	7.00	747,750	6.18%	86,356	0.71%	834,107	**6.90%**
	NEWMAN UNIT 4	33,968,975	R2.5	75	-5.0%	35,667,423	30,609,768	5,057,655	7.00	479,887	1.41%	242,636	0.71%	722,522	**2.13%**
	NEWMAN UNIT 5	61,650,972	R2.5	75	-5.0%	64,733,521	9,414,378	55,319,143	39.51	1,322,111	2.14%	78,019	0.13%	1,400,130	**2.27%**
	NEWMAN COMMON	58,097	R2.5	75	-5.0%	61,002	107,629	-46,628	0.00						
	Total Account 314.00	152,464,615			-5.0%	160,087,846	85,294,619	74,793,227	14.75	4,043,626	2.65%	1,028,326	0.67%	5,071,952	**3.33%**
315.00	ACCESSORY ELECTRIC EQUIPMENT														
	RIO GRANDE UNIT 6	784,259	S4	65	-5.0%	823,472	739,032	84,440	1.90	23,804	3.04%	20,638	2.63%	44,442	**5.67%**
	RIO GRANDE UNIT 7	856,688	S4	65	-5.0%	899,522	646,912	252,610	3.00	69,925	8.16%	14,278	1.67%	84,203	**9.83%**
	RIO GRANDE UNIT 8	6,535,523	S4	65	-5.0%	6,862,299	2,002,447	4,859,852	14.00	323,791	4.95%	23,341	0.36%	347,132	**5.31%**
	NEWMAN UNIT 1	1,148,175	S4	65	-5.0%	1,205,584	1,147,547	58,037	2.90	217	0.02%	19,796	1.72%	20,013	**1.74%**
	NEWMAN UNIT 2	1,052,955	S4	65	-5.0%	1,105,603	1,052,959	52,644	2.90	-1	0.00%	18,154	1.72%	18,153	**1.72%**
	NEWMAN UNIT 3	1,150,892	S4	65	-5.0%	1,208,437	785,370	423,067	6.80	53,753	4.67%	8,462	0.74%	62,216	**5.41%**
	NEWMAN UNIT 4	6,332,763	S4	65	-5.0%	6,649,401	6,332,739	316,662	6.80	3	0.00%	46,564	0.74%	46,568	**0.74%**
	NEWMAN UNIT 5	24,098,577	S4	65	-5.0%	25,303,506	5,716,844	19,586,662	41.05	447,789	1.86%	29,353	0.12%	477,142	**1.98%**
	NEWMAN COMMON	157,237	S4	65	-5.0%	165,098	4	165,095	41.43	3,795	2.41%	190	0.12%	3,985	**2.53%**
	Total Account 315.00	42,117,069			-5.0%	44,222,922	18,423,853	25,799,069	23.37	923,077	2.19%	180,778	0.43%	1,103,854	**2.62%**
316.00	MISCELLANEOUS POWER PLANT EQUIPMENT														
	RIO GRANDE UNIT 6	1,489,364	S2.5	70	-5.0%	1,563,832	1,489,365	74,467	2.00	-1	0.00%	37,234	2.50%	37,234	**2.50%**
	RIO GRANDE UNIT 7	1,851,433	S2.5	70	-5.0%	1,944,004	1,896,993	47,011	3.00	-15,187	-0.82%	30,857	1.67%	15,670	**0.85%**
	RIO GRANDE UNIT 8	5,951,707	S2.5	70	-5.0%	6,249,293	4,746,012	1,503,280	13.80	87,369	1.47%	21,564	0.36%	108,933	**1.83%**
	RIO GRANDE COMMON	1,938,696	S2.5	70	-5.0%	2,035,631	799,702	1,235,929	14.00	81,357	4.20%	6,924	0.36%	88,281	**4.55%**

Depreciation Rate Development

		[1]	[2]		[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]
			Iowa Curve							Service Life		Net Salvage		Total	
Account No.	Description	Plant 12/31/2019	Type	AL	Net Salvage	Depreciable Base	Book Reserve	Future Accruals	Remaining Life	Accrual	Rate	Accrual	Rate	Accrual	Rate
	NEWMAN UNIT 1	2,177,691	S2.5	70	-5.0%	2,286,576	2,176,490	110,085	3.00	400	0.02%	36,295	1.67%	36,695	**1.69%**
	NEWMAN UNIT 2	2,829,108	S2.5	70	-5.0%	2,970,564	2,829,106	141,458	3.00	1	0.00%	47,152	1.67%	47,153	**1.67%**
	NEWMAN UNIT 3	5,645,296	S2.5	70	-5.0%	5,927,561	5,395,175	532,386	7.00	35,732	0.63%	40,324	0.71%	76,055	**1.35%**
	NEWMAN UNIT 4	11,495,252	S2.5	70	-5.0%	12,070,014	11,495,252	574,762	7.00	0	0.00%	82,109	0.71%	82,109	**0.71%**
	NEWMAN UNIT 5	1,771,257	S2.5	70	-5.0%	1,859,820	773,576	1,086,244	39.15	25,484	1.44%	2,262	0.13%	27,746	**1.57%**
	NEWMAN ZERO LIQUID DISCHARGE	14,375,574	S2.5	70	-5.0%	15,094,353	3,273,166	11,821,187	39.43	281,573	1.96%	18,229	0.13%	299,802	**2.09%**
	NEWMAN COMMON	3,070,930	S2.5	70	-5.0%	3,224,476	657,238	2,567,238	39.40	61,261	1.99%	3,897	0.13%	65,158	**2.12%**
	Total Account 316.00	52,596,308			-5.0%	55,226,124	35,532,076	19,694,048	22.26	557,989	1.06%	326,847	0.62%	884,836	**1.68%**
	Total Steam Production Plant	565,455,715			-4.3%	590,051,488	250,674,029	339,377,459	19.34	15,074,249	2.67%	2,478,031	0.44%	17,552,280	**3.10%**
	GAS TURBINE PLANT														
341.00	STRUCTURES AND IMPROVEMENTS														
	COPPER POWER STATION	791,864	R4	60	0.0%	791,864	676,484	115,380	10.90	10,585	1.34%	0	0.00%	10,585	**1.34%**
	RIO GRANDE UNIT 9	22,158,133	R4	60	0.0%	22,158,133	2,511,851	19,646,282	37.51	523,761	2.36%	0	0.00%	523,761	**2.36%**
	MONTANA POWER STATION UNIT 1	315,347	R4	60	0.0%	315,347	29,788	285,559	39.85	7,166	2.27%	0	0.00%	7,166	**2.27%**
	MONTANA POWER STATION UNIT 2	257,181	R4	60	0.0%	257,181	24,321	232,860	39.88	5,839	2.27%	0	0.00%	5,839	**2.27%**
	MONTANA POWER STATION UNIT 3	206,815	R4	60	0.0%	206,815	18,930	187,885	40.80	4,605	2.23%	0	0.00%	4,605	**2.23%**
	MONTANA POWER STATION UNIT 4	237,486	R4	60	0.0%	237,486	19,541	217,945	40.79	5,343	2.25%	0	0.00%	5,343	**2.25%**
	MONTANA POWER STATION COMMON	18,007,977	R4	60	0.0%	18,007,977	1,381,319	16,626,658	40.51	410,433	2.28%	0	0.00%	410,433	**2.28%**
	SOLAR FACILITIES	91,868	R4	60	0.0%	91,868	28,369	63,499	14.30	4,440	4.83%	0	0.00%	4,440	**4.83%**
	Total Account 341.00	42,066,673			0.0%	42,066,673	4,690,603	37,376,069	38.45	972,173	2.31%	0	0.00%	972,173	**2.31%**
342.00	FUEL HOLDERS														
	COPPER POWER STATION	511,691	R4	50	0.0%	511,691	480,918	30,773	10.60	2,903	0.57%	0	0.00%	2,903	**0.57%**
	RIO GRANDE UNIT 9	3,768,778	R4	50	0.0%	3,768,778	541,045	3,227,734	36.40	88,674	2.35%	0	0.00%	88,674	**2.35%**
	MONTANA POWER STATION COMMON	20,877,428	R4	50	0.0%	20,877,428	1,344,928	19,532,500	39.35	496,379	2.38%	0	0.00%	496,379	**2.38%**
	Total Account 342.00	25,157,897			0.0%	25,157,897	2,366,890	22,791,006	38.76	587,956	2.34%	0	0.00%	587,956	**2.34%**
343.00	PRIME MOVERS														
	RIO GRANDE UNIT 9	59,555,058	S1	40	0.0%	59,555,058	8,957,443	50,597,615	29.67	1,705,346	2.86%	0	0.00%	1,705,346	**2.86%**
	MONTANA POWER STATION UNIT 1	78,609,841	S1	40	0.0%	78,609,841	8,434,351	70,175,490	32.15	2,182,752	2.78%	0	0.00%	2,182,752	**2.78%**
	MONTANA POWER STATION UNIT 2	73,503,725	S1	40	0.0%	73,503,725	7,883,880	65,619,845	32.08	2,045,506	2.78%	0	0.00%	2,045,506	**2.78%**
	MONTANA POWER STATION UNIT 3	63,009,557	S1	40	0.0%	63,009,557	5,360,075	57,649,482	32.68	1,764,060	2.80%	0	0.00%	1,764,060	**2.80%**
	MONTANA POWER STATION UNIT 4	62,425,439	S1	40	0.0%	62,425,439	4,746,607	57,678,832	32.70	1,763,879	2.83%	0	0.00%	1,763,879	**2.83%**
	MONTANA POWER STATION COMMON	34,687,535	S1	40	0.0%	34,687,535	3,863,968	30,823,567	31.99	963,538	2.78%	0	0.00%	963,538	**2.78%**
	Total Account 343.00	371,791,155			0.0%	371,791,155	39,246,324	332,544,832	31.90	10,425,081	2.80%	0	0.00%	10,425,081	**2.80%**
344.00	GENERATORS														
	COPPER POWER STATION	10,369,392	S3	45	0.0%	10,369,392	6,437,801	3,931,591	10.80	364,036	3.51%	0	0.00%	364,036	**3.51%**
	RIO GRANDE UNIT 9	8,420,577	S3	45	0.0%	8,420,577	977,806	7,442,771	34.53	215,545	2.56%	0	0.00%	215,545	**2.56%**
	MONTANA POWER STATION UNIT 1	6,122,691	S3	45	0.0%	6,122,691	398,681	5,724,010	36.54	156,651	2.56%	0	0.00%	156,651	**2.56%**
	MONTANA POWER STATION UNIT 2	6,122,691	S3	45	0.0%	6,122,691	405,064	5,717,627	36.52	156,562	2.56%	0	0.00%	156,562	**2.56%**
	MONTANA POWER STATION UNIT 3	6,241,096	S3	45	0.0%	6,241,096	459,179	5,781,917	37.43	154,473	2.48%	0	0.00%	154,473	**2.48%**
	MONTANA POWER STATION UNIT 4	6,126,228	S3	45	0.0%	6,126,228	416,026	5,710,202	37.42	152,598	2.49%	0	0.00%	152,598	**2.49%**
	MONTANA POWER STATION COMMON	63	S3	45	0.0%	63	10	53	36.36	1	2.31%	0	0.00%	1	**2.31%**
	SOLAR FACILITIES	1,187,262	S2.5	25	0.0%	1,187,262	367,724	819,538	13.20	62,086	5.23%	0	0.00%	62,086	**5.23%**
	Total Account 344.00	44,590,001			0.0%	44,590,001	9,462,291	35,127,709	27.84	1,261,951	2.83%	0	0.00%	1,261,951	**2.83%**
345.00	ACCESSORY ELECTRIC EQUIPMENT														
	COPPER POWER STATION	2,306,861	S1.5	45	0.0%	2,306,861	649,418	1,657,443	10.80	153,467	6.65%	0	0.00%	153,467	**6.65%**
	RIO GRANDE UNIT 9	5,186,611	S1.5	45	0.0%	5,186,611	834,096	4,352,515	32.23	135,045	2.60%	0	0.00%	135,045	**2.60%**
	MONTANA POWER STATION UNIT 1	3,115,518	S1.5	45	0.0%	3,115,518	271,887	2,843,632	34.53	82,352	2.64%	0	0.00%	82,352	**2.64%**
	MONTANA POWER STATION UNIT 2	3,029,962	S1.5	45	0.0%	3,029,962	269,436	2,760,527	34.50	80,015	2.64%	0	0.00%	80,015	**2.64%**
	MONTANA POWER STATION UNIT 3	2,686,650	S1.5	45	0.0%	2,686,650	192,777	2,493,873	35.25	70,748	2.63%	0	0.00%	70,748	**2.63%**
	MONTANA POWER STATION UNIT 4	2,250,774	S1.5	45	0.0%	2,250,774	138,436	2,112,338	35.31	59,823	2.66%	0	0.00%	59,823	**2.66%**
	MONTANA POWER STATION COMMON	9,316,081	S1.5	45	0.0%	9,316,081	1,059,360	8,256,721	34.75	237,603	2.55%	0	0.00%	237,603	**2.55%**
	SOLAR FACILITIES	167,360	S1.5	45	0.0%	167,360	53,304	114,056	12.90	8,842	5.28%	0	0.00%	8,842	**5.28%**
	Total Account 345.00	28,059,816			0.0%	28,059,816	3,468,713	24,591,104	29.70	827,896	2.95%	0	0.00%	827,896	**2.95%**

Depreciation Rate Development

Account No.	Description	[1] Plant 12/31/2019	[2] Iowa Curve Type	AL	[3] Net Salvage	[4] Depreciable Base	[5] Book Reserve	[6] Future Accruals	[7] Remaining Life	[8] Service Life Accrual	[9] Rate	[10] Net Salvage Accrual	[11] Rate	[12] Total Accrual	[13] Rate
346.00	MISCELLANEOUS POWER PLANT EQUIPMENT														
	COPPER POWER STATION	4,170,624	R4	50	0.0%	4,170,624	4,034,370	136,254	11.00	12,387	0.30%	0	0.00%	12,387	**0.30%**
	RIO GRANDE UNIT 9	410,060	R4	50	0.0%	410,060	62,171	347,889	36.31	9,581	2.34%	0	0.00%	9,581	**2.34%**
	MONTANA POWER STATION UNIT 1	297,569	R4	50	0.0%	297,569	32,999	264,570	38.61	6,852	2.30%	0	0.00%	6,852	**2.30%**
	MONTANA POWER STATION UNIT 2	275,751	R4	50	0.0%	275,751	31,927	243,823	38.59	6,318	2.29%	0	0.00%	6,318	**2.29%**
	MONTANA POWER STATION UNIT 3	229,358	R4	50	0.0%	229,358	21,831	207,528	39.44	5,262	2.29%	0	0.00%	5,262	**2.29%**
	MONTANA POWER STATION UNIT 4	231,228	R4	50	0.0%	231,228	19,538	211,690	39.45	5,366	2.32%	0	0.00%	5,366	**2.32%**
	MONTANA POWER STATION COMMON	740,931	R4	50	0.0%	740,931	126,522	614,409	39.06	15,730	2.12%	0	0.00%	15,730	**2.12%**
	Total Account 346.00	6,355,521			0.0%	6,355,521	4,329,358	2,026,163	32.95	61,496	0.97%	0	0.00%	61,496	**0.97%**
	Total Gas Turbine Plant	518,021,063			0.0%	518,021,063	63,564,180	454,456,883	32.15	14,136,554	2.73%	0	0.00%	14,136,554	**2.73%**
	TRANSMISSION PLANT														
350.10	LAND RIGHTS	18,917,746	R3	80	0.0%	18,917,746	6,016,208	12,901,538	66.90	192,848	1.02%	0	0.00%	192,848	**1.02%**
350.10	LAND RIGHTS - ISLETA	16,824,156	SQ		0.0%	16,824,156	1,540,524	15,283,632	24.00	636,818	3.79%	0	0.00%	636,818	**3.79%**
352.00	STRUCTURES AND IMPROVEMENTS	12,463,443	R4	75	-5.0%	13,086,615	4,224,229	8,862,386	61.20	134,628	1.08%	10,183	0.08%	144,810	**1.16%**
353.00	STATION EQUIPMENT	188,643,566	R3	58	-5.0%	198,075,744	88,164,203	109,911,541	41.52	2,420,023	1.28%	227,172	0.12%	2,647,195	**1.40%**
354.00	STEEL TOWERS AND FIXTURES	30,170,782	R4	75	-10.0%	33,187,860	14,800,075	18,387,784	51.10	300,797	1.00%	59,043	0.20%	359,839	**1.19%**
355.00	WOOD AND STEEL POLES	163,484,540	S3	55	-15.0%	188,007,221	64,248,195	123,759,026	42.40	2,340,480	1.43%	578,365	0.35%	2,918,845	**1.79%**
356.00	OVERHEAD CONDUCTORS AND DEVICES	98,265,749	R4	65	-10.0%	108,092,324	54,924,539	53,167,785	39.99	1,083,801	1.10%	245,726	0.25%	1,329,527	**1.35%**
359.00	ROADS AND TRAILS	3,573,353	R3	70	0.0%	3,573,353	662,951	2,910,402	63.40	45,905	1.28%	0	0.00%	45,905	**1.28%**
	Total Transmission Plant	532,343,334			-8.9%	579,765,018	234,580,925	345,184,094	41.71	7,155,300	1.34%	1,120,488	0.21%	8,275,788	**1.55%**
	DISTRIBUTION PLANT														
360.10	LAND RIGHTS	2,578,795	R4	70	0.0%	2,578,795	622,987	1,955,808	57.60	33,955	1.32%	0	0.00%	33,955	**1.32%**
361.00	STRUCTURES AND IMPROVEMENTS	21,788,555	R3	70	-5.0%	22,877,983	2,820,363	20,057,620	63.10	300,605	1.38%	17,265	0.08%	317,870	**1.46%**
362.00	STATION EQUIPMENT	287,622,780	R1.5	71	0.0%	287,622,780	70,431,015	217,191,765	60.86	3,568,711	1.24%	0	0.00%	3,568,711	**1.24%**
364.00	POLES, TOWERS AND FIXTURES	183,367,772	R3	45	-25.0%	229,209,715	61,904,538	167,305,177	31.00	3,918,169	2.14%	1,478,772	0.81%	5,396,941	**2.94%**
365.00	OVERHEAD CONDUCTORS AND DEVICES	117,036,296	R2.5	48	-15.0%	134,591,740	35,065,798	99,525,943	36.20	2,264,378	1.93%	484,957	0.41%	2,749,335	**2.35%**
366.00	UNDERGROUND CONDUIT	141,830,292	R4	71	0.0%	141,830,292	40,502,369	101,327,924	56.16	1,804,272	1.27%	0	0.00%	1,804,272	**1.27%**
367.00	UNDERGROUND CONDUCTORS AND DEVICES	166,797,046	S2	41	-20.0%	200,156,456	48,664,055	151,492,400	29.60	3,990,979	2.39%	1,127,007	0.68%	5,117,987	**3.07%**
368.00	LINE TRANSFORMERS	283,609,012	R3	52	-10.0%	311,969,913	67,802,856	244,167,057	39.00	5,533,491	1.95%	727,203	0.26%	6,260,694	**2.21%**
369.00	SERVICES	56,297,452	S3	65	0.0%	56,297,452	26,484,850	29,812,602	49.10	607,181	1.08%	0	0.00%	607,181	**1.08%**
370.00	METERS	61,010,255	R2.5	35	-15.0%	70,161,794	28,815,140	41,346,653	25.90	1,243,055	2.04%	353,341	0.58%	1,596,396	**2.62%**
371.00	INSTALLATIONS ON CUSTOMERS' PREMISES	14,098,584	R2	35	-15.0%	16,213,371	5,638,247	10,575,125	23.30	363,105	2.58%	90,763	0.64%	453,868	**3.22%**
373.00	STREET LIGHTING AND SIGNAL SYSTEMS	11,751,010	R3	55	-20.0%	14,101,212	6,077,418	8,023,794	33.10	171,408	1.46%	71,003	0.60%	242,411	**2.06%**
	Total Distribution Plant	1,347,787,849			-10.4%	1,487,611,503	394,829,634	1,092,781,869	38.82	23,799,310	1.77%	4,350,312	0.32%	28,149,622	**2.09%**
	GENERAL PLANT														
390.00	STRUCTURES AND IMPROVEMENTS														
	SYSTEMS OPERATIONS BUILDING	15,318,735	R2.5	80	0.0%	15,318,735	3,475,891	11,842,845	21.10	561,272	3.66%	0	0.00%	561,272	**3.66%**
	STANTON TOWER	38,933,123	R2.5	80	0.0%	38,933,123	5,776,854	33,156,269	37.00	896,115	2.30%	0	0.00%	896,115	**2.30%**
	EASTSIDE OPERATIONS CENTER	42,631,420	R2.5	80	0.0%	42,631,420	3,214,715	39,416,705	43.90	897,875	2.11%	0	0.00%	897,875	**2.11%**
	OTHER STRUCTURES	17,628,831	S0.5	40	0.0%	17,628,831	3,113,647	14,515,184	27.70	524,014	2.97%	0	0.00%	524,014	**2.97%**
	Total Account 390.00	114,512,108			0.0%	114,512,108	15,581,106	98,931,002	34.36	2,879,276	2.51%	0	0.00%	2,879,276	**2.51%**
391.00	OFFICE FURNITURE AND EQUIPMENT	6,751,956	SQ	20	0.0%	6,751,956	6,175,042	576,914	17.60	32,779	0.49%	0	0.00%	32,779	**0.49%**
393.00	STORES EQUIPMENT	53,348	SQ	25	0.0%	53,348	51,489	1,858	9.50	196	0.37%	0	0.00%	196	**0.37%**
394.00	TOOLS, SHOP AND GARAGE EQUIPMENT	5,680,076	SQ	25	0.0%	5,680,076	1,853,025	3,827,051	19.60	195,258	3.44%	0	0.00%	195,258	**3.44%**
395.00	LABORATORY EQUIPMENT	5,226,132	SQ	15	0.0%	5,226,132	1,910,104	3,316,028	9.50	349,056	6.68%	0	0.00%	349,056	**6.68%**
396.00	POWER OPERATED EQUIPMENT	4,300,329	R2.5	21	15.0%	3,655,279	1,036,366	2,618,914	15.80	206,580	4.80%	-40,826	-0.95%	165,754	**3.85%**
397.00	COMMUNICATION EQUIPMENT	30,616,208	SQ	15	0.0%	30,616,208	12,705,626	17,910,582	6.90	2,595,737	8.48%	0	0.00%	2,595,737	**8.48%**
398.00	MISCELLANEOUS EQUIPMENT	4,575,362	SQ	15	0.0%	4,575,362	1,385,677	3,189,685	8.00	398,711	8.71%	0	0.00%	398,711	**8.71%**
	Total General Plant	171,715,519			0.4%	171,070,469	40,698,436	130,372,033	19.70	6,657,591	3.88%	-40,826	-0.02%	6,616,766	**3.85%**
	TOTAL DEPRECIABLE PLANT	**$ 3,135,323,480**			**-6.7%**	**$ 3,346,519,542**	**$ 984,347,203**	**$ 2,362,172,338**	**31.61**	**$ 66,823,004**	**2.13%**	**$ 7,908,005**	**0.25%**	**$ 74,731,009**	**2.38%**

Depreciation Rate Development

		[1]	[2]		[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]
Account		Plant	Iowa Curve		Net	Depreciable	Book	Future	Remaining	Service Life		Net Salvage		Total	
No.	Description	12/31/2019	Type	AL	Salvage	Base	Reserve	Accruals	Life	Accrual	Rate	Accrual	Rate	Accrual	Rate

[1] From depreciation study
[2] Average life and Iowa curve shape developed through statistical analysis and professional judgment
[3] Mass net salvage rates developed through statistical analysis and professional judgment
[4] = [1]*(1-[3])
[5] From depreciation study
[6] = [4] - [5]
[7] Composite remaining life based on Iowa cuve in [2]; see remaining life exhibit for detailed calculations
[8] = ([1] - [5]) / [7]
[9] = [8] / [1]
[10] = [12] - [8]
[11] = [13] - [9]
[12] = [6] / [7]
[13] = [12] / [1]

Account 353 Curve Fitting

[1]	[2]	[3]	[4]	[5]	[6]	[7]
Age (Years)	**Exposures (Dollars)**	**Observed Life Table (OLT)**	**Company R4-50**	**Garrett R3-58**	**Company SSD**	**Garrett SSD**
0.0	124,971,285	100.00%	100.00%	100.00%	0.0000	0.0000
0.5	123,285,263	100.00%	100.00%	99.99%	0.0000	0.0000
1.5	119,973,354	100.00%	100.00%	99.96%	0.0000	0.0000
2.5	114,067,017	100.00%	99.99%	99.92%	0.0000	0.0000
3.5	106,098,721	99.99%	99.99%	99.88%	0.0000	0.0000
4.5	98,012,081	99.99%	99.99%	99.84%	0.0000	0.0000
5.5	98,507,346	99.98%	99.98%	99.79%	0.0000	0.0000
6.5	93,945,324	99.68%	99.97%	99.73%	0.0000	0.0000
7.5	90,095,080	99.68%	99.96%	99.66%	0.0000	0.0000
8.5	108,423,856	99.68%	99.95%	99.59%	0.0000	0.0000
9.5	107,733,043	99.68%	99.93%	99.51%	0.0000	0.0000
10.5	99,773,471	99.51%	99.91%	99.41%	0.0000	0.0000
11.5	87,162,295	99.45%	99.88%	99.31%	0.0000	0.0000
12.5	88,268,362	99.41%	99.85%	99.19%	0.0000	0.0000
13.5	87,576,947	99.34%	99.81%	99.06%	0.0000	0.0000
14.5	91,177,671	99.34%	99.76%	98.92%	0.0000	0.0000
15.5	89,422,538	99.06%	99.70%	98.76%	0.0000	0.0000
16.5	81,791,927	99.03%	99.62%	98.59%	0.0000	0.0000
17.5	80,820,992	99.03%	99.53%	98.39%	0.0000	0.0000
18.5	81,053,283	99.01%	99.43%	98.18%	0.0000	0.0001
19.5	76,601,021	99.01%	99.30%	97.95%	0.0000	0.0001
20.5	77,068,074	98.20%	99.14%	97.70%	0.0001	0.0000
21.5	77,510,512	98.20%	98.96%	97.42%	0.0001	0.0001
22.5	70,282,388	98.06%	98.75%	97.12%	0.0000	0.0001
23.5	70,034,193	97.83%	98.50%	96.79%	0.0000	0.0001
24.5	68,442,289	96.09%	98.20%	96.44%	0.0004	0.0000
25.5	67,603,103	96.06%	97.87%	96.06%	0.0003	0.0000
26.5	66,668,069	94.73%	97.47%	95.64%	0.0008	0.0001
27.5	66,330,609	94.60%	97.02%	95.20%	0.0006	0.0000
28.5	65,772,107	94.49%	96.51%	94.72%	0.0004	0.0000
29.5	64,567,954	94.49%	95.92%	94.20%	0.0002	0.0000
30.5	46,253,006	94.48%	95.25%	93.65%	0.0001	0.0001
31.5	46,137,531	94.32%	94.50%	93.06%	0.0000	0.0002
32.5	42,338,532	94.18%	93.65%	92.42%	0.0000	0.0003
33.5	41,712,188	93.60%	92.70%	91.75%	0.0001	0.0003
34.5	41,239,758	93.54%	91.65%	91.02%	0.0004	0.0006
35.5	10,632,523	92.47%	90.48%	90.25%	0.0004	0.0005
36.5	10,564,176	92.47%	89.18%	89.43%	0.0011	0.0009
37.5	9,990,821	91.60%	87.76%	88.56%	0.0015	0.0009
38.5	9,522,704	91.48%	86.20%	87.63%	0.0028	0.0015
39.5	7,704,316	90.82%	84.51%	86.65%	0.0040	0.0017
40.5	7,408,332	89.36%	82.67%	85.60%	0.0045	0.0014
41.5	4,031,385	86.73%	80.69%	84.49%	0.0037	0.0005
42.5	3,951,237	85.00%	78.55%	83.31%	0.0042	0.0003
43.5	3,291,692	85.00%	76.25%	82.07%	0.0076	0.0009
44.5	3,279,082	85.00%	73.76%	80.74%	0.0126	0.0018
45.5	2,821,871	85.00%	71.02%	79.35%	0.0195	0.0032
46.5	1,991,746	85.00%	68.03%	77.88%	0.0288	0.0051

Account 353 Curve Fitting

[1]	[2]	[3]	[4]	[5]	[6]	[7]
Age (Years)	**Exposures (Dollars)**	**Observed Life Table (OLT)**	**Company R4-50**	**Garrett R3-58**	**Company SSD**	**Garrett SSD**
47.5	526,623	85.00%	64.75%	76.32%	0.0410	0.0075
48.5	0	85.00%	61.20%	74.68%	0.0567	0.0107
49.5	0	85.00%	57.38%	72.95%	0.0763	0.0145
50.5			53.33%	71.14%		
Sum of Squared Differences				[8]	0.2684	0.0537
Up to 1% of Beginning Exposures				[9]	0.0944	0.0209

[1] Age in years using half-year convention

[2] Dollars exposed to retirement at the beginning of each age interval

[3] Observed life table based on the Company's property records. These numbers form the original survivor curve.

[4] The Company's selected Iowa curve to be fitted to the OLT.

[5] My selected Iowa curve to be fitted to the OLT.

[6] = ([4] - [3])^2. This is the squared difference between each point on the Company's curve and the observed survivor curve.

[7] = ([5] - [3])^2. This is the squared difference between each point on my curve and the observed survivor curve.

[8] = Sum of squared differences. The smallest SSD represents the best mathematical fit.

Account 356 Curve Fitting

[1] Age (Years)	[2] Exposures (Dollars)	[3] Observed Life Table (OLT)	[4] Company R5-60	[5] Garrett R4-65	[6] Company SSD	[7] Garrett SSD
0.0	37,130,703	100.00%	100.00%	100.00%	0.0000	0.0000
0.5	36,274,644	100.00%	100.00%	100.00%	0.0000	0.0000
1.5	36,881,807	100.00%	100.00%	100.00%	0.0000	0.0000
2.5	36,735,606	100.00%	100.00%	100.00%	0.0000	0.0000
3.5	63,229,141	100.00%	100.00%	99.99%	0.0000	0.0000
4.5	56,982,661	100.00%	100.00%	99.99%	0.0000	0.0000
5.5	57,783,965	99.99%	100.00%	99.99%	0.0000	0.0000
6.5	52,500,290	99.99%	100.00%	99.98%	0.0000	0.0000
7.5	52,548,878	99.99%	100.00%	99.98%	0.0000	0.0000
8.5	62,700,553	99.99%	100.00%	99.97%	0.0000	0.0000
9.5	62,310,752	99.96%	100.00%	99.96%	0.0000	0.0000
10.5	61,916,385	99.96%	100.00%	99.95%	0.0000	0.0000
11.5	57,020,862	99.93%	100.00%	99.94%	0.0000	0.0000
12.5	57,295,950	99.93%	100.00%	99.93%	0.0000	0.0000
13.5	57,409,383	99.93%	100.00%	99.91%	0.0000	0.0000
14.5	63,722,385	99.93%	100.00%	99.89%	0.0000	0.0000
15.5	62,164,974	99.93%	100.00%	99.87%	0.0000	0.0000
16.5	61,816,251	99.91%	100.00%	99.84%	0.0000	0.0000
17.5	62,027,451	99.91%	100.00%	99.81%	0.0000	0.0000
18.5	62,128,749	99.91%	100.00%	99.77%	0.0000	0.0000
19.5	62,079,752	99.91%	100.00%	99.73%	0.0000	0.0000
20.5	61,975,597	99.91%	100.00%	99.68%	0.0000	0.0000
21.5	61,350,363	99.90%	100.00%	99.62%	0.0000	0.0000
22.5	60,087,186	99.90%	100.00%	99.55%	0.0000	0.0000
23.5	62,761,294	99.90%	100.00%	99.47%	0.0000	0.0000
24.5	62,517,012	99.90%	100.00%	99.38%	0.0000	0.0000
25.5	62,463,173	99.89%	100.00%	99.28%	0.0000	0.0000
26.5	59,404,758	99.88%	99.99%	99.16%	0.0000	0.0001
27.5	59,505,121	99.88%	99.99%	99.03%	0.0000	0.0001
28.5	58,023,920	99.86%	99.98%	98.87%	0.0000	0.0001
29.5	57,515,559	99.85%	99.96%	98.70%	0.0000	0.0001
30.5	25,352,994	99.85%	99.94%	98.51%	0.0000	0.0002
31.5	25,371,981	99.83%	99.90%	98.29%	0.0000	0.0002
32.5	24,071,047	99.78%	99.85%	98.04%	0.0000	0.0003
33.5	24,117,396	99.76%	99.78%	97.76%	0.0000	0.0004
34.5	24,129,708	99.75%	99.69%	97.46%	0.0000	0.0005
35.5	14,373,832	99.67%	99.57%	97.11%	0.0000	0.0007
36.5	14,669,872	99.66%	99.41%	96.73%	0.0000	0.0009
37.5	14,746,512	99.61%	99.20%	96.31%	0.0000	0.0011
38.5	14,654,961	99.55%	98.95%	95.84%	0.0000	0.0014
39.5	14,380,984	99.50%	98.64%	95.33%	0.0001	0.0017
40.5	14,261,057	99.49%	98.25%	94.77%	0.0002	0.0022
41.5	8,044,440	98.92%	97.80%	94.15%	0.0001	0.0023
42.5	8,002,933	98.89%	97.25%	93.47%	0.0003	0.0029
43.5	7,715,623	96.35%	96.59%	92.74%	0.0000	0.0013
44.5	7,426,012	95.40%	95.83%	91.94%	0.0000	0.0012
45.5	7,173,179	93.56%	94.92%	91.08%	0.0002	0.0006
46.5	7,071,433	93.35%	93.86%	90.14%	0.0000	0.0010

Account 356 Curve Fitting

[1] Age (Years)	[2] Exposures (Dollars)	[3] Observed Life Table (OLT)	[4] Company R5-60	[5] Garrett R4-65	[6] Company SSD	[7] Garrett SSD
47.5	7,060,264	93.26%	92.63%	89.13%	0.0000	0.0017
48.5	6,912,388	93.13%	91.20%	88.04%	0.0004	0.0026
49.5	6,656,994	92.93%	89.53%	86.87%	0.0012	0.0037
50.5	2,260,928	92.65%	87.61%	85.63%	0.0025	0.0049
51.5	2,191,311	92.51%	85.41%	84.30%	0.0050	0.0067
52.5	2,133,882	92.21%	82.90%	82.88%	0.0087	0.0087
53.5	1,923,329	91.58%	80.08%	81.39%	0.0132	0.0104
54.5	1,818,010	91.25%	76.90%	79.80%	0.0206	0.0131
55.5	1,739,384	91.22%	73.38%	78.12%	0.0318	0.0172
56.5	1,317,527	91.11%	69.52%	76.34%	0.0466	0.0218
57.5	1,257,211	91.06%	65.32%	74.44%	0.0662	0.0276
58.5	1,225,741	90.98%	60.82%	72.42%	0.0909	0.0344
59.5	1,051,041	90.83%	56.07%	70.23%	0.1208	0.0424
60.5	990,508	90.73%	51.11%	67.90%	0.1570	0.0521
61.5	854,819	90.66%	46.01%	65.40%	0.1994	0.0638
62.5	146,908	90.34%	40.85%	62.73%	0.2449	0.0762
63.5	0	89.95%	35.72%	59.90%	0.2941	0.0903
64.5			30.72%	56.92%		
Sum of Squared Differences				[8]	1.3043	0.4972
Up to 1% of Beginning Exposures				[9]	0.7653	0.3306

[1] Age in years using half-year convention
[2] Dollars exposed to retirement at the beginning of each age interval
[3] Observed life table based on the Company's property records. These numbers form the original survivor curve.
[4] The Company's selected Iowa curve to be fitted to the OLT.
[5] My selected Iowa curve to be fitted to the OLT.
[6] = ([4] - [3])^2. This is the squared difference between each point on the Company's curve and the observed survivor curve.
[7] = ([5] - [3])^2. This is the squared difference between each point on my curve and the observed survivor curve.
[8] = Sum of squared differences. The smallest SSD represents the best mathematical fit.

Account 362 Curve Fitting

[1] Age (Years)	[2] Exposures (Dollars)	[3] Observed Life Table (OLT)	[4] Company R2-65	[5] Garrett R1.5-71	[6] Company SSD	[7] Garrett SSD
0.0	248,828,114	100.00%	100.00%	100.00%	0.0000	0.0000
0.5	201,849,775	100.00%	99.93%	99.88%	0.0000	0.0000
1.5	176,409,889	100.00%	99.78%	99.62%	0.0000	0.0000
2.5	165,161,928	99.98%	99.62%	99.36%	0.0000	0.0000
3.5	161,826,959	99.98%	99.45%	99.10%	0.0000	0.0001
4.5	154,548,514	99.95%	99.27%	98.82%	0.0000	0.0001
5.5	139,248,866	99.90%	99.09%	98.54%	0.0001	0.0002
6.5	126,903,879	99.88%	98.89%	98.25%	0.0001	0.0003
7.5	112,196,449	99.82%	98.69%	97.95%	0.0001	0.0003
8.5	108,902,705	99.69%	98.47%	97.65%	0.0001	0.0004
9.5	104,297,485	99.42%	98.25%	97.34%	0.0001	0.0004
10.5	91,740,879	99.29%	98.01%	97.02%	0.0002	0.0005
11.5	81,733,466	99.15%	97.77%	96.69%	0.0002	0.0006
12.5	82,480,744	98.99%	97.51%	96.35%	0.0002	0.0007
13.5	75,916,167	97.23%	97.24%	96.01%	0.0000	0.0001
14.5	72,817,079	96.99%	96.95%	95.65%	0.0000	0.0002
15.5	63,288,093	96.26%	96.66%	95.29%	0.0000	0.0001
16.5	59,875,959	96.15%	96.35%	94.92%	0.0000	0.0002
17.5	59,670,008	95.75%	96.02%	94.54%	0.0000	0.0001
18.5	57,375,543	95.59%	95.68%	94.15%	0.0000	0.0002
19.5	52,939,249	95.41%	95.33%	93.75%	0.0000	0.0003
20.5	52,603,940	95.18%	94.96%	93.34%	0.0000	0.0003
21.5	49,537,435	95.16%	94.58%	92.93%	0.0000	0.0005
22.5	47,755,815	90.33%	94.17%	92.50%	0.0015	0.0005
23.5	44,599,419	89.56%	93.75%	92.06%	0.0018	0.0006
24.5	42,812,608	88.88%	93.32%	91.61%	0.0020	0.0007
25.5	37,854,351	87.94%	92.86%	91.15%	0.0024	0.0010
26.5	33,965,172	87.44%	92.39%	90.68%	0.0025	0.0011
27.5	33,459,976	86.81%	91.90%	90.20%	0.0026	0.0011
28.5	31,712,819	86.47%	91.39%	89.71%	0.0024	0.0010
29.5	29,127,131	85.97%	90.85%	89.20%	0.0024	0.0010
30.5	31,869,456	85.68%	90.30%	88.68%	0.0021	0.0009
31.5	32,202,120	84.76%	89.72%	88.15%	0.0025	0.0012
32.5	30,513,599	84.35%	89.13%	87.61%	0.0023	0.0011
33.5	30,495,791	83.95%	88.50%	87.05%	0.0021	0.0010
34.5	29,497,777	83.19%	87.86%	86.48%	0.0022	0.0011
35.5	29,199,281	82.91%	87.19%	85.90%	0.0018	0.0009
36.5	26,795,173	82.52%	86.50%	85.30%	0.0016	0.0008
37.5	27,537,745	82.23%	85.78%	84.68%	0.0013	0.0006
38.5	26,911,602	81.57%	85.03%	84.05%	0.0012	0.0006
39.5	25,096,668	80.89%	84.26%	83.40%	0.0011	0.0006
40.5	25,010,695	80.38%	83.45%	82.74%	0.0009	0.0006
41.5	23,825,171	80.09%	82.63%	82.06%	0.0006	0.0004
42.5	23,705,122	79.77%	81.77%	81.36%	0.0004	0.0003
43.5	21,787,906	79.36%	80.88%	80.65%	0.0002	0.0002
44.5	20,026,479	78.92%	79.96%	79.92%	0.0001	0.0001
45.5	19,198,028	78.48%	79.01%	79.17%	0.0000	0.0000
46.5	18,948,452	77.96%	78.03%	78.40%	0.0000	0.0000

Account 362 Curve Fitting

[1]	[2]	[3]	[4]	[5]	[6]	[7]
Age (Years)	**Exposures (Dollars)**	**Observed Life Table (OLT)**	**Company R2-65**	**Garrett R1.5-71**	**Company SSD**	**Garrett SSD**
47.5	17,890,985	76.73%	77.02%	77.61%	0.0000	0.0001
48.5	17,128,820	76.32%	75.97%	76.81%	0.0000	0.0000
49.5	16,435,498	76.04%	74.90%	75.98%	0.0001	0.0000
50.5	15,602,745	75.42%	73.78%	75.14%	0.0003	0.0000
51.5	14,512,462	75.24%	72.64%	74.27%	0.0007	0.0001
52.5	13,619,252	72.26%	71.46%	73.39%	0.0001	0.0001
53.5	12,853,322	70.85%	70.25%	72.48%	0.0000	0.0003
54.5	12,431,615	70.14%	69.01%	71.56%	0.0001	0.0002
55.5	11,939,540	69.63%	67.73%	70.61%	0.0004	0.0001
56.5	11,796,546	69.30%	66.42%	69.65%	0.0008	0.0000
57.5	5,749,888	68.95%	65.07%	68.66%	0.0015	0.0000
58.5	4,769,299	68.05%	63.70%	67.66%	0.0019	0.0000
59.5	4,133,619	66.14%	62.29%	66.63%	0.0015	0.0000
60.5	3,582,340	65.19%	60.85%	65.58%	0.0019	0.0000
61.5	3,349,527	64.32%	59.38%	64.52%	0.0024	0.0000
62.5	2,942,965	63.71%	57.89%	63.43%	0.0034	0.0000
63.5	2,273,680	63.49%	56.36%	62.32%	0.0051	0.0001
64.5	1,120,932	63.01%	54.81%	61.20%	0.0067	0.0003
65.5	877,104	62.23%	53.23%	60.06%	0.0081	0.0005
66.5	485,016	61.90%	51.64%	58.89%	0.0105	0.0009
67.5	301,737	61.53%	50.02%	57.72%	0.0133	0.0015
68.5	287,268	61.52%	48.38%	56.52%	0.0173	0.0025
69.5	132,785	61.52%	46.73%	55.31%	0.0219	0.0039
70.5			45.07%	54.08%		
Sum of Squared Differences				[8]	0.1372	0.0338
Up to 1% of Beginning Exposures				[9]	0.0544	0.0241

[1] Age in years using half-year convention

[2] Dollars exposed to retirement at the beginning of each age interval

[3] Observed life table based on the Company's property records. These numbers form the original survivor curve.

[4] The Company's selected Iowa curve to be fitted to the OLT.

[5] My selected Iowa curve to be fitted to the OLT.

[6] = ([4] - [3])^2. This is the squared difference between each point on the Company's curve and the observed survivor curve.

[7] = ([5] - [3])^2. This is the squared difference between each point on my curve and the observed survivor curve.

[8] = Sum of squared differences. The smallest SSD represents the best mathematical fit.

Account 366 Curve Fitting

[1] Age (Years)	[2] Exposures (Dollars)	[3] Observed Life Table (OLT)	[4] Company R4-65	[5] Garrett R4-71	[6] Company SSD	[7] Garrett SSD
0.0	123,775,207	100.00%	100.00%	100.00%	0.0000	0.0000
0.5	117,342,859	99.98%	100.00%	100.00%	0.0000	0.0000
1.5	112,780,532	99.92%	100.00%	100.00%	0.0000	0.0000
2.5	108,800,246	99.86%	100.00%	100.00%	0.0000	0.0000
3.5	103,589,990	99.79%	99.99%	99.99%	0.0000	0.0000
4.5	100,716,580	99.74%	99.99%	99.99%	0.0000	0.0000
5.5	96,218,297	99.66%	99.99%	99.99%	0.0000	0.0000
6.5	92,916,643	99.59%	99.98%	99.99%	0.0000	0.0000
7.5	89,570,213	99.53%	99.98%	99.98%	0.0000	0.0000
8.5	88,157,941	99.48%	99.97%	99.98%	0.0000	0.0000
9.5	86,590,707	99.42%	99.96%	99.97%	0.0000	0.0000
10.5	82,364,298	99.35%	99.95%	99.96%	0.0000	0.0000
11.5	77,698,441	99.29%	99.94%	99.95%	0.0000	0.0000
12.5	71,522,842	99.21%	99.93%	99.94%	0.0001	0.0001
13.5	67,174,028	99.16%	99.91%	99.93%	0.0001	0.0001
14.5	61,129,159	99.13%	99.89%	99.92%	0.0001	0.0001
15.5	53,571,898	99.06%	99.87%	99.90%	0.0001	0.0001
16.5	48,879,296	98.98%	99.84%	99.88%	0.0001	0.0001
17.5	44,198,503	98.86%	99.81%	99.86%	0.0001	0.0001
18.5	40,960,411	98.80%	99.77%	99.83%	0.0001	0.0001
19.5	37,436,926	98.73%	99.73%	99.80%	0.0001	0.0001
20.5	33,253,414	98.68%	99.68%	99.76%	0.0001	0.0001
21.5	28,806,342	98.54%	99.62%	99.72%	0.0001	0.0001
22.5	26,647,700	98.44%	99.55%	99.67%	0.0001	0.0002
23.5	24,046,716	98.29%	99.47%	99.62%	0.0001	0.0002
24.5	21,586,692	98.14%	99.38%	99.56%	0.0002	0.0002
25.5	20,067,013	98.01%	99.28%	99.49%	0.0002	0.0002
26.5	18,986,208	97.87%	99.16%	99.41%	0.0002	0.0002
27.5	17,975,477	97.63%	99.03%	99.31%	0.0002	0.0003
28.5	16,938,469	97.41%	98.87%	99.21%	0.0002	0.0003
29.5	15,803,917	97.20%	98.70%	99.09%	0.0002	0.0004
30.5	14,635,597	97.09%	98.51%	98.97%	0.0002	0.0004
31.5	13,385,775	96.96%	98.29%	98.82%	0.0002	0.0003
32.5	11,981,315	96.92%	98.04%	98.65%	0.0001	0.0003
33.5	10,766,242	96.85%	97.76%	98.47%	0.0001	0.0003
34.5	9,452,771	96.80%	97.46%	98.27%	0.0000	0.0002
35.5	7,911,386	96.77%	97.11%	98.04%	0.0000	0.0002
36.5	7,020,899	96.71%	96.73%	97.79%	0.0000	0.0001
37.5	6,327,334	96.65%	96.31%	97.51%	0.0000	0.0001
38.5	5,502,588	96.52%	95.84%	97.20%	0.0000	0.0000
39.5	4,597,122	96.23%	95.33%	96.87%	0.0001	0.0000
40.5	3,869,267	96.04%	94.77%	96.50%	0.0002	0.0000
41.5	3,140,855	95.95%	94.15%	96.09%	0.0003	0.0000
42.5	2,784,009	95.60%	93.47%	95.64%	0.0005	0.0000
43.5	2,094,506	95.16%	92.74%	95.15%	0.0006	0.0000
44.5	1,766,345	94.45%	91.94%	94.62%	0.0006	0.0000
45.5	986,344	93.94%	91.08%	94.05%	0.0008	0.0000
46.5	682,270	93.49%	90.14%	93.42%	0.0011	0.0000

Account 366 Curve Fitting

[1] Age (Years)	[2] Exposures (Dollars)	[3] Observed Life Table (OLT)	[4] Company R4-65	[5] Garrett R4-71	[6] Company SSD	[7] Garrett SSD
47.5	661,912	91.22%	89.13%	92.75%	0.0004	0.0002
48.5	631,803	90.01%	88.04%	92.02%	0.0004	0.0004
49.5	508,909	88.93%	86.87%	91.24%	0.0004	0.0005
50.5	336,089	88.58%	85.63%	90.39%	0.0009	0.0003
51.5	300,922	87.21%	84.30%	89.49%	0.0008	0.0005
52.5	282,699	85.43%	82.88%	88.52%	0.0006	0.0010
53.5	252,967	84.41%	81.39%	87.49%	0.0009	0.0009
54.5	172,372	84.20%	79.80%	86.39%	0.0019	0.0005
55.5	159,640	81.81%	78.12%	85.23%	0.0014	0.0012
56.5	138,762	77.97%	76.34%	83.99%	0.0003	0.0036
57.5	62,391	74.73%	74.44%	82.68%	0.0000	0.0063
58.5	57,499	74.57%	72.42%	81.30%	0.0005	0.0045
59.5	48,225	74.17%	70.23%	79.85%	0.0015	0.0032
60.5	45,322	71.28%	67.90%	78.32%	0.0011	0.0050
61.5	21,596	70.90%	65.40%	76.70%	0.0030	0.0034
62.5	3,438	69.58%	62.73%	75.00%	0.0047	0.0029
63.5	3,317	67.13%	59.90%	73.17%	0.0052	0.0037
64.5	3,313	67.04%	56.92%	71.24%	0.0102	0.0018
65.5	3,309	66.97%	53.81%	69.17%	0.0173	0.0005
66.5	72	66.90%	50.59%	66.97%	0.0266	0.0000
67.5	0	64.94%	47.29%	64.63%	0.0311	0.0000
68.5			43.95%	62.14%		
Sum of Squared Differences				[8]	0.1168	0.0454
Up to 1% of Beginning Exposures				[9]	0.0053	0.0050

[1] Age in years using half-year convention

[2] Dollars exposed to retirement at the beginning of each age interval

[3] Observed life table based on the Company's property records. These numbers form the original survivor curve.

[4] The Company's selected Iowa curve to be fitted to the OLT.

[5] My selected Iowa curve to be fitted to the OLT.

[6] = ([4] - [3])^2. This is the squared difference between each point on the Company's curve and the observed survivor curve.

[7] = ([5] - [3])^2. This is the squared difference between each point on my curve and the observed survivor curve.

[8] = Sum of squared differences. The smallest SSD represents the best mathematical fit.

EPE
Electric Division
353.00 Station Equipment

Observed Life Table
Retirement Expr. 1993 TO 2019
Placement Years 1969 TO 2019

Age Interval	$ Surviving At Beginning of Age Interval	$ Retired During The Age Interval	Retirement Ratio	% Surviving At Beginning of Age Interval
0.0 - 0.5	$124,971,285.03	$0.00	0.00000	100.00
0.5 - 1.5	$123,285,263.12	$3,520.00	0.00003	100.00
1.5 - 2.5	$119,973,354.34	$1,874.00	0.00002	100.00
2.5 - 3.5	$114,067,017.42	$10,443.00	0.00009	100.00
3.5 - 4.5	$106,098,720.97	$1,247.00	0.00001	99.99
4.5 - 5.5	$98,012,080.97	$7,501.00	0.00008	99.99
5.5 - 6.5	$98,507,346.22	$289,681.00	0.00294	99.98
6.5 - 7.5	$93,945,323.98	$46.00	0.00000	99.68
7.5 - 8.5	$90,095,080.40	$1,164.52	0.00001	99.68
8.5 - 9.5	$108,423,855.87	$521.00	0.00000	99.68
9.5 - 10.5	$107,733,042.87	$181,378.75	0.00168	99.68
10.5 - 11.5	$99,773,470.96	$64,442.00	0.00065	99.51
11.5 - 12.5	$87,162,294.86	$30,920.11	0.00035	99.45
12.5 - 13.5	$88,268,362.30	$69,676.35	0.00079	99.41
13.5 - 14.5	$87,576,946.98	$369.00	0.00000	99.34
14.5 - 15.5	$91,177,670.50	$254,630.76	0.00279	99.34
15.5 - 16.5	$89,422,537.63	$25,833.00	0.00029	99.06
16.5 - 17.5	$81,791,927.47	$1,882.00	0.00002	99.03
17.5 - 18.5	$80,820,991.91	$10,119.00	0.00013	99.03
18.5 - 19.5	$81,053,282.78	$1,565.00	0.00002	99.01
19.5 - 20.5	$76,601,021.43	$626,508.71	0.00818	99.01
20.5 - 21.5	$77,068,073.72	$506.18	0.00001	98.20
21.5 - 22.5	$77,510,511.54	$111,260.00	0.00144	98.20
22.5 - 23.5	$70,282,387.76	$163,279.63	0.00232	98.06
23.5 - 24.5	$70,034,192.61	$1,250,013.00	0.01785	97.83
24.5 - 25.5	$68,442,288.85	$23,121.00	0.00034	96.09
25.5 - 26.5	$67,603,102.85	$935,034.17	0.01383	96.06
26.5 - 27.5	$66,668,068.68	$91,741.91	0.00138	94.73
27.5 - 28.5	$66,330,609.05	$71,847.00	0.00108	94.60
28.5 - 29.5	$65,772,107.22	$1,282.00	0.00002	94.49
29.5 - 30.5	$64,567,954.13	$10,227.00	0.00016	94.49
30.5 - 31.5	$46,253,006.13	$75,192.00	0.00163	94.48
31.5 - 32.5	$46,137,531.13	$70,396.00	0.00153	94.32
32.5 - 33.5	$42,338,532.13	$261,251.00	0.00617	94.18
33.5 - 34.5	$41,712,188.13	$26,157.00	0.00063	93.60
34.5 - 35.5	$41,239,758.13	$471,144.00	0.01142	93.54
35.5 - 36.5	$10,632,523.00	$605.00	0.00006	92.47

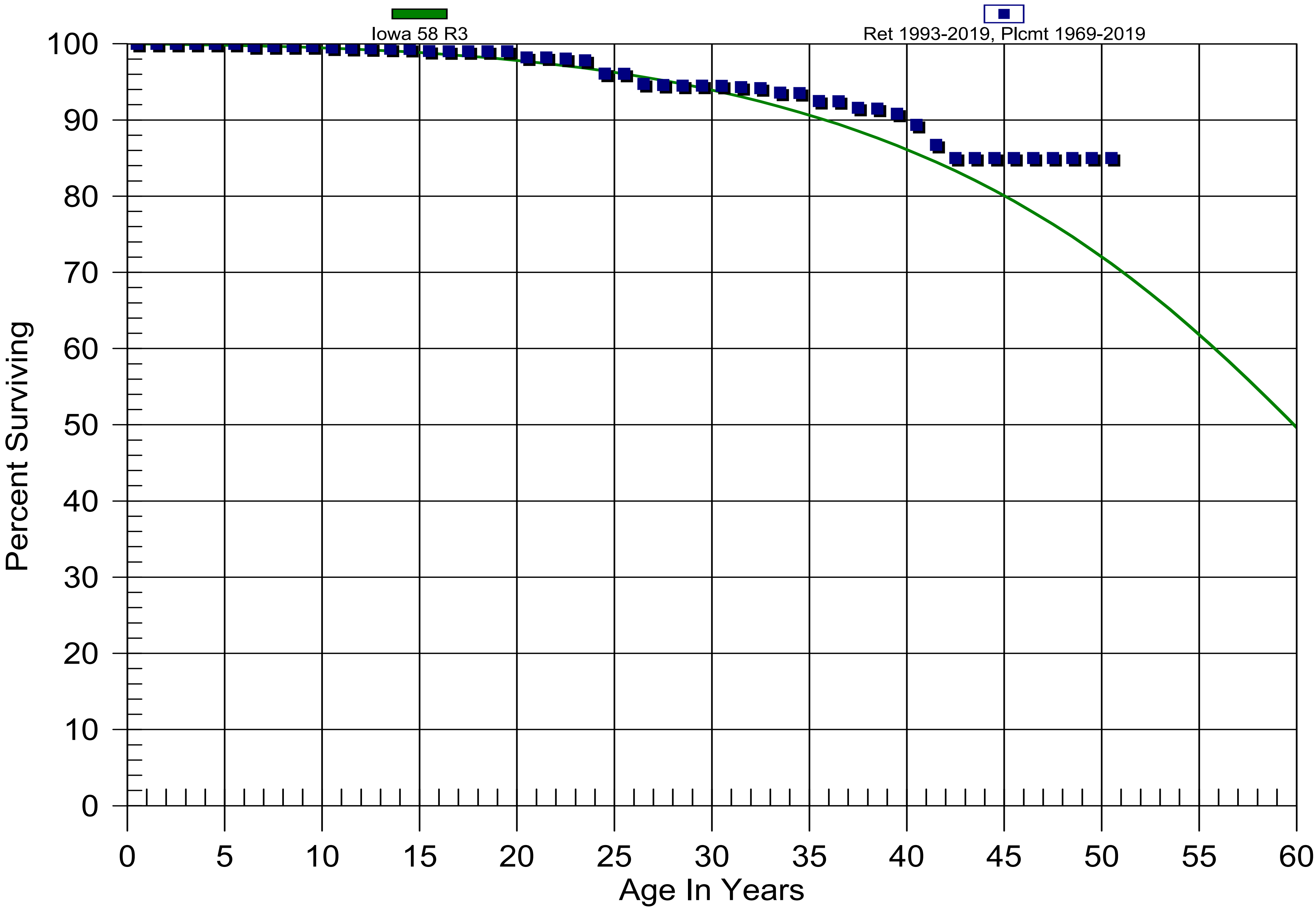
EPE
Electric Division
353.00 Station Equipment

Observed Life Table
Retirement Expr. 1993 TO 2019
Placement Years 1969 TO 2019

Age Interval	$ Surviving At Beginning of Age Interval	$ Retired During The Age Interval	Retirement Ratio	% Surviving At Beginning of Age Interval
36.5 - 37.5	$10,564,176.00	$99,040.00	0.00938	92.47
37.5 - 38.5	$9,990,821.00	$13,126.00	0.00131	91.60
38.5 - 39.5	$9,522,704.00	$68,151.00	0.00716	91.48
39.5 - 40.5	$7,704,316.00	$123,831.00	0.01607	90.82
40.5 - 41.5	$7,408,332.00	$218,419.00	0.02948	89.36
41.5 - 42.5	$4,031,385.00	$80,148.00	0.01988	86.73
42.5 - 43.5	$3,951,237.00	$96.00	0.00002	85.00
43.5 - 44.5	$3,291,692.00	$170.00	0.00005	85.00
44.5 - 45.5	$3,279,082.00	$62.00	0.00002	85.00
45.5 - 46.5	$2,821,871.00	$0.00	0.00000	85.00
46.5 - 47.5	$1,991,746.00	$0.00	0.00000	85.00
47.5 - 48.5	$526,623.00	$0.00	0.00000	85.00
48.5 - 49.5	$0.00	$0.00	0.00000	85.00
49.5 - 50.5	$0.00	$0.00	0.00000	85.00

EPE

Electric Division
353.00 Station Equipment
Original And Smooth Survivor Curves



EPE
Electric Division
356.00 Overhead Conductors and Devices
Observed Life Table
Retirement Expr. 1993 TO 2019
Placement Years 1941 TO 2019

Age Interval	$ Surviving At Beginning of Age Interval	$ Retired During The Age Interval	Retirement Ratio	% Surviving At Beginning of Age Interval
0.0 - 0.5	$37,130,703.35	$74.39	0.00000	100.00
0.5 - 1.5	$36,274,644.28	$722.83	0.00002	100.00
1.5 - 2.5	$36,881,806.66	$339.00	0.00001	100.00
2.5 - 3.5	$36,735,605.65	$248.00	0.00001	100.00
3.5 - 4.5	$63,229,141.22	$353.00	0.00001	100.00
4.5 - 5.5	$56,982,661.22	$797.00	0.00001	100.00
5.5 - 6.5	$57,783,965.22	$369.00	0.00001	99.99
6.5 - 7.5	$52,500,289.74	$4,083.00	0.00008	99.99
7.5 - 8.5	$52,548,877.54	$305.00	0.00001	99.99
8.5 - 9.5	$62,700,552.54	$15,747.00	0.00025	99.99
9.5 - 10.5	$62,310,751.54	$812.00	0.00001	99.96
10.5 - 11.5	$61,916,385.45	$15,511.00	0.00025	99.96
11.5 - 12.5	$57,020,862.45	$227.00	0.00000	99.93
12.5 - 13.5	$57,295,950.16	$1,040.46	0.00002	99.93
13.5 - 14.5	$57,409,383.23	$431.43	0.00001	99.93
14.5 - 15.5	$63,722,384.81	$1,389.63	0.00002	99.93
15.5 - 16.5	$62,164,974.42	$13,640.00	0.00022	99.93
16.5 - 17.5	$61,816,250.67	$187.34	0.00000	99.91
17.5 - 18.5	$62,027,451.34	$151.00	0.00000	99.91
18.5 - 19.5	$62,128,749.34	$124.00	0.00000	99.91
19.5 - 20.5	$62,079,752.34	$309.00	0.00000	99.91
20.5 - 21.5	$61,975,597.34	$926.00	0.00001	99.91
21.5 - 22.5	$61,350,363.34	$1,431.00	0.00002	99.90
22.5 - 23.5	$60,087,186.34	$0.00	0.00000	99.90
23.5 - 24.5	$62,761,294.34	$2,400.91	0.00004	99.90
24.5 - 25.5	$62,517,012.43	$4,366.76	0.00007	99.90
25.5 - 26.5	$62,463,172.67	$3,992.34	0.00006	99.89
26.5 - 27.5	$59,404,758.16	$857.50	0.00001	99.88
27.5 - 28.5	$59,505,120.66	$11,602.71	0.00019	99.88
28.5 - 29.5	$58,023,919.86	$6,963.71	0.00012	99.86
29.5 - 30.5	$57,515,559.49	$1,485.89	0.00003	99.85
30.5 - 31.5	$25,352,993.60	$5,076.65	0.00020	99.85
31.5 - 32.5	$25,371,980.73	$13,379.94	0.00053	99.83
32.5 - 33.5	$24,071,047.29	$4,599.97	0.00019	99.78
33.5 - 34.5	$24,117,395.75	$754.96	0.00003	99.76
34.5 - 35.5	$24,129,708.30	$20,883.78	0.00087	99.75
35.5 - 36.5	$14,373,832.09	$636.24	0.00004	99.67

EPE
Electric Division
356.00 Overhead Conductors and Devices

Observed Life Table
Retirement Expr. 1993 TO 2019
Placement Years 1941 TO 2019

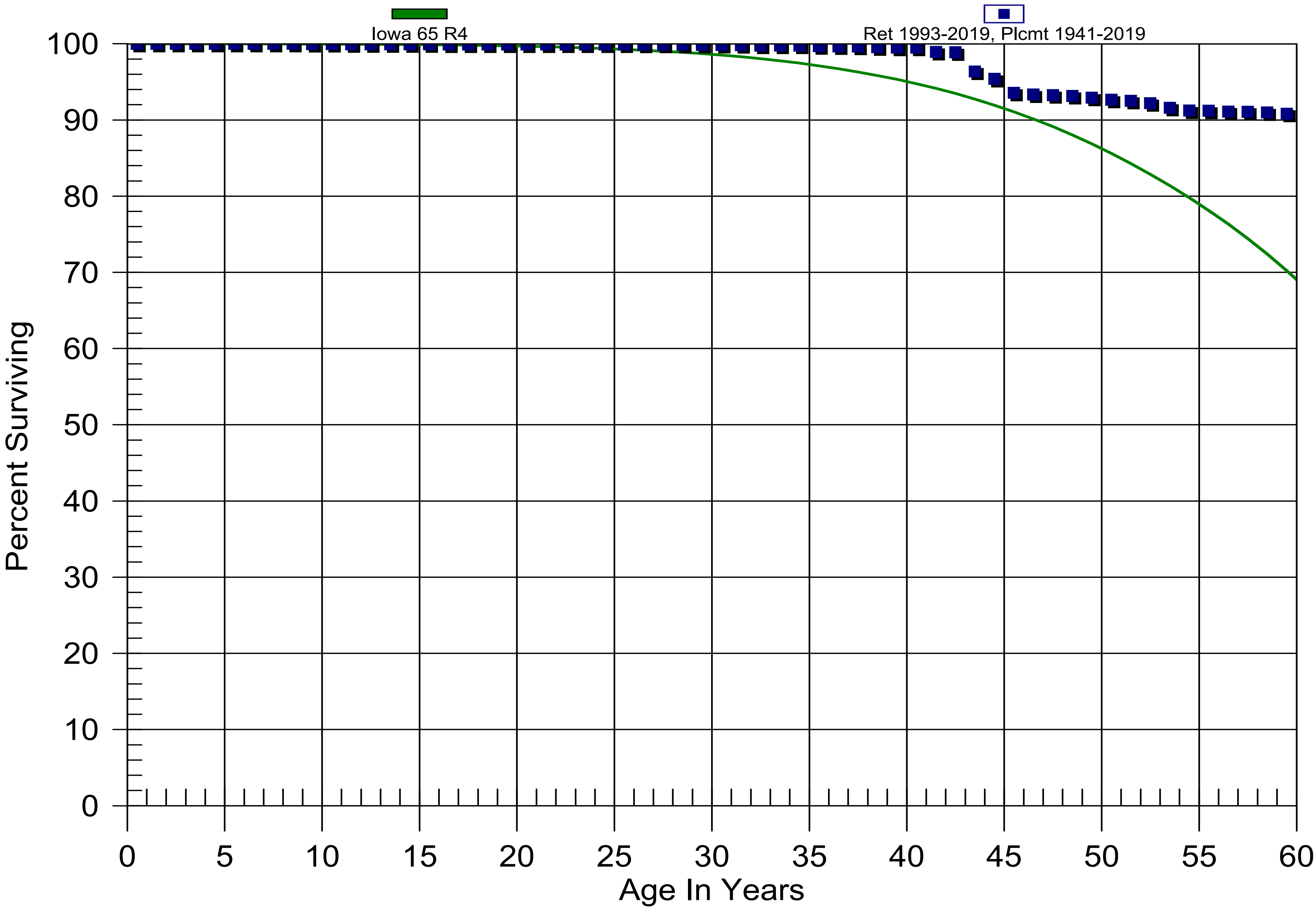
Age Interval	$ Surviving At Beginning of Age Interval	$ Retired During The Age Interval	Retirement Ratio	% Surviving At Beginning of Age Interval
36.5 - 37.5	$14,669,871.68	$7,304.79	0.00050	99.66
37.5 - 38.5	$14,746,511.83	$9,757.18	0.00066	99.61
38.5 - 39.5	$14,654,960.61	$7,114.84	0.00049	99.55
39.5 - 40.5	$14,380,983.93	$907.95	0.00006	99.50
40.5 - 41.5	$14,261,056.65	$82,064.92	0.00575	99.49
41.5 - 42.5	$8,044,439.51	$2,802.14	0.00035	98.92
42.5 - 43.5	$8,002,932.95	$205,362.93	0.02566	98.89
43.5 - 44.5	$7,715,622.98	$76,079.59	0.00986	96.35
44.5 - 45.5	$7,426,012.17	$143,308.89	0.01930	95.40
45.5 - 46.5	$7,173,179.34	$15,656.22	0.00218	93.56
46.5 - 47.5	$7,071,433.49	$6,838.06	0.00097	93.35
47.5 - 48.5	$7,060,264.12	$9,753.19	0.00138	93.26
48.5 - 49.5	$6,912,388.17	$15,343.43	0.00222	93.13
49.5 - 50.5	$6,656,994.32	$19,541.32	0.00294	92.93
50.5 - 51.5	$2,260,928.04	$3,417.35	0.00151	92.65
51.5 - 52.5	$2,191,311.44	$7,200.73	0.00329	92.51
52.5 - 53.5	$2,133,881.73	$14,493.43	0.00679	92.21
53.5 - 54.5	$1,923,328.62	$7,019.62	0.00365	91.58
54.5 - 55.5	$1,818,010.39	$617.95	0.00034	91.25
55.5 - 56.5	$1,739,384.33	$2,169.71	0.00125	91.22
56.5 - 57.5	$1,317,526.74	$645.87	0.00049	91.11
57.5 - 58.5	$1,257,211.10	$1,115.95	0.00089	91.06
58.5 - 59.5	$1,225,741.28	$2,064.38	0.00168	90.98
59.5 - 60.5	$1,051,040.98	$1,122.59	0.00107	90.83
60.5 - 61.5	$990,507.61	$721.90	0.00073	90.73
61.5 - 62.5	$854,818.74	$3,066.85	0.00359	90.66
62.5 - 63.5	$146,908.47	$636.45	0.00433	90.34
63.5 - 64.5	$0.00	$0.00	0.00000	89.95
64.5 - 65.5	$0.00	$0.00	0.00000	89.95
65.5 - 66.5	$0.00	$0.00	0.00000	89.95
66.5 - 67.5	$0.00	$0.00	0.00000	89.95
67.5 - 68.5	$0.00	$0.00	0.00000	89.95
68.5 - 69.5	$0.00	$0.00	0.00000	89.95
69.5 - 70.5	$0.00	$0.00	0.00000	89.95
70.5 - 71.5	$0.00	$0.00	0.00000	89.95
71.5 - 72.5	$0.00	$0.00	0.00000	89.95
72.5 - 73.5	$0.00	$0.00	0.00000	89.95

EPE
Electric Division
356.00 Overhead Conductors and Devices
Observed Life Table
Retirement Expr. 1993 TO 2019
Placement Years 1941 TO 2019

Age Interval	$ Surviving At Beginning of Age Interval	$ Retired During The Age Interval	Retirement Ratio	% Surviving At Beginning of Age Interval
73.5 - 74.5	$0.00	$0.00	0.00000	89.95
74.5 - 75.5	$0.00	$0.00	0.00000	89.95
75.5 - 76.5	$0.00	$0.00	0.00000	89.95
76.5 - 77.5	$0.00	$0.00	0.00000	89.95
77.5 - 78.5	$0.00	$0.00	0.00000	89.95

EPE

Electric Division
356.00 Overhead Conductors and Devices
Original And Smooth Survivor Curves



EPE
Electric Division
362.00 Station Equipment

Observed Life Table
Retirement Expr. 1993 TO 2019
Placement Years 1949 TO 2019

Age Interval	$ Surviving At Beginning of Age Interval	$ Retired During The Age Interval	Retirement Ratio	% Surviving At Beginning of Age Interval
0.0 - 0.5	$248,828,113.87	$5,778.23	0.00002	100.00
0.5 - 1.5	$201,849,775.43	$4,784.00	0.00002	100.00
1.5 - 2.5	$176,409,888.50	$18,582.00	0.00011	100.00
2.5 - 3.5	$165,161,927.89	$1,958.00	0.00001	99.98
3.5 - 4.5	$161,826,959.26	$62,406.20	0.00039	99.98
4.5 - 5.5	$154,548,514.06	$62,318.00	0.00040	99.95
5.5 - 6.5	$139,248,865.67	$30,881.00	0.00022	99.90
6.5 - 7.5	$126,903,879.44	$82,346.20	0.00065	99.88
7.5 - 8.5	$112,196,448.51	$140,310.72	0.00125	99.82
8.5 - 9.5	$108,902,704.69	$294,339.58	0.00270	99.69
9.5 - 10.5	$104,297,484.90	$142,182.29	0.00136	99.42
10.5 - 11.5	$91,740,879.23	$130,114.00	0.00142	99.29
11.5 - 12.5	$81,733,465.70	$126,518.30	0.00155	99.15
12.5 - 13.5	$82,480,743.80	$1,465,394.20	0.01777	98.99
13.5 - 14.5	$75,916,167.30	$190,666.65	0.00251	97.23
14.5 - 15.5	$72,817,079.34	$547,479.60	0.00752	96.99
15.5 - 16.5	$63,288,093.37	$70,888.33	0.00112	96.26
16.5 - 17.5	$59,875,959.27	$249,501.60	0.00417	96.15
17.5 - 18.5	$59,670,008.47	$100,451.61	0.00168	95.75
18.5 - 19.5	$57,375,543.43	$111,757.68	0.00195	95.59
19.5 - 20.5	$52,939,249.35	$123,541.79	0.00233	95.41
20.5 - 21.5	$52,603,939.55	$11,976.14	0.00023	95.18
21.5 - 22.5	$49,537,435.32	$2,516,788.67	0.05081	95.16
22.5 - 23.5	$47,755,814.65	$407,437.43	0.00853	90.33
23.5 - 24.5	$44,599,418.83	$334,540.66	0.00750	89.56
24.5 - 25.5	$42,812,608.33	$454,914.64	0.01063	88.88
25.5 - 26.5	$37,854,350.77	$215,487.90	0.00569	87.94
26.5 - 27.5	$33,965,171.87	$245,079.91	0.00722	87.44
27.5 - 28.5	$33,459,976.34	$129,982.81	0.00388	86.81
28.5 - 29.5	$31,712,818.78	$185,503.97	0.00585	86.47
29.5 - 30.5	$29,127,130.54	$96,300.61	0.00331	85.97
30.5 - 31.5	$31,869,456.49	$342,588.78	0.01075	85.68
31.5 - 32.5	$32,202,120.49	$156,140.02	0.00485	84.76
32.5 - 33.5	$30,513,599.04	$143,418.19	0.00470	84.35
33.5 - 34.5	$30,495,791.42	$278,167.21	0.00912	83.95
34.5 - 35.5	$29,497,776.99	$97,429.59	0.00330	83.19
35.5 - 36.5	$29,199,281.20	$136,641.71	0.00468	82.91

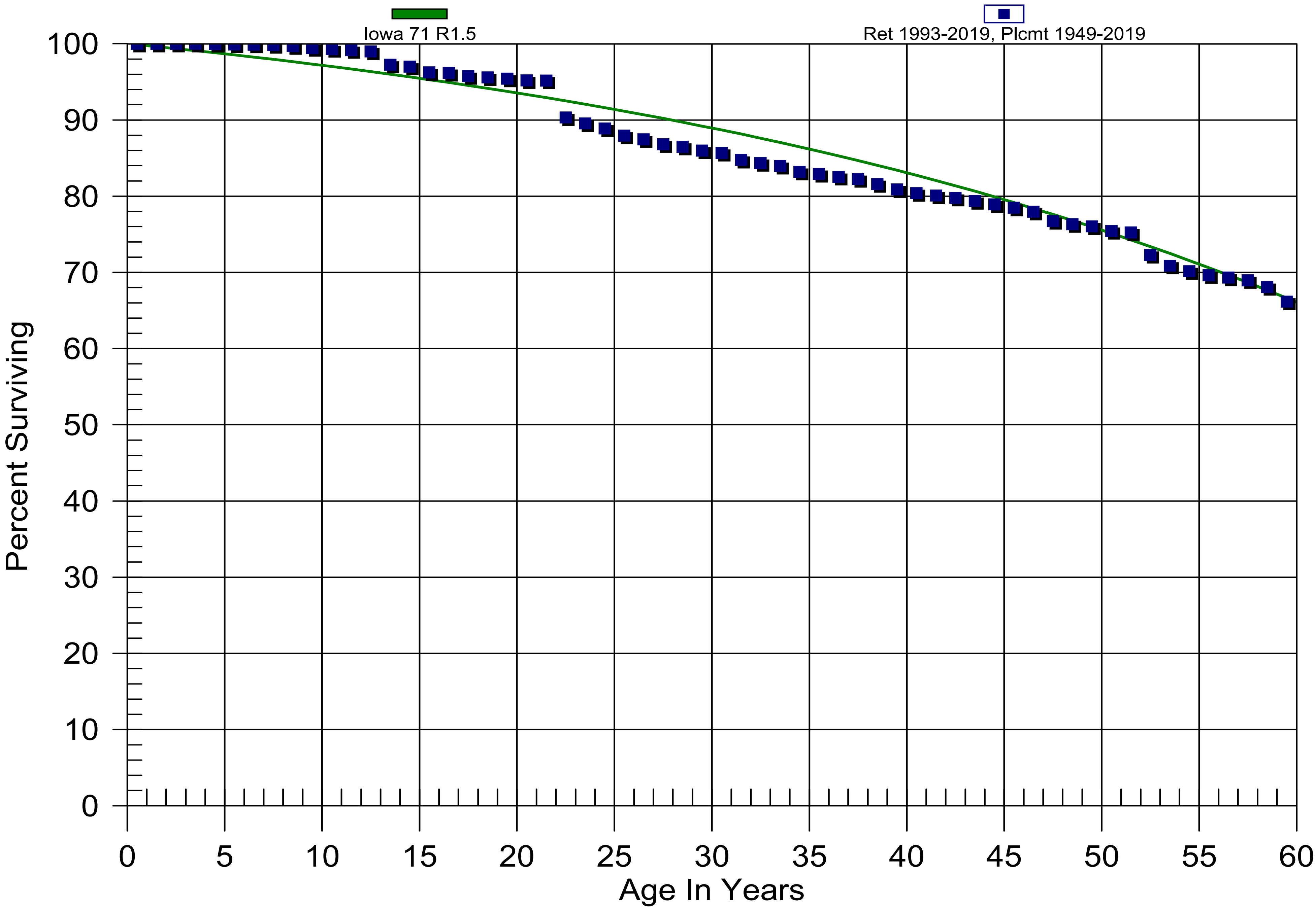
EPE
Electric Division
362.00 Station Equipment

Observed Life Table
Retirement Expr. 1993 TO 2019
Placement Years 1949 TO 2019

Age Interval	*$ Surviving At Beginning of Age Interval*	*$ Retired During The Age Interval*	*Retirement Ratio*	*% Surviving At Beginning of Age Interval*
36.5 - 37.5	$26,795,173.03	$94,828.93	0.00354	82.52
37.5 - 38.5	$27,537,745.30	$221,447.79	0.00804	82.23
38.5 - 39.5	$26,911,601.98	$225,935.61	0.00840	81.57
39.5 - 40.5	$25,096,668.08	$157,312.50	0.00627	80.89
40.5 - 41.5	$25,010,695.04	$90,830.84	0.00363	80.38
41.5 - 42.5	$23,825,170.50	$94,047.81	0.00395	80.09
42.5 - 43.5	$23,705,122.27	$122,967.33	0.00519	79.77
43.5 - 44.5	$21,787,905.97	$118,797.43	0.00545	79.36
44.5 - 45.5	$20,026,479.49	$112,786.78	0.00563	78.92
45.5 - 46.5	$19,198,028.17	$127,441.10	0.00664	78.48
46.5 - 47.5	$18,948,451.55	$299,803.65	0.01582	77.96
47.5 - 48.5	$17,890,984.54	$94,512.42	0.00528	76.73
48.5 - 49.5	$17,128,819.90	$62,560.67	0.00365	76.32
49.5 - 50.5	$16,435,498.36	$135,239.61	0.00823	76.04
50.5 - 51.5	$15,602,744.71	$36,825.12	0.00236	75.42
51.5 - 52.5	$14,512,462.13	$574,109.97	0.03956	75.24
52.5 - 53.5	$13,619,251.81	$265,582.86	0.01950	72.26
53.5 - 54.5	$12,853,322.39	$128,814.12	0.01002	70.85
54.5 - 55.5	$12,431,615.00	$91,519.10	0.00736	70.14
55.5 - 56.5	$11,939,540.22	$55,072.54	0.00461	69.63
56.5 - 57.5	$11,796,545.50	$61,007.76	0.00517	69.30
57.5 - 58.5	$5,749,888.33	$74,318.42	0.01293	68.95
58.5 - 59.5	$4,769,298.74	$133,887.02	0.02807	68.05
59.5 - 60.5	$4,133,618.69	$59,612.61	0.01442	66.14
60.5 - 61.5	$3,582,339.94	$47,698.70	0.01331	65.19
61.5 - 62.5	$3,349,526.95	$32,003.27	0.00955	64.32
62.5 - 63.5	$2,942,965.33	$10,064.80	0.00342	63.71
63.5 - 64.5	$2,273,679.52	$17,267.50	0.00759	63.49
64.5 - 65.5	$1,120,932.12	$13,770.32	0.01228	63.01
65.5 - 66.5	$877,103.71	$4,753.97	0.00542	62.23
66.5 - 67.5	$485,016.37	$2,860.06	0.00590	61.90
67.5 - 68.5	$301,736.94	$38.69	0.00013	61.53
68.5 - 69.5	$287,267.97	$0.00	0.00000	61.52
69.5 - 70.5	$132,785.39	$0.00	0.00000	61.52

EPE

Electric Division
362.00 Station Equipment
Original And Smooth Survivor Curves



EPE

Electric Division

366.00 Underground Conduit

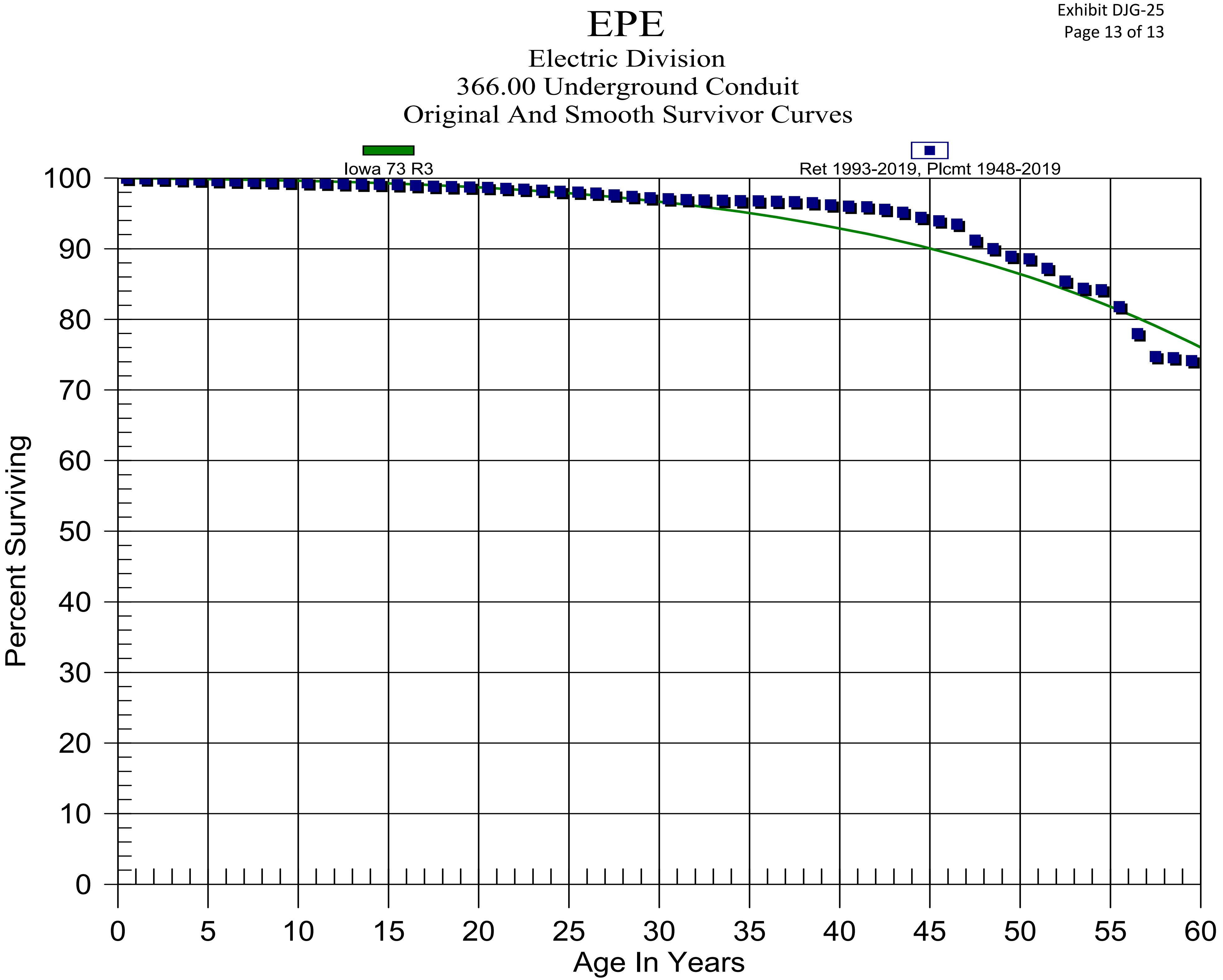
Observed Life Table

Retirement Expr. 1993 TO 2019
Placement Years 1948 TO 2019

Age Interval	*$ Surviving At Beginning of Age Interval*	*$ Retired During The Age Interval*	*Retirement Ratio*	*% Surviving At Beginning of Age Interval*
0.0 - 0.5	$123,775,206.70	$19,148.00	0.00015	100.00
0.5 - 1.5	$117,342,859.11	$80,380.34	0.00069	99.98
1.5 - 2.5	$112,780,531.89	$57,901.34	0.00051	99.92
2.5 - 3.5	$108,800,245.56	$79,074.78	0.00073	99.86
3.5 - 4.5	$103,589,990.14	$58,458.36	0.00056	99.79
4.5 - 5.5	$100,716,580.22	$72,839.13	0.00072	99.74
5.5 - 6.5	$96,218,297.15	$68,398.93	0.00071	99.66
6.5 - 7.5	$92,916,642.66	$58,176.97	0.00063	99.59
7.5 - 8.5	$89,570,213.34	$47,614.71	0.00053	99.53
8.5 - 9.5	$88,157,941.45	$51,300.53	0.00058	99.48
9.5 - 10.5	$86,590,707.17	$59,638.22	0.00069	99.42
10.5 - 11.5	$82,364,297.58	$54,601.87	0.00066	99.35
11.5 - 12.5	$77,698,440.61	$58,636.66	0.00075	99.29
12.5 - 13.5	$71,522,841.68	$33,614.15	0.00047	99.21
13.5 - 14.5	$67,174,027.75	$24,978.74	0.00037	99.16
14.5 - 15.5	$61,129,158.99	$38,554.99	0.00063	99.13
15.5 - 16.5	$53,571,897.90	$48,243.79	0.00090	99.06
16.5 - 17.5	$48,879,295.82	$55,889.15	0.00114	98.98
17.5 - 18.5	$44,198,502.59	$27,633.33	0.00063	98.86
18.5 - 19.5	$40,960,410.93	$29,631.74	0.00072	98.80
19.5 - 20.5	$37,436,925.65	$19,315.86	0.00052	98.73
20.5 - 21.5	$33,253,414.39	$47,398.04	0.00143	98.68
21.5 - 22.5	$28,806,342.12	$29,485.11	0.00102	98.54
22.5 - 23.5	$26,647,700.02	$40,706.20	0.00153	98.44
23.5 - 24.5	$24,046,716.09	$35,369.68	0.00147	98.29
24.5 - 25.5	$21,586,692.43	$28,767.69	0.00133	98.14
25.5 - 26.5	$20,067,012.75	$29,119.51	0.00145	98.01
26.5 - 27.5	$18,986,208.18	$46,445.43	0.00245	97.87
27.5 - 28.5	$17,975,477.21	$41,221.14	0.00229	97.63
28.5 - 29.5	$16,938,469.06	$34,983.28	0.00207	97.41
29.5 - 30.5	$15,803,917.21	$18,307.88	0.00116	97.20
30.5 - 31.5	$14,635,597.33	$19,878.39	0.00136	97.09
31.5 - 32.5	$13,385,774.57	$4,992.38	0.00037	96.96
32.5 - 33.5	$11,981,314.86	$8,984.05	0.00075	96.92
33.5 - 34.5	$10,766,242.48	$6,115.65	0.00057	96.85
34.5 - 35.5	$9,452,770.68	$2,490.50	0.00026	96.80
35.5 - 36.5	$7,911,386.06	$5,137.62	0.00065	96.77

EPE
Electric Division
366.00 Underground Conduit
Observed Life Table
Retirement Expr. 1993 TO 2019
Placement Years 1948 TO 2019

Age Interval	$ Surviving At Beginning of Age Interval	$ Retired During The Age Interval	Retirement Ratio	% Surviving At Beginning of Age Interval
36.5 - 37.5	$7,020,899.08	$3,943.86	0.00056	96.71
37.5 - 38.5	$6,327,333.78	$8,934.94	0.00141	96.65
38.5 - 39.5	$5,502,587.51	$16,590.28	0.00301	96.52
39.5 - 40.5	$4,597,122.33	$8,883.76	0.00193	96.23
40.5 - 41.5	$3,869,267.48	$3,598.33	0.00093	96.04
41.5 - 42.5	$3,140,855.09	$11,565.57	0.00368	95.95
42.5 - 43.5	$2,784,009.15	$12,597.63	0.00452	95.60
43.5 - 44.5	$2,094,505.95	$15,804.50	0.00755	95.16
44.5 - 45.5	$1,766,345.21	$9,461.34	0.00536	94.45
45.5 - 46.5	$986,344.04	$4,712.03	0.00478	93.94
46.5 - 47.5	$682,270.19	$16,550.46	0.02426	93.49
47.5 - 48.5	$661,912.30	$8,819.76	0.01332	91.22
48.5 - 49.5	$631,802.76	$7,593.60	0.01202	90.01
49.5 - 50.5	$508,908.73	$2,007.32	0.00394	88.93
50.5 - 51.5	$336,089.20	$5,171.91	0.01539	88.58
51.5 - 52.5	$300,921.70	$6,164.49	0.02049	87.21
52.5 - 53.5	$282,698.96	$3,358.84	0.01188	85.43
53.5 - 54.5	$252,966.50	$622.75	0.00246	84.41
54.5 - 55.5	$172,372.35	$4,906.09	0.02846	84.20
55.5 - 56.5	$159,639.65	$7,487.96	0.04691	81.81
56.5 - 57.5	$138,762.44	$5,766.26	0.04155	77.97
57.5 - 58.5	$62,390.67	$136.33	0.00219	74.73
58.5 - 59.5	$57,498.92	$305.87	0.00532	74.57
59.5 - 60.5	$48,225.33	$1,879.00	0.03896	74.17
60.5 - 61.5	$45,321.76	$240.63	0.00531	71.28
61.5 - 62.5	$21,595.86	$402.22	0.01862	70.90
62.5 - 63.5	$3,438.01	$120.87	0.03516	69.58
63.5 - 64.5	$3,317.14	$4.64	0.00140	67.13
64.5 - 65.5	$3,312.50	$3.68	0.00111	67.04
65.5 - 66.5	$3,308.82	$3.40	0.00103	66.97
66.5 - 67.5	$71.98	$2.11	0.02931	66.90
67.5 - 68.5	$0.00	$0.00	0.00000	64.94
68.5 - 69.5	$0.00	$0.00	0.00000	64.94
69.5 - 70.5	$0.00	$0.00	0.00000	64.94
70.5 - 71.5	$0.00	$0.00	0.00000	64.94


EPE
Electric Division
366.00 Underground Conduit
Original And Smooth Survivor Curves
Iowa 73 R3
Ret 1993-2019, Plcmt 1948-2019
Percent Surviving
100
90
80
70
60
50
40
30
20
10
0
0
5
10
15
20
25
30
35
40
45
50
55
60
Age In Years

EPE
Electric Division
311.00 Structures and Improvements

Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2019
Based Upon Broad Group/Remaining Life Procedure and Technique

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)

Newman Unit 5

Interim Survivor Curve: Iowa 100 R3
Probable Retirement Year: 2061

2009	24,010,650.00	51.07	470,167.32	40.68	19,125,814.40
2013	808,896.00	47.29	17,105.02	40.85	698,664.16
2014	116,803.00	46.34	2,520.66	40.88	103,052.76
2015	551,902.00	45.38	12,160.76	40.92	497,599.10
2017	372,742.54	43.47	8,575.19	40.98	351,451.82
2018	71,334.90	42.51	1,678.23	41.02	68,834.29
Total	25,932,328.44	50.63	512,207.19	40.70	20,845,416.53

Newman Common

Interim Survivor Curve: Iowa 100 R3
Probable Retirement Year: 2061

2007	160,779.12	52.94	3,037.09	40.58	123,257.10
2008	20,186.31	52.01	388.16	40.63	15,772.07
2009	64.00	51.07	1.25	40.68	50.98
2011	94,960.00	49.19	1,930.67	40.77	78,705.13
2012	1,839.00	48.24	38.12	40.81	1,555.67
2013	457,993.00	47.29	9,684.78	40.85	395,580.27
2014	471,692.00	46.34	10,179.33	40.88	416,163.66
2015	311,977.00	45.38	6,874.19	40.92	281,280.87
2016	12,694.27	44.43	285.73	40.95	11,701.57
2017	305,492.93	43.47	7,028.06	40.98	288,043.44
2018	12,733,852.36	42.51	299,578.14	41.02	12,287,473.33
2019	4,329,051.87	41.54	104,208.84	41.04	4,277,251.27

EPE

Electric Division

311.00 Structures and Improvements

Original Cost Of Utility Plant In Service

And Development Of Composite Remaining Life as of December 31, 2019

Based Upon Broad Group/Remaining Life Procedure and Technique

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
Total	18,900,581.86	42.64	443,234.37	41.01	18,176,835.36
Account Total	44,832,910.30	46.92	955,441.55	40.84	39,022,251.89

Composite Average Remaining Life ... 40.8 Years

EPE
Electric Division
312.00 Boiler Plate Equipment

Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2019
Based Upon Broad Group/Remaining Life Procedure and Technique

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)

Newman Unit 5

Interim Survivor Curve: Iowa 70 R4
Probable Retirement Year: 2061

Year	Original Cost	Avg. Service Life	Avg. Annual Accrual	Avg. Remaining Life	Future Annual Accruals
2009	284,318.00	50.89	5,587.22	40.40	225,748.40
2011	105,108,024.98	49.10	2,140,608.36	40.61	86,936,205.39
2014	33,449.00	46.36	721.53	40.86	29,484.06
2015	665,280.00	45.43	14,644.57	40.93	599,431.15
2016	147,060.00	44.49	3,305.32	40.99	135,499.39
2017	866,997.74	43.55	19,908.42	41.05	817,256.72
2018	431,841.46	42.60	10,136.88	41.10	416,644.45
2019	5,304,640.56	41.65	127,369.80	41.15	5,240,984.71
Total	112,841,611.74	48.59	2,322,282.09	40.65	94,401,254.28

Newman Common

Interim Survivor Curve: Iowa 70 R4
Probable Retirement Year: 2061

Year	Original Cost	Avg. Service Life	Avg. Annual Accrual	Avg. Remaining Life	Future Annual Accruals
2010	43,764.00	50.00	875.29	40.51	35,460.72
2011	17,000.35	49.10	346.23	40.61	14,061.21
2012	2,397,353.00	48.20	49,742.25	40.70	2,024,706.84
2013	416,566.00	47.28	8,810.48	40.79	359,355.36
2015	528.00	45.43	11.62	40.93	475.74
2016	248,959.73	44.49	5,595.61	40.99	229,388.63
2017	3,457,802.02	43.55	79,399.70	41.05	3,259,422.50
2018	160,966.13	42.60	3,778.46	41.10	155,301.54
2019	9,731.17	41.65	233.66	41.15	9,614.40
Total	6,752,670.40	45.38	148,793.29	40.91	6,087,786.94

EPE

Electric Division

312.00 Boiler Plate Equipment

Original Cost Of Utility Plant In Service

And Development Of Composite Remaining Life as of December 31, 2019

Based Upon Broad Group/Remaining Life Procedure and Technique

Year	Original Cost	Avg. Service Life	Avg. Annual Accrual	Avg. Remaining Life	Future Annual Accruals
(1)	(2)	(3)	(4)	(5)	(6)
Account Total	119,594,282.14	48.40	2,471,075.38	40.67	100,489,041.22

Composite Average Remaining Life ... 40.7 Years

EPE
Electric Division
313.00 Engines and Engine-Driven Generators

Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2019
Based Upon Broad Group/Remaining Life Procedure and Technique

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
			Newman Unit 5		
Interim Survivor Curve: Iowa 55 R2.5					
Probable Retirement Year: 2061					
2009	31,709,713.19	46.12	687,513.29	36.26	24,927,941.24
2010	1,153.00	45.50	25.34	36.56	926.25
2011	1,348.00	44.87	30.05	36.84	1,106.81
2012	17,187.00	44.21	388.78	37.11	14,426.22
2013	3,794,837.00	43.53	87,174.30	37.36	3,257,062.00
2014	59,128.00	42.84	1,380.28	37.61	51,906.60
2015	76,615.00	42.13	1,818.68	37.84	68,812.82
2016	9,235,878.45	41.40	223,091.06	38.06	8,489,912.74
2017	187,497.81	40.66	4,611.72	38.26	176,458.49
2018	1,299,787.62	39.90	32,576.87	38.46	1,252,908.19
2019	2,049,572.36	39.13	52,382.31	38.65	2,024,398.84
Total	48,432,717.43	44.39	1,090,992.67	36.91	40,265,860.22
Account Total	48,432,717.43	44.39	1,090,992.67	36.91	40,265,860.22

Composite Average Remaining Life ... 36.9 Years

EPE
Electric Division
314.00 Turbogenerator Units

Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2019
Based Upon Broad Group/Remaining Life Procedure and Technique

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
		Newman Unit 5			
Interim Survivor Curve: Iowa 75 R2.5					
Probable Retirement Year: 2061					
2011	38,397,553.01	47.45	809,223.52	39.29	31,791,579.92
2012	156,960.00	46.60	3,367.98	39.39	132,664.32
2016	148,338.99	43.15	3,437.93	39.76	136,701.57
2017	21,483,821.45	42.27	508,282.12	39.85	20,253,470.00
2018	1,001,016.75	41.38	24,190.17	39.93	965,839.58
2019	463,281.94	40.49	11,442.18	40.00	457,726.72
Total	61,650,972.14	45.33	1,359,943.91	39.51	53,737,982.11
		Newman Common			
Interim Survivor Curve: Iowa 75 R2.5					
Probable Retirement Year: 2061					
2009	30,272.00	49.12	616.30	39.07	24,076.27
2019	27,824.94	40.49	687.22	40.00	27,491.29
Total	58,096.94	44.57	1,303.52	39.56	51,567.57
Account Total	61,709,069.08	45.33	1,361,247.43	39.51	53,789,549.67

Composite Average Remaining Life ... 39.5 Years

EPE
Electric Division
315.00 Accessory Electric Equipment

Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2019
Based Upon Broad Group/Remaining Life Procedure and Technique

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
		Newman Unit 5			
Interim Survivor Curve: Iowa 65 S4					
Probable Retirement Year: 2061					
2009	7,527,349.00	51.31	146,707.08	40.81	5,986,924.66
2011	12,308,989.00	49.53	248,512.49	41.03	10,196,632.85
2017	46,588.25	43.88	1,061.71	41.38	43,933.98
2019	4,215,650.49	41.93	100,539.89	41.43	4,165,380.55
Total	24,098,576.74	48.51	496,821.16	41.05	20,392,872.04
		Newman Common			
Interim Survivor Curve: Iowa 65 S4					
Probable Retirement Year: 2061					
2019	157,236.60	41.93	3,749.97	41.43	155,361.62
Total	157,236.60	41.93	3,749.97	41.43	155,361.62
Account Total	24,255,813.34	48.46	500,571.13	41.05	20,548,233.66

Composite Average Remaining Life ... 41.0 Years

EPE
Electric Division
316.00 Miscellaneous Power Plant Equipment

Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2019
Based Upon Broad Group/Remaining Life Procedure and Technique

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
			Newman Unit 5		
Interim Survivor Curve: Iowa 70 S2					
Probable Retirement Year: 2061					
2009	1,111,963.00	49.48	22,472.36	39.00	876,324.33
2011	659,294.00	47.89	13,766.76	39.40	542,353.38
Total	1,771,257.00	48.88	36,239.13	39.15	1,418,677.72
			Newman Zero Liquid Discharge		
Interim Survivor Curve: Iowa 70 S2					
Probable Retirement Year: 2061					
2011	13,079,566.00	47.89	273,115.33	39.40	10,759,610.86
2013	799,390.00	46.25	17,284.27	39.75	687,071.33
2014	496,618.00	45.41	10,935.92	39.91	436,478.63
Total	14,375,574.00	47.71	301,335.52	39.43	11,883,160.82
			Newman Common		
Interim Survivor Curve: Iowa 70 S2					
Probable Retirement Year: 2061					
2004	49,032.56	53.22	921.29	37.80	34,825.26
2005	0.40	52.50	0.01	38.06	0.29
2006	134,487.48	51.77	2,597.89	38.31	99,528.89
2007	534,839.12	51.02	10,483.02	38.55	404,124.19
2008	139,666.00	50.26	2,779.02	38.78	107,767.12
2009	745,434.00	49.48	15,064.95	39.00	587,467.35
2011	4,804.00	47.89	100.31	39.40	3,951.90
2012	2,791.00	47.08	59.29	39.58	2,346.53
2013	311,991.00	46.25	6,745.81	39.75	268,154.56

EPE
Electric Division
316.00 Miscellaneous Power Plant Equipment

Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2019
Based Upon Broad Group/Remaining Life Procedure and Technique

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
2014	551,150.00	45.41	12,136.76	39.91	484,406.92
2015	196,656.34	44.56	4,413.04	40.06	176,799.09
2016	60,024.22	43.70	1,373.47	40.20	55,217.22
2017	113,496.72	42.83	2,649.77	40.33	106,872.30
2018	101,106.19	41.95	2,410.00	40.45	97,491.20
2019	125,450.88	41.06	3,055.05	40.56	123,923.35
Total	3,070,929.91	47.40	64,789.67	39.40	2,552,876.19
Account Total	19,217,760.91	47.76	402,364.31	39.40	15,854,714.72

Composite Average Remaining Life ... 39.4 Years

EPE
Electric Division
341.00 Structures and Improvements

Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2019
Based Upon Broad Group/Remaining Life Procedure and Technique

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)

Rio Grande Unit 9

Interim Survivor Curve: Iowa 60 R4
Probable Retirement Year: 2058

Year	Original Cost	Avg. Service Life	Avg. Annual Accrual	Avg. Remaining Life	Future Annual Accruals
2012	14,315.00	44.87	319.06	37.38	11,925.39
2013	21,964,717.00	43.99	499,259.12	37.50	18,723,498.10
2014	55,737.00	43.11	1,292.87	37.62	48,633.77
2015	57,899.00	42.22	1,371.50	37.72	51,732.97
2016	0.16	41.31	0.00	37.81	0.15
2019	65,464.88	38.54	1,698.72	38.04	64,615.96
Total	22,158,133.04	43.97	503,941.27	37.51	18,900,406.33

Montana Power Station Unit 1

Interim Survivor Curve: Iowa 60 R4
Probable Retirement Year: 2060

Year	Original Cost	Avg. Service Life	Avg. Annual Accrual	Avg. Remaining Life	Future Annual Accruals
2015	0.37	43.99	0.01	39.50	0.33
2016	0.13	43.11	0.00	39.61	0.12
2017	53,393.15	42.22	1,264.76	39.72	50,233.54
2018	44,026.81	41.31	1,065.76	39.81	42,429.15
2019	217,926.95	40.39	5,394.92	39.90	215,230.93
Total	315,347.41	40.82	7,725.45	39.85	307,894.08

Montana Power Station Unit 2

Interim Survivor Curve: Iowa 60 R4
Probable Retirement Year: 2060

Year	Original Cost	Avg. Service Life	Avg. Annual Accrual	Avg. Remaining Life	Future Annual Accruals
2016	0.13	43.11	0.00	39.61	0.12
2018	38,756.30	41.31	938.18	39.81	37,349.89

EPE

Electric Division

341.00 Structures and Improvements

Original Cost Of Utility Plant In Service

And Development Of Composite Remaining Life as of December 31, 2019

Based Upon Broad Group/Remaining Life Procedure and Technique

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
2019	218,425.00	40.39	5,407.25	39.90	215,722.82
Total	257,181.43	40.53	6,345.43	39.88	253,072.84

Montana Power Station Unit 3

Interim Survivor Curve: Iowa 60 R4
Probable Retirement Year: 2061

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
2016	0.17	43.99	0.00	40.50	0.16
2018	21,889.97	42.22	518.52	40.72	21,112.67
2019	184,924.94	41.31	4,476.49	40.81	182,687.92
Total	206,815.08	41.40	4,995.02	40.80	203,800.75

Montana Power Station Unit 4

Interim Survivor Curve: Iowa 60 R4
Probable Retirement Year: 2061

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
2018	52,232.69	42.22	1,237.27	40.72	50,377.94
2019	185,253.51	41.31	4,484.44	40.81	183,012.52
Total	237,486.20	41.51	5,721.72	40.79	233,390.45

Montana Power Station Common

Interim Survivor Curve: Iowa 60 R4
Probable Retirement Year: 2061

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
2015	12,407,156.00	44.87	276,539.34	40.37	11,163,954.82
2016	462,284.88	43.99	10,507.76	40.50	425,538.96
2017	20,325.37	43.11	471.47	40.61	19,147.58
2018	69,116.48	42.22	1,637.21	40.72	66,662.19
2019	5,049,094.68	41.31	122,223.75	40.81	4,988,016.26

EPE
Electric Division
341.00 Structures and Improvements

Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2019
Based Upon Broad Group/Remaining Life Procedure and Technique

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
Total	18,007,977.41	43.77	411,379.52	40.51	16,663,319.82
Account Total	41,182,940.57	43.81	940,108.40	38.89	36,561,884.26

Composite Average Remaining Life ... 38.9 Years

EPE
Electric Division
342.00 Fuel Holders

Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2019
Based Upon Broad Group/Remaining Life Procedure and Technique

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
		Rio Grande Unit 9			
Interim Survivor Curve: Iowa 50 R4					
Probable Retirement Year: 2058					
2013	3,118,540.00	42.72	72,994.17	36.23	2,644,885.24
2015	280,628.00	41.22	6,807.46	36.73	250,031.69
2016	26,734.00	40.44	661.11	36.94	24,422.51
2018	89,857.58	38.81	2,315.61	37.31	86,386.72
2019	253,018.91	37.96	6,665.36	37.46	249,688.31
Total	3,768,778.49	42.14	89,443.71	36.40	3,255,414.47
		Montana Power Station Common			
Interim Survivor Curve: Iowa 50 R4					
Probable Retirement Year: 2061					
2015	5,489,927.00	43.43	126,399.85	38.94	4,921,858.96
2016	9,689,787.30	42.72	226,804.19	39.23	8,896,837.78
2017	40,162.88	41.99	956.58	39.49	37,773.64
2018	41,440.78	41.22	1,005.27	39.72	39,934.06
2019	5,616,109.70	40.44	138,881.00	39.94	5,546,715.44
Total	20,877,427.66	42.26	494,046.89	39.35	19,443,119.89
Account Total	24,646,206.15	42.24	583,490.60	38.90	22,698,534.36

Composite Average Remaining Life ... 38.9 Years

EPE
Electric Division
343.00 Prime Movers

Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2019
Based Upon Broad Group/Remaining Life Procedure and Technique

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)

Rio Grande Unit 9

Interim Survivor Curve: Iowa 40 S1
Probable Retirement Year: 2058

Year	Original Cost	Avg. Service Life	Avg. Annual Accrual	Avg. Remaining Life	Future Annual Accruals
2013	55,119,692.31	35.80	1,539,868.23	29.48	45,398,238.41
2015	226,256.00	34.98	6,468.99	30.55	197,596.52
2016	740,668.00	34.53	21,448.69	31.07	666,341.27
2017	376,461.48	34.07	11,050.91	31.58	348,989.32
2018	2,128,825.45	33.58	63,400.47	32.08	2,033,924.66
2019	963,154.84	33.07	29,128.17	32.57	948,596.75
Total	59,555,058.08	35.63	1,671,365.46	29.67	49,593,686.92

Montana Power Station Unit 1

Interim Survivor Curve: Iowa 40 S1
Probable Retirement Year: 2060

Year	Original Cost	Avg. Service Life	Avg. Annual Accrual	Avg. Remaining Life	Future Annual Accruals
2015	41,566,855.25	35.80	1,161,245.23	31.37	36,424,297.04
2016	12,002,288.82	35.40	339,082.06	31.93	10,827,575.97
2017	314,755.88	34.98	8,999.33	32.49	292,387.44
2018	2,676,625.13	34.53	77,511.26	33.04	2,560,609.79
2019	22,049,315.82	34.07	647,251.05	33.57	21,725,827.60
Total	78,609,840.90	35.19	2,234,088.94	32.15	71,830,697.83

Montana Power Station Unit 2

Interim Survivor Curve: Iowa 40 S1
Probable Retirement Year: 2060

Year	Original Cost	Avg. Service Life	Avg. Annual Accrual	Avg. Remaining Life	Future Annual Accruals
2015	50,230,343.00	35.80	1,403,275.42	31.37	44,015,957.49
2017	709,092.25	34.98	20,273.98	32.49	658,699.90
2018	56,092.24	34.53	1,624.35	33.04	53,660.98

EPE
Electric Division
343.00 Prime Movers

Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2019
Based Upon Broad Group/Remaining Life Procedure and Technique

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
2019	22,508,197.70	34.07	660,721.39	33.57	22,177,977.17
Total	73,503,725.19	35.24	2,085,895.15	32.08	66,906,295.54

Montana Power Station Unit 3

Interim Survivor Curve: Iowa 40 S1
Probable Retirement Year: 2061

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
2016	50,480,044.14	35.80	1,410,251.27	32.33	45,594,990.88
2017	35,212.76	35.40	994.81	32.91	32,740.27
2018	51,285.90	34.98	1,466.34	33.48	49,091.21
2019	12,443,014.35	34.53	360,332.03	34.03	12,262,925.83
Total	63,009,557.15	35.54	1,773,044.46	32.68	57,939,748.20

Montana Power Station Unit 4

Interim Survivor Curve: Iowa 40 S1
Probable Retirement Year: 2061

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
2016	49,380,041.64	35.80	1,379,520.71	32.33	44,601,437.79
2017	5,665.96	35.40	160.07	32.91	5,268.12
2018	51,228.00	34.98	1,464.68	33.48	49,035.79
2019	12,988,503.50	34.53	376,128.62	34.03	12,800,520.08
Total	62,425,439.10	35.52	1,757,274.09	32.70	57,456,261.78

Montana Power Station Common

Interim Survivor Curve: Iowa 40 S1
Probable Retirement Year: 2061

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
2015	24,750,764.00	36.17	684,258.03	31.74	21,721,103.38
2016	7,977,795.33	35.80	222,874.13	32.33	7,205,768.37
2017	227,231.98	35.40	6,419.63	32.91	211,276.72

EPE
Electric Division
343.00 Prime Movers

Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2019
Based Upon Broad Group/Remaining Life Procedure and Technique

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
2018	1,051,552.70	34.98	30,065.43	33.48	1,006,553.42
2019	680,190.98	34.53	19,697.37	34.03	670,346.53
Total	34,687,534.99	36.01	963,314.59	31.99	30,815,048.43
Account Total	371,791,155.41	35.46	10,484,982.69	31.91	334,541,738.71

Composite Average Remaining Life ... 31.9 Years

EPE
Electric Division
344.00 Generators

Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2019
Based Upon Broad Group/Remaining Life Procedure and Technique

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
			Rio Grande Unit 9		
Interim Survivor Curve: Iowa 45 S3					
Probable Retirement Year: 2058					
2014	8,420,577.00	40.03	210,330.66	34.53	7,263,767.04
Total	8,420,577.00	40.03	210,330.66	34.53	7,263,767.04
			Montana Power Station Unit 1		
Interim Survivor Curve: Iowa 45 S3					
Probable Retirement Year: 2060					
2015	4,453,424.00	40.55	109,819.36	36.05	3,959,237.61
2016	0.07	40.03	0.00	36.53	0.06
2017	15,176.96	39.48	384.39	36.98	14,215.98
2019	1,654,089.86	38.28	43,213.18	37.78	1,632,483.27
Total	6,122,690.89	39.91	153,416.93	36.54	5,605,936.93
			Montana Power Station Unit 2		
Interim Survivor Curve: Iowa 45 S3					
Probable Retirement Year: 2060					
2015	4,518,913.00	40.55	111,434.29	36.05	4,017,459.45
2016	0.07	40.03	0.00	36.53	0.06
2017	20,165.07	39.48	510.73	36.98	18,888.25
2019	1,583,612.76	38.28	41,371.96	37.78	1,562,926.78
Total	6,122,690.90	39.93	153,316.97	36.52	5,599,274.54

EPE
Electric Division
344.00 Generators

Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2019
Based Upon Broad Group/Remaining Life Procedure and Technique

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
Montana Power Station Unit 3					
Interim Survivor Curve: Iowa 45 S3					
Probable Retirement Year: 2061					
2016	4,534,801.97	40.55	111,826.10	37.05	4,143,411.11
2018	43,254.16	39.48	1,095.51	37.98	41,610.89
2019	1,663,040.30	38.90	42,754.90	38.40	1,641,662.85
Total	6,241,096.43	40.09	155,676.52	37.43	5,826,684.85
Montana Power Station Unit 4					
Interim Survivor Curve: Iowa 45 S3					
Probable Retirement Year: 2061					
2016	4,490,700.58	40.55	110,738.58	37.05	4,103,116.04
2019	1,635,527.31	38.90	42,047.58	38.40	1,614,503.52
Total	6,126,227.89	40.10	152,786.16	37.42	5,717,619.56
Montana Power Station Common					
Interim Survivor Curve: Iowa 45 S3					
Probable Retirement Year: 2061					
2015	63.16	41.03	1.54	36.53	56.23
Total	63.16	41.03	1.54	36.53	56.23
Account Total	33,033,346.27	40.01	825,528.78	36.36	30,013,339.16

Composite Average Remaining Life ... 36.4 Years

EPE
Electric Division
345.00 Accessory Electric Equipment

Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2019
Based Upon Broad Group/Remaining Life Procedure and Technique

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)

Rio Grande Unit 9

Interim Survivor Curve: Iowa 45 S1.5
Probable Retirement Year: 2058

Year	Original Cost	Avg. Service Life	Avg. Annual Accrual	Avg. Remaining Life	Future Annual Accruals
2013	4,666,024.00	38.54	121,083.55	32.11	3,888,493.01
2014	50,603.00	38.02	1,330.82	32.57	43,349.02
2015	193,495.00	37.49	5,161.38	33.02	170,413.37
2016	248,559.77	36.93	6,730.41	33.44	225,095.61
2019	27,928.77	35.12	795.25	34.62	27,531.20
Total	5,186,610.54	38.39	135,101.42	32.23	4,354,882.20

Montana Power Station Unit 1

Interim Survivor Curve: Iowa 45 S1.5
Probable Retirement Year: 2060

Year	Original Cost	Avg. Service Life	Avg. Annual Accrual	Avg. Remaining Life	Future Annual Accruals
2015	2,298,034.00	38.54	59,634.10	34.06	2,031,402.27
2016	6,460.42	38.02	169.90	34.54	5,868.16
2017	73,776.95	37.49	1,967.96	34.99	68,867.42
2019	737,246.97	36.35	20,282.04	35.85	727,107.52
Total	3,115,518.34	37.97	82,054.00	34.53	2,833,245.36

Montana Power Station Unit 2

Interim Survivor Curve: Iowa 45 S1.5
Probable Retirement Year: 2060

Year	Original Cost	Avg. Service Life	Avg. Annual Accrual	Avg. Remaining Life	Future Annual Accruals
2015	2,319,983.00	38.54	60,203.67	34.06	2,050,804.61
2017	11,595.07	37.49	309.29	34.99	10,823.47
2018	11,229.51	36.93	304.07	35.43	10,773.84
2019	687,154.74	36.35	18,903.98	35.85	677,704.22

EPE
Electric Division
345.00 Accessory Electric Equipment

Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2019
Based Upon Broad Group/Remaining Life Procedure and Technique

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
Total	3,029,962.32	38.01	79,721.01	34.50	2,750,106.13

Montana Power Station Unit 3

Interim Survivor Curve: Iowa 45 S1.5
Probable Retirement Year: 2061

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
2016	2,305,411.81	38.54	59,825.55	35.05	2,096,880.70
2019	381,237.87	36.93	10,323.01	36.43	376,077.18
Total	2,686,649.68	38.30	70,148.56	35.25	2,472,957.88

Montana Power Station Unit 4

Interim Survivor Curve: Iowa 45 S1.5
Probable Retirement Year: 2061

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
2016	1,837,822.10	38.54	47,691.57	35.05	1,671,585.82
2019	412,952.31	36.93	11,181.76	36.43	407,362.31
Total	2,250,774.41	38.23	58,873.34	35.31	2,078,948.13

Montana Power Station Common

Interim Survivor Curve: Iowa 45 S1.5
Probable Retirement Year: 2061

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
2015	7,655,912.00	39.02	196,185.14	34.55	6,778,821.41
2016	718,565.63	38.54	18,646.81	35.05	653,569.31
2017	398,263.35	38.02	10,474.02	35.53	372,134.36
2018	33,384.89	37.49	890.53	35.99	32,050.38
2019	509,954.69	36.93	13,808.36	36.43	503,051.60
Total	9,316,080.56	38.82	240,004.86	34.75	8,339,627.05

EPE

Electric Division

345.00 Accessory Electric Equipment

Original Cost Of Utility Plant In Service

And Development Of Composite Remaining Life as of December 31, 2019

Based Upon Broad Group/Remaining Life Procedure and Technique

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
Account Total	25,585,595.85	38.42	665,903.19	34.28	22,829,766.75

Composite Average Remaining Life ... *34.3 Years*

EPE
Electric Division
346.00 Miscellaneous Power Plant Equipment

Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2019
Based Upon Broad Group/Remaining Life Procedure and Technique

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)

Rio Grande Unit 9

Interim Survivor Curve: Iowa 50 R4
Probable Retirement Year: 2058

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
2013	347,016.00	42.72	8,122.44	36.23	294,310.00
2015	63,044.00	41.22	1,529.32	36.73	56,170.44
Total	410,060.00	42.49	9,651.75	36.31	350,480.43

Montana Power Station Unit 1

Interim Survivor Curve: Iowa 50 R4
Probable Retirement Year: 2060

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
2015	157,176.29	42.72	3,678.95	38.23	140,641.93
2016	9,448.44	41.99	225.04	38.49	8,661.65
2017	25,577.62	41.22	620.46	38.73	24,027.88
2019	105,366.45	39.63	2,658.65	39.13	104,037.99
Total	297,568.80	41.43	7,183.09	38.61	277,369.45

Montana Power Station Unit 2

Interim Survivor Curve: Iowa 50 R4
Probable Retirement Year: 2060

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
2015	163,198.86	42.72	3,819.92	38.23	146,030.95
2016	9,445.55	41.99	224.97	38.49	8,659.00
2017	1,398.71	41.22	33.93	38.73	1,313.96
2019	101,707.62	39.63	2,566.33	39.13	100,425.29
Total	275,750.74	41.50	6,645.14	38.59	256,429.20

EPE
Electric Division
346.00 Miscellaneous Power Plant Equipment

Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2019
Based Upon Broad Group/Remaining Life Procedure and Technique

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
		Montana Power Station Unit 3			
Interim Survivor Curve: Iowa	***50 R4***				
Probable Retirement Year:	***2061***				
2016	164,399.45	42.72	3,848.02	39.23	150,946.06
2019	64,958.90	40.44	1,606.37	39.94	64,156.25
Total	229,358.35	42.05	5,454.39	39.44	215,102.31
		Montana Power Station Unit 4			
Interim Survivor Curve: Iowa	***50 R4***				
Probable Retirement Year:	***2061***				
2016	159,884.27	42.72	3,742.33	39.23	146,800.38
2019	71,343.41	40.44	1,764.25	39.94	70,461.87
Total	231,227.68	41.99	5,506.59	39.45	217,262.25
		Montana Power Station Common			
Interim Survivor Curve: Iowa	***50 R4***				
Probable Retirement Year:	***2061***				
2015	460,840.04	43.43	10,610.36	38.94	413,154.80
2016	246,367.59	42.72	5,766.61	39.23	226,206.46
2017	28,253.29	41.99	672.92	39.49	26,572.54
2018	13.50	41.22	0.33	39.72	13.01
2019	5,456.71	40.44	134.94	39.94	5,389.29
Total	740,931.13	43.11	17,185.16	39.06	671,336.09

EPE

Electric Division

346.00 Miscellaneous Power Plant Equipment

Original Cost Of Utility Plant In Service

And Development Of Composite Remaining Life as of December 31, 2019

Based Upon Broad Group/Remaining Life Procedure and Technique

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
Account Total	2,184,896.70	42.32	51,626.13	38.51	1,987,979.73

Composite Average Remaining Life ... 38.5 Years

EPE
Electric Division
353.00 Station Equipment

Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2019
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 58 *Survivor Curve:* R3

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
1971	526,623.00	58.00	9,079.70	16.89	153,356.47
1972	1,465,123.00	58.00	25,260.74	17.52	442,505.52
1973	830,125.00	58.00	14,312.50	18.16	259,889.77
1974	457,149.00	58.00	7,881.88	18.81	148,272.30
1975	12,440.00	58.00	214.48	19.48	4,177.30
1976	659,449.00	58.00	11,369.81	20.16	229,170.46
1978	3,158,528.00	58.00	54,457.37	21.55	1,173,431.58
1979	172,153.00	58.00	2,968.15	22.26	66,080.27
1980	1,750,237.00	58.00	30,176.49	22.99	693,725.45
1981	454,991.00	58.00	7,844.67	23.73	186,114.88
1982	474,315.00	58.00	8,177.84	24.47	200,106.26
1983	67,742.00	58.00	1,167.97	25.23	29,463.83
1984	30,136,091.13	58.00	519,587.66	25.99	13,505,825.94
1985	446,273.00	58.00	7,694.36	26.77	205,972.84
1986	365,093.00	58.00	6,294.71	27.55	173,439.80
1987	3,728,603.00	58.00	64,286.24	28.35	1,822,423.14
1988	40,283.00	58.00	694.53	29.15	20,247.43
1989	18,304,721.00	58.00	315,598.57	29.96	9,456,369.84
1990	1,202,871.09	58.00	20,739.15	30.79	638,464.13
1991	486,654.83	58.00	8,390.60	31.62	265,275.46
1992	245,717.72	58.00	4,236.51	32.45	137,492.62
1994	816,065.00	58.00	14,070.08	34.15	480,558.52
1995	341,890.76	58.00	5,894.67	35.02	206,416.11
1996	91,907.52	58.00	1,584.61	35.89	56,865.41
1997	7,116,863.78	58.00	122,704.52	36.76	4,511,175.35
1998	175,658.00	58.00	3,028.59	37.65	114,026.46
1999	590,888.00	58.00	10,187.72	38.54	392,659.72

EPE

Electric Division

353.00 Station Equipment

Original Cost Of Utility Plant In Service

And Development Of Composite Remaining Life as of December 31, 2019

Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 58 *Survivor Curve:* R3

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
2000	5,501,615.28	58.00	94,855.42	39.44	3,741,132.88
2001	283,287.13	58.00	4,884.26	40.35	197,063.96
2002	983,371.56	58.00	16,954.68	41.26	699,537.92
2003	8,363,933.16	58.00	144,205.71	42.18	6,082,280.25
2004	1,451,295.11	58.00	25,022.32	43.10	1,078,497.87
2005	30,224.48	58.00	521.11	44.03	22,945.56
2006	823,449.97	58.00	14,197.41	44.97	638,424.71
2007	875,249.45	58.00	15,090.50	45.91	692,767.68
2008	13,069,854.10	58.00	225,342.26	46.85	10,558,111.52
2009	8,325,190.16	58.00	143,537.73	47.80	6,861,715.76
2010	768,558.00	58.00	13,251.00	48.76	646,106.62
2011	11,856,654.77	58.00	204,425.04	49.72	10,163,478.81
2012	4,266,962.65	58.00	73,568.31	50.68	3,728,474.60
2013	4,698,296.24	58.00	81,005.09	51.65	4,183,667.54
2014	3,791,123.75	58.00	65,364.19	52.62	3,439,251.07
2015	8,131,729.00	58.00	140,202.19	53.59	7,513,336.11
2016	27,725,691.45	58.00	478,029.06	54.57	26,083,775.74
2017	7,271,160.92	58.00	125,364.82	55.54	6,963,234.07
2018	4,284,404.78	58.00	73,869.03	56.52	4,175,394.43
2019	2,023,057.91	58.00	34,880.30	57.51	2,005,882.82
Total	188,643,565.70	58.00	3,252,474.56	41.52	135,048,586.78

Composite Average Remaining Life ... *41.52 Years*

EPE

Electric Division

356.00 Overhead Conductors and Devices

Original Cost Of Utility Plant In Service

And Development Of Composite Remaining Life as of December 31, 2019

Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 65 **Survivor Curve:** R4

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
1956	146,272.02	65.00	2,250.33	10.24	23,040.38
1957	704,843.42	65.00	10,843.69	10.76	116,642.89
1958	134,966.97	65.00	2,076.40	11.29	23,449.52
1959	59,410.78	65.00	914.01	11.86	10,842.25
1960	172,635.92	65.00	2,655.92	12.45	33,057.49
1961	30,353.87	65.00	466.98	13.06	6,099.53
1962	59,669.77	65.00	917.99	13.69	12,570.22
1963	419,687.88	65.00	6,456.70	14.34	92,581.54
1964	78,008.11	65.00	1,200.12	15.00	18,004.23
1965	98,298.61	65.00	1,512.28	15.67	23,704.14
1966	196,059.68	65.00	3,016.29	16.36	49,348.85
1967	50,228.98	65.00	772.75	17.05	13,178.54
1968	78,467.25	65.00	1,207.18	17.76	21,441.36
1969	4,389,413.96	65.00	67,529.08	18.48	1,247,660.00
1970	240,182.42	65.00	3,695.09	19.21	70,966.92
1971	140,778.76	65.00	2,165.82	19.94	43,191.59
1972	4,331.31	65.00	66.64	20.70	1,379.05
1973	86,552.63	65.00	1,331.57	21.46	28,569.08
1974	125,203.94	65.00	1,926.20	22.23	42,822.99
1975	214,114.22	65.00	3,294.05	23.02	75,823.60
1976	82,001.04	65.00	1,261.55	23.81	30,043.05
1977	45,063.42	65.00	693.28	24.62	17,071.45
1978	6,274,378.22	65.00	96,528.38	25.44	2,455,943.70
1979	120,396.33	65.00	1,852.24	26.27	48,667.49
1980	273,032.84	65.00	4,200.48	27.12	113,896.34
1981	83,929.04	65.00	1,291.21	27.97	36,113.37
1982	85,727.06	65.00	1,318.87	28.83	38,022.15

EPE
Electric Division
356.00 Overhead Conductors and Devices

Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2019
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 65 **Survivor Curve:** R4

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
1983	7,433.17	65.00	114.36	29.70	3,396.71
1984	10,445,319.43	65.00	160,696.36	30.58	4,914,547.29
1985	122,949.49	65.00	1,891.52	31.48	59,535.63
1986	8,924.57	65.00	137.30	32.37	4,444.76
1987	1,461,532.50	65.00	22,484.99	33.28	748,337.63
1988	6,526.22	65.00	100.40	34.20	3,433.52
1989	32,221,214.00	65.00	495,708.33	35.12	17,409,002.74
1990	924,495.66	65.00	14,222.93	36.05	512,731.63
1991	1,548,213.09	65.00	23,818.54	36.99	880,930.37
1993	3,252,007.17	65.00	50,030.61	38.88	1,944,946.66
1994	104,011.00	65.00	1,600.16	39.83	63,732.71
1995	323,456.00	65.00	4,976.22	40.79	202,961.65
1996	1,749,955.00	65.00	26,922.24	41.75	1,123,989.65
1997	1,503,797.00	65.00	23,135.21	42.72	988,232.23
1998	767,106.00	65.00	11,801.57	43.69	515,569.63
1999	108,455.00	65.00	1,668.53	44.66	74,516.21
2000	136,281.00	65.00	2,096.62	45.64	95,684.19
2001	24,980.00	65.00	384.31	46.62	17,915.30
2002	4,542.99	65.00	69.89	47.60	3,326.81
2003	417,846.75	65.00	6,428.38	48.58	312,317.88
2004	1,601,976.76	65.00	24,645.66	49.57	1,221,702.89
2005	11,239.99	65.00	172.92	50.56	8,742.82
2006	18,896.47	65.00	290.71	51.55	14,986.04
2007	61.29	65.00	0.94	52.54	49.54
2008	4,964,821.00	65.00	76,381.45	53.53	4,088,958.14
2009	480,169.09	65.00	7,387.18	54.53	402,803.11
2010	381,848.00	65.00	5,874.55	55.52	326,166.59

EPE

Electric Division

356.00 Overhead Conductors and Devices

Original Cost Of Utility Plant In Service

And Development Of Composite Remaining Life as of December 31, 2019

Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 65 **Survivor Curve:** R4

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
2011	331,951.00	65.00	5,106.91	56.52	288,630.60
2012	72,725.20	65.00	1,118.84	57.51	64,348.94
2013	5,292,660.48	65.00	81,425.11	58.51	4,764,249.39
2014	671,915.00	65.00	10,337.10	59.51	615,142.72
2015	6,252,900.00	65.00	96,197.95	60.51	5,820,561.39
2016	5,757,857.43	65.00	88,581.95	61.50	5,448,175.22
2017	1,078,321.01	65.00	16,589.47	62.50	1,036,889.37
2018	959,064.79	65.00	14,754.76	63.50	936,952.93
2019	856,286.68	65.00	13,173.57	64.50	849,705.05
Total	98,265,748.68	65.00	1,511,772.65	39.99	60,461,749.64

Composite Average Remaining Life ... 39.99 Years

EPE
Electric Division
362.00 Station Equipment

Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2019
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 71 *Survivor Curve:* R1.5

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
1949	132,785.39	71.00	1,870.20	23.06	43,127.53
1950	154,482.58	71.00	2,175.79	23.54	51,211.19
1951	14,430.28	71.00	203.24	24.02	4,882.23
1952	180,419.37	71.00	2,541.09	24.51	62,290.47
1953	387,333.37	71.00	5,455.34	25.01	136,446.20
1954	230,058.09	71.00	3,240.22	25.52	82,687.87
1955	1,135,479.90	71.00	15,992.51	26.03	416,322.12
1956	659,221.01	71.00	9,284.71	26.55	246,549.04
1957	374,558.35	71.00	5,275.42	27.08	142,870.13
1958	185,114.29	71.00	2,607.22	27.62	72,002.71
1959	491,666.14	71.00	6,924.80	28.16	195,009.02
1960	501,793.03	71.00	7,067.43	28.71	202,905.52
1961	906,271.17	71.00	12,764.25	29.27	373,582.30
1962	5,985,649.41	71.00	84,304.06	29.83	2,514,887.05
1963	87,922.18	71.00	1,238.33	30.40	37,645.93
1964	400,555.68	71.00	5,641.57	30.98	174,775.26
1965	292,893.27	71.00	4,125.22	31.56	130,205.23
1966	500,346.56	71.00	7,047.06	32.16	226,601.50
1967	319,100.35	71.00	4,494.33	32.75	147,199.97
1968	1,053,457.46	71.00	14,837.28	33.36	494,899.33
1969	697,514.04	71.00	9,824.04	33.97	333,697.81
1970	630,760.87	71.00	8,883.86	34.58	307,233.08
1971	667,652.22	71.00	9,403.46	35.21	331,073.61
1972	757,663.36	71.00	10,671.21	35.84	382,415.11
1973	122,135.52	71.00	1,720.20	36.47	62,739.55
1974	715,664.54	71.00	10,079.68	37.11	374,087.76
1975	1,642,629.05	71.00	23,135.38	37.76	873,570.09

EPE
Electric Division
362.00 Station Equipment

Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2019
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 71 **Survivor Curve:** R1.5

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
1976	1,959,201.97	71.00	27,594.11	38.41	1,059,978.99
1977	224,490.42	71.00	3,161.80	39.07	123,534.67
1978	1,112,069.70	71.00	15,662.79	39.74	622,373.67
1979	156,304.54	71.00	2,201.45	40.40	88,949.17
1980	2,060,100.29	71.00	29,015.20	41.08	1,191,901.04
1981	677,360.53	71.00	9,540.19	41.76	398,397.24
1982	495,451.80	71.00	6,978.12	42.44	296,181.01
1983	3,041,273.46	71.00	42,834.40	43.14	1,847,671.97
1984	640,730.20	71.00	9,024.28	43.83	395,532.15
1985	937,138.22	71.00	13,198.99	44.53	587,731.71
1986	451,516.43	71.00	6,359.32	45.23	287,659.89
1987	2,121,394.43	71.00	29,878.49	45.94	1,372,696.79
1988	383,155.22	71.00	5,396.50	46.66	251,784.71
1989	4,195,982.44	71.00	59,097.74	47.37	2,799,721.53
1990	2,502,513.27	71.00	35,246.30	48.10	1,695,188.08
1991	2,083,436.75	71.00	29,343.88	48.82	1,432,657.24
1992	603,189.62	71.00	8,495.54	49.55	420,975.59
1993	4,259,761.00	71.00	59,996.02	50.29	3,017,056.61
1994	4,877,113.92	71.00	68,691.04	51.03	3,504,968.66
1995	2,686,212.84	71.00	37,833.60	51.77	1,958,489.38
1996	3,565,975.39	71.00	50,224.49	52.51	2,637,416.49
1998	3,836,536.09	71.00	54,035.17	54.01	2,918,664.77
1999	1,099,558.01	71.00	15,486.57	54.77	848,193.25
2000	4,471,004.40	71.00	62,971.25	55.53	3,496,760.00
2001	3,036,108.43	71.00	42,761.65	56.29	2,407,134.43
2002	1,880,479.20	71.00	26,485.35	57.06	1,511,180.63
2003	6,876,593.16	71.00	96,852.43	57.83	5,600,743.31

EPE
Electric Division
362.00 Station Equipment

Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2019
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 71 **Survivor Curve: R1.5**

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
2004	9,247,214.37	71.00	130,241.12	58.60	7,632,111.31
2005	4,210,946.31	71.00	59,308.49	59.38	3,521,537.10
2006	5,283,396.30	71.00	74,413.27	60.16	4,476,386.73
2007	1,516,022.60	71.00	21,352.21	60.94	1,301,156.95
2008	10,664,651.53	71.00	150,204.82	61.72	9,271,374.10
2009	12,989,999.38	71.00	182,955.86	62.51	11,437,259.36
2010	7,839,712.21	71.00	110,417.35	63.31	6,990,205.92
2011	3,903,549.10	71.00	54,979.00	64.10	3,524,308.39
2012	15,715,505.73	71.00	221,342.88	64.90	14,365,450.83
2013	12,841,627.23	71.00	180,866.13	65.70	11,883,793.33
2014	17,697,216.39	71.00	249,254.01	66.51	16,577,930.98
2015	7,662,667.00	71.00	107,923.78	67.32	7,265,426.29
2016	8,088,380.63	71.00	113,919.69	68.13	7,761,570.10
2017	14,099,908.61	71.00	198,588.23	68.95	13,692,014.30
2018	27,826,349.93	71.00	391,916.40	69.77	27,342,671.11
2019	48,573,423.21	71.00	684,125.71	70.59	48,291,094.03
Total	287,622,779.74	71.00	4,050,983.53	60.86	246,528,751.38

Composite Average Remaining Life ... 60.86 Years

EPE

Electric Division

366.00 Underground Conduit

Original Cost Of Utility Plant In Service

And Development Of Composite Remaining Life as of December 31, 2019

Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 71 *Survivor Curve:* R4

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
1952	69.87	71.00	0.98	12.16	11.97
1953	3,233.44	71.00	45.54	12.72	579.06
1957	17,755.63	71.00	250.08	15.15	3,789.31
1958	23,485.27	71.00	330.78	15.80	5,226.55
1959	1,024.57	71.00	14.43	16.47	237.65
1960	8,967.72	71.00	126.31	17.14	2,165.06
1961	4,755.42	71.00	66.98	17.83	1,194.09
1962	70,605.51	71.00	994.44	18.52	18,418.31
1963	13,389.25	71.00	188.58	19.22	3,625.02
1964	7,826.61	71.00	110.23	19.94	2,197.99
1965	79,971.40	71.00	1,126.36	20.66	23,272.08
1966	26,373.62	71.00	371.46	21.40	7,948.39
1967	12,058.25	71.00	169.83	22.14	3,760.35
1968	29,995.59	71.00	422.47	22.89	9,672.14
1969	170,812.21	71.00	2,405.80	23.66	56,929.61
1970	115,300.43	71.00	1,623.95	24.44	39,686.50
1971	21,289.78	71.00	299.86	25.23	7,564.74
1972	3,807.43	71.00	53.63	26.02	1,395.59
1973	299,361.82	71.00	4,216.35	26.83	113,142.97
1974	770,539.83	71.00	10,852.65	27.65	300,100.91
1975	320,544.24	71.00	4,514.70	28.48	128,575.57
1976	679,247.57	71.00	9,566.85	29.32	280,502.23
1977	348,744.37	71.00	4,911.88	30.17	148,178.86
1978	736,270.06	71.00	10,369.98	31.03	321,744.50
1979	723,393.09	71.00	10,188.61	31.89	324,943.49
1980	894,628.90	71.00	12,600.38	32.77	412,876.87
1981	815,811.33	71.00	11,490.28	33.65	386,685.43

EPE
Electric Division
366.00 Underground Conduit

Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2019
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 71 **Survivor Curve:** R4

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
1982	700,253.44	71.00	9,862.70	34.54	340,704.27
1983	892,305.36	71.00	12,567.65	35.45	445,475.81
1984	1,605,075.12	71.00	22,606.64	36.35	821,829.65
1985	1,337,967.15	71.00	18,844.57	37.27	702,283.50
1986	1,207,537.33	71.00	17,007.53	38.19	649,527.00
1987	1,411,487.33	71.00	19,880.06	39.12	777,666.31
1988	1,235,347.37	71.00	17,399.22	40.05	696,893.28
1989	1,229,239.00	71.00	17,313.19	40.99	709,712.87
1990	1,114,041.57	71.00	15,690.69	41.94	658,020.29
1991	1,004,159.01	71.00	14,143.05	42.89	606,575.47
1992	1,049,587.54	71.00	14,782.89	43.84	648,125.73
1993	1,081,834.06	71.00	15,237.07	44.80	682,667.34
1994	1,504,406.99	71.00	21,188.78	45.77	969,727.87
1995	2,457,277.98	71.00	34,609.47	46.73	1,617,388.39
1996	2,738,595.73	71.00	38,571.69	47.70	1,840,022.59
1997	2,252,983.99	71.00	31,732.10	48.68	1,544,630.43
1998	4,445,985.23	71.00	62,619.37	49.65	3,109,322.77
1999	4,190,942.40	71.00	59,027.23	50.63	2,988,741.35
2000	3,818,249.54	71.00	53,778.05	51.62	2,775,759.85
2001	4,019,085.33	71.00	56,606.71	52.60	2,977,441.85
2002	4,977,792.08	71.00	70,109.60	53.58	3,756,764.76
2003	5,358,382.29	71.00	75,470.01	54.57	4,118,547.24
2004	7,901,354.10	71.00	111,286.44	55.56	6,183,169.82
2005	6,794,769.02	71.00	95,700.76	56.55	5,412,020.32
2006	5,073,437.78	71.00	71,456.72	57.54	4,111,842.21
2007	7,071,508.27	71.00	99,598.49	58.54	5,830,076.53
2008	5,443,699.10	71.00	76,671.65	59.53	4,564,249.41

EPE

Electric Division

366.00 Underground Conduit

Original Cost Of Utility Plant In Service

And Development Of Composite Remaining Life as of December 31, 2019

Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 71 **Survivor Curve:** R4

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
2009	4,886,039.37	71.00	68,817.31	60.52	4,165,126.25
2010	2,440,363.75	71.00	34,371.25	61.52	2,114,517.92
2011	3,022,456.18	71.00	42,569.71	62.52	2,661,289.92
2012	4,692,725.35	71.00	66,094.58	63.51	4,197,842.47
2013	4,486,032.56	71.00	63,183.42	64.51	4,075,961.48
2014	5,850,132.74	71.00	82,396.06	65.51	5,397,567.10
2015	3,812,436.00	71.00	53,696.17	66.51	3,571,099.65
2016	6,402,652.64	71.00	90,178.01	67.50	6,087,376.55
2017	5,067,903.99	71.00	71,378.77	68.50	4,889,630.97
2018	5,500,517.88	71.00	77,471.91	69.50	5,384,414.72
2019	7,552,464.59	71.00	106,372.51	70.50	7,499,319.06
Total	141,830,292.37	71.00	1,997,605.42	56.16	112,187,758.24

Composite Average Remaining Life ... 56.16 Years

BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

IN THE MATTER OF THE APPLICATION OF EL PASO ELECTRIC COMPANY FOR REVISION OF ITS RETAIL ELECTRIC RATES PURSUANT TO ADVICE NOTICE NO. 267	))))))	**Case No. 20-00104-UT**

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the **Direct Testimony of David J. Garrett (on behalf of City of Las Cruces and Doña Ana County)** were sent via email on October 9, 2020, to the following persons listed below:

Nancy Burns	nancy.burns@epelectric.com;	Fred Kennon	fredk@donaanacounty.org;
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DATED this 9th day of October, 2020.

Respectfully submitted,

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