Mr. Sullivan further testified that on Page 18, Lines 9 through 10, Mr. Garrett states that "Mr. Sullivan, however, provided no other analysis, documentation, or support for the proposed lifespan decreases." This statement is misleading on a couple of fronts. First, it fails to indicate that Mr. Sullivan also recommended lifespan increases set forth above. Furthermore, all of the lifespans Mr. Garrett recommended are based on Mr. Sullivan's recommendations from either Schedule TJS-2 or his 2010 Report (and not based on currently approved lifespans as Mr. Garrett asserts, as there are none because the settlement was not based on a lifespan methodology) and Mr. Sullivan essentially provided the same support and/or rationale for both sets of lifespan recommendations. The recommendations in TJS-2 are based on more current expectations; that is the only real difference between the two sets of numbers.

According to Mr. Sullivan, The OIEC is using a zero net salvage allowance. While Mr. Garrett's testimony on Pages 13 through 16 only discusses terminal net salvage, in fact, the OIEC has not included any salvage or cost of removal allowance on interim or final retirements. In his testimony, Mr. Garrett appears to confuse salvage and cost of removal associated with interim retirements (retirements that occur over the life of the asset) and final or terminal cost of removal and salvage associated with the decommissioning of the power plant. However, the OIEC's recommendations are not limited to terminal net salvage but rather reflect no cost of removal or salvage allowances at all.

Mr. Sullivan testified that the OIEC did not accurately characterize the net salvage allowances he used in the development of the depreciation rates he recommended for the Company's production facilities and his responses to their data requests.

On Page 15, Lines 6 through 8, Mr. Garrett asks and answers the following:

"Q. Did Empire provide any other adequate support for its proposed terminal net salvage rates?

A. No. When asked in discovery to provide all justification and support for the proposed net salvage rates, Mr. Sullivan states that the proposed net salvage amounts "represent minimal allowances that we deem reasonable absent specific demolition studies".

In fact, the above question and answer are a complete fabrication achieved by cutting and pasting three different answers to three different data requests regarding two separate and distinct issues.

In Schedule TJS-3, Mr. Sullivan provided copies of his responses to OIEC data requests 2.14, 4.2, and 9.1.

In data request 2.14, the OIEC asked for all decommissioning studies Mr. Sullivan relied upon. In his response, he indicated that the only decommissioning studies relied upon were for Riverton 7, 8 and 9. Mr. Garrett's discussion on Pages 13 through 16 of his direct testimony did not pertain to Riverton 7, 8 and 9, because neither the OIEC nor the Company recommended depreciation rates for Riverton 7, 8 and 9 since these units are retired. Thus, nowhere in Mr. Sullivan's recommended depreciation rates for the Company's production units did he include any allowance for terminal net salvage.

In Mr. Sullivan's response to OIEC data request 4.2, his response clearly stated that the Company did not include any terminal net salvage in our determination of the depreciation rates for the Company's production units. The response clearly states that: "All net salvage rates for production accounts are for interim retirements".

Finally, in Mr. Sullivan's response to OIEC data request 9.1, he indicated what net salvage allowances he used for interim retirements, having previously established through OIEC data request 4.2 that all salvage rates were for interim retirements. The last sentence that is quoted in Mr. Garrett's testimony is taken completely out of context. The last sentence is properly interpreted to mean that the Company used minimal allowances (for interim retirements only), and when taken in the context of the other two data requests, Empire did not use any terminal net salvage unless there were specific demolition studies (as was the case for Riverton 7,8 and 9).

Mr. Sullivan testified that OIEC's recommendation regarding net salvage for the production facilities was not reasonable.

First, Mr. Garrett's testimony does not address the actual net salvage amounts Mr. Sullivan recommended. He is actually discussing a fabrication of a terminal net salvage recommendation that does not exist. The actual net salvage allowances Mr. Sullivan had reflected are minimal allowances that he deemed reasonable for interim cost of removal and salvage. The adjustment for terminal net salvage that Mr. Garrett actually makes relative to Mr. Sullivan's recommendation is to remove minimal allowances for interim activity for which he provides no justification in his testimony. Mr. Garrett provides justification for removing an adjustment that does not exist.

Mr. Sullivan further testified that on Page 17, Lines 3 through 10 of his direct testimony, Mr. Garrett's response to his question again tries to cleverly combine unrelated statements to create the appearance of something that is simply not there. First, the question between Lines 2 and 3 asks: "Is the cost recovery of plant that has not been deemed prudent or "used and useful" appropriate?" Nowhere in Mr. Sullivan's analyses did he advocate the recovery of investment through depreciation expense for plant that is not in service. Yet, Mr. Garrett's response essentially acknowledges that the question creates a premise that is not true because his response to this question actually answers a different question than the question he poses. On Page 17, Lines 6 through 8, Mr. Garrett states: "Mr. Sullivan's proposed depreciation rates for the Company's production accounts mathematically incorporate these unapproved future plant additions." While this statement is also not accurate, nowhere does Mr. Garrett say (because it is patently not true) that Mr.Sullivan recommended that depreciation expense be calculated based on plant that is not yet in service. Yet, his question insinuates this false premise.

According to Mr. Sullivan, the analyses contained in Appendix A of Schedule TJS-2 show the detailed calculation of the depreciation rates he recommended for Empire's production facilities. They do not show the calculation of depreciation expenses. This analysis includes the historical additions and retirements by account for each generating unit property as well as forecasts of future additions and retirements based on this historical experience. The purpose of this analysis is to estimate the amount of plant balance that would be available each of the remaining years such that a true straight line depreciation rate can be determined that will depreciate all the investment in the facility as (and only as) that investment is actually made.

Mr. Sullivan testified that the failure to consider the impact of future interim retirements and additions results in depreciation rates that are low during the early years of the generating units' lifespan and higher during the later years. This happens primarily for the following reasons:

1. Failure to recognize that many of the component assets have an average service life that is less than the entire lifespan of the generating units.

2. Failure to recognize that capital improvements that are made after the initial in-service date of the asset will have service lives that are less than the entire lifespan of the generating units.

3. Failure to recognize that in order for the generating units to achieve the relatively long lifespans historically experienced, significant capital improvements are made to extend the assets' life and/or to bring the units up to current technology and regulations such that the plants can continue to economically provide service. These relatively large capital additions usually have service lives much less than the lifespan of the generating unit.

Mr. Sullivan testified that it is clearly demonstrated in the existing depreciation rates for Empire's steam production units as shown in Schedule TJS-2. The lowest current depreciation rate is 2.10 percent for Iatan II (put in service in 2010) which is Empire's newest steam production unit. Plum Point (2010) is roughly the same age but has a shorter estimated life, so its current depreciation rate is 2.33 percent. Iatan 1 (1980) is the next oldest unit and is significantly older than Iatan 2 and it has a current depreciation rate of 3.12 percent. The Company's oldest steam production unit is Asbury (1970) and it has a depreciation rate of 4.73 percent. Asbury best demonstrates the phenomena Mr.Sullivan discussed above as shown on Page A-6 of the Depreciation Study (Schedule TJS-2).

The net effect is loading most of the depreciation expense near the end of, and even beyond, the useful life of the generating unit. This creates a huge disconnect between the recovery of the cost of the facility and the value received by the customers who most benefit from the facility. This is further exacerbated when one also takes into account that base load generating units tend to be used less and less as they approach the end of their useful life because newer units tend to be more efficient and economical to dispatch, and are therefore utilized more.

Mr. Sullivan testified that his recommended method did not accelerate depreciation expense accrual.

As Schedules TJS-4 and TJS-5 demonstrates, the deprecation accrual rates are stable throughout the entire service life of the asset.

Mr. Sullivan further testified that his recommended method did not result in mathematically collecting depreciation expense on future costs that are not in service and used and useful.

The depreciation rates are applied to the current period actual plant in service balance, the same balance as the depreciation rates developed using the OIEC's approach. There are not any future dollars in the calculation of depreciation expense (depreciation rate times current plant in service balance).

As shown in Section I, Schedule 2 of the Company's revenue requirement model, the depreciation rates are multiplied by plant balances at June 30, 2016, which do not include the interim additions and retirements used in the development of the depreciation rates.

According to Mr. Sullivan, while there is still higher depreciation expense at the end of the asset's life using the approach he is recommending, a more stable depreciation rate results if forecasted interim retirements and additions are included in the determination of the depreciation rate than if they are not included. The approach he is recommending is a reasonable compromise between the OIEC's approach which defers significant amounts of depreciation expense to the later years of (and even beyond) the generating facility's life, and a unit of production approach which would seek to directly match the investment in the facility with the use (i.e. output) of the facility.

The interim retirements and additions he included are only based on historical experience excluding large capital projects. For the newer base load units such as Iatan 2 and Plum Point, there is virtually no way these units are going to be in service in 2070 and 2060, respectively, without large capital improvements (that will have much shorter remaining lives) than what has been reflected in Schedule TJS 2. As such, the depreciation rates for these units will increase significantly if these plants are still in service that far into the future.

Mr. Sullivan testified that if the Commission were to disallow interim retirements and additions, then the plant lives should be shortened. It is not proper to accept the extra life of the plant due to the interim additions while ignoring the cost of those additions. Both need to either be included or both excluded or the depreciation rate will not match the use of the power plant.

As stated on Pages 6-38 through 6-39 of Accounting for Public Utilities:

> "A depreciation study attempts to predict the future. Therefore, these studies endeavor to consider the estimated effects of future events, of which power plant life extension projects are examples. Such projects have two aspects that are linked:
>
> 1) the capital expenditures made to accomplish life extension; and
> 2) the extra life that is the direct result of these expenditures.

Deferral of recording and recovery of depreciation will occur if the link between these two aspects is broken by elimination from the depreciation rate calculations the capital expenditures until they are recorded in plant-in-service, but currently included in the extra life resulting from the expenditures. Because some of the rate calculation components become inconsistent, depreciation rates will initially decrease and will later increase as the expenditures are made and the rates are recalculated. Increasing depreciation rates for power plants are not rational because they do not match the consumption or usage of the underlying asset."

Mr. Sullivan continued his rebuttal by testifying that beginning on Page 16, Line 13 and continuing onto Page 17, Mr. Garrett states that he has never seen depreciation rates for production units calculated the way he had calculated them in Appendix A of Schedule TJS-2. The testimony filed in the Company's last Oklahoma rate case in Cause No. PUD 201100082 included the 2010 Report discussed earlier in this rebuttal testimony. This report uses the same methodology used in Schedule TJS-2.

Prior to starting his own company in 2011, Mr. Sullivan worked for over 30 years for Black & Veatch Corporation. The first depreciation study he worked on for Black & Veatch was in the late 1980's for Black Hills Power and Light Company and it incorporated this same methodology. This methodology was developed coincident with the widespread use of personal computers. The senior experts at Black and Veatch at that time determined that developing a more transparent analysis of unit properties for which a finite retirement date was known was preferable to using what, up until that time, was largely done in a black box program by mainframe computers. While many of those programs have been converted to use on personal computers, they still lack the flexibility and transparency of performing the calculations using a spreadsheet analysis. Thus the methodology used in Appendix A of Schedule TJS-2 has been the standard practice at Black & Veatch since the 1980's.

Mr. Sullivan testified that there were two significant problems with the OIEC's mass property accounts analyses. First, OIEC excluded historical data from their analyses even though the OIEC claims its analyses are based on all the historical data. The result of excluding this data artificially skews the OIEC's results towards longer service lives. Second, the OIEC mischaracterizes the analyses Mr. Sullivan performed by mismatching his recommended Iowa curves to the abbreviated datasets used in their analyses thus leading one to conclude that his results do not match the underlying data used (which includes all the Company's historical data).

On Page 20, Lines 11 and 12, Mr. Garrett states: "I used all of the Company's property data and created an observed life table ("OLT") for each account."

Mr. Sullivan testified that statement was not correct. In fact, Mr. Garrett has truncated the placement and experience bands of the data he presented in his testimony and exhibits. This is most evident by the fact that none of the accounts in Exhibits 2-6 through 2-17 have exposures older than 55 years, yet Empire's continuing property records contain data as far back as 1900.

According to Mr. Sullivan, the following are the accounts which Mr. Garrett identified as material and the full data available for each account:

1. Account 353 – 1900 to the present
2. Account 362 – 1912 to the present
3. Account 364 – 1900 to the present
4. Account 369 – 1926 to the present
5. Account 390 – 1903 to the present

Mr. Garrett's analysis begins with data from 1960 to the present, not "all of the Company's property data". In addition to the accounts listed above, there are several others where Mr. Garrett has used something less than the full set of data available.

Mr. Sullivan testified that the OIEC had mischaracterized the analyses he performed by mismatching Mr. Sullivan's recommended Iowa curves to the abbreviated datasets used in OIEC's analyses.

In Figures 2 through 6 of his testimony, Mr. Garrett claims he is comparing the Company's selected Iowa curve, the OIEC's selected Iowa curve, and the OLT (Observed Life Table) curve, which as Mr. Sullivan indicated earlier he claimed includes all of the Company's property data. First, his analyses did not use all of the Company's property data. Second, the

OIEC graphs are further truncated at 50 percent surviving. Third, the Company analyses Mr. Garrett shows are based on the Iowa curves shown in Mr. Sullivan's Schedule TJS-2 which do include all of the Company's property data. By making these apples and oranges comparisons, Mr. Garrett's figures mislead the reader into believing that his selected curves fit all of the Company's data better than the curves Mr. Sullivan used, when in fact they do not. His curves fit the truncated (1960 to present) data better. Nowhere in his testimony does Mr. Garrett make this critical distinction. In Mr. Sullivan's workpapers, he provided analyses using both the full data sets and also a test against the 1960 to present shortened data set, but his recommended Iowa curves are based on the full data sets available.

Mr. Sullivan prepared curves showing how his selected curves actually fit all the Company data.

These curves are included in Schedule TJS-6. This schedule shows that the curves Mr. Sullivan recommended fit all of the data better than the curves selected by the OIEC.

In response to a question of what was the net effect of the OIEC using the abbreviated data set, Mr. Sullivan testified that there were two impacts that bias the results towards producing longer lives. By Mr. Garrett removing the older plant and focusing on only the top half of the survivor curve (100% to 50% surviving), he has stretched out the curve by removing the tails of the curve and by removing plant that has gone through its full life cycle. Mr. Sullivan stated that it needed to be made clear that the mathematical analyses underlying his analyses and the OIEC's are essentially the same, a least squares or best fit analysis comparing actual data to standardized Iowa curves. The only difference results from using different data band; the full data band versus the truncated data band. The OIEC has not used all of the Company's data as it claims it has used.

In response to AG witness Farrar, Mr. Sullivan testified that on Page 11, beginning at line 2, Mr. Farrar states that Empire's proposed depreciation rates should be rejected because "future additions to plant were included in the filed depreciation study". Mr. Sullivan assumed Mr. Farrar was referring to interim additions which he addressed in his rebuttal testimony.

He disagreed that consideration of the effective interim activity on the calculation of depreciation rates is an "inappropriate rate making policy". If one excludes the expenditures one must also exclude the extra life which is a result of those expenditures. To not do so would certainly be inappropriate rate making policy.

Mr. Sullivan testified that the depreciation rates recommended in Schedule TJS-2 (based on total Company plant in service at June 30, 2015) resulted in a reduction in depreciation expenses of $198,726 for transmission plant, a reduction in depreciation expenses of $3,654,194 for distribution plant, and an increase in depreciation expenses of $68,859 for general plant. The reductions in depreciation expenses for transmission and distribution plant resulted primarily from recommending longer lives than the lives underlying the existing depreciation rates.

According to Mr. Sullivan, the depreciation rates were reviewed by the Missouri Public Service Commission Staff in Docket No. ER-2016-0023. For the mass property accounts, the Missouri Public Service Commission Staff's findings were so close that he did not even bother to rebut them in that case. Further, the Staff's overall recommendation on the mass property accounts was for generally shorter lives than Mr. Sullivan recommended.

Mr. Sullivan concluded by stating the OIEC's testimony and exhibits are based on misrepresentations and unreasonable and inaccurately supported recommendations. The AG's recommendation is contrary to sound depreciation theory. Therefore, neither should be relied upon by the Commission.

DR. JAMES H. VANDER WEIDE

Direct Testimony

Dr. James H. Vander Weide, President of Financial Strategy Associates, a firm that provides strategic and financial consulting services to business clients, testified on behalf of Empire.

Dr. Vander Weide testified that he estimated Empire's cost of equity by applying several standard cost of equity methods to market data for a large proxy group of electric utility companies.

According to Dr. Vander Weide, he applied his cost of equity methods to a large group of comparable risk companies because standard cost of equity methods such as the discounted cash flow ("DCF"), risk premium, and capital asset pricing model ("CAPM") require inputs of quantities that are not easily measured. Because these inputs can only be estimated, there is naturally some degree of uncertainty surrounding the estimate of the cost of equity for each company. However, the uncertainty in the estimate of the cost of equity for an individual company can be greatly reduced by applying cost of equity methods to a large sample of comparable companies; and thus, unusually high estimates for some individual companies are offset by unusually low estimates for other individual companies. Intuitively, unusually high estimates for some individual companies are offset by unusually low estimates for other individual companies. Thus, financial economists invariably apply cost of equity methods to one or more groups of comparable companies. In utility regulation, the practice of using comparable companies, called the comparable company approach, is further supported by the principle enunciated by the United States Supreme Court that the utility should be allowed to earn a return on its investment that is commensurate with returns being earned on other investments of the same risk (*see Bluefield Water Works and Improvement Co. v. Public Service Comm'n.* 262 U.S. 679, 692 (1923) and *Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 561, 603 (1944)).

Dr. Vander Weide testified that on the basis of his studies, he found that the cost of equity for his proxy companies is in the range 9.3 percent to 10.5 percent, with an average equal to 9.9 percent. This conclusion was based on his application of standard cost of equity estimation techniques, including the DCF model, the ex ante risk premium approach, the ex post risk premium approach, and the CAPM, to a broad group of electric utilities, and on the evidence he presented in his testimony that the CAPM, as typically applied, significantly underestimates the cost of equity for companies such as his proxy companies with betas significantly less than 1.0.

He recommended that Empire be authorized a rate of return on equity equal to 9.9 percent.

According to Dr. Vander Weide, his recommended 9.9 percent return on equity is conservative because it does not reflect the higher financial risk implicit in the Company's ratemaking capital structure compared to the average financial risk of the proxy companies' market value capital structure. The financial risk of the proxy companies depends on the market values of the debt and equity in the companies' capital structures.

According to Dr. Vander Weide, economists define the cost of capital as the return investors expect to receive on alternative investments of comparable risk.

The cost of capital is a hurdle rate, or cut-off rate, for investment in a company or project. If investors do not expect to earn a return on their investment in a company or project that is at least as large as the return they expect to receive on other investments of comparable risk, rational investors will not invest in the company or project.

Debt investors have a fixed claim on a firm's assets and income that must be paid prior to any payment to the firm's equity investors. Since the firm's equity investors have only a residual claim on the firm's assets and income, equity investments are riskier than debt investments. Thus, the cost of equity exceeds the cost of debt.

The overall or average cost of capital is a weighted average of the cost of debt and cost of equity, where the weights are the percentages of debt and equity in a firm's capital structure.

According to Dr. Vander Weide economists define the cost of equity as the return investors expect to receive on alternative equity investments of comparable risk. Since the return on an equity investment of comparable risk is not a contractual return, the cost of equity is more difficult to measure than the cost of debt. However, as he noted, there is agreement among economists that the cost of equity is greater than the cost of debt. There is also agreement among economists that the cost of equity, like the cost of debt, is both forward looking and market based.

Dr. Vander Weide testified that investors estimate the expected rate of return in several steps. First, they estimate the amount of their investment in the company. Second, they estimate the timing and amounts of the cash flows they expect to receive from their investment over the life of the investment. Third, they determine the return, or discount rate, that equates the present value of the expected cash receipts from their investment in the company to the current value of their investment in the company.

Dr. Vander Weide further testified that investors generally measure investment risk by estimating the probability, or likelihood, of earning less than the required return on investment. For investments with potential returns distributed symmetrically about the expected, or mean, return, investors can also measure investment risk by estimating the variance, or volatility, of the potential return on investment.

Dr. Vander Weide explained that business risk is the underlying risk that investors will earn less than their required return on investment when the investment is financed entirely with equity. Financial risk is the additional risk of earning less than the required return when the investment is financed with both fixed-cost debt and equity.

He further testified that the business risk of investing in electric utility companies such as Empire is caused by: (1) demand uncertainty; (2) operating expense uncertainty; (3) investment cost uncertainty; (4) high operating leverage; and (5) regulatory uncertainty.

With regard to regulatory uncertainty, Dr. Vander Weide also testified that investors' perceptions of the business and financial risks of electric utilities are strongly influenced by their views of the quality of regulation. Investors are keenly aware that regulators in some jurisdictions have been unwilling at times to set rates that allow companies an opportunity to recover their cost of service in a timely manner and earn a fair and reasonable return on investment. As a result of the perceived increase in regulatory risk, investors will demand a higher rate of return for electric utilities operating in those jurisdictions. On the other hand, if investors perceive that regulators will provide a reasonable opportunity for the company to maintain its financial integrity and earn a fair rate of return on its investment, investors will view regulatory risk as minimal.

Dr. Vander Weide testified that the risks of investing in electric utilities such as Empire can be distinguished from the risks of investing in companies in many other industries in several ways. First, the risks of investing in electric utilities are increased because of the greater capital intensity of the electric energy business and the fact that most investments in electric energy facilities are largely irreversible once they are made. Second, unlike returns in competitive industries, the returns from investment in electric utilities such as Empire are largely asymmetric. That is, there is little opportunity for the utility to earn more than its required return, but a significant chance that the utility will earn less than its required return.

Dr. Vander Weide testified that he used several generally accepted methods for estimating the cost of equity for Empire. These are the Discounted Cash Flow (DCF), the ex ante risk premium, the ex post risk premium, and the capital asset pricing model (CAPM). The DCF method assumes that the current market price of a firm's stock is equal to the discounted value of all expected future cash flows. The ex ante risk premium method assumes that an investor's current expectations regarding the equity risk premium can be estimated from data on the DCF expected rate of return on equity compared to the interest rate on long-term bonds. The ex post risk premium method assumes that an investor's current expectations regarding the equity-debt return differential is equal to the historical record of comparable returns on stock and bond investments. The cost of equity under both risk premium methods is then equal to the interest rate on bond investments plus the risk premium. The CAPM assumes that the investor's required rate of return on equity is equal to a risk-free rate of interest plus the product of a company-specific risk factor, beta, and the expected risk premium on the market portfolio.

In regard to Dr. Vander Weide's DCF study, Dr. Vander Weide explained that the DCF equation requires estimates of the growth, dividend, and price terms. As his estimate of growth in his DCF model, Dr. Vander Weide used the analysts' estimates of future earnings per share ("EPS") growth reported by I/B/E/S Thomson Reuters. Dr. Vander Weide explained that he used the I/B/E/S growth estimates because his studies indicate that analysts' forecasts are the best estimate of investors' expectation of future long-term growth, and the DCF model requires the growth expectations of investors. Dr. Vander Weide also described his statistical study comparing historical growth rates with the average I/B/E/S analysts' forecasts. In every case, the regression equations containing the average of analysts' forecasts statistically outperformed the regression equations containing the historical growth estimates. These results are consistent with the hypothesis that investors use analysts' forecasts, rather than historically oriented growth calculations, in making stock buy and sell decisions. They provide strong evidence to support the conclusion that the analysts' forecasts of future growth are superior to historically-oriented growth measures in predicting a firm's stock price. He noted that researchers at State Street Financial Advisors updated his study in 2004, and their results continue to confirm that analysts' growth forecasts are superior to historically-oriented growth measures in predicting a company's stock price.

As his estimate for the price term, Dr. Vander Weide used a simple average of the monthly high and low stock prices for each firm for the three-month period ending October 2016. These high and low stock prices were obtained from Thomson Reuters. Dr. Vander Weide testified that he used the three-month average stock price in applying the DCF method because stock prices fluctuate daily, while financial analysts' forecasts for a given company are generally changed less frequently, often on a quarterly basis. Thus, to match the stock price with an earnings forecast, it is appropriate to average stock prices over a three-month period.

He further testified that because Empire is seeking to recover its equity flotation costs as an expense over a five-year period, he did not include an allowance for flotation costs in his cost of equity calculations.

He applied the DCF approach to the Value Line electric companies shown in his Schedule JVW-1.

He selected all the companies in Value Line's groups of electric companies that: (1) paid dividends during every quarter of the last two years; (2) did not decrease dividends during any quarter of the past two years; (3) have an I/B/E/S long-term growth forecast; and (4) are not the subject of a merger offer that has not been completed. In addition, each of the utilities included in his comparable groups had an investment grade bond rating and a Value Line Safety Rank of 1, 2, or 3.

Dr. Vander Weide obtained an average DCF result of 9.3 percent for his proxy company group.

Dr. Vander Weide also employed the risk premium approach to estimate Empire's cost of equity, using two risk premium methods, an ex ante risk premium approach and an ex post risk premium approach. As Dr. Vander Weide explained, the risk premium method is based on the principle that investors expect to earn a return on an equity investment in Empire that reflects a "premium" over and above the return they expect to earn on an investment in a portfolio of bonds. This equity risk premium compensates equity investors for the additional risk they bear in making equity investments versus bond investments.

Dr. Vander Weide's ex ante risk premium method is based on studies of the DCF expected return on a proxy group of electric companies compared to the interest rate on Moody's A-rated utility bonds. Dr. Vander Weide performed a regression analysis to determine if there is a relationship between the calculated risk premium and interest rates and uses the results of the regression analysis to estimate the investors' required risk premium. To estimate the cost of equity using the ex ante risk premium method, according to Dr. Vander Weide, one may add the estimated risk premium over the yield on A-rated utility bonds to the forecasted yield to maturity on A-rated utility bonds. He obtained the expected yield to maturity on A-rated utility bonds, 5.8 percent, by averaging the most recent forecast data from Value Line and the U.S. Energy

Information Administration ("EIA"). For his electric utility sample, his analyses produced an estimated risk premium over the yield on A-rated utility bonds equal to 4.7 percent. Adding an estimated risk premium of 4.7 percent to the expected 5.8 percent yield to maturity on A-rated utility bonds produces a cost of equity estimate of 10.5 percent using the ex ante risk premium method.

Dr. Vander Weide described in detail his ex post risk premium method for measuring the required risk premium on an equity investment in Empire.

Dr. Vander Weide concluded that his ex post risk premium analyses provide evidence that investors today require an equity return of at least 3.9 to 4.5 percentage points above the expected yield on A-rated utility bonds. As discussed above, the expected yield on A-rated utility bonds is 5.8 percent. Adding a 3.9 to 4.5 percentage point risk premium to a yield of 5.8 percent on A-rated utility bonds, he obtained an expected return on equity in the range 9.7 percent to 10.3 percent, with a midpoint estimate equal to 10.0 percent.

Dr. Vander Weide stated that the CAPM is an equilibrium model of the security markets in which the expected or required return on a given security is equal to the risk-free rate of interest, plus the company equity "beta," times the market risk premium:

Cost of equity = Risk-free rate + Equity beta x Market risk premium

The risk-free rate in this equation is the expected rate of return on a risk-free government security, the equity beta is a measure of the company's risk relative to the market as a whole, and the market risk premium is the premium investors require to invest in the market basket of all securities compared to the risk-free security.

According to Dr. Vander Weide, the CAPM requires an estimate of the risk-free rate, the company-specific risk factor or beta, and the expected return on the market portfolio. For his estimate of the risk-free rate, he used the forecasted yield to maturity on 20-year Treasury bonds of 4.45 percent, using forecast data from Value Line and EIA.

For his estimate of the company-specific risk, or beta, he used the average 0.72 Value Line beta for his proxy electric companies and the 0.90 beta estimated from the relationship between the historical risk premium on utilities and the historical risk premium on the market portfolio.

For his estimate of the expected risk premium on the market portfolio, he used two approaches. First, he estimated the risk premium on the market portfolio using historical risk premium data reported in the 2016 Valuation Handbook for the years 1926 through 2015, data which are consistent with the data previously reported by Ibbotson® SBBI®. Second, he estimated the risk premium on the market portfolio from the difference between the DCF cost of equity for the S&P 500 and the forecasted yield to maturity on 20-year Treasury bonds.

Dr. Vander Weide concluded that based on his application of several cost of equity methods to his proxy companies, his proxy companies' cost of equity is in the range 9.3 percent to 10.5 percent, with an average result equal to 9.9 percent. Dr. Vander Weide provided the following table:

TABLE 1
COST OF EQUITY MODEL RESULTS

METHOD	MODEL RESULT
Discounted Cash Flow	9.3%
Ex Ante Risk Premium	10.5%
Ex Post Risk Premium	10.0%
CAPM-Historical	9.7%
CAPM-DCF Based	10.2%
Average	9.9%

Dr. Vander Weide testified that his cost of equity conclusion reflects the financial risk associated with the average market value capital structure of his proxy companies, which has approximately 64 percent equity.

Empire is recommending that its consolidated capital structure containing approximately 49.68 percent common equity be used for rate making purposes in this proceeding.

According to Dr. Vander Weide, although Empire's recommended capital structure contains an appropriate mix of debt and equity and is a reasonable capital structure for rate making purposes in this proceeding, this recommended rate making capital structure embodies greater financial risk than is reflected in his cost of equity estimates from his proxy companies.

Dr. Vander Weide testified that he conservatively recommends an ROE equal to 9.9 percent. This recommendation is conservative in that it does not reflect the higher financial risk implicit in Empire's rate making capital structure compared to the average financial risk of the proxy companies implicit in the values of debt and equity in their market value capital structures.

Rebuttal Testimony

Dr. Vander Weide filed rebuttal testimony to respond to the allowed rate of return on equity and cost of equity recommendations of Mr. David J. Garrett ("OIEC") and Mr. Geoffrey M. Rush ("PUD").

Mr. Garrett recommended an allowed return on equity equal to 9.0 percent, and Mr. Rush recommended an allowed return on equity equal to 9.9 percent. Mr. Garrett estimated a cost of equity equal to 7.5 percent, and Mr. Rush estimated a cost of equity equal to 7.91 percent. According to Dr. Vander Weide, there was nothing in these testimonies that would cause him to change his cost of equity recommendations.

Dr. Vander Weide testified that Mr. Garrett arrived at his recommended 9.0 percent recommended ROE by: (1) estimating that Empire's cost of equity is 7.5 percent; (2) noting that Empire's current allowed ROE is 9.9 percent; and (3) recommending that the Commission gradually reduce Empire's current 9.9 percent allowed return on equity to his 7.5 percent estimate of Empire's cost of equity. In Mr. Garrett's opinion, a reduction of Empire's allowed return on equity from 9.9 percent to 9.0 percent would be a move in the right direction, without increasing Empire's risk.

According to Dr. Vander Weide, Mr. Garrett tested the reasonableness of his recommendations by comparing the average awarded ROE for U.S. electric utilities from 2005 to 2016 to Dr. Damodaran's estimates of the market cost of equity over the same period. The average electric utility awarded ROE over the period 2005 to 2016 was approximately 200 basis points higher than Dr. Damodaran's average estimate of the market cost of equity. Because Mr. Garrett believes that Dr. Damodaran has provided a reasonable estimate of the required market return, Mr. Garrett concludes that: (1) utility commissions, such as the Oklahoma Corporation Commission, have consistently awarded allowed ROEs that exceed utilities' costs of equity by more than 200 basis points; and (2) the Commission should significantly reduce Empire's current 9.9 percent allowed ROE.

Dr. Vander Weide testified that Dr. Damodaran's data simply represents the results of a mechanical application of his market model to market data for the S&P 500. Mr. Garrett fails to acknowledge that public utility commissions generally set a utility's allowed ROE equal to the commission's best estimate of the utility's cost of equity based on the evidence presented in each proceeding. According to Dr. Vander Weide, Mr. Garrett provided no evidence that utility commissions intentionally set a utility's allowed return above the best estimate of the utility's cost of equity. To suggest otherwise is an insult to Commissioners, according to Dr. Vander Weide.

Dr. Vander Weide noted that one of Mr. Garrett's sources in his testimony is the Graham and Harvey annual survey of chief financial officers. In this survey, Graham and Harvey ask the CFO survey participants to provide information on: (1) their companies' internally calculated weighted average costs of capital; and (2) the hurdle rates their companies use to make investment decisions. Graham and Harvey find that the average internally calculated WACC for U.S. companies is in the range 9.3 percent to 9.7 percent, and that the average hurdle rate used to make investment decisions is in the range 13.1 percent to 14.2 percent.

Dr. Vander Weide explained that the "hurdle rate" is the "cut-off" return a company uses as the target rate of return that must be expected to be earned in order to make the investment in the project. For example, a company with a "hurdle rate" of 12 percent, will only accept projects with a return on total invested capital (debt plus equity) greater than 12 percent. He further stated that the company's weighted average cost of capital is the minimum return on total capital that would allow a company to break-even on a project; that is, the project would have a net present value equal to zero. Companies generally set the investment hurdle rate higher than the WACC, in a world of capital constraints, in order to earn a positive net present value on a project.

Dr. Vander Weide further explained the relevance of the Graham and Harvey finding. The data provides a better test of the reasonableness of Mr. Garrett's recommended 9.0 percent ROE and 7.14 percent WACC because they reflect the costs of capital managers actually use to make real-world investment decisions rather than a mechanical application of a formula to market data without any consideration of whether investors actually use this formula in making investment decisions. Thus, in summary, the WACCs and hurdle rates reported by Graham and

Harvey indicate that Mr. Garrett's recommended 9.0 percent allowed ROE and 7.14 percent WACC are far below a reasonable estimate of Empire's cost of equity and weighted average cost of capital. ["The Equity Risk Premium in 2016," John R. Graham and Campbell R. Harvey]

Dr. Vander Weide rebutted Mr. Garrett's 7.5 percent estimate of Empire's cost of equity.

According to Dr. Vander Weide, Mr. Garrett applied the discounted cash flow ("DCF") model and the Capital Asset Pricing Model ("CAPM") to a group of eighteen Value Line electric utilities. Mr. Garrett also applied his cost of equity models to Dr. Vander Weide's larger proxy group, attempting to establish that "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." [Garrett at 23] Mr. Garrett's group excludes companies with market capitalizations "considerably higher than Empire's market capitalization."

Dr. Vander Weide testified that both Mr. Garrett and Dr. Vander Weide used the quarterly DCF model. Mr. Garrett obtained a result of 7.6 percent.

Dr. Vander Weide testified that using the analysts' growth forecasts in Mr. Garrett's DCF model produces a result equal to 9.5 percent, not the 7.6 percent reported by Mr. Garrett.

Dr. Vander Weide's quarterly DCF model results differ from Mr. Garrett's primarily because he used analysts' estimates of long-term growth for the growth component of the DCF model, whereas Mr. Garrett used his estimate of long-run growth in Gross Domestic Product ("GDP") for the growth component of his DCF model.

Dr. Vander Weide used analysts' growth rates reported by I/B/E/S Thomson Reuters because his studies indicate that the analysts' growth rates are highly correlated with stock prices. This evidence provides strong support for the conclusion that investors use analysts' growth rates in making stock buy and sell decisions, and thus the analysts' growth rates should be used to estimate the growth component of the DCF model.

Dr. Vander Weide discussed the analysts' estimates of future EPS growth by saying that part of their research, financial analysts working at Wall Street firms periodically estimate EPS growth for each firm they follow. The EPS forecasts for each firm are then published. Investors who are contemplating purchasing or selling shares in individual companies review the forecasts.

He further testified that I/B/E/S is a division of Thomson Reuters that reports analysts' EPS growth forecasts for a broad group of companies. The forecasts are expressed in terms of a mean forecast and a standard deviation of forecast for each firm. Investors use the mean forecast as an estimate of future firm performance.

Dr. Vander Weide used the I/B/E/S growth rates: (1) are widely circulated in the financial community, (2) include the projections of reputable financial analysts who develop estimates of future EPS growth, (3) are reported on a timely basis to investors, and (4) are widely used by institutions and other investors.

Dr. Vander Weide relies on analysts' projections of future EPS growth rather than historical growth, retention growth, or long-run growth in GDP because there is considerable empirical evidence that analysts' forecasts are the best estimate of investors' expectation of future long-term growth. The evidence that analysts' forecasts are the best estimate of investors' expectation of future long-term growth is important according to Dr. Vander Weide because the DCF model requires the growth expectations of investors.

Dr. Vander Weide testified that he had prepared a study in conjunction with Willard T. Carleton, Professor of Finance Emeritus at the University of Arizona, on why analysts' forecasts are the best estimate of investors' expectation of future long-term growth. This study is described in a paper entitled "Investor Growth Expectations and Stock Prices: the Analysts versus History," published in *The Journal of Portfolio Management*.

Dr. Vander Weide summarized the results of the study. First, a correlation analysis was performed to identify the historically oriented growth rates which best described a firm's stock price. Then a regression study comparing the historical growth rates with the average I/B/E/S analysts' forecasts. In every case, the regression equations containing the average of analysts' forecasts statistically outperformed the regression equations containing the historical growth estimates.

These results are consistent with the hypothesis that investors use analysts' forecasts, rather than historically oriented growth calculations, in making stock buy and sell decisions. They provide strong evidence to support the conclusion that the analysts' forecasts of future growth are superior to historically-oriented growth measures in predicting a firm's stock price. It should be noted that researchers at State Street Financial Advisors updated Dr. Vander Weide's study, and their results continue to confirm that analysts' growth forecasts are superior to historically-oriented growth measures in predicting a company's stock price.

Dr. Vander Weide testified that Mr. Garrett believes that it is inappropriate to use analysts' growth rate forecasts to estimate investors' growth expectations in the DCF model because analysts' growth forecasts generally exceed the projected long-term growth of the economy as a whole; and, in Mr. Garrett's opinion, it would be irrational for investors to believe that companies can grow forever at a rate in excess of the expected growth in the economy.

According to Dr. Vander Weide, Mr. Garrett also considers inflation, real GDP, and the current risk-free rate as additional estimates of long-term GDP growth. However, the 4.1 percent long-term growth estimate that Mr. Garrett uses in his DCF calculation is based entirely on an estimate of nominal GDP growth.

Dr. Vander Weide did not believe it was appropriate for Mr. Garrett to adjust the growth term in his DCF model, without also adjusting the stock price term in his model.

Dr. Vander Weide testified that Mr. Garrett failed to recognize that the DCF model requires the growth expectations of *investors*, not the growth expectations of Mr. Garrett. If investors use analysts' growth rates to value stocks in the marketplace, Mr. Garrett should use analysts' growth rates to estimate the growth component of the DCF model. Mr. Garrett also failed to recognize that companies do not have to grow at the same rate forever for the single-stage DCF Model to be a reasonable approximation of how prices are determined in capital markets.

Dr. Vander Weide further testified that Mr. Garrett's opinion that a company's earnings cannot grow at a rate greater than the rate of growth in the GDP forever does not imply that companies must grow at an expected GDP growth rate in every year. Mr. Garrett's assumption that companies must only grow at the same rate as his estimate of expected GDP growth is completely arbitrary. Further, Mr. Garrett did not examine more than one estimate of nominal long-term GDP growth according to Dr. Vander Weide.

Dr. Vander Weide further testified that he did not believe that long-term GDP growth is the growth estimate investors use when they invest in stocks and, therefore, is not appropriately used as the estimate of growth in the DCF model. He was aware that estimates of nominal long-term GDP growth are available from the Social Security Administration and the Energy Information Administration, for example; and the current nominal long-term GDP estimates from these sources are 4.6 percent and 4.3 percent, approximately 50 basis points and 20 basis points higher than the 4.1 percent estimate used by Mr. Garrett.

Dr. Vander Weide did not agree with Mr. Garrett's CAPM result. Mr. Garrett's estimate of the risk-free rate, his estimate of the risk premium on the market portfolio, and his failure to acknowledge the substantial evidence that the CAPM tends to underestimate the cost of equity for companies such as his proxy companies with betas less than 1.0 were all points of disagreement.

Dr. Vander Weide disagreed with Mr. Garrett's 3.04 percent estimate of the risk-free rate because the analysis presented in his direct testimony indicates that the forecasted yield on long-term Treasury bonds is approximately 4.1 percent. In estimating the forward-looking equity risk premium on equity investments, it is reasonable to use a forecasted interest rate rather than a current interest rate on long-term Treasury securities.

Given the convincing evidence that the CAPM underestimates the cost of equity for companies with betas less than 1.0, Mr. Garrett should have recognized, for this reason alone, that his cost of equity estimates underestimates Empire's cost of equity.

Dr. Vander Weide further testified that Graham and Harvey state that executives report that their firms use actual weighted average costs of capital in the range 9.3 percent to 9.7 percent, and they report that they use investment hurdle rates in the range 13.1 percent to 14.2 percent. Graham and Harvey's reported information on the WACCs and hurdle rates actually used by executives to make investment decisions is more relevant to assessing Empire's cost of equity than the information on executives' views on expected returns.

Because both the weighted average cost of capital and the hurdle rate are weighted averages of the cost of debt and the cost of equity, and the cost of debt is less than the cost of equity, the costs of equity that executives actually use in making real world investment decisions must be significantly higher than the weighted average cost of capital or hurdle rate. Thus, based on this evidence, the market risk premium must be considerably higher than Mr. Garrett's assumed 5.8 percent, and the cost of equity must be considerably higher than Mr. Garrett's calculated 7.4 percent CAPM cost of equity using a 5.8 percent market risk premium.

Dr. Vander Weide also had several concerns with Mr. Garrett's study of the implied market return on the S&P 500. First, his Equation 9 for the value of the S&P 500 is misspecified: the value of each year's forecasted earnings should be discounted by the cost of equity, not by the risk-free rate plus the cost of equity. Second, as shown in his Exhibit DG1-10, Mr. Garrett uses the historical growth over the five-year period 2010 - 2015, 3.14 percent, to forecast future growth, rather than using analysts' forecasts of future growth. Because the economy was in a recession over much of those five years and is expected to perform better in the future, Mr. Garrett's decision to use historical growth ending in a recession year understates investors' expected future growth. For example, the average analysts' forecast for all companies in the S&P 500 is currently 11.6 percent, compared to Mr. Garrett's historical growth rate of 3.14 percent.

With regard to the risk-free rate component of the CAPM, Dr. Vander Weide recommends using a forecasted yield to maturity on Treasury bonds rather than a current yield to maturity because the fair rate of return standard requires that a company have an opportunity to earn its required return on its investment during the forward-looking period during which rates will be in effect. Because current interest rates are depressed as a result of the Federal Reserve's efforts to stimulate the economy by keeping interest rates low, current interest rates at this time are a poor indicator of expected future interest rates. Economists project that future interest rates will be higher than current interest rates as the Federal Reserve allows interest rates to rise in order to prevent inflation. Thus, the use of forecasted interest rates is consistent with the fair rate of return standard, whereas the use of current interest rates at this time is not.

Dr. Vander Weide concluded that Mr. Garrett's CAPM cost of equity estimate is unreasonably low and significantly less than Empire's true cost of equity.

Dr. Vander Weide also rebutted Mr. Garrett's views regarding: (1) the risk of investing in regulated utilities such as Empire; (2) the appropriate upper bound estimate of Empire's cost of equity; and (3) the relationship between depreciation and the cost of capital.

Dr. Vander Weide discussed the risks of investing in regulated electric utilities in his direct testimony on pages 13 – 19. In his discussion, he noted that the business risks of investing in electric utilities is caused by: (1) demand uncertainty; (2) operating expense uncertainty; (3) investment cost uncertainty; (4) high operating leverage; and (5) regulatory uncertainty.

Mr. Garrett argues that Dr. Vander Weide's analysis of the business risks of investing in regulated utilities is misleading because the risks he identifies are all "firm-specific risks" that have no "meaningful effect on the cost of equity estimate," and his view that the regulatory process creates additional risks for utilities is completely untrue. Garrett believes that regulation significantly reduces the risk of investing in electric utilities, rather than increasing the risk of investing in electric utilities.

Dr. Vander Weide testified that the business risks he identified cannot be diversified away because they reflect general risks faced by investors in all industries, rather than the specific risks faced only by investors in electric utilities. He discusses these risks in the context of the electric utility industry to emphasize that the risks of investing in electric utilities has increased as a result of the high costs of meeting increasingly stringent environmental regulations, the impact of technological change has on reducing the demand for electricity generated and sold by electric utilities, and the challenge and complexity of identifying appropriate responses to changing economic conditions in the industry. The structure of the electric utility industry is changing dramatically as more customers are able to obtain electricity from sources other than traditional utilities.

Dr. Vander Weide testified that Mr. Garrett estimated that the average market cost of equity is 8.1 percent.

Mr. Garrett arrives at his 8.1 percent estimate of the market cost of equity by examining the results of the IESE survey, the Graham and Harvey survey, Damodaran, and his own study.

Mr. Garrett concludes that the upper bound for a reasonable estimate of Empire's cost of equity is 8.1 percent.

Dr. Vander Weide testified that Mr. Garrett's conclusion is based on sources that do not provide studies of the cost of equity either for utilities or for the market. Market surveys of executive opinions regarding the expected risk premium on the S&P 500, such as the IESE survey and the Graham and Harvey survey, are not designed to establish an appropriate upper bound for the cost of equity for electric utilities. The Graham and Harvey survey, for example, provides evidence that the executives responding to the survey, in fact, do not use the risk premium data they provide in response to the survey when they are committing their companies' funds to capital projects. Rather, the Graham and Harvey survey provides evidence that companies' use hurdle rates in the range 13.1 percent to 14.2 percent. This 13.1 percent to 14.2 percent range includes both debt and equity costs. Mr. Garrett's 8.1 percent estimate of an upper bound for an electric utility's cost of equity is far below the costs equity that are used to establish hurdle rates for real-world investment decisions.

Mr. Garrett's study on the implied market return on the S&P 500 is flawed in several ways. First, his Equation 9 for the value of the S&P 500 is misspecified: the value of each year's forecasted earnings should be discounted by the cost of equity, not by the risk-free rate plus the cost of equity. Second, as shown in his Exhibit DG1-10, Mr. Garrett uses the historical growth over the five-year period 2010 - 2015, 3.14 percent, to forecast future growth, rather than using analysts' forecasts of future growth. Because the economy was in a recession over much of those five years and is expected to perform better in the future, Mr. Garrett's decision to use historical growth ending in a recession year understates investors' expected future growth. For example, the average analysts' forecast for all companies in the S&P 500 is currently 11.6 percent, compared to Mr. Garrett's historical growth rate of 3.14 percent.

Dr. Vander Weide testified that Mr. Garrett claimed that it was best to over-estimate depreciation lives in depreciation studies because such over-estimation does not harm the company and benefits shareholders. Mr. Garrett stated:

> Moreover, since the Company's awarded and earned returns on equity are far above its true cost of equity, the Company's shareholders further benefit from the excess wealth transfer from ratepayers while these costs are in rate base. 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 overestimated rather than underestimated. [Garrett Depreciation Testimony at 7 – 8]

According to Dr. Vander Weide, Mr. Garrett's assertion is based on his faulty conclusion that Empire's cost of equity is 7.5 percent. Dr. Vander Weide noted that he had been involved in regulatory proceedings for many years, and he could not recall any regulatory commission awarding an allowed rate of return on equity as low as Mr. Garrett's recommended 7.5 percent cost of equity. He had not experienced, and did not believe, Mr. Garrett's assertion that regulators have awarded allowed returns on equity above utilities' cost of equity.

Dr. Vander Weide further testified that Mr. Garrett's statement that utilities "routinely propose awarded returns on equity that far exceed their actual costs of equity for the sole benefit of shareholders, as Empire has done in this case" [Garrett Depreciation Testimony at 34 – 35] is specious, self-serving, and contrary to the extensive evidence presented by the Company in this proceeding. Dr. Vander Weide provided evidence in this case on Empire's cost of equity, and Empire has proposed an allowed return on equity that is equal to his cost of equity estimate, which is based on the average result of his application of the DCF model, the ex ante risk premium approach, the ex post risk premium approach, and the CAPM, to a broad group of electric utilities. Dr. Vander Weide's estimate of Empire's cost of equity is not only equal to Empire's current allowed ROE in Oklahoma, but is also in line with allowed rates of return for electric utilities throughout the country. To the contrary, Mr. Garrett's 7.5 percent estimate of the cost of equity is far lower than any allowed rates of return on equity.

Dr. Vander Weide did not agree with Mr. Garrett's claim that a company's shareholders benefit if depreciable lives are over-estimated. If depreciable lives are over-estimated, shareholders face the considerable risk that they will not recover the full cost of their investment in these assets.

Mr. Rush accepts Empire's requested 9.9 percent ROE, Dr. Vander Weide did not rebut his recommendation to award Empire an allowed ROE equal to 9.9 percent.

Dr. Vander Weide did not agree with the method that Mr. Rush arrived at his 7.91 percent cost of equity estimate.

Mr. Rush arrives at his 7.91 percent cost of equity estimate by applying the DCF, CAPM, and comparable earnings methods to a proxy group of 29 Value Line electric utilities.

Dr. Vander Weide disagreed with Mr. Rush's decisions to: (1) use quarterly dividends from the second quarter of 2016 along with stock prices for the period December 23, 2016, through February 7, 2017; and (2) use of historical dividend growth and fundamental growth along with Value Line's projected earnings growth to estimate the growth component of the DCF model.

Dr. Vander Weide disagreed with Mr. Rush's use of quarterly dividends from the second quarter of 2016 with stock prices from December 23, 2016, through February 7, 2017, inputs because the DCF model is based on the assumption that investors value a stock based on their estimate of the present value of all expected future dividends. Mr. Rush's decision to use dividends from the second quarter 2016 with stock prices from December 23, 2016, through February 7, 2017, violates this basic assumption because Mr. Rush's dividends were paid prior to the observed stock prices. Thus, Mr. Rush's DCF analysis includes a fundamental mismatch of data.

According to Dr. Vander Weide, Mr. Rush estimates the growth component of his DCF analysis from information on his proxy companies': (1) historical dividend growth over the last five years as reported by Value; (2) projected earnings per share growth as reported by Value Line; and (3) fundamental growth. Mr. Rush's final growth estimate is the average of these three growth estimates. Mr. Rush's data for these growth inputs are shown in Exhibit DG-C-6 in his Excel work papers.

The DCF model requires the growth forecasts investors use to value stocks in the marketplace; and Dr. Vander Weide's studies indicate that investors use consensus analysts' earnings per share growth ("EPS") forecasts to value stocks in the marketplace. Mr. Rush should have relied on analysts' earnings per share growth forecasts rather than on historical dividend growth and fundamental growth forecasts.

Dr. Vander Weide further testified that there appeared to be errors in Mr. Rush's growth data. Mr. Rush's work papers indicate that rather than using the Value Line reported historical dividend growth rates for his proxy companies, the formula on his spreadsheet substitutes a zero percent historical growth rate for 18 out of his 29 proxy companies. Mr. Rush reports an average historical growth rate equal to 2.16 percent, whereas the historical average dividend growth rate is 4.93 percent once his formula and data are corrected.

If Mr. Rush had correctly matched dividend and stock price inputs and used the I/B/E/S growth forecasts, he would have obtained a DCF result equal to 9.1 percent. Using the Value Line projected earnings growth forecast as the growth term in his DCF model, Mr. Rush would have obtained a DCF result equal to 9.0 percent.

Dr. Vander Weide testified that because of an error in the formula in his spreadsheet, Mr. Rush reports an annual DCF model result equal to 4.49 percent. However, once errors in the formula that produces this result are corrected, along with the corrections in the growth rates and dividend inputs in the analysis, the annual DCF model result is 9.0 percent.

Regarding the CAPM analysis of Mr. Rush, Dr. Vander Weide testified that for his estimate of the risk-free rate, Mr. Rush uses the 2.90 percent average yield on 30-year Treasury bonds over the period December 15, 2016, through January 30, 2017. For his estimate of the company-specific risk factor or beta, Mr. Rush uses the average 0.71 Value Line beta for his proxy companies. For his estimate of the expected risk premium on the market portfolio, Mr. Rush uses: (1) historical geometric and arithmetic mean risk premium data reported by Ibbotson; (2) the expected risk premiums reported in the Graham and Harvey and the IESE Business School surveys discussed above; and (3) an implied equity risk premium calculation, which is the same as that used by Mr. Garrett. Based on these data, Mr. Rush uses 5.5 percent as his estimate of the risk premium on the market portfolio.

According to Dr. Vander Weide, Mr. Rush should have used a forecasted yield on Treasury bonds because interest rates have been at unusually low levels, and investors are forecasting that interest rates will increase over the period when Empire's rates will be in effect.

Dr. Vander Weide did not agree with Mr. Rush's historical equity risk premium estimates. Mr. Rush used an average of both the geometric and arithmetic mean historical risk premium estimates. The arithmetic mean risk premium is the only risk premium that will make the initial investment grow to the expected value of the investment at the end of the period. For an investment, such as an equity investment in stocks, which has an uncertain outcome, the arithmetic mean is the best historically-based measure of the return investors expect to receive in the future.

Dr. Vander Weide also disagreed with Mr. Rush's use of total return on long-term government bonds to estimate the difference between stock and bond returns because the CAPM requires an estimate of the risk-free rate, but the total return on long-term government bonds is not risk free because it includes capital gains and losses. A correct estimate of the historical risk premium is 6.9 percent, not the 5.2 percent reported by Mr. Rush.

In regards to Mr. Rush's comparable earnings method, Dr. Vander Weide stated that Mr. Rush calculates the average annual earned return on equity for each of his proxy utilities for the years 2012 through 2016. Mr. Rush reports that the average earned return for his group of proxy utilities over this historical period is 9.82 percent, and he uses 9.82 percent as his comparable earnings estimate of Empire's cost of equity.

Dr. Vander Weide had at least three criticisms of Mr. Rush's comparable earnings method. First, Mr. Rush should have used forecasted returns on equity rather than historical returns on equity to estimate each company's ROE. Mr. Rush himself acknowledges that historical returns on equity "should be considered with caution" because they do "not account for any prospective forward-looking factors." [Rush at 35] Further, the historical reported returns include factors such as one-time write-offs that are not expected to occur in the future. Second, Mr. Rush should have examined forecasted earned returns for comparable-risk industrial companies, as Mr. Rush himself also acknowledges [Rush at 34 – 35]. Third, Mr. Rush failed to recognize that Value Line calculates its expected rates of return on book equity by dividing each company's expected earnings by its estimate of the company's year-end equity. Because a rate of return based on year-end equity understates the rate of return on the average equity investment during the year, Mr. Rush should have adjusted Value Line's estimates to reflect rates of return on average equity for each year.

BLAKE A. MERTENS

Direct Testimony

Mr. Blake A. Mertens, Vice President Energy Supply and Delivery Operations for Empire, testified on behalf of Empire.

Mr. Mertens testified that the Asbury Power Plant is a 195 MW coal-fired power plant in northern Jasper County, Missouri, near the Missouri–Kansas state line. The Asbury Power Plant commenced commercial operations on July 1, 1970. The Babcock & Wilcox cyclone boiler was designed to be fueled by bituminous coal from the Pittsburg & Midway mine, which was adjacent to the Asbury Power Plant. Superheated steam from the boiler drove a Westinghouse turbine generator set to generate electrical energy.

According to Mr. Mertens, early pollution controls consisted of an electrostatic precipitator to capture particulate emissions. In the early 1990s, the Environmental Protection Agency created the Acid Rain Program, which required Empire to reduce sulfur dioxide emissions and led to a fuel switch from the local bituminous coal to lower sulfur sub-bituminous coal from the Powder River Basin of Wyoming. This required changes to the fuel handling system to accommodate the higher volume of this less energy dense coal and most notably, the construction of a rotary car dumper to unload the trainloads of coal. In 2008, in anticipation of nitrogen oxides emissions reductions to be required by the Clean Air Interstate Rule, Empire installed a selective catalytic reduction ("SCR") system at the Asbury Power Plant. The SCR injects anhydrous ammonia into the flue gas stream, where in the presence of a catalyst, it reacts with nitrogen oxides to eliminate them.

According to Mr. Mertens, the Federal Clean Air Act and state laws regulate air emissions from stationary sources such as electric power plants through permitting and/or emission control requirements. These requirements include maximum emission limits for sulfur dioxide ("SO2"), particulate matter, nitrogen oxides ("NOx"), carbon monoxide ("CO") and hazardous air pollutants, including mercury. To comply with current and pending environmental regulations, Empire needed to implement a compliance plan at its Asbury unit if the unit was to continue in service. The regulations primarily driving Empire's compliance plan are the Mercury and Air Toxics Standards ("MATS") and the Clean Air Interstate Rule ("CAIR") and its subsequent replacement rule.

Mr. Mertens testified that as part of its 2010 Integrated Resource Plan ("IRP") -- a twenty year planning study -- Empire developed seventeen different resource cases for analysis. Among the alternative resource cases analyzed, the study considered cases that included the construction of the Asbury AQCS or the retirement of Asbury in 2015. Capacity expansion modeling was done for all cases. New conventional and renewable resources, as well as demand-side management programs, were considered available for the capacity expansion required to meet Empire's projected future loads. The resources evaluated to replace or supplement the energy produced by Asbury included supercritical coal, simple cycle combustion turbine, combined cycle, nuclear power purchase agreement, distributed generation, integrated gasification combined cycle, wind, biomass and solar thermal.

Each of the seventeen cases analyzed in the 2010 IRP produced an optimized set of supply-side resources resulting in the lowest present value of revenue requirements ("PVRR") for the scenario represented by that case. Each plan was subjected to stochastic analysis and financial modeling over the planning horizon. Each plan was analyzed at all levels of four critical uncertain factors - environmental costs, market and fuel prices, load forecast and capital and transmission costs and interest rates. This analysis generated seventy-two endpoints for each plan, which make up the risk profiles for the plans.

The risk profiles of the cases that utilized the base case assumptions were compared, and the plan with the lowest risk with respect to PVRR was selected by Empire as its Preferred Plan. This Preferred Plan included the installation of the Asbury AQCS in the 2015 timeframe.

Mr. Mertens further testified that the economic analyses conducted before, during and after the preparation of the 2010 IRP, found that the Asbury AQCS project was the low-cost option for Empire. Additionally, this plan kept approximately 189 MW of Empire owned coal-fired capacity in Empire's generation mix, which helps with fuel diversity and fuel price volatility. With the continued operation of Asbury, Empire's owned generation mix is about 33% coal and 63% natural gas.

According to Mr. Mertens, in March 2010, Empire awarded Black & Veatch an engineering assignment to gather information about Empire's Asbury unit and perform studies to select the preferred technology for reducing emissions – specifically sulfur dioxide, particulate matter and mercury – at the plant. Black & Veatch prepared four individual reports as a result of this assignment:

- Balanced Draft Conversion Study, which examined the adequacy of the existing draft system, including the forced draft fans and recommended the boiler be converted from forced draft to balanced draft operation.

- Air Quality Control Technology Description Study, which identified spray dry absorber and circulating dry scrubber ("CDS") as flue gas desulfurization technologies that should be studied further.

- Study of the Two Alternative Suites of Air Emission Control Technology Equipment, the further study recommended by the Air Quality Control Technology Description Study, which identified CDS as the preferred technology for flue gas desulfurization at the Asbury unit.

- Chimney Analysis, which examined the adequacy of the existing chimney at the Asbury unit and recommended the construction of a new chimney as part of the project.

These four reports – along with site arrangement drawings, process flow diagrams, cost estimates and schedules – comprise the Asbury Environmental Retrofit Project Definition.

The cost estimates in the Asbury Environmental Retrofit Project Definition were incorporated with the estimate Empire used in the 2010 IRP, and used in affirming the decision to move forward with developing and issuing a request for proposals in mid-2011. Five Asbury AQCS construction proposals were received in September 2011, and all but one of the proposals compared favorably to previous estimates of the project cost, further affirming the decision to move forward with the project.

Mr. Mertens testified that a matrix was developed for the preliminary evaluation of the proposals. The proposals were evaluated on the following criteria: cost, including construction and operation and maintenance costs; schedule; performance guarantees; commercial terms and conditions; contractor safety record and project experience. Sega, Empire's owner's engineer for the project, aided in the technical evaluation of the proposals without sharing in any pricing or other commercial information. Following preliminary evaluations of the proposals, two bidders were selected to come to Empire's offices to present their experience and their plan to successfully complete the Asbury Environmental Retrofit. Empire's project team recommended to Empire's Board of Directors Strategic Project Committee that a budget be approved to allow for contract negotiations and the completion of the Asbury AQCS. The Board of Directors approved a resolution based on the project team's recommendation at its regular meeting in October 2011.

Mr. Mertens described the construction of the AQCS. He stated that work on the site began in February 2012, with actual construction activities getting underway in May of that year. Foundations and underground utilities were the first activities to be completed. Construction of the new chimney was also scheduled early in the sequence due to the large personnel exclusion zone that comes with overhead work. Structural steel deliveries and erection began in early 2013 and were completed in late 2013. Construction of the scrubber and baghouse began in May 2013 and finished in the second quarter of that year. Commissioning of Asbury AQCS systems began in January 2014, and the Asbury unit came offline for tie-in of the AQCS on September 11,

2014. Asbury returned to service on November 5, 2014, and initial scrubber tuning began on November 8, 2014. In-service testing began on December 7, 2014, and was completed on December 13th. Empire declared the Asbury AQCS in-service on December 15, 2014, upon validation of the test results. All performance testing was completed on February 5, 2015.

Mr. Mertens testified that the Riverton 12 NGCC project involved converting the existing Riverton Unit 12 simple cycle gas turbine, which went into service in 2007, to a combined cycle gas turbine. The conversion included the installation of a heat recovery steam generator, steam turbine generator, auxiliary boiler, cooling tower, and other balance of plant equipment. The Riverton 12 NGCC will be the most efficient generator in Empire's fleet and was identified in Empire's 2013 IRP, filed with the Missouri Public Service Commission ("MPSC") in Docket No. EO-2013-0547, as a least cost option to comply with environmental regulations including the Cross State Air Pollution Rule ("CSAPR").

According to Mr. Mertens, the Missouri Electric Utility Resource Planning rules "require the utility to select a preferred resource plan, develop an implementation plan, and officially adopt a resource acquisition strategy." (Missouri Code of State Regulations 4 C.S.R. 240-22.070). In addition, among other conditions, "in the judgment of the utility decision-makers, the preferred plan, in conjunction with the deployment of emergency demand response measures and access to short-term and emergency power supplies, [must have] sufficient resources to serve load forecasted under extreme weather conditions pursuant to 4 CSR 240-22.030(8)(B) for the implementation period." Also, among the fundamental objectives of the resource planning process included in the Missouri IRP rules is that a utility shall "[u]se minimization of the present worth of long-run utility costs as the primary selection criterion in choosing the preferred resource plan, subject to the constraints in" 4 CSR 240-22.010(1)(C).

The preferred plan, which included the Riverton 12 NGCC conversion project, was selected among 18 alternative resource plans developed by Empire in MPSC Docket EO-2013-0547.

According to Mr. Mertens, the parties to the MPSC Docket EO-2013-0547 came to an agreement concerning Empire's 2013 IRP filing on January 31, 2014.

Mr. Mertens further testified that Black and Veatch, an engineering firm based in Kansas City, Kansas, was contracted by Empire to serve as Owners Engineer in the development of the RFP for the Riverton 12 NGCC Engineer, Procure, Construct ("EPC") Contract. The EPC Contract RFP included Commercial and Technical Sections for the construction of Riverton 12 NGCC. Also included in the EPC contract were Commissioning activities. Work began on the RFP specifications in September 2012 and was completed in December 2012. The RFP was sent out on January 3, 2013, to six different firms: Burns & McDonnell, SEGA Engineering, Kiewit Construction, Enerfab, Alberici Constructors, Sargent & Lundy, and Fluor. Bids were due on April 9, 2013. A Pre-bid meeting was held on January 16, 2013, at the Riverton site.

The EPC contract did not include Empire labor & overheads, professional services, permitting, fuel costs net of market revenue, and site preparation.

Mr. Mertens testified that the proposals were received from four bidders: Burns & McDonnell, Enerfab, Sega, and Riverton Partners – a joint venture of Alberici Constructors and Sargent & Lundy. Proposals were reviewed for technical acceptability and completeness by the

Empire Team and Black & Veatch. Commercial Terms and Conditions were reviewed by the Empire Team. A matrix was developed for the preliminary evaluation of the proposals. The proposals were evaluated on the following criteria: cost, schedule; performance guarantees; commercial terms and conditions; contractor safety record and project experience. Black & Veatch, Empire's owner's engineer for the project, aided in the technical evaluation of the proposals without sharing in any pricing or other commercial information. Burns & McDonnell was ultimately selected as the preferred EPC contractor and the EPC contract was agreed to by both parties on July 9, 2013.

Burns & McDonnell performed all Engineering, Procurement, and Construction aspects of Riverton 12 NGCC. All engineering documents including design, layout, construction, and equipment supplier information was reviewed by the Empire Riverton 12 Project Team and Black & Veatch for technical acceptability. Any questions regarding such documents were submitted to Burns & McDonnell for clarification. Weekly telephone conference calls were held between Burns & McDonnell, the Empire Riverton 12 Project Team and Black & Veatch throughout the project. In addition, monthly progress meetings were held either at Burns and McDonnell in Kansas City or at the Riverton 12 site. Burns & McDonnell provided construction management services while subcontracting major aspects of the project. Daily on-site construction meetings were held each morning with on-site contractors to discuss daily activities and issues. Weekly construction and schedule meetings were held with each on-site contractor separately to discuss construction progress and schedule. The Empire team attended all daily and weekly on-site meetings. An important aspect of all of these meetings was safety. The Empire team was in the field directly observing and witnessing construction and commissioning activities. Where appropriate, the Empire team was direct participants in the construction and commissioning process. Weekly construction progress meetings were held by the entire Empire Riverton 12 Project Team.

According to Mr. Mertens, Burns & McDonnell submitted monthly reports describing engineering, procurement, and construction efforts. Included in this report were engineering and construction progress reports discussing completed activities and upcoming activities. Construction issues were also discussed as well as schedule impacts. The Empire Riverton 12 Project Team also generated a monthly report discussing construction progress, project financial information, and any project issues.

The Riverton 12 NGCC unit went into service on May 1, 2016.

<u>Rebuttal Testimony</u>

Mr. Mertens' rebuttal testimony addressed the purported reliability issues raised by Mark E. Garrett and Edwin C. Farrar in their direct testimonies with regards to service provided to Empire's Oklahoma customers. He also addressed Mr. Garrett's claims that sufficient evidence has not been provided regarding plant additions.

According to Mr. Mertens, in 2010, Empire developed a 10-year plan to construct system improvements solely to improve the reliability of the system. This reliability plan is often referred to as Operation Toughen-Up. Empire is still in the midst of implementing this plan which is slated for completion in 2021. The Oklahoma projects included in Operation Toughen-Up were discussed by Mr. Mertens and Exhibit BAM-1 illustrated the geographic area impacted by these projects.

Mr. Mertens testified regarding the following projects:

Distribution automation for Welch (Completed 2013) – This project created a backup distribution source to support the Welch load in the event that their primary radial source was no longer energized. This is an automated process that changes the configuration of the distribution system such that the Welch load will be served from the Fairland Substation. With this system, the Welch load is restored in less than 3 minutes after the initial power outage. The cost of this project was $700,010.

Welch transmission line rebuild (Completed in 2016) – The transmission system that supplied the Welch substation was in poor condition due to its age. Therefore, the entire 27 miles of Radial transmission line was rebuilt with all new components and conductor. In an effort to improve the reliability of this transmission line, the phase spacing was increased to prevent flashovers, the conductor was significantly increased in size to improve resistance to physical damage, and all of the wood poles were replaced with steel to resist damage from wood peckers and decay. The cost of this project was $11,322,194.

Welch transmission voltage upgrade (Scheduled for 2018) – This project will be to convert the transmission system serving the Welch substation from the existing 34.5 kV to 69 kV. This will reduce the specialized equipment needed to maintain and operate the 34.5 kV system. Currently, Empire utilizes predominantly 69 kV or higher systems on its transmission system. Therefore, spare equipment is more readily available for repairs at the 69 kV voltage. This project is estimated as $3,959,000.

Fairland installation of 2 - 69 kV breakers and increase substation transformer size (Completed in 2015) – This project removed the exposure of 15.5 miles of transmission line from the customers served by the Fairland West, the Fairland Southwest and the Fairland Shell substations. Prior to this system upgrade, any incident that caused an outage on the transmission line also caused the customers served by any of these substations to experience an outage. The cost of this project was $1,474,426

Installation of 69 kV throw-over switching scheme at Commerce Tap (Scheduled in 2018) – This project is to install a throw-over switch in the transmission line that serves Commerce so that automatic sectionalization can occur to restore service to Commerce in the event of a transmission line event. This project is estimated to cost $500,000.

Fairland installation of additional 12 kV breaker and circuit conductor (Completed in 2016) – This project increased sectionalization of the distribution system and reduced the number of customer outages due to a single distribution event. The cost of this project was $140,029.

Reducing Distribution Outage Exposure (Ongoing) – To date, Empire has spent $223,215 to install sectionalizing devices (reclosers and fuses) to reduce the number of customers that experience an outage for each fault.

Mr. Mertens testified that Oklahoma customers make up less than three percent of Empire's customer base. However, since the inception of this reliability program, Empire has spent nearly 32% of its expenditures for the benefit of Oklahoma customers. At the completion of the program, Empire reasonably expects that approximately 14% of the expenditures will provide benefit to Oklahoma customers.

According to Mr. Mertens, Empire did not distinguish between the states with regards to its maintenance programs. In 2008, the Missouri Public Service Commission ("PSC") implemented reliability inspection standards that dictated the frequency and thoroughness of system inspections and repairs. Since the implementation of that rule, Empire has elected to implement the Missouri standards for inspections and repairs for facilities in all jurisdictions served by Empire. The Missouri rules for system inspections and repairs exceed any Oklahoma requirements for inspections and repairs. Additionally, Empire adheres to the Oklahoma vegetation management rules, which are more restrictive than those established for Missouri.

Mr. Mertens testified that Empire was in the midst of substantial system upgrades to improve the service to the customers in Oklahoma; however, the impact from these new systems take time to effect annual SAIDI and SAIFI indices, as not all of the projects are installed. Also, in order to install these systems economically, the system is put into a less reliable condition during the construction of the new upgrades. Naturally this results in SAIDI and SAIFI indices that are much worse than what will be expected at the conclusion of the overall program.

According to Mr. Mertens, Empire monitors the reliability during construction of these reliability projects to make adjustments to construction methodologies to reduce the exposure to outages.

Mr. Mertens testified that in 2014 during the construction of the Welch transmission line, the method of construction caused significant reliability issues to the town of Welch. Due to the condition of the system at the time the reliability issues arose, there was no solution other than to expedite the construction with additional manpower. During the next phase of the construction of the transmission line, a different construction plan was developed to drastically limit the exposure of our customers to outages. During this phase of construction, the reliability for the town of Welch went from a SAIFI of 6.9 to 0.175.

Oklahoma reliability statistics have lagged compared to Empire's overall system reliability statistics. As reflected in BAM-Table 1 below, since the inception of the Operation Toughen-up program in 2011 our SAIDI and SAIFI statistics have continually improved due to system-wide improvements, as well as vegetation management program initiatives. As Empire completes the projects outlined above Empire reasonably expect Oklahoma's reliability metrics will follow suit.

BAM-TABLE 1: System 2010 – 2016 SAIFI and SAIDI (Excluding Major Events)

YEAR	SAIDI - EME	SAIFI - EME
2010	148.28	1.434
2011	239.69	1.696
2012	140.48	1.361
2013	146.53	1.345
2014	132.81	1.458
2015	114.77	1.357
2016	102.98	1.145

Mr. Mertens explained why the 2011 SAIFI and SAIDI statistics reflected in Table 1 were significantly higher relative to the other years. According to Mr. Mertens, in 2011 the city of Joplin was struck by a tornado inflicting substantial damage to the electrical system and causing an unusual number of outages.

In response to Mr. Garrett's reference to a 2016 JD Powers Customer Satisfaction Rating, Mr. Mertens testified that Empire did not subscribe to JD Power's service and is unaware of an official document in which a comprehensive customer satisfaction service was performed. Mr. Garrett's testimony did not include the reference for this document, nor did he identify the actual rating that Empire received or the JD Powers average rating. Empire is aware that JD Powers performs sample surveys in an effort to sell their services; however, Empire is not aware that a sample survey was performed.

EMPIRE DID NOT AGREE WITH MR. GARRETT'S STATEMENT ON PAGE 7 OF HIS RESPONSIVE TESTIMONY BEGINNING ON LINE 1 "SINCE ITS LAST RATE CASE IN 2011, EMPIRE HAS BEEN INVESTING LARGE AMOUNTS IN NEW RATE BASE WITH NO NOTICE TO THE COMMISSION OR TO THE COMPANY'S CUSTOMERS. IN HIS OPINION, IT IS IRRESPONSIBLE FOR A UTILITY TO SIT QUIETLY FOR FIVE YEARS BEFORE IT INFORMS ITS CUSTOMERS THAT IT INTENDS TO NEARLY DOUBLE THEIR BASE RATES."

The Company has engaged in significant customer communications, both direct and through the media, concerning the environmental compliance efforts and the potential impact on electric rates. The Company notified the Commission in its 2013 triennial Integrated Resource Plan ("IRP") reports of its planned generation investments. Furthermore, the Company again notified the Commission that it was making significant investments in its generation fleet and that rather than file two rate cases, one in 2015 and another in the third quarter of 2016, it would be more cost effective to file one case for the approximate 4,700 Oklahoma customers.

Additionally, the Company notes that PUD was aware of the investments and the subsequent rate increases to recover such investments. Please refer to the Testimony of Geoffrey M. Rush who testified in December 2014 that the Company completed improvements to its Asbury Plant and was in the process of converting the Riverton 12 Plant into a combined cycle unit. The estimated completion date of Riverton 12 Plant was mid-2016. It was Mr. Rush's opinion that back-to-back rate cases would not only be burdensome to Empire but would not serve the public interest.

Finally, the Company would point out that in response to data request AG-EDE-2.16, for each electric plant addition project costing more than $1 million, since the last rate case and continuing through to six months after the end of the test year, Empire provided requested information related to its investments in generation, transmission and systems software which were included as BAM-Attachment 1.

BETHANY Q. KING

Bethany Q. King, employed by Empire as the Manager of Strategic Planning, testified on behalf of Empire.

Ms. King's testimony provided explanation of the customer growth, weather, and unbilled revenue adjustments made to Empire's income statement.

According to Ms. King, Oklahoma jurisdictional revenues have been adjusted to reflect the amount of revenue that would have been generated if the number of Empire customers existing at June 30, 2016, had been served by the Company for the entire test year. For the residential and commercial classes, the differences between the June 30, 2016, level of customers and the average customers billed in each month of the test year were multiplied by the average weather normalized kWh per customer for that month. The resulting change in kWh sales was then multiplied by the average class weather normalized cost per kWh to obtain the revenue adjustment related to customer growth.

In total, the customer growth adjustment to revenue resulted in an increase of $7,148 in revenue and 48,007 kWh in sales.

Ms. King further testified that the test year sales and revenue were adjusted to account for the impact of abnormal weather. The adjustment resulted in an increase to Oklahoma jurisdictional rate revenue of $173,250.

According to Ms. King, the revenue in the test year should equal the amount actually billed to customers and the portion of sales that were used but not billed during the test year. While the amount of revenues actually billed to customers is known, the portion not yet billed to customers is not known, and therefore, must be estimated. This adjustment is calculated by multiplying a rate per kWh to the unbilled sales by pricing plan. The unbilled sales computation is calendar normalized sales minus revenue cycle normalized sales. The unbilled sales were multiplied by the determined rates to derive the unbilled revenue. This resulted in an increase to revenue of $3,314.

DAVID SWAIN

Mr. David Swain, President of Empire, adopted the testimony of Brad P. Beecher.

Mr. Swain testified that Empire is a Kansas corporation with its principal office and place of business in Joplin, Missouri. Empire provides electrical utility services in Missouri, Kansas, Arkansas, and Oklahoma.

According to Mr. Swain, Empire provides electric service in an area of approximately 10,000 square miles in southwest Missouri and the adjacent corners of the states of Kansas, Oklahoma, and Arkansas. Empire's operations are regulated by the utility regulatory commissions of these four states, as well as by the Federal Energy Regulatory Commission ("FERC"). Empire's service area embraces 119 incorporated communities in 21 counties in the four-state area. Most of the communities in Empire's service area are small, with only 32 containing a population in excess of 1,500. Only 10 communities have a population in excess of 5,000, and the largest city, Joplin, Missouri, has a population of approximately 50,000. The economy in Empire's service area is diversified. The service territory features small to medium manufacturing operations, medical, agricultural, entertainment, tourism, and retail interests.

Mr. Swain testified that since the Company's last rate increase, which became effective on January 6, 2012, Empire has continued to construct facilities necessary for the provision of service to its customers, including those located in Oklahoma. Total capital expenditures in this period were about $670 million. This includes the addition of Empire's Asbury Air Quality Control System environmental retrofit project ("AQCS"), the Riverton 12 Natural Gas Combined Cycle conversion project ("Riverton 12"), as well as significant additions to the Company's transmission and distribution systems.

In recent years, according to Mr. Swain, the EPA has tightened air quality standards for SOx, NOx, and Hg. These new standards affected the operations of several of Empire's power plants. Empire's Asbury and Riverton power plants were most affected by these revised standards. Environmental retrofits were already completed on Iatan 1, and the Plum Point and Iatan 2 facilities were constructed to meet the new standards. In response to the EPA's revised standards, Empire implemented a compliance plan. Empire's compliance plan called for the installation of a scrubber, fabric filter, and powder activated carbon injection system at the Asbury plant (collectively referred to as the "Asbury air-quality control system" or "AQCS") by early 2015. The addition of this air quality control equipment also required the retirement of Asbury Unit 2, a small steam turbine that was used for peaking purposes. The retirement of this unit took place in December of 2013, and the environmental project at Asbury was in service on December 31, 2014. Empire also invested in the conversion of its Riverton 12 generating unit to a combined cycle, which is the final component of Empire's compliance plan to meet EPA rules on air quality regarding SOx, NOx, and mercury ("Hg"). Empire's compliance plan also originally called for the eventual retirement of Riverton Units 7, 8, and 9 in 2016, though retirement of the units actually occurred slightly ahead of schedule. Unit 9 was a small combustion turbine that required steam from Unit 7 for start-up. Units 7 and 8 began operation in 1950 and 1954, respectively.

According to Mr. Swain, Empire representatives have attended various community forums and discussed the environmental compliance plan and how that plan may ultimately result in increased electrical rates for customers. In addition to these public presentations at various community forums, Empire has held meetings with community leaders and with the larger customers to discuss the environmental compliance activities and the estimated impact these activities will have on electric rates. Empire has also contacted the communications media to discuss the environmental compliance plan and its estimated impact on electric rates.

Mr. Swain further testified that the amount of the rate increase Empire is requesting is not related to the pending merger with Liberty, and all merger related costs have been excluded from Empire's request.

The transaction will have no adverse effect on Empire's customers. Empire has a dedicated and skilled workforce of managers, administrators and professional and field staff with expertise in regulated utility operations that has a strong reputation for delivering excellent customer service. The current work force will be retained as the transaction will not result in any involuntary reductions in Empire's current administrative, professional, and field workforce.

JEFFREY P. LEE, SR.

Jeffery P. Lee, Sr. Manager of Accounting & Administration for Empire, testified on behalf of Empire.

Mr. Lee testified that at this time, Empire is requesting total annual Oklahoma pension expense of $289,356, which represents an increase of $78,505 to the amounts authorized in rates pursuant to Cause No. PUD 201100082. This total includes actuarially determined expense of $240,660 and five-year tracker amortization of $48,696 for the pension plan.

Mr. Lee further testified that Empire is requesting total annual Oklahoma OPEB expense of $44,451, which represents a decrease of $32,441 to the amounts currently authorized. This total includes actuarially determined expense of $50,136 and a negative five-year tracker amortization of ($5,685).

These expenses for both Pension ("FAS 87") and OPEB ("FAS 106") costs for 2016 are final, according to Mr. Lee.

The 2016 actuarial valuation of the plans, which provides the cost, were completed in September of 2016.

MARK QUAN

Mr. Mark Quan, Principal Consultant in Itron's Forecasting Solutions group, testified on behalf of Empire.

Mr. Quan testified that he developed weather-normalized sales estimates for Empire. Using a statistical-based modeling approach, he developed weather-normalized sales for the historical test year. The test year is from July 1, 2015, through June 30, 2016. Mr. Quan stated that weather-normalized sales are estimated for the following five classes: Residential, Commercial, General Power, and Total Electric Building.

According to Mr. Quan, weather Normalization is the process of determining what historical consumption would have been if normal weather conditions existed. The process is a mathematical method which adjusts actual monthly sales for a class based on a statistical model and normal weather conditions.

AARON J. DOLL

Aaron J. Doll, the Associate Director of Supply Management for Empire, testified on behalf of Empire.

Mr. Doll testified that Empire first received approval of the Southwest Power Pool ("SPP") Transmission Tariff ("SPPTC") in the Final Order Approving Joint Stipulation and Settlement Agreement (Order No. 592623) in Cause PUD 201100082 on December 7, 2011. Original Tariff Sheet No. 24 ("Schedule SPPTC") became effective January 6, 2012. One of the components of the original SPPTC tariff was the requirement to file a base rate case within 42 months of the tariff's effective date (on or before July 5, 2015). In January 2015, Empire witness Bryan Owens filed Direct Testimony with the Commission proposing an amendment to the SPPTC tariff to remove the requirement to file a base rate case on or before July 5, 2015. The basis for this amendment was in regards to the timing of two separate investments in Empire's generation fleet. The first being the Asbury air quality control system ("AQCS") upgrade with an in-service completion date in late 2014 and the second being the Riverton 12 Combined Cycle conversion project with an expected in-service completion date in 2016. Empire's testimony stated that to "avoid rate case fatigue and significant costs associated with litigating back-to-back base rate cases", the proposed amendment would push back a general rate case until after the Riverton 12 project was in-service and therefore remove the July 5, 2015, base rate case requirement and authorize the continuation of the SPPTC tariff. On March 26, 2015, the Commission issued the Final Order in Cause PUD 201500012 stating that the amended SPPTC tariff would be granted but that in Empire's next general rate case a series of findings shall be presented in testimony.

Mr. Doll further testified that the findings require Empire to: 1) identify each of the third party upgrades and facilities that were constructed and included in the Third Party Owned Transmission Costs recovered from Oklahoma retail customers for the previous years; 2) demonstrate that the amounts recovered under the SPP tracker were eligible for recovery, properly calculated, and appropriately allocated to rate classes; and 3) demonstrate that the costs of such upgrades were included in FERC-approved rates and allocated under an SPP cost allocation methodology and incurred by Empire during the previous years.

According to Mr. Doll, due to the voluminous nature of the documentation required to identify each of the third party upgrades and facilities that were constructed and included in the third party owned transmission costs, he included a link to the Revenue Requirement and Rates ("RRR") spreadsheets prepared by SPP for the timeframe beginning January 1, 2012. The RRR spreadsheet provides project specific details regarding revenue requirements and rates as they relate to both SPP zonal and regional Schedule 11 investment (tab labeled "Base Plan Rev. Req. Alloc"). Although SPP issues a new RRR spreadsheet as a result of a change to an input or formula rate update, the link included the most current January updates for years 2012 through 2016, as well as the most recent updated RRR at the time of filing (October 2016), which includes all of the projects and upgrades needed to satisfy the first requirement.

Mr. Doll testified the amounts recovered under the SPP tracker were eligible for recovery and were both calculated and allocated properly to the rate classes.

Mr. Doll testified that all of the rates that Empire has paid with respect to Schedule 11 were pursuant to the SPP Open Access Transmission Tariff ("OATT") which is a lawful tariff as determined by FERC. Regarding the SPP cost allocation methodology, the RRR spreadsheets provide details for the transmission investments including the cost allocation methodology (postage stamp-MW Mile methodology and highway/byway methodology). These cost allocation methodologies were detailed in the FERC approved SPP OATT.

Mr. Doll testified that Empire fulfilled all of the requirements listed in the final order in Cause PUD 201500012.

According to Mr. Doll, there were benefits of Empire's SPP membership. According to Mr. Doll, the SPP is a non-profit FERC approved Regional Transmission Organization ("RTO") operating out of Little Rock, Arkansas. The SPP provides services on behalf of its members including reliability coordination, tariff administration, regional scheduling, transmission investment planning, market operations, compliance and training. SPP began in 1941 and has evolved from a reliability council in the late 1960's, to an RTO in 2004, a Regional Entity in 2007, and administrators of the Energy Imbalance System ("EIS") also in 2007. The most recent evolution of the SPP has been the coordination of next day generation across the region through the creation of the SPP Integrated Marketplace ("IM") which commenced on March 1, 2014.

Mr. Doll testified that based on internal analysis simulating a bilateral market and utilizing production cost modeling with updated market prices, Empire estimates that the benefits of the SPP IM have resulted in \$19.2 million or about 5% in total company fuel and purchased power savings from March 2014 through Third Quarter 2016.

ROBERT W. SAGER

Mr. Rob Sager, the Vice President of Finance and Administration for Empire, testified on behalf of Empire.

According to Mr. Sager, Ms. Champion has testified that the PUD's recommended revenue increase would result in significant impacts to customers if implemented at one time. As a result, PUD proposes that the increase be implemented over four (4) years to allow customers to better prepare for, and adjust to, the increase. Ms. Champion's proposal provides approximately 30% of the requested increase in year one (1), an additional 20% in year two (2), an additional 25% in year three (3), and the final 25% in year four (4), at which point the full amount of the recommended revenue increase would be recovered in rates.

Mr. Sager testified that PUD's proposed mitigation plan was not an adequate means of controlling the impact of the rate increase. Ms. Champion, as well as other witnesses, testified that Empire's last rate case was Cause No. PUD 201100082, which was based on 2010 costs, and that during this time Empire made significant capital investments. By not seeking recovery sooner, Empire incurred significant regulatory lag and forfeited the ability to earn on these investments earlier. While good intentioned, PUD's proposal exacerbates this rate lag by not allowing the full revenue requirement into rates until four (4) years into the future and fails to take into account the time value of money. PUD witness Mr. Robert Thompson recommends a rate increase of approximately \$3.04 million. Ms. Champion acknowledges that recommendation, and proposes an approach that effectively reduces the total revenue that should be recovered over the proposed four (4) year period.

Mr. Sager testified that Empire would address the inadequacies in two ways. First, the Company suggested that the plan be reduced from four (4) years to three (3) with recovery of 50% of the increase in the first year, 75% of the increase in the second year and the full increase included in rates in the third year. Second, Empire recommended that the portion of the revenue increase not included in rates during the first two years be deferred, with a carrying charge, to be recovered over a specified period of time. Making these two changes would ensure that Empire is permitted to recover and earn on the full amount of the investments that have been made, and achieves PUD's goal of spreading the impact of the increase over time.

CHRISTOPHER D. KRYGIER

Mr. Christopher D. Krygier gave rebuttal testimony on behalf of Empire. Mr. Krygier is employed by Liberty Utilities Services Corp. as its Director of Rates and Regulatory Affairs for its electric, natural gas, water and wastewater utilities located in Missouri, Oklahoma, Kansas, Arkansas, Iowa and Illinois. Mr. Krygier testified that Empire appreciated PUD's attempt to mitigate the impact on customer rates, while at the same time recognizing and recommending a needed base rate increase of slightly over \$3 million.

Mr. Krygier described the recommendations of the AG and OIEC as the "Kansas Plan." According to Mr. Krygier, AG witness Farrar stated on Page 11 of his Responsive Testimony, beginning at line 12, "For any increased recovery allowed at this time, the Commission should follow the approach employed by the KCC and establish a rider for the recovery of a return and expense increases related to the environmental compliance upgrades to Empire's production plant."

Mr. Garrett set forth OIEC's recommendation as follows:

> "I believe that the Commission could authorize a rider for Empire's collection of the capital costs of the Asbury and Riverton 12 projects, subject to refund and subject to a Commission review for prudence of these investments in Empire's next Oklahoma rate case. All other cost increases should be rejected at this time and could be considered in Empire's next Oklahoma rate filing, which is consistent with the actions of the KCC."

Mr. Krygier further testified that OIEC's calculation uses a pre-tax return of 9.79%, which is OIEC's recommended rate of return, as well as their recommended depreciation rates resulting in a revenue requirement of $804,205. Mr. Farrar utilized Empire's requested cost of capital and existing depreciation rates which resulted in a revenue requirement of $866,968.

Mr. Krygier testified that the Commission should reject the "Kansas Plan". First, accepting the "Kansas Plan" kicks the can down the road on this rate case for a third time. The Company first filed a case pursuant to the reciprocity rule and, then this rate case. The recommended approach by the Interveners would necessitate a third rate case, an action that is not in the public interest. Second, according to Mr. Krygier, the Interveners are "cherry picking" to find the regulatory solution that best fits their perspective. Finally, according to Mr. Krygier, accepting the "Kansas Plan" is single issue ratemaking.

Mr. Krygier stated that the genesis of this current case was a previous case, Cause No. PUD 201600098. That case, which was filed under the electric company reciprocity rule, OAC 165: 5-7-60, requested this Commission to adopt the rates (with a few deductions for solar incentives and some other items) approved by the Missouri Public Service Commission. However, once those rates were approved in Missouri (which was a settled rate case), both the AG and OIEC wanted another rate case to be filed, which would allow Oklahoma specific information to be the basis for rates. Empire worked with the parties and agreed to file the current case.

Mr. Krygier testified that the Interveners are now recommending a proposal that will require the Company file a third rate case to recover legitimately incurred capital investments and increasing operating expenses. A third consecutive rate case is not necessary to evaluate the reasonableness of Empire's request.

As detailed in the Company's initial direct testimony filings, data request responses and contained in Empire's rebuttal testimony, the Company has made significant investments in the utility infrastructure system that are in-service providing benefits to customers today. No party to this proceeding is alleging disallowances based on imprudent decisions by the Company.

Mr. Krygier testified that in an effort to find the lowest possible rate increase, the Interveners are picking a settlement from another jurisdiction to make their case, rather than looking at the facts, Oklahoma accounting data, and circumstances of this case. After rejecting the Missouri settlement, they are now trying to advocate for the Kansas settlement. Mr. Krygier stated that the Kansas case they refer to, Docket 16-EPDE-410-ACQ, was the Company's merger application in a different state. While the merger application did have a connection to the Kansas rate case that was filed, it is a different state with a different set of circumstances. Now, after this unrelated merger case settlement in Kansas, the Interveners are requesting that the Commission ignore the facts presented in the Company's current Oklahoma rate case and adopt the merger related settlement made in Kansas, not a base rate case. Mr. Krygier further testified that their approach to regulatory cherry picking, which is essentially looking for the lowest rate from an unrelated proceeding, is inconsistent with the intended goal of having new rates based on Oklahoma specific accounting information.

Mr. Krygier further testified that the AG's recommendation is single issue ratemaking. Mr. Farrar's recommendation only considers part of the environmental investment, but ignores everything else. This is the epitome of single issue ratemaking.

According to Mr. Krygier, OIEC's recommendation has the same single issue ratemaking concerns as mentioned above in respect to the AG. However, OIEC's recommendations exacerbates [*sic*] the ratemaking issues by asking the Commission to reduce depreciation rates from current rates and lower the allowed return.

Mr. Krygier testified that if the Commission ultimately supports the Interveners' recommendation to implement an environmental rider providing recovery of only the Asbury and Riverton 12 investments, the Company will not be able to earn a reasonable rate of return for its stakeholders. As such, it will be necessary for the Company to file a third application for an increase in rates.

In response to PUD witness Ms. Champion's recommendation that a four year mitigation plan of the ultimately approved revenue requirement be implemented, Mr. Krygier stated that Empire is sensitive to the magnitude of this increase and is willing to work with the parties to find a plan that balances the interests of the Company and its customers.

In Mr. Krygier's opinion, there are two important considerations when evaluating a mitigation plan. First, recovery of uncollected revenue. Second, recovery of interest on that uncollected revenue.

Uncollected revenue is revenue that the Commission authorizes but is not immediately implemented. According to Mr. Krygier, if the Commission were to adopt PUD's recommendation, a rate increase of approximately $3 million would be authorized. If the Commission then accepts PUD's plan as currently outlined, only 30%, or approximately $900,000 of revenue would be collected the first year. The remaining $2,100,000 would permanently not be collected by the utility in year one. Some amount of uncollected revenue would occur in each year of the proposed mitigation plan until the full revenue requirement is ultimately implemented in year four.

Mr. Krygier testified that the Commission should authorize the collection of uncollected revenue for several reasons. First, is that the capital investments and operating expenses used to operate the utility are currently in-service and providing benefits to customers. That means that customers are enjoying the benefit of this infrastructure but are not paying the full cost for it.

Second, if the Company is expected to continue to re-invest into the necessary infrastructure, depriving the utility of the revenues to make that continued investment proves challenging. Finally, as Company witness Mr. Sager describes, not providing the full recovery of uncollected revenue could create accounting implications for the Oklahoma operations.

Mr. Krygier testified that interest on the uncollected revenue is an important consideration. In the example above, $2,100,000 was uncollected, applying the weighted average cost of capital agreed to by the Company and PUD, 7.59%, yields approximately $159,000 on an annualized basis.

In Mr. Krygier's opinion, in addition to the reasons articulated above on the uncollected revenue, it did not seem reasonable to withhold the utility from collecting its fully authorized revenue requirement and also deprive it of the interest associated with the uncollected amounts.

TIMOTHY S. LYONS

Mr. Timothy S. Lyons, a Partner at ScottMadden, Inc., adopted the Direct Testimony of Mr. Bryan Owens.

Mr. Lyons testified that Empire was requesting an overall increase of $3.8 million in Oklahoma jurisdictional revenue, or an increase of 27.58 percent. The increase is based on an overall rate of return of 7.59 percent and a return on equity of 9.9 percent. The primary factors driving the need for a rate increase include capital expenditures associated with the AQCS and related depreciation and property tax expense, capital expenditures associated with the Riverton 12 and related depreciation and property tax expense, normal integrity capital expenditures and related depreciation and property tax expense, increased expense levels associated with plant maintenance, and increased expense levels associated with payroll, pension, and healthcare.

The supporting schedules included in this filing are based on the twelve-month period ending June 30, 2016, adjusted for known and measurable changes.

According to Mr. Lyons, Empire was filing this rate case to adjust its base rates for electric service to more accurately reflect the Company's revenues, expenses, and investments necessary to provide service to its customers. Without the proposed increase, the Company will not have a real opportunity to earn a reasonable rate of return and recover its investment and increased costs incurred since base rates were last revised on January 6, 2012. The Company's current base rates were developed in its last general rate case in Cause No. PUD 201100082 using a test year ending December 31, 2010. While the revenue requirement developed in that case included the Company's significant investment in new generation at the Plum Point and Iatan facilities, the Company has experienced significant other changes since the conclusion of that case.

Since the rates from the Company's last general rate case took effect on January 6, 2012, Empire has made significant capital investments that have not been fully included in electric rates. Empire is also experiencing increases in other costs that, without a rate adjustment, will erode the Company's earnings and undermine its ability to earn a fair return.

According to Mr. Lyons, since January 2011, Empire invested approximately $670 million in total Company capital projects. Of this amount, approximately $122 million (total Company) is related to the AQCS project placed in service December 2014 and approximately $182 million (total Company) is related to the Riverton 12 Combined Cycle conversion project placed in service May 2016. Of the $3.8 million requested deficiency, the AQCS project and the Riverton 12 project represents approximately $1.1 million of the requested revenue increase. Table 1 below summarizes by broad category, total Company investments since January 2011. The Company's property taxes, depreciation, plant maintenance, tree-trimming, salaries, pension, health care, and other operating costs have also increased.

H. EDWIN OVERCAST

H. Edwin Overcast, Director, Black & Veatch Management Consulting LLC, testified on behalf of Empire.

According to Dr. Overcast, cost of service is a necessary element of the rate case process. At the most fundamental level, it provides the revenue requirement necessary to permit the utility to recover the prudently incurred costs of providing service, including a return of and on the capital employed to provide services. When prepared correctly to reflect actual cost causation, the cost of service study is also useful as a guide to allocating costs among customer classes and for determining the rates that provide a utility with a reasonable opportunity to earn the allowed return. It also provides useful metrics for determining if rates meet the just and reasonable and non-discriminatory tests required for rate approval.

Dr. Overcast testified that cost studies are a basic and ultimately a necessary tool of ratemaking. A properly developed cost of service study represents an attempt to analyze which customer or group of customers cause the utility to incur the costs to provide service. Understanding cost causation requires an in-depth understanding of the planning, engineering, and operations of the utility system, as well as the basic economics of the unbundled components of the electric system.

The requirement to develop cost studies results from the nature of utility costs. Utility costs are characterized by the existence of common and joint costs. In addition, utility costs may be fixed or variable costs. Finally, utility costs exhibit significant economies of scale. These characteristics have implications for both cost analysis and rate design from a theoretical and practical perspective.

Dr. Overcast testified that cost causation is the key element to selecting an allocation factor. This has been the standard by which an allocation method is evaluated and it continues to be the gold standard for assessing cost allocation.

Dr. Overcast further testified that under the traditional embedded cost allocation, the process follows three steps: functionalization, classification, and allocation. This three-step process underlies the determination of cost causation. By identifying the functions of utility service-production or generation, transmission, distribution, and customer for electric service-and the costs of these functions, the foundation is laid for classifying costs based on the factors that cause the utility to incur these costs-energy, demand, and customers. The development of allocation factors by rate schedule or class uses principles of both economics and engineering to develop allocation factors appropriate for different elements of costs. If these factors properly reflect cost causation, the cost of service study is a reasonable tool for use in assigning revenue requirements to each class of service.

In many cases, according to Dr. Overcast, it is as simple as asking the question of whether a particular cost changes when some potential allocation factor changes. If a factor causes costs, costs will vary with changes in that factor. For example, if the number of kWhs increases, does the cost of some input such as miles of conductor increase with more kWhs? Since the miles of conductor do not change with kWhs either monthly or annually, energy consumption is not a cause of conductor costs. What we do know is that miles of conductor increases for customers added to the periphery of the system. We also know that the miles of conductor increases with the growth of the peak load on the conductor by paralleling the system, looping the system, or networking the system. It may also mean building added capacity through expanding the system to a three-phase conductor. In any case, the factors driving the cost of conductor are customers and non-coincident peak demand. Following this logical process allows one to determine cost causation.

Despite the simplicity of this approach, it is also necessary to understand key differences as related to cost causation based on the practical engineering and operation of the system. Essentially, there are fundamental differences in the cost to serve the same customer with identical loads depending on any number of factors that cause large differences in cost between urban service and rural service for example. Urban service may have more underground delivery service with higher costs or be served from a three-phase overhead primary looped system with its higher costs than a rural customer served off a single-phase overhead system requiring less conductor and lower cost for overhead poles.

Dr. Overcast testified that cost of service studies use a three-step process that includes functionalization, classification, and allocation.

The process of functionalization requires determining the utility costs associated with each of the functions provided by the utility. The typical functions used in a cost study are production, transmission, distribution and customer service.

The production function consists of the costs of power generation and purchased power. This includes the cost of generating units and fuel for the units. In addition, any cost of purchased power along with the cost of the delivery of purchased power is also functionalized as production.

The transmission function consists of the assets and expenses associated with the high voltage system used by the power system to interconnect with the grid and to move power from generation to load.

The distribution function includes the system that connects transmission to loads. Different customers use different components of the distribution system.

The customer service function includes plant and expenses caused by individual customers. Customer service includes meters, service lines, meter reading and billing, for example. It also includes a portion of the distribution system including transformers, conductor and poles.

Dr. Overcast testified that once costs are functionalized, they must be classified based on the categories customer, demand and energy. The classification step is critical to developing allocation factors that reflect cost causation. In particular, it is imperative to understand not only the accounting basis for costs but the engineering and operational analysis of the system as it is planned, built and operated. Essentially, all costs incurred by the utility are directly or in some cases indirectly related to one of these three factors. That is a utility incurs costs based on (1) the number, size and type of customers, (2) a combination of several measures of customer demand or (3) a measure on the energy used by customers. Within these three classifications there may be different measures of the factor based on how costs are incurred when allocation factors are developed.

Each of these functions is described below.

Demand costs are those costs that vary with some measure of maximum demand. Measures of maximum demand include coincident peak demand, class non-coincident peak demand and customer non-coincident peak demand.

Energy costs are those costs that vary directly with the production of energy such as fuel costs; other fuel related expenses or purchased power expense.

Customer costs are those costs that vary with number of customers such as meters and service lines.

According to Dr. Overcast, costs can be classified into more than one category. For example, some distribution costs may have both a demand and a customer cost component.

In the allocation process, costs are allocated to customer classes based on a variety of factors. The purpose of allocation is to assign costs to classes in a manner that reflects the factors that cause the costs to be incurred.

Dr. Overcast testified that costs are functionalized and classified in the study based on data from the Uniform System of Accounts ("USOA"). The cost study uses two types of allocation factors: external factors and internal factors. *External* allocation factors are based on direct knowledge from data in the utility's accounting and other records such as the load research data. Generation is functionalized to production accounts and allocated based on both an external capacity and energy allocation factor depending on the nature of the account. Transmission costs are functionalized to transmission FERC accounts and are assigned by an external transmission allocation factor. Another example of an external allocation factor is allocation of distribution system costs, both the demand and customer components. The costs of distribution facilities are known and assigned directly to the distribution function as substations, poles, towers and fixtures, overhead and underground conductors, transformers, service lines and meters. Once assigned to distribution, the poles, conductors, conduit and transformers are allocated using the minimum system to classify the costs between demand and customer related costs and then are allocated on an external allocation factor. *Internal* allocation factors are based on some combination of external allocation factors, previously directly assigned costs, and other internal allocation factors. For example, the allocation factors for property insurance costs are based on plant investment amounts assigned to each function; therefore it is necessary to compute the amount of plant by function before property insurance costs can be assigned. Both external and internal allocation factors are used in each of the functional and classification steps outlined below.

Dr. Overcast further testified that the National Association of Regulatory Utility Commissioners ("NARUC") Electric Utility Cost Allocation Manual identifies three fundamental methods for allocation of demand related costs: Coincident Peak ("CP") methods, Non-Coincident Peak ("NCP") methods and Average and Excess Demand ("AED") methods. Within each of these categories, there are numerous specific formulations of the methods. Further, to reflect the cost of an electric system, a complete cost of service study requires application of more than one demand category of these allocation factors. For example, class non-coincident peaks drive the allocation of part of the distribution system capacity while it is some combination of coincident peaks and demand and energy methods for generation. Within each classification category, there may be multiple specific methods. Under the CP allocation category, options include a single CP, 4 CP, 12 CP, winter/summer CP and so forth.

According to Dr. Overcast, in the case of production, the choice of an allocation factor depends on how costs are incurred for the capacity portion of production costs. It is a basic proposition of reliable utility service that the utility must have adequate capacity to meet the peak load requirements of its customers plus a level of reserves to maintain reliability. This means that peak load causes capacity costs to be incurred. However, when a utility plans its system, it uses a combination of different technologies to meet both capacity and energy requirements by taking into account the system load duration curve as well as peak load. Typically, some units have high capital costs but low operating costs. Units that are designed to run many hours of the year, referred to as base-load units, have the lowest total cost (capital costs and fuel) of any technology for long hours of operation. Units with lower capital cost but higher running costs such as combustion turbines are added to the system to operate flexibly at peak hours and when needed to meet rapidly changing load conditions. The higher cost for a base-load unit is incurred to produce lower annual fuel costs and recognizes that some of the higher capacity cost is offset by fuel cost savings. Under these circumstances, a portion of the cost of a base-load unit is incurred for the purpose of lowering energy costs. Thus, some portion of the capital cost for base load is related to energy. The AED method recognizes a portion of cost is related to energy and the excess cost is a pure demand related cost.

Dr. Overcast described the five schedules that made up his cost-of-service study.

According to Dr. Overcast, the use of the AED/12CP cost allocation methodology is the most appropriate cost allocation method for Empire's production costs. He developed the AED method based on a review of the total demand on system capacity, not simply the system load demand. This is an important distinction because load is not the only demand placed on capacity. Generation capacity must also be maintained and based on certain conditions and may not be fully available to serve load. Also, unplanned outages place a demand on the available capacity. Thus the demand on system capacity is the sum of the load demand to serve customers, the scheduled outage demand for maintenance, the forced outage demand for unplanned outages and the demand that occurs because of weather or operating issues that limit capacity to less than the full output of the generator. Based on the full demand on capacity, the appropriate AED allocation factor consists of average demand (energy divided by 8760 hours) and the excess demand based on twelve coincident peaks (12 CP). AED/12CP reflects cost causation for the system based on all of the operating characteristics of the system. The excess demand component is allocated on the class NCP.

Dr. Overcast further testified that a part of the cost study review was to evaluate the total demand for capacity on the Empire system. Table 1 shows the total monthly system demand on capacity resources, and the following bar chart illustrates the total demand on capacity for the system based on the maximum demand occurring in each month of the year. The line on the graph shows the average total demand for the system and the months that exceed the average of the total demand.

Table 1
Total Monthly System Demand on Capacity Resources[1]

Month	MWH
January	1,149
February	1,057
March	907
April	638
May	749
June	1,026
July	1,094
August	1,039
September	951
October	707
November	704
December	812

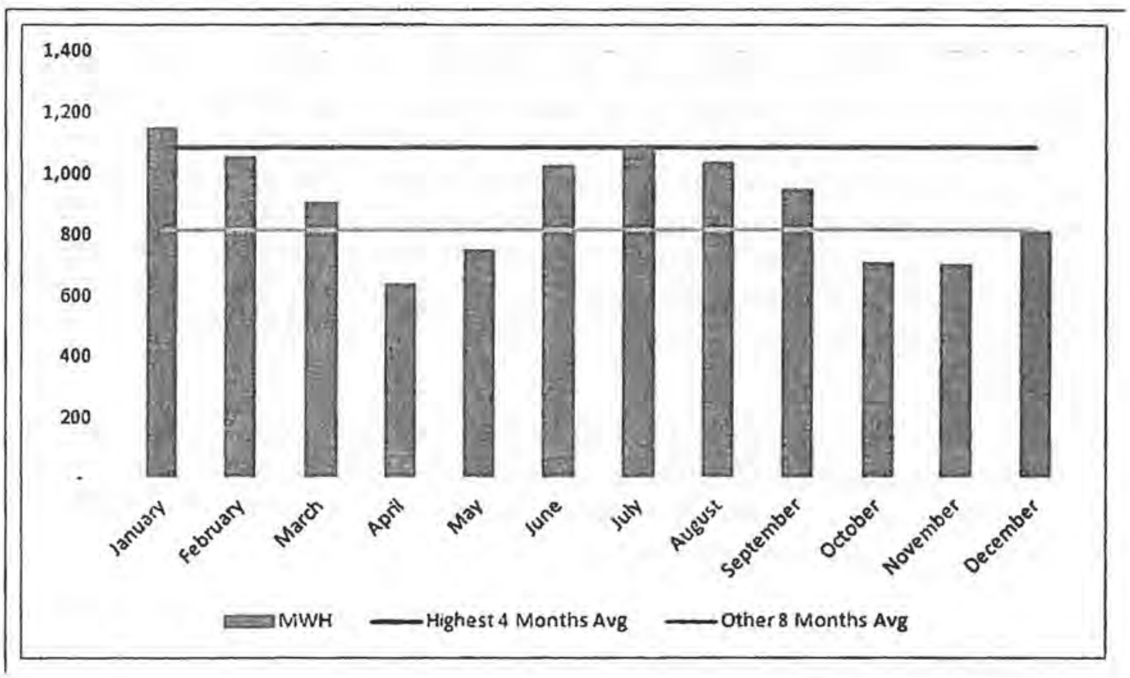

Table 1 provided guidance on the selection of the appropriate number of months to be used as the system peak in the preferred AED method for allocating production capacity that he utilized in Empire's case. If we add to the load demand scheduled maintenance, forced outages and unit deratings, the monthly demands flatten out because maintenance is scheduled in low use months. The data shows that Empire is a dual peaking utility in the summer and winter for load. The actual system peak may change with weather during a calendar year. Typically unit deratings occur in the summer and would add to the peak load in those months. Forced outage rates vary and as noted above, maintenance is scheduled in spring and fall months. Based on these facts, peak total demand falls in a narrow band for all 12 months. He defined the system peak for the AED method based on the 12 CPs for Empire.

According to Dr. Overcast, the AED allocation factor was made up of two components: (1) the system average demand and (2) the system excess demand. The following formula is used to calculate the AED allocation factor for each rate class.

$$APCC_i=((E_i/8760)/(UE/8760))*((UE/8760)/UCP) + ((NCP_i-AD_i)/((\sum_{i=1}^{c} NCP_i) - UAD)))*(1- (UE/8760)/UCP)$$

Where $APCC_i$ equals the allocation percentage for the i^{th} customer class. E_i equals the energy consumption of the i^{th} customer class. $E_i/8760$ equals the average demand of the i^{th} customer class also denoted by AD_i. UE equals the total energy for the utility and UE/8760 equals the utility average demand also denoted UAD. UCP equals the utility coincident peak or peaks. (UE/8760)/UCP equals the utility's annual load factor. NCP_i is the class non- coincident peak. NCP_i-AD_i is the class excess demand for the i^{th} customer class. $\sum_{i=1}^{c} NCP_i$ is the sum of the class non-coincident peaks for the classes. UAD equals the utility average demand. $((\sum_{i=1}^{c} NCP_i)$ - UAD)) equals the utility excess demand. (1- (UE/8760)/UCP)) equals 1 minus the utility load factor. Stated in words rather than by formula, the AED allocation factor is the sum of the class average demand as a percent of the system average demand weighted by the system load factor and the class excess demand defined as the difference between the class average demand and the class non-coincident peak demand as a percent of the system total excess demand defined as the sum of the classes non-coincident peak demands less the system average demand times 1 minus the utility load factor as the weight of the excess component. The peak used to determine excess demand may be the average of more than one hour. For example AED/12CP would determine the system excess demand using the average of the highest 12 monthly peaks. Using multiple months to determine the excess demand has the effect of weighting the average demand component more than using a single peak. The choice of the factor to determine the excess demand is based on an analysis of the total demand on the system, not just load demand.

The allocation of excess demand using NCP is a critical component of the AED allocation. If one were to use the CP allocator instead on the NCP, the allocation becomes the mathematical equivalent of the CP allocation factor. As described above, the AED/12CP is the option that best meets the criteria of cost causation.

Dr. Overcast testified that the transmission Plant was allocated based on 12 CP. The use of 12 CP reflects the use of Transmission Plant on a monthly basis. Absent significant differences in monthly loading of the transmission system, such as high summer peaks and low winter peaks, a 12 CP allocation factor is consistent with the design and use of Transmission Plant. For Empire, winter and summer peaks are very close in terms of load. Further, the transmission system is designed to move generation output from the generation nodes on the system to the load nodes on the system and off the system when dispatched for the SPP. At any one time, the capacity of the system must be such that load nodes have access to adequate generation, including the purchase of power to lower costs or to assure reliability at each load node. The fact that different load nodes peak at different times and that a different combination of resources serves the node means that transmission capacity is used differently over time and that the monthly peaks represent the best reflection of cost causation as opposed to the system peak load periods only.

Next, Dr. Overcast testified regarding the allocation of distribution plant. Distribution Plant includes substations, poles and wires, transformers, meters, and services. In addition, Distribution Plant includes lighting. The allocation of Distribution Plant requires that the investment be classified as demand or customer, since these are the two factors that cause the cost. For distribution costs found in Account Nos. 364 - 374 either all or a portion of the costs are customer related because they are caused by customers. There is no basis for arguing that Account Nos. 369 - 373 are not customer related. For Account No. 369- Services, each customer has a service designed to meet that customer's own load characteristics. The service line is dedicated to the customer to meet the load of the customer premise. Services are dedicated to a customer and each customer causes the cost of its service even if the customer never consumes any energy beyond a single light bulb. If the customer is able to avoid all volumetric electric charges and pays only a nominal, non-compensatory customer charge the result is not just and reasonable and is a case of undue discrimination unless that minimum charge covers not only the service line costs but the component of all of the other distribution costs related to providing the customer access to the electric system.

Electricity will not flow into a premise without an electric meter (Account No. 370). For smaller customers, meters are virtually the same for each customer. As customers increase in size, the meter installation becomes increasingly complex and the cost of meter sets increase. In addition, Account Nos. 371 - 373 represent facilities that are also customer related. In the case of these facilities, the customers who request the extra service provided by these facilities typically pay for these directly as in the case of Account No. 373 related to lighting. In addition to the costs of Account Nos. 369 - 373, a customer cannot be connected to the system and cannot receive service without a minimum level of distribution services provided through the assets in Account Nos. 364 - 368. These accounts support the basic distribution facilities that must be extended to connect new customers to the system. All existing premises were at one time new customers for whom the system must have been extended. Further, the utility must continually replace aging infrastructure to continue to serve these customers regardless of their annual kWh usage. In the case of these distribution facilities, the minimum size of equipment commonly installed under current policies and procedures represents the costs caused by customers in order to connect the minimum load to the system. The minimum system concept assures that customers who cause the costs of facilities to interconnect to the utility are properly allocated those costs.

Dr. Overcast further testified that it was important to understand the role of scale economies in distribution service when allocating costs and designing rates for delivery service. The cost of distribution facilities declines per kWh consumed for any given level of demand. For example, the cost of facilities such as transformers has a lower per unit of demand cost for higher demands. The following table provides data for a range of transformers that may be installed for residential customers and the cost per kVa of each size of transformer.

Table 2
Cost per kVa of Transformer Capacity

Single Phase Transformer	Installed Cost	Cost per kVa
15 kVa	$1,342.97	$89.53
25 kVa	$1,600.57	$64.02
50 kVa	$2,167.86	$43.36
75 kVa	$2,678.73	$35.72

The above table illustrates the cost per kVa of transformer capacity declines dramatically as the size of the transformers increases. For customers with an NCP below 10 kW, the unit cost is over twice as much as for customers served off a 50 kVa transformer. Since a 15 kVa transformer is the minimum size installed based on engineering standards for the Company, smaller customers served off this transformer cost more to serve per unit of NCP than do larger customers served off larger transformers. This same phenomenon occurs for other elements of the distribution system including poles and conductor.

The implications for cost of service are that customers with higher NCP may actually have lower total costs than smaller customers. Compare two customers as follows: first, a customer with central air conditioning and an electric water heater with an NCP of 12 kVa and second, an all-electric customer with an NCP of 17 kVa. Further assume that the all-electric home is in a subdivision where three homes are served off a 50 kVa transformer. The total cost of transformer capacity is about $723 each for the all-electric homes and $1,342.97 for the smaller demand customer's home. When recovering the cost from each customer, it is necessary to take into account the relative load factor of each customer since the greatest portion of fixed costs are recovered volumetrically. The typical all-electric home has a higher load factor based on NCP than the typical non all-electric home, resulting in an even lower cost per kWh for the all-electric home. In addition, the all-electric home has a much higher CP load factor when the system peaks in the summer like it does for Empire. On a CP basis, the rates for the all-electric customer should be substantially lower than the other customers. This is the fundamental basis for declining block residential rates and demonstrates that such rates are cost based.

Dr. Overcast testified that distribution plant was classified as demand, demand and customer, or just customer depending on the costs. Each component of the distribution system requires a different allocation factor based on the classification of the costs and the role that diversity plays in causing the costs. For plant functionalized as distribution plant and found in accounts related to facilities associated with distribution substations (USOA 360-363), the plant is classified as demand and is allocated on the class contribution to the system NCP. Substations reflect the diversity of the customers served out of a particular substation. Typically, substations have different mixes of customer class and loads. As a result, substations often peak at times different from the system peak loads. Some substations may even have peak loads in a different season of the year than the system. The use of the sum of the class NCPs accounts for the differences that occur in the capacity demand on substations. Diversity of load on the distribution system is greatest at the substation level where multiple feeders serve a variety of customers and loads.

For distribution facilities in the accounts related to the power lines (USOA 364-368) where power is delivered to the interconnection point with the customer, the costs are classified as both customer and demand. While there are several methods to classify these costs between