Ohio | Public Utilities Commission

LARGE FILING SEPARATOR SHEET

CASE NUMBER: 17-0032-EL-AIR, 17-0033-EL-ATA, 17-0034-EL-AAM

FILE DATE: 3/16/2017

SECTION: 1 of 2

FILED BY: Jeanne Kingery

FILED ON BEHALF OF: Duke Energy Ohio, Inc.

NUMBER OF PAGES: 205

DESCRIPTION OF DOCUMENT: Testimony, Volume 2

205

BEFORE

THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Duke Energy Ohio, Inc., for an Increase in Electric Distribution Rates.	)))	Case No. 17-32-EL-AIR
In the Matter of the Application of Duke Energy Ohio, Inc., for Tariff Approval.	)))	Case No. 17-33-EL-ATA
In the Matter of the Application of Duke Energy Ohio, Inc., for Approval to Change Accounting Methods.	)))	Case No. 17-34-EL-AAM

TESTIMONY

VOLUME 2

March 16, 2017

DUKE ENERGY OHIO EXHIBIT____

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DIRECT TESTIMONY OF

ROGER A. MORIN, Ph.D.,

ON BEHALF OF

DUKE ENERGY OHIO, INC.

______	Management policies, practices, and organization
______	Operating income
______	Rate Base
______	Allocations
X	Rate of return
______	Rates and tariffs
______	Other: Rate Case Drivers

March 16, 2017

TABLE OF CONTENTS

PAGE

I. INTRODUCTION AND SUMMARY OF RECOMMENDATION 1

II. REGULATORY FRAMEWORK AND RATE OF RETURN 7

III. COST OF EQUITY CAPITAL ESTIMATES 15

A. DCF Estimates 18

B. CAPM Estimates 32

C. Historical Risk Premium Estimates 49

D. Allowed Risk Premium Estimates 51

E. Need for Flotation Cost Adjustment 54

IV. CONCLUSION 59

Attachments:

RAM-1: Resume of Roger A. Morin

RAM-2: Investment-Grade Combination Gas & Electric Utilities
DCF Analysis: Value Line Growth Projections

RAM-3: Investment-Grade Combination Gas & Electric Utilities
DCF Analysis: Analysts' Growth Forecasts

RAM-4: S&P Utility Index Companies
DCF Analysis: Value Line Growth Forecasts

RAM-5: S&P Utility Index Companies
DCF Analysis: Analysts' Growth Forecasts

RAM-6: Utility Beta Estimates

RAM-7: S&P Utility Index Common Stocks Over Long-Term
Utility Bonds Annual Long-Term Risk Premium Analysis

RAM-8: Equity Risk Premium – Treasury Bond

Appendix:

Appendix A: CAPM, Empirical CAPM

Appendix B: Flotation Cost Allowance

I. INTRODUCTION AND SUMMARY OF RECOMMENDATION

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

A. My name is Dr. Roger A. Morin. My business address is Georgia State University, Robinson College of Business, University Plaza, Atlanta, Georgia, 30303. I am Emeritus Professor of Finance at the Robinson College of Business, Georgia State University and Professor of Finance for Regulated Industry at the Center for the Study of Regulated Industry at Georgia State University. I am also a principal in Utility Research International, an enterprise engaged in regulatory finance and economics consulting to business and government. I am testifying on behalf of Duke Energy of Ohio, Inc. (Duke Energy Ohio or the Company).

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND.

A. I hold a Bachelor of Engineering degree and an MBA in Finance from McGill University, Montreal, Canada. I received my Ph.D. in Finance and Econometrics at the Wharton School of Finance, University of Pennsylvania.

Q. PLEASE SUMMARIZE YOUR ACADEMIC AND BUSINESS CAREER.

A. I have taught at the Wharton School of Finance, University of Pennsylvania, Amos Tuck School of Business at Dartmouth College, Drexel University, University of Montreal, McGill University, and Georgia State University. I was a faculty member of Advanced Management Research International, and I am currently a faculty member of The Management Exchange Inc. and Exnet, Inc. (now SNL Knowledge Center or SNL), where I continue to conduct frequent national executive-level education seminars throughout the United States and

Canada. In the last 30 years, I have conducted numerous national seminars on "Utility Finance," "Utility Cost of Capital," "Alternative Regulatory Frameworks," and "Utility Capital Allocation," which I have developed on behalf of The Management Exchange Inc. and SNL.

I have authored or co-authored several books, monographs, and articles in academic scientific journals on the subject of finance. They have appeared in a variety of journals, including The Journal of Finance, The Journal of Business Administration, International Management Review, and Public Utilities Fortnightly. I published a widely-used treatise on regulatory finance, Utilities' Cost of Capital, Public Utilities Reports, Inc., Arlington, Va. 1984. In late 1994, the same publisher released my book, Regulatory Finance, a voluminous treatise on the application of finance to regulated utilities. A revised and expanded edition of this book, The New Regulatory Finance, was published in 2006. I have been engaged in extensive consulting activities on behalf of numerous corporations, legal firms, and regulatory bodies in matters of financial management and corporate litigation.

Please see Attachment RAM-1 for my professional qualifications.

Q. HAVE YOU PREVIOUSLY TESTIFIED ON COST OF CAPITAL BEFORE UTILITY REGULATORY COMMISSIONS?

A. Yes, I have been a cost of capital witness before nearly 50 regulatory bodies in North America, including the Public Utility Commission of Ohio (PUCO, or the Commission). I have testified before the following state, provincial, and other local regulatory commissions:

Alabama	Florida	Missouri	Ontario
Alaska	Georgia	Montana	Oregon
Alberta	Hawaii	Nevada	Pennsylvania
Arizona	Illinois	New Brunswick	Quebec
Arkansas	Indiana	New Hampshire	South Carolina
British Columbia	Iowa	New Jersey	South Dakota
California	Kentucky	New Mexico	Tennessee
City of New Orleans	Louisiana	New York	Texas
Colorado	Maine	Newfoundland	Utah
CRTC	Manitoba	North Carolina	Vermont
Delaware	Maryland	North Dakota	Virginia
District of Columbia	Michigan	Nova Scotia	Ohio
FCC	Minnesota	Ohio	West Virginia
FERC	Mississippi	Oklahoma	Nebraska
Wisconsin			

The details of my participation in regulatory proceedings are also provided in Attachment RAM-1.

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

A. The purpose of my testimony in this proceeding is to present an independent appraisal of the fair and reasonable rate of return on common equity (ROE) on the common equity capital invested in Duke Energy Ohio's electric distribution operations in the State of Ohio. Based upon this appraisal, I have formed my professional judgment as to a return on such capital that would:

(1) be fair to ratepayers;

(2) allow Duke Energy Ohio to attract the capital needed for

infrastructure and reliability investments on reasonable terms;

(3) maintain Duke Energy Ohio's financial integrity; and

(4) be comparable to returns offered on comparable risk investments.

Q. PLEASE BRIEFLY IDENTIFY THE ATTACHMENTS AND APPENDICES ACCOMPANYING YOUR TESTIMONY.

A. I have attached to my testimony Attachment RAM-1 through Attachment RAM-8, and Appendices A and B. These attachments and appendices relate directly to points in my testimony, and are described in further detail in connection with the discussion of those points in my testimony.

Q. PLEASE SUMMARIZE YOUR FINDINGS CONCERNING DUKE ENERGY OHIO'S COST OF COMMON EQUITY.

A. It is my opinion that a fair, reasonable and sufficient ROE for Duke Energy Ohio falls in the upper half of a range between 9.5% and 10.7%, that is, 10.1% - 10.7%. This range is based on the Commission's adoption of Duke Energy Ohio's proposed common equity ratio of approximately 51%.

In reaching this conclusion, I have employed the traditional cost of capital estimating methodologies which assume business-as-usual circumstances, and then recommended that the Commission adopt a ROE in the upper portion of my recommended range of 10.1% - 10.7% in order to account for Duke Energy Ohio's high external financing risks relative to its size, a substantial increase in interest rates predicted over the next several years and a higher degree of regulatory risk.

A ROE in the range of 10.1% - 10.7% for Duke Energy Ohio is required in order for the Company to: (i) attract capital on reasonable terms, (ii) maintain its financial integrity, and (iii) earn a return commensurate with returns on comparable risk investments.

My ROE range is derived from cost of capital studies that I performed using the financial models available to me and from the application of my professional judgment to the results. I applied various cost of capital methodologies, including Discounted Cash Flow (DCF), Capital Asset Pricing Model (CAPM) and Risk Premium methodologies, to a group of investment-grade dividend-paying combination gas and electric utilities which are covered in Value Line's Electric Utility Composite. The companies were also required to have the majority of their revenues from regulated utility operations.

My recommended rate of return reflects the application of my professional judgment to the results in light of the indicated returns from my DCF, CAPM, and Risk Premium analyses.

Q. WOULD IT BE IN THE BEST INTERESTS OF RATEPAYERS FOR THE COMMISSION TO APPROVE A ROE IN THE RANGE OF 10.1% - 10.7% FOR DUKE ENERGY OHIO'S ELECTRIC UTILITY OPERATIONS?

A. Yes. My analysis shows that this range fairly compensates investors, maintains Duke Energy Ohio's credit strength, and attracts the capital needed for utility infrastructure and reliability capital investments. Adopting a lower ROE would increase costs for ratepayers.

Q. PLEASE EXPLAIN HOW LOW ALLOWED ROES CAN INCREASE BOTH THE FUTURE COST OF EQUITY AND DEBT FINANCING.

A. If a utility is authorized a ROE below the level required by equity investors, the utility or its parent will find it difficult to access equity capital. Investors will not provide equity capital at the current market price if the earnable return on equity is below the level they require given the risks of an equity investment in the utility. The equity market corrects this by generating a stock price in equilibrium that reflects the valuation of the potential earnings stream from an equity investment at the risk-adjusted return equity investors require. In the case of a utility that has been authorized a return below the level investors believe is appropriate for the risk they bear, the result is a decrease in the utility's market price per share of common stock. This reduces the financial viability of equity financing in two ways. First, because the utility's price per share of common stock decreases, the net proceeds from issuing common stock are reduced. Second, since the utility's market to book ratio decreases with the decrease in the share price of common stock, the potential risk from dilution of equity investments reduces investors' inclination to purchase new issues of common stock. The ultimate effect is the utility will have to rely more on debt financing to meet its capital needs.

As a company relies more on debt financing, its capital structure becomes more leveraged. Because debt payments are a fixed financial obligation to the utility, and income available to common equity is subordinate to fixed charges, this decreases the operating income available for dividend and earnings growth.

Consequently, equity investors face greater uncertainty about future dividends and earnings from the firm. As a result, the firm's equity becomes a riskier investment. The risk of default on a company's bonds also increases, making the utility's debt a riskier investment. This increases the cost to the utility from both debt and equity financing and increases the possibility a company will not have access to the capital markets for its outside financing needs. Ultimately, to ensure that Duke Energy Ohio has access to capital markets for its capital needs, a fair and reasonable authorized ROE in the range of 10.1% - 10.7% is required.

Duke Energy Ohio must secure outside funds from capital markets to finance required utility plant and equipment investments irrespective of capital market conditions, interest rate conditions and the quality consciousness of market participants. Thus, rate relief requirements and supportive regulatory treatment, including approval of my recommended ROE, are essential requirements.

II. REGULATORY FRAMEWORK AND RATE OF RETURN

Q. PLEASE EXPLAIN HOW A REGULATED COMPANY'S RATES SHOULD BE SET UNDER TRADITIONAL COST OF SERVICE REGULATION.

A. Under the traditional regulatory process, a regulated company's rates should be set so that the company recovers its costs, including taxes and depreciation, plus a fair and reasonable return on its invested capital. The allowed rate of return must necessarily reflect the cost of the funds obtained, that is, investors' return requirements. In determining a company's required rate of return, the starting point is investors' return requirements in financial markets. A rate of return can then be set at a level sufficient to enable a company to earn a return commensurate with the cost of those funds.

Funds can be obtained in two general forms, debt capital and equity capital. The cost of debt funds can be easily ascertained from an examination of the contractual interest payments. The cost of common equity funds (i.e., investors' required rate of return) is more difficult to estimate. It is the purpose of the next section of my testimony to estimate fair and reasonable ROE ranges for Duke Energy Ohio's cost of common equity capital.

Q. WHAT FUNDAMENTAL PRINCIPLES UNDERLIE THE DETERMINATION OF A FAIR AND REASONABLE ROE?

A. The heart of utility regulation is the setting of just and reasonable rates by way of a fair and reasonable return. There are two landmark United States Supreme Court cases that define the legal principles underlying the regulation of a public utility's rate of return and provide the foundations for the notion of a fair return:

1. *Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia*, 262 U.S. 679 (1923); and
2. *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).

The *Bluefield* case set the standard against which just and reasonable rates of return are measured:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public *equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties* ... The *return should be*

> *reasonable*, sufficient to assure confidence in the financial soundness of the utility, and should be adequate, under efficient and economical management, to *maintain and support its credit* and *enable it to raise money* necessary for the proper discharge of its public duties.

Bluefield Water Works & Improvement Co., 262 U.S. at 692 (emphasis added).

The *Hope* case expanded on the guidelines to be used to assess the reasonableness of the allowed return. The Court reemphasized its statements in the *Bluefield* case and recognized that revenues must cover "capital costs." The Court stated:

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

Hope Natural Gas Co., 320 U.S. at 603 (emphasis added).

The United States Supreme Court reiterated the criteria set forth in *Hope* in *Federal Power Commission v. Memphis Light, Gas & Water Division*, 411 U.S. 458 (1973); in *Permian Basin Rate Cases*, 390 U.S. 747 (1968); and, most recently, in *Duquesne Light Co. v. Barasch*, 488 U.S. 299 (1989). In the *Permian Basin Rate Cases*, the Supreme Court stressed that a regulatory agency's rate of return order should reasonably be expected to maintain financial integrity, attract necessary capital, and fairly compensate investors for the risks they have assumed. *Permian Basin Rate Cases*, 390 U.S. at 792.

Therefore, the "end result" of this Commission's decision should be to allow Duke Energy Ohio the opportunity to earn a return on equity that is:

(i) commensurate with returns on investments in other firms having corresponding risks;
(ii) sufficient to assure confidence in Duke Energy Ohio's financial integrity; and
(iii) sufficient to maintain Duke Energy Ohio's creditworthiness and ability to attract capital on reasonable terms.

Q. HOW IS THE FAIR RATE OF RETURN DETERMINED?

A. The aggregate return required by investors is called the "cost of capital." The cost of capital is the opportunity cost, expressed in percentage terms, of the total pool of capital employed by the utility. It is the composite weighted cost of the various classes of capital (e.g., bonds, preferred stock, common stock) used by the utility, with the weights reflecting the proportions of the total capital that each class of capital represents. The fair return in dollars is obtained by multiplying the rate of return set by the regulator by the utility's "rate base." The rate base is essentially the net book value of the utility's plant and other assets used to provide utility service in a particular jurisdiction.

Although utilities like Duke Energy Ohio enjoy varying degrees of monopoly in the sale of public utility services, they (or their parent companies) must compete with everyone else in the free, open market for the input factors of production, whether labor, materials, machines, or capital, including the capital investments required to support the utility infrastructure. The prices of these inputs are set in the competitive marketplace by supply and demand, and it is these input prices that are incorporated in the cost of service computation. This is just as true for capital as for any other factor of production. Since utilities and other investor-owned businesses must go to the open capital market and sell their securities in competition with every other issuer, there is obviously a market price to pay for the capital they require (e.g., the interest on debt capital or the expected return on equity). In order to attract the necessary capital, utilities must compete with alternative uses of capital and offer a return commensurate with the associated risks.

Q. HOW DOES THE CONCEPT OF A FAIR RETURN RELATE TO THE CONCEPT OF OPPORTUNITY COST?

A. The concept of a fair return is intimately related to the economic concept of "opportunity cost." When investors supply funds to a utility by buying its stocks or bonds, they are not only postponing consumption, giving up the alternative of spending their dollars in some other way, they are also exposing their funds to risk and forgoing returns from investing their money in alternative comparable risk investments. The compensation they require is the price of capital. If there are differences in the risk of the investments, competition among firms for a limited supply of capital will bring different prices. The capital markets translate these differences in risk into differences in required return, in much the same way that differences in the characteristics of commodities are reflected in different prices.

The important point is that the required return on capital is set by supply and demand and is influenced by the relationship between the risk and return expected for those securities and the risks expected from the overall menu of available securities.

Q. WHAT ECONOMIC AND FINANCIAL CONCEPTS HAVE GUIDED YOUR ASSESSMENT OF DUKE ENERGY OHIO'S COST OF COMMON EQUITY?

A. Two fundamental economic principles underlie the appraisal of Duke Energy Ohio's cost of equity, one relating to the supply side of capital markets, the other to the demand side.

On the supply side, the first principle asserts that rational investors maximize the performance of their portfolios only if they expect the returns on investments of comparable risk to be the same. If not, rational investors will switch out of those investments yielding lower returns at a given risk level in favor of those investment activities offering higher returns for the same degree of risk. This principle implies that a company will be unable to attract capital funds unless it can offer returns to capital suppliers that are comparable to those achieved on competing investments of similar risk.

On the demand side, the second principle asserts that a company will continue to invest in real physical assets if the return on these investments equals, or exceeds, a company's cost of capital. This principle suggests that a regulatory board should set rates at a level sufficient to create equality between the return on physical asset investments and a company's cost of capital.

Q. HOW DOES DUKE ENERGY OHIO OBTAIN ITS CAPITAL AND HOW IS ITS OVERALL COST OF CAPITAL DETERMINED?

A. The funds employed by Duke Energy Ohio are obtained in two general forms, debt capital and equity capital. The cost of debt funds can be ascertained easily from an examination of the contractual interest payments. The cost of common equity funds, that is, equity investors' required rate of return, is more difficult to estimate because the dividend payments received from common stock are not contractual or guaranteed in nature. They are uneven and risky, unlike interest payments. Once a cost of common equity estimate has been developed, it can then easily be combined with the embedded cost of debt based on the utility's capital structure, in order to arrive at the overall cost of capital (overall rate of return).

Q. WHAT IS THE MARKET REQUIRED RATE OF RETURN ON EQUITY CAPITAL?

A. The market required rate of return on common equity, or cost of equity, is the return demanded by the equity investor. Investors establish the price for equity capital through their buying and selling decisions in capital markets. Investors set return requirements according to their perception of the risks inherent in the investment, recognizing the opportunity cost of forgone investments in other companies, and the returns available from other investments of comparable risk.

Q. WHAT MUST BE CONSIDERED IN ESTIMATING A FAIR ROE?

A. The basic premise is that the allowable ROE should be commensurate with returns on investments in other firms having corresponding risks. The allowed return should be sufficient to assure confidence in the financial integrity of the firm, in order to maintain creditworthiness and ability to attract capital on reasonable terms. The "attraction of capital" standard focuses on investors' return requirements that are generally determined using market value methods, such as the DCF, CAPM, or risk premium methods. These market value tests define "fair return" as the return investors anticipate when they purchase equity shares of comparable risk in the financial marketplace. This is a market rate of return, defined in terms of anticipated dividends and capital gains as determined by expected changes in stock prices, and reflects the opportunity cost of capital. The economic basis for market value tests is that new capital will be attracted to a firm only if the return expected by the suppliers of funds is commensurate with that available from alternative investments of comparable risk.

Q. PLEASE EXPLAIN HOW LOW ALLOWED ROES CAN INCREASE BOTH THE FUTURE COST OF EQUITY AND DEBT FINANCING.

A. If a utility is authorized a ROE below the level required by equity investors, the utility will find it difficult to access the equity market through common stock issuance at its current market price. Investors will not provide equity capital at the current market price if the earnable return on equity is below the level they require given the risks of an equity investment in the utility. The equity market corrects this by generating a stock price in equilibrium that reflects the valuation of the potential earnings stream from an equity investment at the risk-adjusted return equity investors require. In the case of a utility that has been authorized a return below the level investors believe is appropriate for the risk they bear, the result is a decrease in the utility's market price per share of common stock. This reduces the financial viability of equity financing in two ways. First, because the utility's price per share of common stock decreases, the net proceeds from issuing common stock are reduced. Second, since the utility's market to book ratio decreases with the decrease in the share price of common stock, the potential risk from dilution of equity investments reduces investors' inclination to purchase new issues of common stock. The ultimate effect is the utility will have to rely more on debt financing to meet its capital needs.

As a company relies more on debt financing, its capital structure becomes more leveraged. Because debt payments are a fixed financial obligation to the utility, and income available to common equity is subordinate to fixed charges, this decreases the operating income available for dividend and earnings growth. Consequently, equity investors face greater uncertainty about future dividends and earnings from the firm. As a result, the firm's equity becomes a riskier investment. The risk of default on a company's bonds also increases, making the utility's debt a riskier investment. This increases the cost to the utility from both debt and equity financing and increases the possibility the company will not have access to the capital markets for its outside financing needs.

III. COST OF EQUITY CAPITAL ESTIMATES

Q. HOW DID YOU ESTIMATE A FAIR ROE FOR DUKE ENERGY OHIO?

A. To estimate a fair ROE for Duke Energy Ohio, I employed three methodologies:

(i) DCF methodology;
(ii) CAPM methodology; and
(iii) Risk Premium methodology.

All three methodologies are market-based methodologies designed to estimate the return required by investors on the common equity capital committed to Duke Energy Ohio.

Q. WHY DID YOU USE MORE THAN ONE APPROACH FOR ESTIMATING THE COST OF EQUITY?

A. No one single method provides the necessary level of precision for determining a fair return, but each method provides useful evidence to facilitate the exercise of an informed judgment. Reliance on any single method or preset formula is inappropriate when dealing with investor expectations because of possible measurement difficulties and vagaries in individual companies' market data. Examples of such vagaries include dividend suspension, insufficient or unrepresentative historical data due to a recent merger, impending merger or acquisition, and a new corporate identity due to restructuring activities. The advantage of using several different approaches is that the results of each one can be used to check the others.

As a general proposition, it is extremely dangerous to rely on only one generic methodology to estimate equity costs. The difficulty is compounded when only one variant of that methodology is employed. It is compounded even further when that one methodology is applied to a single company. Hence, several methodologies applied to several comparable risk companies should be employed to estimate the cost of common equity.

As I have stated, there are three broad generic methods available to measure the cost of equity: DCF, CAPM, and risk premium. All three of these methods are accepted and used by the financial community and firmly supported in the financial literature. The weight accorded to any one method may vary depending on unusual circumstances in capital market conditions.

Each methodology requires the exercise of considerable judgment on the reasonableness of the assumptions underlying the method and on the reasonableness of the proxies used to validate the theory and apply the method. Each method has its own way of examining investor behavior, its own premises, and its own set of simplifications of reality. Investors do not necessarily subscribe to any one method, nor does the stock price reflect the application of any one single method by the price-setting investor. There is no guarantee that a single DCF result is necessarily the ideal predictor of the stock price and of the cost of equity reflected in that price, just as there is no guarantee that a single CAPM or risk premium result constitutes the perfect explanation of a stock's price or the cost of equity.

Q. ARE THERE ANY PRACTICAL DIFFICULTIES IN APPLYING COST OF CAPITAL METHODOLOGIES IN ENVIRONMENTS OF VOLATILITY IN CAPITAL MARKETS AND ECONOMIC UNCERTAINTY?

A. Yes, there are. The traditional cost of equity estimation methodologies are difficult to implement when you are dealing with the instability and volatility in the capital markets and the highly uncertain economy both in the U.S. and abroad. This is not only because stock prices are volatile at this time, but also because utility company historical data have become less meaningful for an industry experiencing substantial change, for example, the transition to stringent renewable standards and the need to secure vast amounts of external capital over the next decade, regardless of capital market conditions. Past earnings and dividend trends may simply not be indicative of the future. For example, historical growth rates of earnings and dividends have been depressed by eroding margins due to a variety of factors, including the sluggish economy, declining customer usage, restructuring, and falling margins. As a result, this historical data may not be representative of the future long-term earning power of these companies. Moreover, historical growth rates may not be necessarily representative of future trends for several electric utilities involved in mergers and acquisitions, as these companies going forward are not the same companies for which historical data are available.

In short, given the volatility in capital markets and economic uncertainties, the utilization of multiple methodologies is critical, and reliance on a single methodology is highly hazardous.

A. DCF Estimates

Q. PLEASE DESCRIBE THE DCF APPROACH TO ESTIMATING THE COST OF EQUITY CAPITAL.

A. According to DCF theory, the value of any security to an investor is the expected discounted value of the future stream of dividends or other benefits. One widely used method to measure these anticipated benefits in the case of a non-static company is to examine the current dividend plus the increases in future dividend payments expected by investors. This valuation process can be represented by the following formula, which is the traditional DCF model:

$$K_e = D_1/P_0 + g$$

where: K_e = investors' expected return on equity

D_1 = expected dividend at the end of the coming year

P_0 = current stock price

g = expected growth rate of dividends, earnings, stock price, and book value

The traditional DCF formula states that under certain assumptions, which are described in the next paragraph, the equity investor's expected return (K_e) can be viewed as the sum of an expected dividend yield (D_1/P_0) plus the expected growth rate of future dividends and stock price (g). The returns anticipated at a given market price are not directly observable and must be estimated from statistical market information. The idea of the market value approach is to infer K_e from the observed share price, the observed dividend, and an estimate of investors' expected future growth.

The assumptions underlying this valuation formulation are well known, and are discussed in detail in Chapter 4 of my reference book, *Regulatory Finance*, and Chapter 8 of my more recent reference text, *The New Regulatory Finance*. The standard DCF model requires the following main assumptions:

(i) a constant average growth trend for both dividends and earnings;
(ii) a stable dividend payout policy;
(iii) a discount rate in excess of the expected growth rate; and
(iv) a constant price-earnings multiple, which implies that growth in price is synonymous with growth in earnings and dividends.

The standard DCF model also assumes that dividends are paid at the end of each year when in fact dividend payments are normally made on a quarterly basis.

Q. HOW DID YOU ESTIMATE DUKE ENERGY OHIO'S COST OF EQUITY WITH THE DCF MODEL?

A. In estimating Duke Energy Ohio's cost of equity, I applied the DCF model to a group of investment-grade, dividend-paying, combination gas and electric utilities with the majority of their revenues from regulated operations that are covered in the Value Line database.

In order to apply the DCF model, two components are required: the expected dividend yield (D_1/P_0), and the expected long-term growth (g). The expected dividend (D_1) in the annual DCF model can be obtained by multiplying the current indicated annual dividend rate by the growth factor (1 + g).

Q. HOW DID YOU ESTIMATE THE DIVIDEND YIELD COMPONENT OF THE DCF MODEL?

A. From a conceptual viewpoint, the stock price to employ in calculating the dividend yield is the then-current price of the security at the time of estimating the cost of equity. This is because the current stock prices provide a better indication of expected future prices than any other price in an efficient market. An efficient market implies that prices adjust rapidly to the arrival of new information. Therefore, current prices reflect the fundamental economic value of a security. A considerable body of empirical evidence indicates that capital markets are efficient with respect to a broad set of information. This implies that observed current prices represent the fundamental value of a security, and that a cost of capital estimate should be based on current prices.

In implementing the DCF model, I have used the dividend yields reported in the Value Line Research Web site. Basing dividend yields on average results from a large group of companies reduces the concern that the vagaries of individual company stock prices will result in an unrepresentative dividend yield.

Q. WHY DID YOU MULTIPLY THE SPOT DIVIDEND YIELD BY (1 + g) RATHER THAN BY (1 + 0.5g)?

A. Some analysts multiply the spot dividend yield by one plus one half the expected growth rate (1 + 0.5g) rather than the conventional one plus the expected growth rate (1 + g). This procedure understates the return expected by the investor.

The fundamental assumption of the basic annual DCF model is that dividends are received annually at the end of each year and that the first dividend is to be received one year from now. Thus, the appropriate dividend to use in a DCF model is the full prospective dividend to be received at the end of the year. Since the appropriate dividend to use in a DCF model is the prospective dividend one year from now rather than the dividend one-half year from now, multiplying the spot dividend yield by (1 + 0.5g) understates the proper dividend yield.

Moreover, the basic annual DCF model ignores the time value of quarterly dividend payments and assumes dividends are paid once a year at the end of the year. Multiplying the spot dividend yield by (1 + g) is actually a conservative attempt to capture the reality of quarterly dividend payments. Use of this method is conservative in the sense that the annual DCF model fully ignores the more frequent compounding of quarterly dividends.

Q. HOW DID YOU ESTIMATE THE GROWTH COMPONENT OF THE DCF MODEL?

A. The principal difficulty in calculating the required return by the DCF approach is in ascertaining the growth rate that investors currently expect. Since no explicit estimate of expected growth is observable, proxies must be employed.

As proxies for expected growth, I examined the consensus growth estimate developed by professional analysts. Projected long-term growth rates actually used by institutional investors to determine the desirability of investing in different securities influence investors' growth anticipations. These forecasts are made by large reputable organizations, and the data are readily available and are representative of the consensus view of investors. Because of the dominance of institutional investors in investment management and security selection, and their influence on individual investment decisions, analysts' growth forecasts influence investor growth expectations and provide a sound basis for estimating the cost of equity with the DCF model.

Growth rate forecasts of several analysts are available from published investment newsletters and from systematic compilations of analysts' forecasts, such as those tabulated by Zacks Investment Research Inc. (Zacks) and Yahoo Finance. I used analysts' long-term growth forecasts reported in Zacks as proxies for investors' growth expectations in applying the DCF model. I also used Value Line's growth forecasts as additional proxies.

Q. WHY DID YOU REJECT THE USE OF HISTORICAL GROWTH RATES IN APPLYING THE DCF MODEL TO UTILITIES?

A. I have rejected historical growth rates as proxies for expected growth in the DCF calculation for two reasons. First, historical growth patterns are already incorporated in analysts' growth forecasts that should be used in the DCF model, and are therefore redundant. Second, published studies in the academic literature demonstrate that growth forecasts made by security analysts are reasonable indicators of investor expectations, and that investors rely on analysts' forecasts. This considerable literature is summarized in Chapter 9 of my most recent textbook, *The New Regulatory Finance*.

Q. DID YOU CONSIDER ANY OTHER METHOD OF ESTIMATING EXPECTED GROWTH TO APPLY THE DCF MODEL?

A. Yes, I did. I considered using the so-called "sustainable growth" method, also referred to as the "retention growth" method. According to this method, future growth is estimated by multiplying the fraction of earnings expected to be retained by the company, 'b', by the expected return on book equity, ROE, as follows:

$$g = b \times ROE$$

where: g = expected growth rate in earnings/dividends
b = expected retention ratio
ROE = expected return on book equity

Q. DO YOU HAVE ANY RESERVATIONS IN REGARDS TO THE SUSTAINABLE GROWTH METHOD?

A. Yes, I do. First, the sustainable method of predicting growth contains a logic trap: the method requires an estimate of expected return on book equity to be implemented. But if the expected return on book equity input required by the model differs from the recommended return on equity, a fundamental contradiction in logic follows. Second, the empirical finance literature demonstrates that the sustainable growth method of determining growth is not as significantly correlated to measures of value, such as stock prices and price/earnings ratios, as analysts' growth forecasts. I therefore chose not to rely on this method.

Q. DID YOU CONSIDER DIVIDEND GROWTH IN APPLYING THE DCF MODEL?

A. No, not at this time. The reason is that as a practical matter, while there is an abundance of earnings growth forecasts, there are very few forecasts of dividend growth. Moreover, it is widely expected that some utilities will continue to lower their dividend payout ratios over the next several years in response to heightened business risk and the need to fund very large construction programs over the next decade. Dividend growth has remained largely stagnant in past years as utilities are increasingly conserving financial resources in order to hedge against rising business risks and finance large infrastructure investments. As a result, investors' attention has shifted from dividends to earnings. Therefore, earnings growth provides a more meaningful guide to investors' long-term growth expectations. Indeed, it is growth in earnings that will support future dividends and share prices.

Q. IS THERE ANY EMPIRICAL EVIDENCE DOCUMENTING THE IMPORTANCE OF EARNINGS IN EVALUATING INVESTORS' EXPECTATIONS?

A. Yes, there is an abundance of evidence attesting to the importance of earnings in assessing investors' expectations. First, the sheer volume of earnings forecasts available from the investment community relative to the scarcity of dividend forecasts attests to their importance. To illustrate, Value Line, Yahoo Finance, Zacks Investment, First Call Thompson, Reuters, and Multex provide comprehensive compilations of investors' earnings forecasts. The fact that these investment information providers focus on growth in earnings rather than growth in dividends indicates that the investment community regards earnings growth as a superior indicator of future long-term growth. Second, Value Line's principal investment rating assigned to individual stocks, Timeliness Rank, is based primarily on earnings, which accounts for 65% of the ranking.

Q. HOW DID YOU APPROACH THE COMPOSITION OF COMPARABLE GROUPS IN ORDER TO ESTIMATE DUKE ENERGY OHIO'S COST OF EQUITY WITH THE DCF METHOD?

A. Because Duke Energy Ohio is not publicly traded, the DCF model cannot be applied to Duke Energy Ohio and proxies must be used. There are two possible approaches in forming proxy groups of companies.

The first approach is to apply cost of capital estimation techniques to a select group of companies directly comparable in risk to Duke Energy Ohio. These companies are chosen by the application of stringent screening criteria to a universe of utility stocks in an attempt to identify companies with the same investment risk as Duke Energy Ohio. Examples of screening criteria include bond rating, beta risk, size, percentage of revenues from utility operations, and common equity ratio. The end result is a small sample of companies with a risk profile similar to that of Duke Energy Ohio, provided the screening criteria are defined and applied correctly.

The second approach is to apply cost of capital estimation techniques to a large group of utilities representative of the utility industry average and then make adjustments to account for any difference in investment risk between the company and the industry average, if any. As explained below, in view of substantial changes in circumstances in the utility industry, I have chosen the latter approach.

In the unstable capital market environments, it is important to select relatively large sample sizes representative of the utility industry as a whole, as opposed to small sample sizes consisting of a handful of companies. This is because the equity market as a whole and utility industry capital market data are volatile. As a result of this volatility, the composition of small groups of companies is very fluid, with companies exiting the sample due to dividend suspensions or reductions, insufficient or unrepresentative historical data due to recent mergers, impending merger or acquisition, and changing corporate identities due to restructuring activities.

From a statistical standpoint, confidence in the reliability of the DCF model result is considerably enhanced when applying the DCF model to a large group of companies. Any distortions introduced by measurement errors in the two DCF components of equity return for individual companies, namely dividend yield and growth are mitigated. Utilizing a large portfolio of companies reduces the influence of either overestimating or underestimating the cost of equity for any one individual company. For example, in a large group of companies, positive and negative deviations from the expected growth will tend to cancel out owing to the law of large numbers, provided that the errors are independent.[1] The average growth rate of several companies is less likely to diverge from expected growth than is the estimate of growth for a single firm. More generally, the assumptions of the DCF model are more likely to be fulfilled for a large group of companies than for any single firm or for a small group of companies.

[1] If σ_i^2 represents the average variance of the errors in a group of N companies, and σ_{ij} the average covariance between the errors, then the variance of the error for the group of N companies, σ_N^2 is:

$$\sigma_N^2 = \frac{1}{N}\bar{\sigma}_i^2 + \frac{N-1}{N}\bar{\sigma}_{ij}$$

If the errors are independent, the covariance between them (σ_{ij}) is zero, and the variance of the error for the group is reduced to:

$$\sigma_N^2 = \frac{1}{N}\sigma_i^2$$

As N gets progressively larger, the variance gets smaller and smaller.

Moreover, small samples are subject to measurement error, and in violation of the Central Limit Theorem of statistics.[2] From a statistical standpoint, reliance on robust sample sizes mitigates the impact of possible measurement errors and vagaries in individual companies' market data. Examples of such vagaries include dividend suspension, insufficient or unrepresentative historical data due to a recent merger, impending merger or acquisition, and a new corporate identity due to restructuring.

The point of all this is that the use of a handful of companies in a highly fluid and unstable industry produces fragile and statistically unreliable results. A far safer procedure is to employ large sample sizes representative of the industry as a whole and apply subsequent risk adjustments to the extent that the company's risk profile differs from that of the industry average.

Q. CAN YOU DESCRIBE THE PROXY GROUP FOR DUKE ENERGY OHIO'S UTILITY BUSINESS?

A. As proxies for Duke Energy Ohio, I examined a group of investment-grade dividend-paying combination gas and electric utilities covered in Value Line's Electric Utility industry group, meaning that these companies all possess utility assets similar to Duke Energy Ohio's. I began with all the companies designated as combination gas and electric utilities by AUS Utility Reports that are also

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[2] The Central Limit Theorem describes the characteristics of the distribution of values we would obtain if we were able to draw an infinite number of random samples of a given size from a given population and we calculated the mean of each sample. The Central Limit Theorem asserts: [1] The mean of the sampling distribution of means is equal to the mean of the population from which the samples were drawn. [2] The variance of the sampling distribution of means is equal to the variance of the population from which the samples were drawn divided by the size of the samples. [3] If the original population is distributed normally, the sampling distribution of means will also be normal. If the original population is not normally distributed, the sampling distribution of means will increasingly approximate a normal distribution as sample size increases.

as combination gas and electric utilities by AUS Utility Reports that are also covered in the Value Line Survey as shown on Attachment RAM-2. Sempra Energy was added to the group since it is a combination gas and electric utility covered in the Value Line database. Foreign companies, private partnerships, private companies, non-dividend-paying companies, and companies below investment-grade (with a Moody's bond rating below Baa3 as reported in AUS Utility Reports) were eliminated, as well as those companies whose market capitalization was less than $1 billion, in order to minimize any stock price anomalies due to thin trading.[3]

From the list provided in Attachment RAM-2, and as shown on the accompanying notes in the last column of that attachment, I excluded six companies that have pending merger or acquisition activities. The first excluded company was Black Hills which is in the process of acquiring SourceGas. The second excluded company was Dominion Resources, Inc., which announced an agreement on February 1, 2016, to combine with Questar Corporation. The third excluded company was Duke Energy on account of its acquisition of Piedmont Natural Gas. The fourth excluded company was Empire District Electric which announced an agreement on February 9, 2016, to combine with a subsidiary of Liberty Utilities Co., the wholly owned regulated utility business subsidiary of Algonquin Power & Utilities Corp. The fifth excluded company was Pepco Holdings which has been merged with Exelon. The sixth excluded company was TECO Energy which has been acquired by Emera.

[3] This is necessary in order to minimize the well-known thin trading bias in measuring beta.

Finally, Entergy Corp. was excluded on account of its very high nuclear exposure. After excluding these companies, the final group of companies only included those companies with at least 50% of their revenues from regulated utility operations. Please see Attachment RAM-3 for a list of the eighteen companies that that comprise the Duke Energy Ohio proxy group.

I stress that this proxy group must be viewed as a portfolio of comparable risk. It would be inappropriate to select any particular company or subset of companies from this group and infer the cost of common equity from that company or subset alone.

Q. WHAT DCF RESULTS DID YOU OBTAIN FOR DUKE ENERGY OHIO USING VALUE LINE GROWTH PROJECTIONS?

A. Attachment RAM-4 displays the DCF analysis using Value Line growth projections for the eighteen companies in Duke Energy Ohio's proxy group.

As shown on column 3, line 20 of Attachment RAM-4, the average long-term earnings per share growth forecast obtained from Value Line is 6.03% for Duke Energy Ohio's proxy group. Combining this growth rate with the average expected dividend yield of 3.75% shown on column 4, line 20 of Attachment RAM-4 produces an estimate of equity costs of 9.78% for Duke Energy Ohio's proxy group, as shown on column 5, line 20 of Attachment RAM-4. Recognition of flotation costs brings the cost of equity estimate to 9.98% for the group, shown in Column 6. The need for a flotation cost allowance is discussed at length later in my testimony.

Q. WHAT DCF RESULTS DID YOU OBTAIN FOR DUKE ENERGY OHIO USING ANALYSTS' CONSENSUS GROWTH FORECASTS?

A. Attachment RAM-5 displays the DCF analysis using analysts' consensus growth forecasts for the eighteen companies in Duke Energy Ohio's proxy group. Please note that MGEE and Chesapeake Utilities were eliminated because no analyst growth forecasts were available.

As shown on column 3, line 20, of Attachment RAM-5, the average long-term earnings per share growth forecast obtained from analysts is 5.46% for Duke Energy Ohio's proxy group. Combining this growth rate with the average expected dividend yield of 3.90% shown on column 4, line 20, of Attachment RAM-5 produces an estimate of equity costs of 9.36% for Duke Energy Ohio's proxy group unadjusted for flotation cost, as shown on column 5, line 20, of Attachment RAM-5. Recognition of flotation costs brings the cost of equity estimate to 9.56%, shown in Column 6, line 22.

Q. PLEASE SUMMARIZE THE DCF ESTIMATES FOR DUKE ENERGY OHIO.

A. Table 1 below summarizes the DCF estimates for Duke Energy Ohio:

Table 1. DCF Estimates for Duke Energy Ohio

DCF STUDY	ROE
Electric Utilities Value Line Growth	9.98%
Electric Utilities Analysts Growth	9.56%

B. <u>CAPM Estimates</u>

Q. PLEASE DESCRIBE YOUR APPLICATION OF THE CAPM RISK PREMIUM APPROACH.

A. My first two risk premium estimates are based on the CAPM and on an empirical approximation to the CAPM (ECAPM). The CAPM is a fundamental paradigm of finance. Simply put, the fundamental idea underlying the CAPM is that risk-averse investors demand higher returns for assuming additional risk, and higher-risk securities are priced to yield higher expected returns than lower-risk securities. The CAPM quantifies the additional return, or risk premium, required for bearing incremental risk. It provides a formal risk-return relationship anchored on the basic idea that only market risk matters, as measured by beta (β). According to the CAPM, securities are priced such that:

EXPECTED RETURN = RISK-FREE RATE + RISK PREMIUM

Denoting the risk-free rate by R_F and the return on the market as a whole by R_M, the CAPM is stated as follows:

$$K = R_F + \beta \times (R_M - R_F)$$

where:
K = investors' expected return on equity
R_F = risk-free rate
R_M = return on the market as a whole
β = systematic risk (i.e., change in a security's return relative to that of the market)

This is the seminal CAPM expression, which states that the return required by investors is made up of a risk-free component, R_F, plus a risk premium determined by $\beta \times (R_M - R_F)$. The bracketed expression $(R_M - R_F)$ expression is known as the market risk premium (MRP). To derive the CAPM risk premium estimate, three quantities are required: the risk-free rate (R_F), beta (β), and the MRP, (R_M - R_F).

For the risk-free rate (RF), I used 4.4%, based on forecast interest rates on long-term U.S. Treasury bonds.

For beta (β), I used 0.70 based on Value Line estimates.

For the MRP ((R_M - R_F)), I used 7.0% based on historical market risk premium studies.

These inputs to the CAPM are explained below.

Q. HOW DID YOU ARRIVE AT YOUR RISK-FREE RATE ESTIMATE OF 4.4% IN YOUR CAPM AND RISK PREMIUM ANALYSES?

A. To implement the CAPM and Risk Premium methods, an estimate of the risk-free return is required as a benchmark. I relied on noted economic forecasts which call for a rising trend in interest rates in response to the recovering economy, renewed inflation, and record high federal deficits. Value Line, Global Insight, the Congressional Budget Office, Blue Chip Forecast, the U.S. Energy Information Administration, and the U.S. Bureau of Labor Statistics all project higher long-term Treasury bond rates in the future.

Q. WHY DID YOU RELY ON LONG-TERM BONDS INSTEAD OF SHORT-TERM BONDS?

A. The appropriate proxy for the risk-free rate in the CAPM is the return on the longest-term Treasury bond possible. This is because common stocks are very long-term instruments more akin to very long-term bonds rather than to short-term Treasury bills or intermediate-term Treasury notes. In a risk premium model, the ideal estimate for the risk-free rate has a term to maturity equal to the security being analyzed. Since common stock is a very long-term investment because the cash flows to investors in the form of dividends last indefinitely, the yield on the longest-term possible government bonds, that is the yield on 30-year Treasury bonds, is the best measure of the risk-free rate for use in the CAPM. The expected common stock return is based on very long-term cash flows, regardless of an individual's holding time period. Moreover, utility asset investments generally have very long-term useful lives and should correspondingly be matched with very long-term maturity financing instruments.

While long-term Treasury bonds are potentially subject to interest rate risk, this is only true if the bonds are sold prior to maturity. A substantial fraction of bond market participants, usually institutional investors with long-term liabilities (e.g., pension funds and insurance companies), in fact hold bonds until they mature, and therefore are not subject to interest rate risk. Moreover, institutional bondholders neutralize the impact of interest rate changes by matching the maturity of a bond portfolio with the investment planning period, or by engaging in hedging transactions in the financial futures markets. The merits and mechanics of such immunization strategies are well documented by both academicians and practitioners

Another reason for utilizing the longest maturity Treasury bond possible is that common equity has an infinite life span, and the inflation expectations embodied in its market-required rate of return will therefore be equal to the inflation rate anticipated to prevail over the very long term. The same expectation should be embodied in the risk-free rate used in applying the CAPM model. It stands to reason that the yields on 30-year Treasury bonds will more closely incorporate within their yields the inflation expectations that influence the prices of common stocks than do short-term Treasury bills or intermediate-term U.S. Treasury notes.

Among U.S. Treasury securities, 30-year Treasury bonds have the longest term to maturity and the yields on such securities should be used as proxies for the risk-free rate in applying the CAPM. Therefore, I have relied on the yield on 30-year Treasury bonds in implementing the CAPM and risk premium methods.

Q. ARE THERE OTHER REASONS WHY YOU REJECT SHORT-TERM INTEREST RATES AS PROXIES FOR THE RISK-FREE RATE IN IMPLEMENTING THE CAPM?

A. Yes. Short-term rates are volatile, fluctuate widely, and are subject to more random disturbances than are long-term rates. Short-term rates are largely administered rates. For example, Treasury bills are used by the Federal Reserve as a policy vehicle to stimulate the economy and to control the money supply, and are used by foreign governments, companies, and individuals as a temporary safe-house for money.

As a practical matter, it makes no sense to match the return on common stock to the yield on 90-day Treasury bills. This is because short-term rates, such as the yield on 90-day Treasury bills, fluctuate widely, leading to volatile and unreliable equity return estimates. Moreover, yields on 90-day Treasury bills typically do not match the equity investor's planning horizon. Equity investors generally have an investment horizon far in excess of 90 days.

As a conceptual matter, short-term Treasury bill yields reflect the impact of factors different from those influencing the yields on long-term securities such as common stock. For example, the premium for expected inflation embedded into 90-day Treasury bills is likely to be far different than the inflationary premium embedded into long-term securities yields. On grounds of stability and consistency, the yields on long-term Treasury bonds match more closely with common stock returns.

Q. WHAT IS YOUR ESTIMATE OF THE RISK-FREE RATE IN APPLYING THE CAPM?

A. All the noted interest rate forecasts that I am aware of point to significantly higher interest rates over the next several years. Table 2 below reports the forecast yields on 30-year US Treasury bonds from the Congressional Budget Office, U.S. Department of Labor, U.S. Energy Information Administration, IHS (Global Insight) and Value Line[4].

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[4] When only forecasts of 10-year U.S. Treasury notes are available, 50 basis points were added to obtain the 30-year forecast, based on the historical spread between 30-year and 10-year U.S. Treasury bond yields.

Table 2. Forecast Yields on

30-year U.S. Treasury Bonds

Source	L/T Yield Forecast
Congressional Budget Office[5]	4.6%
U.S. Department of Labor[6]	4.8%
U.S. Energy Information Administration[7]	4.2%
IHS (Global Insight)[8]	4.1%
Value Line Economic Forecast[9]	4.1%
AVERAGE	**4.4%**

Q. WHY DID YOU IGNORE THE CURRENT LEVEL OF INTEREST RATES IN DEVELOPING YOUR PROXY FOR THE RISK-FREE RATE IN A CAPM ANALYSIS?

A. The CAPM is a forward-looking model based on expectations of the future. As a result, in order to produce a meaningful estimate of investors' required rate of return, the CAPM must be applied using data that reflects the expectations of actual investors in the market. While investors examine history as a guide to the future, it is the expectations of future events that influence security values and the cost of capital.

Q. HOW DID YOU SELECT THE BETA FOR YOUR CAPM ANALYSIS?

A. A major thrust of modern financial theory as embodied in the CAPM is that

[5] Congressional Budget Office, "The Budget and Economic Outlook 2016 to 2026," Table E-1, January 2016.

[6] U.S. Department of Labor, "The U.S. Economy to 2024." Table 1, December 2015.

[7] U.S. Energy Information Administration, "Annual Energy Outlook 2016," Annual Projections A20.

[8] IHS (Global Insight) Forecast 10/2016.

[9] Value Line Investment Survey, "Value Line Forecast for the US Economy," 12/2/2016.

perfectly diversified investors can eliminate the company-specific component of risk, and that only market risk remains. The latter is technically known as "beta" (β), or "systematic risk." The beta coefficient measures change in a security's return relative to that of the market. The beta coefficient states the extent and direction of movement in the rate of return on a stock relative to the movement in the rate of return on the market as a whole. It indicates the change in the rate of return on a stock associated with a one percentage point change in the rate of return on the market, and thus measures the degree to which a particular stock shares the risk of the market as a whole. Modern financial theory has established that beta incorporates several economic characteristics of a corporation that are reflected in investors' return requirements.

Duke Energy Ohio is not publicly traded, and therefore, proxies must be used. In the discussion of DCF estimates of the cost of common equity earlier, I examined a sample of investment-grade dividend-paying combination gas and electric utilities covered by Value Line that have at least 50% of their revenues from regulated electric utility operations. The average beta for this group is 0.70. Please see Attachment RAM-6 for the beta estimates of the proxy group for Duke Energy Ohio. Based on these results, I shall use 0.70, as an estimate for the beta applicable to Duke Energy Ohio.

Q. WHAT MRP DID YOU USE IN YOUR CAPM ANALYSIS?

A. For the MRP, I used 7.0%. This estimate was based on the results of historical studies of long-term market risk premiums.

Q. CAN YOU DESCRIBE THE HISTORICAL MRP STUDY USED IN YOUR CAPM ANALYSIS?

A. Yes. The historical MRP estimate is based on the results obtained in Duff & Phelps' 2016 Valuation Handbook (formerly published by Morningstar and earlier by Ibbotson Associates), which compiles historical returns from 1926 to 2015. This well-known study shows that a very broad market sample of common stocks outperformed long-term U.S. Government bonds by 6.0%. The historical MRP over the income component of long-term Government bonds rather than over the total return is 7.0%. The historical MRP should be computed using the income component of bond returns because the intent, even using historical data, is to identify an expected MRP. The income component of total bond return (i.e., the coupon rate) is a far better estimate of expected return than the total return (i.e., the coupon rate + capital gain), because both realized capital gains and realized losses are largely unanticipated by bond investors. The long-horizon (1926-2015) MRP (based on income returns, as required) is 7.0%.

As a check on my 7.0% MRP estimate, I examined the historical return on common stocks in real terms (inflation-adjusted) over the 1926-2015 period and added current inflation expectations to arrive at a current inflation-adjusted common stock return. According to the Duff & Phelps study, the average historical return on common stocks averaged 12.0% over the 1926-2015 period while inflation averaged 3.0% over the same period, implying a real return of 9.0% (12.0% - 3.0% = 9.0%). With current long-term inflation expectations of

2.0%[10], the inflation-adjusted return on common stock becomes 11.0% (9.0% + 2.0% = 11.0%). Given the current yield on 30-year U.S. Treasury bonds of 3.0%, the implied MRP is therefore 8.0% (11.0% - 3.0% = 8.0%). Using the forecast yield of 4.4%, the implied MRP is 6.6% (11.0% - 4.4% = 6.6%). The average of the two estimates is 7.3% which is slightly higher than my 7.0% estimate.

Q. ON WHAT MATURITY BOND DOES THE DUFF & PHELPS HISTORICAL RISK PREMIUM DATA RELY?

A. Because 30-year bonds were not always traded or even available throughout the entire 1926-2014 period covered in the Duff & Phelps study of historical returns, the latter study relied on bond return data based on 20-year Treasury bonds. Given that the normal yield curve is virtually flat above maturities of 20 years over most of the period covered in the Duff & Phelps study, the difference in yield is not material.

Q. WHY DID YOU USE LONG TIME PERIODS IN ARRIVING AT YOUR HISTORICAL MRP ESTIMATE?

A. Because realized returns can be substantially different from prospective returns anticipated by investors when measured over short time periods, it is important to employ returns realized over long time periods rather than returns realized over more recent time periods when estimating the MRP with historical returns. Therefore, a risk premium study should consider the longest possible period for which data are available. Short-run periods during which investors earned a lower risk premium than they expected are offset by short-run periods during which

[10] 30-year U.S. Treasury bonds are currently trading at a 3.0% yield while 30-year inflation-adjusted bonds are trading at an approximate yield of 1.0% implying a long-term inflation rate expectation of 2.0%.

investors earned a higher risk premium than they expected. Only over long time periods will investor return expectations and realizations converge.

I have therefore ignored realized risk premiums measured over short time periods. Instead, I relied on results over periods of enough length to smooth out short-term aberrations, and to encompass several business and interest rate cycles. The use of the entire study period in estimating the appropriate MRP minimizes subjective judgment and encompasses many diverse regimes of inflation, interest rate cycles, and economic cycles.

To the extent that the estimated historical equity risk premium follows what is known in statistics as a random walk, one should expect the equity risk premium to remain at its historical mean. Since I found no evidence that the MRP in common stocks has changed over time, at least prior to the onslaught of the financial crisis of 2008-2009 which has now partially subsided, that is, no significant serial correlation in the Duff & Phelps study prior to that time, it is reasonable to assume that these quantities will remain stable in the future.

Q. SHOULD STUDIES OF HISTORICAL RISK PREMIUMS RELY ON ARITHMETIC AVERAGE RETURNS OR GEOMETRIC AVERAGE RETURNS?

A. Whenever relying on historical risk premiums, only arithmetic average returns over long periods are appropriate for forecasting and estimating the cost of capital, and geometric average returns are not.[11]

[11] *See* Roger A. Morin, Regulatory Finance: Utilities' Cost of Capital, Chapter 11 (1994); Roger A. Morin, The New Regulatory Finance: Utilities' Cost of Capital, Chapter 4 (2006); Richard A Brealey, *et al.*, Principles of Corporate Finance (8th ed. 2006).

Q. PLEASE EXPLAIN HOW THE ISSUE OF WHAT IS THE PROPER "MEAN" ARISES IN THE CONTEXT OF ANALYZING THE COST OF EQUITY?

A. The issue arises in applying methods that derive estimates of a utility's cost of equity from historical relationships between bond yields and earned returns on equity for individual companies or portfolios of several companies. Those methods produce series of numbers representing the annual difference between bond yields and stock returns over long historical periods. The question is how to translate those series into a single number that can be added to a current bond yield to estimate the current cost of equity for a stock or a portfolio. Calculating geometric and arithmetic means are two ways of converting series of numbers to a single, representative figure.

Q. IF BOTH ARE "REPRESENTATIVE" OF THE SERIES, WHAT IS THE DIFFERENCE BETWEEN THE TWO MEANS?

A. Each mean represents different information about the series. The geometric mean of a series of numbers is the value which, if compounded over the period examined, would have made the starting value to grow to the ending value. The arithmetic mean is simply the average of the numbers in the series. Where there is any annual variation (volatility) in a series of numbers, the arithmetic mean of the series, which reflects volatility, will always exceed the geometric mean, which ignores volatility. Because investors require higher expected returns to invest in a company whose earnings are volatile than one whose earnings are stable, the geometric mean is not useful in estimating the expected rate of return which investors require to make an investment.

Q. CAN YOU PROVIDE A NUMERICAL EXAMPLE TO ILLUSTRATE THIS DIFFERENCE BETWEEN GEOMETRIC AND ARITHMETIC MEANS?

A. Yes. Table 3 below compares the geometric and arithmetic mean returns of a hypothetical Stock A, whose yearly returns over a ten-year period are very volatile, with those of a hypothetical Stock B, whose yearly returns are perfectly stable during that period. Consistent with the point that geometric returns ignore volatility, the geometric mean returns for the two series are identical (11.6% in both cases), whereas the arithmetic mean return of the volatile stock (26.7%) is much higher than the arithmetic mean return of the stable stock (11.6%):

Table 3. Arithmetic vs Geometric Mean Returns

Year	***Stock A***	***Stock B***
2006	50.0%	11.6%
2007	-54.7%	11.6%
2008	98.5%	11.6%
2009	42.2%	11.6%
2010	-32.3%	11.6%
2011	-39.2%	11.6%
2012	153.2%	11.6%
2013	-10.0%	11.6%
2014	38.9%	11.6%
2015	20.0%	11.6%
Std. Deviation	64.9%	0.0%
Arith Mean	26.7%	11.6%
Geom Mean	11.6%	11.6%

If relying on geometric means, investors would require the same expected return to invest in both of these stocks, even though the volatility of returns in Stock A is very high while Stock B exhibits perfectly stable returns. That is clearly contrary to the most basic financial theory, that is, the higher the risk the higher the expected return.

Chapter 4 Appendix A of my book <u>The New Regulatory Finance</u> contains a detailed and rigorous discussion of the impropriety of using geometric averages in estimating the cost of capital. Briefly, the disparity between the arithmetic average return and the geometric average return raises the question as to what purposes should these different return measures be used. The answer is that the geometric average return should be used for measuring historical returns that are compounded over multiple time periods. The arithmetic average return should be used for future-oriented analysis, where the use of expected values is appropriate. It is inappropriate to average the arithmetic and geometric average return; they measure different quantities in different ways.

Q. IS YOUR MRP ESTIMATE OF 7.0% CONSISTENT WITH THE ACADEMIC LITERATURE ON THE SUBJECT?

A. Yes, it is, although in the upper portion of the range. In their authoritative corporate finance textbook, Professors Brealey, Myers, and Allen[12] conclude from their review of the fertile literature on the MRP that a range of 5% to 8% is reasonable for the MRP in the United States. My own survey of the MRP literature, which appears in Chapter 5 of my latest textbook, The New Regulatory Finance, is also quite consistent with this range.

Q. WHAT IS YOUR ESTIMATE OF DUKE ENERGY OHIO'S COST OF EQUITY USING THE CAPM APPROACH?

A. Inserting those input values into the CAPM equation, namely a risk-free rate of 4.4%, a beta of 0.70, and a MRP of 7.0%, the CAPM estimate of the cost of common equity is: 4.4% + 0.70 x 7.0% = 9.3%. This estimate becomes 9.5% with flotation costs, discussed later in my testimony.

Q. CAN YOU DESCRIBE YOUR APPLICATION OF THE EMPIRICAL VERSION OF THE CAPM?

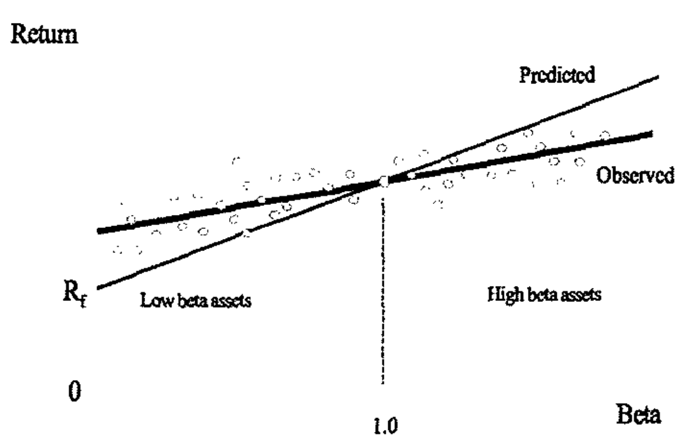
A. There have been countless empirical tests of the CAPM to determine to what

[12] Richard A. Brealey, Stewart C. Myers, and Paul Allen, Principles of Corporate Finance, 8th Edition, Irwin McGraw-Hill, 2006.

extent security returns and betas are related in the manner predicted by the CAPM. This literature is summarized in Chapter 6 of my latest book, The New Regulatory Finance. The results of the tests support the idea that beta is related to security returns, that the risk-return tradeoff is positive, and that the relationship is linear. The contradictory finding is that the risk-return tradeoff is not as steeply sloped as the predicted CAPM. That is, empirical research has long shown that low-beta securities earn returns somewhat higher than the CAPM would predict, and high-beta securities earn less than predicted.

A CAPM-based estimate of cost of capital underestimates the return required from low-beta securities and overstates the return required from high-beta securities, based on the empirical evidence. This is one of the most well-known results in finance, and it is displayed graphically below.

CAPM: Predicted vs Observed Returns



A number of variations on the original CAPM theory have been proposed to explain this finding. The ECAPM makes use of these empirical findings. The ECAPM estimates the cost of capital with the equation:

$$K = R_F + \alpha + \beta \times (MRP - \alpha)$$

where the symbol alpha, α, represents the "constant" of the risk-return line, MRP is the market risk premium (R_M - R_F), and the other symbols are defined as usual.

Inserting the long-term risk-free rate as a proxy for the risk-free rate, an alpha in the range of 1% - 2%, and reasonable values of beta and the MRP in the above equation produces results that are indistinguishable from the following more tractable ECAPM expression:

$$K = R_F + 0.25\,(R_M - R_F) + 0.75\,\beta\,(R_M - R_F)$$

An alpha range of 1% - 2% is somewhat lower than that estimated empirically. The use of a lower value for alpha leads to a lower estimate of the cost of capital for low-beta stocks such as regulated utilities. This is because the use of a long-term risk-free rate rather than a short-term risk-free rate already incorporates some of the desired effect of using the ECAPM. In other words, the long-term risk-free rate version of the CAPM has a higher intercept and a flatter slope than the short-term risk-free version which has been tested. This is also because the use of adjusted betas rather than the use of raw betas also incorporates some of the desired effect of using the ECAPM.[13] Thus, it is reasonable to apply a conservative alpha adjustment.

[13] The regression tendency of betas to converge to 1.0 over time is very well known and widely discussed in the financial literature. As a result of this beta drift, several commercial beta producers adjust their forecasted betas toward 1.00 in an effort to improve their forecasts. Value Line, Bloomberg, and Merrill Lynch betas are adjusted for their long-term tendency to regress toward 1.0 by giving approximately 66% - weight to the measured raw beta and approximately 33% weight to the prior value of 1.0 for each stock:

$$\beta_{adjusted} = 0.33 + 0.66\,\beta_{raw}$$

Please see Appendix A for a discussion of the ECAPM, including its theoretical and empirical underpinnings.

In short, the following equation provides a viable approximation to the observed relationship between risk and return, and provides the following cost of equity capital estimate:

$$K = R_F + 0.25\,(R_M - R_F) + 0.75 \times \beta \times (R_M - R_F)$$

Inserting the risk-free rate (R_F) of 4.4, a MRP ((R_M - R_F)) of 7.0% for (R_M - R_F) and a beta of 0.70 in the above equation, the return on common equity is 9.8%. This estimate becomes 10.0% with flotation costs, discussed later in my testimony.

Q. IS THE USE OF THE ECAPM CONSISTENT WITH THE USE OF ADJUSTED BETAS?

A. Yes, it is. Some have argued that the use of the ECAPM is inconsistent with the use of adjusted betas, such as those supplied by Value Line and Bloomberg. This is because the reason for using the ECAPM is to allow for the tendency of betas to regress toward the mean value of 1.00 over time, and, since Value Line betas are already adjusted for such trend, an ECAPM analysis results in double-counting. This argument is erroneous. Fundamentally, the ECAPM is not an adjustment, increase or decrease in beta. The observed return on high beta securities is actually lower than that produced by the CAPM estimate. The ECAPM is a formal recognition that the observed risk-return tradeoff is flatter than predicted by the CAPM based on myriad empirical evidence. The ECAPM and the use of adjusted betas comprise two separate features of asset pricing. Even if a company's beta is estimated accurately, the CAPM still understates the return for low-beta stocks. Even if the ECAPM is used, the return for low-beta securities is understated if the betas are understated. Referring back to the previous graph, the ECAPM is a return (vertical axis) adjustment and not a beta (horizontal axis) adjustment. Both adjustments are necessary. Moreover, the use of adjusted betas compensates for interest rate sensitivity of utility stocks not captured by unadjusted betas.

Q. PLEASE SUMMARIZE YOUR CAPM ESTIMATES.

A. Table 4 below summarizes the common equity estimates obtained from the CAPM studies.

Table 4. CAPM Results

CAPM Method	ROE
Traditional CAPM	9.5%
Empirical CAPM	10.0%

C. Historical Risk Premium Estimates

Q. PLEASE DESCRIBE YOUR HISTORICAL RISK PREMIUM ANALYSIS OF THE ELECTRIC UTILITY INDUSTRY USING TREASURY BOND YIELDS.

A. A historical risk premium for the utility industry was estimated with an annual time series analysis applied to the utility industry as a whole over the 1930-2015 period, using <u>Standard and Poor's Utility Index</u> (S&P Index) as an industry proxy. The risk premium was estimated by computing the actual realized return on equity capital for the S&P Utility Index for each year, using the actual stock prices and dividends of the index, and then subtracting the long-term Treasury bond return for that year. Please see Attachment RAM-7 for this analysis

As shown on Attachment RAM-7, the average risk premium over the period was 5.5% over long-term Treasury bond yields and 6.1% over the income component of bond yields. As discussed previously, the latter is the appropriate risk premium to use. Given the risk-free rate of 4.4%, and using the historical estimate of 6.1% for bond returns, the implied cost of equity is 4.4% + 6.1% = 10.5% without flotation costs and 10.7% with the flotation cost allowance.

Q. ARE YOU CONCERNED ABOUT THE REALISM OF THE ASSUMPTIONS THAT UNDERLIE THE HISTORICAL RISK PREMIUM METHOD?

A. No, I am not, for they are no more restrictive than the assumptions that underlie the DCF model or the CAPM. While it is true that the method looks backward in time and assumes that the risk premium is constant over time, these assumptions are not necessarily restrictive. By employing returns realized over long time periods rather than returns realized over more recent time periods, investor return expectations and realizations converge. Realized returns can be substantially different from prospective returns anticipated by investors, especially when measured over short time periods. By ensuring that the risk premium study encompasses the longest possible period for which data are available, short-run periods during which investors earned a lower risk premium than they expected are offset by short-run periods during which investors earned a higher risk premium than they expected. Only over long time periods will investor return expectations and realizations converge, or else, investors would be reluctant to invest money.

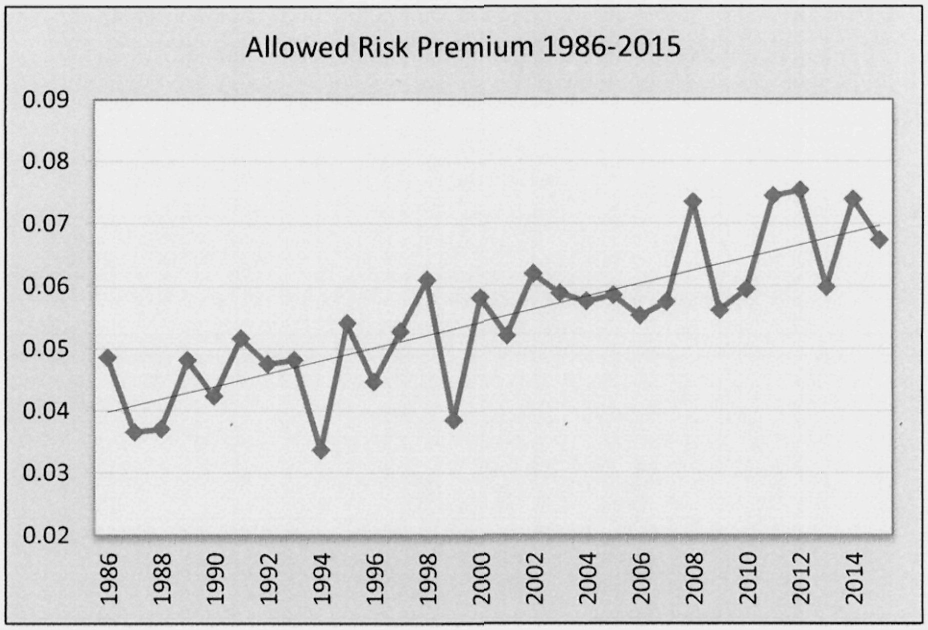
D. Allowed Risk Premium Estimates

Q. PLEASE DESCRIBE YOUR ANALYSIS OF ALLOWED RISK PREMIUMS IN THE ELECTRIC UTILITY INDUSTRY.

A. To estimate the electric utility industry's cost of common equity, I also examined the historical risk premiums implied in the ROEs allowed by regulatory commissions for electric utilities over the 1986-2015 period for which data were available, relative to the contemporaneous level of the long-term Treasury bond yield. Please see Attachment RAM-8 for this analysis.

This variation of the risk premium approach is reasonable because allowed risk premiums are presumably based on the results of market-based methodologies (DCF, CAPM, Risk Premium, *etc.*) presented to regulators in rate hearings and on the actions of objective unbiased investors in a competitive marketplace. Historical allowed ROE data are readily available over long periods on a quarterly basis from Regulatory Research Associates (now S&P Global Intelligence) and easily verifiable from prior issues of that same publication and past commission decision archives.

The average ROE spread over long-term Treasury yields was 5.6% over the entire 1986-2015 period for which data were available from SNL. The graph below shows the year-by-year allowed risk premium. The escalating trend of the risk premium in response to lower interest rates and rising competition is noteworthy.

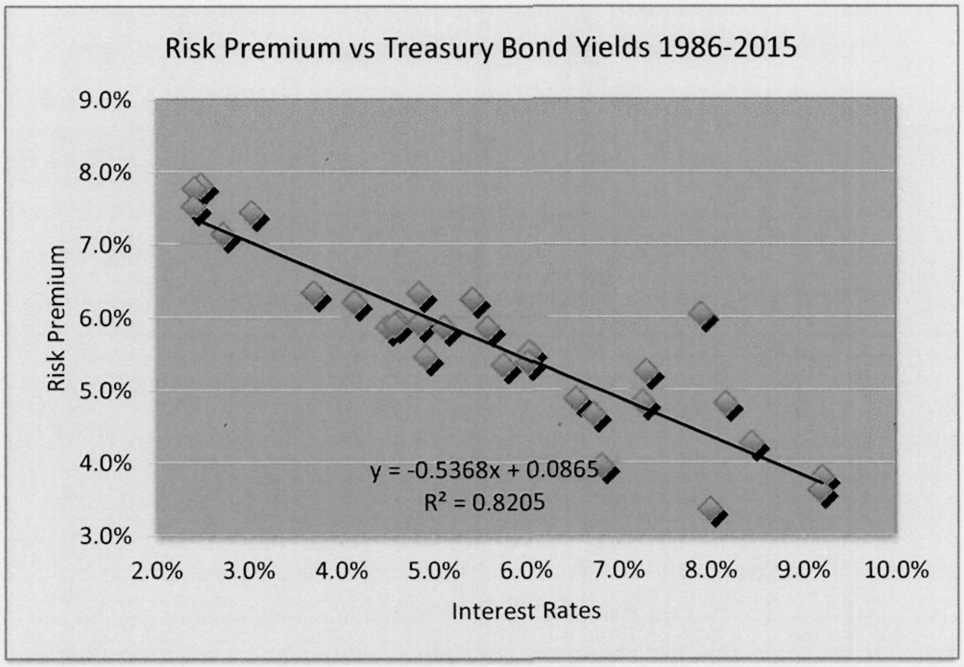


A careful review of these ROE decisions relative to interest rate trends reveals a narrowing of the risk premium in times of rising interest rates, and a widening of the premium as interest rates fall. The following statistical relationship between the risk premium (RP) and interest rates (YIELD) emerges over the 1986-2015 period:

$$RP = 8.6500 - 0.5368 \text{ YIELD} \qquad R^2 = 0.82$$

The relationship is highly statistically significant[14] as indicated by the very high R^2. The graph below shows a clear inverse relationship between the allowed risk premium and interest rates as revealed in past ROE decisions.

[14] The coefficient of determination R^2, sometimes called the "goodness of fit measure," is a measure of the degree of explanatory power of a statistical relationship. It is simply the ratio of the explained portion to the total sum of squares. The higher R^2 the higher is the degree of the overall fit of the estimated regression equation to the sample data.



Inserting the long-term Treasury bond yield of 4.4% in the above equation suggests a risk premium estimate of 6.3%, implying a cost of equity of 10.7%. The latter result is identical to the result of the historical risk premium study.

Q. DO INVESTORS TAKE INTO ACCOUNT ALLOWED RETURNS IN FORMULATING THEIR RETURN EXPECTATIONS?

A. Yes, they do. Investors do indeed take into account returns granted by various regulators in formulating their risk and return expectations, as evidenced by the availability of commercial publications disseminating such data, including Value Line and SNL (formerly Regulatory Research Associates). Allowed returns, while certainly not a precise indication of a particular company's cost of equity capital, are nevertheless important determinants of investor growth perceptions and investor expected returns.

Q. PLEASE SUMMARIZE YOUR RISK PREMIUM ESTIMATES.

A. Table 5 below summarizes the ROE estimates obtained from the two risk premium studies.

Table 5. Risk Premium Estimates for Duke Energy Ohio

Risk Premium Method	ROE
Historical Risk Premium Electric	10.7%
Allowed Risk Premium	10.7%

E. Need for Flotation Cost Adjustment

Q. PLEASE DESCRIBE THE NEED FOR A FLOTATION COST ALLOWANCE.

A. All the market-based estimates reported above include an adjustment for flotation costs. The simple fact of the matter is that issuing common equity capital is not free. Flotation costs associated with stock issues are similar to the flotation costs associated with bonds and preferred stocks. Flotation costs are not expensed at the time of issue, and therefore must be recovered via a rate of return adjustment. This is done routinely for bond and preferred stock issues by most regulatory commissions, including FERC. Clearly, the common equity capital accumulated by the Company is not cost-free. The flotation cost allowance to the cost of common equity capital is discussed and applied in most corporate finance textbooks; it is unreasonable to ignore the need for such an adjustment.

Flotation costs are very similar to the closing costs on a home mortgage. In the case of issues of new equity, flotation costs represent the discounts that must be provided to place the new securities. Flotation costs have a direct and an indirect component. The direct component is the compensation to the security underwriter for his marketing/consulting services, for the risks involved in distributing the issue, and for any operating expenses associated with the issue (*e.g.*, printing, legal, prospectus). The indirect component represents the downward pressure on the stock price as a result of the increased supply of stock from the new issue. The latter component is frequently referred to as "market pressure."

Investors must be compensated for flotation costs on an ongoing basis to the extent that such costs have not been expensed in the past, and therefore the adjustment must continue for the entire time that these initial funds are retained in the firm. Appendix B to my testimony discusses flotation costs in detail, and shows: (1) why it is necessary to apply an allowance of 5% to the dividend yield component of equity cost by dividing that yield by 0.95 (100% - 5%) to obtain the fair return on equity capital; (2) why the flotation adjustment is permanently required to avoid confiscation even if no further stock issues are contemplated; and (3) that flotation costs are only recovered if the rate of return is applied to total equity, including retained earnings, in all future years.

By analogy, in the case of a bond issue, flotation costs are not expensed but are amortized over the life of the bond, and the annual amortization charge is embedded in the cost of service. The flotation adjustment is also analogous to the process of depreciation, which allows the recovery of funds invested in utility plant. The recovery of bond flotation expense continues year after year, irrespective of whether the Company issues new debt capital in the future, until recovery is complete, in the same way that the recovery of past investments in plant and equipment through depreciation allowances continues in the future even if no new construction is contemplated. In the case of common stock that has no finite life, flotation costs are not amortized. Thus, the recovery of flotation costs requires an upward adjustment to the allowed return on equity.

A simple example will illustrate the concept. A stock is sold for $100, and investors require a 10% return, that is, $10 of earnings. But if flotation costs are 5%, the Company nets $95 from the issue, and its common equity account is credited by $95. In order to generate the same $10 of earnings to the shareholders, from a reduced equity base, it is clear that a return in excess of 10% must be allowed on this reduced equity base, here 10.53%.

According to the empirical finance literature discussed in Appendix B, total flotation costs amount to 4% for the direct component and 1% for the market pressure component, for a total of 5% of gross proceeds. This in turn amounts to approximately 20 basis points, depending on the magnitude of the dividend yield component. To illustrate, dividing the average expected dividend yield of around 4.0% for utility stocks by 0.95 yields 4.2%, which is 20 basis points higher.

Sometimes, the argument is made that flotation costs are real and should be recognized in calculating the fair return on equity, but only at the time when the expenses are incurred. In other words, as the argument goes, the flotation cost allowance should not continue indefinitely, but should be made in the year in which the sale of securities occurs, with no need for continuing compensation in future years. This argument is valid only if the Company has already been compensated for these costs. If not, the argument is without merit. My own recommendation is that investors be compensated for flotation costs on an ongoing basis rather than through expensing, and that the flotation cost adjustment continue for the entire time that these initial funds are retained in the firm.

In theory, flotation costs could be expensed and recovered through rates as they are incurred. This procedure, although simple in implementation, is not considered appropriate, however, because the equity capital raised in a given stock issue remains on the utility's common equity account and continues to provide benefits to ratepayers indefinitely. It would be unfair to burden the current generation of ratepayers with the full costs of raising capital when the benefits of that capital extend indefinitely. The common practice of capitalizing rather than expensing eliminates the intergenerational transfers that would prevail if today's ratepayers were asked to bear the full burden of flotation costs of bond/stock issues in order to finance capital projects designed to serve future as well as current generations. Moreover, expensing flotation costs requires an estimate of the market pressure effect for each individual issue, which is likely to prove unreliable. A more reliable approach is to estimate market pressure for a large sample of stock offerings rather than for one individual issue.

There are several sources of equity capital available to a firm including: common equity issues, conversions of convertible preferred stock, dividend reinvestment plans, employees' savings plans, warrants, and stock dividend programs. Each carries its own set of administrative costs and flotation cost components, including discounts, commissions, corporate expenses, offering spread, and market pressure. The flotation cost allowance is a composite factor that reflects the historical mix of sources of equity. The allowance factor is a build-up of historical flotation cost adjustments associated with and traceable to each component of equity at its source. It is impractical and prohibitively costly to start from the inception of a company and determine the source of all present equity. A practical solution is to identify general categories and assign one factor to each category. My recommended flotation cost allowance is a weighted average cost factor designed to capture the average cost of various equity vintages and types of equity capital raised by the Company.

Q. DR. MORIN, CAN YOU PLEASE ELABORATE ON THE MARKET PRESSURE COMPONENT OF FLOTATION COST?

A. The indirect component, or market pressure component of flotation costs represents the downward pressure on the stock price as a result of the increased supply of stock from the new issue, reflecting the basic economic fact that when the supply of securities is increased following a stock or bond issue, the price falls. The market pressure effect is real, tangible, measurable, and negative. According to the empirical finance literature cited in Appendix B, the market pressure component of the flotation cost adjustment is approximately 1% of the gross proceeds of an issuance. The announcement of the sale of large blocks of stock produces a decline in a company's stock price, as one would expect given the increased supply of common stock.

Q. IS A FLOTATION COST ADJUSTMENT REQUIRED FOR AN OPERATING SUBSIDIARY LIKE DUKE ENERGY OHIO THAT DOES NOT TRADE PUBLICLY?

A. Yes, it is. It is sometimes alleged that a flotation cost allowance is inappropriate if the utility is a subsidiary whose equity capital is obtained from its owners, in this case, Duke Energy. This objection is unfounded since the parent-subsidiary relationship does not eliminate the costs of a new issue, but merely transfers them to the parent. It would be unfair and discriminatory to subject parent shareholders to dilution while individual shareholders are absolved from such dilution. Fair treatment must consider that, if the utility-subsidiary had gone to the capital markets directly, flotation costs would have been incurred.

IV. CONCLUSION

Q. PLEASE SUMMARIZE YOUR RESULTS AND RECOMMENDATION.

A. To arrive at my final recommendation, I performed:

(i) a DCF analysis on a group of investment-grade dividend-paying combination gas and electric utilities using Value Line's growth forecasts;

(ii) a DCF analysis on a group of investment-grade dividend-paying combination gas and electric utilities using analysts' growth forecasts;

(iii) a traditional CAPM using current market data;

(iv) an empirical approximation of the CAPM using current market data;

(v) historical risk premium data from electric utility industry aggregate data, using the yield on long-term US Treasury bonds; and

(vi) allowed risk premium data from electric utility industry aggregate data, using the current yield on long-term US Treasury bonds.

Table 6 below summarizes the ROE estimates for Duke Energy Ohio.

Table 6. Summary of ROE Estimates

STUDY	ROE
Combination Utilities Value Line Growth	10.0%
Combination Utilities Analysts Growth	9.6%
CAPM	9.5%
Empirical CAPM	10.0%
Historical Risk Premium Electric	10.7%
Allowed Risk Premium	10.7%

The average estimate is 10.1%, the median result is 10.0%, and the truncated mean[15] is 10.1%. The results range from 9.5% to 10.7%, with a midpoint of 10.1%. Based on all those results, I use the upper half of the range, 10.1% - 10.7% as my recommended ROE range for Duke Energy Ohio.

I stress that no one individual method provides an exclusive foolproof formula for determining a fair return, but each method provides useful evidence so as to facilitate the exercise of an informed judgment. Reliance on any single method or preset formula is hazardous when dealing with investor expectations. Moreover, the advantage of using several different approaches is that the results of each one can be used to check the others. Thus, the results shown in Table 6 above must be viewed as a whole rather than each as a stand-alone. It would be inappropriate to select any particular number from Table 6 and infer the cost of common equity from that number alone.

[15] The truncated mean is obtained by removing the high and low results and computing the average of the remaining observations.

Q. DR. MORIN, WHY DID YOU RECOMMEND THAT THE ROE BE SET IN THE UPPER HALF PORTION OF YOUR ESTIMATED RANGE?

A. For two reasons. First, as discussed earlier, the Company is very likely to raise very large sums of money in a rising interest rate environment over the next five years. Second, high business risks result from a very large infrastructure-related capital investment plan relative to the size of the Company's rate base and common equity capital base, coupled with regulatory uncertainties. The Company's ambitious capital expenditure program which will require approximately $2.5 billion of financing over the next five years for new utility infrastructure investments in order to improve reliability, upgrade the distribution and transmission infrastructure, and enhance reliability. To place that number in proper perspective, the Company's common equity balance is approximately $1.9 billion and its total capital base approximately $3.8 million. In other words, the company is expected to spend an amount which exceeds its entire common equity ownership capital by 130%, and increase its total capital base over the next five years by 66%.

Because of the Company's large construction program over the next few years, rate relief requirements and regulatory treatment uncertainty will increase regulatory risks as well. Generally, regulatory risks include approval risks, lags and delays, potential rate base exclusions, and potential disallowances. Continued regulatory support from the Commission will be required. Reviews of the economic and environmental aspects of new construction can consume as much as one year before approval or denial. Uncertainty of approval increases forecasting and planning risks and complicates the utility's ability to devise optimum electric distribution/transmission networks. Regulatory approval for financings required for new construction may also be required, injecting additional risks.

Q. DR. MORIN, WHAT IS YOUR FINAL CONCLUSION REGARDING DUKE ENERGY OHIO'S RETURN ON COMMON EQUITY CAPITAL?

A. Based on the results of all my analyses, the application of my professional judgment, and the current circumstances in capital markets, it is my opinion that a just and reasonable ROE for Duke Energy Ohio's electric utility operations in the State of Ohio lies in a range of 10.1% - 10.7% range.

Q. DR. MORIN, IS YOUR ROE RECOMMENDATION IMPACTED BY THE COMPANY'S DISTRIBUTION CAPITAL INVESTMENT (DCI) RIDER?

A. No, it is not.

Q. CAN YOU PLEASE DISCUSS THE IMPACT OF THE DCI MECHANISM ON THE COMPANY'S INVESTMENT RISK?

A. The presence of a DCI rider raises the question as to whether such a mechanism reduces the Company's business risk, and to what extent its required ROE should be reduced, if at all.

I did not adjust my recommended ROE downward in order to account for the impact of DCI on the Company's business risks because my recommended market-derived ROE for Duke Energy Ohio is estimated from market information on the cost of common equity for other comparable electric utilities. To the extent that the market-derived cost of common equity for other utility companies already incorporates the impacts of these or similar mechanisms, no further adjustment is appropriate or reasonable in determining the cost of common equity for Duke Energy Ohio. To do so would constitute double-counting.

Most, if not all, electric utilities in the industry are under some form of rider/adjustment clause/cost recovery/mechanisms. The approval of riders, adjustment clauses, cost recovery mechanisms, and various forms of risk-mitigating mechanisms by regulatory commissions is widespread in the utility business and is already largely embedded in financial data, such as bond ratings, stock prices, and business risk scores. Moreover, it is important to note that investors generally do not associate specific increments to their return requirements with specific rate structures. Rather, investors tend to look at the totality of risk-mitigating mechanisms in place relative to those in place at comparable companies when assessing risk.

Q. HOW PREVALENT ARE RISK-MITIGATING MECHANISMS IN THE ELECTRIC UTILITY INDUSTRY?

A. Risk-mitigating mechanisms are becoming the norm for regulated utilities across the U.S. A majority of states either have decoupling/revenue adjustment mechanisms in place, or are reviewing or implementing them. Cost recovery mechanisms are prevalent in most of the fifty states.

The major point of all this is that while risk-mitigating mechanisms such as the DCI rider reduces risk on an absolute basis, they do not necessarily do so on a relative basis, that is, compared to other utilities. For example, a fuel cost adjustment clause does not reduce relative risk since most electric utilities in the industry are under some form of energy cost adjustment mechanism. The approval of adjustment clauses, ROE incentives riders, trackers, forward test years, and cost recovery mechanisms by regulatory commissions is widespread in the utility business and is already largely embedded in financial data, such as stock prices, bond rating and business risk scores.

While adjustment clauses, riders, and cost tracking mechanisms may mitigate (on an absolute basis but not on a relative basis) a portion of the risk and uncertainty related to the day-to-day management of Duke Energy Ohio's operations, there are other significant factors to consider that work in the reverse direction, for example the weakening of the economy, declining customer use, and the Company's dependence on a significant capital spending program requiring external financing.

Q. IS THERE ANY EMPIRICAL EVIDENCE ON THE IMPACT OF RISK MITIGATORS?

A. Yes, there is. A recent comprehensive study by the Brattle Group[16] investigated the impact of a particular risk-mitigating mechanism, namely, revenue decoupling, on risk and the cost of capital and found that its effect on risk and cost of capital, if any, is undetectable statistically.

[16] Wharton, Vilbert, Goldberg & Brown, *The Impact of Decoupling on the Cost of Capital: An Empirical Investigation*, The Brattle Group, February 2011.

Q. DR. MORIN, ARE YOU AWARE OF ANY REGULATORY COMMISSION REDUCING THE ALLOWED ROE IN ORDER TO ACCOUNT FOR THE PRESENCE OF A REVENUE-DECOUPLING MECHANISMS IN RECENT YEARS?

A. No, I am not. Not since 2011 has a regulatory commission applied such a downward return adjustment to the best of my knowledge.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

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(Fall 2016)

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- PhD in Finance & Econometrics, Wharton School of Finance, University of Pennsylvania, 1976.

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- Assistant Professor, University of Montreal School of

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- Associate Professor, University of Montreal School of Business, 1976-1979.

- Professor of Finance, Georgia State University, 1979-2011

- Professor of Finance for Regulated Industry and Director, Center for the Study of Regulated Industry, Robinson College of Business, Georgia State University, 1985-2009

- Visiting Professor of Finance, Amos Tuck School of Business, Dartmouth College, Hanover, N.H., 1986

- Emeritus Professor of Finance, Georgia State University, 2007-16

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- Communications Engineer, Bell Canada, 1962-1967.

- Member Board of Directors, Financial Research Institute of Canada, 1974-1980.

- Co-founder and Director Canadian Finance Research Foundation, 1977.

- Vice-President of Research, Garmaise-Thomson & Associates, Investment Management Consultants, 1980-1981.

- Member Board of Directors, Executive Visions Inc., 1985-2016

- Board of External Advisors, College of Business, Georgia State University, Member 1987-1991.

- Member Board of Directors, Hotel Equities Inc., 2009-2016

PROFESSIONAL CLIENTS

AGL Resources

AT & T Communications

Alagasco - Energen

Alaska Anchorage Municipal Light & Power

Alberta Power Ltd.

Allete

Alliant Energy

AmerenUE

American Water

Ameritech

Arkansas Western Gas

ATC Transmission

Baltimore Gas & Electric – Constellation Energy

Bangor Hydro-Electric

B.C. Telephone

B C GAS

Bell Canada

Bellcore

Bell South Corp.

Bruncor (New Brunswick Telephone)

Burlington-Northern

C & S Bank

California Pacific

Cajun Electric

Canadian Radio-Television & Telecomm. Commission

Canadian Utilities

Canadian Western Natural Gas

Cascade Natural Gas

Centel

Centra Gas

Central Illinois Light & Power Co

Central Telephone

Central & South West Corp.

CH Energy

Chattanooga Gas Company

Cincinnati Gas & Electric

Cinergy Corp.

Citizens Utilities

City Gas of Florida

CN-CP Telecommunications

Commonwealth Telephone Co.

Columbia Gas System

Consolidated Edison

Consolidated Natural Gas

Constellation Energy

Delmarva Power & Light Co

Deerpath Group

Detroit Edison Company

Dayton Power & Light Co.

DPL Energy

Duke Energy Indiana

Duke Energy Kentucky

Duke Energy Ohio

DTE Energy

Edison International

Edmonton Power Company

Elizabethtown Gas Co.

Emera

Energen

Engraph Corporation

Entergy Corp.

Entergy Arkansas Inc.

Entergy Gulf States, Inc.

Entergy Louisiana, Inc.

Entergy Mississippi Power

Entergy New Orleans, Inc.

First Energy

Florida Water Association

Fortis

Garmaise-Thomson & Assoc., Investment Consultants

Gaz Metropolitain

General Public Utilities

Georgia Broadcasting Corp.

Georgia Power Company

GTE California - Verizon

GTE Northwest Inc. - Verizon

GTE Service Corp. - Verizon

GTE Southwest Incorporated - Verizon

Gulf Power Company

Havasu Water Inc.

Hawaiian Electric Company

Hawaiian Elec & Light Co

Heater Utilities – Aqua - America

Hope Gas Inc.

Hydro-Quebec

ICG Utilities

Illinois Commerce Commission

Island Telephone

ITC Holdings

Jersey Central Power & Light

Kansas Power & Light

KeySpan Energy

Maine Public Service

Manitoba Hydro

Maritime Telephone

Maui Electric Co.

Metropolitan Edison Co.

Minister of Natural Resources Province of Quebec

Minnesota Power & Light

Mississippi Power Company

Missouri Gas Energy

Mountain Bell

National Grid PLC

Nevada Power Company

New Brunswick Power

Newfoundland Power Inc. - Fortis Inc.

New Market Hydro

New Tel Enterprises Ltd.

New York Telephone Co.

NextEra Energy

Niagara Mohawk Power Corp

Norfolk-Southern

Northeast Utilities

Northern Telephone Ltd.

Northwestern Bell

Northwestern Utilities Ltd.

Nova Scotia Power

Nova Scotia Utility and Review Board

NUI Corp.

NV Energy

NYNEX

Oklahoma G & E

Ontario Telephone Service Commission

Orange & Rockland

PNM Resources

PPL Corp

Pacific Northwest Bell

People's Gas System Inc.

People's Natural Gas

Pennsylvania Electric Co.

Pepco Holdings

Potomac Electric Power Co.

Price Waterhouse

PSI Energy

Public Service Electric & Gas

Public Service of New Hampshire

Public Service of New Mexico

Puget Sound Energy

Quebec Telephone

Regie de l'Energie du Quebec

Rockland Electric

Rochester Telephone

SNL Center for Financial Execution

San Diego Gas & Electric

SaskPower

Sempra

Sierra Pacific Power Company

Source Gas

Southern Bell

Southern States Utilities

Southern Union Gas

South Central Bell

Sun City Water Company

TECO Energy

The Southern Company

Touche Ross and Company

TransEnergie

Trans-Quebec & Maritimes Pipeline

TXU Corp

US WEST Communications

Union Heat Light & Power

Utah Power & Light

Vermont Gas Systems Inc.

Wisconsin Power & Light

MANAGEMENT DEVELOPMENT AND PROFESSIONAL EXECUTIVE EDUCATION

- Canadian Institute of Marketing, Corporate Finance, 1971-73
- Hydro-Quebec, "Capital Budgeting Under Uncertainty," 1974-75
- Institute of Certified Public Accountants, Mergers & Acquisitions, 1975-78
- Investment Dealers Association of Canada, 1977-78
- Financial Research Foundation, bi-annual seminar, 1975-79
- Advanced Management Research (AMR), faculty member, 1977-80
- Financial Analysts Federation, Educational chapter: "Financial Futures Contracts" seminar
- Exnet Inc. a.k.a. The Management Exchange Inc., faculty member 1981-2008:

  National Seminars: *Risk and Return on Capital Projects*
  Cost of Capital for Regulated Utilities
  Capital Allocation for Utilities
  Alternative Regulatory Frameworks
  Utility Directors' Workshop
  Shareholder Value Creation for Utilities
  Fundamentals of Utility Finance
  Contemporary Issues in Utility Finance

- SNL Center for Financial Education. faculty member 2008-2016. National Seminars: *Essentials of Utility Finance*
- Georgia State University College of Business, Management Development Program, faculty member, 1981-1994.

EXPERT TESTIMONY & UTILITY CONSULTING AREAS OF EXPERTISE

Corporate Finance

Rate of Return

Capital Structure

Generic Cost of Capital

Costing Methodology

Depreciation

Flow-Through vs Normalization

Revenue Requirements Methodology

Utility Capital Expenditures Analysis

Risk Analysis

Capital Allocation

Divisional Cost of Capital, Unbundling

Incentive Regulation & Alternative Regulatory Plans

Shareholder Value Creation

Value-Based Management

REGULATORY BODIES

Alabama Public Service Commission

Alaska Regulatory Commission

Alberta Public Service Board

Arizona Corporation Commission

Arkansas Public Service Commission

British Columbia Board of Public Utilities

California Public Service Commission

Canadian Radio-Television & Telecommunications Comm.

City of New Orleans Council

Colorado Public Utilities Commission

Delaware Public Service Commission

District of Columbia Public Service Commission

Federal Communications Commission

Federal Energy Regulatory Commission

Florida Public Service Commission

Georgia Public Service Commission

Georgia Senate Committee on Regulated Industries

Hawaii Public Utilities Commission

Illinois Commerce Commission

Indiana Utility Regulatory Commission

Iowa Utilities Board

Kentucky Public Service Commission

Louisiana Public Service Commission

Maine Public Utilities Commission

Manitoba Board of Public Utilities

Maryland Public Service Commission

Michigan Public Service Commission

Minnesota Public Utilities Commission

Mississippi Public Service Commission

Missouri Public Service Commission

Montana Public Service Commission

National Energy Board of Canada

Nebraska Public Service Commission

Nevada Public Utilities Commission

New Brunswick Board of Public Commissioners

New Hampshire Public Utilities Commission

New Jersey Board of Public Utilities

New Mexico Public Regulation Commission

New Orleans City Council

New York Public Service Commission

Newfoundland Board of Commissioners of Public Utilities

North Carolina Utilities Commission

Nova Scotia Board of Public Utilities

Ohio Public Utilities Commission

Oklahoma Corporation Commission

Ontario Telephone Service Commission

Ontario Energy Board

Oregon Public Utility Service Commission

Pennsylvania Public Utility Commission

Quebec Regie de l'Energie

Quebec Telephone Service Commission

South Carolina Public Service Commission

South Dakota Public Utilities Commission

Tennessee Regulatory Authority

Texas Public Utility Commission

Utah Public Service Commission

Vermont Department of Public Services

Virginia State Corporation Commission

Washington Utilities & Transportation Commission

West Virginia Public Service Commission

SERVICE AS EXPERT WITNESS

Southern Bell, So. Carolina PSC, Docket #81-201C

Southern Bell, So. Carolina PSC, Docket #82-294C

Southern Bell, North Carolina PSC, Docket #P-55-816

Metropolitan Edison, Pennsylvania PUC, Docket #R-822249

Pennsylvania Electric, Pennsylvania PUC, Docket #R-822250

Georgia Power, Georgia PSC, Docket # 3270-U, 1981

Georgia Power, Georgia PSC, Docket # 3397-U, 1983

Georgia Power, Georgia PSC, Docket # 3673-U, 1987

Georgia Power, F.E.R.C., Docket # ER 80-326, 80-327

Georgia Power, F.E.R.C., Docket # ER 81-730, 80-731

Georgia Power, F.E.R.C., Docket # ER 85-730, 85-731

Bell Canada, CRTC 1987

Northern Telephone, Ontario PSC

GTE-Quebec Telephone, Quebec PSC, Docket 84-052B

Newtel., Nfld. Brd of Public Commission PU 11-87

CN-CP Telecommunications, CRTC

Quebec Northern Telephone, Quebec PSC

Edmonton Power Company, Alberta Public Service Board

Kansas Power & Light, F.E.R.C., Docket # ER 83-418

NYNEX, FCC generic cost of capital Docket #84-800

Bell South, FCC generic cost of capital Docket #84-800

American Water Works - Tennessee, Docket #7226

Burlington-Northern - Oklahoma State Board of Taxes

Georgia Power, Georgia PSC, Docket # 3549-U

GTE Service Corp., FCC Docket #84-200

Mississippi Power Co., Miss. PSC, Docket U-4761

Citizens Utilities, Ariz. Corp. Comm., Docket U2334-86020

Quebec Telephone, Quebec PSC, 1986, 1987, 1992

Newfoundland L & P, Nfld. Brd. Publ Comm. 1987, 1991

Northwestern Bell, Minnesota PSC, Docket P-421/CI-86-354

GTE Service Corp., FCC Docket #87-463

Anchorage Municipal Power & Light, Alaska PUC, 1988

New Brunswick Telephone, N.B. PUC, 1988

Trans-Quebec Maritime, Nat'l Energy Brd. of Cda, '88-92

Gulf Power Co., Florida PSC, Docket #88-1167-EI

Mountain States Bell, Montana PSC, #88-1.2

Mountain States Bell, Arizona CC, #E-1051-88-146

Georgia Power, Georgia PSC, Docket # 3840-U, 1989

Rochester Telephone, New York PSC, Docket # 89-C-022

Noverco - Gaz Metro, Quebec Natural Gas PSC, #R-3164-89

GTE Northwest, Washington UTC, #U-89-3031

Orange & Rockland, New York PSC, Case 89-E-175

Central Illinois Light Company, ICC, Case 90-0127

Peoples Natural Gas, Pennsylvania PSC, Case

Gulf Power, Florida PSC, Case # 891345-EI

ICG Utilities, Manitoba BPU, Case 1989

New Tel Enterprises, CRTC, Docket #90-15

Peoples Gas Systems, Florida PSC

Jersey Central Pwr & Light, N.J. PUB, Case ER 89110912J

Alabama Gas Co., Alabama PSC, Case 890001

Trans-Quebec Maritime Pipeline, Cdn. Nat'l Energy Board

Mountain Bell, Utah PSC,

Mountain Bell, Colorado PUB

South Central Bell, Louisiana PS

Hope Gas, West Virginia PSC

Vermont Gas Systems, Vermont PSC

Alberta Power Ltd., Alberta PUB

Ohio Utilities Company, Ohio PSC

Georgia Power Company, Georgia PSC

Sun City Water Company

Havasu Water Inc.

Centra Gas (Manitoba) Co.

Central Telephone Co. Nevada

AGT Ltd., CRTC 1992

BC GAS, BCPUB 1992

California Water Association, California PUC 1992

Maritime Telephone 1993

BCE Enterprises, Bell Canada, 1993

Citizens Utilities Arizona gas division 1993

PSI Resources 1993-5

CILCORP gas division 1994

GTE Northwest Oregon 1993

Stentor Group 1994-5

Bell Canada 1994-1995

PSI Energy 1993, 1994, 1995, 1999

Cincinnati Gas & Electric 1994, 1996, 1999, 2004

Southern States Utilities, 1995

CILCO 1995, 1999, 2001

Commonwealth Telephone 1996

Edison International 1996, 1998

Citizens Utilities 1997

Stentor Companies 1997

Hydro-Quebec 1998

Entergy Gulf States Louisiana 1998, 1999, 2001, 2002, 2003

Detroit Edison, 1999, 2003

Entergy Gulf States, Texas, 2000, 2004

Hydro Quebec TransEnergie, 2001, 2004

Sierra Pacific Company, 2000, 2001, 2002, 2007, 2010

Nevada Power Company, 2001

Mid American Energy, 2001, 2002

Entergy Louisiana Inc. 2001, 2002, 2004

Mississippi Power Company, 2001, 2002, 2007

Oklahoma Gas & Electric Company, 2002 -2003

Public Service Electric & Gas, 2001, 2002

NUI Corp (Elizabethtown Gas Company), 2002

Jersey Central Power & Light, 2002

San Diego Gas & Electric, 2002, 2012, 2014

New Brunswick Power, 2002

Entergy New Orleans, 2002, 2008

Hydro-Quebec Distribution 2002

PSI Energy 2003

Fortis – Newfoundland Power & Light 2002

Emera – Nova Scotia Power 2004

Hydro-Quebec TransEnergie 2004

Hawaiian Electric 2004

Missouri Gas Energy 2004

AGL Resources 2004

Arkansas Western Gas 2004

Public Service of New Hampshire 2005

Hawaiian Electric Company 2005, 2008, 2009

Delmarva Power & Light Company 2005, 2009

Union Heat Power & Light 2005

Puget Sound Energy 2006, 2007, 2009

Cascade Natural Gas 2006

Entergy Arkansas 2006-7

Bangor Hydro 2006-7

Delmarva 2006, 2007, 2009

Potomac Electric Power Co. 2006, 2007, 2009

Duke Energy Ohio, 2007, 2008, 2009

Duke Energy Kentucky 2009

Consolidated Edison 2007 Docket 07-E-0523

Duke Energy Ohio Docket 07-589-GA-AIR

Hawaiian Electric Company Docket 05-0315

Sierra Pacific Power Docket ER07-1371-000

Public Service New Mexico Docket 06-00210-UT

Detroit Edison Docket U-15244

Potomac Electric Power Docket FC-1053

Delmarva, Delaware, Docket 09-414

Atlantic City Electric, New Jersey, Docket ER-09080664

Maui Electric Co, Hawaii, Docket 2009-0163, 2011

Niagara Mohawk, New York, Docket 10E-0050

Sierra Pacific Power Docket No. 10-06001

Gaz Metro, Regie de l'Energie (Quebec), Docket 2012 R-3752-2011

California Pacific Electric Company, LLC, California PUC, Docket A-12-02-014

Duke Energy Ohio, Ohio Case No. 11-XXXX-EL-SSO

San Diego Gas & Electric, FERC, 2012, 2014

San Diego Gas & Electric, California PUC, 2012, Docket A-12-04

Southern California Gas, California PUC, 2012, Docket A-12-04

Puget Sound Electric

Puget Sound Electric

Duke Energy of Ohio

Duke Energy of Kentucky

Duke Energy of Ohio

Dayton Power & Light

Missouri American Water

California Power Electric Company

PROFESSIONAL AND LEARNED SOCIETIES

- Engineering Institute of Canada, 1967-1972
- Canada Council Award, recipient 1971 and 1972
- Canadian Association Administrative Sciences, 1973-80
- American Association of Decision Sciences, 1974-1978
- American Finance Association, 1975-2002
- Financial Management Association, 1978-2002

ACTIVITIES IN PROFESSIONAL ASSOCIATIONS AND MEETINGS

- Chairman of meeting on "New Developments in Utility Cost of Capital", Southern Finance Association, Atlanta, Nov. 1982

- Chairman of meeting on "Public Utility Rate of Return", Southeastern Public Utility Conference, Atlanta, Oct. 1982

- Chairman of meeting on "Current Issues in Regulatory Finance", Financial Management Association, Atlanta, Oct. 1983

- Chairman of meeting on "Utility Cost of Capital", Financial Management Association, Toronto, Canada, Oct. 1984.

- Committee on New Product Development, FMA, 1985

- Discussant, "Tobin's Q Ratio", paper presented at Financial Management Association, New York, N.Y., Oct. 1986

- Guest speaker, "Utility Capital Structure: New Developments", National Society of Rate of Return Analysts 18th Financial Forum, Wash., D.C. Oct. 1986

- Opening address, "Capital Expenditures Analysis: Methodology vs Mythology," Bellcore Economic Analysis Conference, Naples Fl, 1988.

- Guest speaker, "Mythodology in Regulatory Finance", Society of Utility Rate of Return Analysts (SURFA), Annual Conference, Wash., D.C. February 2007.

PAPERS PRESENTED:

"An Empirical Study of Multi-Period Asset Pricing," annual meeting of Financial Management Assoc., Las Vegas Nevada, 1987.

"Utility Capital Expenditures Analysis: Net Present Value vs Revenue Requirements", annual meeting of Financial Management Assoc., Denver, Colorado, October 1985.

"Intervention Analysis and the Dynamics of Market Efficiency", annual meeting of Financial Management Assoc., San Francisco, Oct. 1982

"Intertemporal Market-Line Theory: An Empirical Study," annual meeting of Eastern Finance Assoc., Newport, R.I. 1981

"Option Writing for Financial Institutions: A Cost-Benefit Analysis", 1979 annual meeting Financial Research Foundation

"Free-lunch on the Toronto Stock Exchange", annual meeting of Financial Research Foundation of Canada, 1978.

"Simulation System Computer Software SIMFIN", HP International Business Computer Users Group, London, 1975.

"Inflation Accounting: Implications for Financial Analysis." Institute of Certified Public Accountants Symposium, 1979.

OFFICES IN PROFESSIONAL ASSOCIATIONS

- President, International Hewlett-Packard Business Computers Users Group, 1977

- Chairman Program Committee, International HP Business Computers Users Group, London, England, 1975

- Program Coordinator, Canadian Assoc. of Administrative Sciences, 1976

- Member, New Product Development Committee, Financial Management Association, 1985-1986

- Reviewer: Journal of Financial Research
  Financial Management
  Financial Review
  Journal of Finance

PUBLICATIONS

"Risk Aversion Revisited", Journal of Finance, Sept. 1983

"Hedging Regulatory Lag with Financial Futures," Journal of Finance, May 1983. (with G. Gay, R. Kolb)

"The Effect of CWIP on Cost of Capital," Public Utilities Fortnightly, July 1986.

"The Effect of CWIP on Revenue Requirements" Public Utilities Fortnightly, August 1986.

"Intervention Analysis and the Dynamics of Market Efficiency," Time-Series Applications, New York: North Holland, 1983. (with K. El-Sheshai)

"Market-Line Theory and the Canadian Equity Market," Journal of Business Administration, Jan. 1982, M. Brennan, editor

"Efficiency of Canadian Equity Markets," International Management Review, Feb. 1978.

"Intertemporal Market-Line Theory: An Empirical Test," Financial Review, Proceedings of the Eastern Finance Association, 1981.

BOOKS

Utilities' Cost of Capital, Public Utilities Reports Inc., Arlington, Va., 1984.

Regulatory Finance, Public Utilities Reports Inc., Arlington, Va., 2004

Driving Shareholder Value, McGraw-Hill, January 2001.

The New Regulatory Finance, Public Utilities Reports Inc., Arlington, Va., 2006.

MONOGRAPHS

Determining Cost of Capital for Regulated Industries, Public Utilities Reports, Inc., and The Management Exchange Inc., 1982 - 1993. (with V.L. Andrews)

Alternative Regulatory Frameworks, Public Utilities Reports, Inc., and The Management Exchange Inc., 1993. (with V.L. Andrews)

Risk and Return in Capital Projects, The Management Exchange Inc., 1980. (with B. Deschamps)

Utility Capital Expenditure Analysis, The Management Exchange Inc., 1983.

Regulation of Cable Television: An Econometric Planning Model, Quebec Department of Communications, 1978.

"An Economic & Financial Profile of the Canadian Cablevision Industry," Canadian Radio-Television & Telecommunication Commission (CRTC), 1978.

Computer Users' Manual: Finance and Investment Programs, University of Montreal Press, 1974, revised 1978.

Fiber Optics Communications: Economic Characteristics, Quebec Department of Communications, 1978.

"Canadian Equity Market Inefficiencies", Capital Market Research Memorandum, Garmaise & Thomson Investment Consultants, 1979.

MISCELLANEOUS CONSULTING REPORTS

"Operational Risk Analysis: California Water Utilities," Calif. Water Association, 1993.

"Cost of Capital Methodologies for Independent Telephone Systems", Ontario Telephone Service Commission, March 1989.

"The Effect of CWIP on Cost of Capital and Revenue Requirements", Georgia Power Company, 1985.

"Costing Methodology and the Effect of Alternate Depreciation and Costing Methods on Revenue Requirements and Utility Finances", Gaz Metropolitan Inc., 1985.

"Simulated Capital Structure of CN-CP Telecommunications: A Critique", CRTC, 1977.

"Telecommunications Cost Inquiry: Critique," CRTC, 1977.

"Social Rate of Discount in the Public Sector", CRTC Policy Statement, 1974.

"Technical Problems in Capital Projects Analysis", CRTC Policy Statement, 1974.

RESEARCH GRANTS

"Econometric Planning Model of the Cablevision Industry," International Institute of Quantitative Economics, CRTC.

"Application of the Averch-Johnson Model to Telecommunications Utilities," Canadian Radio-Television Commission. (CRTC)

"Economics of the Fiber Optics Industry", Quebec Dept. of Communications.

"Intervention Analysis and the Dynamics of Market Efficiency", Georgia State Univ. College of Business, 1981.

"Firm Size and Beta Stability", Georgia State University College of Business, 1982.

"Risk Aversion and the Demand for Risky Assets", Georgia State University College of Business, 1981.

Electric Utilities Covered in Value Line's Electric Utility Industry Group

	Company	Ticker		Note
1	Alliant Energy	LNT		
2	Ameren Corp.	AEE		
3	Avista Corp.	AVA		
4	Black Hills	BKH	x	Acquired SourceGas
5	CenterPoint Energy	CNP		
6	Chesapeake Utilities	CPK		
7	CMS Energy Corp.	CMS		
8	Consol. Edison	ED		
9	Dominion Resources	D	x	Merged with Questar
10	DTE Energy	DTE		
11	Duke Energy	DUK	x	Acquired Piedmont Natual Gas
12	Empire Dist. Elec.	EDE	x	Merged with Liberty Util. subsidiary
13	Entergy Corp	ETR	x	Nuclear exposure
14	Eversource Energy	ES		
15	Exelon Corp	EXC	x	Reg. Revenues < 50%
16	MDU Resource	MDU	x	Reg. Revenues < 50%
17	MGE Energy	MGEE		
18	NorthWestern Corp.	NWE		
19	Pepco Holdings	POM	x	Merged with Exelon
20	PG&E Corp.	PCG		
21	Public Serv. Enterprise	PEG		
22	SCANA Corp.	SCG		
23	Unitil Corp	UTL	x	Market cap < $1B
24	Sempra Energy	SRE		
25	TECO Energy	TE	x	Acquired by Emera
26	Vectren Corp.	VVC		
27	WEC Energy Group	WEC		
28	Xcel Energy Inc.	XEL		

Source: AUS Utility Reports 9/16, Value Line Investment Survey 11/16

Proxy Group for Duke Energy Ohio

	Company	Ticker
1	Alliant Energy	LNT
2	Ameren Corp.	AEE
3	Avista Corp.	AVA
4	CenterPoint Energy	CNP
5	Chesapeake Utilities	CPK
6	CMS Energy Corp.	CMS
7	Consol. Edison	ED
8	DTE Energy	DTE
9	Eversource Energy	ES
10	MGE Energy	MGEE
11	NorthWestern Corp.	NWE
12	PG&E Corp.	PCG
13	Public Serv. Enterprise	PEG
14	SCANA Corp.	SCG
15	Sempra Energy	SRE
16	Vectren Corp.	VVC
17	WEC Energy Group	WEC
18	Xcel Energy	XEL

Combination Elec & Gas Utilities
DCF Analysis Value Line Growth Rates

	(1)	(2)	(3)	(4)	(5)	(6)
Line No.	Company Name	Current Dividend Yield	Projected EPS Growth	% Expected Divid Yield	Cost of Equity	ROE
1	Alliant Energy	3.60	6.0	3.82	9.82	10.02
2	Ameren Corp.	4.00	6.0	4.24	10.24	10.46
3	Avista Corp.	4.00	5.0	4.20	9.20	9.42
4	CenterPoint Energy	5.10	2.0	5.20	7.20	7.48
5	Chesapeake Utilities	1.90	8.5	2.06	10.56	10.67
6	CMS Energy Corp.	3.40	6.0	3.60	9.60	9.79
7	Consol. Edison	4.10	2.5	4.20	6.70	6.92
8	DTE Energy	3.50	6.0	3.71	9.71	9.91
9	Eversource Energy	3.30	6.0	3.50	9.50	9.68
10	MGE Energy	2.80	7.0	3.00	10.00	10.15
11	NorthWestern Corp.	3.60	6.5	3.83	10.33	10.54
12	PG&E Corp.	3.40	12.0	3.81	15.81	16.01
13	Public Serv. Enterprise	3.80	2.0	3.88	5.88	6.08
14	SCANA Corp.	3.90	4.5	4.08	8.58	8.79
15	Sempra Energy	2.70	8.0	2.92	10.92	11.07
16	Vectren Corp.	3.60	9.0	3.92	12.92	13.13
17	WEC Energy Group	3.50	6.0	3.71	9.71	9.91
18	Xcel Energy	3.70	5.5	3.90	9.40	9.61
20	**AVERAGE**	**3.55**	**6.03**	**3.75**	**9.78**	**9.98**

22 Notes:
23 Column 1, 2, 3: Value Line Research Web Site Nov. 2016
24 Column 4 = Column 2 times (1 + Column 3/100)
25 Column 5 = Column 4 + Column 3
26 Column 6 = Column 4/0.95 + Column 3

Combination Elec & Gas Utilities
DCF Analysis Analysts' Growth Forecasts

Line No.	(1) Company Name	(2) Current Dividend Yield	(3) Analysts' Growth Forecast	(4) % Expected Divid Yield	(5) Cost of Equity	(6) ROE
1	Alliant Energy	3.60	6.1	3.82	9.92	10.12
2	Ameren Corp.	4.00	6.1	4.24	10.34	10.57
3	Avista Corp.	4.00	5.3	4.21	9.51	9.73
4	CenterPoint Energy	5.10	5.5	5.38	10.88	11.16
5	Chesapeake Utilities	1.90	na	na	na	na
6	CMS Energy Corp.	3.40	6.6	3.62	10.22	10.42
7	Consol. Edison	4.10	2.8	4.21	7.01	7.24
8	DTE Energy	3.50	5.8	3.70	9.50	9.70
9	Eversource Energy	3.30	6.1	3.50	9.60	9.79
10	MGE Energy	2.80	na	na	na	na
11	NorthWestern Corp.	3.60	5.0	3.78	8.78	8.98
12	PG&E Corp.	3.40	4.3	3.55	7.85	8.03
13	Public Serv. Enterprise	3.80	4.4	3.97	8.37	8.58
14	SCANA Corp.	3.90	5.5	4.11	9.61	9.83
15	Sempra Energy	2.70	6.9	2.89	9.79	9.94
16	Vectren Corp.	3.60	5.3	3.79	9.09	9.29
17	WEC Energy Group	3.50	6.2	3.72	9.92	10.11
18	Xcel Energy	3.70	5.4	3.90	9.30	9.51
20	**AVERAGE**	**3.55**	**5.46**	**3.90**	**9.36**	**9.56**

22 Notes:
23 Column 1, 2: Value Line Research Web Site Nov. 2016
24 Column 3: Zacks Investment Research growth forecast Nov 2016
25 Column 4 = Column 2 times (1 + Column 3/100)
26 Column 5 = Column 4 + Column 3
Column 6 = Column 4/0.95 + Column 3

29 No growth forecast available for MGE Energy, Chesapeake Util.

Combination Elec & Gas Utilities Beta Estimates

	(1)	(2)
Line No.	Company Name	Beta
1	Alliant Energy	0.70
2	Ameren Corp.	0.70
3	Avista Corp.	0.70
4	CenterPoint Energy	0.90
5	Chesapeake Utilities	0.60
6	CMS Energy Corp.	0.70
7	Consol. Edison	0.60
8	DTE Energy	0.70
9	Eversource Energy	0.70
10	MGE Energy	0.70
11	NorthWestern Corp.	0.70
12	PG&E Corp.	0.70
13	Public Serv. Enterprise	0.70
14	SCANA Corp.	0.70
15	Sempra Energy	0.80
16	Vectren Corp.	0.80
17	WEC Energy Group	0.60
18	Xcel Energy	0.60
20	**AVERAGE**	**0.70**
22	Source: Value Line Research Nov. 2016	

2015 Utility Industry Historical Risk Premium

		(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)
Line No.	Year	Long-Term Government Bond Yield	Long-Term Government Income Component Bond Yield	20 year Maturity Bond Value	Gain/Loss	Interest	Bond Total Return	S&P Utility Index Return	Utility Equity Risk Premium Over Bond Returns	Utility Equity Risk Premium Over Bond Return Income Component
1	1931	4.07%	3.33%	1,000.00						
2	1932	3.15%	3.69%	1,135.75	135.75	40.70	17.64%	-0.54%	-18.18%	-4.23%
3	1933	3.36%	3.12%	969.60	-30.40	31.50	0.11%	-21.87%	-21.98%	-24.99%
4	1934	2.93%	3.10%	1,064.73	64.73	33.60	9.83%	-20.41%	-30.24%	-23.51%
5	1935	2.76%	2.81%	1,025.99	25.99	29.30	5.53%	76.63%	71.10%	73.82%
6	1936	2.56%	2.77%	1,031.15	31.15	27.60	5.88%	20.69%	14.81%	17.92%
7	1937	2.73%	2.66%	973.93	-26.07	25.60	-0.05%	-37.04%	-36.99%	-39.70%
8	1938	2.52%	2.64%	1,032.83	32.83	27.30	6.01%	22.45%	16.44%	19.81%
9	1939	2.26%	2.40%	1,041.65	41.65	25.20	6.68%	11.26%	4.58%	8.86%
10	1940	1.94%	2.23%	1,052.84	52.84	22.60	7.54%	-17.15%	-24.69%	-19.38%
11	1941	2.04%	1.94%	983.64	-16.36	19.40	0.30%	-31.57%	-31.87%	-33.51%
12	1942	2.46%	2.46%	933.97	-66.03	20.40	-4.56%	15.39%	19.95%	12.93%
13	1943	2.48%	2.44%	996.86	-3.14	24.60	2.15%	46.07%	43.92%	43.63%
14	1944	2.46%	2.46%	1,003.14	3.14	24.80	2.79%	18.03%	15.24%	15.57%
15	1945	1.99%	2.34%	1,077.23	77.23	24.60	10.18%	53.33%	43.15%	50.99%
16	1946	2.12%	2.04%	978.90	-21.10	19.90	-0.12%	1.26%	1.38%	-0.78%
17	1947	2.43%	2.13%	951.13	-48.87	21.20	-2.77%	-13.16%	-10.39%	-15.29%
18	1948	2.37%	2.40%	1,009.51	9.51	24.30	3.38%	4.01%	0.63%	1.61%
19	1949	2.09%	2.25%	1,045.58	45.58	23.70	6.93%	31.39%	24.46%	29.14%
20	1950	2.24%	2.12%	975.93	-24.07	20.90	-0.32%	3.25%	3.57%	1.13%
21	1951	2.69%	2.38%	930.75	-69.25	22.40	-4.69%	18.63%	23.32%	16.25%
22	1952	2.79%	2.68%	984.75	-15.25	26.90	1.17%	19.25%	18.08%	16.57%
23	1953	2.74%	2.84%	1,007.66	7.66	27.90	3.56%	7.85%	4.29%	5.01%
24	1954	2.72%	2.79%	1,003.07	3.07	27.40	3.05%	24.72%	21.67%	21.93%
25	1955	2.95%	2.75%	965.44	-34.56	27.20	-0.74%	11.26%	12.00%	8.51%
26	1956	3.45%	2.99%	928.19	-71.81	29.50	-4.23%	5.06%	9.29%	2.07%
27	1957	3.23%	3.44%	1,032.23	32.23	34.50	6.67%	6.36%	-0.31%	2.92%
28	1958	3.82%	3.27%	918.01	-81.99	32.30	-4.97%	40.70%	45.67%	37.43%
29	1959	4.47%	4.01%	914.65	-85.35	38.20	-4.71%	7.49%	12.20%	3.48%

2015 Utility Industry Historical Risk Premium

		(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)
Line No.	Year	Long-Term Government Bond Yield	Long-Term Government Income Component Bond Yield	20 year Maturity Bond Value	Gain/Loss	Interest	Bond Total Return	S&P Utility Index Return	Utility Equity Risk Premium Over Bond Returns	Utility Equity Risk Premium Over Bond Return Income Component
30	1960	3.80%	4.26%	1,093.27	93.27	44.70	13.80%	20.26%	6.46%	16.00%
31	1961	4.15%	3.83%	952.75	-47.25	38.00	-0.92%	29.33%	30.25%	25.50%
32	1962	3.95%	4.00%	1,027.48	27.48	41.50	6.90%	-2.44%	-9.34%	-6.44%
33	1963	4.17%	3.89%	970.35	-29.65	39.50	0.99%	12.36%	11.37%	8.47%
34	1964	4.23%	4.15%	991.96	-8.04	41.70	3.37%	15.91%	12.54%	11.76%
35	1965	4.50%	4.20%	964.64	-35.36	42.30	0.69%	4.67%	3.98%	0.47%
36	1966	4.55%	4.49%	993.48	-6.52	45.00	3.85%	-4.48%	-8.33%	-8.97%
37	1967	5.56%	4.59%	879.01	-120.99	45.50	-7.55%	-0.63%	6.92%	-5.22%
38	1968	5.98%	5.50%	951.38	-48.62	55.60	0.70%	10.32%	9.62%	4.82%
39	1969	6.87%	5.96%	904.00	-96.00	59.80	-3.62%	-15.42%	-11.80%	-21.38%
40	1970	6.48%	6.74%	1,043.38	43.38	68.70	11.21%	16.56%	5.35%	9.82%
41	1971	5.97%	6.32%	1,059.09	59.09	64.80	12.39%	2.41%	-9.98%	-3.91%
42	1972	5.99%	5.87%	997.69	-2.31	59.70	5.74%	8.15%	2.41%	2.28%
43	1973	7.26%	6.51%	867.09	-132.91	59.90	-7.30%	-18.07%	-10.77%	-24.58%
44	1974	7.60%	7.27%	965.33	-34.67	72.60	3.79%	-21.55%	-25.34%	-28.82%
45	1975	8.05%	7.99%	955.63	-44.37	76.00	3.16%	44.49%	41.33%	36.50%
46	1976	7.21%	4.89%	1,088.25	88.25	80.50	16.87%	31.81%	14.94%	26.92%
47	1977	8.03%	7.14%	919.03	-80.97	72.10	-0.89%	8.64%	9.53%	1.50%
48	1978	8.98%	7.90%	912.47	-87.53	80.30	-0.72%	-3.71%	-2.99%	-11.61%
49	1979	10.12%	8.86%	902.99	-97.01	89.80	-0.72%	13.58%	14.30%	4.72%
50	1980	11.99%	9.97%	859.23	-140.77	101.20	-3.96%	15.08%	19.04%	5.11%
51	1981	13.34%	11.55%	906.45	-93.55	119.90	2.63%	11.74%	9.11%	0.19%
52	1982	10.95%	13.50%	1,192.38	192.38	133.40	32.58%	26.52%	-6.06%	13.02%
53	1983	11.97%	10.38%	923.12	-76.88	109.50	3.26%	20.01%	16.75%	9.63%
54	1984	11.70%	11.74%	1,020.70	20.70	119.70	14.04%	26.04%	12.00%	14.30%
55	1985	9.56%	11.25%	1,189.27	189.27	117.00	30.63%	33.05%	2.42%	21.80%
56	1986	7.89%	8.98%	1,166.63	166.63	95.60	26.22%	28.53%	2.31%	19.55%
57	1987	9.20%	7.92%	881.17	-118.83	78.90	-3.99%	-2.92%	1.07%	-10.84%
58	1988	9.19%	8.97%	1,000.91	0.91	92.00	9.29%	18.27%	8.98%	9.30%

2015 Utility Industry Historical Risk Premium

		(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)
Line No.	Year	Long-Term Government Bond Yield	Long-Term Government Income Component Bond Yield	20 year Maturity Bond Value	Gain/Loss	Interest	Bond Total Return	S&P Utility Index Return	Utility Equity Risk Premium Over Bond Returns	Utility Equity Risk Premium Over Bond Return Income Component
59	1989	8.16%	8.10%	1,100.73	100.73	91.90	19.26%	47.80%	28.54%	39.70%
60	1990	8.44%	8.19%	973.17	-26.83	81.60	5.48%	-2.57%	-8.05%	-10.76%
61	1991	7.30%	8.22%	1,118.94	118.94	84.40	20.33%	14.61%	-5.72%	6.39%
62	1992	7.26%	7.26%	1,004.19	4.19	73.00	7.72%	8.10%	0.38%	0.84%
63	1993	6.54%	7.17%	1,079.70	79.70	72.60	15.23%	14.41%	-0.82%	7.24%
64	1994	7.99%	6.59%	856.40	-143.60	65.40	-7.82%	-7.94%	-0.12%	-14.53%
65	1995	6.03%	7.60%	1,225.98	225.98	79.90	30.59%	42.15%	11.56%	34.55%
66	1996	6.73%	6.18%	923.67	-76.33	60.30	-1.60%	3.14%	4.74%	-3.04%
67	1997	6.02%	6.64%	1,081.92	81.92	67.30	14.92%	24.69%	9.77%	18.05%
68	1998	5.42%	5.83%	1,072.71	72.71	60.20	13.29%	14.82%	1.53%	8.99%
69	1999	6.82%	5.57%	848.41	-151.59	54.20	-9.74%	-8.85%	0.89%	-14.42%
70	2000	5.58%	6.50%	1,148.30	148.30	68.20	21.65%	59.70%	38.05%	53.20%
71	2001	5.75%	5.53%	979.95	-20.05	55.80	3.57%	-30.41%	-33.98%	-35.94%
72	2002	4.84%	5.59%	1,115.77	115.77	57.50	17.33%	-30.04%	-47.37%	-35.63%
73	2003	5.11%	4.80%	966.42	-33.58	48.40	1.48%	26.11%	24.63%	21.31%
74	2004	4.84%	5.02%	1,034.35	34.35	51.10	8.54%	24.22%	15.68%	19.20%
75	2005	4.61%	4.69%	1,029.84	29.84	48.40	7.82%	16.79%	8.97%	12.10%
76	2006	4.91%	4.68%	962.06	-37.94	46.10	0.82%	20.95%	20.13%	16.27%
77	2007	4.50%	4.86%	1,053.70	53.70	49.10	10.28%	19.36%	9.08%	14.50%
78	2008	3.03%	4.45%	1,219.28	219.28	45.00	26.43%	-28.99%	-55.42%	-33.44%
79	2009	4.58%	3.47%	798.39	-201.61	30.30	-17.13%	11.94%	29.07%	8.47%
80	2010	4.14%	4.25%	1,059.45	59.45	45.80	10.52%	5.49%	-5.03%	1.24%
81	2011	2.48%	3.81%	1,260.50	260.50	41.40	30.19%	19.88%	-10.31%	16.07%
82	2012	2.41%	2.40%	1,011.06	11.06	24.80	3.59%	1.99%	-1.60%	-0.41%
83	2013	3.67%	2.86%	822.57	-177.43	24.10	-15.33%	13.26%	28.59%	10.40%
84	2014	2.40%	3.12%	1,200.79	200.79	36.70	23.75%	28.61%	4.86%	25.49%
85	2015	2.84%	2.84%	933.21	-66.79	24.00	-4.28%	1.38%	5.66%	-1.46%
87	**Mean**								**5.5%**	**6.1%**

2015 Utility Industry Historical Risk Premium

		(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)
Line No.	Year	Long-Term Government Bond Yield	Long-Term Government Income Component Bond Yield	20 year Maturity Bond Value	Gain/Loss	Interest	Bond Total Return	S&P Utility Index Return	Utility Equity Risk Premium Over Bond Returns	Utility Equity Risk Premium Over Bond Return Income Component

89	Source:	Bloomberg Web site: Standard & Poors Utility Stock Index % Annual Change, Jan. to Dec.
90		Bond yields from Ibbotson SBBI 2015 Classic Yearbook (Morningstar) Table A-9 Long-Term Government Bonds Yields

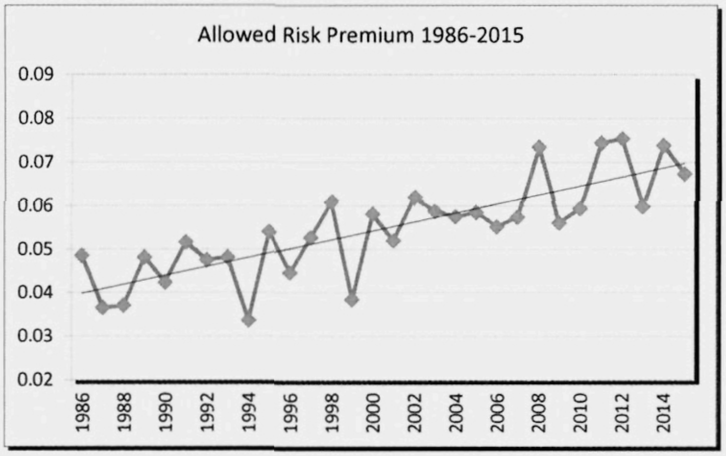
Equity Risk Premium - Treasury Bond

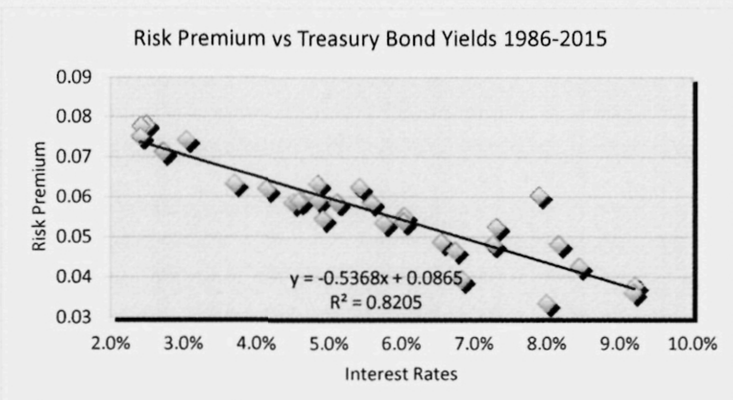
Line	Date	Treasury Bond Yield[1]	Authorized Electric Returns[2]	Indicated Risk Premium
		(1)	(2)	(3)
1	1986	7.89%	13.93%	6.0%
2	1987	9.20%	12.99%	3.8%
3	1988	9.18%	12.79%	3.6%
4	1989	8.16%	12.97%	4.8%
5	1990	8.44%	12.70%	4.3%
6	1991	7.30%	12.55%	5.3%
7	1992	7.26%	12.09%	4.8%
8	1993	6.54%	11.41%	4.9%
9	1994	7.99%	11.34%	3.4%
10	1995	6.03%	11.55%	5.5%
11	1996	6.73%	11.39%	4.7%
12	1997	6.02%	11.40%	5.4%
13	1998	5.42%	11.66%	6.2%
14	1999	6.82%	10.77%	4.0%
15	2000	5.58%	11.43%	5.9%
16	2001	5.75%	11.09%	5.3%
17	2002	4.84%	11.16%	6.3%
18	2003	5.11%	10.97%	5.9%
19	2004	4.84%	10.75%	5.9%
20	2005	4.61%	10.54%	5.9%
21	2006	4.91%	10.36%	5.5%
22	2007	4.50%	10.36%	5.9%
23	2008	3.03%	10.46%	7.4%
24	2009	4.58%	10.48%	5.9%
25	2010	4.14%	10.34%	6.2%
26	2011	2.48%	10.29%	7.8%
27	2012	2.41%	10.17%	7.8%
28	2013	3.70%	10.03%	6.3%
29	2014	2.40%	9.91%	7.5%
30	2015	2.72%	9.85%	7.1%
32	**Average**	**5.62%**	**11.26%**	**5.6%**

Sources:

[1] Morninstar 2015 Classic Yearbook Table A-9

[2] SNL (Regulatory Research Associates)
Major Rate Case Decisions 1986-2015





IF YIELD =	4.40%
THEN RP =	6.29%
Ke =	10.69%

APPENDIX A
CAPM, EMPIRICAL CAPM

The Capital Asset Pricing Model (CAPM) is a fundamental paradigm of finance. Simply put, the fundamental idea underlying the CAPM is that risk-averse investors demand higher returns for assuming additional risk, and higher-risk securities are priced to yield higher expected returns than lower-risk securities. The CAPM quantifies the additional return, or risk premium, required for bearing incremental risk. It provides a formal risk-return relationship anchored on the basic idea that only market risk matters, as measured by beta. According to the CAPM, securities are priced such that their:

EXPECTED RETURN = RISK-FREE RATE + RISK PREMIUM

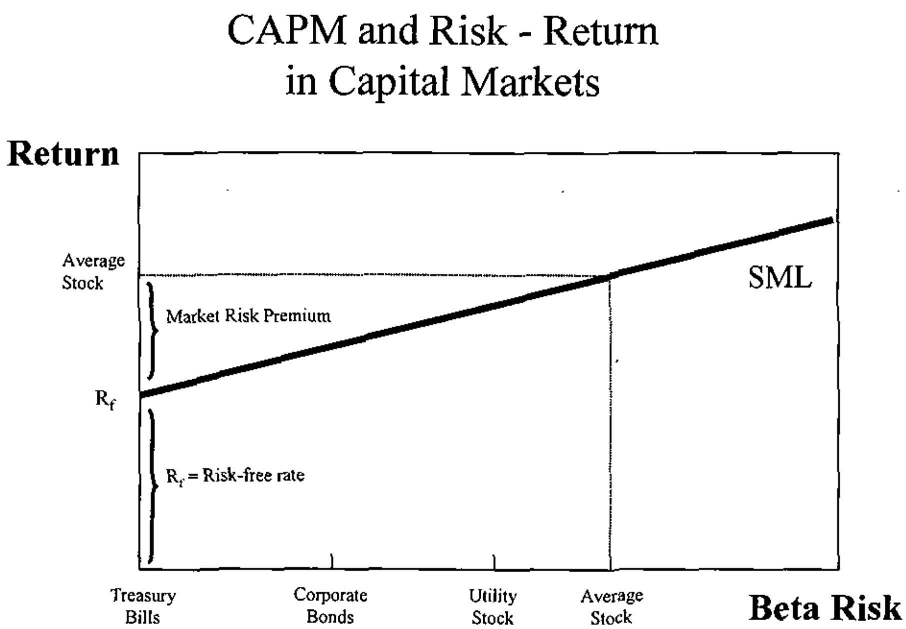
Denoting the risk-free rate by R_F and the return on the market as a whole by R_M, the CAPM is:

$$K = R_F + \beta(R_M - R_F) \qquad (1)$$

Equation 1 is the CAPM expression which asserts that an investor expects to earn a return, K, that could be gained on a risk-free investment, R_F, plus a risk premium for assuming risk, proportional to the security's market risk, also known as beta, β, and the market risk premium, $(R_M - R_F)$, where R_M is the market return . The market risk premium $(R_M - R_F)$ can be abbreviated MRP so that the CAPM becomes:

$$K = R_F + \beta \times MRP \qquad (2)$$

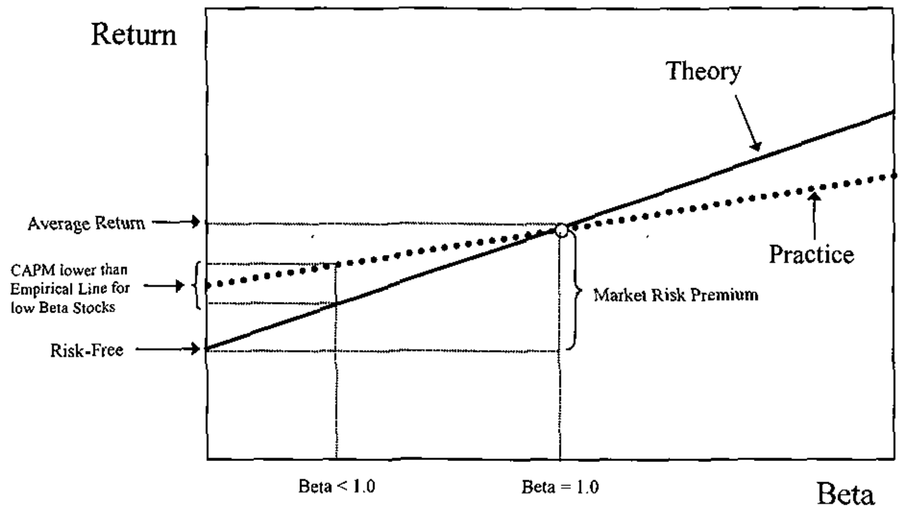
The CAPM risk-return relationship is depicted in the figure below and is typically labeled as the Security Market Line (SML) by the investment community.



A myriad empirical tests of the CAPM have shown that the risk-return tradeoff is not as steeply sloped as that predicted by the CAPM, however. That is, low-beta securities earn returns somewhat higher than the CAPM would predict, and high-beta securities earn less than predicted. In other words, the CAPM tends to overstate the actual sensitivity of the cost of capital to beta: low-beta stocks tend to have higher returns and high-beta stocks tend to have lower risk returns than predicted by the CAPM. The difference between the CAPM and the type of relationship observed in the empirical studies is depicted in the figure below. This is one of the most widely known empirical findings of the finance literature. This extensive literature is summarized in Chapter 13 of Dr. Morin's book [Regulatory Finance, Public Utilities Report Inc., Arlington, VA, 1994].

Risk vs Return

Theory vs. Practice



A number of refinements and expanded versions of the original CAPM theory have been proposed to explain the empirical findings. These revised CAPMs typically produce a risk-return relationship that is flatter than the standard CAPM prediction. The following equation makes use of these empirical findings by flattening the slope of the risk-return relationship and increasing the intercept:

$$K = R_F + \alpha + \beta\ (MRP - \alpha) \qquad (3)$$

where α is the "alpha" of the risk-return line, a constant determined empirically, and the other symbols are defined as before. Alternatively, Equation 3 can be written as follows:

$$K = R_F + a\,MRP + (1-a)\,\beta\,MRP \qquad (4)$$

where a is a fraction to be determined empirically. Comparing Equations 3 and 4, it is easy to see that alpha equals 'a' times MRP, that is, $\alpha = a \times MRP$

Theoretical Underpinnings

The obvious question becomes what would produce a risk return relationship which is flatter than the CAPM prediction, or in other words, how do you explain the presence of "alpha" in the above equation. The exclusion of variables aside from beta would produce this result. Three such variables are noteworthy: dividend yield, skewness, and hedging potential.

The dividend yield effects stem from the differential taxation on corporate dividends and capital gains. The standard CAPM does not consider the regularity of dividends received by investors. Utilities generally maintain high dividend payout ratios relative to the market, and by ignoring dividend yield, the CAPM provides biased cost of capital estimates. To the extent that dividend income is taxed at a higher rate than capital gains, investors will require higher pre-tax returns in order to equalize the after-tax returns provided by high-yielding stocks (e.g. utility stocks) with those of low-yielding stocks. In other words, high-yielding stocks must offer investors higher pre-tax returns. Even if dividends and capital gains are undifferentiated for tax purposes, there is still a tax bias in favor of earnings retention (lower dividend payout), as capital gains taxes are paid only when gains are realized.

Empirical studies by Litzenberger and Ramaswamy (1979) and Litzenberger et al. (1980) find that security returns are positively related to dividend yield as well as to beta. These results are consistent with after-tax extensions of the CAPM developed by Breenan (1973) and Litzenberger and Ramaswamy (1979) and suggest that the relationship between return, beta, and dividend yield should be estimated and employed to calculate the cost of equity capital.

As far as skewness is concerned, investors are more concerned with losing money than with total variability of return. If risk is defined as the probability of loss, it appears more logical to measure risk as the probability of achieving a return which is below the expected return. The traditional CAPM provides downward-biased estimates of cost of capital to the extent that these skewness effects are significant. As shown by Kraus and Litzenberger (1976), expected return depends on both on a stock's systematic risk (beta) and the systematic skewness. Empirical studies by Kraus and Litzenberger (1976), Friend, Westerfield, and Granito (1978), and Morin (1981) found that, in addition to beta, skewness of returns has a significant negative relationship with security returns. This result is consistent with the skewness version of the CAPM developed by Rubinstein (1973) and Kraus and Litzenberger (1976).

This is particularly relevant for public utilities whose future profitability is constrained by the regulatory process on the upside and relatively unconstrained on the downside in the face of socio-political realities of public utility regulation. The process of regulation, by restricting the upward potential for returns and responding sluggishly on the downward side, may impart some asymmetry to the distribution of returns, and is more likely to result in utilities earning less, rather than more, than their cost of capital. The traditional CAPM provides downward-biased estimates of cost of capital to the extent that these skewness effects are significant.

As far as hedging potential is concerned, investors are exposed to another kind of risk, namely, the risk of unfavorable shifts in the investment opportunity set. Merton (1973) shows that investors will hold portfolios consisting of three funds: the risk-free asset, the market portfolio, and a portfolio whose returns are perfectly negatively correlated with the riskless asset so as to hedge against unforeseen changes in the future risk-free rate. The higher the degree of protection offered by an asset against unforeseen changes in interest rates, the lower the required return, and conversely. Merton argues that low beta assets, like utility stocks, offer little protection against changes in interest rates, and require higher returns than suggested by the standard CAPM.

Another explanation for the CAPM's inability to fully explain the process determining security returns involves the use of an inadequate or incomplete market index. Empirical studies to validate the CAPM invariably rely on some stock market index as a proxy for the true market portfolio. The exclusion of several asset categories from the definition of market index mis-specifies the CAPM and biases the results found using only stock market data. Kolbe and Read (1983) illustrate the biases in beta estimates which result from applying the CAPM to public utilities. Unfortunately, no comprehensive and easily accessible data exist for several classes of assets, such as mortgages and business investments, so that the exact relation between return and stock betas predicted by the CAPM does not exist. This suggests that the empirical relationship between returns and stock betas is best estimated empirically (ECAPM) rather than by relying on theoretical and elegant CAPM models expanded to include missing assets effects. In any event, stock betas may be highly correlated with the true beta measured with the true market index.

Yet another explanation for the CAPM's inability to fully explain the observed risk-return tradeoff involves the possibility of constraints on investor borrowing that run counter to the assumptions of the CAPM. In response to this inadequacy, several versions of the CAPM have been developed by researchers. One of these versions is the so-called zero-beta, or two-factor, CAPM which provides for a risk-free return in a market where borrowing and lending rates are divergent. If borrowing rates and lending rates differ, or there is no risk-free borrowing or lending, or there is risk-free lending but no risk-free borrowing, then the CAPM has the following form:

$$K = R_Z + \beta(R_m - R_F)$$

The model, christened the zero-beta model, is analogous to the standard CAPM, but with the return on a minimum risk portfolio which is unrelated to market returns, R_Z, replacing the risk-free rate, R_F. The model has been empirically tested by Black, Jensen, and Scholes (1972), who found a flatter than predicted CAPM, consistent with the model and other researchers' findings.

The zero-beta CAPM cannot be literally employed in cost of capital projections, since the zero-beta portfolio is a statistical construct difficult to replicate.

Empirical Evidence

A summary of the empirical evidence on the magnitude of alpha is provided in the table below.

Empirical Evidence on the Alpha Factor		
Author	**Range of alpha**	**Period relied**
Black (1993)	-3.6% to 3.6%	1931-1991
Black, Jensen and Scholes (1972)	-9.61% to 12.24%	1931-1965
Fama and McBeth (1972)	4.08% to 9.36%	1935-1968
Fama and French (1992)	10.08% to 13.56%	1941-1990
Litzenberger and Ramaswamy (1979)	5.32% to 8.17%	
Litzenberger, Ramaswamy and Sosin (1980)	1.63% to 5.04%	1926-1978
Pettengill, Sundaram and Mathur (1995)	4.6%	
Morin (1994)	2.0%	1926-1984
Harris, Marston, Mishra, and O'Brien (2003)	2.0%	1983-1998

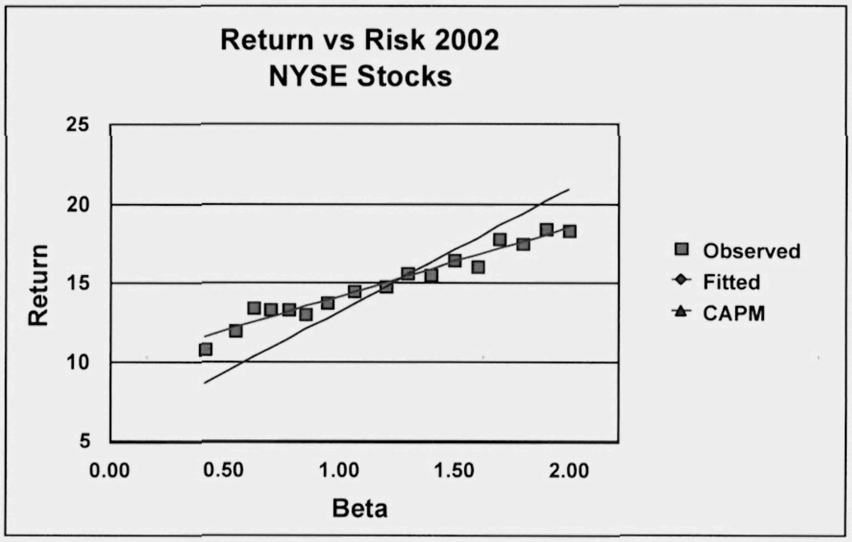
Given the observed magnitude of alpha, the empirical evidence indicates that the risk-return relationship is flatter than that predicted by the CAPM. Typical of the empirical evidence is the findings cited in Morin (1989) over the period 1926-1984 indicating that the observed expected return on a security is related to its risk by the following equation:

$$K = .0829 + .0520\,\beta$$

Given that the risk-free rate over the estimation period was approximately 6 percent, this relationship implies that the intercept of the risk-return relationship is higher than the 6 percent risk-free rate, contrary to the CAPM's prediction. Given that the average return on an average risk stock exceeded the risk-free rate by about 8.0 percent in that period, that is, the market risk premium (R_M - R_F) = 8 percent, the intercept of the observed relationship between return and beta exceeds the risk-free rate by about 2 percent, suggesting an alpha factor of 2 percent.

Most of the empirical studies cited in the above table utilize raw betas rather than Value Line adjusted betas because the latter were not available over most of the time periods covered in these studies. A study of the relationship between return and adjusted beta is reported on Table 6-7 in Ibbotson Associates Valuation Yearbook 2001. If we exclude the portfolio of very small cap stocks from the relationship due to significant size effects, the relationship between the arithmetic mean return and beta for the remaining portfolios is flatter than predicted and the intercept slightly higher than predicted by the CAPM, as shown on the graph below. It is noteworthy that the Ibbotson study relies on adjusted betas as stated on page 95 of the aforementioned study.

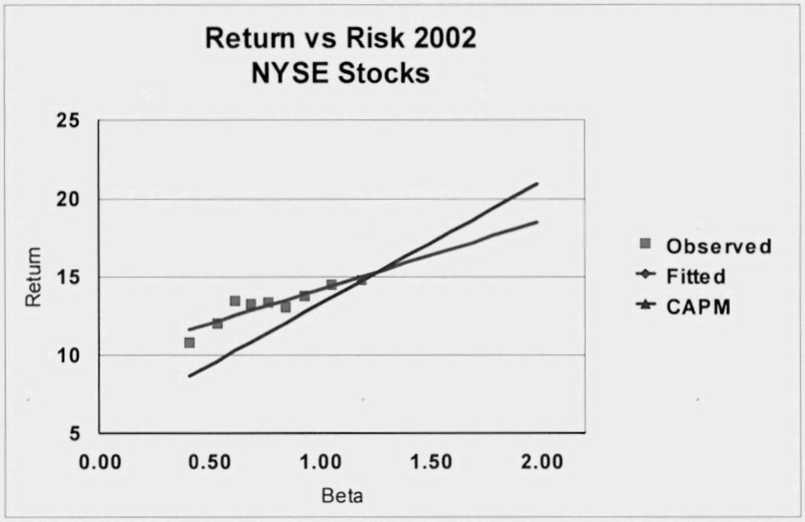
CAPM vs ECAPM



Another study by Morin in May 2002 provides empirical support for the ECAPM. All the stocks covered in the Value Line Investment Survey for Windows for which betas and returns data were available were retained for analysis. There were nearly 2000 such stocks. The expected return was measured as the total shareholder return ("TSR") reported by Value Line over the past ten years. The Value Line adjusted beta was also retrieved from the same data base. The nearly 2000 companies for which all data were available were ranked in ascending order of beta, from lowest to highest. In order to palliate measurement error, the nearly 2000 securities were grouped into ten portfolios of approximately 180 securities for each portfolio. The average returns and betas for each portfolio were as follows:

Portfolio #	**Beta**	**Return**
portfolio 1	0.41	10.87
portfolio 2	0.54	12.02
portfolio 3	0.62	13.50
portfolio 4	0.69	13.30
portfolio 5	0.77	13.39
portfolio 6	0.85	13.07
portfolio 7	0.94	13.75
portfolio 8	1.06	14.53
portfolio 9	1.19	14.78
portfolio 10	1.48	20.78

It is clear from the graph below that the observed relationship between DCF returns and Value Line adjusted betas is flatter than that predicted by the plain vanilla CAPM. The observed intercept is higher than the prevailing risk-free rate of 5.7 percent while the slope is less than equal to the market risk premium of 7.7 percent predicted by the plain vanilla CAPM for that period.



In an article published in Financial Management, Harris, Marston, Mishra, and O'Brien ("HMMO") estimate ex ante expected returns for S&P 500 companies over the period 1983-1998[1]. HMMO measure the expected rate of return (cost of equity) of each dividend-paying stock in the S&P 500 for each month from January 1983 to August 1998 by using the constant growth DCF model. They then investigate the relation between the risk premium (expected return over the 20-year U.S. Treasury Bond yield) estimates for each month to equity betas as of that same month (5-year raw betas).

The table below, drawn from HMMO Table 4, displays the average estimate prospective risk premium (Column 2) by industry and the corresponding beta estimate for that industry, both in raw form (Column 3) and adjusted form (Column 4). The latter were calculated with the traditional Value Line – Merrill Lynch – Bloomberg adjustment methodology by giving 1/3 weight of to a beta estimate of 1.00 and 2/3 weight to the raw beta estimate.

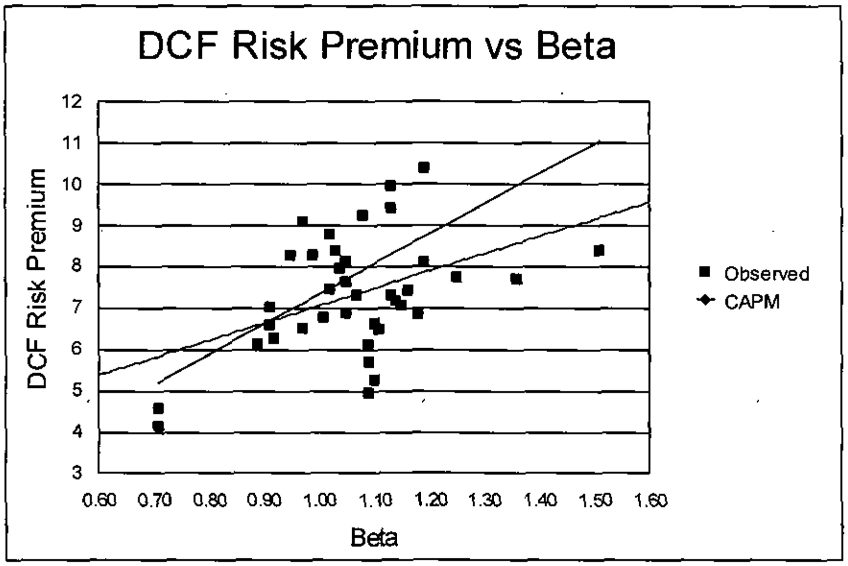
Table A-1 Risk Premium and Beta Estimates by Industry

	Industry (1)	DCF Risk Premium (2)	Raw Industry Beta (3)	Adjusted Industry Beta (4)
1	Aero	6.63	1.15	1.10
2	Autos	5.29	1.15	1.10
3	Banks	7.16	1.21	1.14

[1] Harris, R. S., Marston, F. C., Mishra, D. R., and O'Brien, T. J., "*Ex Ante* Cost of Equity Estimates of S&P 500 Firms: The Choice Between Global and Domestic CAPM," Financial Management, Autumn 2003, pp. 51-66.

4	Beer	6.60	0.87	0.91
5	BldMat	6.84	1.27	1.18
6	Books	7.64	1.07	1.05
7	Boxes	8.39	1.04	1.03
8	BusSv	8.15	1.07	1.05
9	Chems	6.49	1.16	1.11
10	Chips	8.11	1.28	1.19
11	Clths	7.74	1.37	1.25
12	Cnstr	7.70	1.54	1.36
13	Comps	9.42	1.19	1.13
14	Drugs	8.29	0.99	0.99
15	ElcEq	6.89	1.08	1.05
16	Energy	6.29	0.88	0.92
17	Fin	8.38	1.76	1.51
18	Food	7.02	0.86	0.91
19	Fun	9.98	1.19	1.13
20	Gold	4.59	0.57	0.71
21	Hlth	10.40	1.29	1.19
22	Hsld	6.77	1.02	1.01
23	Insur	7.46	1.03	1.02
24	LabEq	7.31	1.10	1.07
25	Mach	7.32	1.20	1.13
26	Meals	7.98	1.06	1.04
27	MedEq	8.80	1.03	1.02
28	Pap	6.14	1.13	1.09
29	PerSv	9.12	0.95	0.97
30	Retail	9.27	1.12	1.08
31	Rubber	7.06	1.22	1.15
32	Ships	1.95	0.95	0.97
33	Stee	4.96	1.13	1.09
34	Telc	6.12	0.83	0.89
35	Toys	7.42	1.24	1.16
36	Trans	5.70	1.14	1.09
37	Txtls	6.52	0.95	0.97
38	Util	4.15	0.57	0.71
39	Whlsl	8.29	0.92	0.95
	MEAN	**7.19**		

The observed statistical relationship between expected return and **adjusted beta** is shown in the graph below along with the CAPM prediction:



If the plain vanilla version of the CAPM is correct, then the intercept of the graph should be zero, recalling that the vertical axis represents returns in excess of the risk-free rate. Instead, the observed intercept is approximately 2 percent, that is approximately equal to 25 percent of the expected market risk premium of 7.2 percent shown at the bottom of Column 2 over the 1983-1998 period, as predicted by the ECAPM. The same is true for the slope of the graph. If the plain vanilla version of the CAPM is correct, then the slope of the relationship should equal the market risk premium of 7.2 percent. Instead, the observed slope of close to 5 percent is approximately equal to 75 percent of the expected market risk premium of 7.2 percent, as predicted by the ECAPM.

In short, the HMMO empirical findings are quite consistent with the predictions of the ECAPM.

Practical Implementation of the ECAPM

The empirical evidence reviewed above suggests that the expected return on a security is related to its risk by the following relationship:

$$K = R_F + \alpha + \beta\ (MRP - \alpha) \qquad (5)$$

or, alternatively by the following equivalent relationship:

$$K = R_F + a\,MRP + (1\text{-}a)\,\beta\,MRP \qquad (6)$$

The empirical findings support values of α from approximately 2 percent to 7 percent. If one is using the short-term U.S. Treasury Bills yield as a proxy for the risk-free rate, and given that utility stocks have lower than average betas, an alpha in the lower range of the empirical findings, 2 percent - 3 percent is reasonable, albeit conservative.

Using the long-term U.S. Treasury yield as a proxy for the risk-free rate, a lower alpha adjustment is indicated. This is because the use of the long-term U.S. Treasury yield as a proxy for the risk-free rate partially incorporates the desired effect of using the ECAPM[2]. An alpha in the range of 1 percent - 2 percent is therefore reasonable.

To illustrate, consider a utility with a beta of 0.80. The risk-free rate is 5 percent, the MRP is 7 percent, and the alpha factor is 2 percent. The cost of capital is determined as follows:

$$\begin{aligned} K &= R_F + \alpha + \beta\ (MRP - \alpha) \\ K &= 5\% + 2\% + 0.80(7\% - 2\%) \\ &= 11\% \end{aligned}$$

A practical alternative is to rely on the second variation of the ECAPM:

$$K = R_F + a\,MRP + (1\text{-}a)\,\beta\,MRP$$

With an alpha of 2 percent, a MRP in the 6 percent - 8 percent range, the 'a" coefficient is 0.25, and the ECAPM becomes[3]:

[2] The Security Market Line (SML) using the long-term risk-free rate has a higher intercept and a flatter slope than the SML using the short-term risk-free rate

[3] Recall that alpha equals 'a' times MRP, that is, alpha = a MRP, and therefore a = alpha/MRP. If alpha is 2 percent, then a = 0.25

$$K = R_F + 0.25\,MRP + 0.75\,\beta\,MRP$$

Returning to the numerical example, the utility's cost of capital is:

$$K = 5\% + 0.25 \times 7\% + 0.75 \times 0.80 \times 7\%$$
$$= 11\%$$

For reasonable values of beta and the MRP, both renditions of the ECAPM produce results that are virtually identical[4].

---

[4] In the Morin (1994) study, the value of "a" was actually derived by systematically varying the constant "a" in equation 6 from 0 to 1 in steps of 0.05 and choosing that value of 'a' that minimized the mean square error between the observed relationship between return and beta:

$$K = 0.0829 + .0520\,\beta$$

The value of a that best explained the observed relationship was 0.25.

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APPENDIX B

FLOTATION COST ALLOWANCE

To obtain the final cost of equity financing from the investors' expected rate of return, it is necessary to make allowance for underpricing, which is the sum of market pressure, costs of flotation, and underwriting fees associated with new issues. Allowance for market pressure should be made because large blocks of new stock may cause significant pressure on market prices even in stable markets. Allowance must also be made for company costs of flotation (including such items as printing, legal and accounting expenses) and for underwriting fees.

1. MAGNITUDE OF FLOTATION COSTS

According to empirical studies, underwriting costs and expenses average at least 4% of gross proceeds for utility stock offerings in the U.S. (See Logue & Jarrow: "Negotiations vs. Competitive Bidding in the Sale of Securities by Public Utilities", Financial Management, Fall 1978.) A study of 641 common stock issues by 95 electric utilities identified a flotation cost allowance of 5.0%. (See Borum & Malley: "Total Flotation Cost for Electric Company Equity Issues", Public Utilities Fortnightly, Feb. 20, 1986.)

Empirical studies suggest an allowance of 1% for market pressure in U.S. studies. Logue and Jarrow found that the absolute magnitude of the relative price decline due to market pressure was less than 1.5%. Bowyer and Yawitz examined 278 public utility stock issues and found an average market pressure of 0.72%. (See Bowyer & Yawitz, "The Effect of New Equity Issues on Utility Stock Prices", Public Utilities Fortnightly, May 22, 1980.)

Eckbo & Masulis ("Rights vs. Underwritten Stock Offerings: An Empirical Analysis", University of British Columbia, Working Paper No. 1208, Sept., 1987) found an average flotation cost of 4.175% for utility common stock offerings. Moreover, flotation costs increased progressively for smaller size issues. They also found that the relative price decline due to market pressure in the days surrounding the announcement amounted to slightly more than 1.5%. In a classic and monumental study published in the prestigious Journal of Financial Economics by a prominent scholar, a market pressure effect of 3.14% for industrial stock issues and 0.75% for utility common stock issues was found (see Smith, C.W., "Investment Banking and the Capital Acquisition Process," Journal of Financial Economics 15, 1986). Other studies of market pressure are reported in Logue ("On the Pricing of Unseasoned Equity Offerings, Journal of Financial and Quantitative Analysis, Jan. 1973), Pettway ("The Effects of New Equity Sales Upon Utility Share Prices," Public Utilities Fortnightly, May 10 1984), and Reilly and Hatfield ("Investor Experience with New Stock Issues," Financial Analysts' Journal, Sept.-Oct. 1969). In the Pettway study, the market pressure effect for a sample of 368 public utility equity sales was in the range of 2% to 3%. Adding the direct and indirect effects of utility common stock issues, the indicated total flotation cost allowance is above 5.0%, corroborating the results of earlier studies.

As shown in the table below, a comprehensive empirical study by Lee, Lochhead, Ritter, and Zhao, "The Costs of Raising Capital," Journal of Financial Research, Vol. XIX, NO. 1, Spring 1996, shows average direct flotation costs for equity offerings of 3.5% - 5% for stock issues between $60 and $500 million. Allowing for market pressure costs raises the flotation cost allowance to well above 5%.

FLOTATION COSTS: RAISING EXTERNAL CAPITAL
(Percent of Total Capital Raised)

Amount Raised in $ Millions	Average Flotation Cost: Common Stock	Average Flotation Cost: New Debt
$ 2 - 9. 99	13.28%	4.39%
10 - 19. 99	8.72	2.76
20 - 39. 99	6.93	2.42
40 - 59. 99	5.87	1.32
60 - 79. 99	5.18	2.34
80 - 99. 99	4.73	2.16
100 - 199. 99	4.22	2.31
200 - 499. 99	3.47	2.19
500 and Up	3.15	1.64

Note: Flotation costs for IPOs are about 17 percent of the value of common stock issued if the amount raised is less than $10 million and about 6 percent if more than $500 million is raised. Flotation costs are somewhat lower for utilities than others.

Source: Lee, Inmoo, Scott Lochhead, Jay Ritter, and Quanshui Zhao, "The Costs of Raising Capital," *The Journal of Financial Research,* Spring 1996.

Therefore, based on empirical studies, total flotation costs including market pressure amount to approximately 5% of gross proceeds. I have therefore assumed a 5% gross total flotation cost allowance in my cost of capital analyses.

2. APPLICATION OF THE FLOTATION COST ADJUSTMENT

The section below shows: 1) why it is necessary to apply an allowance of 5% to the dividend yield component of equity cost by dividing that yield by 0.95 (100% - 5%) to obtain the fair return on equity capital, and 2) why the flotation adjustment is permanently required to avoid confiscation even if no further stock issues are contemplated. Flotation costs are only recovered if the rate of return is applied to total equity, including retained earnings, in all future years.

Flotation costs are just as real as costs incurred to build utility plant. Fair regulatory treatment absolutely must permit the recovery of these costs. An analogy with bond issues is useful to understand the treatment of flotation costs in the case of common stocks.

In the case of a bond issue, flotation costs are not expensed but are rather amortized over the life of the bond, and the annual amortization charge is embedded in the cost of service. This is analogous to the process of depreciation, which allows the recovery of funds invested in utility plant. The recovery of bond flotation expense continues year after year, irrespective of whether the company issues new debt capital in the future, until recovery is complete. In the case of common stock that has no finite life, flotation costs are not amortized. Therefore, the recovery of flotation cost requires an upward adjustment to the allowed return on equity. Roger A. Morin, Regulatory Finance, Public Utilities Reports Inc., Arlington, Va., 1994, provides numerical illustrations that show that even if a utility does not contemplate any additional common stock issues, a flotation cost adjustment is still permanently required. Examples there also demonstrate that the allowance applies to retained earnings as well as to the original capital.

From the standard DCF model, the investor's required return on equity capital is expressed as:

$$K = D_1/P_o + g$$

If P_o is regarded as the proceeds per share actually received by the company from which dividends and earnings will be generated, that is, P_o equals B_o, the book value per share, then the company's required return is:

$$r = D_1/B_o + g$$

Denoting the percentage flotation costs 'f', proceeds per share B_o are related to market price P_o as follows:

$$P - fP = B_o$$

$$P(1 - f) = B_o$$

Substituting the latter equation into the above expression for return on equity, we obtain:

$$r = D_1/P(1\text{-}f) + g$$

that is, the utility's required return adjusted for underpricing. For flotation costs of 5%, dividing the expected dividend yield by 0.95 will produce the adjusted cost of equity capital. For a dividend yield of 6% for example, the magnitude of the adjustment is 32 basis points: .06/.95 = .0632.

In deriving DCF estimates of fair return on equity, it is therefore necessary to apply a conservative after-tax allowance of 5% to the dividend yield component of equity cost.

Even if no further stock issues are contemplated, the flotation adjustment is still permanently required to keep shareholders whole. Flotation costs are only recovered if the rate of return is applied to total equity, including retained earnings, in all future years, even if no future financing is contemplated. This is demonstrated by the numerical example contained in pages 7-9 of this Appendix. Moreover, even if the stock price, hence the DCF estimate of equity return, fully reflected the lack of permanent allowance, the company always nets less than the market price. Only the net proceeds from an equity issue are used to add to the rate base on which the investor earns. A permanent allowance for flotation costs must be authorized in order to insure that in each year the investor earns the required return on the total amount of capital actually supplied.

The example shown on pages 7-9 shows the flotation cost adjustment process using illustrative, yet realistic, market data. The assumptions used in the computation are shown on page 7. The stock is selling in the market for \$25, investors expect the firm to pay a dividend of \$2.25 that will grow at a rate of 5% thereafter. The traditional DCF cost of equity is thus $k = D/P + g = 2.25/25 + .05 = 14\%$. The firm sells one share stock, incurring a flotation cost of 5%. The traditional DCF cost of equity adjusted for flotation cost is thus $ROE = D/P(1\text{-}f) + g = .09/.95 + .05 = 14.47\%$.

The initial book value (rate base) is the net proceeds from the stock issue, which are \$23.75, that is, the market price less the 5% flotation costs. The example demonstrates that only if the company is allowed to earn 14.47% on rate base will investors earn their cost of equity of 14%. On page 8, Column 1 shows the initial common stock account, Column 2 the cumulative retained earnings balance, starting at zero, and steadily increasing from the retention of earnings. Total equity in Column 3 is the sum of common stock capital and retained earnings. The stock price in Column 4 is obtained from the seminal DCF formula: $D_1/(k - g)$. Earnings per share in Column 6 are simply the allowed return of 14.47% times the total common equity base. Dividends start at $2.25 and grow at 5% thereafter, which they must do if investors are to earn a 14% return. The dividend payout ratio remains constant, as per the assumption of the DCF model. All quantities, stock price, book value, earnings, and dividends grow at a 5% rate, as shown at the bottom of the relevant columns. Only if the company is allowed to earn 14.47% on equity do investors earn 14%. For example, if the company is allowed only 14%, the stock price drops from $26.25 to $26.13 in the second year, inflicting a loss on shareholders. This is shown on page 9. The growth rate drops from 5% to 4.53%. Thus, investors only earn 9% + 4.53% = 13.53% on their investment. It is noteworthy that the adjustment is always required each and every year, whether or not new stock issues are sold in the future, and that the allowed return on equity must be earned on total equity, including retained earnings, for investors to earn the cost of equity.

ASSUMPTIONS:

ISSUE PRICE =	$25.00
FLOTATION COST =	5.00%
DIVIDEND YIELD =	9.00%
GROWTH =	5.00%
EQUITY RETURN =	**14.00%**
(D/P + g)	
ALLOWED RETURN ON EQUITY =	**14.47%**
(D/P(1-f) + g)	

Yr	COMMON STOCK (1)	RETAINED EARNINGS (2)	TOTAL EQUITY (3)	STOCK PRICE (4)	MARKET / BOOK RATIO (5)	EPS (6)	DPS (7)	PAYOUT (8)
1	$23.75	$0.000	$23.750	$25.000	1.0526	$3.438	$2.250	65.45%
2	$23.75	$1.188	$24.938	$26.250	1.0526	$3.609	$2.363	65.45%
3	$23.75	$2.434	$26.184	$27.563	1.0526	$3.790	$2.481	65.45%
4	$23.75	$3.744	$27.494	$28.941	1.0526	$3.979	$2.605	65.45%
5	$23.75	$5.118	$28.868	$30.388	1.0526	$4.178	$2.735	65.45%
6	$23.75	$6.562	$30.312	$31.907	1.0526	$4.387	$2.872	65.45%
7	$23.75	$8.077	$31.827	$33.502	1.0526	$4.607	$3.015	65.45%
8	$23.75	$9.669	$33.419	$35.178	1.0526	$4.837	$3.166	65.45%
9	$23.75	$11.340	$35.090	$36.936	1.0526	$5.079	$3.324	65.45%
10	$23.75	$13.094	$36.844	$38.783	1.0526	$5.333	$3.490	65.45%
			5.00%	**5.00%**		**5.00%**	**5.00%**	

Yr	COMMON STOCK (1)	RETAINED EARNINGS (2)	TOTAL EQUITY (3)	STOCK PRICE (4)	MARKET/ BOOK RATIO (5)	EPS (6)	DPS (7)	PAYOUT (8)
------	--------	--------	--------	--------	--------	--------	--------	--------
1	$23.75	$0.000	$23.750	$25.000	1.0526	$3.325	$2.250	67.67%
2	$23.75	$1.075	$24.825	$26.132	1.0526	$3.476	$2.352	67.67%
3	$23.75	$2.199	$25.949	$27.314	1.0526	$3.633	$2.458	67.67%
4	$23.75	$3.373	$27.123	$28.551	1.0526	$3.797	$2.570	67.67%
5	$23.75	$4.601	$28.351	$29.843	1.0526	$3.969	$2.686	67.67%
6	$23.75	$5.884	$29.634	$31.194	1.0526	$4.149	$2.807	67.67%
7	$23.75	$7.225	$30.975	$32.606	1.0526	$4.337	$2.935	67.67%
8	$23.75	$8.627	$32.377	$34.082	1.0526	$4.533	$3.067	67.67%
9	$23.75	$10.093	$33.843	$35.624	1.0526	$4.738	$3.206	67.67%
10	$23.75	$11.625	$35.375	$37.237	1.0526	$4.952	$3.351	67.67%
			4.53%	**4.53%**		**4.53%**	**4.53%**	

DUKE ENERGY OHIO EXHIBIT____

BEFORE

THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Duke Energy Ohio, Inc., for an Increase in Electric Distribution Rates.	)))	Case No. 17-32-EL-AIR
In the Matter of the Application of Duke Energy Ohio, Inc., for Tariff Approval.	)))	Case No. 17-33-EL-ATA
In the Matter of the Application of Duke Energy Ohio, Inc., for Approval to Change Accounting Methods.	)))	Case No. 17-34-EL-AAM

DIRECT TESTIMONY OF

SCOTT B. NICHOLSON

ON BEHALF OF

DUKE ENERGY OHIO, INC.

______ Management policies, practices, and organization

______ Operating income

______ Rate Base

______ Allocations

______ Rate of return

______ Rates and tariffs

__X__ Other: Supplier Services

March 16, 2017

TABLE OF CONTENTS

PAGE

I. INTRODUCTION 1

II. DISCUSSION 2

III. ESTIMATES 13

IV. CONCLUSION 14

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Scott B. Nicholson, and my business address is 139 East Fourth Street, Cincinnati, Ohio 45202.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by Duke Energy Ohio, Inc., (Duke Energy Ohio or the Company) as Manager, Ohio Customer Choice.

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.

A. I hold Master of Science and Bachelor of Science Degrees in Economics from Illinois State University. I began my professional career as a staff member at the Illinois Commerce Commission. Subsequent to leaving the commission, I have held a variety of positions in the electric utility industry, including positions at Potomac Electric Power Company, Central Illinois Public Service Company, and Cadence Network (facility utility expense management). I joined Duke Energy Corporation (Duke Energy) in 1997 and, in my tenure, have worked for various of its affiliates. I was promoted to my current position as Manager, Ohio Customer Choice, in 2016.

Q. PLEASE DESCRIBE YOUR DUTIES AS MANAGER, OHIO CUSTOMER CHOICE.

A. As Manager, Ohio Customer Choice, I have responsibility for overseeing the certified supplier business office where the Company facilitates data flow and billing management with competitive retail energy service (CRES) providers.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE PUBLIC UTILITIES COMMISSION OF OHIO?

A. No.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THESE PROCEEDINGS?

A. The purpose of my testimony is to provide an overview of enhancements to the competitive market that will be enabled by Company's proposal in these proceedings to transition its advanced metering infrastructure (AMI). Specifically, I address the customer energy usage data (CEUD) that is currently available to CRES providers and the modifications necessary to appropriately expand the availability and exchange of such data.

To put these issues in the proper context, my testimony begins with a discussion of Duke Energy Ohio's existing processes for providing customer information to CRES providers and the history of the Secured Certified Supplier Information portal (Portal). I then address how the AMI transition, when coupled with alterations to existing processes, will aid both customers and the competitive market.

II. DISCUSSION

Q. PLEASE DEFINE CEUD AND EXPLAIN HOW DUKE ENERGY OHIO CURRENTLY PROVIDES CEUD TO CRES PROVIDERS.

A. The Commission's rules define CEUD as "data collected from a customer's meter, which is identifiable to a retail customer."[1] The CEUD obtained by the

[1] O.A.C. 4901:1-10-01(J).

Company is available to CRES providers from three sources:

1. Pre-enrollment List – The Pre-enrollment List provides twelve months of monthly customer usage data for all customers (except for those customers who have opted out of the list). The list also includes load profile indicators, current and future Peak Load Contribution (PLC) values, and indicates whether a customer is taking service from a supplier. It is important to note that this list does not contain customer account numbers.
2. Electronic Data Interchange (EDI) – CEUD is also available through an EDI transaction. EDI can provide both monthly and interval customer usage data, for up to twelve months, and interval data is provided in 15-minute intervals. The interval data that is available from EDI is only for those customers who have an Interval Data Recorder (IDR) meter. Such customers are typically commercial customers. As of January 31, 2017, Duke Energy Ohio had 5,182 IDR meters.
3. Portal – An internet Portal is also available to CRES providers to obtain CEUD. This information is available to CRES providers on a per-customer basis. That is, a CRES provider can request information, subject to having obtained the proper authorization, one customer at a time. The Portal provides both monthly and interval customer data, as described below.
    a. The Portal provides up to 24 months of monthly customer usage data (as well as current and future PLC values) for all customer classes, including residential customers with proper authorization.

b. The Portal provides hourly interval customer usage data for customers who have either an IDR or an AMI meter and this data can be requested for either the most recent 12- or 24-month billing periods. Each hourly interval indicates whether the data in that interval is of billing quality or not.

Q. PLEASE EXPLAIN THE HISTORY OF THE COMPANY'S CERTIFIED SUPPLIER PORTAL.

A. The Portal has been available since January 2001 and originally provided twelve months of summary information for all customers. More recently, in Case No. 11-3549-EL-SSO, *et al.*, Duke Energy Ohio agreed to enhance the Portal to enable the release of additional data to suppliers and these enhancements were ready for use in mid-May 2014. While the Company was in the process of enhancing the Portal, the Commission began a rulemaking proceeding to amend rules related to customer authorization.[2] Based on the updated rules regarding residential customer authorizations, the Company was required to build a system that would also allow for this change in the customer authorization process, which required additional time. After making the necessary changes, the Company made non-residential AMI interval CEUD available to CRES providers on the Portal in November 2015.

Under Commission regulation, Duke Energy Ohio is required to retain a residential customer's authorization before releasing that customer's interval

[2] *In the Matter of the Commission's Review of Chapter 4901:1-10, Ohio Administrative Code, Regarding Electric Companies*, Case No. 12-2050-EL-ORD, Entry (July 16, 2012).

CEUD. To comply with this requirement, automated processes were added to the Portal that give CRES providers the ability to upload an individual residential customer's authorization to release interval CEUD. Only after this authorization is received by the Company is the data accessible to the CRES providers. This function was made available in May 2016, at which point interval CEUD from an additional 655,000 meters was made conditionally accessible to CRES providers through the Portal, one customer at a time. Details related to the release of this data have been discussed at the Commission in the Market Development Working Group that was formed by the Commission as the result of its inquiry into the status of the retail electric market.[3]

Q. WHAT INTERVAL CEUD DATA IS CURRENTLY AVAILABLE TO CRES PROVIDERS?

A. CRES providers have access to interval CEUD from:

1. Commercial and Industrial customers with IDR meters,
2. Commercial and Industrial customers with the AMI meters, and
3. Residential customers with AMI meters.

Q. WHY DO YOU DISTINGUISH BETWEEN CUSTOMERS WITH IDR METERS AND CUSTOMERS WITH AMI METERS?

A. The reference to IDR meters highlights the complexity associated with the current system constraints, the complexity in existing rules, and the number of existing meters. It is important to note that there is a significant difference in the number

[3] *In the Matter of the Commission's Investigation of Ohio's Retail Electric Service Market*, Case No. 12-3151-EL-COI, Finding and Order (March 26, 2014).

of IDR meters compared to AMI meters. Indeed, as of January 31, 2017, Duke Energy Ohio had 5,182 IDR meters and 729,695 AMI meters. The data from IDR meters is the original interval data that was available from large commercial and industrial customers and represents situations where there has been a historical need for this level of detail. There have been important systems and processes designed around this data, including systems and processes that allow the data to be used in retail billing and in the PJM Interconnection, L.L.C., (PJM) settlement processes.

The two major areas of difference between how the data is processed and used are:

1. The Validation, Estimation, and Editing (VEE) process, which is the process to identify and account for missed and inaccurate meter reads to derive billing quality data, and
2. The process of settling hourly interval usage data with the PJM wholesale market.

These processes address whether the data is of sufficient quality to use on a retail bill and whether there are systems in place to use the data to settle in the PJM wholesale markets.

Q. CAN THESE ALREADY DEVELOPED SYSTEMS AND PROCESSES USED FOR IDR METERS ALSO BE USED FOR THE ADDITIONAL AMI METERS?

A. No, not at this time. When it comes to changing these processes and systems, it is important to recognize that there are significant changes in scale in handling data from 5,182 IDR meters versus 729,695 AMI meters. This significant change in scale surpasses the existing capacity for many of the processes and systems currently used.

Q. YOU MENTIONED THAT THERE WERE 729,695 AMI METERS AS OF JANUARY 31, 2017. ARE THESE METERS ALL THE SAME?

A. No. Within the broader category of AMI meters, the Duke Energy Ohio distribution system includes electric meters manufactured by Echelon and electric meters manufactured by Itron.

Q. DOES THE EXISTENCE OF THESE DIFFERENT METERING TECHNOLOGIES CREATE LIMITATIONS?

A. Yes. Interval CEUD data from the Echelon and Itron meters are processed through separate meter data management systems that have unique processes for performing VEE.

AMI meters manufactured by Echelon are processed through Oracle's first generation meter data management system, which the Company refers to as Energy Data Management System (EDMS). EDMS does not have scalable VEE functionality for interval AMI CEUD.

AMI meters manufactured by Itron are processed through Oracle's second generation meter data management system, which the Company refers to as the Meter Data Management (MDM) system. MDM performs VEE processes on interval AMI CEUD and meters processed through that MDM system have billing quality interval AMI CEUD. In addition to the Itron AMI meters, there is a limited number of Echelon AMI meters in MDM that were associated with pilot time-of-use rates.

Q. WILL THE AMI TRANSITION DISCUSSED BY MR. DONALD L. SCHNEIDER, JR., MITIGATE AGAINST THESE LIMITATIONS?

A. Yes, in part. The current limitations that affect the provision of CEUD can be remedied in connection with the AMI transition proposed by the Company in these proceedings. As explained in greater detail by Duke Energy Ohio witness Donald L. Schneider, Jr., the Company is proposing that its metering system evolve into one with a single AMI design. This evolution or transition also provides synergies with the Commission's focus on advanced technology and further enables a more consequential exchange of data, as contemplated by the Commission.

Q. PLEASE EXPLAIN WHAT YOU MEAN BY "A MORE CONSEQUENTIAL EXCHANGE OF DATA."

A. As I previously discussed, Duke Energy Ohio's current systems enable CRES providers to receive CEUD, but on an individual customer basis. Consequently, more resources must be invested in order for a CRES provider to obtain data on a larger number of customers; data that can be used to evaluate product offerings. Developing and implementing a system that permits data acquisition on a larger scale, but subject to the appropriate protections, mitigates against these existing limitations. Duke Energy Ohio believes that this more efficient and effective exchange of data is consistent with the Commission's intentions as well as the policies of the state.

Q. ISN'T THE COMPANY ALEADY ADDRESSING THE PROVISION OF CEUD IN ANOTHER DOCKET?

A. Yes, but resolution of that proceeding will not yield the comprehensive solution proposed in these proceedings. Please permit me to explain.

The Commission previously directed all Ohio electric distribution utilities to file tariffs specifying the "terms, conditions and charges associated with providing interval CEUD, based upon their capabilities and cost considerations…".[4] Duke Energy Ohio complied with this directive by instituting a case under Case No. 14-2209-EL-ATA.[5] In that proceeding, the Commission directed the Company and parties to respond to four questions related to providing interval CEUD to CRES providers. However, the scope of that proceeding, as directed by the Commission, does not extend to issues pertinent to cost recovery and, as such, there are likely to be outstanding issues even after resolution of that proceeding. To avoid piecemeal resolution of these related issues, Duke Energy Ohio proposes a solution here that is a reasonable complement to the AMI transition and allows for the implementation of processes that enable a more meaningful production of CEUD in an expedited manner.

Q. PLEASE PROVIDE AN OVERVIEW OF THE ENHANCEMENTS.

First, it is important to understand that the enhancements are based on the AMI transition as discussed by Company witness Schneider. The significance of that transition to the provision of CEUD is that the interval CEUD for Itron meters

[4] *In the Matter of the Commission's Investigation of Ohio's Retail Electric Service Market,* Case No. 12-3151-EL-COI, Entry on Rehearing (May 21, 2014).

[5] *In the Matter of the Application of Duke Energy Ohio, Inc., for Tariff Approval,* Case No.14-2209-EL-ATA, Application (December 16, 2014).

goes through the VEE process and is suitable for retail billing.

In general, the enhancements can be grouped into two large categories: enhancements for retail and enhancements for wholesale. The enhancements for retail include, among other things, customer/meter identification, residential customer authorizations, billing, and "Next Day" usage. The enhancements for wholesale include, among other things, settling interval CEUD from AMI meters with PJM, which is the wholesale market.

The enhancements for retail require:

1. Methods to identify customers that have billing quality interval CEUD. This will include all customers with AMI Itron meters that are certified on MDM (MDM performs VEE on interval CEUD). And this change will keep the lists of these customers current, so that, as additional meters are transitioned from Echelon to Itron, they will be included on the list and CRES providers will be able to market to them. The "lists" that CRES providers will be able see include Sync Lists (a list of customers by supplier), the Pre-Enrollment List, and the Portal.
2. System changes to facilitate the bulk uploading of residential authorizations to release interval CEUD. Currently, CRES providers can upload authorizations one at a time via the CRES Portal; this change will allow bulk uploads. This would also add functionality for customers to self-authorize the release of interval CEUD on the authenticated Duke Energy web site.
3. System changes for billing. These changes would allow much larger volumes of data to flow through EDI transactions, including system

management tools. The current systems process interval CEUD for 5,182 IDR meters and were not designed to handle the volume of data that likely will occur with the addition of 729,695 interval CEUD meters and "Next Day" services (as discussed below). The EDI changes will also add the ability for CRES Providers to receive interval CEUD from AMI meters, similar to what they are now able to with IDR meters. There will also be system changes to the Company's billing systems so that CRES Providers can put their charges, which are associated with interval CEUD, on the Company's bill using Bill Ready Billing (Bill Ready Billing is when the Company sends usage to the CRES provider and the provider calculates the billing amount and sends that back to Duke Energy Ohio to place on the bill). This will allow CRES providers to offer any type of electric commodity product they want, without potential limits to what can be calculated in the Company's systems.

4. System changes to provide "Next Day" usage. This will allow CRES providers the ability to obtain hourly interval CEUD the day after power is consumed. The "enrollment" of a customer and the transmission of "Next Day" interval CEUD will be by EDI transactions. Using EDI will automate both the initiation and daily processes as well as allowing large numbers of customers to be eligible for the "Next Day" services that CRES providers may offer.

The enhancements in the second category, or PJM settlement enhancements, would greatly expand the Company's ability to settle incremental CEUD with PJM, and allow the Company to settle an additional 729,695 meters in PJM. The Company's systems are currently capable of settling interval data from IDR meters only (5,182 meters as of January 31, 2017). Data from AMI meters (729,695 meters as of January 31, 2017) are settled based on scalar data and load profiles.

The enhancement to the PJM settlement systems would allow the AMI meters to be settled based on customers actual hourly loads and allow the PLC and NSPL to be based on actual usage instead of load profiles, which increases precision. In addition, if CRES providers begin offering products based on interval usage, this enhancement will better align the potential CRES pricing (and revenue) with PJM settlement (costs).

Q. IS THE COMPANY PROPOSING TO RECOVER COSTS ASSOCIATED WITH PROVIDING DATA TO CRES PROVIDERS IN THESE PROCEEDINGS?

A. Yes. If the Company is directed to provide interval CEUD to CRES providers as discussed herein, the enhancements to the retail and wholesale systems are necessary and cost recovery should be allowed. The retail enhancements are needed to allow CRES providers the ability to market and bill interval CEUD-related products. The wholesale enhancements are essential to properly manage settlement with consistent data through the PJM settlement process. The enhancements as described above will entail costs that must be recovered. The Company proposes cost recovery for its investment in the infrastructure needed to move operations into a more future-focused and technology driven framework. Duke Energy Ohio witness William Don Wathen, Jr. discusses the Company's proposal for cost recovery.

III. ESTIMATES

Q. DO YOU HAVE COST AND TIME-FRAME ESTIMATES FOR THE ENHANCEMENTS YOU HAVE DISCUSSED?

A. Yes, I have worked with the subject matter experts for these enhancements to obtain both cost and time-frame estimates. Typical project management stages were used and estimated costs were based on functional resources required.

It is important to note that the time periods referenced would begin after the Commission authorizes Duke Energy Ohio to undertake the enhancements and approves cost recovery as proposed by Company witness Wathen.

Q. PLEASE PROVIDE THE ESTIMATE FOR WHAT YOU REFER TO AS THE RETAIL PORTION OF THE ENHANCEMENTS.

A. The estimated cost for retail enhancements is approximately $10 million and would take approximately 36 months to implement. The estimate can be broken down between the functionalities mentioned previously. While some of the work can occur concurrently, other areas require the same resources and would therefore occur consecutively.

1. The cost and time-frame for the identification of customers that have billing quality interval CEUD is approximately $1.5 million and will take approximately 6 months to deploy.
2. The cost and time frame for system changes to facilitate bulk uploading of residential authorizations to release CEUD is approximately $1.0 million and will take approximately 12 months to deploy.
3. The cost and time-frame to increase the data flow capacity on EDI transitions and to modify the billing system so CRES providers can put

their charges, associated with interval CEUD, is approximately $3.0 million and will take approximately 24 months to deploy.

4. The cost and time-frame to provide "Next Day" usage is approximately $3.5 million and will take approximately 12 months to deploy from the completion of the EDI project work.

Q. PLEASE EXPLAIN THE ESTIMATE FOR THE PJM SETTLEMENT ENHANCEMENTS.

A. The cost of the PJM settlement enhancements is based on an estimate that is divided into two phases of work. The first phase will add approximately 100,000 AMI meters that currently reside in MDM. After this first phase is completed, the existing AMI meters in MDM will be settled in PJM on an hourly basis.

The second phase is to add the capability for the approximately 626,000 AMI meters that will be added to MDM to also be settled in PJM on an hourly basis as part of the meter change (as described by Company witness Schneider).

The cost estimates for the first and second phases are approximately $1.662 million and $1.918 million, for a total estimated cost of $3.581 million. The estimated time frame for each phase is approximately one year and, since these phases are consecutive, the total estimated time-frame for the PJM settlement enhancement is two years.

IV. CONCLUSION

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes.

DUKE ENERGY OHIO EXHIBIT______

BEFORE

THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Duke Energy Ohio, Inc., for an Increase in Electric Distribution Rates.	)))	Case No. 17-32-EL-AIR
In the Matter of the Application of Duke Energy Ohio, Inc., for Tariff Approval.	)))	Case No. 17-33-EL-ATA
In the Matter of the Application of Duke Energy Ohio, Inc., for Approval to Change Accounting Methods.	)))	Case No. 17-34-EL-AAM

DIRECT TESTIMONY OF

ROBERT "BEAU" H. PRATT

ON BEHALF OF

DUKE ENERGY OHIO, INC.

________ Management policies, practices, and organization
________ Operating income
________ Rate Base
________ Allocations
________ Rate of return
________ Rates and tariffs
___X___ Other: Budgeting and Forecasting

March 16, 2017

TABLE OF CONTENTS

PAGE

I. INTRODUCTION 1

II. THE BUDGETING AND FORECASTING PROCESS 3

III. SCHEDULES AND FILING REQUIREMENTS SPONSORED BY WITNESS 5

IV. CONCLUSION 5

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Robert "Beau" H. Pratt, and my business address is 550 South Tryon Street, Charlotte, North Carolina 28202.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by Duke Energy Business Services LLC (DEBS), as Director, Regional Financial Forecasting. DEBS provides various administrative and other services to Duke Energy Ohio, Inc., (Duke Energy Ohio or Company) and other affiliated companies of Duke Energy Corporation (Duke Energy).

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.

A. I graduated from the University of North Carolina at Chapel Hill in 2006 with a Bachelor of Science in Business Administration. I started my employment with Progress Energy, Inc., (Progress Energy) in 2006 as a financial specialist in the Treasury and Enterprise Risk Management Department, performing risk reporting and analytics supporting utility and non-utility fuel procurement and trading operations. Subsequently, I held various positions at Progress Energy, including Coal Procurement Agent within the Fuels and Power Optimization Department and Continuous Business Excellence Leader within the Corporate Planning Department. After the merger with Duke Energy was announced in 2011, I performed a dual financial support role within the Investor Relations Department and Fuels and Power Optimization Department. After the merger between Progress Energy and Duke Energy closed in 2012, I became Senior Financial

Analyst within the Investor Relations Department, where I was later promoted to Manager. In March 2015, I became Manager, Regional Financial Forecasting within the Financial Planning and Analysis Department, where I was later promoted to Director, Regional Financial Forecasting. I currently lead forecasting for Duke Energy's Midwest electric utilities, including Duke Energy Ohio, Duke Energy Kentucky, Inc., (Duke Energy Kentucky) and Duke Energy Indiana, Inc., in addition to Duke Energy's gas utilities and other gas ventures.

Q. **PLEASE SUMMARIZE YOUR RESPONSIBILITIES AS DIRECTOR, REGIONAL FINANCIAL FORECASTING.**

A. I am responsible for preparing the budgets and forecasts and performing financial analysis for Duke Energy Ohio and Duke Energy Kentucky.

Q. **HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE PUBLIC UTILITIES COMMISSION OF OHIO?**

A. No.

Q. **WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THESE PROCEEDINGS?**

A. I describe the budgeting and forecasting process underlying the projected data for the test year proposed in this Application. I also sponsor Supplemental Filing Requirements S-1, S-2, and (C)(10). Finally, I provided projected revenue, sales, and customer data for the years 2017 through 2021 to Duke Energy Ohio witness Peggy A. Laub for the preparation of Schedules C-11.1 through C-11.4.

II. THE BUDGETING AND FORECASTING PROCESS

Q. DESCRIBE THE SOURCE OF THE FORECASTED FINANCIAL DATA USED IN THESE PROCEEDINGS.

A. The forecasted data used in these proceedings is based on Duke Energy Ohio's 2016 and 2017 Annual Budgets. This is because the Company's twelve-month test period for this proceeding actually spans two calendar years. I supervised the coordination and development of this budget, and it was reviewed and approved by Duke Energy Ohio's executive management and Duke Energy's Board of Directors.

Q. DESCRIBE THE BUDGETING AND FORECASTING PROCESS THAT YOU USED TO DEVELOP THE TEST PERIOD IN THESE PROCEEDINGS.

A. Budgeting is done at organizational levels known as the "responsibility centers." Each entity (or group) that performs work throughout the organization is assigned a responsibility center, which is specific to a single payroll company. The responsibility centers use guidelines provided by Duke Energy's Budgeting and Business Support organization within the Financial Planning and Analysis Department. The responsibility centers represent detailed responsibility budgets consisting of expense items, certain types of revenues, and construction budgets for capital projects. The information is consolidated, along with sales and revenue data, into a corporate budget and is reviewed by various levels of management. One or more iterations of the annual budget are typically required before final approval by executive management and the Board of Directors. This "bottom-up" approach is reasonable and has been an effective process for managing costs.

Q. DESCRIBE THE GUIDELINES PROVIDED BY THE BUDGETING AND BUSINESS SUPPORT ORGANIZATION IN DEVELOPING DUKE ENERGY OHIO'S ANNUAL RESPONSIBILITY (OPERATING AND MAINTENANCE) CENTER BUDGET.

A. The guidelines provided by the business support organization are a detailed set of instructions for creating a responsibility center budget. For example, there are detailed instructions for budgeting employee labor data, such as the escalation rates for non-union labor expenses and indirect labor and fringe benefit loading rates, and how to handle staff additions or deletions. Individual employees and certain associated costs of the employees are included or excluded in any given center's budget according to the expected future reporting assignment for that employee. Detailed instructions for non-labor related expenses, such as transportation and information technology expenses, are included. There are instructions for handling contract labor and supplies, and guidelines for identifying a capital versus expense item. Budget coordinators are required to use these assumptions and/or instructions in projecting their future departmental expenses. These operating and maintenance budgeting guidelines are reflected in the budgets and forecasts that are submitted to Duke Energy Ohio's executive management and Duke Energy's Board of Directors for approval and are also reflected in the forecasted financial data in these proceedings.

III. SCHEDULES AND FILING REQUIREMENTS SPONSORED BY WITNESS

Q. PLEASE DESCRIBE SUPPLEMENTAL FILING REQUIREMENT S-1.

A. Supplemental Filing Requirement S-1 contains a five-year financial forecast for certain capital expenditure information for the five years 2017 through 2021.

Q. PLEASE DESCRIBE SUPPLEMENTAL FILING REQUIREMENT S-2.

A. Supplemental Filing Requirement S-2 contains a five-year financial forecast for certain revenue requirement information.

Q. PLEASE DESCRIBE SUPPLEMENTAL FILING REQUIREMENT (C)(10).

A. Supplemental Filing Requirement (C)(10) is a summary of the forecasting methods used by Duke Energy Ohio for the test period financial data.

Q. PLEASE DESCRIBE THE INFORMATION YOU PROVIDED FOR THE PREPARATION OF SCHEDULES C-11.1 THROUGH C-11.4.

A. I provided all of the forecasted information shown on Schedules C-11.1 through C-11.4.

IV. CONCLUSION

Q. WERE SUPPLEMENTAL FILING REQUIREMENTS S-1 AND S-2, SUPPLEMENTAL FILING REQUIREMENT (C)(10), AND THE INFORMATION YOU PROVIDED FOR SCHEDULES C-11.1 THROUGH C-11.4 PREPARED BY YOU OR UNDER YOUR SUPERVISION?

A. Yes.

Q. IS THE INFORMATION CONTAINED IN THOSE SCHEDULES AND SUPPLEMENTAL FILING REQUIREMENTS ACCURATE TO THE BEST OF YOUR KNOWLEDGE AND BELIEF?

A. Yes.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes.

DUKE ENERGY OHIO EXHIBIT______

BEFORE

THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Duke Energy Ohio, Inc., for an Increase in Electric Distribution Rates.	)))	Case No. 17-32-EL-AIR
In the Matter of the Application of Duke Energy Ohio, Inc., for Tariff Approval.	)))	Case No. 17-33-EL-ATA
In the Matter of the Application of Duke Energy Ohio, Inc., for Approval to Change Accounting Methods.	)))	Case No. 17-34-EL-AAM

DIRECT TESTIMONY OF

JAMES A. RIDDLE

ON BEHALF OF

DUKE ENERGY OHIO, INC.

PUBLIC VERSION

________	Management policies, practices, and organization
________	Operating income
________	Rate base
________	Allocations
________	Rate of return
________	Rates and tariffs
X	Other: Rate Design

March 16, 2017

TABLE OF CONTENTS

PAGE

I. INTRODUCTION **1**

II. FILING REQUIREMENTS **3**

III. RETAIL ELECTRIC RATE SCHEDULES AND RIDERS **5**

IV. RATE DESIGN **6**

V. TARIFF CHANGES **9**

VI. CONCLUSION **13**

Attachments:

JAR-1: Annualized Test Year Revenues at Proposed vs. Most Current Rates

JAR-2: Monthly Charges - Rate LED, LED Outdoor Lighting Electric Service.
(Redacted version)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is James A. Riddle, and my business address is 139 E. Fourth Street, Cincinnati, Ohio 45202.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by Duke Energy Business Services, LLC (DEBS), as Rates and Regulatory Strategy Manager, Pricing and Rates Options. DEBS provides various administrative and other services to Duke Energy Ohio, Inc., (Duke Energy Ohio or Company) and other affiliated companies of Duke Energy Corporation (Duke Energy).

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.

A. I received a B.S. degree in Agriculture from Wilmington College in Ohio in June 1979. In June 1981, I received a Master of Science degree in Agricultural Economics from the Ohio State University.

I worked as a Field Office Manager/Loan Officer for the Farm Credit System in Ohio from July 1981 to September 1985. In April 1986, I was hired by The Cincinnati Gas & Electric Company (CG&E), the predecessor to Duke Energy Ohio, as an Associate Economic Analyst. In that position, I was involved in all aspects of developing the Gas Long-Term Load Forecast, including data collection and organization, regression analysis, model building and solving, report writing, and dissemination of the forecast throughout CG&E.

In 1990, my duties expanded beyond the Gas Load Forecast to include aspects of the Electric Load Forecast. I became involved in electric end-use forecasting and performing Conditional Demand Analyses on the electric residential sector. In 1995, I was promoted to Supervisor, Load Forecasting in the Retail Market Analysis Department with responsibility for the preparation of CG&E's Gas and Electric Load Forecasts.

I was promoted to the position of Manager, Load Forecasting in 1996, where I was responsible for the preparation of the Gas and Electric Load Forecasts of the Cinergy Corp. (and later Duke Energy) operating company subsidiaries, including Duke Energy Carolinas, Inc., Duke Energy Ohio, Duke Energy Indiana, Inc., and Duke Energy Kentucky, Inc.

In September 2010, I accepted the position of Rates and Regulatory Strategy Manager, Pricing and Rates Options.

Q. PLEASE DESCRIBE YOUR DUTIES AS RATES AND REGULATORY STRATEGY MANAGER, PRICING AND RATES OPTIONS.

A. As Rates and Regulatory Strategy Manager, Pricing and Rates Options, I am responsible for rate design, tariff administration, billing, and revenue reporting issues in Ohio. I prepare filings to modify charges and terms in Duke Energy Ohio's retail tariffs and develop rates for new services. During major rate cases, I am responsible for the design of the new base rates. Additionally, I frequently work with Duke Energy Ohio's customer contact and billing personnel to answer rate-related questions and to apply the retail tariffs to specific situations. Occasionally, I meet with customers and Company representatives to explain rates or provide rate training. I also prepare reports that are required by regulatory authorities.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE PUBLIC UTILITIES COMMISSION OF OHIO?

A. Yes, I have previously submitted pre-filed testimony with the Public Utilities Commission of Ohio (Commission).

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THESE PROCEEDINGS?

A. I describe the Company's rate design and other proposed changes to the Company's retail electric rates, riders, and service regulations as filed in these proceedings. My testimony provides support for certain schedules contained in the Standard Filing Requirements, including Schedules E-1, E-2, E-2.1, E-3, E-3.1, E-4, E-4.1, and E-5. Additionally, I sponsor Supplemental Filing Requirement (C)(9), Attachment JAR-1, and Attachment JAR-2. I quantify the effect of these changes on Duke Energy Ohio's retail electric customers.

II. FILING REQUIREMENTS

Q. PLEASE DESCRIBE SCHEDULE E-1.

A. Schedule E-1 encompasses the proposed rate schedules in clean form.

Q. PLEASE DESCRIBE SCHEDULE E-2.

A. Schedule E-2 contains the Company's current rate schedules.

Q. PLEASE DESCRIBE SCHEDULE E-2.1.

A. Schedule E-2.1 contains the Company's proposed tariffs in scored and redlined forms.

Q. PLEASE DESCRIBE SCHEDULE E-3.

A. Schedule E-3 presents the rationales for the proposed changes. The sheet number of each respective current and proposed rate schedule within Schedules E-1 and E-2 is contained in the Data Reference section.

Q. PLEASE DESCRIBE SCHEDULE E-3.1.

A. Schedule E-3.1 presents the components and computation of the customer charge. This computation has been completed for the residential, small distribution, large distribution, primary distribution, and transmission service rates.

Q. PLEASE DESCRIBE SCHEDULE E-4.

A. Schedule E-4 is the required revenue summary schedule depicting revenues at the current rate level and at the proposed rate level. Sales figures and the associated revenues are brought forward from Schedule E-4.1. These summaries identify sales and total revenues by rate schedule and the percent of revenue each rate schedule contributes to total revenue. In addition, Schedule E-4 displays the amount and percent increase due to the proposed distribution base rates for each class of service, excluding all riders.

Q. HAVE YOU DEVELOPED ANOTHER VERSION OF SCHEDULE E-4 THAT INCLUDES ALL RIDERS?

A. Yes. Attachment JAR-1 is a replication of pages 1 and 2 of Schedule E-4, including all applicable riders, providing a comparison on a total-bill basis.

Q. PLEASE DESCRIBE SCHEDULE E-4.1.

A. Schedule E-4.1 is a series of analyses that develop the revenues shown on Schedule E-4. It shows billing determinants by rate schedule and customer class, appropriately blocked to comply with the Commission's Standard Filing Requirements. The billing determinants are based on eight months weather normalized actual and four months forecasted sales for the period. The summary information from Schedule E-4.1 is carried over to Schedule E-4.

Q. PLEASE DESCRIBE SCHEDULE E-4.3.

A. Schedule E-4.3 requires the submission of actual statistics. This schedule cannot be prepared now since the test year in these proceedings is the twelve months ending March 31, 2017. Schedule E-4.3 will be prepared as soon as practicable after actual data is available and will be filed according to the Commission's regulations.

Q. PLEASE DESCRIBE SCHEDULE E-5.

A. Schedule E-5 is a typical bill comparison that presents the effect of the proposed rates, showing the amount and percent increases for bills at various consumption levels.

Q. PLEASE DESCRIBE SUPPLEMENTAL FILING REQUIREMENT (C)(9).

A. Supplemental Filing Requirement (C)(9) consists of monthly sales by rate schedule consistent with Schedule C-2.1.

III. RETAIL ELECTRIC RATE SCHEDULES AND RIDERS

Q. WHAT ARE THE COMPANY'S MAJOR DISTRIBUTION RETAIL ELECTRIC RATE SCHEDULES?

A. The Company's major retail electric rate schedules include: Rate RS-Residential Service; Rate DM – Secondary Distribution Service-Small; Rate DS – Service at Secondary Distribution Voltage; Rate DP – Service at Primary Distribution

Voltage; and Rate TS – Service at Transmission Voltage. Together, these rate schedules comprise more than ninety-seven (97) percent of the Company's distribution retail electric revenue requirement.

IV. RATE DESIGN

Q. PLEASE DESCRIBE THE SPECIFIC METHOD USED TO DESIGN THE RATES.

A. I believe that the Company's current rate design has served Duke Energy Ohio customers well and is based on sound rate design principles. Therefore, with the exception of the residential rates, no structural changes in the design of the rates are being proposed in these proceedings. The revenue requirement was allocated to the customer charge and the demand/energy charge (block steps where applicable) of the rate based on the current rate design, maintaining the proportions between the various portions of the rate. The proposed residential rate increases the customer charge to fully recover the customer cost component of the revenue requirement, similar in characteristic to a straight-fixed variable (SFV) rate design.

Q. HAS A TARIFF FOR RATE RS BEEN PREPARED?

A. Yes. A customer charge and energy charge are used to meet the allocated revenue requirement. Pursuant to the August 21, 2013, Finding and Order in Case No. 10-3126-EL-UNC[1] in which the Commission instructed electric distribution utilities to apply the characteristics of a SFV rate design, the proposed customer charge is $22.77 per month, which reflects the monthly fixed costs associated with serving

[1] *In the Matter of Aligning Electric Distribution Utility Rate Structure with Ohio's Public Policies to Promote Competition, Energy Efficiency, and Distributed Generation,* Case No. 10-3126-EL-UNC, Finding and Order at pg.19 (August 21, 2013).

residential customers (see Schedule E-3.1). The remainder of the revenue requirement is satisfied in the energy charges of the rate, which, all else being equal, will show a reduction from current levels.

Q. PLEASE COMPARE THE PROPOSED RESIDENTIAL CUSTOMER CHARGE TO CURRENT FIXED CHARGES.

A. In addition to the Company's current customer charge of $6.00 per bill, there are two riders that are also billed on a fixed basis: Rider DR-IM, currently $6.28 per bill but adjusting to $4.84 on April 1, 2017;[2] and Rider DCI, currently 7.976% of base distribution charges. When DCI is applied to the $6.00 customer charge, it adds $0.48 in fixed charges. Therefore, current fixed charges are $11.32 ($6.00+$4.84+$0.48) compared to $22.77.

Q. WHAT IS THE OVERALL EFFECT OF THE PROPOSED RATE ON A RESIDENTIAL CUSTOMER USING 1,000 KWH PER MONTH?

A. A residential customer using 1,000 kWh per month will experience an increase of $1.15, or 0.96 percent on a total bill basis.

Q. ASSUMING THE COMMISSION APPROVES THE COMPANY'S PROPOSED RATE DESIGN FOR RESIDENTIAL CUSTOMERS, DOES THAT ELIMINATE THE NEED FOR THE DISTRIBUTION DECOUPLING RIDER?

A. No. The proposed residential rates, which more closely reflect the characteristics of a SFV rate design, will still leave a significant portion of the Company's cost recovery subject to volumetric charges. The Distribution Decoupling Rider (Rider

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[2] *In the Matter of the Application of Duke Energy Ohio, Inc., to Adjust Rider DR-IM for 2015 Grid Modernization Costs,* Case No. 16-1404-EL-RDR., Entry at pg. 3 (December 21, 2016).

DDR) is a mechanism that mitigates the revenue erosion experienced by the Company when customers lower their energy usage through energy efficiency measures. Consequently, the Company proposes continuation of Rider DDR.

Q. WILL ANY CHANGES BE NECESSARY TO RIDER DDR WHEN THE COMMISSION APPROVES NEW RATES IN THIS CASE?

A. Yes. Rider DDR requires the comparison of weather-adjusted distribution revenue to the base amount that was set in the Company's most recently approved rate case. When new rates are approved by the Commission in this case, the Rider DDR base amount will be updated to reflect the newly approved level of distribution revenue.

Q. HAS A TARIFF FOR RATE DM BEEN PREPARED?

A. Yes. To meet the allocated revenue requirement and maintain the current proportion of customer charge to the energy charges, the customer charge is $9.96 per bill and $19.92 per bill for single-phase and three-phase service, respectively.

Q. HAS A TARIFF FOR RATE DS BEEN PREPARED?

A. Yes. To meet the allocated revenue requirement and maintain the current proportion of customer charge to the demand charge, the proposed monthly customer charges for Rate DS are $25.31 for single-phase service and $50.64 for three-phase service, which compare to the current charges of $22.97 for single-phase and $49.95 for three-phase. The remainder of the revenue requirement was satisfied by modifying the respective kW charge.

Q. HAS A TARIFF FOR RATE DP BEEN PREPARED?

A. Yes. To meet the allocated revenue requirement and maintain the current proportion of customer charge to the demand charge, the proposed monthly customer charge for Rate DP is $247.62, compared to the current $229.92. The remainder of the revenue requirement was satisfied by modifying the respective kW charge.

Q. HAS A TARIFF FOR RATE TS BEEN PREPARED?

A. Yes. The Company is proposing a monthly customer charge of $200 and a kVA charge of $0.00.

Q. PLEASE DESCRIBE THE COMPANY'S RATE DESIGN OBJECTIVES FOR RATE SL – STREET LIGHTING SERVICE; RATE SE – STREET LIGHTING SERVICE, OVERHEAD EQUIVALENT; RATE OL – OUTDOOR LIGHTING SERVICE; AND RATE OL-E – OUTDOOR LIGHTING EQUIPMENT.

A. The rate design objective for these rate schedules, similar to the other rate classes, is to allocate the increased cost of service to the Distribution, Energy & Equipment charge and Pole Rates of the rate schedules.

V. TARIFF CHANGES

Q. DOES THE COMPANY PROPOSE ANY TEXT CHANGES IN ITS TARIFF SCHEDULES?

A. Yes. Duke Energy Ohio proposes the following text changes to its tariff schedules:

(1) Service Regulations – Section IV, Sheet No. 23, under paragraph (3) Installation and Maintenance: Language has been added stating that the Company is not responsible for performing wiring investigations on the customer's side of the point of delivery.

(2) Service Regulations – Section IV, Sheet No. 23, paragraph (6) Special Customer Services: This paragraph has been deleted.

(3) Service Regulations – Section VII, Sheet No. 26: This section has been renamed as "NON-PAYMENT - DISCONNECTION AND RECONNECTION" and duplicative language has been removed.

(4) Rate UOLS, Unmetered Outdoor Lighting Electric Service, Sheet No. 67: Modified the language to clarify that Rate UOLS applies only to energy usage for any street or outdoor pole-mounted system.

(5) Rate OL-E, Outdoor Lighting Equipment Installation, Sheet No. 68: Extended the maximum term of OL-E contracts from ten to twenty years.

(6) Rider NM-H, Net Metering Rider – Hospitals, Sheet No. 47: Added language stating that the Company will recover its costs of net metering through Rider UE-GEN.

(7) Rider NM, Net Metering Rider, Sheet No. 48: Added language stating that the Company will recover its costs of net metering through Rider UE-GEN and that the Company will provide excess generation credits only to Standard Service Offer customers, which credits will be calculated using only Rider RE.

Q. IS THE COMPANY PROPOSING ANY NEW RATE SCHEDULES IN THESE PROCEEDINGS?

A. Yes, the Company is proposing Rate LED, LED Outdoor Lighting Electric Service. Due to the prevalent desire of customers to employ LED lighting technology, this new rate provides the Company the opportunity to offer this service and recover its costs. The LED systems will be owned and maintained by the Company. The charges are based on costs and other relevant data obtained from Company internal sources.

Q. ARE THERE ANY MODIFICATIONS TO RATE LED AS SET FORTH IN THE SCHEDULE INCLUDED IN THE PRE-FILING NOTICE?

A. Yes. Subsequent to the filing of the pre-filing notice, Duke Energy Ohio realized that, through inadvertence, the appropriate charges were not reflected in the schedule. The schedule, therefore, must be amended to incorporate the appropriate charges. Attachment JAR-2 includes the updated LED charges, the red-line version of the schedule (as amended to include the updated charges), and the clean version of the schedule.

Q. IS THE COMPANY PROPOSING TO CANCEL AND WITHDRAW ANY RATE SCHEDULES IN THESE PROCEEDINGS?

A. Yes, the Company is proposing to cancel Rate TD due to the fact that there are only eighteen customers being served under the rate. The number of customers served under this rate has been static for a number of years, indicating a lack of interest among residential customers for this type of rate. Also, the Company cancelled a similar rate, Rate TD-13, in May 2016. Upon cancellation, the eighteen customers would be served under Rate RS.

Q. PLEASE BRIEFLY DESCRIBE ANY OTHER PROPOSED CHANGES TO THE COMPANY'S RATE SCHEDULES.

A. Duke Energy Ohio is proposing to increase the monthly charge for Rate DS and Rate DP customers under Rider LM – Load Management Rider, Sheet No. 76 from $7.50 to $8.27.

Additionally, under Sheet No. 92, Charge for Reconnection of Service, the Company proposes the following:

(1) Charges for reconnections that can be accomplished remotely will be $25.

(2) Charges for reconnections that cannot be accomplished remotely will be $75.

(3) The charge for combined reconnection of gas and electric service will be $88.

(4) The charge for reconnection at the pole will be $125.

(5) If the Company receives notice after 12:30 PM of a customer's desire for same-day reinstatement of service and if the reconnection cannot be performed during normal business hours, the after-hour charge for reconnection will be $100 (or $25 if reconnection at the meter is possible).

(6) The after-hour charge for reconnection at the pole will be $200.

All of the Company's rate schedules not previously discussed have been modified to produce the assigned revenue level from the cost of service study. Standard Filing Requirement Schedule E-4 details the assigned revenue for each of the Company's rate schedules and the revenue level produced by the final rate design.

VI. CONCLUSION

Q. HOW DOES THE COMPANY PROPOSE THAT ITS TARIFFS, INCLUDING THE PREVIOUSLY DISCUSSED RATES AND CHARGES, BE IMPLEMENTED?

A. Duke Energy Ohio proposes that the revised tariffs, including the rates and charges, be implemented in compliance with the Commission's order in these proceedings.

Q. WAS THE INFORMATION CONTAINED IN ATTACHMENT JAR-1 AND JAR-2, SCHEDULES E-1, E-2, E-2.1, E-3, E-3.1, E-4, E-4.1, E-5, AND SUPPLEMENTAL FILING REQUIREMENT (C)(9) EITHER PREPARED BY YOU, UNDER YOUR DIRECTION, OR UNDER YOUR SUPERVISION?

A. Yes.

Q. IS THE INFORMATION CONTAINED IN ATTACHMENT JAR-1 AND JAR-2, SCHEDULES E-1, E-2, E-2.1, E-3, E-3.1, E-4, E-4.1, E-5, AND SUPPLEMENTAL FILING REQUIREMENT (C)(9) ACCURATE TO THE BEST OF YOUR KNOWLEDGE AND BELIEF?

A. Yes.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes.

DUKE ENERGY OHIO
CASE NO. 17-0032-EL-AIR
PROPOSED
ANNUALIZED CLASS AND SCHEDULE REVENUE SUMMARY (1)
(ELECTRIC SERVICE)

DATA: __8__ MONTHS ACTUAL & __4__ MONTHS ESTIMATED
TYPE OF FILING: __X__ ORIGINAL _____ UPDATED _____ REVISED
WORK PAPER REFERENCE NO(S).:

SCHEDULE E-4
PAGE 1 OF 2
WITNESS:
J. A. RIDDLE

LINE NO.	RATE CODE (A)	CLASS / DESCRIPTION (B)	PROPOSED ANNUALIZED CUSTOMER BILLS (2) (C)	SALES (D)	PROPOSED RATES (E)	PROPOSED REVENUE (F)	% OF REVENUE TO TOTAL REVENUE (G)	PROPOSED REVENUE TOTAL (I)
				(KWH)	(¢/KWH)	($)	(%)	($)
		RESIDENTIAL SERVICE						
1	RS	RESIDENTIAL SERV	7,532,388	7,086,071,316	11.300668	800,773,416	97.86	800,773,416
2	ORH	OPTIONAL HEATING SERVICE	2,372	6,041,706	8.754658	528,931	0.06	528,931
3	TD	OPTIONAL TIME OF DAY	0	0	0	0	0.00	0
4	CUR	COMMON USE RESIDENTIAL SERVICE	169,920	85,996,776	12.314274	10,589,879	1.29	10,589,879
5	RS3P	RESIDENTIAL THREE-PHASE SERVICE	2,148	5,379,776	7.869235	423,347	0.05	423,347
6	RSLI	RESIDENTIAL SERVICE-LOW INCOME	79,135	61,399,210	9.789473	6,010,659	0.73	6,010,659
7	TOTAL RESIDENTIAL		7,785,963	7,244,888,785	11.295221	818,326,232	46.65	818,326,232
8		DISTRIBUTION VOLTAGE SERVICE						
9	DS	SEC DISTRIBUTION SERV	225,458	6,410,036,906	8.678768	556,312,223	70.42	556,312,223
10	DS RTP	SEC DISTRIBUTION SERV RTP	24	1,730,484	2.127324	36,813	0.00	36,813
11	GSFL	UNMTRED SMALL FIXED LOAD	4,464	29,179,225	9.340338	2,725,438	0.34	2,725,438
12	EH	ELEC SPACE HTG	4,434	61,371,005	9.439032	5,792,829	0.73	5,792,829
13	DM	SEC DIST SERV-SMALL	497,979	550,283,765	11.579781	63,721,652	8.07	63,721,652
14	DP	PRIM DIST VOLTAGE	3,227	2,141,317,150	7.525455	161,143,860	20.40	161,143,860
15	DP RTP	PRIM DIST VOLTAGE RTP	24	11,998,691	2.502598	300,279	0.04	300,279
16	SFL-ADPL	OPT UNMTRED SM FX LD ATTACH DIRECTLY PWR LINE	12	61,651	9.274891	5,718	0.00	5,718
17	TOTAL DISTRIBUTION		735,622	9,205,978,876	8.581801	790,038,813	45.04	790,038,813
18		TRANSMISSION VOLTAGE SERVICE						
19	TS	TRANSMISSION SERV	348	3,275,988,392	3.493149	114,435,170	99.99	114,435,170
20	TS RTP	TRANSMISSION SERV RTP	24	153,516,864	0.005081	7,800	0.01	7,800
21	TOTAL TRANSMISSION		372	3,429,505,256	3.337011	114,442,970	6.52	114,442,970
22		LIGHTING SERVICE						
23	SL	STREET LIGHTING	488,036	37,328,354	21.319526	7,958,228	50.58	7,958,228
24	TL	TRAFFIC LIGHTING	396,062	13,158,928	6.462361	850,377	5.40	850,377
25	OL	OUTDOOR LIGHTING	197,355	20,287,810	16.751612	3,398,535	21.60	3,398,535
26	NSU	NON STD STREET LIGHTING	20,460	954,028	18.294387	174,534	1.11	174,534
27	NSP	NON STD POL'S	23,856	1,317,264	30.558221	402,532	2.56	402,532
28	SC	S L - CUST OWNED	3,336	17,468,422	5.996437	1,047,483	6.66	1,047,483
29	SE	S L - OVERHEAD EQUIV	77,016	4,829,947	16.120266	778,600	4.95	778,600
30	UOLS	UNMETERED OUTDOOR LIGHTING	12,702	18,658,676	6.025385	1,124,257	7.15	1,124,257
31	TOTAL LIGHTING		1,218,823	114,003,429	13.801819	15,734,547	0.90	15,734,547
32		TOTAL RETAIL	9,740,780	19,994,376,346		1,738,542,561	99.11	1,738,542,561
33		OTHER MISCELLANEOUS REVENUE						
34	INTERDEPARTMENTAL		12	3,718,926	7.960847	296,058	1.89	296,058
35	BAD CHECK CHARGES		0	0	-	220,260	1.41	220,260
36	LATE PAYMENT CHARGES		0	0	-	0	0.00	0
37	RECONNECTION CHARGES		0	0	-	1,482,046	9.47	1,482,046
38	RENTS		0	0	-	8,724,514	55.74	8,724,514
39	POLE CONTACT RENTALS		0	0	-	2,272,615	14.52	2,272,615
40	INTERCOMPANY		0	0	-	0	0.00	0
41	SPECIAL CONTRACTS		24	359,127	5.185353	18,622	0.12	18,622
42	OTHER MISC		0	0	-	2,637,819	16.85	2,637,819
43	TOTAL MISC		36	4,078,053	383.809001	15,651,934	0.89	15,651,934
44	TOTAL COMPANY		9,740,816	19,998,454,399	8.771650	1,754,194,495	100.00	1,754,194,495

NOTE: DETAIL CONTAINED ON SCHEDULES E-4.1 PAGES 1 THROUGH 54.
(1) FOR THE TWELVE MONTHS ENDED MARCH 31, 2017
(2) THE NUMBER OF UNITS IS USED FOR DESIGNING LIGHTING RATES (NOT THE NUMBER OF BILLS).

DUKE ENERGY OHIO
CASE NO. 17-0032-EL-AIR
CURRENT
ANNUALIZED CLASS AND SCHEDULE REVENUE SUMMARY (1)
(ELECTRIC SERVICE)

DATA: _8_ MONTHS ACTUAL & _4_ MONTHS ESTIMATED
TYPE OF FILING: _X_ ORIGINAL ____ UPDATED ____ REVISED
WORK PAPER REFERENCE NO(S).:

SCHEDULE E-4
PAGE 2 OF 2
WITNESS:
J. A. RIDDLE

			CURRENT ANNUALIZED						
LINE NO.	RATE CODE (A)	CLASS / DESCRIPTION (B)	CUSTOMER BILLS (2) (C)	SALES (D)	MOST CURRENT RATES (J)	CURRENT ANNUALIZED REVENUE (K)	% OF REVENUE TO TOTAL REVENUE (L)	% INCREASE IN REVENUE (F-K / K) (N)	TOTAL REVENUE % INCREASE (O)
				(KWH)	(¢/KWH)	($)	(%)	(%)	(%)
		RESIDENTIAL SERVICE							
1	RS	RESIDENTIAL SERV	7,532,388	7,086,071,316	11.113609	787,518,278	97.98	1.7	1.7
2	ORH	OPTIONAL HEATING SERVICE	2,372	6,041,706	8.616750	520,599	0.06	1.6	1.6
3	TD	OPTIONAL TIME OF DAY	0	0	0	0	0.00	0.0	0
4	CUR	COMMON USE RESIDENTIAL SERVICE	169,920	85,996,776	11.081810	9,530,000	1.19	11.1	11.1
5	RS3P	RESIDENTIAL THREE-PHASE SERVICE	2,148	5,379,776	8.450188	454,601	0.06	(6.9)	(6.9)
6	RSLI	RESIDENTIAL SERVICE-LOW INCOME	79,135	61,399,210	9.302633	5,711,743	0.71	5.2	5.2
7		TOTAL RESIDENTIAL	7,785,963	7,244,888,785	11.093824	803,735,221	46.22	1.8	1.8
8		DISTRIBUTION VOLTAGE SERVICE							
9	DS	SEC DISTRIBUTION SERV	225,458	6,410,036,906	8.665286	555,448,062	70.36	0.2	0.2
10	DS RTP	SEC DISTRIBUTION SERV RTP	24	1,730,484	2.112357	36,554	0.00	0.7	0.7
11	GSFL	UNMTRED SMALL FIXED LOAD	4,464	29,179,225	9.265469	2,703,592	0.34	0.8	0.8
12	EH	ELEC SPACE HTG	4,434	61,371,005	9.314171	5,716,201	0.72	1.3	1.3
13	DM	SEC DIST SERV-SMALL	497,979	550,283,765	11.631472	64,006,102	8.11	(0.4)	(0.4)
14	DP	PRIM DIST VOLTAGE	3,227	2,141,317,150	7.529349	161,227,233	20.42	(0.1)	(0.1)
15	DP RTP	PRIM DIST VOLTAGE RTP	24	11,998,691	2.511607	301,360	0.04	0.7	(0.4)
16	SFL-ADPL	OPT UNMTRED SM FX LD ATTACH DIRECTLY PWR LINE	12	61,651	9.203278	5,674	0.00	0.8	0.8
17		TOTAL DISTRIBUTION	735,622	9,205,978,876	8.575349	789,444,777	45.40	0.1	0.1
18		TRANSMISSION VOLTAGE SERVICE							
19	TS	TRANSMISSION SERV	348	3,275,988,392	3.493149	114,435,170	99.99	0.0	-
20	TS RTP	TRANSMISSION SERV RTP	24	153,516,864	0.005081	7,800	0.01	0.0	-
21		TOTAL TRANSMISSION	372	3,429,505,256	3.337011	114,442,970	6.58	0.0	-
22		LIGHTING SERVICE							
23	SL	STREET LIGHTING	488,036	37,328,354	20.956890	7,822,862	50.42	1.7	1.7
24	TL	TRAFFIC LIGHTING	396,062	13,158,928	6.438260	847,206	5.46	0.4	0.4
25	OL	OUTDOOR LIGHTING	197,355	20,287,810	16.489387	3,345,335	21.56	1.6	1.6
26	NSU	NON STD STREET LIGHTING	20,460	954,028	17.989758	171,627	1.11	1.7	1.7
27	NSP	NON STD POL'S	23,856	1,317,264	29.974099	394,838	2.54	1.9	1.9
28	SC	S L - CUST OWNED	3,336	17,468,422	5.980682	1,044,731	6.73	0.3	0.3
29	SE	S L - OVERHEAD EQUIV	77,016	4,829,947	15.867966	766,414	4.94	1.6	1.6
30	UOLS	UNMETERED OUTDOOR LIGHTING	12,702	18,658,676	6.009858	1,121,360	7.23	0.3	0.3
31		TOTAL LIGHTING	1,218,823	114,003,429	13.608691	15,514,374	0.89	1.4	1.4
32		TOTAL RETAIL	9,740,780	19,994,376,346		1,723,137,342	99.10	0.9	0.9
33		OTHER MISCELLANEOUS REVENUE							
34	INTERDEPARTMENTAL		12	3,718,926	7.960847	296,058	1.89	0.0	0.0
35	BAD CHECK CHARGES		0	0	-	220,260	1.41	0.0	0.0
36	LATE PAYMENT CHARGES		0	0	-	0	0.00	0.0	0.0
37	RECONNECTION CHARGES		0	0	-	1,482,046	9.47	0.0	0.0
38	RENTS		0	0	-	8,724,514	55.74	0.0	0.0
39	POLE CONTACT RENTALS		0	0	-	2,272,615	14.52	0.0	0.0
40	INTERCOMPANY		0	0	-	0	0.00	0.0	0.0
41	SPECIAL CONTRACTS		24	359,127	5.185353	18,622	0.12	0.0	0.0
42	OTHER MISC		0	0	-	2,637,819	16.85	0.0	0.0
43		TOTAL MISC	36	4,078,053	383.81	15,651,934	0.90	0.0	0.0
44		TOTAL COMPANY	9,740,816	19,998,454,399	8.694618	1,738,789,276	100.00	0.9	0.9

NOTE: DETAIL CONTAINED ON SCHEDULES E-4.1 PAGES 1 THROUGH 54.
(1) FOR THE TWELVE MONTHS ENDED MARCH 31, 2017
(2) THE NUMBER OF UNITS IS USED FOR DESIGNING LIGHTING RATES (NOT THE NUMBER OF BILLS).

CONFIDENTIAL PROPRIETARY TRADE SECRET

DESCRIPTION	Total	Monthly Rate
50W Standard LED-BLACK	[redacted]	$7.23
70W Standard LED-BLACK	[redacted]	$7.21
110W Standard LED-BLACK	[redacted]	$8.18
150W Standard LED-BLACK	[redacted]	$10.83
220W Standard LED-BLACK	[redacted]	$12.28
280W Standard LED-BLACK	[redacted]	$15.11
50W Deluxe Acorn LED-BLACK	[redacted]	$21.07
50W Acorn LED-BLACK	[redacted]	$18.98
50W Mini Bell LED-BLACK	[redacted]	$17.90
70W Bell LED-BLACK	[redacted]	$22.80
50W Traditional LED-BLACK	[redacted]	$13.75
50W Open Traditional LED-BLACK	[redacted]	$13.75
50W Enterprise LED-BLACK	[redacted]	$18.50
70W LED Open Deluxe Acorn	[redacted]	$20.55
150W LED Teardrop	[redacted]	$27.59
50W LED Teardrop Pedestrian	[redacted]	$22.38
220W LED Shoebox	[redacted]	$19.11
MW-LIGHT LED 50W 4521 LUMENS STANDARD LED BLACK TYPE III 4000K	[redacted]	$7.23
MW-LIGHT LED 70W 6261 LUMENS STANDARD LED BLACK TYPE III 4000K	[redacted]	$7.21
MW-LIGHT LED 110W 9336 LUMENS STANDARD LED BLACK TYPE III 4000K	[redacted]	$8.18
MW-LIGHT LED 150W 12642 LUMENS STANDARD LED BLACK TYPE III 4000K	[redacted]	$10.83
MW-LIGHT LED 150W 13156 LUMENS STANDARD LED TYPE IV BLACK 4000K	[redacted]	$10.83
MW-LIGHT LED 150W 13156 LUMENS STANDARD LED TYPE IV BLACK 4000K	[redacted]	$10.83
MW-LIGHT LED 220W 18642 LUMENS STANDARD LED BLACK TYPE III 4000K	[redacted]	$12.28
MW-LIGHT LED 280W 24191 LUMENS STANDARD LED BLACK TYPE III 4000K	[redacted]	$15.11
MW-LIGHT LED 50W DELUXE ACORN BLACK TYPE III 4000K	[redacted]	$21.07
MW-LIGHT LED 70W OPEN DELUXE ACORN BLACK TYPE III 4000K	[redacted]	$20.55
MW-LIGHT LED 50W ACORN BLACK TYPE III 4000K	[redacted]	$18.98
MW-LIGHT LED 50W MINI BELL LED BLACK TYPE III 4000K MIDWEST	[redacted]	$17.90
MW-LIGHT LED 70W 5508 LUMENS SANIBELL BLACK TYPE III 4000K	[redacted]	$22.80
MW-LIGHT LED 50W TRADITIONAL BLACK TYPE III 4000K	[redacted]	$13.75
MW-LIGHT LED 50W OPEN TRADITIONAL BLACK TYPE III 4000K	[redacted]	$13.75
MW-LIGHT LED 50W ENTERPRISE BLACK TYPE III 4000K	[redacted]	$18.50
MW-LIGHT LED 150W LARGE TEARDROP BLACK TYPE III 4000K	[redacted]	$27.59
MW-LIGHT LED 50W TEARDROP PEDESTRIAN BLACK TYPE III 4000K	[redacted]	$22.38
MW-LIGHT LED 220W SHOEBOX BLACK TYPE IV 4000K	[redacted]	$19.11
150W Sanibel	[redacted]	$22.80
420W LED Shoebox	[redacted]	$28.51
50W Neighborhood	[redacted]	$5.88
50W Neighborhood with Lens	[redacted]	$6.13

DESCRIPTION	Total	Monthly Rate
12' C-Post Top- Anchor Base-Black	[redacted]	$15.91
25' C-Davit Bracket- Anchor Base-Black	[redacted]	$41.86
25' C-Boston Harbor Bracket- Anchor Base-Black	[redacted]	$42.32
12' E-AL - Anchor Base-Black	[redacted]	$15.91
35' AL-Side Mounted-Direct Buried Pole	[redacted]	$26.94
30' AL-Side Mounted-Anchor Base	[redacted]	$20.75
35' AL-Side Mounted-Anchor Base	[redacted]	$20.19
40' AL-Side Mounted-Anchor Base	[redacted]	$24.97
30' Class 7 Wood Pole	[redacted]	$9.87
35' Class 5 Wood Pole	[redacted]	$10.73
40' Class 4 Wood Pole	[redacted]	$16.16
45' Class 4 Wood Pole	[redacted]	$16.75
20' Galleria Anchor Based Pole	[redacted]	$14.24
30' Galleria Anchor Based Pole	[redacted]	$16.83
35' Galleria Anchor Based Pole	[redacted]	$48.42
MW-Light Pole-12' MH- Style A-Aluminum-Anchor Base-Top Tenon-Black	[redacted]	$9.65
MW-Light Pole-Post Top-12' MH- Style A-Alum-Direct Buried-Top Tenon-Black	[redacted]	$8.26
Light Pole-15' MH-Style A-Aluminum-Anchor Base-Top Tenon-Black	[redacted]	$9.93
Light Pole-15' MH-Style A-Aluminum-Direct Buried-Top Tenon-Black	[redacted]	$8.59
Light Pole-20' MH-Style A-Aluminum-Anchor Base-Top Tenon-Black	[redacted]	$10.41
Light Pole-20' MH-Style A-Aluminum-Direct Buried-Top Tenon-Black	[redacted]	$15.95
Light Pole-25' MH-Style A-Aluminum-Anchor Base-Top Tenon-Black	[redacted]	$12.33
Light Pole-25' MH-Style A-Aluminum-Direct Buried-Top Tenon-Black	[redacted]	$17.78
Light Pole-30' MH-Style A-Aluminum-Anchor Base-Top Tenon-Black	[redacted]	$14.59
Light Pole-30' MH-Style A-Aluminum-Direct Buried-Top Tenon-Black	[redacted]	$19.79
Light Pole-35' MH-Style A-Aluminum-Anchor Base-Top Tenon-Black	[redacted]	$16.84
Light Pole-35' MH-Style A-Aluminum-Direct Buried-Top Tenon-Black	[redacted]	$21.38
MW-Light Pole-12' MH- Style B Aluminum Anchor Base-Top Tenon Black Pri	[redacted]	$11.75
MW-Light Pole-12' MH-Style C-Post Top-Alum-Anchor Base-TT-Black Pri	[redacted]	$15.91
MW-LT Pole-16' MH-Style C-Davit Bracket-Alum-Anchor Base-TT-Black	[redacted]	$21.30
MW-Light Pole-25' MH-Style C-Davit Bracket-Alum-Anchor Base-TT-Black Pri	[redacted]	$41.86
MW-LT Pole-16' MH-Style C-Boston Harbor Bracket-AL-AB-TT-Black Pri	[redacted]	$17.07
MW-LT Pole-25' MH-Style C-Boston Harbor Bracket-AL-AB-TT-Black Pri	[redacted]	$42.32
MW-LT Pole 12 Ft MH Style D Alum Breakaway Anchor Base TT Black Pri	[redacted]	$15.75
MW-Light Pole-12' MH-Style E-Alum-Anchor Base-Top Tenon-Black	[redacted]	$15.91
MW-Light Pole-12' MH-Style F-Alum-Anchor Base-Top Tenon-Black Prie	[redacted]	$17.05
MW-15210-Galleria Anchor Base-20FT Bronze Steel-OLE	[redacted]	$14.24
MW-15210-Galleria Anchor Base-30FT Bronze Steel-OLE	[redacted]	$16.83
MW-15210-Galleria Anchor Base-35FT Bronze Steel-OLE	[redacted]	$48.42
MW-15310-35FT MH Aluminum Direct Embedded Pole-OLE	[redacted]	$26.94
MW-15320-30FT Mounting Height Aluminum Achor Base Pole-OLE	[redacted]	$20.75
MW-15320-35FT Mounting Height Aluminum Achor Base Pole-OLE	[redacted]	$20.19
MW-15320-40FT Mounting Height Aluminum Achor Base Pole-OLE	[redacted]	$24.97
MW-POLE-30-7	[redacted]	$9.87
MW-POLE-35-5	[redacted]	$10.73
MW-POLE-40-4	[redacted]	$16.16
MW-POLE-45-4	[redacted]	$16.75

RATE LED

P.U.C.O Electric Sheet No. 19
Original Sheet 69

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RATE LED

LED OUTDOOR LIGHTING ELECTRIC SERVICE

APPLICABILITY

To any customer for the sole purpose of lighting roadways or other outdoor land use areas with LED technology fixtures; served from Company fixtures of the LED type available under this rate schedule. Service hereunder is provided for the sole and exclusive benefit of the customer, and nothing herein or in the contract executed hereunder is intended to benefit any third party or to impose any obligation on the Company to any such third party.

Service under this tariff schedule shall require a written agreement between the customer and the Company specifying the calculated lighting kilowatt-hours. The LED System shall comply with the connection requirements in the Company's Electric Service Regulations, Section III, Customer's and Company's Installations.

For customers taking service under any or all of the provisions of this tariff schedule, this same schedule shall constitute the Company's Standard Service Offer.

CHARACTER OF SERVICE

Automatically controlled lighting service (i.e., photoelectric cell, or digitally controlled node); alternating current, 60 cycle, single phase, at the Company's standard voltage available. This service may include "smart" lighting technologies, at the sole discretion of the Company.

The Company will provide unmetered electric service based on the calculated annual energy usage for each luminaire's lamp wattage plus ballast usage (impact wattage). The LED System kilowatt-hour usage shall be determined by the number of lamps and other LED System particulars as defined in the written agreement between the customer and Company. The monthly kilowatt-hour amount will be billed at the rate contained in the NET MONTHLY BILL section below.

NET MONTHLY BILL

Computed in accordance with the following charge:

1. Base Rate Distribution $0.006531 per kWh

NET MONTHLY BILL (Contd.)

2. Applicable Riders
   The following riders are applicable pursuant to the specific terms contained within each rider:
   Sheet No. 83, Rider OET, Ohio Excise Tax Rider
   Sheet No. 86, Rider USR, Universal Service Fund Rider
   Sheet No. 88, Rider UE-GEN, Uncollectible Expense – Electric Generation Rider
   Sheet No. 89, Rider BTR, Base Transmission Rider
   Sheet No. 97, Rider RTO, Regional Transmission Organization Rider
   Sheet No. 105, Rider DR-ECF, Economic Competitiveness Fund Rider
   Sheet No. 108, Rider UE-ED, Uncollectible Expense – Electric Distribution Rider
   Sheet No. 110, Rider AER-R, Alternative Energy Recovery Rider
   Sheet No. 111, Rider RC, Retail Capacity Rider
   Sheet No. 112, Rider RE, Retail Energy Rider
   Sheet No. 113, Rider ESSC, Electric Security Stabilization Charge Rider
   Sheet No. 115, Rider SCR, Supplier Cost Reconciliation Rider

3. Monthly Maintenance, Fixture, and Pole Charges

I. Fixtures:				PER UNIT PER MONTH		
BILLING TYPE	DESCRIPTION	INITIAL LUMENS OUTPUT	LAMP WATTAGE	kWh	FIXTURE	MAINTENANCE
LF-LED-50W-SL-BK-MW	50W Standard LED-BLACK	4,521	50	17.3	$ 7.23	$ 4.38
LF-LED-70W-SL-BK-MW	70W Standard LED-BLACK	6,261	70	24.3	$ 7.21	$ 4.38
LF-LED-110W-SL-BK-MW	110W Standard LED-BLACK	9,336	110	38.1	$ 8.18	$ 4.38
LF-LED-150W-SL-BK-MW	150W Standard LED-BLACK	12,642	150	52.0	$ 10.83	$ 4.38
LF-LED-220W-SL-BK-MW	220W Standard LED-BLACK	18,641	220	76.3	$ 12.28	$ 5.34
LF-LED-280W-SL-BK-MW	280W Standard LED-BLACK	24,191	280	97.1	$ 15.11	$ 5.34
LF-LED-50W-DA-BK-MW	50W Deluxe Acorn LED-BLACK	5,147	50	17.3	$ 21.07	$ 4.38
LF-LED-50W-AC-BK-MW	50W Acorn LED-BLACK	5,147	50	17.3	$ 18.98	$ 4.38
LF-LED-50W-MB-BK-MW	50W Mini Bell LED-BLACK	4,500	50	17.3	$ 17.90	$ 4.38
LF-LED-70W-BE-BK-MW	70W Bell LED-BLACK	5,508	70	24.3	$ 22.80	$ 4.38
LF-LED-50W-TR-BK-MW	50W Traditional LED-BLACK	3,230	50	17.3	$ 13.75	$ 4.38
LF-LED-50W-OT-BK-MW	50W Open Traditional LED-BLACK	3,230	50	17.3	$ 13.75	$ 4.38
LF-LED-50W-EN-BK-MW	50W Enterprise LED-BLACK	3,880	50	17.3	$ 18.50	$ 4.38
LF-LED-70W-ODA-BK-MW	70W LED Open Deluxe Acorn	6,500	70	24.3	$ 20.55	$ 4.38
LF-LED-150W-TD-BK-MW	150W LED Teardrop	12,500	150	52.0	$ 27.59	$ 4.38
LF-LED-50W-TDP-BK-MW	50W LED Teardrop Pedestrian	4,500	50	17.3	$ 22.38	$ 4.38
220W LED SHOEBOX	220W LED Shoebox	18,500	220	76.3	$ 19.11	$ 5.34

LF-LED-50W-SL-BK-MW	LED 50W 4521 LUMENS STANDARD LED BLACK TYPE III 4000K	4,521	50	17.3	$ 7.23	$ 4.38
LF-LED-50W-SL-BK-MW	LED 50W 4521 LUMENS STANDARD LED BLACK TYPE III 4000K	4,521	50	17.3	$ 7.23	$ 4.38
LF-LED-70W-SL-BK-MW	LED 70W 6261 LUMENS STANDARD LED BLACK TYPE III 4000K	6,261	70	24.3	$ 7.21	$ 4.38
LF-LED-70W-SL-BK-MW	LED 70W 6261 LUMENS STANDARD LED BLACK TYPE III 4000K	6,261	70	24.3	$ 7.21	$ 4.38
LF-LED-110W-SL-BK-MW	LED 110W 9336 LUMENS STANDARD LED BLACK TYPE III 4000K	9,336	110	38.1	$ 8.18	$ 4.38
LF-LED-110W-SL-BK-MW	LED 110W 9336 LUMENS STANDARD LED BLACK TYPE III 4000K	9,336	110	38.1	$ 8.18	$ 4.38
LF-LED-150W-SL-BK-MW	LED 150W 12642 LUMENS STANDARD LED BLACK TYPE III 4000K	12,642	150	52.0	$ 10.83	$ 4.38
LF-LED-150W-SL-BK-MW	LED 150W 12642 LUMENS STANDARD LED BLACK TYPE III 4000K	12,642	150	52.0	$ 10.83	$ 4.38
LF-LED-150W-SL-IV-BK-MW	LED 150W 13156 LUMENS STANDARD LED TYPE IV BLACK 4000K	13,156	150	52.0	$ 10.83	$ 4.38
LF-LED-150W-SL-IV-BK-MW	LED 150W 13156 LUMENS STANDARD LED TYPE IV BLACK 4000K	13,156	150	52.0	$ 10.83	$ 4.38
LF-LED-220W-SL-BK-MW	LED 220W 18642 LUMENS STANDARD LED BLACK TYPE III 4000K	18,642	220	76.3	$ 12.28	$ 5.34
LF-LED-220W-SL-BK-MW	LED 220W 18642 LUMENS STANDARD LED BLACK TYPE III 4000K	18,642	220	76.3	$ 12.28	$ 5.34
LF-LED-280W-SL-BK-MW	LED 280W 24191 LUMENS STANDARD LED BLACK TYPE III 4000K	24,191	280	97.1	$ 15.11	$ 5.34
LF-LED-280W-SL-BK-MW	LED 280W 24191 LUMENS STANDARD LED BLACK TYPE III 4000K	24,191	280	97.1	$ 15.11	$ 5.34
LF-LED-50W-DA-BK-MW	LED 50W DELUXE ACORN BLACK TYPE III 4000K	5,147	50	17.3	$ 21.07	$ 4.38
LF-LED-70W-ODA-BK-MW	LED 70W OPEN DELUXE ACORN BLACK TYPE III 4000K	6,500	70	24.3	$ 20.55	$ 4.38
LF-LED-50W-AC-BK-MW	LED 50W ACORN BLACK TYPE III 4000K	5,147	50	17.3	$ 18.98	$ 4.38
LF-LED-50W-MB-BK-MW	LED 50W MINI BELL LED BLACK TYPE III 4000K MIDWEST	4,500	50	17.3	$ 17.90	$ 4.38
LF-LED-70W-BE-BK-MW	LED 70W 5508 LUMENS SANIBELL BLACK TYPE III 4000K	5,508	70	24.3	$ 22.80	$ 4.38
LF-LED-50W-TR-BK-MW	LED 50W TRADITIONAL BLACK TYPE III 4000K	3,303	50	17.3	$ 13.75	$ 4.38
LF-LED-50W-OT-BK-MW	LED 50W OPEN TRADITIONAL BLACK TYPE III 4000K	3,230	50	17.3	$ 13.75	$ 4.38
LF-LED-50W-EN-BK-MW	LED 50W ENTERPRISE BLACK TYPE III 4000K	3,880	50	17.3	$ 18.50	$ 4.38
LF-LED-150W-TD-BK-MW	LED 150W LARGE TEARDROP BLACK TYPE III 4000K	12,500	150	52.0	$ 27.59	$ 4.38
LF-LED-50W-TDP-BK-MW	LED 50W TEARDROP PEDESTRIAN BLACK TYPE III 4000K	4,500	50	17.3	$ 22.38	$ 4.38
LF-LED-220W-SB-BK-MW	LED 220W SHOEBOX BLACK TYPE IV 4000K	18,500	220	76.3	$ 19.11	$ 5.34
LF-LED-150W-BE-BK-MW	150W Sanibel	39,000	150	52.0	$ 22.80	$ 4.38
LF-LED-420W-SB-BK-MW	420W LED Shoebox	39,078	420	145.6	$ 28.51	$ 5.34
LF-LED-50W-NB-GY-MW	50W Neighborhood	5,000	50	17.3	$ 5.88	$ 4.38
LF-LED-50W-NBL-GY-MW	50W Neighborhood with Lens	5,000	50	17.3	$ 6.13	$ 4.38

Duke Energy Ohio
139 East Fourth Street
Cincinnati, Ohio 45202

P.U.C.O. Electric No. 19
Original Sheet No. 69
Page 4 of 7

II. POLES BILLING TYPE	DESCRIPTION	CHARGE PER UNIT PER MONTH
LP-12-C-PT-AL-AB-TT-BK-MW	12' C-Post Top- Anchor Base-Black	$ 15.91
LP-25-C-DV-AL-AB-TT-BK-MW	25' C-Davit Bracket- Anchor Base-Black	$ 41.86
LP-25-C-BH-AL-AB-TT-BK-MW	25' C-Boston Harbor Bracket- Anchor Base-Black	$ 42.32
LP-12-E-AL-AB-TT-BK-MW	12' E-AL - Anchor Base-Black	$ 15.91
15310-40FTALEMB-OLE	35' AL-Side Mounted-Direct Buried Pole	$ 26.94
15320-30FTALAB-OLE	30' AL-Side Mounted-Anchor Base	$ 20.75
15320-35FTALAB-OLE	35' AL-Side Mounted-Anchor Base	$ 20.19
15320-40FTALAB-OLE	40' AL-Side Mounted-Anchor Base	$ 24.97
POLE-30-7	30' Class 7 Wood Pole	$ 9.87
POLE-35-5	35' Class 5 Wood Pole	$ 10.73
POLE-40-4	40' Class 4 Wood Pole	$ 16.16
POLE-45-4	45' Class 4 Wood Pole	$ 16.75
15210-20BRZSTL-OLE	20' Galleria Anchor Based Pole	$ 14.24
15210-30BRZSTL-OLE	30' Galleria Anchor Based Pole	$ 16.83
15210-35BRZSTL-OLE	35' Galleria Anchor Based Pole	$ 48.42
LP-12-A-AL-AB-TT-BK-MW	MW-Light Pole-12' MH- Style A-Aluminum-Anchor Base-Top Tenon-Black	$ 9.65
LP-12-A-AL-DB-TT-BK-MW	MW-Light Pole-Post Top-12' MH- Style A-Alum-Direct Buried-Top Tenon-Black	$ 8.26
LP-15-A-AL-AB-TT-BK-MW	Light Pole-15' MH-Style A-Aluminum-Anchor Base-Top Tenon-Black	$ 9.93
LP-15-A-AL-DB-TT-BK-MW	Light Pole-15' MH-Style A-Aluminum-Direct Buried-Top Tenon-Black	$ 8.59
LP-20-A-AL-AB-TT-BK-MW	Light Pole-20' MH-Style A-Aluminum-Anchor Base-Top Tenon-Black	$ 10.41
LP-20-A-AL-DB-TT-BK-MW	Light Pole-20' MH-Style A-Aluminum-Direct Buried-Top Tenon-Black	$ 15.95
LP-25-A-AL-AB-TT-BK-MW	Light Pole-25' MH-Style A-Aluminum-Anchor Base-Top Tenon-Black	$ 12.33
LP-25-A-AL-DB-TT-BK-MW	Light Pole-25' MH-Style A-Aluminum-Direct Buried-Top Tenon-Black	$ 17.78
LP-30-A-AL-AB-TT-BK-MW	Light Pole-30' MH-Style A-Aluminum-Anchor Base-Top Tenon-Black	$ 14.59
LP-30-A-AL-DB-TT-BK-MW	Light Pole-30' MH-Style A-Aluminum-Direct Buried-Top Tenon-Black	$ 19.79
LP-35-A-AL-AB-TT-BK-MW	Light Pole-35' MH-Style A-Aluminum-Anchor Base-Top Tenon-Black	$ 16.84
LP-35-A-AL-DB-TT-BK-MW	Light Pole-35' MH-Style A-Aluminum-Direct Buried-Top Tenon-Black	$ 21.38
LP-12-B-AL-AB-TT-GN-MW	MW-Light Pole-12' MH- Style B Aluminum Anchor Base-Top Tenon Black Pri	$ 11.75
LP-12-C-PT-AL-AB-TT-BK-MW	MW-Light Pole-12' MH-Style C-Post Top-Alum-Anchor Base-TT-Black Pri	$ 15.91
LP-16-C-DV-AL-AB-TT-GN-MW	MW-LT Pole-16' MH-Style C-Davit Bracket-Alum-Anchor Base-TT-Black	$ 21.30
LP-25-C-DV-AL-AB-TT-BK-MW	MW-Light Pole-25' MH-Style C-Davit Bracket-Alum-Anchor Base-TT-Black Pri	$ 41.86
LP-16-C-BH-AL-AB-TT-GN-MW	MW-LT Pole-16' MH-Style C-Boston Harbor Bracket-AL-AB-TT-Black Pri	$ 17.07

Filed pursuant to an Order dated May ____ in Case No. 17-0032-EL-AIR before the Utilities Commission of Ohio.

Issued:

Effective:

Issued by James P. Henning, President

LP-25-C-BH-AL-AB-TT-BK-MW	MW-LT Pole-25' MH-Style C-Boston Harbor Bracket-AL-AB-TT-Black Pri	$ 42.32
LP-12-D-AL-AB-TT-GN-MW	MW-LT Pole 12 Ft MH Style D Alum Breakaway Anchor Base TT Black Pri	$ 15.75
LP-12-E-AL-AB-TT-BK-MW	MW-Light Pole-12' MH-Style E-Alum-Anchor Base-Top Tenon-Black	$ 15.91
LP-12-F-AL-AB-TT-GN-MW	MW-Light Pole-12' MH-Style F-Alum-Anchor Base-Top Tenon-Black Prie	$ 17.05
15210-20BRZSTL-OLE	MW-15210-Galleria Anchor Base-20FT Bronze Steel-OLE	$ 14.24
15210-30BRZSTL-OLE	MW-15210-Galleria Anchor Base-30FT Bronze Steel-OLE	$ 16.83
15210-35BRZSTL-OLE	MW-15210-Galleria Anchor Base-35FT Bronze Steel-OLE	$ 48.42
15310-40FTALEMB-OLE	MW-15310-35FT MH Aluminum Direct Embedded Pole-OLE	$ 26.94
15320-30FTALAB-OLE	MW-15320-30FT Mounting Height Aluminum Achor Base Pole-OLE	$ 20.75
15320-35FTALAB-OLE	MW-15320-35FT Mounting Height Aluminum Achor Base Pole-OLE	$ 20.19
15320-40FTALAB-OLE	MW-15320-40FT Mounting Height Aluminum Achor Base Pole-OLE	$ 24.97
POLE-30-7	MW-POLE-30-7	$ 9.87
POLE-35-5	MW-POLE-35-5	$ 10.73
POLE-40-4	MW-POLE-40-4	$ 16.16
POLE-45-4	MW-POLE-45-4	$ 16.75

LATE PAYMENT CHARGE

Payment of the total amount due must be received in the Company's office by the due date shown on the bill. When not so paid, an additional amount equal to one and one-half percent (1.5%) of the unpaid balance is due and payable. The late payment charge is not applicable to unpaid account balances for services received from a Certified Supplier.

OWNERSHIP OF SERVICE LINES

Company will provide, install, own, operate and maintain the necessary facilities for furnishing electric service to the System defined in the agreement. If the customer requires the installation of a System at a location which requires the extension, relocation, or rearrangement of the Company's distribution system, the customer shall, in addition to the monthly charge, pay the Company on a time and material basis, plus overhead charges, the cost of such extension, relocation, or rearrangement, unless in the judgment of the Company no charge should be made. An estimate of the cost will be submitted for approval before work is carried out.

The Company shall erect the service lines necessary to supply electric energy to the System within the limits of the streets and highways or on property as mutually agreed upon by the Company and the customer. The customer shall assist the Company, if necessary, in obtaining adequate written easements covering permission to install and maintain any service lines required to serve the System.

The Company shall not be required to pay for obtaining permission to trim or re-trim trees where such trees interfere with lighting output or with service lines or wires of the Company used for supplying electric energy to the System. The customer shall assist the Company, if necessary, in obtaining permission to trim trees where the Company is unable to obtain such permission through its own best efforts.

TERMS OF SERVICE:

Service under this rate schedule shall be for a minimum initial term of ten (10) years from the commencement of service and shall continue thereafter until terminated by either party by written notice sixty (60) days or to termination. Upon early termination of service under this schedule, the customer shall pay an amount equal to the remaining monthly lease amount for the term of contract, applicable Customer Charges and removal cost of the facilities.

Special Provisions:

1. The customer shall execute a contract on the Company's standard filed contract form for service under this rate schedule.
2. Where the Company provides a LED fixture or pole type other than those listed above, the monthly charges, as applicable shall be computed as follows:

   I. Fixture
      a. Fixture Charge: Based on the Company's average installed cost including overhead/loadings, applicable property tax, applicable income tax, depreciation and rate of return.
      b. Maintenance Charge: Based on the Company's average cost of performing maintenance on lighting equipment.

   II. Pole
      a. Pole Charge: Based on the Company's average installed cost including overhead/loadings, applicable property tax, applicable income tax, depreciation and rate of return.

3. The customer shall be responsible for the cost incurred to repair or replace any fixture or pole which has been willfully damaged. The Company shall not be required to make such repair or replacement or to payment by the customer for damage.

4. kWh consumption for Company-owned fixtures shall be estimated in lieu of installing meters. Monthly kWh estimates will be made using the following formula:
   kWh = Unit Wattage x (4160 hours per year / 12 months) / 1,000

5. kWh consumption for customer-owned fixtures shall be metered. Installation of customer-owned lighting facilities shall be provided for by the customer.

6. No Pole Charge shall be applicable for a fixture installed on a company-owned pole which is utilized for other general electrical distribution purposes.

7. The Company will repair or replace malfunctioning lighting fixtures maintained by the Company

8. For a fixture type restricted to existing installations and requiring major renovation or replacement, the fixture shall be replaced by an available similar non-restricted LED fixture of the customer's choosing and the customer shall commence being billed at its appropriate rate.

9. The customer will be responsible for trimming trees and other vegetation that obstruct the light output from fixture(s) or maintenance access to the facilities.

10. All new leased LED lighting shall be installed on poles owned by the Company.

11. Alterations to leased LED lighting facilities requested by the customer after date of installation (i.e. redirect, install shields, etc.), will be billed to the customer in accordance with the Company's policy.

12. Service for street or area lighting is normally provided from existing distribution facilities. Where suitable distribution facilities do not exist, it will be the customer's responsibility to pay for necessary additional facilities.

13. For available LEDs, the customer may opt to make an initial, one-time payment of 50% of the installed cost of fixtures rated greater than 200 Watts and/or poles other than standard wood poles, to reduce the Company's installed cost, therefore reducing their monthly rental rates for such fixtures and poles. If a customer chooses this option, the monthly fixture and/or pole charge shall be computed as the reduced installed cost times the corresponding monthly percentage in 2.I.(a) and/or 2.II above.

SERVICE REGULATIONS

The supplying of, and billing for, service and all conditions applying thereto, are subject to the jurisdiction of the Utilities Commission of Ohio and to the Company's Service Regulations currently in effect, as filed with the Utilities Commission of Ohio.

RATE LED

P.U.C.O Electric Sheet No. 19
Original Sheet 69

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RATE LED

LED OUTDOOR LIGHTING ELECTRIC SERVICE

APPLICABILITY

To any customer for the sole purpose of lighting roadways or other outdoor land use areas with LED technology fixtures; served from Company fixtures of the LED type available under this rate schedule. Service hereunder is provided for the sole and exclusive benefit of the customer, and nothing herein or in the contract executed hereunder is intended to benefit any third party or to impose any obligation on the Company to any such third party.

Service under this tariff schedule shall require a written agreement between the customer and the Company specifying the calculated lighting kilowatt-hours. The LED System shall comply with the connection requirements in the Company's Electric Service Regulations, Section III, Customer's and Company's Installations.

For customers taking service under any or all of the provisions of this tariff schedule, this same schedule shall constitute the Company's Standard Service Offer.

CHARACTER OF SERVICE

Automatically controlled lighting service (i.e., photoelectric cell, or digitally controlled node); alternating current, 60 cycle, single phase, at the Company's standard voltage available. This service may include "smart" lighting technologies, at the sole discretion of the Company.

The Company will provide unmetered electric service based on the calculated annual energy usage for each luminaire's lamp wattage plus ballast usage (impact wattage). The LED System kilowatt-hour usage shall be determined by the number of lamps and other LED System particulars as defined in the written agreement between the customer and Company. The monthly kilowatt-hour amount will be billed at the rate contained in the NET MONTHLY BILL section below.

NET MONTHLY BILL

Computed in accordance with the following charge:

1. Base Rate Distribution $0.006531 per kWh

Duke Energy Ohio
139 East Fourth Street
Cincinnati, Ohio 45202

P.U.C.O. Electric No. 19
Original Sheet No. 69
Page 2 of 7

NET MONTHLY BILL (Contd.)

2. Applicable Riders
   The following riders are applicable pursuant to the specific terms contained within each rider:
   Sheet No. 83, Rider OET, Ohio Excise Tax Rider
   Sheet No. 86, Rider USR, Universal Service Fund Rider
   Sheet No. 88, Rider UE-GEN, Uncollectible Expense – Electric Generation Rider
   Sheet No. 89, Rider BTR, Base Transmission Rider
   Sheet No. 97, Rider RTO, Regional Transmission Organization Rider
   Sheet No. 105, Rider DR-ECF, Economic Competitiveness Fund Rider
   Sheet No. 108, Rider UE-ED, Uncollectible Expense – Electric Distribution Rider
   Sheet No. 110, Rider AER-R, Alternative Energy Recovery Rider
   Sheet No. 111, Rider RC, Retail Capacity Rider
   Sheet No. 112, Rider RE, Retail Energy Rider
   Sheet No. 113, Rider ESSC, Electric Security Stabilization Charge Rider
   Sheet No. 115, Rider SCR, Supplier Cost Reconciliation Rider

3. Monthly Maintenance, Fixture, and Pole Charges

I. Fixtures:				PER UNIT PER MONTH		
BILLING TYPE	**DESCRIPTION**	**INITIAL LUMENS OUTPUT**	**LAMP WATTAGE**	**kWh**	**FIXTURE**	**MAINTENANCE**
LF-LED-50W-SL-BK-MW	50W Standard LED-BLACK	4,521	50	17.3	$ 7.23 ~~$ 5.81~~	$ 4.38
LF-LED-70W-SL-BK-MW	70W Standard LED-BLACK	6,261	70	24.3	$ 7.21 ~~$ 5.79~~	$ 4.38
LF-LED-110W-SL-BK-MW	110W Standard LED-BLACK	9,336	110	38.1	$ 8.18 ~~$ 6.61~~	$ 4.38
LF-LED-150W-SL-BK-MW	150W Standard LED-BLACK	12,642	150	52.0	$ 10.83 ~~$ 8.83~~	$ 4.38
LF-LED-220W-SL-BK-MW	220W Standard LED-BLACK	18,641	220	76.3	$ 12.28 ~~$ 10.05~~	$ 5.34
LF-LED-280W-SL-BK-MW	280W Standard LED-BLACK	24,191	280	97.1	$ 15.11 ~~$ 12.42~~	$ 5.34
LF-LED-50W-DA-BK-MW	50W Deluxe Acorn LED-BLACK	5,147	50	17.3	$ 21.07 ~~$ 17.41~~	$ 4.38
LF-LED-50W-AC-BK-MW	50W Acorn LED-BLACK	5,147	50	17.3	$ 18.98 ~~$ 15.67~~	$ 4.38
LF-LED-50W-MB-BK-MW	50W Mini Bell LED-BLACK	4,500	50	17.3	$ 17.90 ~~$ 14.76~~	$ 4.38
LF-LED-70W-BE-BK-MW	70W Bell LED-BLACK	5,508	70	24.3	$ 22.80 ~~$ 18.86~~	$ 4.38
LF-LED-50W-TR-BK-MW	50W Traditional LED-BLACK	3,230	50	17.3	$ 13.75 ~~$ 11.28~~	$ 4.38
LF-LED-50W-OT-BK-MW	50W Open Traditional LED-BLACK	3,230	50	17.3	$ 13.75 ~~$ 11.28~~	$ 4.38
LF-LED-50W-EN-BK-MW	50W Enterprise LED-BLACK	3,880	50	17.3	$ 18.50 ~~$ 15.26~~	$ 4.38
LF-LED-70W-ODA-BK-MW	70W LED Open Deluxe Acorn	6,500	70	24.3	$ 20.55 ~~$ 16.98~~	$ 4.38
LF-LED-150W-TD-BK-MW	150W LED Teardrop	12,500	150	52.0	$ 27.59 ~~$ 22.88~~	$ 4.38
LF-LED-50W-TDP-BK-MW	50W LED Teardrop Pedestrian	4,500	50	17.3	$ 22.38 ~~$ 18.51~~	$ 4.38

Filed pursuant to an Order dated May ____ in Case No. 17-0032-EL-AIR before the Utilities Commission of Ohio.

Issued:

Effective:

Issued by James P. Henning, President

220W LED SHOEBOX	220W LED Shoebox	18,500	220	76.3	$ 19.11 ~~$ 15.77~~	$ 5.34
LF-LED-50W-SL-BK-MW	LED 50W 4521 LUMENS STANDARD LED BLACK TYPE III 4000K	4,521	50	17.3	$ 7.23 ~~$ 5.81~~	$ 4.38
LF-LED-50W-SL-BK-MW	LED 50W 4521 LUMENS STANDARD LED BLACK TYPE III 4000K	4,521	50	17.3	$ 7.23 ~~$ 5.81~~	$ 4.38
LF-LED-70W-SL-BK-MW	LED 70W 6261 LUMENS STANDARD LED BLACK TYPE III 4000K	6,261	70	24.3	$ 7.21 ~~$ 5.79~~	$ 4.38
LF-LED-70W-SL-BK-MW	LED 70W 6261 LUMENS STANDARD LED BLACK TYPE III 4000K	6,261	70	24.3	$ 7.21 ~~$ 5.79~~	$ 4.38
LF-LED-110W-SL-BK-MW	LED 110W 9336 LUMENS STANDARD LED BLACK TYPE III 4000K	9,336	110	38.1	$ 8.18 ~~$ 6.61~~	$ 4.38
LF-LED-110W-SL-BK-MW	LED 110W 9336 LUMENS STANDARD LED BLACK TYPE III 4000K	9,336	110	38.1	$ 8.18 ~~$ 6.61~~	$ 4.38
LF-LED-150W-SL-BK-MW	LED 150W 12642 LUMENS STANDARD LED BLACK TYPE III 4000K	12,642	150	52.0	$ 10.83 ~~$ 8.83~~	$ 4.38
LF-LED-150W-SL-BK-MW	LED 150W 12642 LUMENS STANDARD LED BLACK TYPE III 4000K	12,642	150	52.0	$ 10.83 ~~$ 8.83~~	$ 4.38
LF-LED-150W-SL-IV-BK-MW	LED 150W 13156 LUMENS STANDARD LED TYPE IV BLACK 4000K	13,156	150	52.0	$ 10.83 ~~$ 8.83~~	$ 4.38
LF-LED-150W-SL-IV-BK-MW	LED 150W 13156 LUMENS STANDARD LED TYPE IV BLACK 4000K	13,156	150	52.0	$ 10.83 ~~$ 8.83~~	$ 4.38
LF-LED-220W-SL-BK-MW	LED 220W 18642 LUMENS STANDARD LED BLACK TYPE III 4000K	18,642	220	76.3	$ 12.28 ~~$ 10.05~~	$ 5.34
LF-LED-220W-SL-BK-MW	LED 220W 18642 LUMENS STANDARD LED BLACK TYPE III 4000K	18,642	220	76.3	$ 12.28 ~~$ 10.05~~	$ 5.34
LF-LED-280W-SL-BK-MW	LED 280W 24191 LUMENS STANDARD LED BLACK TYPE III 4000K	24,191	280	97.1	$ 15.11 ~~$ 12.42~~	$ 5.34
LF-LED-280W-SL-BK-MW	LED 280W 24191 LUMENS STANDARD LED BLACK TYPE III 4000K	24,191	280	97.1	$ 15.11 ~~$ 12.42~~	$ 5.34
LF-LED-50W-DA-BK-MW	LED 50W DELUXE ACORN BLACK TYPE III 4000K	5,147	50	17.3	$ 21.07 ~~$ 17.41~~	$ 4.38
LF-LED-70W-ODA-BK-MW	LED 70W OPEN DELUXE ACORN BLACK TYPE III 4000K	6,500	70	24.3	$ 20.55 ~~$ 16.98~~	$ 4.38
LF-LED-50W-AC-BK-MW	LED 50W ACORN BLACK TYPE III 4000K	5,147	50	17.3	$ 18.98 ~~$ 15.67~~	$ 4.38
LF-LED-50W-MB-BK-MW	LED 50W MINI BELL LED BLACK TYPE III 4000K MIDWEST	4,500	50	17.3	$ 17.90 ~~$ 14.76~~	$ 4.38
LF-LED-70W-BE-BK-MW	LED 70W 5508 LUMENS SANIBELL BLACK TYPE III 4000K	5,508	70	24.3	$ 22.80 ~~$ 18.86~~	$ 4.38
LF-LED-50W-TR-BK-MW	LED 50W TRADITIONAL BLACK TYPE III 4000K	3,303	50	17.3	$ 13.75 ~~$ 11.28~~	$ 4.38
LF-LED-50W-OT-BK-MW	LED 50W OPEN TRADITIONAL BLACK TYPE III 4000K	3,230	50	17.3	$ 13.75 ~~$ 11.28~~	$ 4.38
LF-LED-50W-EN-BK-MW	LED 50W ENTERPRISE BLACK TYPE III 4000K	3,880	50	17.3	$ 18.50 ~~$ 15.26~~	$ 4.38
LF-LED-150W-TD-BK-MW	LED 150W LARGE TEARDROP BLACK TYPE III 4000K	12,500	150	52.0	$ 27.59 ~~$ 22.88~~	$ 4.38
LF-LED-50W-TDP-BK-MW	LED 50W TEARDROP PEDESTRIAN BLACK TYPE III 4000K	4,500	50	17.3	$ 22.38 ~~$ 18.51~~	$ 4.38
LF-LED-220W-SB-BK-MW	LED 220W SHOEBOX BLACK TYPE IV 4000K	18,500	220	76.3	$ 19.11 ~~$ 15.77~~	$ 5.34
LF-LED-150W-BE-BK-MW	150W Sanibel	39,000	150	52.0	$ 22.80 ~~$ 18.86~~	$ 4.38
LF-LED-420W-SB-BK-MW	420W LED Shoebox	39,078	420	145.6	$ 28.51 ~~$ 23.65~~	$ 5.34
LF-LED-50W-NB-GY-MW	50W Neighborhood	5,000	50	17.3	$ 5.88 ~~$ 4.68~~	$ 4.38

LF-LED-50W-NBL-GY-MW	50W Neighborhood with Lens	5,000	50	17.3	$ 6.13 ~~$ 4.89~~	$ 4.38

II. POLES BILLING TYPE	DESCRIPTION	CHARGE PER UNIT PER MONTH
LP-12-C-PT-AL-AB-TT-BK-MW	12' C-Post Top- Anchor Base-Black	$ 15.91 ~~$ 14.54~~
LP-25-C-DV-AL-AB-TT-BK-MW	25' C-Davit Bracket- Anchor Base-Black	$ 41.86 ~~$ 38.65~~
LP-25-C-BH-AL-AB-TT-BK-MW	25' C-Boston Harbor Bracket- Anchor Base-Black	$ 42.32 ~~$ 39.08~~
LP-12-E-AL-AB-TT-BK-MW	12' E-AL - Anchor Base-Black	$ 15.91 ~~$ 14.53~~
15310-40FTALEMB-OLE	35' AL-Side Mounted-Direct Buried Pole	$ 26.94 ~~$ 24.79~~
15320-30FTALAB-OLE	30' AL-Side Mounted-Anchor Base	$ 20.75 ~~$ 19.04~~
15320-35FTALAB-OLE	35' AL-Side Mounted-Anchor Base	$ 20.19 ~~$ 18.52~~
15320-40FTALAB-OLE	40' AL-Side Mounted-Anchor Base	$ 24.97 ~~$ 22.95~~
POLE-30-7	30' Class 7 Wood Pole	$ 9.87 ~~$ 8.93~~
POLE-35-5	35' Class 5 Wood Pole	$ 10.73 ~~$ 9.72~~
POLE-40-4	40' Class 4 Wood Pole	$ 16.16 ~~$ 14.77~~
POLE-45-4	45' Class 4 Wood Pole	$ 16.75 ~~$ 15.31~~
15210-20BRZSTL-OLE	20' Galleria Anchor Based Pole	$ 14.24 ~~$ 12.98~~
15210-30BRZSTL-OLE	30' Galleria Anchor Based Pole	$ 16.83 ~~$ 15.39~~
15210-35BRZSTL-OLE	35' Galleria Anchor Based Pole	$ 48.42 ~~$ 44.75~~
LP-12-A-AL-AB-TT-BK-MW	MW-Light Pole-12' MH- Style A-Aluminum-Anchor Base-Top Tenon-Black	$ 9.65 ~~$ 8.72~~
LP-12-A-AL-DB-TT-BK-MW	MW-Light Pole-Post Top-12' MH- Style A-Alum-Direct Buried-Top Tenon-Black	$ 8.26 ~~$ 7.43~~
LP-15-A-AL-AB-TT-BK-MW	Light Pole-15' MH-Style A-Aluminum-Anchor Base-Top Tenon-Black	$ 9.93 ~~$ 8.98~~
LP-15-A-AL-DB-TT-BK-MW	Light Pole-15' MH-Style A-Aluminum-Direct Buried-Top Tenon-Black	$ 8.59 ~~$ 7.74~~
LP-20-A-AL-AB-TT-BK-MW	Light Pole-20' MH-Style A-Aluminum-Anchor Base-Top Tenon-Black	$ 10.41 ~~$ 9.43~~
LP-20-A-AL-DB-TT-BK-MW	Light Pole-20' MH-Style A-Aluminum-Direct Buried-Top Tenon-Black	$ 15.95 ~~$ 14.58~~
LP-25-A-AL-AB-TT-BK-MW	Light Pole-25' MH-Style A-Aluminum-Anchor Base-Top Tenon-Black	$ 12.33 ~~$ 11.21~~
LP-25-A-AL-DB-TT-BK-MW	Light Pole-25' MH-Style A-Aluminum-Direct Buried-Top Tenon-Black	$ 17.78 ~~$ 16.27~~
LP-30-A-AL-AB-TT-BK-MW	Light Pole-30' MH-Style A-Aluminum-Anchor Base-Top Tenon-Black	$ 14.59 ~~$ 13.31~~
LP-30-A-AL-DB-TT-BK-MW	Light Pole-30' MH-Style A-Aluminum-Direct Buried-Top Tenon-Black	$ 19.79 ~~$ 18.14~~
LP-35-A-AL-AB-TT-BK-MW	Light Pole-35' MH-Style A-Aluminum-Anchor Base-Top Tenon-Black	$ 16.84 ~~$ 15.40~~
LP-35-A-AL-DB-TT-BK-MW	Light Pole-35' MH-Style A-Aluminum-Direct Buried-Top Tenon-Black	$ 21.38 ~~$ 19.62~~
LP-12-B-AL-AB-TT-GN-MW	MW-Light Pole-12' MH- Style B Aluminum Anchor Base-Top Tenon Black Pri	$ 11.75 ~~$ 10.67~~
LP-12-C-PT-AL-AB-TT-BK-MW	MW-Light Pole-12' MH-Style C-Post Top-Alum-Anchor Base-TT-Black Pri	$ 15.91 ~~$ 14.54~~
LP-16-C-DV-AL-AB-TT-GN-MW	MW-LT Pole-16' MH-Style C-Davit Bracket-Alum-Anchor Base-TT-Black	$ 21.30 ~~$ 19.54~~
LP-25-C-DV-AL-AB-TT-BK-MW	MW-Light Pole-25' MH-Style C-Davit Bracket-Alum-Anchor Base-TT-Black Pri	$ 41.86 ~~$ 38.65~~

LP-16-C-BH-AL-AB-TT-GN-MW	MW-LT Pole-16' MH-Style C-Boston Harbor Bracket-AL-AB-TT-Black Pri	$ 17.07 ~~$ 15.61~~
LP-25-C-BH-AL-AB-TT-BK-MW	MW-LT Pole-25' MH-Style C-Boston Harbor Bracket-AL-AB-TT-Black Pri	$ 42.32 ~~$ 39.08~~
LP-12-D-AL-AB-TT-GN-MW	MW-LT Pole 12 Ft MH Style D Alum Breakaway Anchor Base TT Black Pri	$ 15.75 ~~$ 14.39~~
LP-12-E-AL-AB-TT-BK-MW	MW-Light Pole-12' MH-Style E-Alum-Anchor Base-Top Tenon-Black	$ 15.91 ~~$ 14.53~~
LP-12-F-AL-AB-TT-GN-MW	MW-Light Pole-12' MH-Style F-Alum-Anchor Base-Top Tenon-Black Prie	$ 17.05 ~~$ 15.60~~
15210-20BRZSTL-OLE	MW-15210-Galleria Anchor Base-20FT Bronze Steel-OLE	$ 14.24 ~~$ 12.98~~
15210-30BRZSTL-OLE	MW-15210-Galleria Anchor Base-30FT Bronze Steel-OLE	$ 16.83 ~~$ 15.39~~
15210-35BRZSTL-OLE	MW-15210-Galleria Anchor Base-35FT Bronze Steel-OLE	$ 48.42 ~~$ 44.75~~
15310-40FTALEMB-OLE	MW-15310-35FT MH Aluminum Direct Embedded Pole-OLE	$ 26.94 ~~$ 24.79~~
15320-30FTALAB-OLE	MW-15320-30FT Mounting Height Aluminum Achor Base Pole-OLE	$ 20.75 ~~$ 19.04~~
15320-35FTALAB-OLE	MW-15320-35FT Mounting Height Aluminum Achor Base Pole-OLE	$ 20.19 ~~$ 18.52~~
15320-40FTALAB-OLE	MW-15320-40FT Mounting Height Aluminum Achor Base Pole-OLE	$ 24.97 ~~$ 22.95~~
POLE-30-7	MW-POLE-30-7	$ 9.87 ~~$ 8.93~~
POLE-35-5	MW-POLE-35-5	$ 10.73 ~~$ 9.72~~
POLE-40-4	MW-POLE-40-4	$ 16.16 ~~$ 14.77~~
POLE-45-4	MW-POLE-45-4	$ 16.75 ~~$ 15.31~~

LATE PAYMENT CHARGE

Payment of the total amount due must be received in the Company's office by the due date shown on the bill. When not so paid, an additional amount equal to one and one-half percent (1.5%) of the unpaid balance is due and payable. The late payment charge is not applicable to unpaid account balances for services received from a Certified Supplier.

OWNERSHIP OF SERVICE LINES

Company will provide, install, own, operate and maintain the necessary facilities for furnishing electric service to the System defined in the agreement. If the customer requires the installation of a System at a location which requires the extension, relocation, or rearrangement of the Company's distribution system, the customer shall, in addition to the monthly charge, pay the Company on a time and material basis, plus overhead charges, the cost of such extension, relocation, or rearrangement, unless in the judgment of the Company no charge should be made. An estimate of the cost will be submitted for approval before work is carried out.

The Company shall erect the service lines necessary to supply electric energy to the System within the limits of the streets and highways or on property as mutually agreed upon by the Company and the customer. The customer shall assist the Company, if necessary, in obtaining adequate written easements covering permission to install and maintain any service lines required to serve the System.

The Company shall not be required to pay for obtaining permission to trim or re-trim trees where such trees interfere with lighting output or with service lines or wires of the Company used for supplying electric energy to the System. The customer shall assist the Company, if necessary, in obtaining permission to trim trees where the Company is unable to obtain such permission through its own best efforts.

TERMS OF SERVICE:

Service under this rate schedule shall be for a minimum initial term of ten (10) years from the commencement of service and shall continue thereafter until terminated by either party by written notice sixty (60) days or to termination. Upon early termination of service under this schedule, the customer shall pay an amount equal to the remaining monthly lease amount for the term of contract, applicable Customer Charges and removal cost of the facilities.

Special Provisions:

1. The customer shall execute a contract on the Company's standard filed contract form for service under this rate schedule.
2. Where the Company provides a LED fixture or pole type other than those listed above, the monthly charges, as applicable shall be computed as follows:

   I. Fixture
      a. Fixture Charge: Based on the Company's average installed cost including overhead/loadings, applicable property tax, applicable income tax, depreciation and rate of return.
      b. Maintenance Charge: Based on the Company's average cost of performing maintenance on lighting equipment.

   II. Pole
      a. Pole Charge: Based on the Company's average installed cost including overhead/loadings, applicable property tax, applicable income tax, depreciation and rate of return.

3. The customer shall be responsible for the cost incurred to repair or replace any fixture or pole which has been willfully damaged. The Company shall not be required to make such repair or replacement or to payment by the customer for damage.

4. kWh consumption for Company-owned fixtures shall be estimated in lieu of installing meters. Monthly kWh estimates will be made using the following formula:
   kWh = Unit Wattage x (4160 hours per year / 12 months) / 1,000

5. kWh consumption for customer-owned fixtures shall be metered. Installation of customer-owned lighting facilities shall be provided for by the customer.

6. No Pole Charge shall be applicable for a fixture installed on a company-owned pole which is utilized for other general electrical distribution purposes.

7. The Company will repair or replace malfunctioning lighting fixtures maintained by the Company

8. For a fixture type restricted to existing installations and requiring major renovation or replacement, the fixture shall be replaced by an available similar non-restricted LED fixture of the customer's choosing and the customer shall commence being billed at its appropriate rate.

9. The customer will be responsible for trimming trees and other vegetation that obstruct the

light output from fixture(s) or maintenance access to the facilities.

10. All new leased LED lighting shall be installed on poles owned by the Company.

11. Alterations to leased LED lighting facilities requested by the customer after date of installation (i.e. redirect, install shields, etc.), will be billed to the customer in accordance with the Company's policy.

12. Service for street or area lighting is normally provided from existing distribution facilities. Where suitable distribution facilities do not exist, it will be the customer's responsibility to pay for necessary additional facilities.

13. For available LEDs, the customer may opt to make an initial, one-time payment of 50% of the installed cost of fixtures rated greater than 200 Watts and/or poles other than standard wood poles, to reduce the Company's installed cost, therefore reducing their monthly rental rates for such fixtures and poles. If a customer chooses this option, the monthly fixture and/or pole charge shall be computed as the reduced installed cost times the corresponding monthly percentage in 2.I.(a) and/or 2.II above.

SERVICE REGULATIONS

The supplying of, and billing for, service and all conditions applying thereto, are subject to the jurisdiction of the Utilities Commission of Ohio and to the Company's Service Regulations currently in effect, as filed with the Utilities Commission of Ohio.

DUKE ENERGY OHIO EXHIBIT____

BEFORE

THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Duke Energy Ohio, Inc., for an Increase in Electric Distribution Rates.	)))	Case No. 17-32-EL-AIR
In the Matter of the Application of Duke Energy Ohio, Inc., for Tariff Approval.	)))	Case No. 17-33-EL-ATA
In the Matter of the Application of Duke Energy Ohio, Inc., for Approval to Change Accounting Methods.	)))	Case No. 17-34-EL-AAM

DIRECT TESTIMONY OF

DONALD L. SCHNEIDER, JR.

ON BEHALF OF

DUKE ENERGY OHIO, INC.

________ Management policies, practices, and organization

________ Operating income

________ Rate Base

________ Allocations

________ Rate of return

________ Rates and tariffs

___X___ Other: Overview

March 16, 2017

TABLE OF CONTENTS

Page

I. INTRODUCTION 1

II. BACKGROUND ON DUKE ENERGY OHIO'S AMI ENVIRONMENT 3

III. CURRENT STATE OF THE COMPANY'S AMI ENVIRONMENT 8

IV. FUTURE STATE OF THE COMPANY'S AMI ENVIRONMENT 11

V. BENEFITS OF THE PROPOSED AMI TRANSITION 14

VI. COSTS OF THE PROPOSED AMI TRANSITION 17

VII. CONCLUSION 18

Attachment:

DLS-1: Ohio AMI Transition Analysis

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Donald L. Schneider, Jr., and my business address is 400 South Tryon Street, Charlotte, North Carolina 28202.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by Duke Energy Business Services LLC (DEBS), as General Manager, Advanced Metering Infrastructure (AMI) Program Management. DEBS provides various administrative and other services to Duke Energy Ohio, Inc., (Duke Energy Ohio or Company) and other affiliated companies of Duke Energy Corporation (Duke Energy).

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.

A. I received a Bachelor of Science Degree in Electrical Engineering from the University of Evansville in 1986. After graduation, I was employed by Duke Energy Indiana, Inc., (then known as Public Service Indiana) as an electrical engineer. Throughout my career, I have held various positions of increasing responsibility in the areas of engineering and operations, including distribution planning, distribution design, field operations, and capital budgets. Prior to my current role, I was General Manager, Midwest Premises Services, responsible for managing all of Duke Energy's Midwest Premises Services and Meter Reading departments. I was promoted to my current position in 2008.

Q. ARE YOU A REGISTERED PROFESSIONAL ENGINEER?

A. Yes. I have been registered as a professional engineer with the State Board of Registration for Professional Engineers in the state of Indiana since 1995.

Q. PLEASE DESCRIBE YOUR DUTIES AS GENERAL MANAGER, AMI PROGRAM MANAGEMENT.

A. As General Manager, AMI Program Management, my primary responsibility is managing the project execution of AMI-related projects and AMI systems operations for all Duke Energy jurisdictions. Prior to the merger between Duke Energy and Progress Energy, I was responsible for managing the project execution for both AMI and Distribution Automation (DA) deployments for all legacy Duke Energy jurisdictions.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE PUBLIC UTILITIES COMMISSION OF OHIO?

A. Yes. I have provided written testimony in several prior Duke Energy Ohio SmartGrid Rider proceedings.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THESE PROCEEDINGS?

A. I will begin by providing a background on Duke Energy Ohio's AMI. Then I will describe the current state of the Company's AMI environment and some challenges to that environment and explain how the Company plans to address those challenges. Finally, I will discuss and quantify the benefits and costs associated with the Company's AMI proposal.

II. BACKGROUND ON DUKE ENERGY OHIO'S AMI ENVIRONMENT

Q. WHAT IS AMI?

A. AMI involves a two-way communication network between the utility and its meters that is used to provide operational efficiencies and to enable customer services not possible with metering programs involving walk-by or one-way communications network (drive-by) readings.

Q. DESCRIBE THE CURRENT AMI ENVIRONMENT FOR DUKE ENERGY OHIO.

A. Today, the Company has two AMI metering environments, which I will describe as the node and mesh environments. The node environment is composed of Echelon electric meters, Badger gas communication modules, and communication nodes that were originally manufactured by Ambient, which has since been acquired by Ericsson. The mesh environment is composed of Itron electric meters, Itron gas communications modules, Itron range extenders, and Cisco Connected Grid Routers (CGRs).

Q. HOW DO COMMUNICATIONS WORK IN THE AMI NODE ENVIRONMENT?

A. Echelon electric meters communicate with nodes via two-way, low-voltage power-line carrier technology, and Badger gas communication modules communicate with nodes via one-way wireless radiofrequency signals. Each node is equipped with a cellular modem that allows for data and signals to be sent to and received from the node environment. The devices within the node environment are managed by head-end control systems. The Echelon Networked Energy Services (Echelon NES) head-end system manages Echelon AMI meters, the Badger Read Center manages the gas communication modules, and the Ambient Network Management System (Ambient NMS) manages the communication nodes.

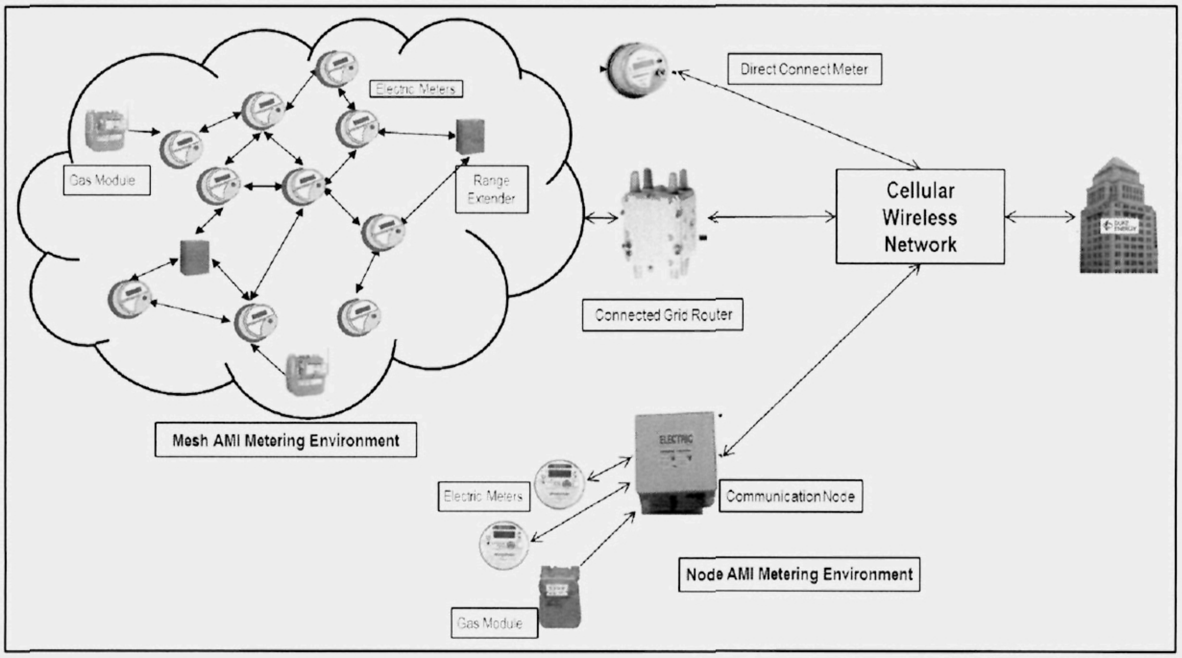
Q. HOW DO COMMUNICATIONS WORK IN THE AMI MESH ENVIRONMENT?

A. The mesh environment is so described because Itron electric meters communicate with one another and CGRs using wireless radiofrequency signals with IPv6 communication protocol, effectively forming a meshed communication network across a geographic area. Itron gas communication modules communicate with Itron electric AMI meters using a separate wireless radiofrequency signal that uses a communication protocol known as ZigBee, and that data is then carried over the mesh network to CGRs. Each CGR is equipped with a cellular modem that allows for data and signals to be sent to and received from the mesh environment. Itron range extenders are used in the mesh environment to help extend the wireless radiofrequency signal when necessary. The Itron OpenWay head-end system manages the Itron AMI meters and the Cisco Network Management System (CGNMS) manages the CGRs.

Figure 1 below illustrates Duke Energy Ohio's overall AMI network architecture. The mesh environment is depicted in the top left corner of the image. It shows gas modules communicating with electric meters and the electric meters communicating with one another and the CGR wirelessly. It then shows how the

CGR communicates through the cellular wireless network. The node environment is portrayed at the bottom of the image. It shows electric meters and gas modules communicating directly to a communication node, which also then communicates through the cellular wireless network. Finally, at the top of Figure 1 there is a depiction of an Itron Direct Connect electric AMI meter, which communicates directly over the cellular wireless network using a built-in cellular radio. The Direct Connect meters are used as an alternative for situations in which an Itron mesh electric meter at a specific premises cannot connect reliably with other mesh network meters in that area and it is cost prohibitive to extend the mesh utilizing Itron range extenders.

Figure 1:



Q. WHAT IS THE MAJOR DIFFERENCE BETWEEN THE AMI NODE AND MESH METERING ENVIRONMENTS?

A. Since the node environment utilizes low-voltage power-line carrier technology that requires installation of communication nodes at power transformers associated with the downstream electric meters, individual communication nodes only support about five electric AMI meters on average. In comparison, the mesh environment is typically designed so that 500 to 1,000 meters can communicate with a single CGR.

Q. WHAT CUSTOMER CLASSES ARE SERVED BY THE SEPARATE AMI ENVIRONMENTS?

A. The node environment serves most of Duke Energy Ohio's residential electric and residential combination gas and electric customers. The mesh environment serves most of the Company's commercial/industrial customer classes, as well as some residential customers. The mesh environment also serves some combination gas and electric customers in both the residential and commercial/industrial customer classes.

Q. WHY IS THERE A DIFFERENCE IN AMI ENVIRONMENTS BASED ON CUSTOMER TYPE?

A. Beginning in 2009, the Company installed the AMI node environment technology with electric meters manufactured by Echelon. Echelon began manufacturing AMI meters with the Form 2s Class 200 meter type, which is primarily used by residential customers. Echelon had planned to continue development of AMI electric meters for all other meter forms but the market never developed in North

America for this technology so they did not start manufacturing other meter forms. Therefore, the majority of Duke Energy Ohio's residential electric customers are served by an Echelon meter. After analyzing other AMI environments, the Company standardized on the Itron AMI mesh environment and installed electric AMI meters manufactured by Itron for most of its commercial/industrial electric customers and any additional customers who could not be served by an Echelon Form 2s Class 200 AMI meter. In some cases, such as when a customer requires demand readings, Duke Energy Ohio installed Itron AMI meters for residential electric customers as well.

Q. WHERE IS DUKE ENERGY OHIO'S AMI METER DATA STORED?

A. Duke Energy Ohio's AMI meter data is stored in two separate meter data management systems, which are responsible for processing and storing vast amounts of collected meter data. For the node environment, interval AMI Customer Energy Usage Data (CEUD) is stored in Oracle's first-generation meter data management system called the Energy Data Management System (EDMS). For the mesh environment, interval AMI CEUD is stored in Oracle's second-generation meter data management system, which Duke Energy Ohio calls MDM. Data in EDMS and MDM is used by Duke Energy Ohio's billing system known as the Customer Management System (CMS) for billing functions.

Q. DESCRIBE THE DIFFERENCES BETWEEN EDMS AND MDM WITH REGARD TO HOW THEY PROCESS INTERVAL AMI CEUD.

A. MDM provides <u>scalable</u> Validation, Estimation, & Editing (VEE) functionality for interval AMI CEUD. EDMS relies on the CMS system to provide scalable

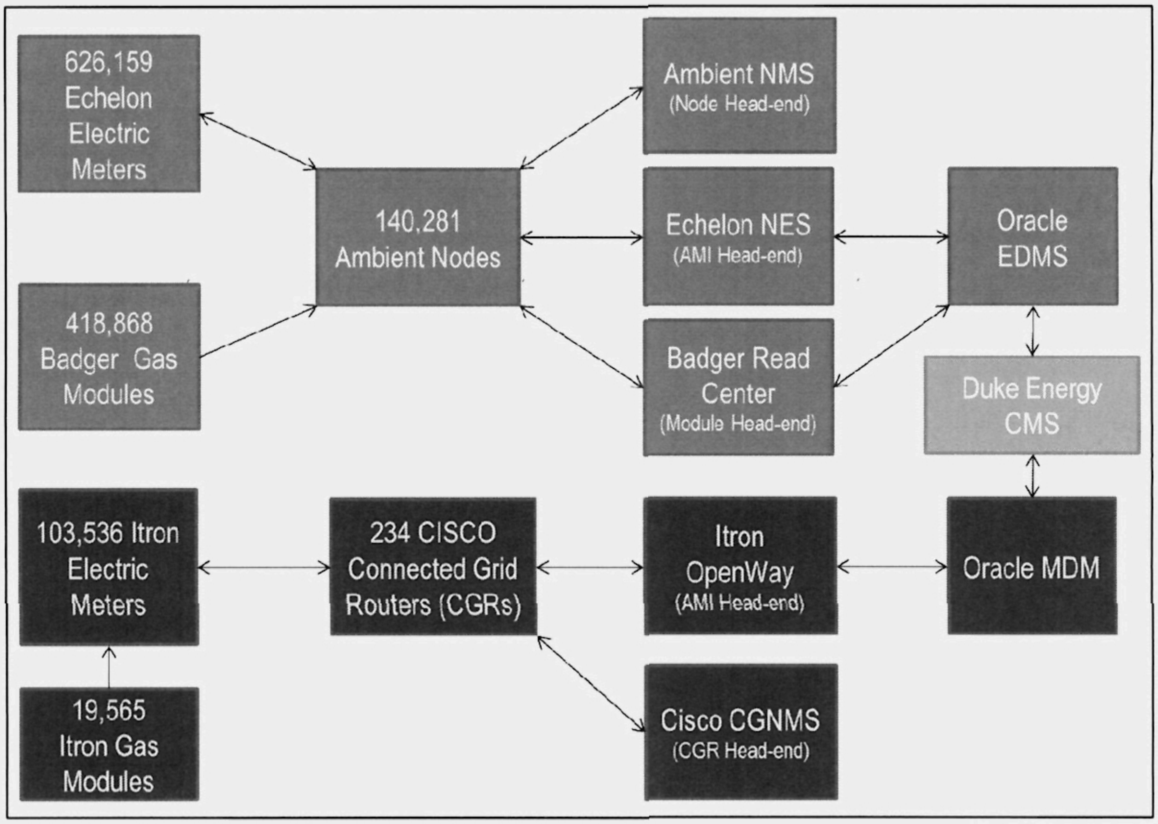
VEE functionality for interval AMI CEUD. Interval AMI CEUD coming out of the MDM system is considered billing-quality interval AMI CEUD, while interval AMI CEUD that comes out of EDMS is not considered billing-quality interval AMI CEUD.

III. CURRENT STATE OF THE COMPANY'S AMI ENVIRONMENT

Q. WHAT IS THE CURRENT BREAKDOWN OF DEVICES DEPLOYED ACROSS DUKE ENERGY OHIO'S TWO AMI METERING ENVIRONMENTS?

Figure 2 provides a visual representation of this device breakdown as of January 31, 2017. It also displays the respective head-ends, network management systems, and meter data management systems for the two AMI metering environments.

Figure 2:



Using figures as of January 31, 2017, 626,159 Echelon electric meters and 418,868 Badger gas communication modules communicate directly with 140,281 communication nodes in the node environment. As of the same date, 103,536 Itron electric meters communicate with 234 CGRs and 19,565 Itron gas communication modules communicate through the Itron electric meters to the CGRs in the mesh environment.

Q. IS DUKE ENERGY OHIO FACING ANY ISSUES WITH ITS AMI METERING ENVIRONMENTS?

A. In Duke Energy Ohio's AMI node environment, Ericsson is no longer manufacturing communication nodes. Duke Energy Ohio's inventory of nodes is therefore depleting beyond the desired stocking level with each device failure. Additionally, communication nodes have been failing at a higher rate than expected.

Q. WHAT IS DUKE ENERGY OHIO DOING TO ADDRESS THIS ISSUE IN THE NEAR TERM?

A. Duke Energy Ohio has begun a business continuity effort for the years 2017-2018 to remove approximately 23,700 communication nodes currently deployed in the field, in order to restore inventory back to desired stocking levels. Removing these nodes – transitioning from the AMI node environment to the mesh environment – requires expanding the footprint of the Company's existing mesh environment; consequently, the Company will replace approximately 80,000 Echelon electric meters and 48,800 Badger gas communication modules with Itron electric meters and Itron gas communication modules. Upon completion of the effort, the AMI node environment will contain approximately 546,000 Echelon electric meters, 370,000 Badger gas communication modules, and 120,000 communication nodes remaining in the field.

Q. WHAT IS THE ESTIMATED TIMELINE TO ADDRESS THIS NODE ISSUE AS DESCRIBED ABOVE?

A. The Company began expanding the mesh environment footprint in early 2017. This business continuity work is expected to conclude by the end of 2018.

IV. <u>FUTURE STATE OF THE COMPANY'S AMI ENVIRONMENT</u>

Q. PLEASE DESCRIBE ANY MAJOR HARDWARE UPGRADES REQUIRED FOR DUKE ENERGY OHIO'S AMI METERING ENVIRONMENTS IN THE COMING YEARS.

A. Verizon, the Company's primary cellular provider, has alerted the Company that their second generation (2G) and third generation (3G) cellular networks will be discontinued, or sunset, in 2022. Verizon originally planned to discontinue these networks earlier than 2022, but through Duke Energy's partnership with Verizon, it was agreed to extend the sunset to 2022. No further extension is expected. The 2G and 3G sunset will require Duke Energy Ohio to completely transition all of its communication devices – whether they are nodes or CGRs – to the Verizon 4G network prior to end of 2022. The 2G and 3G sunset applies to all users of the Verizon cellular network, including anyone using Verizon's personal cellular services.

Q. HOW DOES VERIZON'S DECISION TO DISCONTINUE SUPPORTING THE 2G AND 3G SYSTEMS AFFECT THE COMPANY'S AMI MESH ENVIRONMENT?

A. Cisco has already released a 4G CGR. Duke Energy Ohio will need to upgrade 233 of its current 234 CGRs to 4G communications technology before Verizon ends its support. Upgrading a CGR involves swapping out the 3G communication card for a 4G communication card and replacing the CGR's antennas.

Q. HOW DOES VERIZON'S DECISION TO DISCONTINUE SUPPORTING THE 2G AND 3G SYSTEMS AFFECT THE COMPANY'S AMI NODE ENVIRONMENT?

A. The loss of support for 2G and 3G is a significant long-term challenge for Duke Energy Ohio's node environment due to the sheer volume of communication nodes. As I mentioned previously, there are far more communication nodes installed since the ratio of meters to nodes is so much lower than the ratio of meters to CGRs. The Company would need to upgrade at least 140,000 nodes. Adding to the challenge, I also mentioned that the communication nodes are no longer being manufactured, but the Company could work with the vendor to source a replacement 4G modem and antenna that could be retrofitted into the node. Upgrading a node to the 4G network is more complicated than the upgrade process for CGRs. The node design incorporates a cellular modem chip that is soldered onto the communication node's motherboard; so, it is a more delicate and labor-intensive process than what is required for CGRs, which incorporates a cellular modem card design.

Q. ARE THERE ANY OTHER LONG-TERM CHALLENGES IN SUPPORTING THE AMI NODE ENVIRONMENT?

A. Since the Company began its AMI deployment, Ambient has been purchased by Ericsson and Duke Energy Ohio remains the only customer utilizing the specific communication nodes that were manufactured by Ambient. While Echelon has had success in other countries, Duke Energy Ohio remains the only North American company utilizing the Echelon AMI nodal solution. The failure of nodes, the lack of North American adoption, and the fact that the nodes are no longer manufactured are all factors that present risk to Duke Energy Ohio and its customers. Even if the Company were to upgrade all its communication nodes to the Verizon 4G network, the node failure issue would not be resolved. The nodes are already approaching the end of their expected 10 year useful lives. The Company would need to continue removing nodes and switching customers to the mesh environment, just for business continuity beyond 2018. The Company has a support contract in place for node repair but, with the higher than expected failure rates, Ericsson is not able to keep up with the repairs.

Q. HOW DOES DUKE ENERGY OHIO PLAN TO ADDRESS THE LONG-TERM CHALLENGE WITH THE NODE ENVIRONMENT?

A. Rather than upgrading the communication nodes to 4G and perpetuating the support concerns the Company is already confronting in the near-term, the Company proposes to transition entirely from the AMI node environment to the AMI mesh environment. The estimated total cost of the Ohio AMI Transition effort is approximately $143.4 million, most of which will be capital costs. The work would begin in 2019 and conclude by the end of 2022. Attachment DLS-1 shows the estimated costs of ownership/operation and a net present value (NPV) comparison of the Ohio AMI Transition effort versus retaining the node environment. I will discuss the benefits and costs of the Ohio AMI Transition in depth over the next two sections of testimony.

V. BENEFITS OF THE PROPOSED AMI TRANSITION

Q. WHAT ARE THE OVERARCHING BENEFITS OF COMPLETELY TRANSITIONING FROM THE NODE TO THE MESH AMI METERING ENVIRONMENT?

A. The Ohio AMI Transition would allow Duke Energy Ohio to avoid approximately $91.2 million in total costs to upgrade its AMI node environment to 4G, as shown on Attachment DLS-1. Having all meters in the Itron AMI mesh environment would mean that the Company would have billing-quality interval AMI CEUD for all its electric customers with AMI meters because Itron meters necessarily feed data into MDM rather than EDMS.

Going forward, support for the mesh environment will be significantly less costly – in terms of both avoided costs and reduced costs – than the cost of continuing to support the node environment. Attachment DLS-1 shows that the 20-year NPV of costs associated with keeping the node environment in place is approximately $190.3 million, while the 20-year NPV of costs associated with the Ohio AMI Transition is approximately $134.7 million.

Finally, the Ohio AMI Transition will better serve Duke Energy Ohio's customers, since we will be able to offer the full suite of Enhanced Basic Services described in the testimony of Company witness Dr. Alexander (Sasha) J. Weintraub.

Q. WHAT IS THE BENEFIT OF AVOIDING THE 4G UPGRADE COSTS FOR THE COMMUNICATION NODES?

A. Duke Energy Ohio would face significant costs to upgrade its communication nodes to 4G, an unavoidable upgrade if it continues using the AMI node environment. The Company estimates that it would cost approximately $91.2 million for the project, which would begin in 2019 and end in 2021. The Ohio AMI Transition will allow Duke Energy Ohio to avoid those costs by installing 4G CGRs and Itron AMI meters.

Q. WHAT IS THE BENEFIT OF HAVING BILLING-QUALITY INTERVAL AMI CEUD?

A. In his testimony in this case, Company witness Scott B. Nicholson explains the Company's plans to enhance the customer electricity experience and promote competition in Ohio. Mr. Nicholson describes the Company's current status and, consistent with Commission directive, plans for providing interval CEUD to CRES providers. The Ohio AMI Meter Transition will allow Duke Energy Ohio to pursue a comprehensive solution, since the electric Itron meters in MDM will have billing-quality interval AMI CEUD going forward. Once new meters are in place and the data can be certified as billing quality, the data can be provided to CRES providers. This, in turn, will allow the CRES providers to offer new products and services to allow customers to use the data to their best advantage.

Q. WHAT IS THE BENEFIT OF NO LONGER SUPPORTING THE NODE ENVIRONMENT?

A. If Duke Energy Ohio does not receive necessary regulatory approval and has to continue with the node environment instead of undertaking the Ohio AMI Meter Transition, the Company estimates it would spend $1 million in 2019 just to develop a long-term solution to address the node failure issue. At that point, the business continuity effort will have concluded, but the node failure rate is expected to continue increasing.

Besides addressing the node failure issue, the future costs to support the node environment and its related systems would be avoided or reduced if the Company pursues the Ohio AMI Meter Transition. Duke Energy Ohio would spend less in annual on-going operation and maintenance (O&M) costs if it transitions the entire node environment to the mesh environment. That includes reduced costs for monthly cellular contracts and for managing communication node failures, as well as avoided costs for system upgrades and vendor maintenance.

Q. WHAT IS THE BENEFIT OF BEING ABLE TO OFFER ENHANCED BASIC SERVICES THROUGH THE MESH ENVIRONMENT?

A. With all of its AMI meters part of the mesh environment, Duke Energy Ohio would be able to offer the full suite of Enhanced Basic Services described in the testimony of Company witness Weintraub, subject to any necessary regulatory approvals.

VI. COSTS OF THE PROPOSED AMI TRANSITION

Q. WHAT IS THE ESTIMATED COST AND TIMELINE FOR THE OHIO AMI TRANSITION?

A. Duke Energy Ohio estimates that the Ohio AMI Transition will cost approximately $143.4 million, most of which will be capital costs. Attachment DLS-1 shows a breakdown of project costs between electric, gas, communications, and software by capital and O&M. The deployment would begin in 2019 and conclude in 2022.

Q. WHAT PORTION OF THE TOTAL OHIO AMI METER TRANSITION COSTS IS FOR ELECTRIC SERVICE AND GAS SERVICE?

A. About $106.5 million of total costs for the Ohio AMI Transition are attributable to electric service. Just under $36.9 million of total costs are attributable to gas service.

Q. HOW DO THE COSTS OF THE BUSINESS CONTINUITY EFFORT AND OHIO AMI TRANSITION COMPARE TO THE BENEFITS OF AVOIDING THE NODE ENVIRONMENT COSTS?

A. As mentioned earlier, Attachment DLS-1 shows that the NPV of costs to maintain the node environment from 2019 through 2038 is $190.2 million versus $134.7 million to pursue the Ohio AMI Transition over the same time period. The 20-year NPV analysis was used in alignment with typical internal cost analyses.

VII. CONCLUSION

Q. WAS ATTACHMENT DLS-1 PREPARED BY YOU OR UNDER YOUR SUPERVISION?

A. Yes.

Q. IS THE INFORMATION CONTAINED IN ATTACHMENT DLS-1 TRUE AND ACCURATE TO THE BEST OF YOUR KNOWLEDGE AND BELIEF?

A. Yes.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes.

Total (All Electric and Gas Costs)

Discount Rate (DEO before tax): 7.73%

		NPV	TOTAL (2019-2038)
	Continue Node Environment		
O&M	4G Communication Node Upgrade	**78,694,632**	91,162,500
	EDMS to MDM Conversion	**14,140,117**	15,800,000
	Long-term Communication Node Solution	**928,247**	1,000,000
	NES Headend Upgrades	**5,123,981**	10,589,310
	Monthly Cellular Cost	**15,487,719**	33,216,510
	Communication Device Failures	**49,779,269**	118,383,860
	Vendor Maintenance	**26,129,276**	56,039,456
		190,283,240	***326,191,636***
	Transition to Mesh Environment		
Capital	Ohio AMI Transition	**123,299,685**	143,398,848
O&M	Monthly Cellular Cost	**6,418,755**	14,237,970
	Communication Device Failures	**372,557**	930,746
	Vendor Maintenance	**4,615,356**	10,644,198
		134,706,353	**169,211,762**

Electric Costs Only

Discount Rate (DEO before tax): 7.73%

		NPV	TOTAL (2019-2038)
	Continue Node Environment		
O&M	4G Communication Node Upgrade	**69,487,360**	80,496,488
	EDMS to MDM Conversion	**8,625,471**	9,638,000
	Long-term Communication Node Solution	**566,230**	610,000
	NES Headend Upgrades	**5,123,981**	10,589,310
	Monthly Cellular Cost	**9,447,509**	20,262,071
	Communication Device Failures	**43,955,094**	104,532,948
	Vendor Maintenance	**19,073,436**	40,906,796
		156,279,082	**267,035,613**
	Transition to Mesh Environment		
Capital	Ohio AMI Transition	**91,584,689**	106,505,554
			-
O&M	Monthly Cellular Cost	**3,915,440**	8,685,162
	Communication Device Failures	**328,968**	821,849
	Vendor Maintenance	**3,528,090**	8,141,157
		99,357,188	**124,153,722**

Gas Costs Only

Discount Rate (DEO before tax): 7.73%

		NPV	TOTAL (2019-2038)
	Continue Node Environment		
O&M	4G Communication Node Upgrade	**9,207,272**	10,666,013
	EDMS to MDM Conversion	**5,514,645**	6,162,000
	Long-term Communication Node Solution	**362,016**	390,000
	NES Headend Upgrades	**-**	-
	Monthly Cellular Cost	**6,040,211**	12,954,439
	Communication Device Failures	**5,824,174**	13,850,911
	Vendor Maintenance	**7,055,839**	15,132,659
		34,004,158	**59,156,021**
	Transition to Mesh Environment		
Capital	Ohio AMI Transition	**31,714,995**	36,893,294
			-
O&M	Monthly Cellular Cost	**2,503,314**	5,552,808
	Communication Device Failures	**43,589**	108,896
	Vendor Maintenance	**1,087,267**	2,503,044
		35,349,165	**45,058,042**